U.S. DEPARTMENT OF THE INTERIOR

U.S. GEOLOGICAL SURVEY

UNDISCOVERED PETROLEUM OF SOUTHERN SOUTH AMERICA

by

John Kingston[1]

Open-File Report 94-559

This report is preliminary and has not been reviewed for conformity with U.S. Geological Survey editorial standards and stratigraphic nomenclature.

1 Palo Alto, CA (retired)

Table of Contents

Undiscovered Petroleum of Southern South America

Page

List of Figures iii
List of Tables xvii
Abstract 1
I. Introduction 1
A. Regions of Study 1
B. Purpose and Method of Study 1
II. Brazilian Craton Region 4
A. The Rifted Continental Margin Basins 7
1. General 7
2. Individual Basin Assessment 16
a. Southern Rifted Continental Margins 16
1) Campos 16
2) Santos 53
3) Pelotas 59
4) Espirito Santo..63
5) Bahia Sul..74
6) Sergipe-Alagoas..79
b. Northeastern Rifted and Wrenched Margin 89
1) Potiguar..92
2) Caera..101
3) Barreirinhas..109
4) Para-Maranhoa..117
5) Foz do Amazonas..123
6) Guyana..132
B. Brazilian Interior Rift Basins 138
1. Recancavo 138
2. Tucano and Jatoba 144
3. Tacutu 152
C. Brazilian Interior Sag Basins 157
1. Solimoes 158
2. Amazonas 168
3. Parnaiba 175
4. Parana 186
5. Chaco 194
D. Subandian Foreland 194
1. Acre 194
III. Patagonian Accreted Region 201
A. Foreland/Interior Rift Basins 201
1. Magallanes 203
2. Malvinas 212
3. Malvinas Plateau 218
4. Malvinas Trough 221
5. San Jorge 223
6. Colorado 234
7. Salado 239
8. Nirihuah 244
9. Neuquen 244

10. Cuyo....................................253
B. Rifted Continental Margin Basin 260
1. East Patagonia 260
IV. Subandian Basins 267
A. Foreland Basins 269
1. Pampeanas 270
2. Oran 274
3. Santa Cruz-Tarija 284
4. Beni 294
5. Madre de Dios 300
6. Ucayali 304
7. Maranon-Oriente-Putumayo 314
B. Overthrust and Fold Belt Basins 329
1. Huallaga 329
2. Santiago 336
C. Andean Intra-Arc Basin 338
1. Altiplano 339
D. Pacific Coastal Forearc and Intra-arc Basins 344
1. Puruvian and Ecuadorian Coastal Basins 344
a. Forearc Basins 345
1) Talara....................348
2) Progreso....................355
3) Esmeraldas-Caraquez....................363
4) Trujillo....................366
5) Lima....................371
6) Mellenda-Tarapaca....................371
b. Intra-arc Basins 374
1) Lancones....................374
2) Manibi....................376
3) Borbon....................378
4) Sechura....................380
5) Salaverry....................383
6) Pisco....................386
7) Moquegua-Tamaruga....................390
8) Salar de Atacama (Antofagasta)...........392
2. South Chilean Coastal Basins 393
a. Forearc Basins 393
1) Central Chilean 395
2) Madre de Dios....................403
3) Diego Ramirez....................406
b. Coastal Intra-arc Basins 409
1) Osorno-Llanquehue....................409
2) Temuco....................411
3) Carico....................412
4) Penas....................413
V. Summary and Conclusions 415
Bibliography 428
Appendix A 438

List of Figures

Page

1. Map showing the five principal geotectonic regions of South America. 3

2. Map showing principal sedimentary basins of the Brazilian Shield area. 5

3. Map of the Brazilian Atlantic margin. 9

4. Structure map on top of acoustic basement in the Campos basin. 10

5. Section showing tecto-sedimentary evolution of the Brazilian continental margin in the Campos basin. 12

6. Geologic strike section through the Brazilian rifted continental marginal basins. 14

7. Index map of the Campos basin. 18

8. Stratigraphic column of Campos basin shelf. 19

9. Geochemical profiles of various parameters as observed in through the oil-generating zone of Wildcat R-JS-76 of central Campos basin. 21

10. Subsidence rates along the Brazilian continental margin. 23

11. Campos basin oil fields and production systems, 1988. 26

12. Graph showing the relation of the quantity of discovered oil and gas against the number of wildcat drilled in the Campos basin. 28

13. Structural-stratigraphic section through the Badejo high of the Campos basin. 31

14. Dip seismic section through the Campos basin. 34

15. Isopach maps of Cretaceous combined sandstone thicknesses, in meters, on the Campos basin shelf. 35

16. Stratigraphic column of the Tertiary section of the Albacora Field of the Campos basin. 37

17. Paleogeography of the Oligocene turbidite system in Campos basin. 38

18. Location map of the Albacora and Marlim fields and 3-D surveys in deep water (modified from Souza et al, 1989). 40

19. A 3-D seismic dip section across the Albacora Field and its interpretation. 41

20. Seismic profiles (A and B) across the Marlin and Barracuda complex of fields. 42

21. A 3-D seismic strike section through the Marlim field showing its interpretation and the anomalously high reflection amplitude at the top interface of an oil-filled Eocene turbidite. 43

22. Maps of the Marlim-Barracuda field complexes showing how clearly the fields, particularly the Marlim complex, are outlined by high amplitude effects at the top of the main Oligocene turbidites. 44

23. Map showing prospective deep-water areas of the Campos basin being considered for future drilling. 46

24. Seismic section A-A′ indicating eastward extension of reservoirs (cross-hatched) of Campos basin identified in wildcat 1-RJS-366 and independent structure to southeast. 47

25. Seismic section B-B′ in the Albacora area showing reservoirs (cross-hatched) of Campos basin and emphasizing synrift targets. 48

26. Seismic section C-C′ in wildcat 1-RJS-490 area of Campos basin showing interpreted reservoirs (cross-hatched) including possible (OLIG) Oligocene lowstand fan system. 49

27. Seismic section D-D at extreme south of Campos basin showing complex structure and in particular faults which cut Miocene reservoir horizons (cross-hatched) and may serve as conduits for oil migration. 50

28. Index map of the Santos basin showing position of gas and oil fields, geologic sections and wildcats. 54

29. Stratigraphic chart of Santos basin. 55

30. Geologic section in southern portion of Santos basin. 56

31. Geologic section of central portion of Santos basin. 57

32. Structure map of the Pelotas basin, Brazil. 60

33. Geologic section across Pelotas basin. 61

34. Structural framework map of Espirito Santo basin. 64

35. Geologic cross-section across Espirito Basin. 65

36. Stratigraphic column of Espirito Santo Basin. 66

37. Schematic strike and dip geologic sections in the Espirito Santo basin. 68

38. Maps showing areal distribution and accumulation models for the three main shelf plays of the Espirito Santo basin. 71

39. Graph showing the relation of cumulative discovered oil and gas quantity to the number of wildcats drilled in the Espirito Santo basin. 72

40. Schematic structure map of the Cumuruxatiba subbasin and portions of the adjoining Jequitinhonha subbasin and Espirito Santos. 75

41. Index map of the Jequitinhonha subbasin. 76

42. Geologic section across the Jequitinhonha subbasin. 78

43. Map showing structural framework of Sergipe-Alagoas basin with key petroleum accumulations. 81

44. Stratigraphic column of the Sergipe-Alagoas basin. 82

45. Map showing areas of petroleum generation in the Sergipe-Alagoas basin. 83

46. Schematic geologic sections across the Sergipe-Alagoas basin showing structural and stratigraphic relations. 84

47. Graph showing the relation of cumulative discovered oil and gas quantity to the number of wildcats drilled in the Sergipe-Alagoas basin. 88

48. Map showing the physiographic provinces of the northwestern margin of the Brazilian craton area of South America. 90

49. Sketch tectonic map of Brazilian northeast coast showing basins and structural elements. 91

50. Structural map at top of synrift sediments showing the general structure of the Potiguar basin to the shelf edge. 93

51. Stratigraphic column of the Potiguar basin. 94

52. Geologic dip section across the interior rift and marginal rift parts of the Potiguar basin. 96

53. Potiguar basin map of petroleum generation areas of the synrift Neocomian lacustrine shales and of the postrift-Aptian restricted-marine shales, and the accumulations of petroleum from each source. 97

54. Geologic cross section of the Potiguar through the Ubarana and Agulha Fields. 99

55. Graph showing the relation of the cumulative discovered oil and gas quantity to the number of wildcats drilled in the Potiguar basin. 100

56. Location map and structural framework of Caera basin. 102

57. Stratigraphic chart of Mundau subbasin, Caera basin. 103

58. Structural dip section of Mundau subbasin indicating main plays. 104

59. Geological strike section of Caera basin. 105

60. Graph showing relation of cumulative discovered oil quantities to the number of exploration wells drilled in the Caera basin. 108

61. Map showing structural framework of its Barreirinhas basin. 111

62. Geologic dip sections across the Barreirinhas basin. 112

63. Stratigraphic chart of the Barreirinhas basin. 113

64. WSW-ENE geologic cross section across the Sao Joao Field, Barreirinhas basin. 116

65. Index map of the Para-Marahoa basin. 118

66. Diagrammatic sedimentary history at wildcat MAS-11. 119

67. Depth to basement map of the Para-Maranhoa basin in seconds of reflection time. 121

68. Schematic geologic dip sections across the western and eastern positions of the Para-Maranhoa basin. 122

69. Structural framework of the Foz do Amagonas basin. 125

70. Geologic deep section across Foz do Amazonas basin drawn from seismic profiles. 126

71. Dip and strike stratigraphic cross-sections of Foz do Amazonas basin. 128

72. Geologic section across the Marijo (Limoeiro) basin. 129

73. Sketch map of the Guyana basin showing structural elements and significant wildcat positions. 133

74. Stratigraphic column and dip section showing vertical and horizontal distribution of sedimentary units in the Guyana basin. 135

75. Geologic dip section across offshore Guyana basin. 136

76. Index map of the Recancavo basin. 139

77. Stratigraphic column of the Recancavo basin. 140

78. Schematic cross section of the Recancavo basin illustrating the various trap possibilities or plays. 143

79. Graph showing relation of the cumulative amount of discovered oil and gas to the number of exploration wells drilled in the Recancavo basin. 145

80. Tectonic map of the south Tucano subbasin. 146

81. Structural element map of the Tucano and Jatoba basins showing the zones of sinistral wrenching and the reversal of dip direction at the wrench zone of the Rio Vaza-Barris. 147

82. Stratigraphic column of Tucano and Jatoba basins. 148

83. Geologic section across Tucano basin at Rio Vasa-Barris. 150

84. Map of structural framework of the Tacutu basin. 153

85. Stratigraphic column of the Tacutu basin. 154

86. Schematic geologic section across the Tacutu graben. 156

87. Structure map of the Solimoes and adjoining basins showing the Jandiatuba and Juria subbasins and separating Carauari high. 159

88. Stratigraphic column and lithostratigraphic chart of the Solimoes basin. 160

89. Map of the Solimoes basin structural framework. 162

90. Seismic profile across the gas-bearing Jurua trend of the Solimoes basin. 163

91. Seismic profile across the oil and gas-bearing Urucu trench of the Solimoes basin. 164

92. Isopach map of the deepest diabase sill of the Solimoes basin. 165

93. Diagram showing the thermal effects of Solimos basin diabase sills. 166

94. Map of Amazonas basin showing distribution of mature petroleum source rock and exploration plays plus a diagrammatic representation of the four main trap types. 169

95. Stratigraphic chart of the Amazonas basin. 171

96. Simplified depth-to-economic basement map of the Amazonas basin. 172

97. Paleoenvironmental map of the Amazonas basin. 173

98. Isopach map of the total thickness of the Parnaiba basin and of the adjoining Barreirinhas basin and Sao Luis graben. 176

99. Stratigraphic column of the Parnaiba basin. 178

100. East-west geologic section across the Parnaiba basin. 179

101. Maturation map of the Pimenteiras Formation of the Parnaiba basin. 181

102. Map of the main structural features of the Parnaiba basin. 182

103. Northwest-southwest seismic profile 218-RL-01, in the Parnaiba basin. 184

104. Northwest-southeast seismic profile 59-RL-115 in the Parnaiba basin. 185

105. Location map of the depocenter area of the Parana basin. 187

106. Stratigraphic column of the Parana basin. 188

107. Regional correlation section from Paraguay (wildcat ASU-2) eastward through the depocenter (wildcats 2-AN-1-PR and 2-R1-PR) of the Parana basin. 189

108. Detail of Irati Formation interval in two Parana basin wildcats showing the depletion of TOC (total organic carbon) by the thermal efforts of diabase intrusion. 192

109. South to north geologic cross-section across the Chaco basin. 195

110. Sketch depth-to-basement map of Acre basin separated from the adjoining Solimos basin by the Arch of Iquitos and from the Ocayali basin by the Divisor Range. 197

111. Stratigraphic columns of the Acre basin of western Brazil.and the adjoining Maranan subbasin of eastern Peru 198

112. Diagrammatic west-east geologic section from the Acre basin into the Solimoes basin. 199

113. Depth to "technical basement" (seismic velocities greater than 15,000 ft/sec (4.5 km/sec) map of the Patagonia area showing the major basins. 202

114. Structure contour map of top of Tobifera volcanic rocks, Magallanes basin. 204

115. South to North stratigraphic section through Magallanes basin. 205

116. Sketch of seismic southwest-northeast dip section of the Magallanes basin from frontal folds of the Chilean fold and thrust belt to the edge of the Dungeness Arch. 206

117. Graph showing relation of the cumulative amount of oil discovered to the number of wildcats drilled in the Argentina and Chile portions of the Magallanes basin. 210

118. Graph showing relation of the cumulative amount of gas discovered to the number of wildcats drilled in the Argentina and Chile positions of Magallanes basin. 211

119. Tentative isopach map of sediments of seismic velocity less than 4.2 km/sec covering the Malvinas (Falkland) platform and vicinity. 213

120. Tectonic element map showing the relation of the Malvinas Basin to the Magallanes Basin. 214

121. Time isopach map of the Cretaceous sediments adjoining the Dungenes Arch in the Magallanes and Malvinas basins and cross sections across the Dungenes Arch. 215

122. Seismic structure section across the Malvinas basin. 216

123. A seismic reflection section A-A' north-south across Malvinas Plateau and B-B' a seismic refraction section west-east across Malvinas Plateau. 219

124. Structural sketch map of San Jorge basin. 224

125. Chronostratigraphic chart, based on a northeast-trending cross-section of the San Jorge basin. 225

126. Cross-section of Bella Vista and Canadon Perdido Fields. 228

127. Structure contour map on the top of the Lonco Trapial volcanics of the San Jorge basin. 229

128. Cross-section of the San Jorge basin. 230

129. Map of the San Jorge basin showing the oil and gas field distribution as of about 1980, the limits of the Chubut Group (Upper Cretaceous reservoirs) and the offshore limits of the D-129 Formation (principal source). 232

130. Graph of cumulative oil and gas discoveries versus cumulative wildcat wells drilled from 1916 to 1989 in the San Jorge basin. 233

131. Generalized isopach map of the Cretaceous sediments of the Colorado basin. 235

132. Schematic west-east structure section along the strike of the Colorado basin. 236

133. Schematic north-south structure section across the Colorado basin. 237

134. Generalized isopach map of the Cretaceous sediments of the Salada basin. 240

135. Stratigraphic column of the Salad basin. 241

136. Sketch structure map of the Salada basin. 243

137. Index map of the Neuquen basin. 245

138. Stratigraphic cross section of Mesozoic sediments of the Neuquen basin. 246

139. Map of North Neuquen or Malargue subbasin showing westward shaling of Lower Cretaceous formations and cross section of the subbasin showing the division between fold belt and platform and effects of the evaporites on petroleum migration. 248

140. Structure map of the southern, or largely platform, portion of the Neuquen basin drawn on the top of basement. 249

141. Schematic southwest-northeast cross section of the platform portion of the Neuquen basin. 250

142. Schematic west-east cross section to the Neuquen basin. 252

143. Graph showing the cumulative amount of discovered oil versus the cumulative number of wildcats in the Neuquen basin. 254

144. Graph showing the cumulative amount of discovered gas versus cumulative number of wildcats in the Neuquen basin. 255

145. Index map of the Cuyo basin showing trends of petroleum accumulations. 256

146. Stratigraphic column of Cuyo basin. 258

147. Geologic section across Cuyo basin. 259

148. Graph of oil discovery rate in the Cuyo basin showing the amount of cumulative oil discovered per cumulative number of wildcats. 261

149. Graph of gas discovery rate in the Cuyo basin showing the cumulative amount of gas discovered per cumulative number of wildcats. 262

150. Generalized subsurface structure map of the Argentine continental margin. 263

151. West-east cross-section from San Jorge basin to across the East Patagonia basin at the continental margin. 264

152. West-east cross-section from Colorado basin across East Patagonia basin at the continental margin. 266

153. Sketch map of northwestern South America showing the foreland Subandean basins (stippled) and their relation to the Andes orogeny. 268

154. Map of west-central South America showing the Pampeanas Ranges (Sierras Pampeanas) area. 271

155. Cross-sections of the Pampeanas Ranges (Sierra Pampeanas). 272

156. Map of northern Argentina showing the Oran basin and its fold belt and platform elements. 275

157. Map of central Oran basin and southern Santa Cruz-Tarija basin showing principal oil and gas fields, significant wildcats, and profile positions. 276

158. Stratigraphic column of Oran basin. 277

159. South to north stratigraphic section showing stratigraphic relation of the mainly Cretaceous Oran basin to the mainly Paleozoic Santa Cruz-Tarija basin. 278

160. West to east stratigraphic section of the Oran basin. 279

161. West to east structural cross-section of the Oran basin. 281

162. Graph showing the cumulative amount of oil and gas discovered in the Oran basin versus the cumulative number of wildcats drilled. 283

163. Tectonic map of Bolivia showing the Santa Cruz-Tarija basin, along with the ontrend Beni and Madre-de Dios foreland basins. 285

164. Stratigraphic column of the Santa Cruz-Tarija basin. 287

165. Map of southern Bolivia and adjoining countries showing isopach and extent of the Siluro-Devonian sequence in the Santa Cruz-Tarija basin. 288

166. Diagrammatic cross-section of the Santa Cruz-Tarija basin. 289

167. Map of southern Bolivia and adjoining countries showing the extent of the Lower Carboniferous, the Tupambi (and part of Tarija?) formations in the Santa Cruz-Tarija basin vicinity. 290

168. West to east diagrammatic cross-section across the Subandino high thrust belt and the Pie de Monte low belt of folding and reverse faulting, Santa Cruz-Tarija basin. 293

169. Graphs showing the cumulative amounts of oil and gas discovered in the Santa Cruz-Tarija basin versus the number of wildcats drilled. 295

170. Tectonic map of Bolivia and southern Peru showing the Beni and other subandian foreland basins. 296

171. Geologic cross-sections across the sub-Andean overthrust and fold belt of the Beni basin. 299

172. Composite stratigraphic column of eastern Peru. 301

173. Geologic map of the Ucayali basin. 305

174. Diagrammatic west to east geologic section through the Ucayali basin of eastern Peru and the Acre basin of western Brazil. 308

175. (A) Seismic cross-section through the Aquaytia gas field, Ucayali basin. (B) Seismic cross-section through the Cashiboya structure, Ucayali basin. 310

176. (A) Seismic cross-section through the Maquia field; (B) Seismic section through Huaya structure 311

177. Structure map of the Maranon-Oriente-Putumayo basin. 315

178. Stratigraphic columns upper Amazon foreland basins. 317

179. Schematic section across the Maranon sector of the Maranon-Oriente-Putumayo basin showing the relation of the oil window to basin structure and to the source and reservoir formations. 319

180. Structure map of the Maranon sector of the Maranon-Oriente-Putumayo basin. 321

181. Structure map of the Oriente sector of the Maranon-Oriente-Putumayo basin. 322

182. Structure map of a portion of the Putumayo sector of the Maranon-Oriente-Putumayo basin. 323

183. Geologic cross sections across the Maranon-Oriente-Putumayo basin. 324

184. Seismic section across the Shushufindi field of the Oriente sector of the Maranon-Oriente-Pulumayo basin. 325

185. Graph showing Maranon-Oriente-Putumayo cumulative oil and gas discoveries versus number of wildcat wells. 328

186. Geologic map of Peru, showing principal sedimentary basins east of the Andes. 330

187. Geologic map of Huallaga basin. 332

188. Generalized stratigraphic column of Huallaga basin. 333

189. Geologic cross-section Huallaga basin. 335

190. Regional east-west cross-section of northeastern Peru. 337

191. Map of the central Andes showing major tectonic provinces. 340

192. Geologic cross-sections of the Altiplano basin. 342

193. Diagram of stratigraphic units in vicinity of Lake Titicaco, Altiplano basin. 343

194. Map of Peru and adjoining Ecuador and Chile, showing coastal basins and their relation to the Coastal Range, an outer arc ridge or slope-break ridge. 346

195. Structural map of coastal Peru and Ecuador. 347

196. Generalized stratigraphic column of south and north Talara basin. 349

197. Simplified cross-section through the offshore Humboldt Norte and on-shore Los Organos-el Alto oil field complexes, Talara basin. 352

198. Index map of Talara basin showing location of oil fields. 353

199. Index map of the Progreso basin showing fields, important wildcats and approximate areas of subbasins. 356

200. Stratigraphic sections of three principal coastal basins of Ecuador. 357

201. Schematic SW-NE cross section of the Gulf of Guayaquil. 360

202. Geologic map of the Progreso (sensu stricto) and Santa Elena Peninsula subbasins and location map of fields of the Santa Elena Peninsula area. 361

203. Index map of Ecuador showing the principal sedimentary basins. 364

204. Interpreted seismic section SW-NE through wildcats Delfin 20-X1 and Ballena 8-1 from the east flank of the Trujillo basin, over the Coastal Range's southward subsurface project (outer arc ridge), into the west flank of the Salaverry basin. 368

205. Columnar section, Trujillo basin. 369

206. Interpreted seismic dip section across the Mollenda-Tarapaca basin. 372

207. Northeast-southwest geologic section through the Lancones, Talara, and Progreso (Tumbes) basins. 375

208. Columnar section of Sechura basin. 381

209. Interpreted seismic section through the offshore area of the Sechura basin. 382

210. Columnar section of the Salaverry basin. 384

211. Diagrammatic sketch section showing the relation of the Salaverry basin to a subduction process involving tectonic erosion. 385

212. Columnar section of the eastern Pisco basin. 388

213. Interpreted seismic dip section in the offshore Pisco basin. 389

214. Columnar section Moquego (Tamaraga) basin. 391

215. Index map of Chilean central coast. 394

216. South to north stratigraphic correlation of exploration boreholes along strike of Central Chilean Forearc basin. 396

217. West-east geologic cross-sections of Central Chilean Forearc basin. 397

218. West-east geologic cross-section across the subbasin of the Central Chilean Forearc basin and the Osborno-Llanquihue intra-arc or intermontane basin. 398

219. Index map of southern Chile showing the forearc primary basins. 404

220. West-east seismic cross-section through exploratory well, A-1X of the Madre de Dios. 405

221. Southwest-northeast geologic cross-section across the Diego Ramirez basin of southernmost Chile. 408

222. South-north seismic section through the Los Muermos-1 exploratory well of the Osorno-Llanquihue basin. 411a

223. Northwest-southeast seismic section across the Penas basin. 413a

In Appendix A

Figure 1. The growth of estimates of amounts of oil and gas discovered in a given year in the conterminous United States versus the number of years after the year of discovery 438a

Tables

Page

I Petroleum Basins of Brazil--Estimated original Petroleum Reserves 8

II Campos Basin Recoverable Reserves 29

III Reservoir Characteristics of the Albacora and Marlim Fields 39

IV Campos Basin, Undiscovered Recoverable Petroleum 52

V Sergipe-Alagoas Basin Petroleum Resources 86

VI Estimated Original Reserves of Petroleum Producing Countries of South America (Exclusive of Venezuela and Colombia) 416

VII Preliminary Individual Basin Summary of Petroleum Resources of Southern South America (3 pages) 417

VIII Unadjusted Undiscovered Oil and Gas by Geologic Province (Based on 1990 Data), South America (Exclusive of Venezuela and Colombia) 420

IX Estimated Original Identified Reserves of South American Key Basins which are Representative of Their Geologic Province 421

X Undiscovered Oil Estimates Based on Comparisons to Original Identified Reserves of Geologically Analogous Accumulations 423

XI Undiscovered Oil and Gas by Geologic Province, (Based on 1990 Data) South America (Exclusive of Venezuela and Colombia 424

XII Undiscovered Oil and Gas by Country, South America (Exclusive of Venezuela and Colombia) 425

In Appendix A

A. Relation and Definition of Petroleum Reserve Nomenclature 439

B. Annual Petroleum Discoveries in the Lower 48 States 441

UNDISCOVERED PETROLEUM OF SOUTHERN SOUTH AMERICA

by

John Kingston

ABSTRACT

Southern South America (i.e. exclusive of Venezuela and Colombia, amounting to 88 percent of the continental area) has only half the continent's original reserves. The estimated undiscovered oil and gas amount to some 43 BBO and 140 TCFG. Of the southern South American countries studied, Brazil apparently has 52 percent of the undiscovered oil and gas, Peru 18 percent, Argentina 15 percent, Ecuador 8 percent, and the remaining southern South American countries together have 7 percent. The plays deemed to have the highest petroleum potential are the turbidites of the Atlantic continental margin rift basins, the overthrust and fold belt of the eastern Andes, and suspected Cretaceous foreland stratigraphic traps in northern Peru and in Ecuador. Of lower potential are the Paleozoic interior sags and the Pacific region forearc and intra-arc basins. Exploration is generally immature, though some on-shore basins have reached the mature stage; the higher potential plays largely involve frontier exploration.

I. Introduction

A. Regions of Study

In this study southern South America is taken to be all of South America south of Venezuela and Colombia. For organization of this study, South America is divided into five geotectonic regions or superprovinces (fig. 1): 1) the Brazilian craton region, largely occupied by Brazil, is made up of the Brazilian and Guiana Shields, occupied in part by interior rift and interior sag basins and including the Atlantic rifted continental margin basins; 2) the Patagonian accreted region, south of the Brazilian craton and east of the Andes, is made up of subcontinental blocks, or massifs, divided by rifts following old sutures and occupied in part by rift and foreland basins; 3) the Subandean foreland region is made up of a string of foreland basins developed east of the Andes on the west perimeter of the Brazilian craton from northern Argentina to Colombia; 4) the Pacific subduction region made up of related forearc, and intra-arc basins, largely west of the Andes from southern Chili to Colombia; and 5) the Tethyan collision region, made up of Venezuela and part of Colombia affected by the Caribbean tectonics and the site of Tethyan marine sediments. The undiscovered petroleum in the first four of these regions is the subject of this report.

B. Purpose and Method of Study

The purpose of this study is to provide a quantitative assessment of the undiscovered recoverable oil and gas in the regions studied. To this end, every appropriate estimate of a geological or historical factor is quantified numerically, even though it may only be an informed guess; the rationale for the numerical estimate is explained. Later information may cause a revision of the estimated number which can then be reintroduced back into the system, effecting a corresponding change in the overall resource assessment. Reserve values used are original reserves and, as far as can be determined, represent proved amounts of recoverable oil and gas as of around 1990.

Although background geology is presented briefly as necessary, the focus of this study is on those geologic factors most directly concerning petroleum occurrence. The study is structured to support what is essentially a play-analysis approach, but where appropriate or necessary, projections of current exploration (e.g. field-size distributions) and analogies with geologically similar basins are employed in the assessment of undiscovered petroleum resources.

After preliminary estimates were made, the results were presented to a panel of U.S. Geological Survey geologists (The World Energy Resource Program) who, after an in-depth discussion and deliberation from the perspective of their individual experiences, arrive at a consensus as to the amount of undiscovered petroleum in each country. Conditional upon recoverable resources being present, estimates for each of the assessed provinces were made as follows:

(1) A low resource estimate corresponding to a 95% probability that there is more than that amount.

(2) A high resource estimate corresponding to a 5% probability that there is more than that amount.

(3) A modal ("most likely") estimate of the quantity of resource associated with the greatest likelihood of occurrence.

A mean probability value was arrived at by fitting a log normal distribution curve to the 5 percent and modal estimates (Courtesy D.H. Root).

In the last stages of this study it became evident, on the basis of an historical review of the 1983 to 1993 growing rate of reserves, that these consensus estimates of undiscovered petroleum were too low. This was probably the result of basing the undiscovered petroleum estimates on available reserve numbers of geologically analogous fields or basins, numbers which were presumably Original Proved Reserves rather than the total amount of petroleum which will be produced from the accumulation, i.e., the Original Identified Reserves. (Original Indicated Reserves include cumulative production, Proved Reserves, and Unproved (probable plus

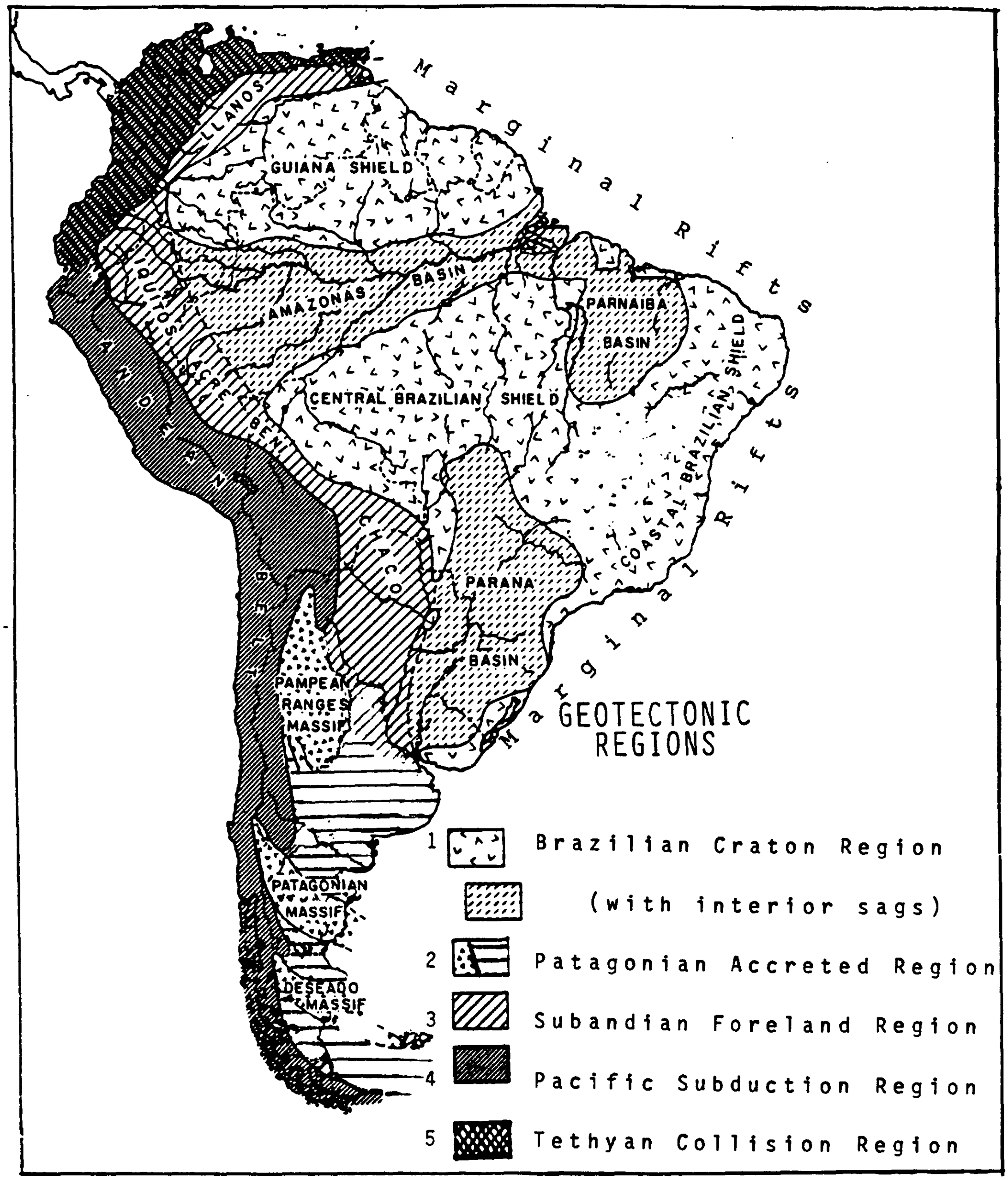


Figure 1 Map showing the five principal geotectonic regions of South America (modified from Dietzman and Rafidi, 1983).

Possible) Reserves. Accordingly, calculated estimates are made of the Original Indicated Reserves of the analogous fields or basins upon which the undiscovered petroleum estimates were based and the initial dependent undiscovered petroleum estimates revised upward accordingly. An explanation of these adjustments, including definition of the reserve categories, is in Appendix A and the results included in the Summary and Conclusions.

The issuance of this report has been delayed by the late recognition of the impact of field growth on the undiscovered oil and gas estimates and other problems, so that most of the information is somewhat dated, of about 1990 vintage.

II. Brazilian Craton Region

General

Area. The Brazilian craton region or superprovince encompasses the east and central South America largely occupied by Brazil; it includes all of Brazil, Guyana, Suriname, French Guiana, and Uruguay (fig. 1). It also includes peripheral parts of southern Venezuela, southeastern Colombia, and the eastern edges of Peru, Bolivia, Paraguay, and northern Argentina. It does not include and is limited by a trend of foreland sub-Andian provinces on the west, extending from eastern Venezuela southward through central Colombia, eastern Ecuador and Peru, central Bolivia, western Paraguay to northern Argentina. The Brazilian craton is bounded on the south by Argentina which is largely made up of continental fragments accreted from the Pacific region. The area of study also includes the largely offshore rifted continental margin with the Atlantic Ocean.

This area of some four million sq mi (10.4 million sq km), counting the offshore shelf and slope, has twenty major sedimentary basins with an approximate combined area of 1.5 million sq mi (4 million sq km). The size and distribution of the sedimentary basins in and adjoining the Brazilian craton which will be discussed are shown in figure 2.

For discussion purposes the basinal areas of the Brazilian craton region (fig. 2) may be divided into a number of geological similar entities: 1) the rifted continental margin which in turn can be divided into 1) the southeast marginal rift basins (Pelotas through Seripe-Alagoas) and b) the northeast marginal rift basins (Potiguar through Guyana); 2) the interior rift basins, (Recancovo, Tucano, Jatoba, and Tacutu); and 3) the interior sag basins, (Solimoes, Amazonas, Parnaiba, Parana, and Chaco). (The Acre basin is briefly discussed as part of the Brazil assessment, but actually belongs to the Subandian foreland region).

Exploration History and Petroleum Occurrence. Practically all the petroleum exploration and production of the region has been in

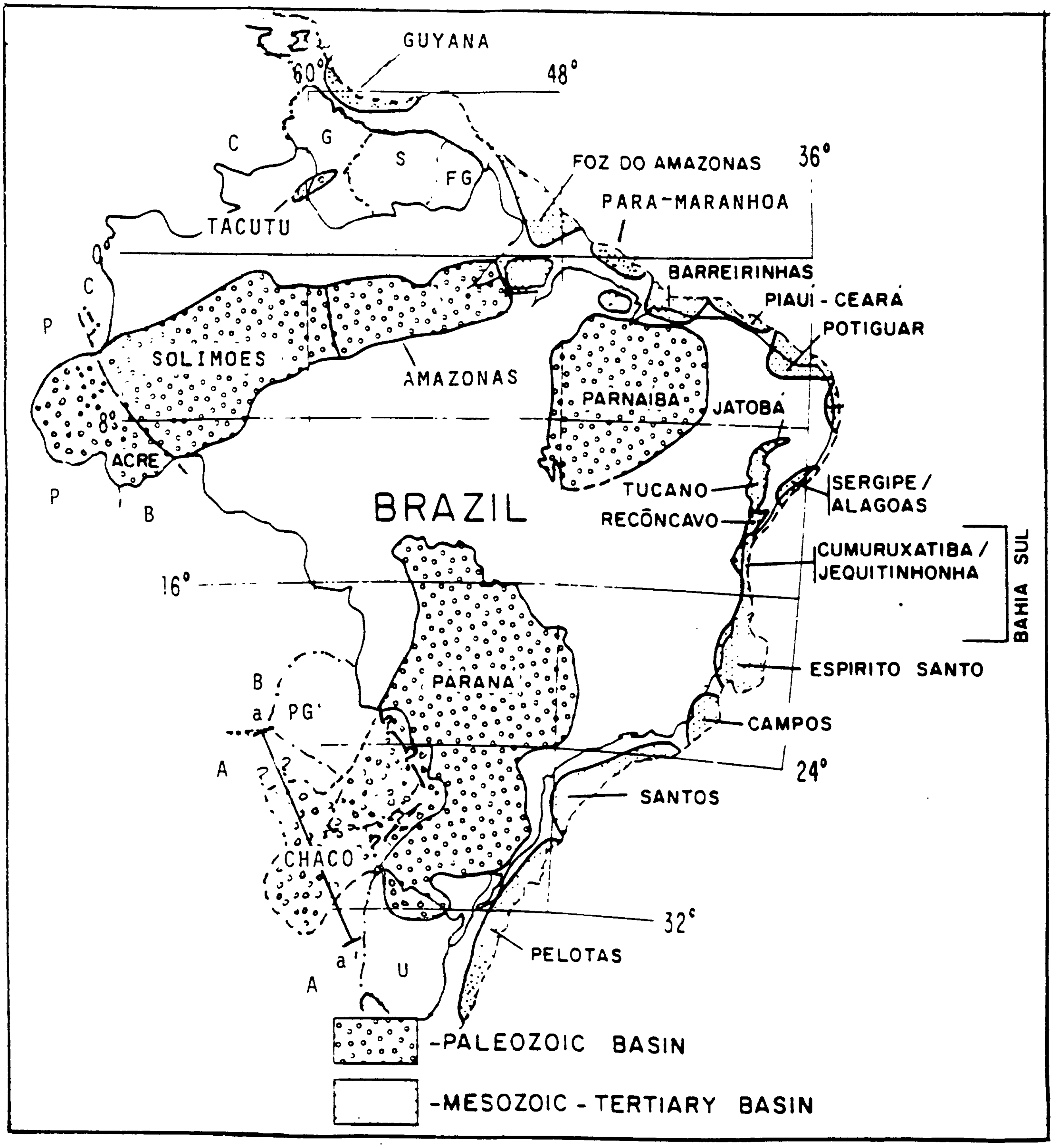


Figure 2 Map showing principal sedimentary basins of the Brazilian Shield area (modified from Ojeda, 1982). A=Argentina, B=Bolivia, C=Colombia, FG=French Guiana, G=Guyana, P=Peru, PG=Paraguay, S=Surinam, and U=Uruguay.

Brazil. The first Brazilian petroleum concession was granted in 1864, but no discoveries were made until 1939 when a shallow hole, drilled on the basis of oil seeps, discovered the small Lobato field of the Reconcavo basin (fig. 2). Subsequent exploration in this single basin discovered most of Brazil's petroleum production up to the end of the 1960's. In the late 1950's and early 1960's the continental shelves of Campos, Espirito Santo, Sergipe-Alagoas, and Barreirinhas basins (fig. 2) were covered by sparse seismic surveys. Later, during the 1960's, the shelves of the Sergipe-Alagoas and Campos basins (fig. 2) were covered by gravity surveys. In the early 1970's the Brazilian shelf was almost entirely covered by airborn magnetometry. Subsequently, the shelf has been surveyed in considerable detail by geophysical means including very extensive 3-D seismic surveys.

The first offshore well was drilled in 1968 in the Espirito Santo basin. A second well drilled in the same year in the Sergipe-Alagoas basin was a discovery. Since then, drilling activity has increased, especially after the first commercial discovery in the Campos basin in 1974.

Since 1984, drilling in waters deeper than 1,300 ft (400 m) has been extensive and with a high rate of success. Six oil fields have been discovered, one in the Sergipe-Alagoas basin and five in the Campos basin, three of which are the giant fields, Marlim, Albacora and Barracuda.

Exploration has been carried on almost exclusively by Petrobas, the Brazilian national oil company, and its predecessor, the National Petroleum Council. Only limited, less prospective, areas were made available to foreign risk contractors who spent 1.66 billion dollars and drilled some 161 wells (Riva, 1989), but only found one field.

Exploration of Brazil to date has discovered some 29 sedimentary basins of varying prospectiveness. Oil and gas shows have been found in 23 basins, subcommercial accumulations may be in 16 basins, and production amounting to 600,000 barrels of oil per day (BOD) was reported for seven basins (Oil and Gas Journal, 1989). About 88 percent of the oil and gas reserves are in three basins, 63 percent in the Campos basin, 18 percent in the Reconcavo basin, and 7 percent in the Sergipe-Alagoas basin. Except for one basin, Reconcavo, which has been rather thoroughly investigated, exploration is generally still in an immature stage. As of 1989, Petrobas's exploration effort amounts to 1.24 miles of seismic line to 1 square mile of basin area (or 1 km of line per 5.2 km^2) and one wildcat for every 486 sq mi (1,260 sq km) of basin area (Oil & Gas Journal, 1989).

Exploration has established estimated original reserves of some 9.9 billion barrels of oil (BBO) and 12.6 trillion cubic feet of gas (TCFG). These reserves figures, derived from various Petrobras publications, are summarized in Table 1. Although it is not clear, most of the reserve figures are assumed to generally represent original proved reserves.

A. The Rifted Continental Margin Basins

General

Extent. The shelfal parts of the continental margin basins of Brazil are shown in figure 2. The basins of the continental margin, as defined here, lie between the presedimentary rock outcrops of the continent and the offshore continental-oceanic crust boundary (COB). The outer boundary of the rifted continental margin is taken to be at the COB rather than the edge of the continental shelf since well-defined horst and graben structure appears to extend to the COB and, in many cases, the depocenter of the continental margin basins lies under the slope rather than the shelf.

The COB is difficult to locate and has been seldom mapped here or elsewhere. Its position may be estimated, however, on the basis of the following criteria:

(1) Bathymetry. The less-dense continental crust is buoyant in contrast to the oceanic crust and is therefore indicated by the shallower depths of the shelf and slope. Where corroborating evidence is available it appears that the COB is approximately at the base of the slope or top of the rise at about the 2000-meter isobath (fig. 3).

(2) Oceanic magnetic anomalies. Unfortunately, the magnetic anomalies are not so evident in this part of the South Atlantic, but a few anomalies have been recognized in three areas (fig. 3): (a) parallel and just off the continental slope of the Sergipe Alagoas basin, (b) along the northwest side of the Sao Paulo Plateau, and (c) just inside the continental-shelf edge of the Pelotas basin.

(3) Presence of rifting. The continental crust was subject to rifting as it was stretched prior to continental separation. After separation, the stretching, and therefore rifting, of the continental crust ceased so that the COB approximately coincides with the outboard side of the zone of evident rifting as seen in the Campos basin (fig. 4).

(4) Outer ridge. Often the outer edge of the rifted continental crust is marked by a ridge or horst of basement or volcanic rock as indicated in the Espirito Santo basin.

(5) Salt and evaporites. Some authors believe that evaporite deposits are generally limited to the continental crust, but this is certainly not true in all cases.

TABLE I

PETROLEUM BASINS OF BRAZIL

ESTIMATED ORIGINAL PETROLEUM RESERVES (P+P)

OIL + NGL (BB)

	OIL(BBO) (+NGL)	GAS(TCF)
BAHIA SUL	0.021	0.001
BARREIRINHAS	0.004	----
CAERA	0.084	0.065
CAMPOS	7.440	4.522
ESPIRITU SANTOS	0.108	0.528
FOZ DO AMAZONAS	----	0.880
PARA-MARANHOA	0.007	----
POTIGUAR	0.220	----
RECONCAVO	1.436	3.043
SANTOS	0.048	0.725
SERGIPE-ALAGOAS	0.499	0.790
SOLIMOES	0.037	2.000
TUCANO	----	0.060
TOTAL	9.904	12.614

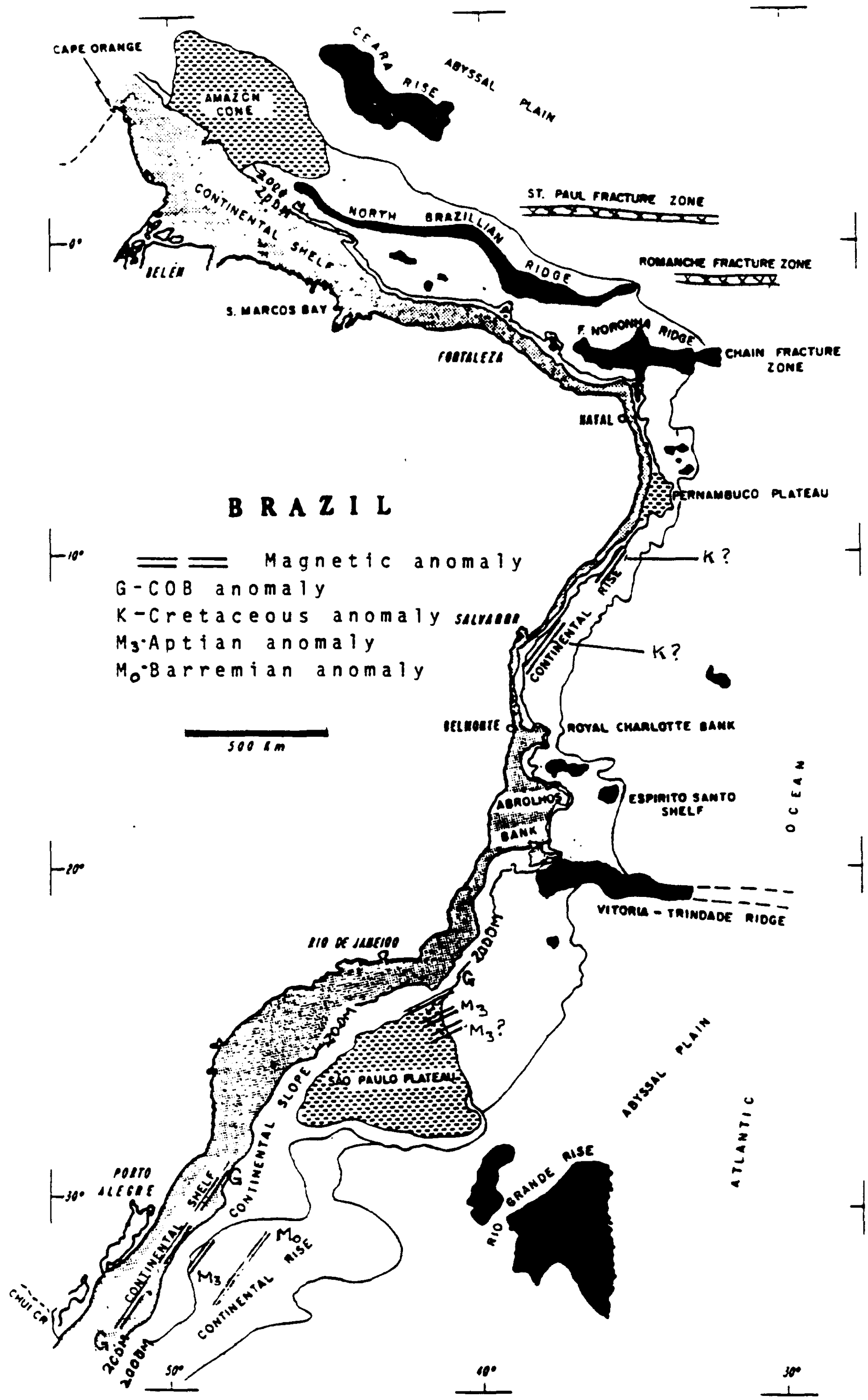


Figure 3 Map of the Brazilian Atlantic margin showing the coastline, continental shelf, continental slope, continental rise and volcanic plateaus, rises and ridges. Also shown are the few oceanic magnetic anomalies of the South Pacific defining the continental-oceanic crust boundary (modified from Campos, Ponte, and Miura, 1975).

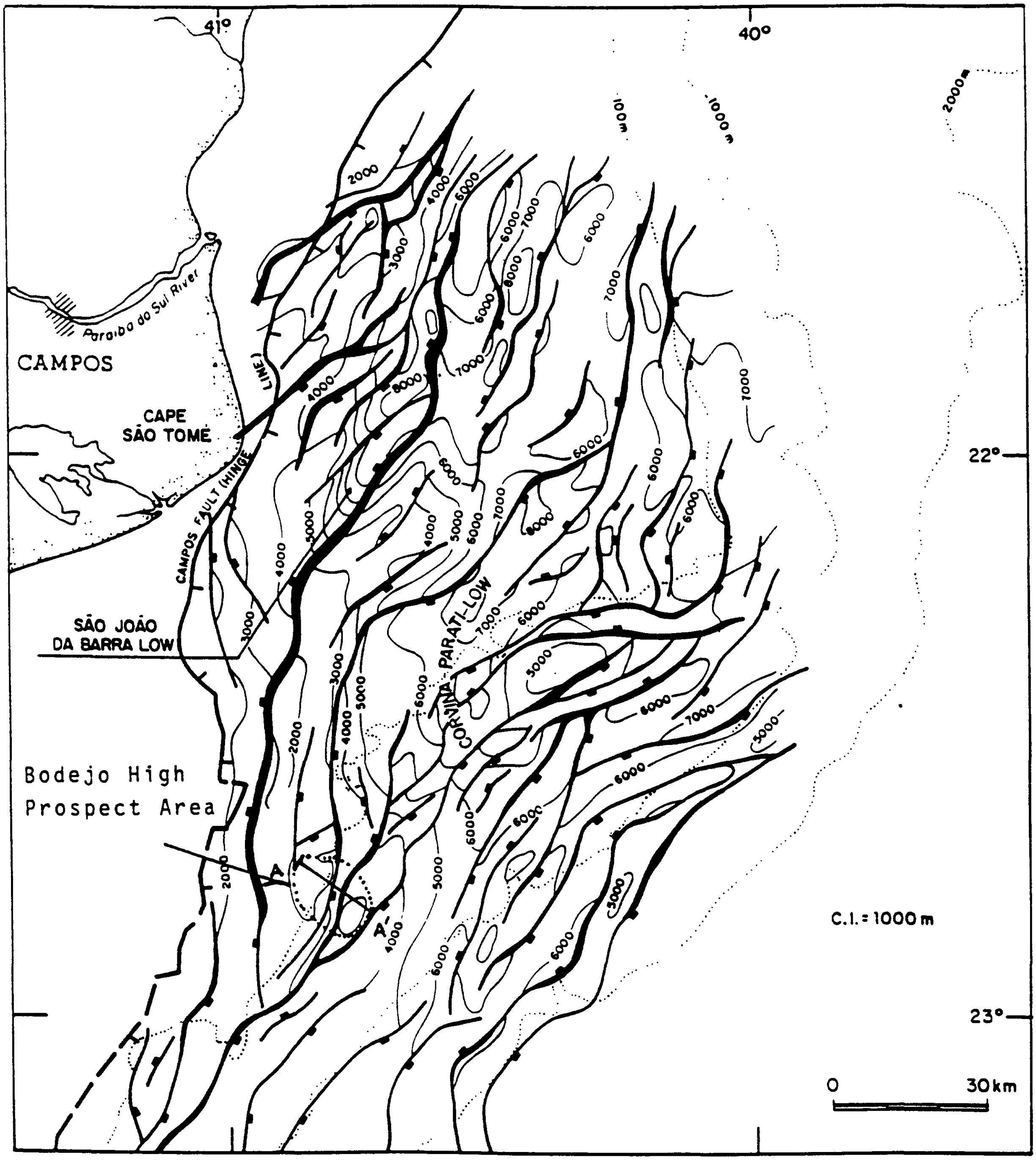


Figure 4 Structure map on top of acoustic basement in the Campos basin showing faulting on the continental shelf and slope of the Brazilian continental margin. Area outlined in heavy dots and containing section line A-A is prospective area for synrift plays (from Guardado et al, 1990).

The COB of the southern coast of Brazil is deemed to extend southwestwards from the Pernambuco Plateau along the base of the continental slope (at the 2000-meter water depth) to near Salvador as indicated by the bathymetry and sea-floor-spreading magnetic anomalies (fig. 3). From Salvador the COB is interpreted to extend due south at about the 2000-meter isobath (by analogy to the previous sector) to the Royal Charlette Bank. The Royal Charlette Bank is largely made up of Cretaceous volcanics plus a block of uplifted basement on its western side (Asmus and Ponte, 1973); the COB is assumed to lie between the basement block and the extensive volcanics further offshore. Two hundred kilometers further south is the Abrolhos Bank which likewise appears to be made up of Cretaceous volcanics with an uplifted basement block on its western side. The COB is assumed to continue southwards through the basement-volcanic interfaces of these two banks to the Campos basin area where it presumably lies outboard of the continental rifts as indicated by geophysical surveys (fig. 4). Southwards, there is an abrupt westward jog in the continental shore line and also probably in the COB as indicated by the position of sea-floor-spreading magnetic anomalies which show the Sao Paulo Plateau is over oceanic crust. Further south in the Pelotas basin the COB, as indicated by magnetic anomalies, actually lies under the outer edge of the shelf.

South of Brazil, in Argentina, the position of the COB becomes more clear, the landward extent of the oceanic magnetic anomalies approximately coinciding with the base of the continental slope.

<u>Structural Framework.</u> The factors governing the generation and accumulation of petroleum are the direct consequence of the rift tectonics and associated sedimentation (fig. 5). The Brazilian marginal basins originated as a trend of rift valleys through the central part of the African-South American continent during late Jurassic-Neocomian time (fig. 5A). Rifting ceased in early Aptian time with the separation of the two continents (fig. 5B). This was followed by widespread erosion, leveling the horst and graben topography, probably in part as a consequence of lowering the base of erosion to sea-level. At the same time, cooling of the continental crust, as the hot spreading center separated further from the continent, caused the marginal basinal area to sag allowing restricted entry of seawater into a shallow linear interior sea between the separating continents. A sequence of fine clastics and evaporites (fig. 5B) and, eventually, platform carbonates, was deposited in the central part of the interior sea. As separation and cooling continued, the subsiding continental margin and the associated sedimentation changed from that of a restricted environment of evaporites, fine clastics and platform carbonates to that of the open sea and clastics of progressively deeper water environments. As the margin slope steepened and the sedimentary load increased, the salt began to flow, forming salt domes and pillows in some cases and seaward-dipping salt-soled listric faults in other cases (fig. 5C and D), depending on the local degree of the slope. Turbidite flow became more prevalent.

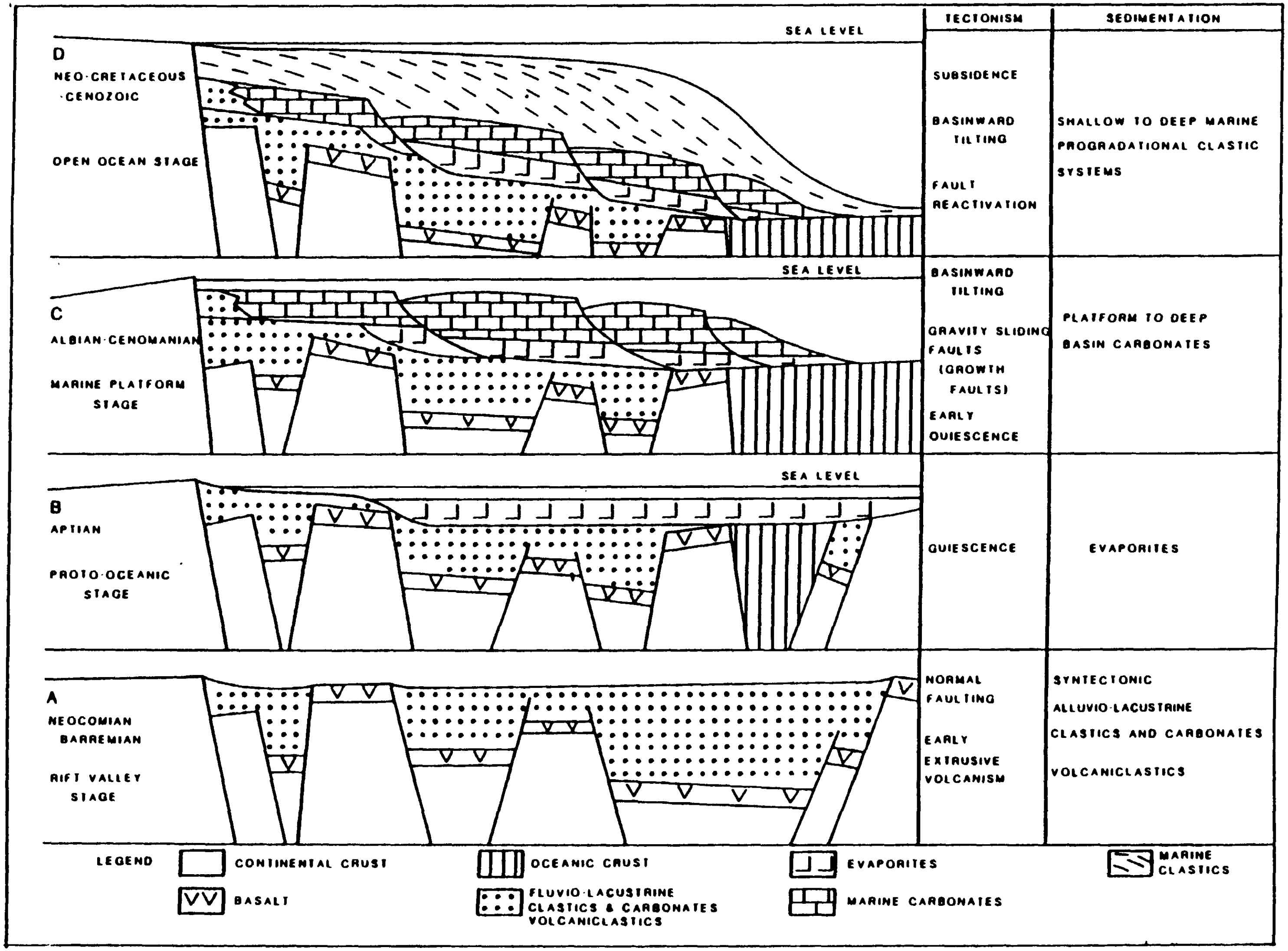


Figure 5 Section showing tecto-sedimentary evolution of the Brazilian continental margin in the Campos basin (modified after Ponte and Asmus, 1978).

The above description applies generally to the eastern coast of the Brazilian region, the structure of the northeast coast differs in two principal aspects: 1) regional sinistral wrenching is prevalent with strike-slip faults and associated transitional faulting and transpressional, or drag, folds, and 2) in the general absence of evaporities, no salt associated structure occurs.

General Stratigraphy. The stratigraphy of the marginal basins may be grouped into five general sequences in relation to tectonic events. They include prerift, synrift, interior sag, postrift, and slope strata.

(1) Prerift sequence. These continental rocks were laid down as extensive, largely fluvial deposits over the Africa-South American craton surface in pre-late Jurassic time, mainly prior to the rifting. Although prerift strata occur in many of the marginal and interior rift basins of Brazil, these rocks are missing, presumably after pre- and synrift arching, with consequent erosion or nondeposition, in the southern marginal basins and also in the northeast coastal basins (fig. 6).

(2) Synrift sequence. The synrift rocks are of continental origin and range in age from Neocomian to Aptian along the southern coast of Brazil. They are largely clastic: dark lacustrine shales, sandstones, and syntectonic conglomerates. The shales are the principal source rock of the rifted continental margin basins. Fresh water coquina banks provide important reservoirs. Volcanic activity accompanied the rifting and volcanic sedimentation and flows were prevalent in many of the synrift sequences, especially in the southern basins. In the Santos basin for example, the rift fill apparently is almost entirely volcanics. Fractured basalt is a reservoir in the Campos and perhaps other basins.

(3) Interior sag sediments. With the beginning of postrift, continental separation in the Aptian, the continental margin began to sag, forming linear interior seas between the two continents into which marine water initially had restricted entry. The sedimentary rocks are made up of salt and other evaporites, euxinic shales, sandstones, and eventually platform carbonates. This evaporite-bearing sequence is confined to those basins which are between the zone of equatorial fracture ridges, which separate the South from the North Atlantic, on the north (approximately B of fig. 6), and the Rio Grande Rise-Walvis Ridge to the south (opposite Florianopolis of fig. 6). The shales of this sequence are an important source in some basins. The salt has a role as a trap former and as a controller of primary migration between the synrift source rock and younger reservoirs. The platform carbonates formed significant reservoirs.

(4) Postrift marginal sag open-sea sediments. As subsiding of the continental margin continued through the Cretaceous into the Tertiary, the carbonates of the shallow, more stable interior sea

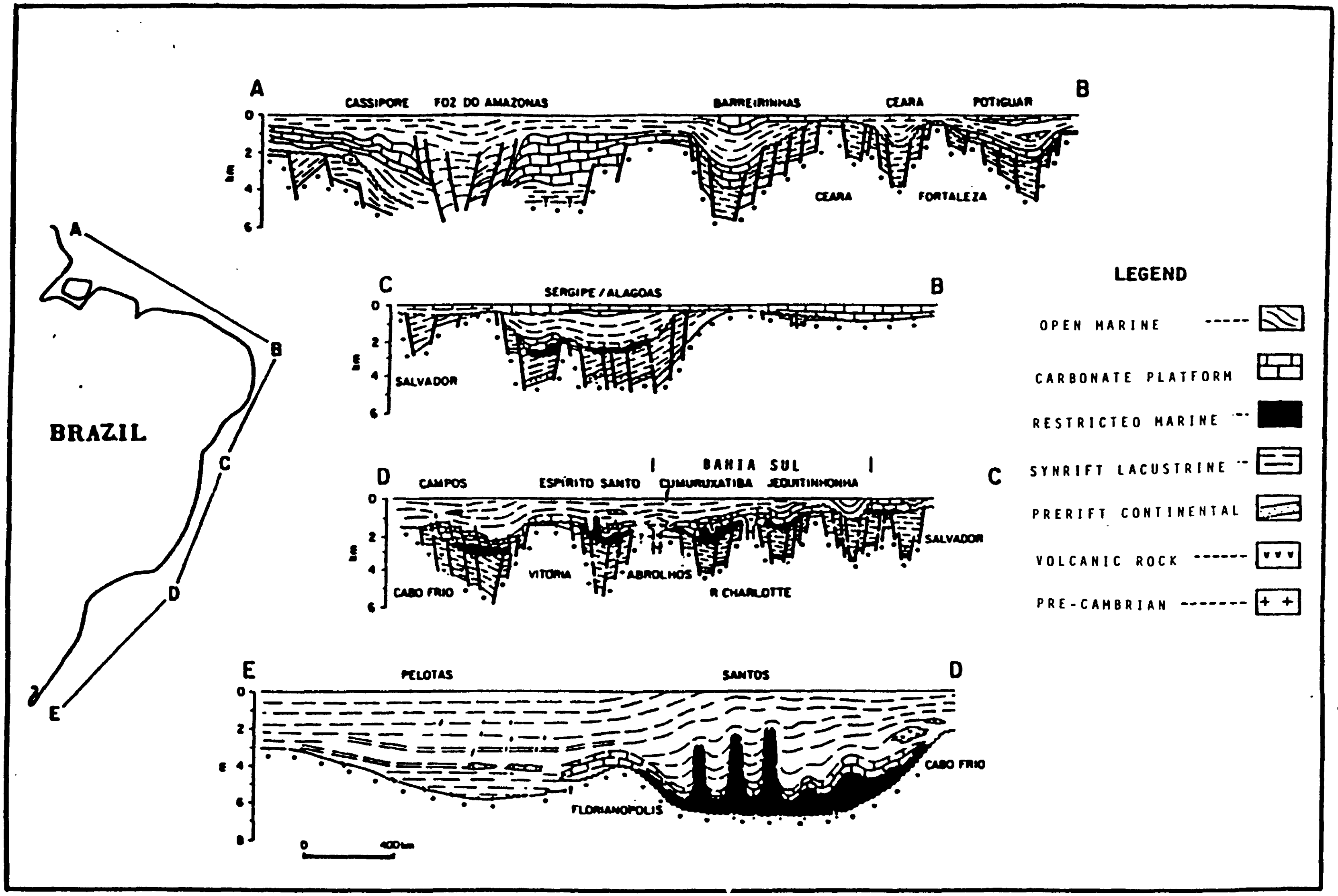


Figure 6 Geologic strike section through the Brazilian rifted continental marginal basins showing the principal sedimentary sequences (modified from Asmus, 1981).

areas were drowned out by clastics as subsidence intensified. Deltas and submarine fans became prevalent and extensive turbidites formed important potential reservoirs.

(5) Slope sediments. The postrift slope sediments are turbidites genetically related to the platform turbidites, but treated separately because of their greater extent and thickness.

Plays. On the basis of the geologic framework, and particularly the reservoir distribution, it appears there are six principal plays in the rifted continental margin basins off the Brazilian shield.

No single basin contains, to a significant degree, all six plays and, in some cases, a number of plays must be grouped together in this study owing to a lack of data. In assessing the various basins, each of the following plays have been considered, and where they have been determined to be significant, have been evaluated.

1. Prerift Play. Reservoirs are principally Jurassic sequences, with perhaps minor reservoirs of fractured basement or volcanics. Significant prerift reservoirs are missing in the southern basins, but are important in the Bahia Sul and Sorgipe-Alagoas rifted margin basins and the adjoining interior rift Reconcavo basin. Traps are principally fault closures.

2. Synrift Play. Reservoirs are mainly fresh-water coquina banks and fractured volcanics. Traps are fault closures, drapes, and stratigraphic traps. The play to date has been largely confined to the shelf.

3. Interior Sag or Transitional Play. Reservoirs are sandstones of very limited distribution. Traps are mainly fault closures and drapes. (Salt of the interior sag phase play an important role in the formation of traps and migration paths.) Play is largely confined to the shelf. So far, interior sag reservoirs have only produced petroleum in the Potiguar basin.

4. Postrift Carbonate Play. Petroleum in Albian carbonate reservoirs are trapped in tilted fault blocks associated with salt-soled listric faults and in closures over salt domes and pillows. The play is largely confined to the shelf.

5. Postrift Shelf Turbidites. Reservoirs are largely Cretaceous sandstones, mainly turbidites. The facies and thickness variation are influenced by underlying salt-flow-originated topography. Traps are in stratigraphic, salt- and fault-closures. The play is largely confined to the shelf.

6. Postrift Slope Turbidites. The reservoirs are mainly Tertiary sandstones. Accumulations are in stratigraphic traps or in

salt flow structures. The play is largely confined to the slope. Sixty-five percent of Brazil's oil reserves are in these reservoirs.

Individual Basin Assessment

Southern Rifted Continental Margins

General. The southern portion of the Brazilian rifted continental margin basins, i.e., those south of the easternmost point of Brazil (fig. 2), are geologically less complicated than the northeastern rifted margin, the rift basins being essentially an extensional pull apart, while those of the northern coast have a strong wrench component. Because of the relative structural simplicity, the southern margin is discussed and assessed first. Of the southern rifted basins, the Campos basin is assessed first because its geology is the best known. From there the two basins to the south, Santos and Pelotas, are described and assessed and then the basins progressively northward, the Espirito Santo, the Bahia Sul and the Sergipe-Alagoa basins. There are two basins sometimes mentioned in the literature which are not evaluated. The Bahia Norte basin (between Bahia Sul and Sergipe-Alagoas) is deemed too narrow to have significant potential and Pernambuco-Paraiba (Recife) basin is deemed too shallow for petroleum generation.

Campos Basin

Introduction.

Area--Shelf: 6800 sq mi (17600 sq km), Slope: 7400 sq mi (19200 sq km), Total: 14,200 sq mi (36800 sq km).

Reserves-- 7.44 BBO and 4,52 TCFG (estimated from published Petrobras data) (7.29 BBO and 8.959 TCFG from Petroconsultants data).

Description of Area--The Campos basin is situated off the central southeastern coast of Brazil. The basin, as defined here, extends from the faulted hinge-line, lying sub-parallel to the coast through Cabo de Sao Tome, basinward to the continental-oceanic crust boundary (COB), approximately at the base of the continental slope, near the 6500 ft (2000 m) isobath. It is generally limited by the basement arches of Vitoria to the north and Cabo Frio to the south (fig. 7 and 2).

The Campos basin, as the most explored of the marginal rift basins, serves as a prototype for the lesser known basins. This applies especially to the structural framework. Figure 5 shows diagrammatically the structural evolution of the Campos basin and its effects on the sedimentation. The actual geology is considerably more complicated, however, as indicated by the map of the density of the rifting (fig. 4).

Stratigraphy

General. The Campos basin stratigraphy is portrayed in Figure 8. The Neocomian sedimentary strata are the graben-fill of the rift sequences, made up of volcanics and overlying, largely lacustrine source shales containing fresh-water coquina beds and some sandstones, the lower Lagoa Feia Formation. Reservoirs are largely the coquina banks and fractured basalts. After continental separation, approximately during the Aptian, interior sag evaporites and euxigenic source shales, the upper Lagoa Feia Formation, were laid down in the narrow gulf of restricted marine circulation between the diverging South American and African continents. Slow, continuous subsidence during the Albian under deepening marine conditions led to a shallow carbonate facies (lower Macae Formation). The effect on the sea-bottom configuration by movement of the underlying salt was important in controlling the distribution of the high-energy carbonate reservoir facies. During late Albian-Cenomanian, the carbonate was drowned by more rapid subsidence resulting in a Cenomanian-Turonian period of medium to deep neritic environment into which reservoir turbidites (Namorado Sandstone) of the upper Macae Formation were deposited. At the end of the Turonian, bathyal conditions prevailed. Reservoirs are turbidite sandstones concentrated in depositional troughs controlled by salt movement (Carapebus member).

In the Paleogene, rejuvenation of the sedimentary source area, resulted in the deposition of a Tertiary section (Carapebus member), containing huge turbidites over Cretaceous sediments of the shelf and particularly the slope. These turbidites are the principal reservoirs of the basin.

Source Rock. The source rocks of the Campos basin, as well as the other rifted continental margin basins of Brazil, are concentrated in three stratigraphic intervals which are well displayed in a geochemical profile of Petrobas well 1-RJS-76 of the Campos basin (fig. 9).

1) The Neocomian [Brazilian Buracica and Jiquia stages] synrift shales. These shales were deposited in interior rift lakes (fig. 5) and are highly organic with total organic carbon averaging over 1 percent and frequently ranging over 2 percent. The kerogen is largely type I or type II, high hydrogen index (S_2/TOC) indicates oil prone petroleum (fig. 9). In most of the rift basin this source sequence is in the thermally mature zone with projected vitrinite reflectance of 0.6 per cent and over (fig. 9).

2) Interior sag shales of late Neocomian and Aptian age. This is a relatively thin sequence, deposited in an elongate narrow interior gulf between separating continents which was subject to restricted entry by the sea (fig. 5B and 6). The shale sequence contains evaporites, carbonates, and euxinic shales containing organic material (TOC of about 1 percent); however, it is not so well developed or organically rich in the southern marginal basins

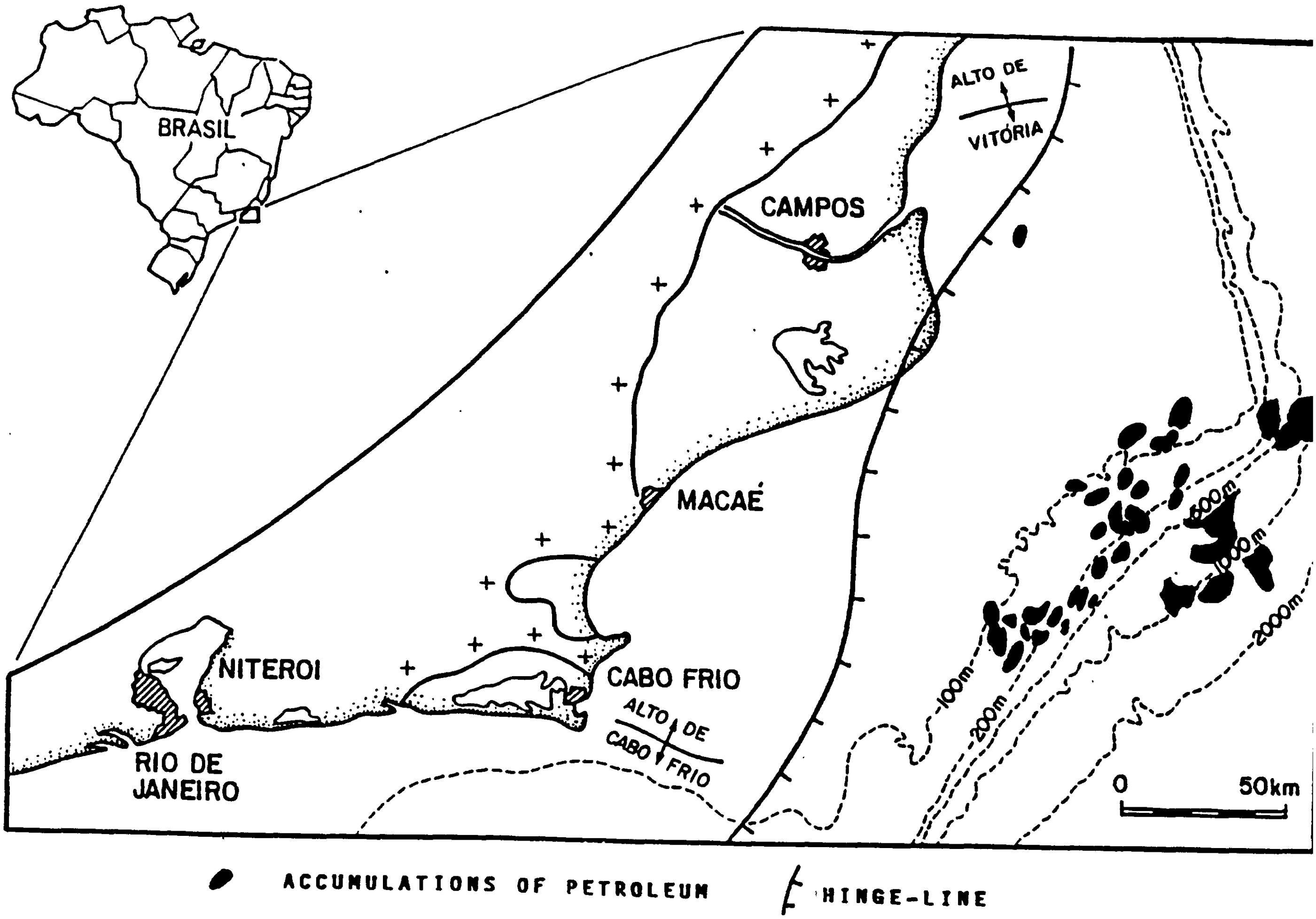


Figure 7 Index map of the Campos basin (modified from Marroquim et al, 1984).

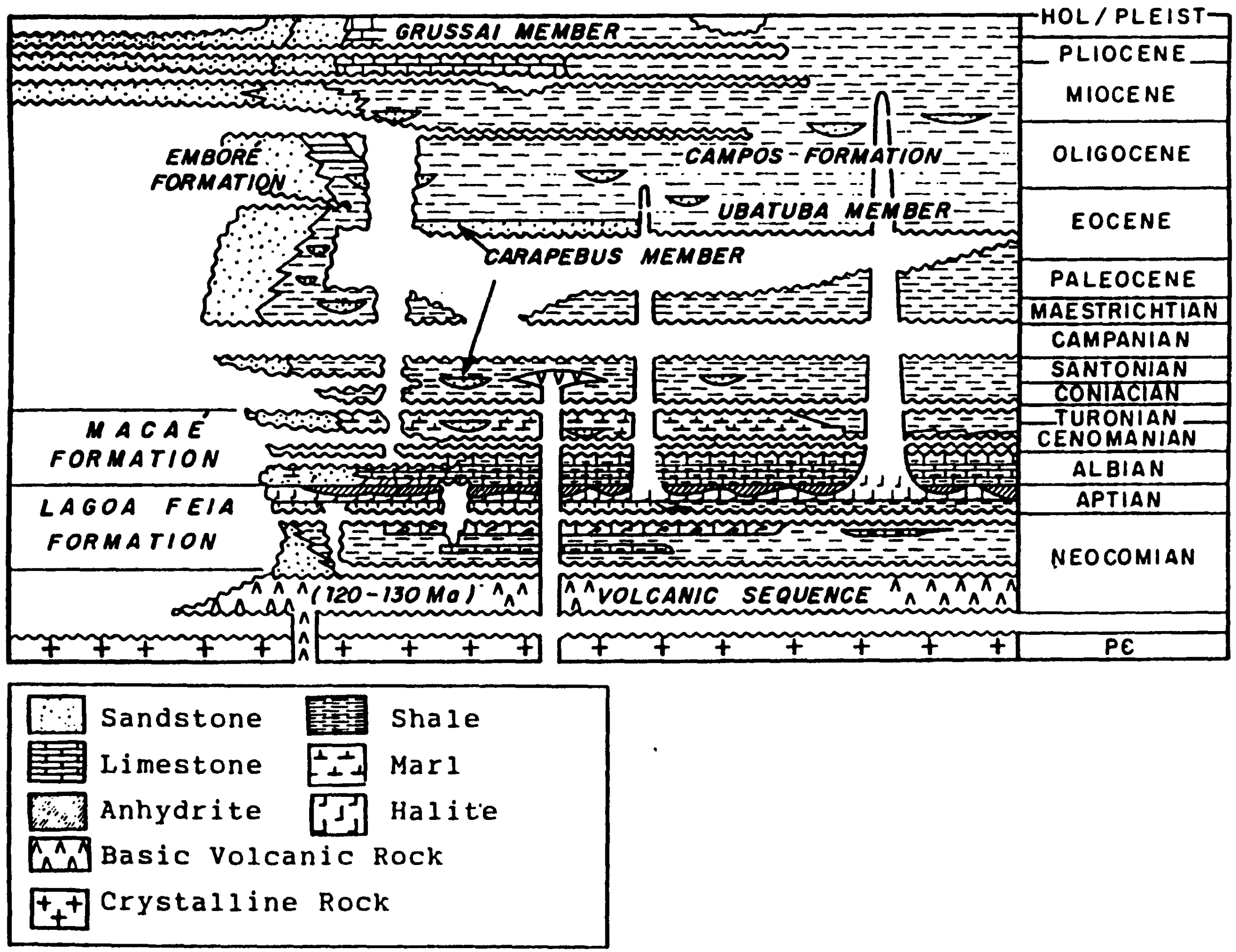


Figure 8 Stratigraphic column of Campos basin shelf (from Moraes, 1989).

such as the Campos basin (fig. 9). High hydrogen indices indicate this source is oil-prone.

3) Postrift shales of middle Cretaceous (Albian-Cenomanian) have source potential (fig. 9). The organic richness of these shales appear to be the result of a global anoxic event of the middle Cretaceous known as OAE-2 (oceanic anoxic event-2), the most notable of all Cretaceous anoxic events. In most of the marginal basins, these strata are too shallow to be mature source rock. However, it may be the main source of the relatively deep Santos basin. This zone, however, is of only minor source potential in comparison with the Neocomian lacustrine sequence.

Reservoirs. The reservoirs, briefly mentioned in the earlier discussion of stratigraphy, will be further discussed under the individual play analyses. No appreciable reservoirs are in prerift or interior sag sequences. In ascending order the principal reservoirs are listed below, the oldest reservoirs first:

1. Synrift reservoirs are relatively sparse and thin. In the Campos basin reservoirs are fresh water coquina banks, fractured basalt and probably syndepositional sandstones and conglomerates.

2. Postrift carbonate. Occurs in the Campos and the other rifted marginal basins and represents transition from interior sag to marine conditions. It is almost entirely platform limestone of a restricted to shallow water marine environment (fig. 5C). The reservoirs are largely secondary porosity zones.

3. Middle Cretaceous, mainly Albian, turbidite reservoirs, as represented by the Namorado sandstone of the Campos basin, are sandstone bodies in calcareous shale and marl. They form channel-fills and extensive blankets and are largely restricted to the shelf.

4. Upper Cretaceous, Cenomanian-Turonian turbidites, where occurring on the shelf, are also largely affected by movements of the underlying salt. Some deposition of these turbidites also appears to have occurred on the slope, but of a lesser extent.

5. Tertiary slope turbidite reservoirs are dominantly medium to coarse-grained sandstones. Relative lowering of sea level, combined with regional uplift including the sandstone provenance of the adjoining Serra do Mar coastal range, in the Tertiary, resulted in erosion of submarine canyons and extensive turbidite deposition.

Seals. The principal seals of the Campos basin are the Tertiary and Upper Cretaceous shales (of the Ubatuba member of the Campos Formation) which cover the shelf carbonate Macae Formation, and cover and enclose the Upper Cretaceous and Tertiary turbidites. The seals are slope and basinal black shales and moderately to strongly burrowed, greenish grey marls (Moraes, 1989). These shales

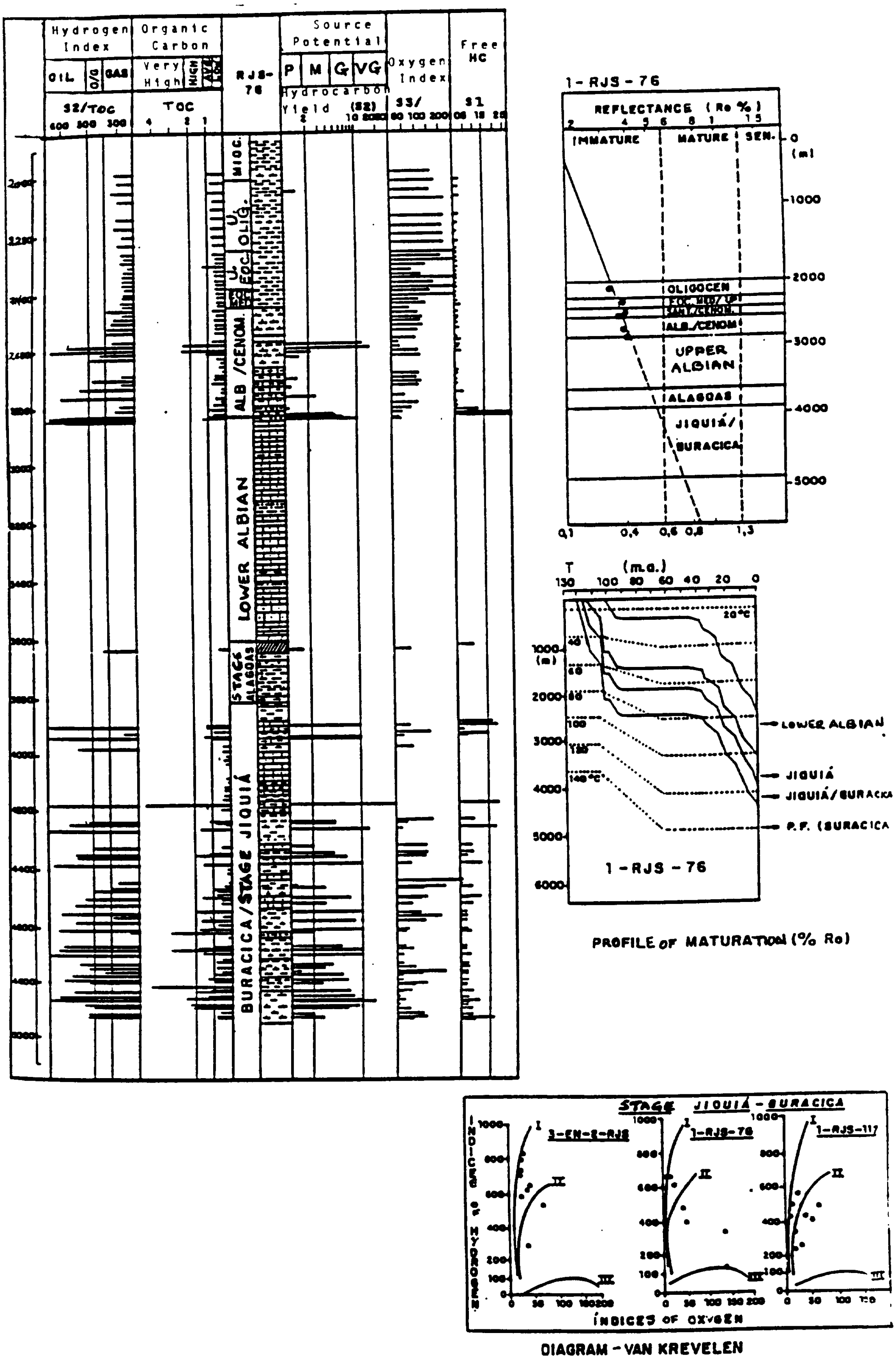


Figure 9 Geochemical profiles of various parameters as observed through the oil-generating zone of Wildcat R-JS-76 of central Campos basin. Note: Andar Alagoas ≅ Aptian and Buracica/Andar Jiquia ≅ Neocomian. P=poor, M=moderate, G=good; VG=very good; pyrolysis terms S1=free hydrocarbon, S2=hydrocarbon yield, and S3=released CO2. TOC=total organic content (modified from Pereira et al, 1984).

appear to be only moderately effective seals and leakage must be considerable. However, the relative youth (middle Tertiary and younger) of the oil generation and migration indicates that the bulk of the oil is still in the principal reservoirs.

Another prominent sealing lithology is also represented by the Aptian salt of the Lagoa Feia Formation, which is important in controlling and restricting the primary migration paths from the synrift source of petroleum to postrift reservoir strata. It is not, however, an effective seal of any pre-salt, synrift accumulations as it has been breached by listric faults, necking around salt-domes, and areas of non-deposition. Most of the breaching must have occurred during salt flowage which began near the end of the Cretaceous when the overburden reached some 3300 ft (1000 m) but largely before the uninvolved, low-dipping Tertiary strata were deposited. The breaching appears to have been largely prior to the Tertiary oil generation.

Structure.

General. The structure of the Campos basin taken as the model for the rifted continental margin of the Brazilian craton region has been previously discussed. The Campos basin may be unique, as indicated by Ponte and Asmus's (1976) subsidence curves, in that abrupt subsidence took place largely since the Eocene, whereas the other basins had an initially earlier subsidence over a longer time span (fig 10).

Traps. The structural traps of the rifted continental margins are briefly listed, from oldest to youngest:

1. Normal fault traps. These extensional faults formed in the Jurassic Neocomian rifting. They form closures in tilted fault blocks localizing synrift reservoir development.

2. Drape Closures. These traps are drapes over the faulted features. They mainly affect synrift, but also, to a lesser extent, postrift reservoirs.

3. Salt domes and pillows. The salt deposited during mid-Cretaceous (Aptian) time began to flow during the Cenomanian, resulting in structural traps but also stratigraphic traps by affecting the distribution of later Cretaceous turbidites around and abutting the pillows and domes.

4. Listric-fault associated traps. Fault blocks containing mainly carbonate reservoirs were tilted into listric faults soled by lubricating salt.

Aside from structural traps there are several types of stratigraphic traps:

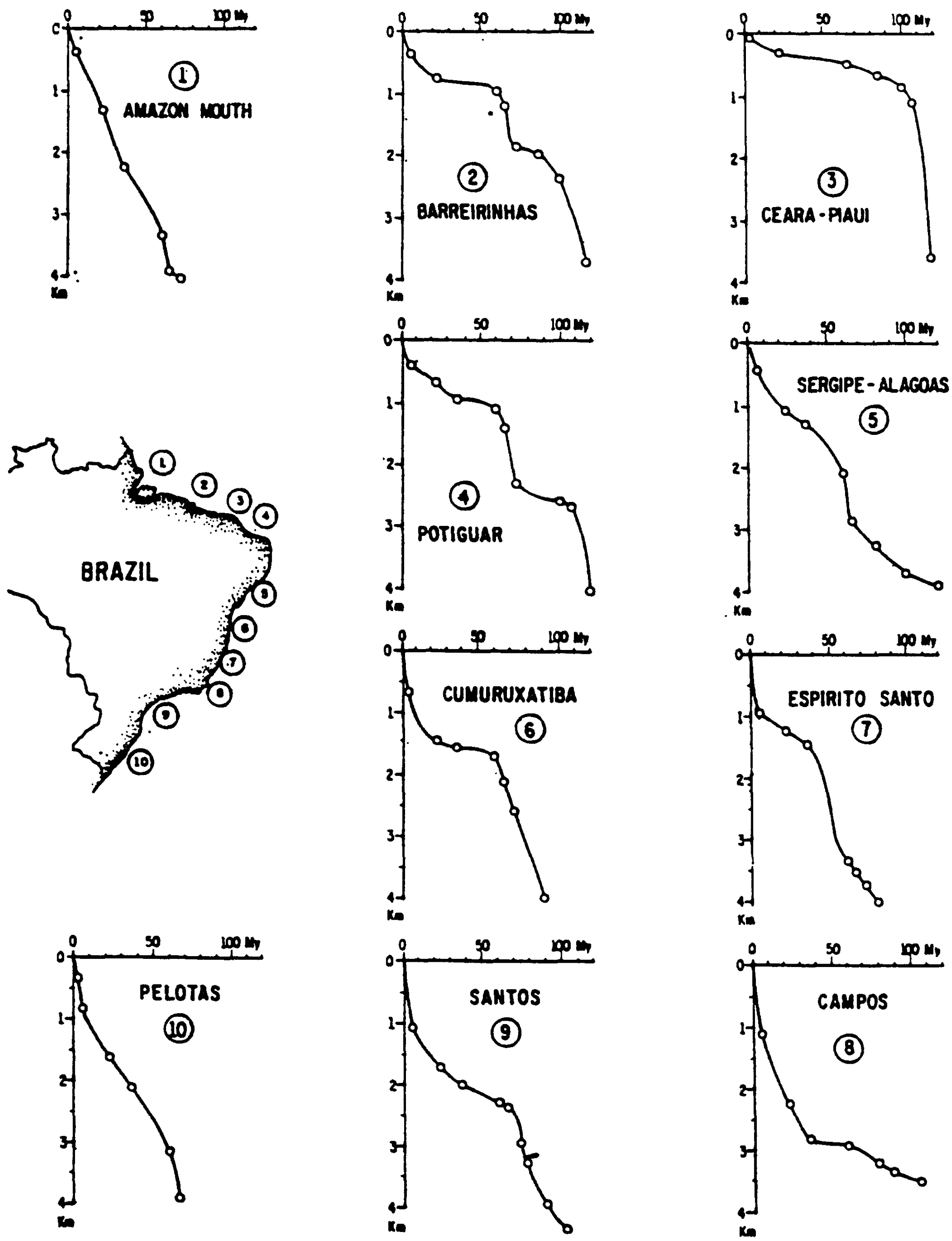


Figure 10 Subsidence rates along the Brazilian continental margin from selected Petrobras offshore wildcats (from Ponte and Asmus, 1976).

(1) Coquina banks of the synrift sequence.

(2) Syntectonic sandstones and fanglomerates associated with rifting are potential, if minor, traps of the synrift sequence.

(3) The turbidites are largely stratigraphic traps, although in many cases, closure is partly effected by the listric faulting and salt doming. The Campos basin's relatively abrupt Tertiary subsidence combined with the simultaneous rising of the adjoining region including the Serra do Mar coastal range and the lowering of sea level may have been responsible for a perhaps uniquely large volume of turbidites.

Generation, Migration, and Entrapment. As previously discussed, there is well-documented geochemical evidence for good to excellent source shales within the zone of oil-generation. The resolution of migration paths in the Campos, and most of the rifted marginal, basins is simplified by the fact that the primary source is a single unit, the Lower Cretaceous lacustrine shales, and further resolved that in the Campos basin, and most marginal basins, these source shales are the only thermally mature strata in the basin.

The timing of the migration in the Campos basin is important and may, to some extent, be unique since migration appears to be later than in the other marginal basins. According to the Ponte and Asmus (1976) curves (fig. 10) the Campos basin's abrupt subsidence took place largely since the Eocene so that only by mid-Tertiary, the oldest source shales (120-140 MY) would have reached a sufficient depth of about 10,000 ft (3 km) which, if the present-day thermal gradient of 1.3°F/100 ft (23.36°C/km) (Jahnert, 1982) remained constant, should be about the top of the oil-generating zone. The uppermost lacustrine source shales would have only reached the oil-generating zone in the Quaternary. This late maturation would cause migration to occur after the breaching of the Aptian salt layer, after and during trap formation including the Tertiary turbidites. Perhaps, equally important, the late migration allows less time for leakage through the Tertiary shale seals.

Plays. The geology of the Campos basin indicates that four of the six potential plays of the Brazilian rifted continental margin basins are prospective in the Campos basin. The prospects of the prerift play and the interior sag or transitional play are considered negligible in this sector of the coast.

1) The synrift play. Petroleum is in Neocomian coquina banks and fractured basalts and may be regarded as a single drilling objective over paleo-highs. Some petroleum may occur in syntectonic sandstones and conglomerates. The amounts of oil and gas recovered are relatively minor.

2) Postrift carbonate play. The reservoirs are Albian carbonates which are affected by gravity tectonics of the underlying Aptian salt. Oil may have been trapped in domes, pillows and more importantly, tilted blocks associated with salt-soled listric faults. The play is restricted to the shelf and may be largely explored.

3) Postrift shelf turbidites. Petroleum is mainly in Cretaceous turbidites reservoirs in a progressively subsiding shelf. Distribution and facies of the reservoirs are governed by the salt-affected paleotopography. Closures include stratigraphic traps, salt structure, and fault traps.

4) Postrift slope turbidites. Turbidites are primarily of Tertiary age and secondarily of late Cretaceous age. Turbidite traps are largely stratigraphic, but may also be associated with salt doming and listric faulting.

<u>Exploration history and petroleum occurrence</u>. Systematic exploration of the Campos basin began in 1968 with marine seismic and other surveys. The first offshore wildcat was drilled in 1971 and the first discovery (Garoupa Field) (fig. 11) was made in 1974 after 11 dry holes. The discovery was followed by many others resulting, by 1982, in 26 oil and 3 gas fields located on the shelf (considered by Petrobras to extend to the 400-meter [1300 ft] isobath). The first wildcat located beyond the 400-meter isobath was drilled in 1982 and the first slope discovery was made in 1984 in water depths of 866 ft (383 m). Since 1983 the rate of drilling success has substantially increased (to 50 percent giving an overall average of about 40 percent), a key factor being the high quality of the seismic data, notably 3-D seismic shooting, quantitative amplitude mapping, and other techniques allowing the delineation of turbidite traps. In November 1984 the continental-slope turbidite accumulation, Albacora, with reserves of over 1.0 BBO, was discovered, and a similar accumulation, Marlim, adding some 4.00 BBO to the reserves, was discovered in February 1985. In May of 1991 a further slope turbidite discovery, Barracuda, was made, raising the reserves an estimated 1.1 BBO.

By the end of 1988, 484 "exploratory wells," and 148,000 mi (239,000 km) of seismic line including 78,000 mi (126,000 km) of 3-D seismic were accomplished resulting in the discovery of 42 petroleum accumulations (fig. 11) (Figureredo and Martins, 1990). The wildcats had a reported over-all success of 16 percent (indicating some 262 wildcats.)

Figure 12 is a graph showing the amount of cumulative oil and gas discoveries versus the cumulative number of wildcats (data from Petroconsultants 1989, which is not entirely complete and does not include the 1991 Barracuda discovery). The initial steep incline from 0 to 60 wildcats reflects the high success of the first surge of shelf structural discoveries. The gentler slope from 60 to 130 wildcats reflects the lower, more stable, continued rate of success

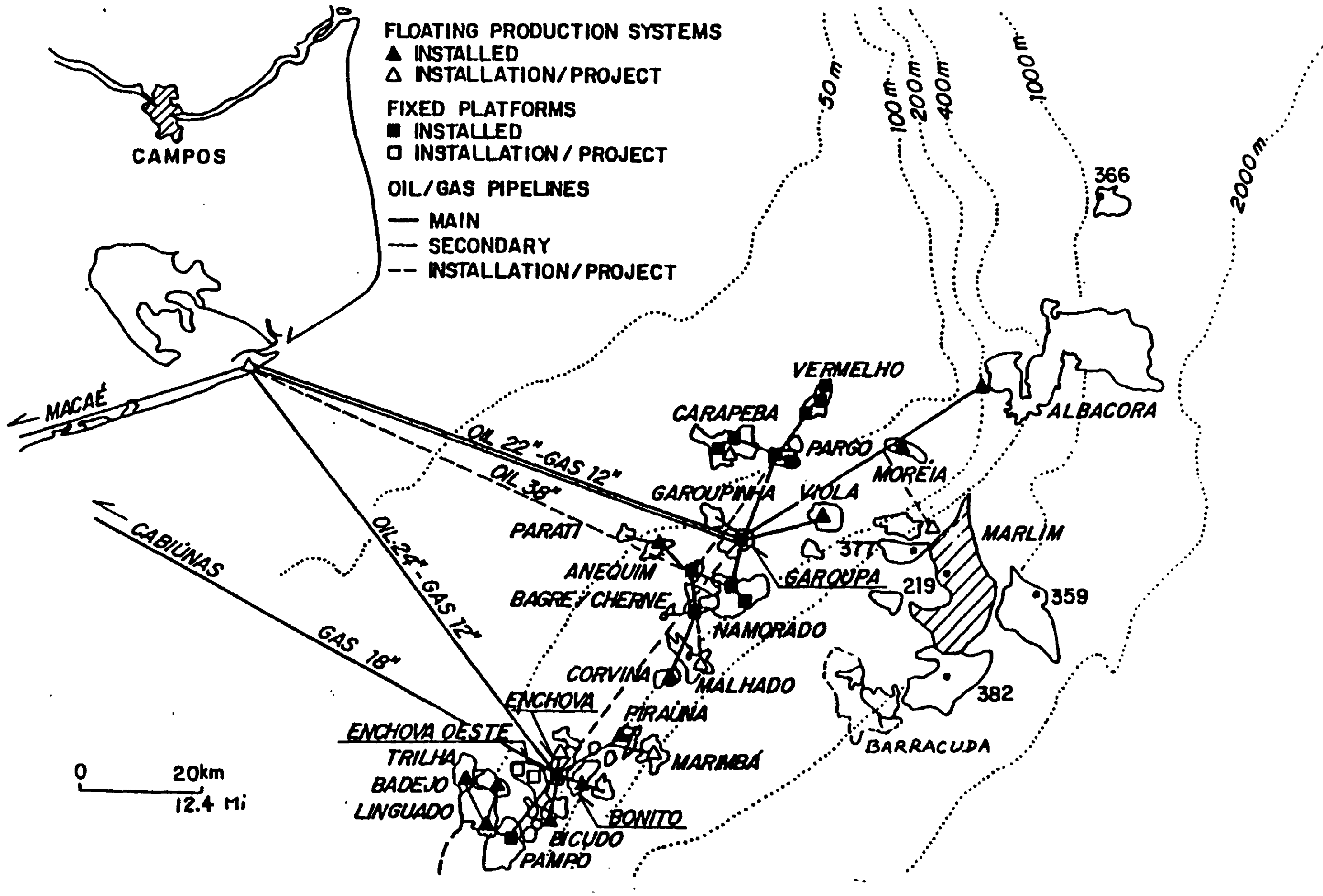


Figure 11 Campos basin oil fields and production systems, 1988 (modified from Friere, 1988).

in the exploration for shelf structures averaging about .7 MMBO and .7 BCFG per wildcat. The increased oil-slope from 130 to 185 wildcats probably indicates the additional success of stratigraphic trap, largely shelf turbidites, exploration. The abrupt very steep ascent from 180 to 200 wildcats denotes the slope turbidite discoveries. The continued ascending slope after 200 wildcats signifies that the exploration of the slope is still immature and of high potential. The 1991 discovery of the Barracuda giant field (data as yet largely unavailable) is not reflected in this curve.

The petroleum of the rifted continental margin appears to be around 90 percent oil and 10 percent gas on an oil-equivalent basis and almost all the gas is associated gas. For estimation purposes, it is assumed from the literature (Figueirado and Martins, 1990, and Freire, 1989) that the GOR of 762 CFG/BO would apply to the shelf plays and the less gaseous 575 CFG/BO would apply to the slope turbidites.

The 1990 oil and gas recoverable reserves amounting to 6.34 BBO and 3.89 TCFG for the Campos basin, broken down in the various plays or formations, are shown in Table II. An estimate of the 1992 total reserves of 7.44 BBO and 4.52 TCFG is made by a final addition to Table II of the estimated reserves of the 1991 Barracuda slope-turbidite discovery (Petrobras, 1992).

Table II is derived from in-place oil and in-place oil-equivalent reserve figures (prior to the 1991 Barracuda discovery) of Figuieredo and Martins, 1990, which are combined with recovery factors indicated in the literature (Baumgarten et al 1988, and Friere, 1989). To approximately fit the reserves of the formations and time-stratigraphic units, used by Petrobras in their estimates, to the plays defined by tectonic sequences used in this study, the Petrobras reserves of the Senonian and Tertiary are assumed to be largely in the slope play (and the pre-Senonian to the shelf plays).

It should be pointed out that Petrobras's indicated oil recovery factors appear conservatively low (perhaps only considering primary recovery) so that Table II derived recoverable oil and gas reserves are correspondingly conservative. For instance, the recoverable reserve estimates of Petroconsultants (1989) for the Campos basin amount to 7.3 BBO and 8.9 TCFG against the 1990 estimates of 6.34 BBO and 3.89 TCFG arrived at in Table II.

Estimation of Undiscovered Oil and Gas

General. For this study there appears to be four distinct plays of the six possible major plays of a rifted margin; however,for lack of sufficient information, two have been combined so that three plays are described and assessed separately. The plays are: 1) a synrift play, 2) a postrift shelf carbonate and shelf turbidite play which are combined as a single shelf play, and 3) a slope play. For convenience in dealing and comparing with the

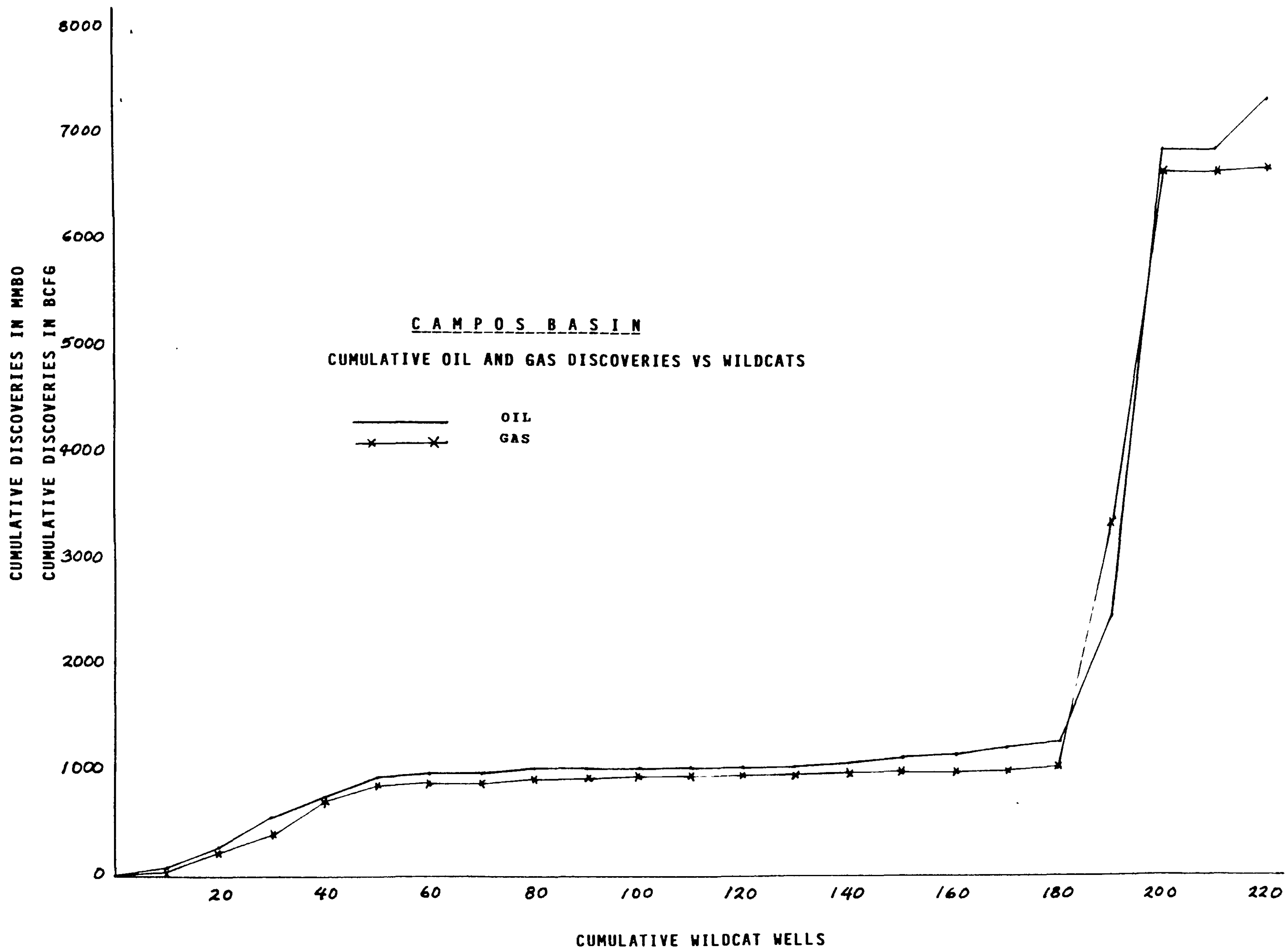


Figure 12 Graph showing the relation of the quantity of discovered oil and gas against the number of wildcat drilled in the Campos basin (data from Petroconsultant 1990 which may be incomplete).

TABLE II

CAMPOS BASIN

RECOVERABLE RESERVES (DERIVED FROM PETROBRAS, 1990)

		- 1 -	- 2-	- 3 -	- 4 -	- 5 -	- 6 -	- 7 -	- 8 -	- 9 -
		OEIP(1) (MM3)	OIP(2) (MM3)	OEIP(GAS)(3) (MM3)	OIP (MMBO)	GIP(4) (BCFG)	OIL RECOVERY FACTOR(%)	RECOVERABLE OIL(MMBO)	GAS/OIL RATIO CFG/BO	RECOVERABLE GAS(BCFG)
Synrift	Basalt	10,864	10,311	553	64.856	20.903	20.0(5)	12.971	762(8)	9.884
	Coquina	104,551	92,230	12,321	580.903	465.734	24.6(5)	142.711	"	108.746
Postrift	Albian carb.	749,748	692,051	57,427	4,353.000	2,170.741	16.6(5)	722.598	"	550.620
Shelf	E.Cret.clastic	329,427	305,182	24,245	1,919.595	916.461	22.2(6)	426.150	"	324.726
Slope	L.Cretaceous	242,771	231,222	11,549	1,454.386	436.552	22.2(7)	322.874	575(9)	185.653
Turbidites	Eocene	370,429	342,292	28,137	2,153.017	1,063.579	22.2(7)	557.890	"	320.787
	Oligocene	2,880,613	2,646,489	234,124	16,646.415	8,849.887	22.2(7)	3,695.504	"	2,124.915
	Miocene	362,572	328,845	33,427	2,068.435	1,274.881	22.2(6)	459.193	"	264.036
TOTAL (1990)		5,052,705	4,469,442	403,263	29,239.831	15,243.341		6,339.891		3,889.367
TOTAL,1992 (10)								7,439.891	(10)	4,521.867 (10)

(1) Oil-equivalent in-place estimates.(Figueireda, Martins, 1990).

(2) Oil in-place estimates (Figueiredo, Martins,1990)

(3) Column 1 minus column 2.

(4) Gas in-place -- column I x 6.3(Bbls/M3) x 6,000(CFG/BO)

(5) Derived from Baumgarten et al, 1988,

(6) Assumed same as (7).

(7) Derived from Freire,1989

(8) Derived from Campos shelf oil and gas reserves (Figueiredo, Martins,1990)

(9) Derived from Merlim and Albacora oil and gas reserves (Figueiredo, Martins, 1990)

(10) The 1991 giant slope-turbidite Barracuda discovery (1.1 BBO and estimated 0.6325 TCFG), made after these 1990 reserve data were published, is assumed to increase the reserves accordingly.

limited data, it is assumed that the Lower Cretaceous (Neoconian to Turonian) prospects are largely restricted to the shelf and that the Upper Cretaceous (Senonian) and Tertiary prospects to the slope.

Assessments of these three plays, based on indirect evidence such as analogies and field-size distribution, will be compared with the published play analysis of Petrobras. The Petrobras play analyses and estimates (Figuieredo and Martins, 1990), however, are reported in oil-equivalent and in-place terms, and relate to prospects in eight formations rather than the three plays as limited by data available for this study; furthermore, the data and rationale behind the Petrobras play analyses and estimates are unavailable. Therefore, a discussion of the relevant geology and petroleum occurrence of the three plays along with general estimate of undiscovered petroleum, arrived at from perhaps a different perspective than the Petrobras play-analysis are considered worthwhile, and are discussed prior to a comparison with the Petrobras play-analysis-derived estimates.

Synrift Play.

Area of Play. 14,200 mi^2 (36,800 km^2) corresponding to entire basin area.

Reserves. 155.7 MMBO, 118.6 BCFG (Table II) or 175.5 MMBOE..

Description of Play. The petroleum potential of the synrift play is limited by the amount of reservoirs. Presently producing reservoirs are fresh-water coquina banks and fractured basalts; synrift sandstones and conglomerates are potential reservoirs, but thus far are not productive. Figure 13 shows the relation of coquina strata to structure and the fractured volcanics. About 90 percent of the synrift oil is produced from the coquina. The four producing fields and most of the exploration to date are confined to an early Cretaceous syndepositional high, the Badejo High, which makes up only about 1 percent of the play area (fig. 4). The net thickness of the coquina banks range up to 130 ft (40 M). Porosity of the coquina is irregular and generally low, averaging 13 percent. Fractured basalt parameters are unknown.

A cross-plot of the cumulative discoveries made from the 60th to 130th wildcat (shelf structural plays) versus number of wildcats indicates a curve with a fairly stable discovery rate after the first discovery surge averaging about .71 million barrels of oil (MMBO) per wildcat (fig. 12). Assuming that the same number of wildcats are drilled on the shelf in the future, and that the discovery rate remained stable (new technology and plays counter-balancing increasing discovery difficulties), 92 MMBO (130 X .71) would be discovered. An estimated one-third of this discovered oil would be from synrift prospects (the other two-thirds being from the postrift shelf carbonates and turbidites), giving .031 BBO for the play. Gas discoveries per wildcat have approximately the same slope

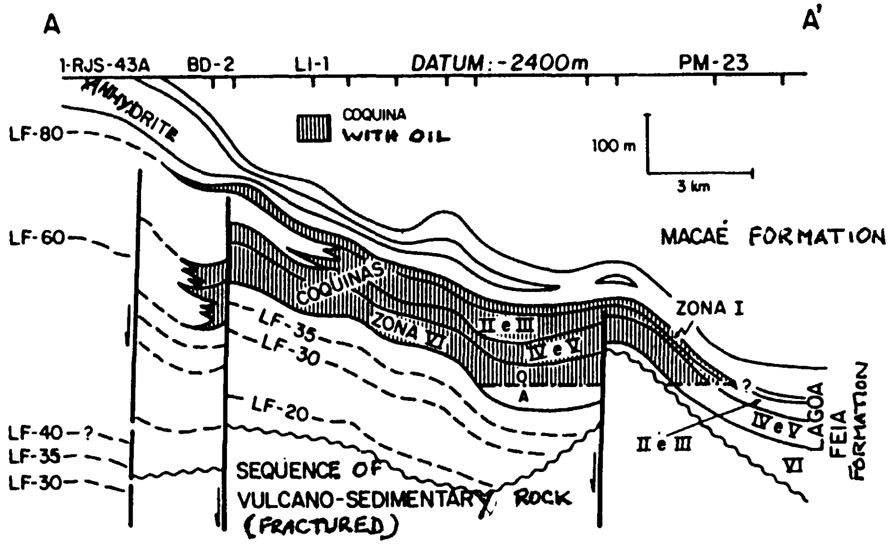


Figure 13 Structural-stratigraphic section through the Badejo high of the Campos basin showing the oil-filled Coquina reservoirs, the volcanic-sedimentary contact, the anhydrite bearing cover rock and the faulted structure location on figure 4 (modified from Baumgarten et al, 1988).

(fig. 12), or .67 BCFG/wildcat, indicating some .030 BCFG will be discovered. This estimate may be too low, however, since the exploration drilling in this play has been confined to the very limited area of the southern end of the Badejo high (1 percent of the play area, fig. 4).

The southern part of the Badejo high appears to be a pre-evaporite regional paleo-high as indicated by the thin, volcanic-to-evaporite interval of as little as 330 ft (100 m) (fig. 27) compared to a thickness of over 2000 ft (600 m) elsewhere (figs. 14, 25, and 27). The paleo-high localized good reservoir development and also provides relatively shallow drilling depth with less salt cover. It is likely that other such syndepositional highs are present in other parts of the play area, perhaps obscured under thicker salt or at greater depths under the slope. I estimate that about three times the presently known syndeposition high area is yet to be found, indicating undiscovered reserve on an oil-equivalent basis of three times the resources (reserves plus estimated undiscovered resources) of the Badejo high or 0.60 BBOE. Since the undiscovered resources are probably deeper, it is assumed the petroleum, would be about 50 percent gas indicating resources of 0.30 BBO and 1.80 TCF.

By areal analogy to the estimated oil resources (reserves plus undiscovered oil) of the presalt play of the once nearby Congo basin (1.9 BBO) (Kingston, 1988), the Campos presalt oil resources would be 0.9 BBO. However, less than half of the Congo presalt oil comes from the synrift play (more than half coming from the prerift play which does not occur in the Campos basin). Accordingly, about 0.45 BBO (0.9 x.5) are indicated for this play in the Campos basin.

By areal analogy to the once nearby Gabon basin of Africa resources (reserves and estimated undiscovered oil) as indicated by recent establishment of the Rabi-Kuanga discovery) the pre-sault resources of the Campos basin would be 1.09 BBO. However, since there is no Campos basin counterpart to the Gabon basin thick, petroliferous synrift reservoirs (Gamba and Dentale Formations), this estimate is reduced to half or 0.54 BBO.

These indirect methods yield resource estimates of 0.30, 0.45, and 0.54 BBO, averaging some 0.43 BBO. Assuming that the GOR in the basin shelf of 726 CFG/BO (derived from Freire, 1989) applies, the accompanying gas amounts to about 0.2 TCFG. Subtracting present reserves, the undiscovered petroleum of the synrift play is estimated to be 0.27 BBO and 0.20 TCFG.

Shelf Play (Postrift Carbonate Play and Postrift Albian Turbidite Play)

Area of Play. 6,800 mi^2 (17,600 km^2)

Reserves of Shelf. 1.15 BBO, 0.88 TCFG (Table II) (Shelf reserves are estimated by limiting them to Petrobras, (1) Albian carbonate and (2) Lower Cretaceous clastics reserves of the basin.

Description of Play. The carbonate portion of the shelf play pertains to the Albian platform calcarenite and calcirudite (Macae Formation) reservoirs with essentially intergranular porosity. These facies were deposited in restricted to shallow marine seas as offshore bars in shoaling-upwards cycles controlled by salt tectonics. Traps were formed by salt-tectonics either by salt doming or in salt-soled listric faults which formed tilted carbonate-surfaced blocks (fig. 14).

The turbidite portion of the shelf play includes (1) Turonian-Cenomanian turbidites (Namorado Member) that occur in lenses and channels just above the carbonate in the upper Macae Formation (fig. 8 and 15A) and (2) overlying upper Cretaceous (Senonian) turbidites which are confined to narrow troughs between salt pillows and domes. These turbidites show rapid lateral variation in thickness (figs. 2 and 15B).

The shelf carbonate and turbidite portions of the shelf play are quite different and require different exploration techniques and drilling sites; even the two forms of turbidites may be considered as separate plays, but, because of data limitations, they are treated here as a single play, thus the shelf play includes all prospects on the shelf above the salt.

The oil discovery-rate curve, between wildcats 60 and 189, prior to the slope drilling, indicates only minor further shelf discoveries at a level 2.36 MMBO/wildcat; assuming an additional 100 wildcats (about half those already drilled) are drilled on the shelf, 0.236 BBO will be discovered. Gas discoveries during the same time average 1.03 BCF per wildcat and if the same number of wildcats are drilled, .103 TCF of gas will be discovered.

Analogy of the post-salt Campos shelf plays to the geologically similar offshore Congo or Gabin basins shelves are of little value since the postrift reserves of the Campos basin, on an areal basis, are about twice that of the African basins. It is speculated that this difference may be ascribed to the better development of the turbidites reservoirs in the Campos basin.

In summary, the shelf has reached a mature stage in exploration and only modest amounts of undiscovered oil and gas remain. Total undiscovered resources in the shelf portion (48 percent by area) of

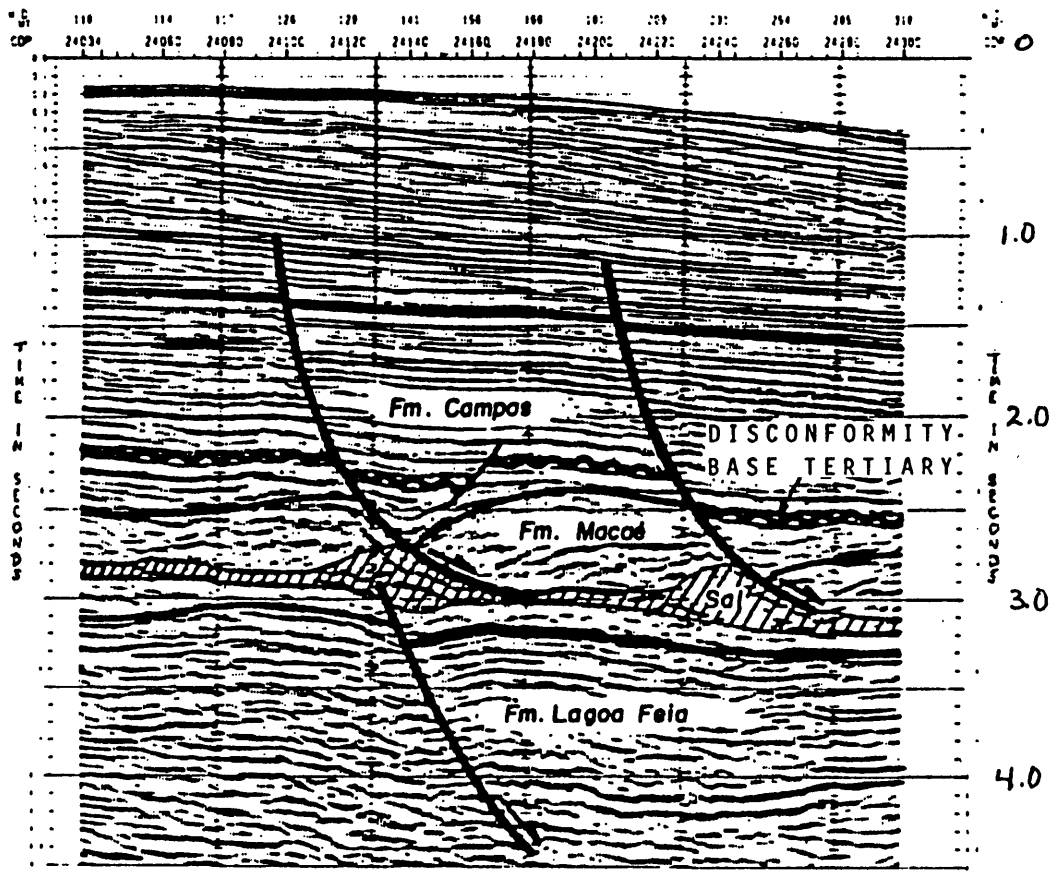


Figure 14 Dip seismic section through the Campos basin showing the carbonate Macae Formation as it is affected by salt doming and by salt-soled listric faulting. It also shows the structure of the overlying Cretaceous clastic, some of which was syndepositional with the salt movement (modified after Figueiredo and Mohriak, 1984).

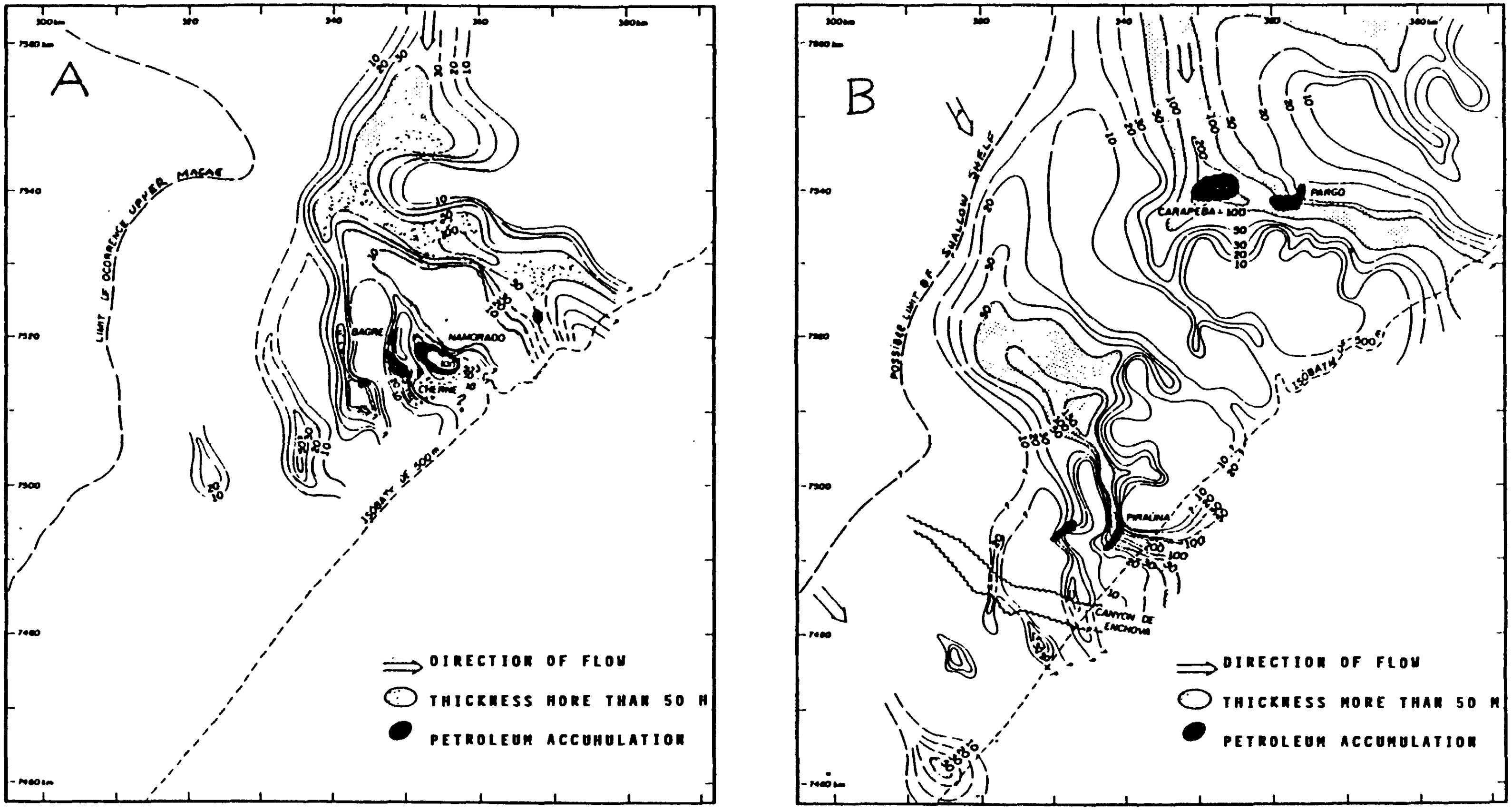


Figure 15 Isopach maps of Cretaceous combined sandstone thicknesses, in meters, on the Campos basin shelf. Map A is of the Namorado sandstones which are essentially channels and sand lenses of turbidites in the top part of the Macae Formation (Turonian-Cenomanian) and Map B is of the overlying sandstones of the upper Cretaceous (Senonian) turbidites. Sandstone is concentrated in lows and channels between paleo-topographic highs of the shelf (modified from Figueiredo and Mohriak, 1984).

the synrift play and the shelf postrift plays are 0.384 BBO and .211 TCFG or .419 BBOE. Petrobras indicates that 10 percent of their estimate of Campos undiscovered oil-equivalent petroleum is in water depths less than 400 m (Figueredo and Martins, 1990). This would amount to recoverable resources of .574 BBOE, compared to my estimate of .419 BBOE for the Campos shelf.

<u>Slope Play</u>

<u>Area of Play</u>. 7,400 mi^2 (1,920 km^2)

<u>Reserves</u>. 5.15 BBO 3.52 TCFG (Table II). For correlation with Petrobras estimates, the reserves of the slope are assumed approximately equal to the sum of the Senonian and Tertiary turbidites, although some older Cretaceous turbidite reserves are also on the slope and some, possible offsetting, Senonian and Tertiary turbidite reserves are on the shelf.

<u>Description of Play</u>. Beginning in the Paleogene, uplift of the adjoining continental areas (Serra do Mar Coastal Range), combined with sea level changes, caused prograding Tertiary sequences, consisting mainly of huge turbidite sandstone volumes derived from previously deposited shelf sediments, to be redeposited on the eroded surface of Cretaceous slope/continental rise and abyssal plain rocks. Thickest sandstones, up to 330 ft (100 m), are the Oligocene turbidites (Bacoccoli and Toffoli, 1988). The Tertiary turbidites are spread over hundreds of square miles. Fig. 16 shows a typical stratigraphic column through the Oligocene section of an Albacora well, showing the lithology of the turbidites and their relation to sea level changes. Fig. 17 shows the distribution of the Oligocene turbidites and related scour areas and canyons.

The slope reserves are largely from the Albacora, Barracuda, and Marlim complex of fields (two additional fields are RJS.-366 with an estimated 100 MMBO [Petroconsultants 1990] and RJS-409 of unknown potential [fig. 18]. Table III, drawn from 1989 data, shows the turbidite reservoir characteristics and the in-place reserves of Albacora and Marlem fields. A late addition to the slope reserves are those of Barracuda field, discovered in May 1991, amounting to 1.1 BBO [Petrobras, 1992] and presumably a corresponding .63 TCFG.)

Fig. 19A is a seismic dip section across part of the Albacora field, and Fig. 19B its interpretations. They show the structure as well as the unconformity and onset of progradation near the base of the Tertiary. Fig. 20A is a seismic section through the northern part of the Marlim field showing the effects of the salt flowage on the folding and faulting and the high-amplitude reflections of Oligocene reservoirs. Figure 20B shows the relation of Marlim and Barracuda fields, apparently separated by faults.

Figure 21 is a north-south seismic section of the Marlim field showing the structure, but in particular, the very high amplitude reflections at the top of the oil-filled Oligocene turbidite.

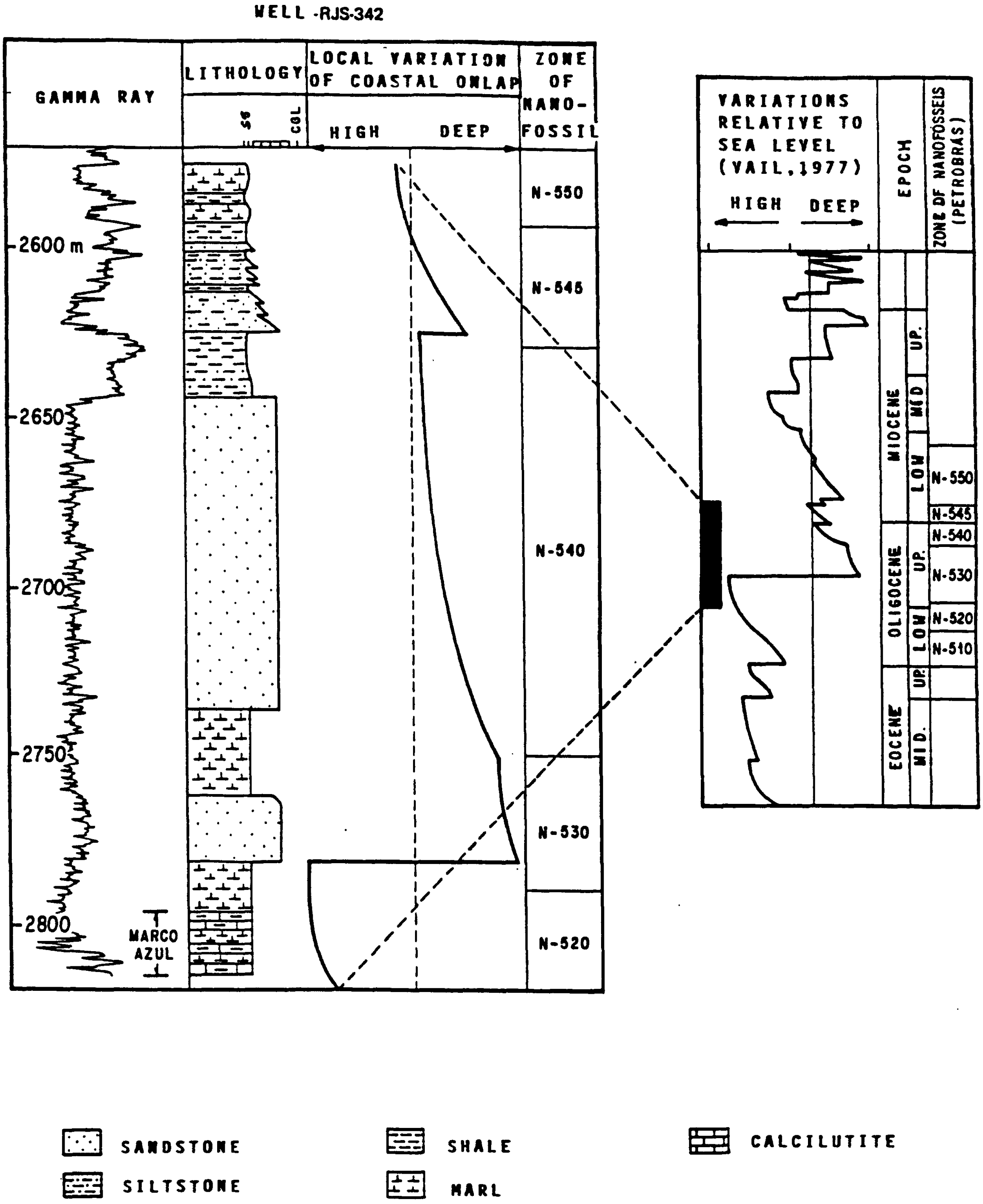


Figure 16 Stratigraphic column of the Oligocene section of the Albacora Field of the Campos basin showing lithology, gamma ray profile, curve of local variation of sea level during the Tertiary, and relation to global variation in sea level (modified from Cruz et al, 1987).

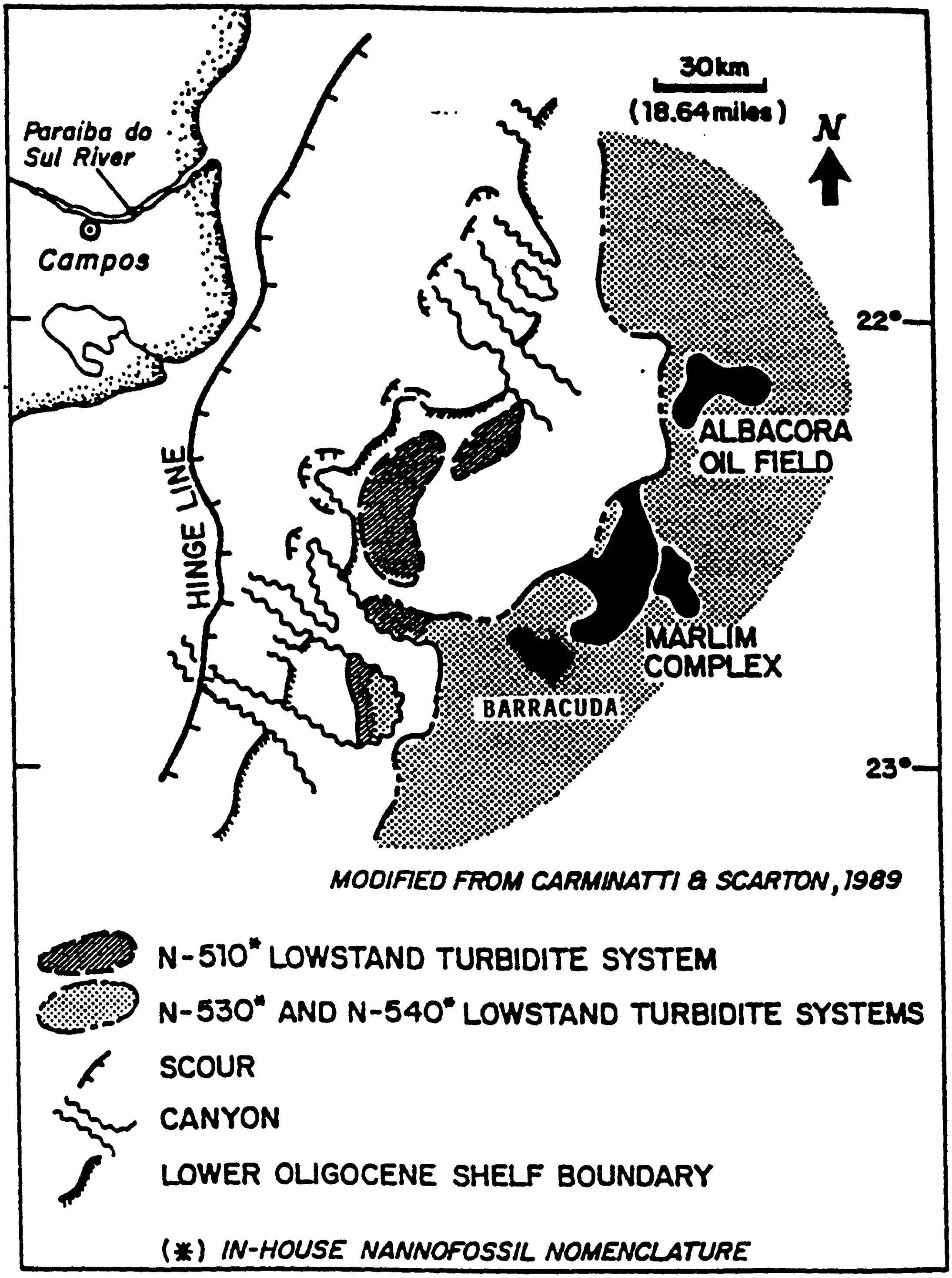


Figure 17 Paleogeography of the Oligocene turbidite system in Campos basin, N-510 ≅ basal Oligocene, N-530 and N-540 ≅ Upper Oligocene (see figure 16).

TableI I I RESERVOIR CHARACTERISTICS OF THE ALBACORA AND MARLIM FIELDS

	ALBACORA						MARLIM
PARAMETER / RESERVOIR	MIOCENE	OLIG. 1	OLIG. 2	OLIG. 3	EOCENE	ALBIAN	OLIGOCENE
BATHYMETRY (m)	700-2,000	300-650	300-1,100	500-650	900-1,000	200 - 500	500-1,100
DEPTH (m)	2,350-2,480	2,500-2,645	2,550-2,645	2,600-2,645	2,830-2,930	3,180 - 3,260	2,500-2,700
AVERAGE NET PAY (m)	16.8	18.5	16.1	19.0	10.5	29.9	44.5
POROSITY (%)	27.8	24.5	23.4	29.0	26.4	17.0	25.0
WATER SATURATION (%)	22.8	20.1	24.9	20.0	18.3	30.7	14.0
OIL GRAVITY (°API)	17.6-25.6	26.0-29.0	24.0-27.0	-	29.7-29.8	25.4-30.6	19.0-20.0
INITIAL SOLUTION GOR (m^3/m^3)	376.0	95.0	97.0	-	118.0	65.0	80.0
EFFECTIVE PERMEABILITY (mD)	1,460-1,750	280-3,460	433-3,270	-	-	11-71	1,325-5,372
PRODUCTIVITY INDEX (m^3/DAY/kg/cm^2)	6-37	7-79	9-40	-	28-43	1-6	4-47
OIL IN PLACE ($10^6 m^3$)	226.0	121.1	209.6	4.8	14.5	73.4	1,298.5
OIL IN PLACE (10^6 BBL)	1,421.54	761.72	1,318.38	30.19	91.20	461.69	8,167.57
MAIN OIL/WATER CONTACT (WATER TABLE)	NOT KNOWN	2645	2645	2645	NOT KNOWN	3260	2740

From Souza et al, 1989

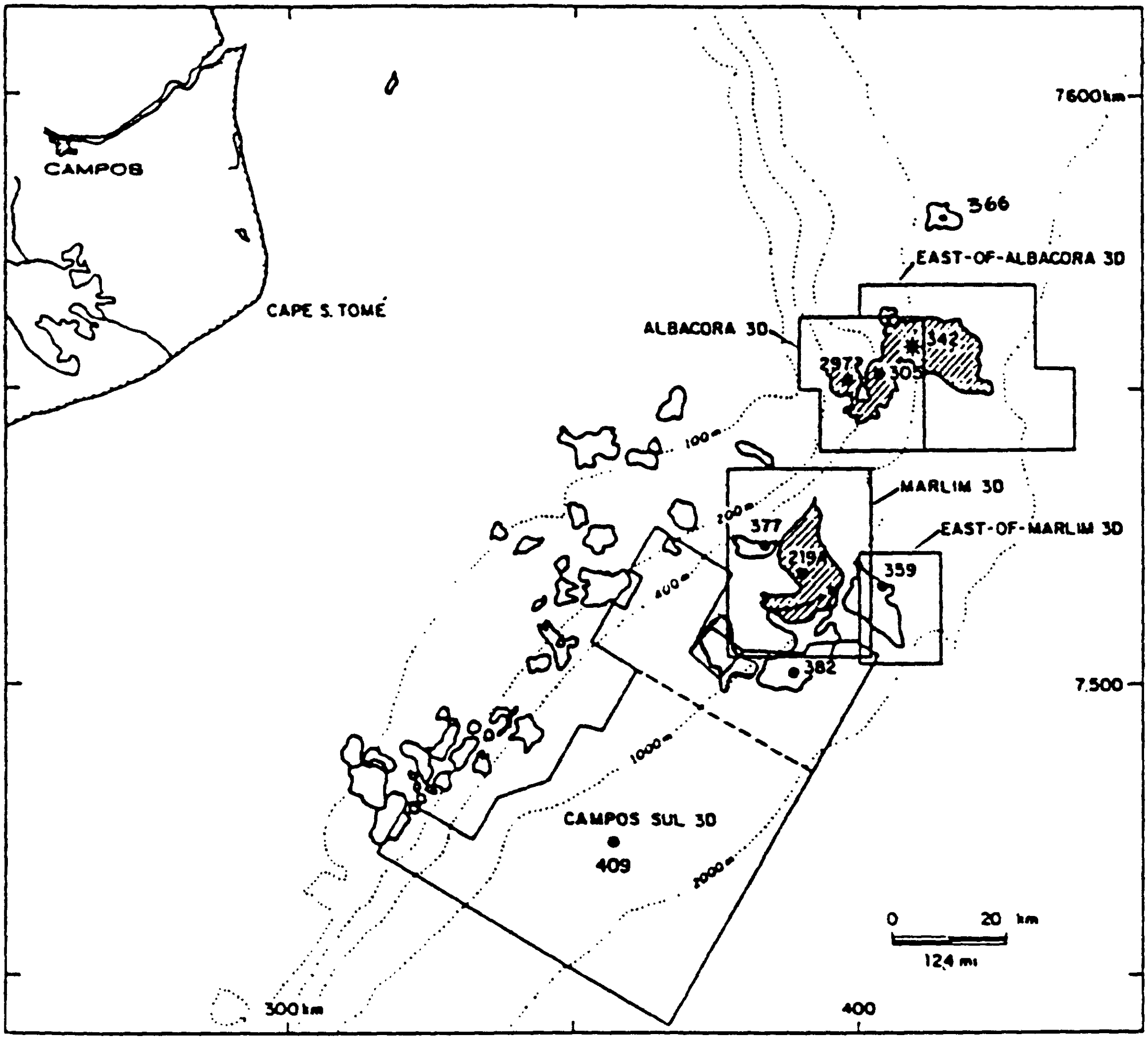


Figure 18 Location map of the Albacora and Marlim fields and 3-D surveys in deep water (modified from Souza et al, 1989).

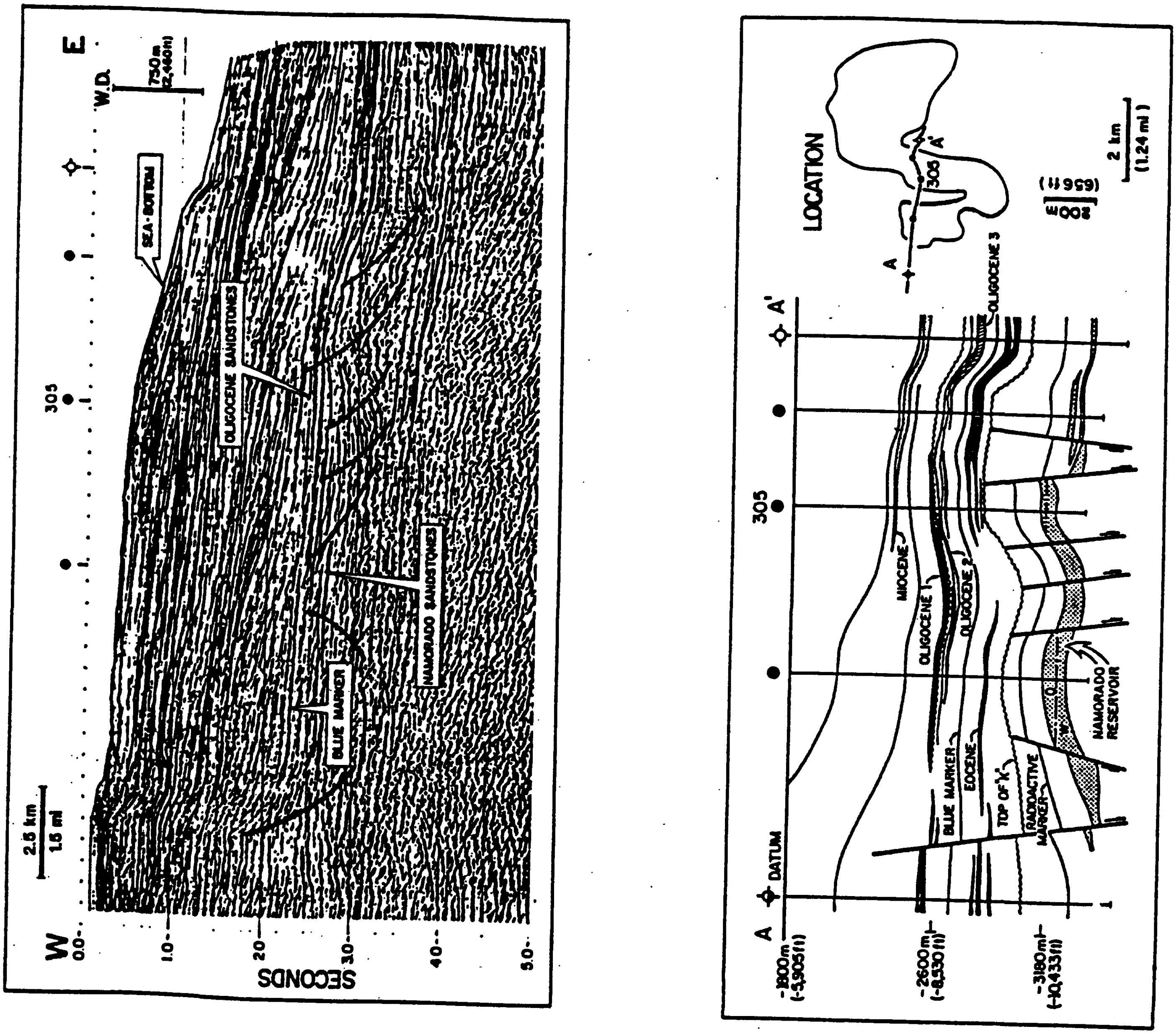


Figure 19 A 3-D seismic dip section across the Albacora Field and its interpretation showing the Cretaceous salt-soled listric faulting and structure, and the basal Tertiary unconformity, progradation, and turbidites (after Souza et al, 1989).

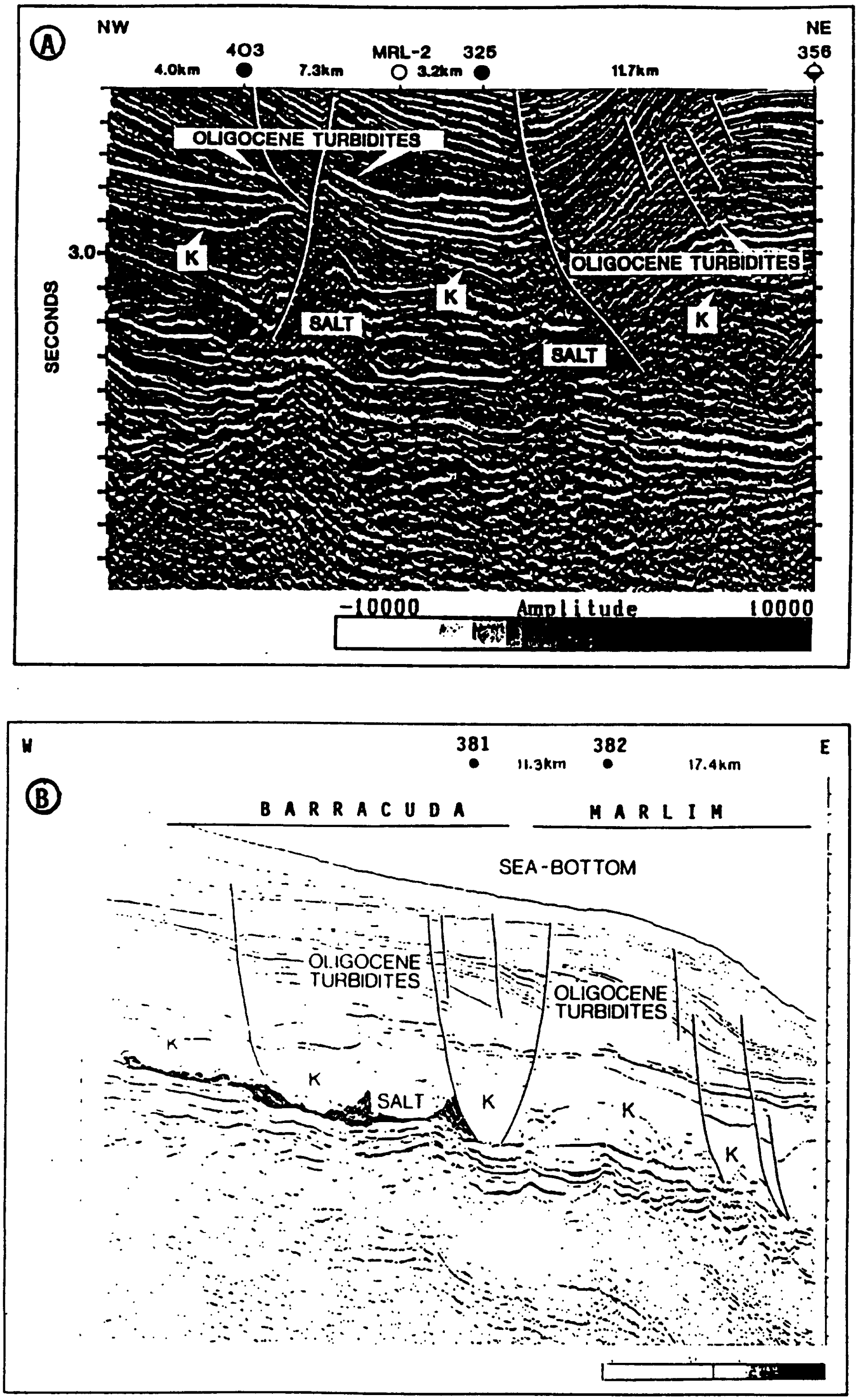


Figure 20 Seismic profiles (A and B) across the Marlin and Barracuda complex of fields. A, across the north part of the Marlim fields shows the role of salt and faults in trap formation and the high amplitude reservoir reflections. B shows the relation between the Marlim and Barracuda Fields. Locations on fig. 22 (after Possato et al, 1990).

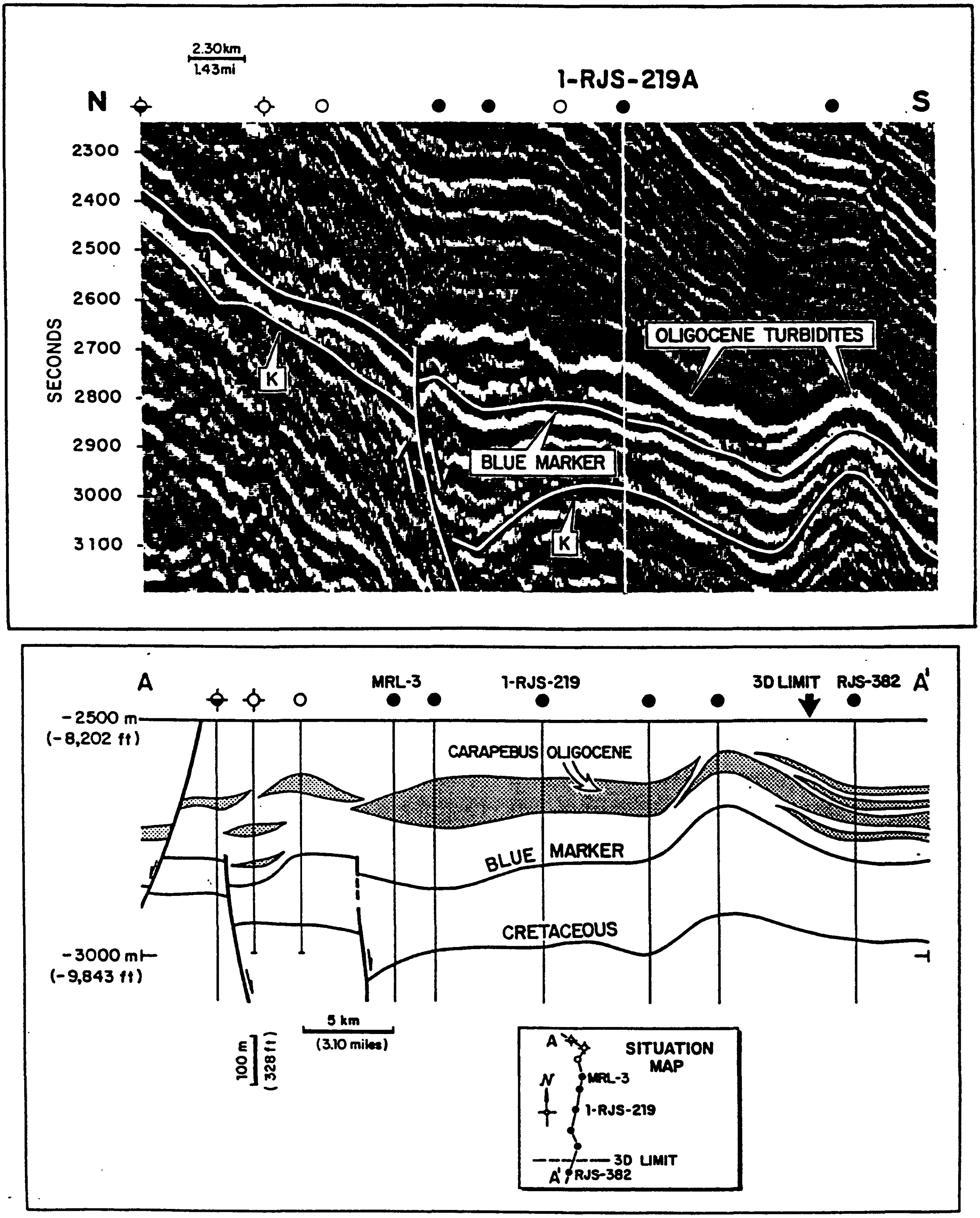
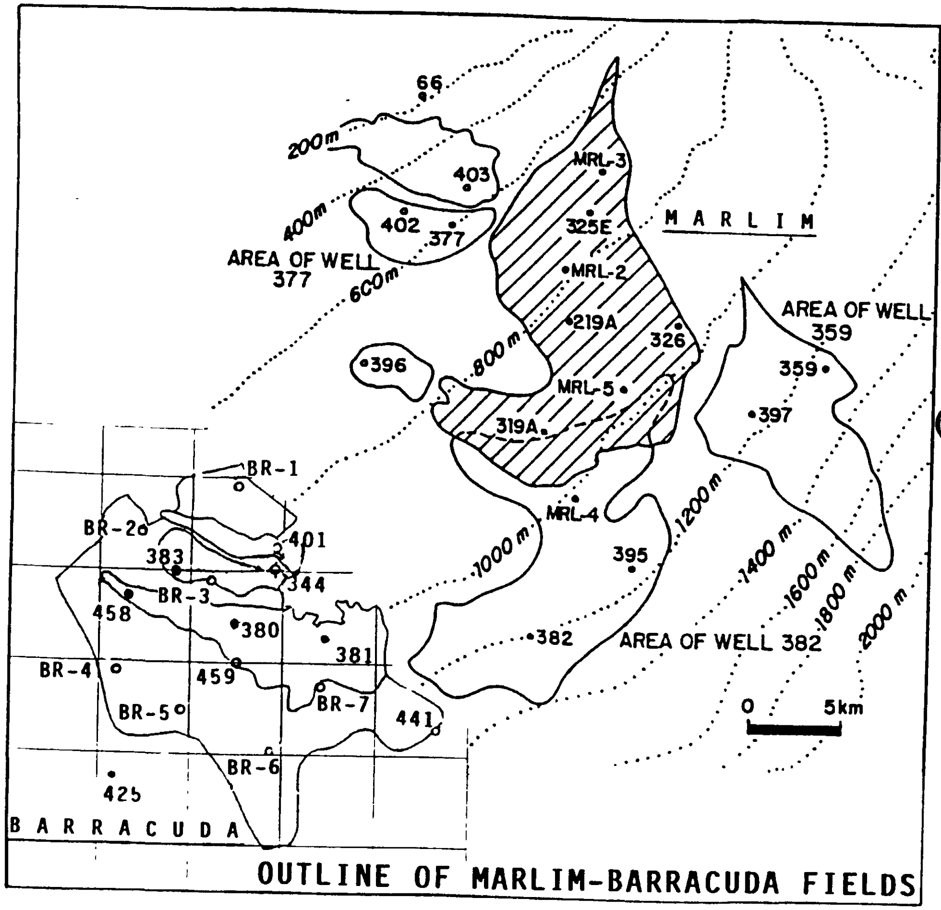
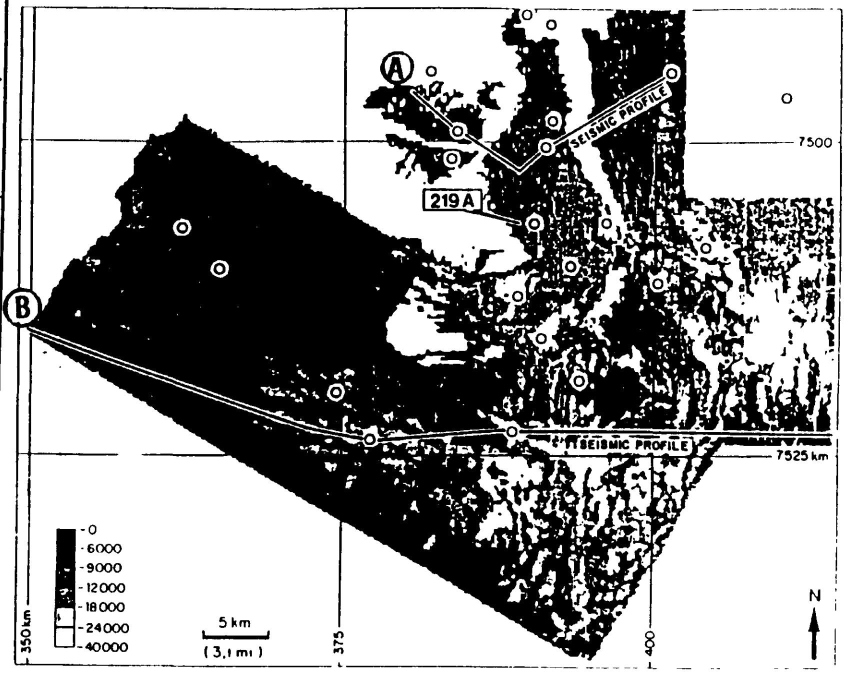


Figure 21 A 3-D seismic strike section through the Marlim field showing its interpretation and the anomalously high reflection amplitude at the top interface of an oil-filled Eocene turbidite (after Souza et al, 1989).



OUTLINE OF MARLIM-BARRACUDA FIELDS



SEISMIC AMPLITUDE MAP TOP OF OLIGOCENE TURBIDITES, MARLIM-BARRACUDA AREA

Figure 22 Maps of the Marlim-Barracuda field complexes showing how clearly the fields, particularly the Marlim complex, are outlined by high amplitude effects at the top of the main Oligocene turbidites. Solid circles of the outline map are producing wells; open circles are yet to be drilled as of early 1992 (modified from Olivera and Coehla, 1989, and Possato et al, 1990).

Three-D (three dimensional) seismic high amplitude mapping by Petrobras has been highly successful in defining fields; figure 22A and B compare the mapped outline of the Marlim and Barracuda complex of fields with the seismic amplitude map at the top of the main Oligocene turbidite reservoirs, as seen in figure 18A. The amplitude map indicates, in particular, the outline of the Marlim field and adjoining fields while the Barracuda field is only faintly indicated.

There is no analog for estimating undiscovered petroleum in the unique Campos slope play. There can be no doubt, however, that very considerable amounts of additional petroleum will be discovered in future slope exploration. Fig. 23 shows, as envisioned by Freire in early 1989, two exploration areas, A and B. The A area (heavy outline) (approximately 1,600 mi^2 or 4,140 km^2), containing the Albacora, RJS-366, and Marlim complex areas, has reserves of 5.15 BBO and 3.52 TCFG (including the 1991 Barracuda discovery reserves). As of 1992 in area A, 3-D seismic surveys have presumably been completed and exploration has reached a more mature stage and about 15 percent more oil is to be discovered, i.e., 0.77 BBO. The B area (approximately 3,120 mi^2 and 8,080 km^2) "areas to be drilled in the early nineties," containing the RJS-409, the southern, and the northern dashed-outline areas, have no published reserves though early surveys have already discovered at least one field, PJS-409, and a number of promising leads. Exploration of area B is presumably in a relatively immature stage.

Published seismic lines and maps (Figueiredo and Martins, 1990) show a multitude of leads in both A and B areas (figs. 24-27). Seismic line A of area A (fig. 24) shows the Cretaceous, Oligocene and Miocene reservoirs in well RJS-366 extending to the southeast down the slope and salt structure. Seismic line B-B' of area A (fig. 25) shows a section through Albacora (approximately same location as fig. 19) showing deep Cretaceous leads beneath the presently producing turbidite reservoirs. On the basis of such indicated pre-turbidite leads, I estimate that, even in the more maturely explored blocks of area A, some 10 percent more oil (i.e. 0.51 BBO) will be discovered.

Seismic line C-C' of area B (fig. 26) shows reservoirs identified in well RJS-409 extending into the deeper waters. Seismic line D-D' (fig. 27) near the south end of the B area shows numberous leads and normal, possible feeder faults reaching to Miocene potential reservoirs.

The B area is certainly prospective, but probably of lower priority than the A area where earlier exploration was concentrated and where all the present reserves are. A reasonable estimate would be that the B area would, on an areal basis, have about a third of the eventual oil resources (reserves plus undiscovered oil) of the A area. Since the B area is approximately twice the size of the A

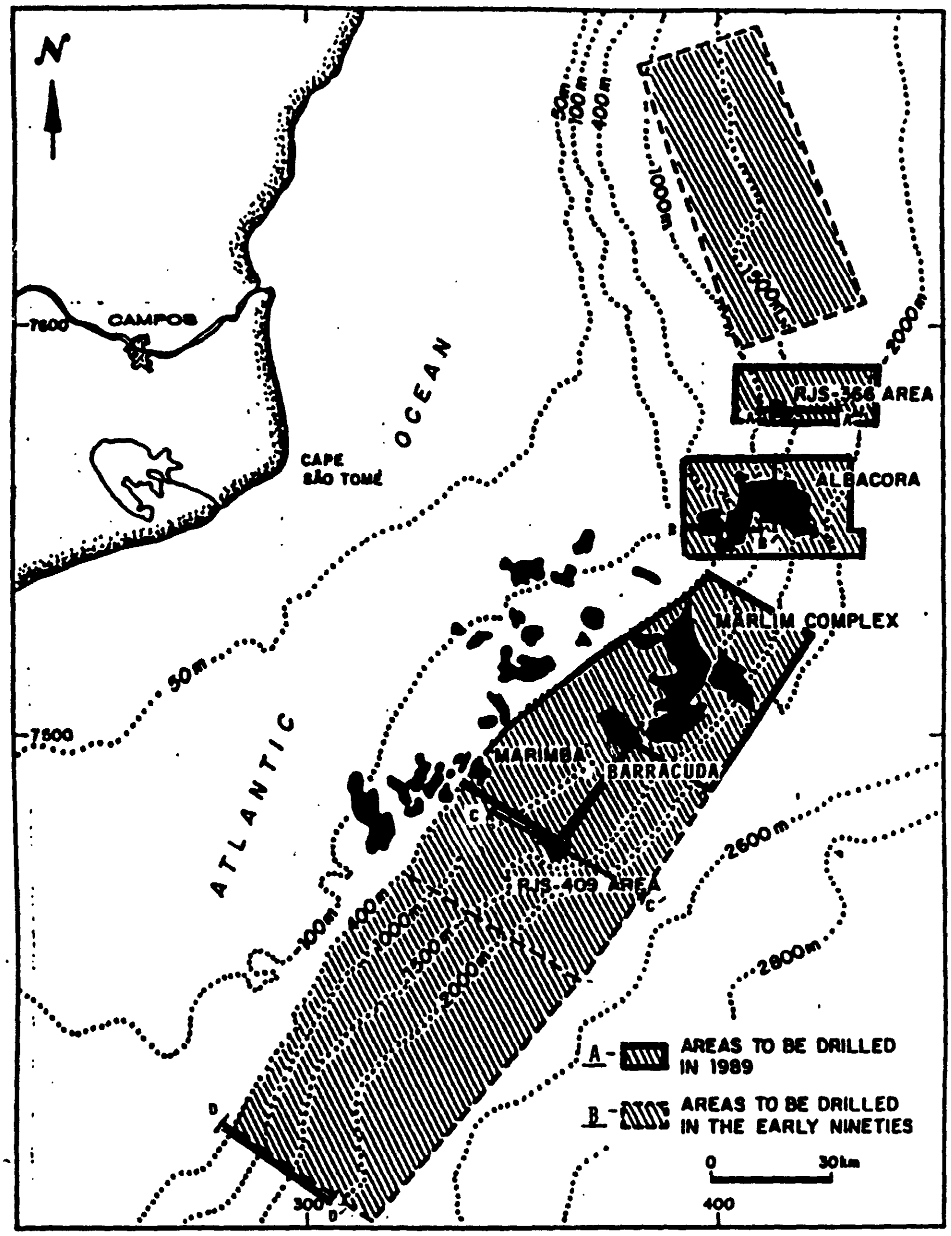


Figure 23 Map showing prospective deep-water areas of the Campos basin being considered for future drilling and locations of seismic sections figures 24-27 (modified from Freire, 1989).

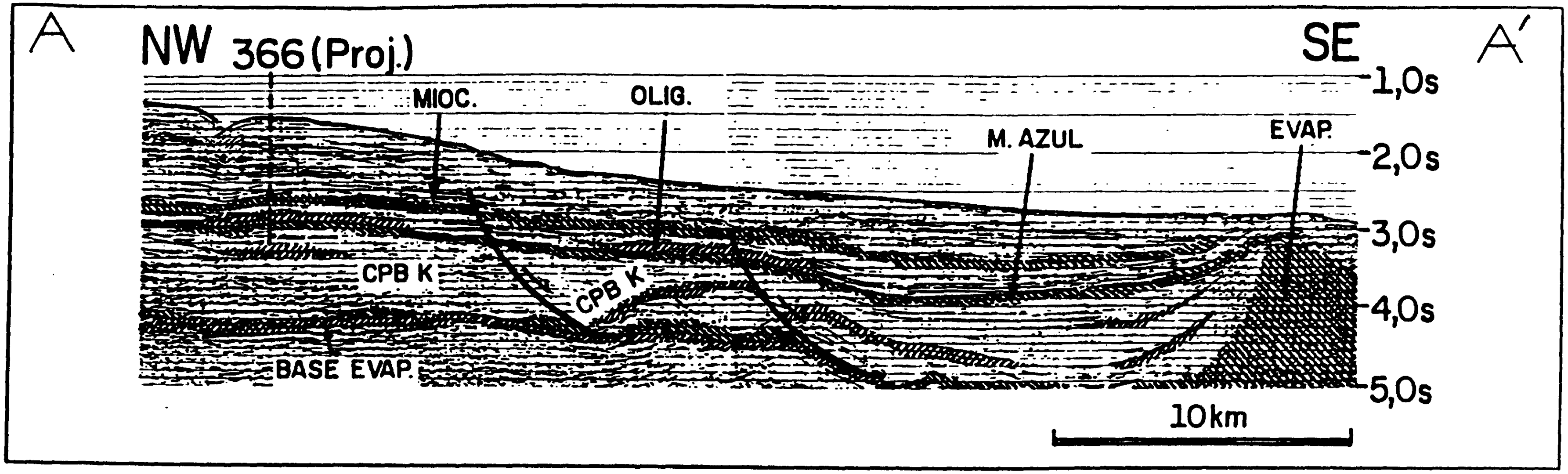


Figure 24 Seismic section A-A' indicating eastward extension of reservoirs (cross-hatched) of Campos basin identified in wildcat 1-RJS-366 and independent structure to southeast (M.AZUL = Blue Marker near Eocene-Oligocene boundary). Location figure 23 (Martins et al, 1989, in Figueiredo and Martins, 1990).

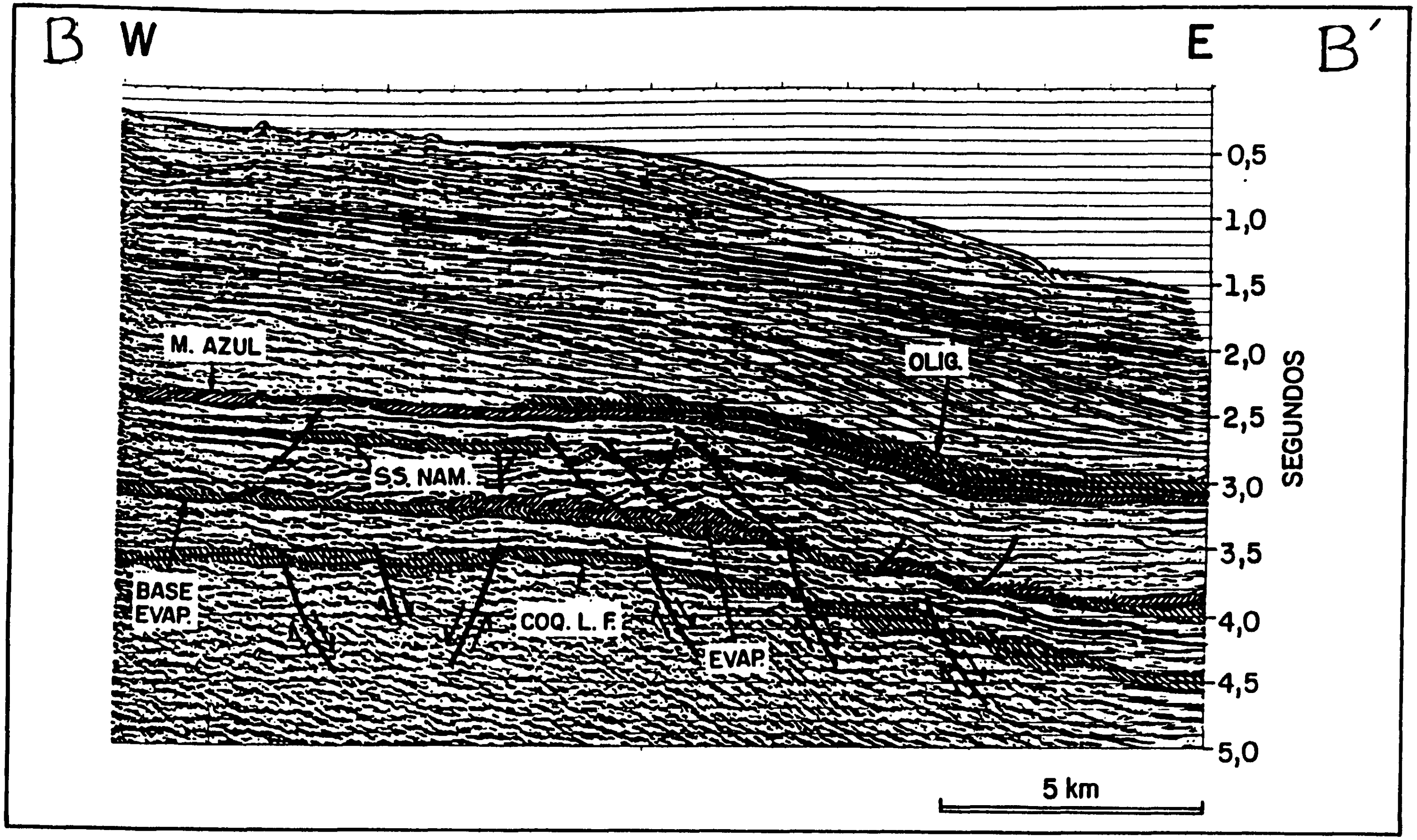


Figure 25 Seismic section B-B′ in the Albacora area showing reservoirs (cross-hatched) of Campos basin and emphasizing synrift targets (S.S.NAM = Namarado sandstone, COQ.L.F.=Coquina, Lagoa Feia Fm). Location figure 23 (Martins et al, 1989 in Figueiredo and Martins, 1990).

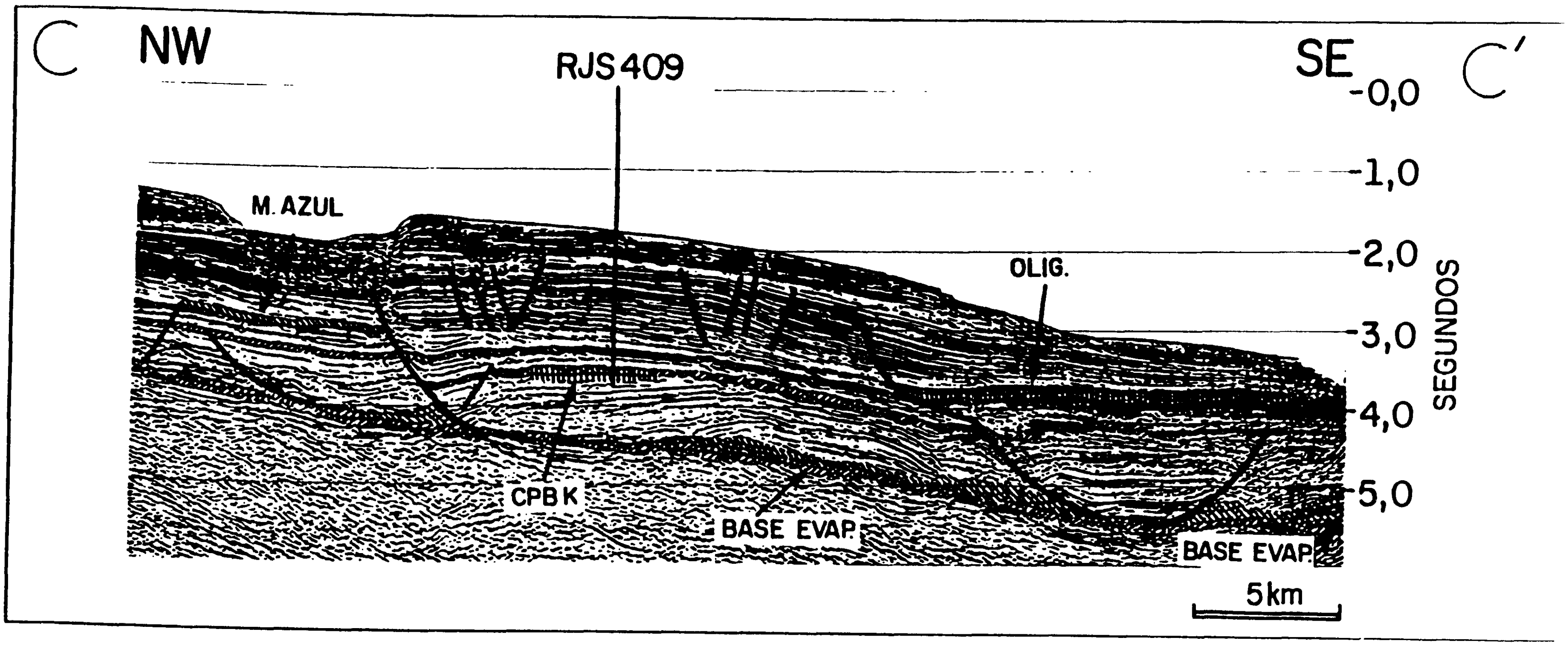


Figure 26 Seismic section C-C′ in wildcat 1-RJS-490 area of Campos basin showing interpreted reservoirs (cross-hatched) including possible (OLIG) Oligocene lowstand fan system (CPBK=Cretaceous reservoir). Location figure 23 (Martins, et al, 1989 in Figueiredo and Martins 1990).

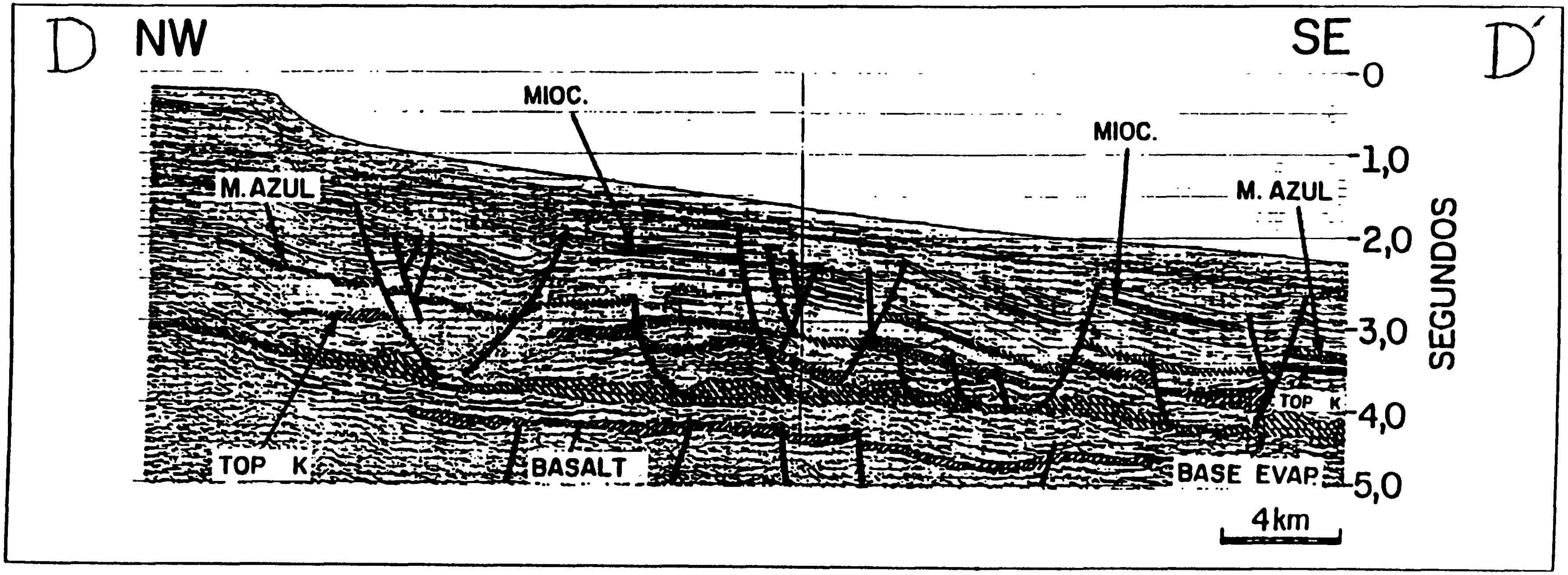


Figure 27 Seismic section D-D at extreme south of Campos basin showing complex structure and in particular faults which cut Miocene reservoir horizons (cross-hatched) and may serve as conduits for oil migration. Location figure 23 (Martins, et al, 1989 in Figueiredo and Martins 1990).

area, one would expect it to contain some 3.95 BBO ([5.15 + .77] x $\frac{1}{3}$ x 2). The undiscovered oil of the entire slope would accordingly be 4.72 BBO (.77 + 3.95). Based on present slope reserve oil to gas ratios, the undiscovered gas would amount to 2.71 TCFG.

Conclusions Regarding Estimates of Undiscovered Petroleum in the Campos Basin.

Table IV is derived from Petrobras play analysis as of 1990 in which the plays are related to formations or age-group sequences. The undiscovered petroleum is reported as in-place and oil-equivalent terms. From these data estimates of in-place undiscovered oil and in-place undiscovered gas are obtained by assuming the same ratio of in-place oil-equivalent petroleum to in-place oil as in Table II (Reserves) from Figueiredo and Martins (1990). To obtain recoverable oil and gas assessments, the same oil recovery factors and gas/oil ratios as used in Table II (Reserves) derived from Petrobras literature (Baumgarten et al 1988, and Freiere, 1989) were employed.

There is difficulty in comparing the play estimates of this study with Petrobras estimates since the plays of this study are defined within structural as well as stratigraphic constraints while the Petrobras-derived estimates are presented only in relation to formation or age-group sequences. Nevertheless, an approximate fit is obtained in constructing Table IV by assuming the Late Cretaceous and younger turbidite undiscovered petroleum is largely on the slope. Under this assumption, the equivalent Petrobras estimates for the three plays of the study amount to:

	Petrobras Derived		This Study	
	BBO	TCFG	BBO	TCFG
Synrift (Basalt, Coquina)	0.196	0.149	.27	.20
Postrift Shelf (Macae L.S., L. Cretaceous clastics)	0.506	0.386	.37	.20
Slope (All younger turbidites)	4.552	2.618	4.30	2.47
Total	5.254	3.153	4.94	2.87

The two estimates are similar. Although a geologic rationale is presented for this study's estimates of oil and gas resources while the geologic rationale for the Petrobras play analysis estimates is unknown, it is likely that the Petrobras-derived

TABLE IV

CAMPOS BASIN

UNDISCOVERED RECOVERABLE PETROLEUM (DERIVED FROM PETROBRAS PLAY ANAYLSIS, 1990)

		- 1 -	- 2-	- 3 -	- 4 -	- 5 -	- 6 -	- 7 -	- 8 -	- 9 -
		OEIP(1) (MM3)	OIP(2) (MM3)	GIP(2) (MM3)	OIP (MMBO)	GIP (BCFG)	OIL(3) RECOVERY FACTOR(%)	RECOVERABLE OIL(MMBO)	GAS/OIL(4) RATIO CFG/BO	RECOVERABLE GAS(BCFG)
Synrift	Basalt	21,000	119,931	1,069	125,565	37.736	20.0	25,113	762	19.136
	Coquina	125,000	110,269	14,731	694,695	520.004	24.6	170.895	"	130.222
Postrift	Albian carb.	82,000	75,716	6,284	477,011	221.825	16.6	79.184	"	60.338
Shelf	E.Cret.clastic	330,000	305,437	24,563	1,924,253	867.074	22.2	427.184	"	325.514
Slope	L.Cretaceous	971,000	924,808	46,192	5,826,240	1,630.578	22.2	1,293.425	575	743.719
Turbidites	Eocene	152,000	140,454	11,546	884,860	407.574	22.2	196.438	"	112.952
	Oligocene	1,698,000	1,559,994	138,006	9,827,962	4,871.611	22.2	2,181.808	"	1254.540
	Miocene	694,000	629,443	64,557	3,965,491	2,278.827	22.2	880.339	"	506.195
TOTAL (1990)		4,073,000						5,254.386		3,152.616
TOTAL (1992)		(5)						(4,154.386)	(5)	(2,520.616) (5)

(1) Oil-equivalent in-place play analysis estimate (Figueireda, Martins, 1990).

(2) Assumes in-place oil-gas ratios of (Table II) prevail

(3) Assumes recovery factors of oil reserves (Table II) prevail

(4) Gas-oil ratios of Column 8, (Table II)

(5) The 1991 discovery of the giant Barracuda field (1.1 BBO and presumably .632 TCFG) would theoretically reduce this 1990-determined amount of undiscovered resources by a corresponding amount.

estimates, determined from more direct and complete data, are more reliable. Both estimates, based on 1990 and earlier data, do not take into account the 1991 Barracuda discovery of 1.1 BBO (and assumedly .632 TCFG). This would reduce the present estimate of undiscovered resources accordingly to 4.154 BBO and 2.521 TCFG.

Santos Basin

Area. Total basin - 50,000 mi^2 (130,000 km^2)

Continental shelf - 27,000 mi^2 (70,000 km^2)

slope - 23,000 mi^2 (60,000 km^2)

Original Reserves. .038 BBO, .725 TCFG, .01 BBNGL (Petrobras, 1990)

Description of area: The Santos basin extends seawards from the Santos Hinge Line to the COB. The COB is taken to be at the western edge of the volcanic Sao Paulo Plateau and at the southern extension of a COB magnetic anomaly (figs. 2, 3, 6 and 28). The basin extends from an inferred east-trending wrench fault zone at Cabo Frio south-westwards to a transverse arch near Florianopolis.

Stratigraphy and Structure

The geology is analogous to that of the Campos basin, having the same continental-margin structural framework with equivalent lithologic units (fig. 29) and similar tectonics (figs. 30 and 31).

The geology of the Santos and Campos basins differ, however, in several significant respects:

1) The Santos basin is three times as extensive as the Campos basin.

2) Exploration to date of the Santos basin has not established a significant presence of the thick, rich Neocomian lacustrine source beds which supply the Campos reservoirs, the synrift interval apparently being more largely volcanics.

3) The Santos basin is considerably deeper than the Campos basin so that any synrift shales would, in large part, probably be thermally senile, although some oil may have escaped by earlier migration.

4. The greater depth of the Santos basin is such that the post-rift Upper Cretaceous organically-rich shales of the AOE-2 anoxic event are within the oil window, rather than above it, as is the case in the Campos basin. This source, however, is minor compared to the synrift lacustrine shales.

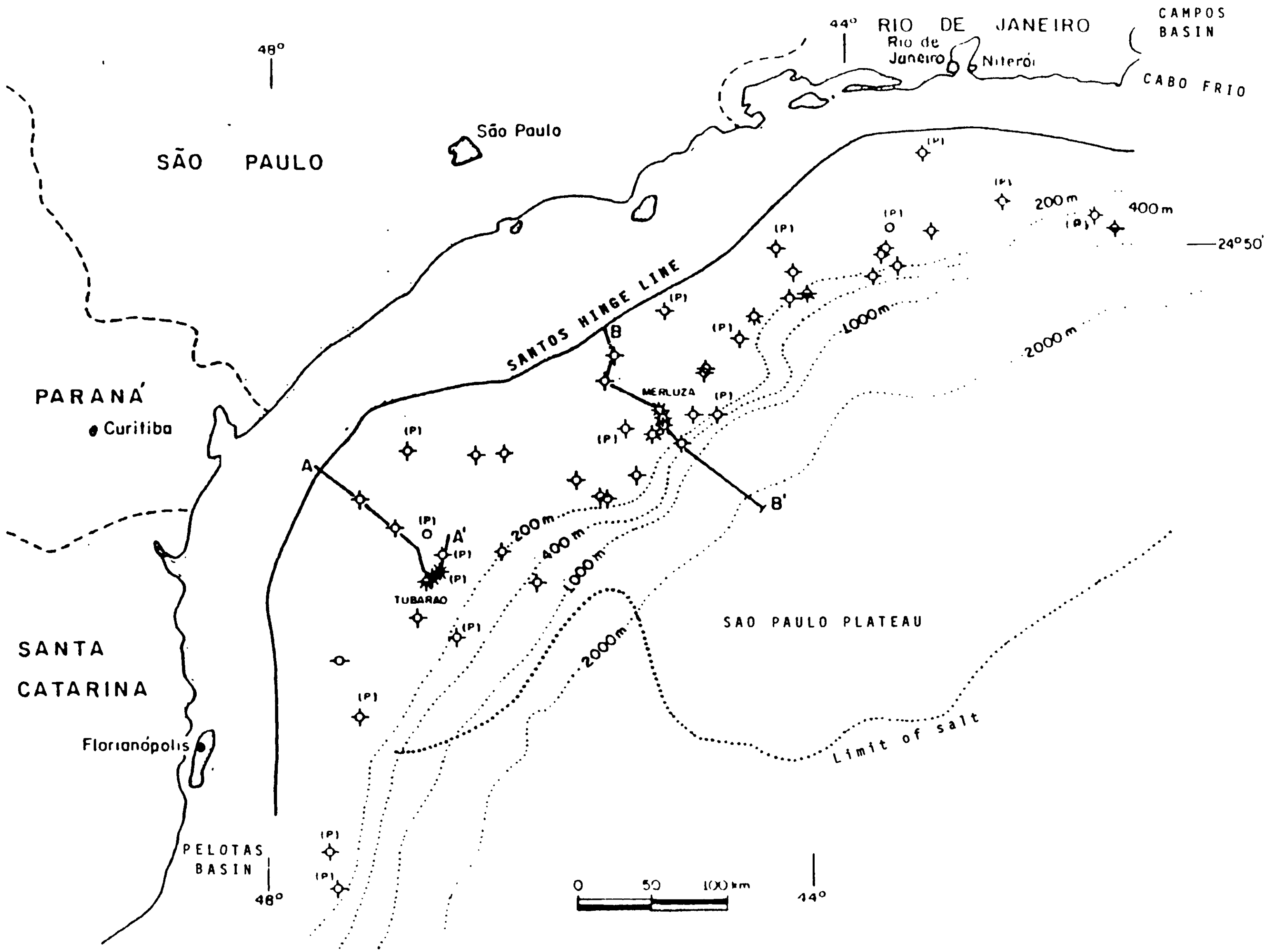


Figure 28 Index map of the Santos basin showing position of gas and oil fields, geologic sections and wildcats. (P) indicates wildcats by Petrobras; others are by contractors (modified after Periera and Macedo, 1990).

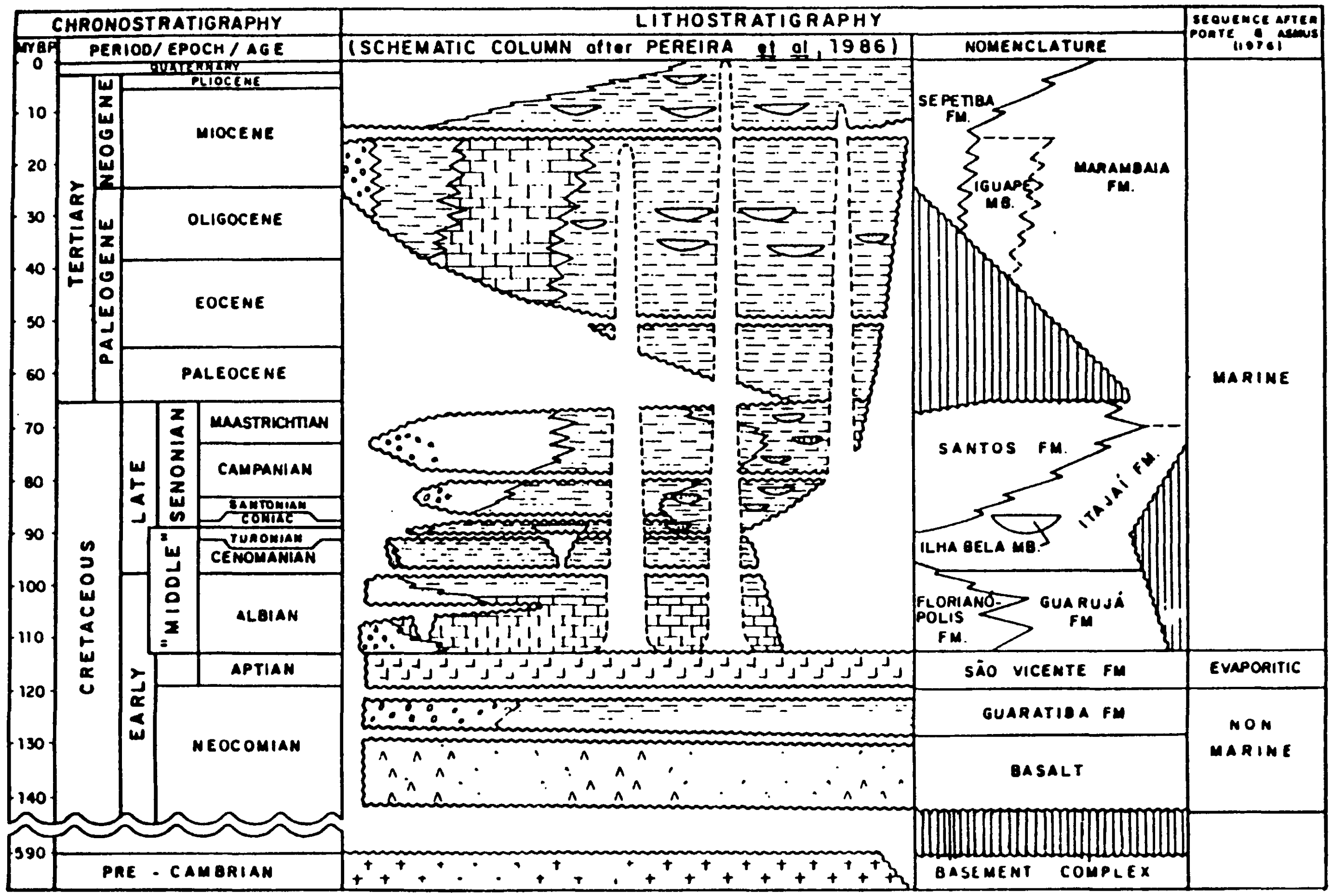


Figure 29 Stratigraphic chart of Santos basin (from Arai, 1988).

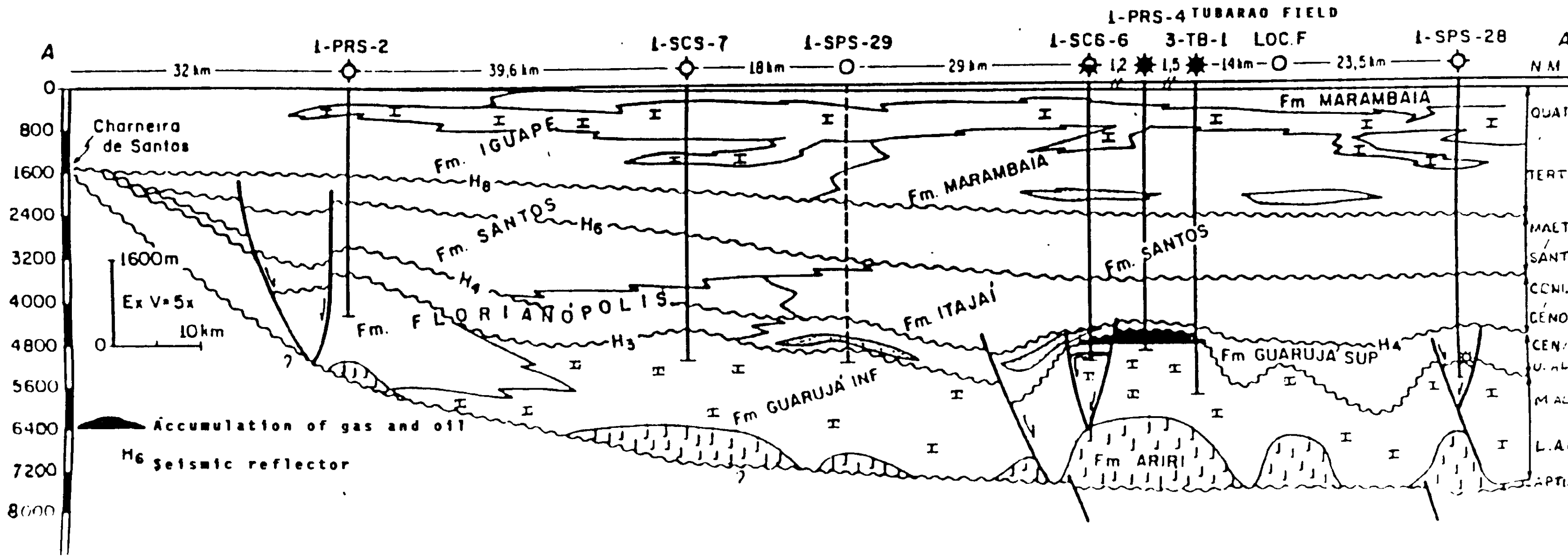


Figure 30 Geologic section in southern portion of Santos basin showing Tubarao oil and gas field. Location figure 28 (modified from Periera and Macedo, 1990).

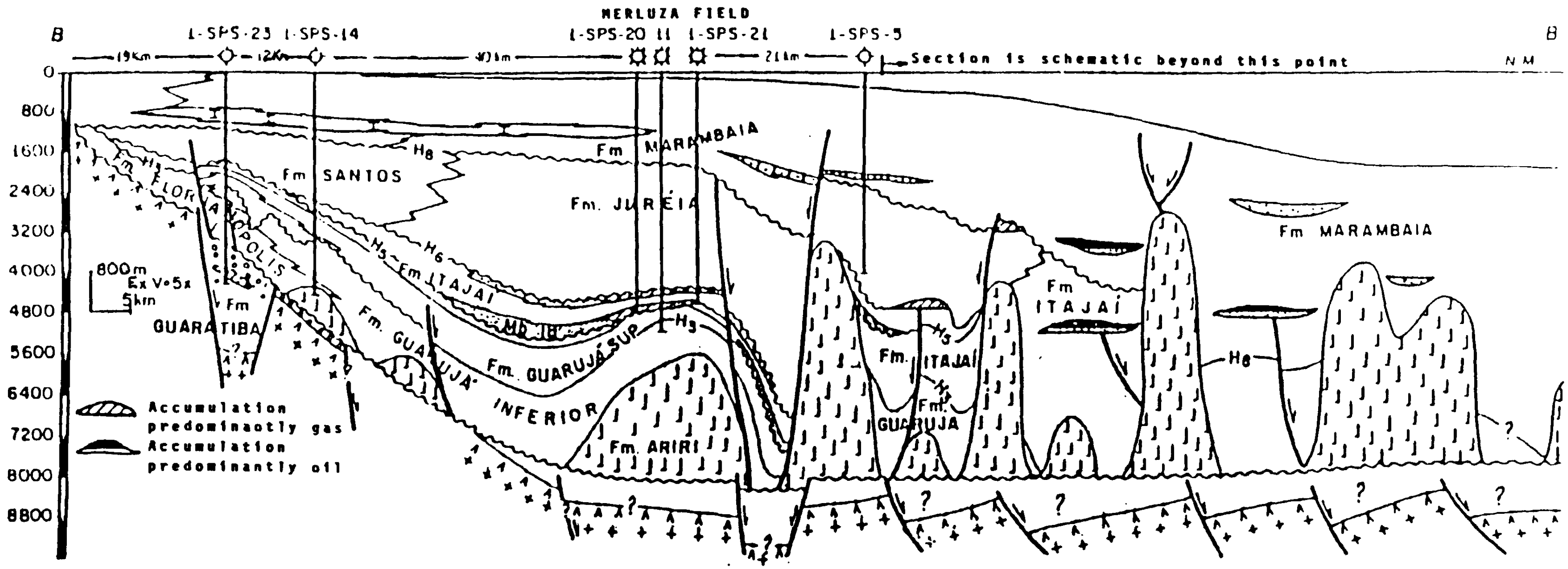


Figure 31 Geologic section of central portion of Santos basin showing Merluza Field and other possible plays. Location figure 28 (modified from Periera and Macedo, 1990).

5. Subsidence curves (fig. 10) indicate that any generation and migration, particularly from Neocomian source rock, would be considerably earlier (15-20 my) than in the Campos basin, probably before some of the trap formation and particularly the Tertiary turbidite emplacement. The Santos basin did not subside so precipitously as did the Campos basin during the Tertiary indicating less turbidite development. This indirect evidence in conjunction with the lack of a rising clastic provenance, such as the Serra do Mar Coastal Range of the Campos basin, indicates a considerably less volume of turbidites, perhaps 25 percent of the volume on an areal basis.

The Aptian salt in the Santos basin is thicker and more prone to salt doming than in the Campos basin. The salt-soled listric, possibly feeder, faulting (and accompanying tilted blocks or roll-over structures) also appear to be less dominant (compare figs. 30 and 31 with figs. 26 and 27).

History of Exploration and Petroleum Occurrence. The first wildcat of the Santos basin was drilled in 1971 and the first discovery, the Merluza gas field, was drilled in 1984, The only other discovery, the Tubarao oil field, was in 1986. As of 1990, fifty-one wildcats have been drilled.

Each of the two discovered fields is in one of the two main plays of the Campos shelf: the Tubarao oil and gas field producing from oolitic grainstone reservoirs of the Albian platform carbonate, the Guaruja Formation (postrift carbonate play) (figs. 28,29,30) and the Merluza gas field from a Late Cretaceous-Early Tertiary sandstone turbidite reservoir, the Ilha Bela Member of the Itajai (Jureio) Formation (postrift shelf turbidite play) (figs. 28,29,31).

The reserves of the fields are: Merluza 303.58 BCFG and 10.7 MMBNGL, and Tubora 37.8 MMBO and 423.6 BCFG (Pereire and Macedo, 1990).

Estimation of Undiscovered Oil and Gas. The resources of the Santos basin compared to the Campos basin appear to be limited by relative lack of, or accessibility to, the primary source of the Campos petroleum, i.e., Neocomian lacustrine shales. These shales are apparently largely undeveloped in favor of volcanics, and in any case, probably thermally senile. Furthermore, primary migration of any synrift petroleum may be largely hindered by a thicker salt barrier. Assuming the Upper Cretaceous rocks are a minor petroleum source, it would appear, therefore, that the petroleum potential of the plays of the Santos basin would be very considerably less, perhaps 5 percent, on a unit area basis, than that of the Campos basin, and because of the greater depth and probable thermal senility of some of the source, more gaseous, perhaps 50 percent gas.

The undiscovered oil and gas in the synrift play of the Santos basin, under the above constraints (5 percent of Campos resources, 50 percent gas) and assuming its area is limited to the shelf, would by areal analogy to the ultimate resources of the synrift play of the Campos basin, amount to .079 BBOE or .039 BBO and .237 TCFG. By similar analogy the ultimate resources of the postrift shelf would be .371 BBOE or .186 BBO and 1.113 TCFG. After subtracting the total present shelf reserves the undiscovered oil (and NGL) and gas amounts to .177 BBO and .625 TCFG (or .281 BBOE). The prospectiveness of the Santos slope, by analogy to the slope of the Campos basin, taking into account that the lesser turbidite volume is assumed to be only 25 percent on an areal basis of the Campos basin, indicating undiscovered oil and gas amounting to .408 BBOE or .204 BBO and 1.226 TCFG. Altogether the undiscovered oil and gas of the Santos basin is indicated to be .381 BBO and 2.339 TCFG amounting to .671 BBOE. This estimate is generally comparable with the play analysis, from presumably much more detailed data of Petrobras which indicates a potential of .453 BBOE (versus this study, .281 BBOE) for the shelf (i.e. water depth less than 400 m, largely including the synrift and postrift shelf plays) and .416 BBOE (versus .671 BBOE) for the slope, totalling .869 BBOE (versus .952 BBOE) for the Santos basin (Pereira and Macedo, 1990). The Petrobras play analysis provides the more reliable assessment.

Pelotas Basin

Area:	Total basin	45,000 mi^2 (116,000 km^2)
	Continental shelf	21,000 mi^2 (54,000 km^2)
	Continental slope	24,000 mi^2 (62,000 km^2)

Original Reserves: None

Description of area: Pelotas basin is taken to extend eastward, seaward, from the Pelotas (or Rio Grande) Fault to the base of the continental slope. In this case, exceptional to the other Brazilian rifted continental margin basins, the basin extends beyond the edge of the continental crust (as marked by the oceanic magnetic anomaly, "G") and is underlain in part by oceanic crust (figs. 2, 3, 32 and 33). The basin extends southward along the coast from the Torres Arch (or Florianopolis), which separates it from the Santos basin to the Polonio high (fig. 32). It is the most southerly of the rifted margin basins adjoining the Brazilian craton, and lies south of the evaporitic, lagoonal sediments of the restricted Aptian interior sag seas.

Stratigraphy and Structure

The geology of the Pelotas basin is similar to that of the Santos basin, but different in several significant, generally unfavorable, respects.

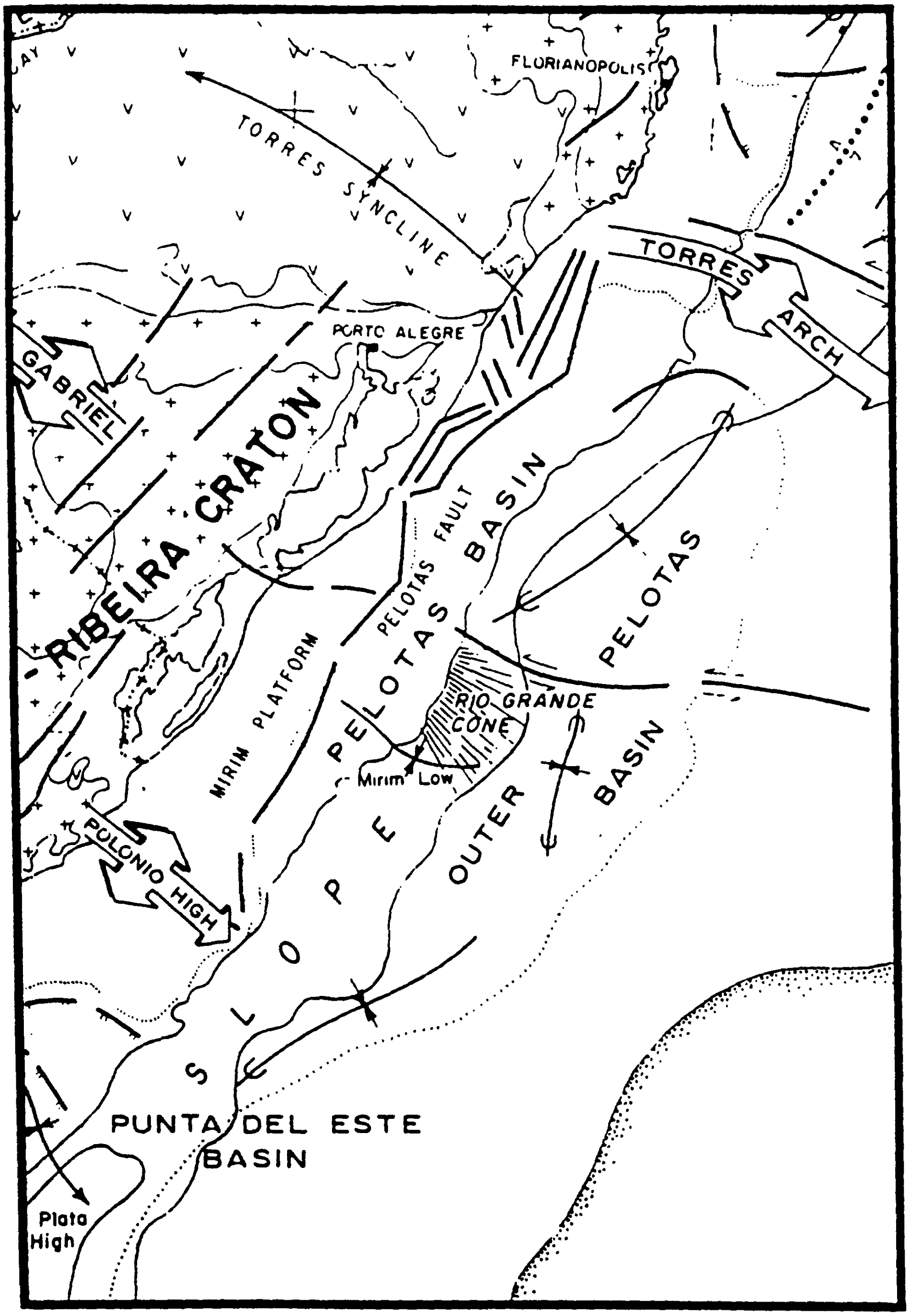


Figure 32 Structure map of the Pelotas basin, Brazil (after Urien, 1981).

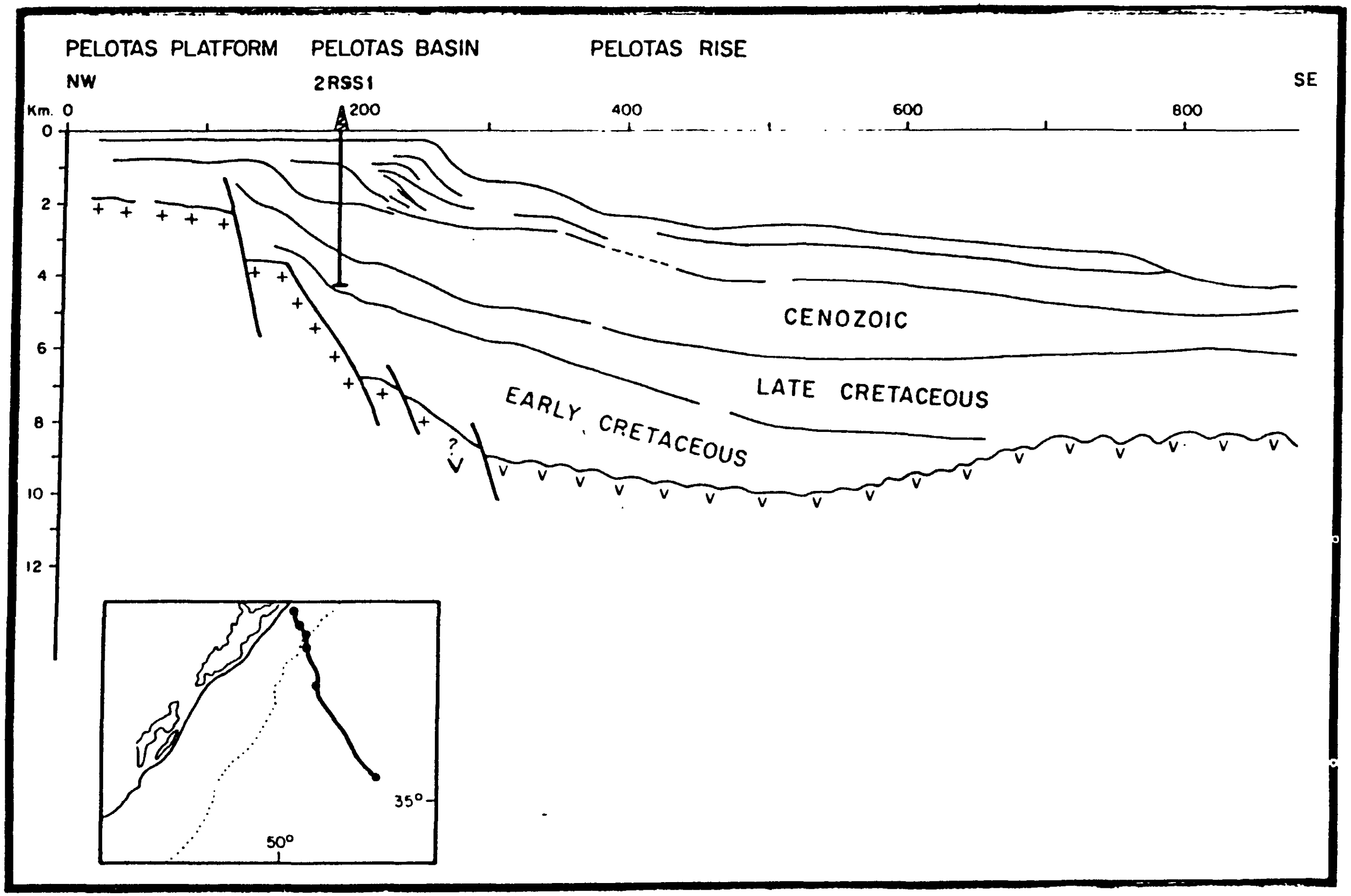


Figure 33 Geologic section across Pelotas basin; + = continental crust; v = oceanic crust (after Urien, 1981).

1) The oceanic crust as indicated by the oceanic magnetic anomalies underlies the slope and also part of the shelf (fig. 3). This limits much of the rifted continental margin and, therefore, synrift play or synrift source from some of the shelf and all of the slope.

2) The evaporites of the Aptian interior sag, restricted marine sequence of the basins to the north are absent from the Pelotas basin (fig. 6 and 28). Therefore, the basin does not have salt dome features or the salt-soled listric faults and associated closures. The basin also lacks the petroleum source of the euxinic shales which usually accompany evaporates and the possibility of salt seals.

3) The Albian platform carbonates, representing an important play of the northern rifted margin basins, appear to be only poorly developed in the Pelotas basin.

<u>Exploration History and Petroleum Occurrence:</u> There has been little exploration in this basin, possibly because of the apparent adverse geology. As of 1985 Petrobras had only drilled 3 wildcats, the deepest of which penetrated the "rift sequence" (Petroconsultants, 1989). No shows have been reported in the basin.

<u>Estimation of Undiscovered Oil and Gas:</u> The best estimate of resources may be made by analogy to the ultimate resources (reserves plus estimated undiscovered resources) of the Santos basin. The Pelotas shelf by a straight areal analogy to the Santos shelf would have resources of .174 BBO and .865 TCFG. However, the factors outlined above probably diminish the prospects of the shelf play to some 25 percent of the Santos basin or an areal basis, reducing the estimated resources to .044 BBO and .262 TCFG or .087 BBOE.

The Pelotas slope by areal analogy to the Santo basin, under the above constraints, would have resources of .212 BBO and 1.279 TCFG. However, since the synrift source (already heavily discounted in the analogous Santos basin) would be totally absent from the Pelotas slope play, the prospectivity of the slope is further lowered to about 20 percent, indicating resources of .042 BBO and .26 TCFG or .085 BBOE.

The resources of the total basin are .086 BBO and .518 TCFG amounting to .172 BBOE.

Espirito Santo Basin

Area: Total basin: 7,000 mi^2 (18,000 km^2)

Continental shelf: 5,400 mi^2 (14,000 km^2)

Continental slope: 1,600 mi^2 (4,000 km^2)

Original Reserves: 0.108 BBO 0.528 TCFG

Description of area:

The basin extends along shore from approximately the Espirito Santo-Bahia border southward to an arch transverse to the coast at Vitoria (fig. 34). It extends eastwards from the basement outcrop to the COB which is presumed to lie between the uplifted basement and the offshore Cretaceous volcanics of the Abrohas Bank (figs. 34,35, and 40).

Stratigraphy.

The Espirito Santo basin stratigraphy (fig. 36) is fairly analogous to the adjacent on-trend Campos basin, having a synrift sequence (Mucuri member of the Mariricu Formation), a postrift transitional restricted marine sequence (Itaunus member of the Mariricu Formation), a postrift carbonate platform (Regencia member of the Barra Nova Formation), and a postrift clastic sequence. The stratigraphy differs from that of the Campos basin, however, in several significant respects.

Firstly, the synrift pre-evaporite section, encountered to date in the exploration of the Espirito Santo basin, appears to be a coarse clastic sequence (apparently with little of the lacustrine source shales of the Campos basin (fig. 36). Such lacustrine shales may occur downdip, however, but may be at a depth which would generate largely gas.

Secondly, the configuration of the Espirito Santo basin has been strongly affected by the presence of massive Cretaceous volcanic outpourings which built up the offshore volcanic complex of the Abrolhas Bank. These volcanics may have supplanted more prospective strata downdip and have reduced the gradient of the continental slope and thereby precluded significant turbidite development.

Thirdly, the Tertiary shelf of the Espirito basin appears to be largely carbonates and coarser clastics signifying neritic deposition while that of the Campos basin is largely shale, indicating a deeper water environment.

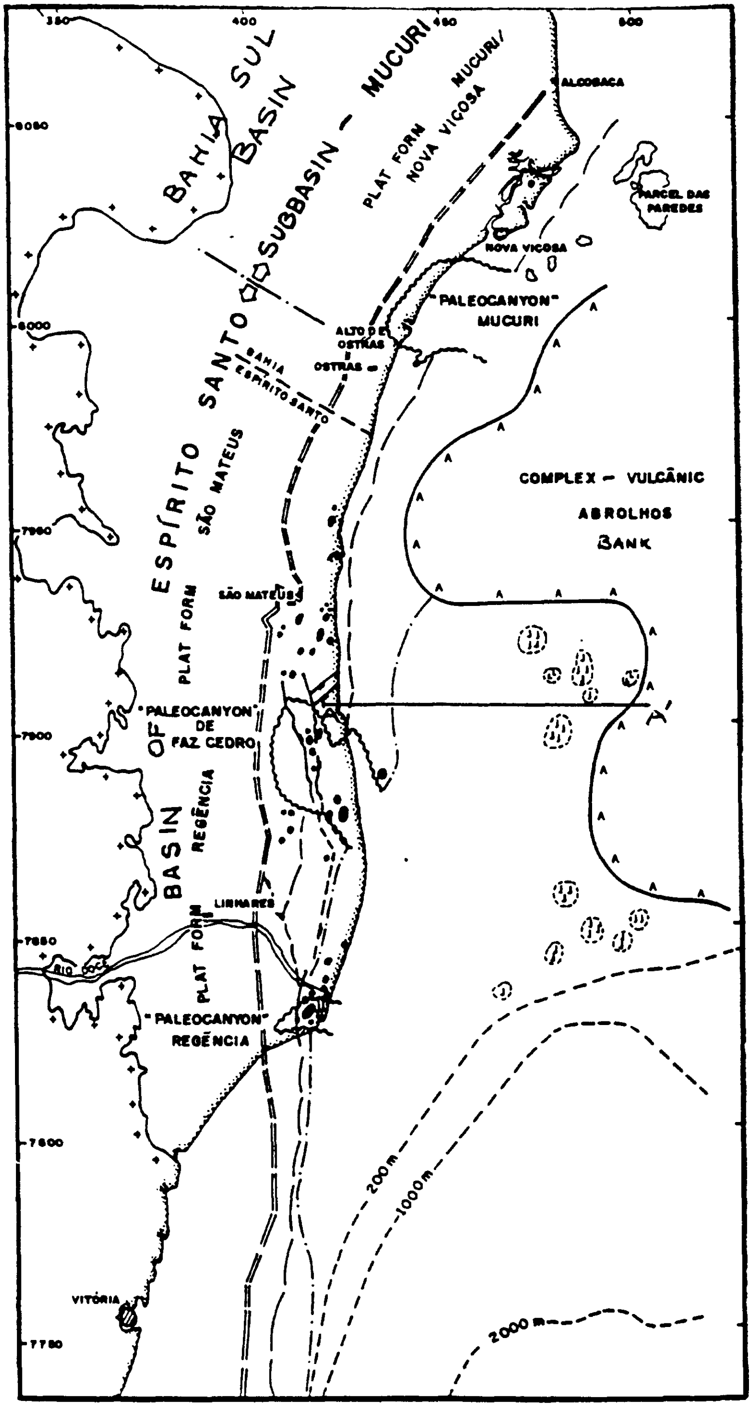


Figure 34 Structural framework map of Espirito Santo basin showing the updip edge of prospective sediment - dashed double line, paleocanyon borders - wiggly line, Albian hinge line - dash-dot line, Neocomian hinge line - scalloped-dashed line and water depth-dashed line. Oil fields, salt domes and volcanics indicated by conventional symbols (modified from Blassusi, et al, 1990).

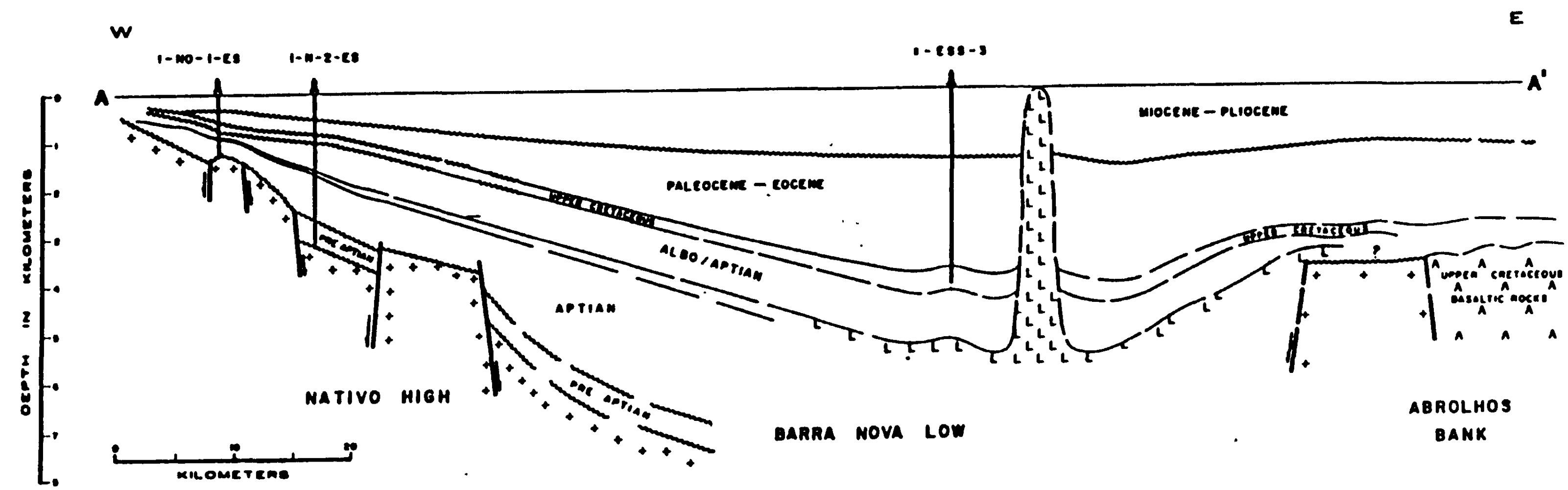


Figure 35 Geologic cross-section across Espirito Basin (after Ponte and Asmus, 1976). Location figure 34.

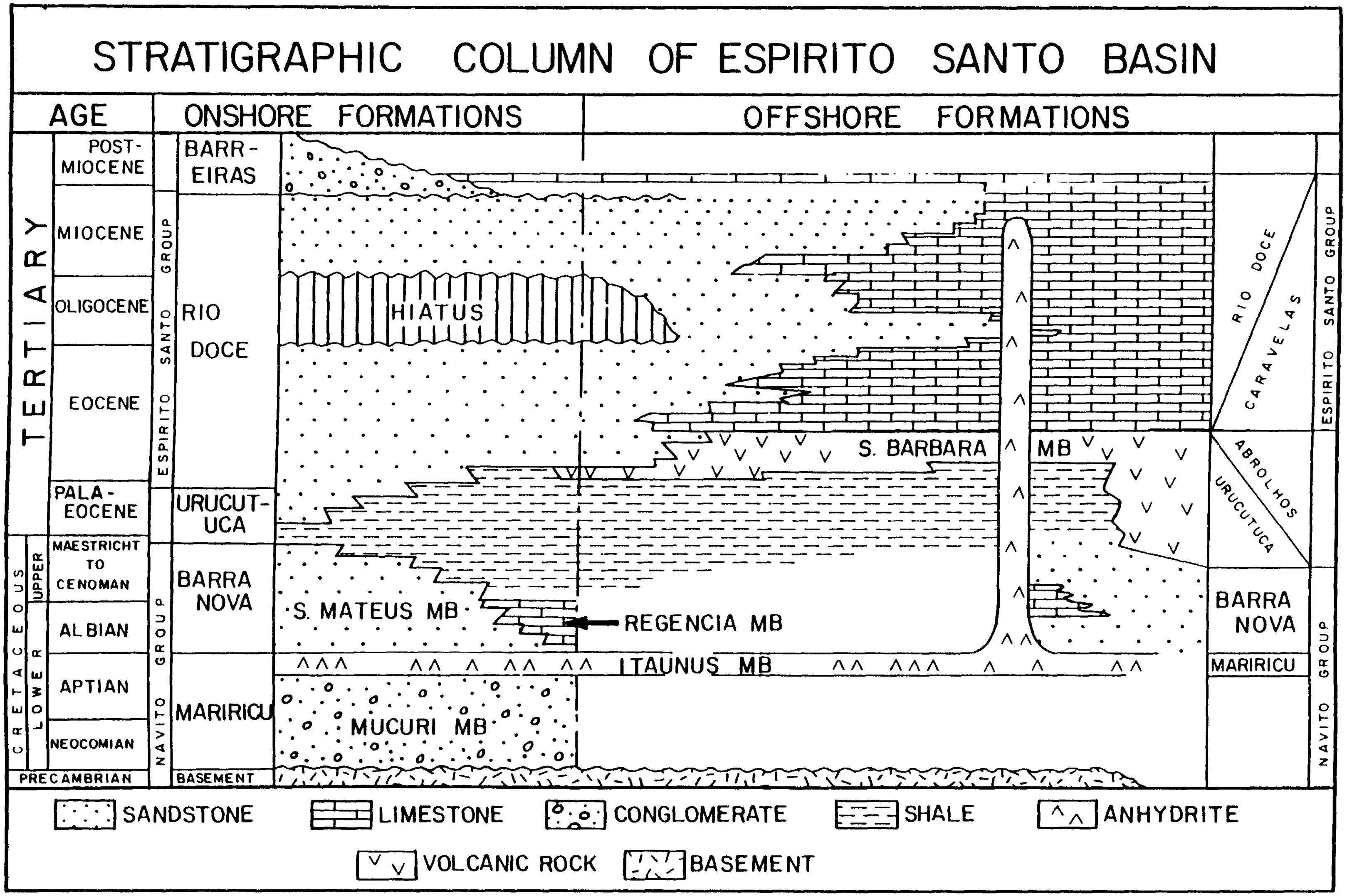


Figure 36 Stratigraphic column of Espirito Santo Basin (after Petro-consultants, 1989).

Fourthly, prominent eastward trending paleocanyons of late Cretaceous-early Tertiary age transect the updip part of the basin (fig. 37).

Source: The source rocks are assumed to be the same as those of the Campos basin, the Neocomian shales. However, available data indicates that these shales were not encountered to date, though they may be downdip. Subsidence curves suggest that the Neocomian interval in the Espirito Santo basin became thermally mature for petroleum generation relatively early, that is, in Cretaceous-early Tertiary time versus mid- Tertiary time for the Campos basin.

A second, less organically rich, source rock sequence may be upper Cretaceous shales as suggested by the occurrence of petroleum in postrift carbonate reservoirs. These shales may be part of the organically rich OAE-2 zone (See Source Rock of the Rifted Continental Margins).

Reservoirs and seals: The Espirito Santo basin has reservoirs in approximately the same stratigraphic levels as in the Campos basin. No reservoir characteristics are available, but the best reservoirs appear to be in three horizons:

1) The synrift reservoirs are sandstones in a generally sandy sequence, unlike the Campos synrift sequence in which reservoirs are poorly developed (coquina banks and fractured basalts in a largely shale section). These sandstone contain about 36 percent of the Espirito Santo petroleum reserves. 2) Postrift platform carbonates contain petroleum, found to date in one offshore field which makes up 10 percent of the Espirito Santo reserves. 3) 54 percent of the petroleum reserves are in upper Cretaceous and Tertiary sandstones which are largely channel fills, but turbidites are potential reservoirs. However, turbidites are probably not well-developed as in the Campos basin.

The Aptian evaporites formed the seal over the synrift petroleum accumulations. However, if a Neocomian source is assumed, the evaporites have not been a complete barrier to primary petroleum migration owing, as in the Campos basin, to faulting (fig. 37B), non-deposition, and possibly necking. The postrift Cretaceous and Tertiary shales are probably not very effective seals.

Structure

The structure of the Espirito Santo basin is similar to that of the Campos basin except in two respects: 1) The massive offshore Cretaceous volcanic outpourings of the Espirito Santo basin appear to have covered and buttressed the continental margin, decreasing the slope so that the sedimentary slumping, listric faulting, and large slope turbidites, such as those of the Campos basin, are less developed in the Espirito Santo basin. 2) Secondly, the Espirito Santo shelf appears to have a signifi-

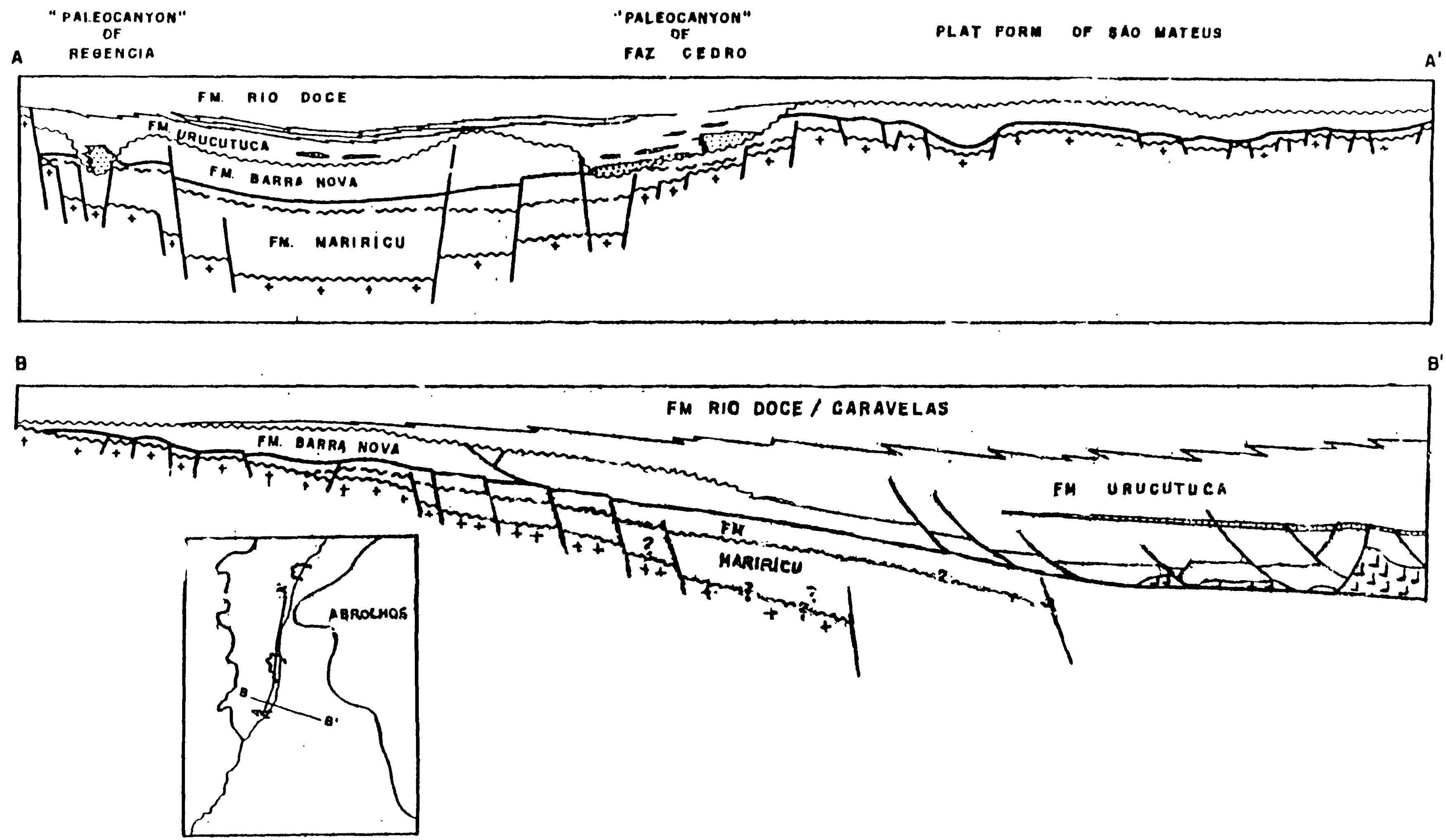


Figure 37 Schematic strike and dip geologic sections in the Espirito Santo basin showing stratigraphic and structural relationships (after Blassusi, et al, 1990).

cantly different subsidence history than the Campos basin. According to projections of Ponte and Asmus (1976) (fig. 10), the subsidence curve of the Espirito Santo indicates that the projected Neocomian strata (140-120 MY) would have subsided to sufficient depths for oil generation, estimated from 10,000 ft (3 km) to 18,000 ft (5.km), in late Cretaceous-early Tertiary time in contrast to the Campos basin where the Neocomian source shales apparently did not reach a comparable depth until mid-Tertiary. This relatively slow subsidence through the mid-Tertiary may have hindered the abundant turbidite formation such as that in the Campos basin where subsidence has been more rapid since the Eocene (and approximately coinciding with the rising of the adjoining Serra do Mar Coastal Range provenance).

The principal structural traps of the Espirito Santo basin are: 1) synrift fault block features, and 2) postrift tilted fault blocks and rollovers associated with listric faults which, however, are possibly less developed than in the Campos basin, owing to buttressing of the slope by oceanic volcanic outpourings. Salt domes occur and may be regarded as potential traps, but, from available data, no commercial petroleum has yet been found associated with salt-doming.

Sedimentary traps are channel fills and turbidites.

Generation, Migration and Accumulation. Generation and migration apparently began by late Cretaceous or early Tertiary time when any supposed Neocomian source shales subsided into the petroleum generating zone. Potential synrift fault-block traps had already formed in the early Cretaceous. Postrift trap formation was synchronous or later than some of the migration. The principal reservoirs are synrift sandstones (Neocomian), postrift platform carbonates (Albian), and channel fill and turbide sandstones (Late Cretaceous and Tertiary). Depending on the preservation of the synrift reservoirs, migration timing appears generally favorable, but perhaps not as favorable as the late Cretaceous-early Tertiary migration of the Campos basin, since it allows for a longer period of leakage through shale seals and loses some petroleum prior to Tertiary trap formation.

Plays. Of the six possible continental margin plays in these rifted continental margin basins, three plays are prominent in the Espirito Santos basin. They are related to reservoir development and are: 1) the synrift pre-evaporite non-marine clastics, 2) the postrift carbonates, and 3) the combined Upper Cretaceous and Tertiary shelf turbidites and channel fills. The slope-turbidites of the Campos basin appear less developed in this basin.

The synrift (and perhaps early postrift) oil fields found to date are largely on shore in an updip position (fig. 38A). They are in Aptian or pre-Aptian clastic reservoirs of the Mariricu Member, capped by evaporites. The source undoubtedly is down-dip, whether it is Neocomian lacustrine shales or Aptian restricted-marine shales is not evident. The traps are drapes over horst blocks or in pinchouts between the capping evaporites and older strata or basement.

Postrift, post-salt carbonates, and accompanying sandstones, contain oil. The tilted block, buried-hill geometry of the occurrences (fig. 38B) suggest that at least part of the source may be the superjacent Upper Cretaceous shale in addition to the supposed Neocomian-shale-sourced hydrocarbon which probably migrated up the tilt-block-associated listric faults.

The youngest play is the Upper Cretaceous and Tertiary clastic reservoirs which occur in channel fills in "paleocanyons" or in turbidites (figs. 37, A-A', and 38C) or in pinchouts along the so-called Upper Cretaceous hinge of figure 34 and 38C. Turbidites apparently have the most potential for future petroleum discoveries, although minor compared to the Campos basin..

History of Exploration and Petroleum Occurrence. Systematic exploration of the basin began in 1958. The first discovery was made in 1969. As of 1989, 285 "exploration" holes have been drilled onshore and 66 offshore, resulting in 36 discoveries, 35 onshore and 1 offshore (Blassusi et al., 1990) (fig. 34). This is a success rate of 10 percent (assuming "exploration" holes are all wildcats). Discovered reserves amount to 0.108 BBO and 0.528 TCFG, with .350 TCFG coming from one field, ESS-067, giving a high percentage of gas for the basin, 45 percent versus 10 percent for the Campos Basin.

The cumulative oil and gas reserves discovered versus cumulative wildcats is shown in figure 39 (based on 211 wildcats as reported by Petroconsultants, 1988). After only moderate initial discoveries in the first 75 wildcats, most of the basins large fields were discovered in the next 50 wells (1977-1981). Subsequently, the size of the discoveries have declined to an average level of 0.12 MMBO and .042 BCFG per 25 wildcat. Figure 34 shows the distribution of oil fields; a comparison of this figure with the play maps of figure 38 indicates in which plays the fields are located.

Estimation of Undiscovered Oil and Gas

The closest analog to the Espirito Santo basin is the Campos basin. However, the available data allows only comparison of a combined synrift play, a combined postrift shelf play, and a postrift slope play.

Synrift Play

An areal analogy of the Espirito Santo synrift play (38A) to that of the Campos basin indicates that ultimate resources of .314 BBOE may be expected. However, owing to 1) the uncertainty regarding the presence of sufficient quantities of Neocomian source shales, 2) the indicated earlier migration and thus longer residence

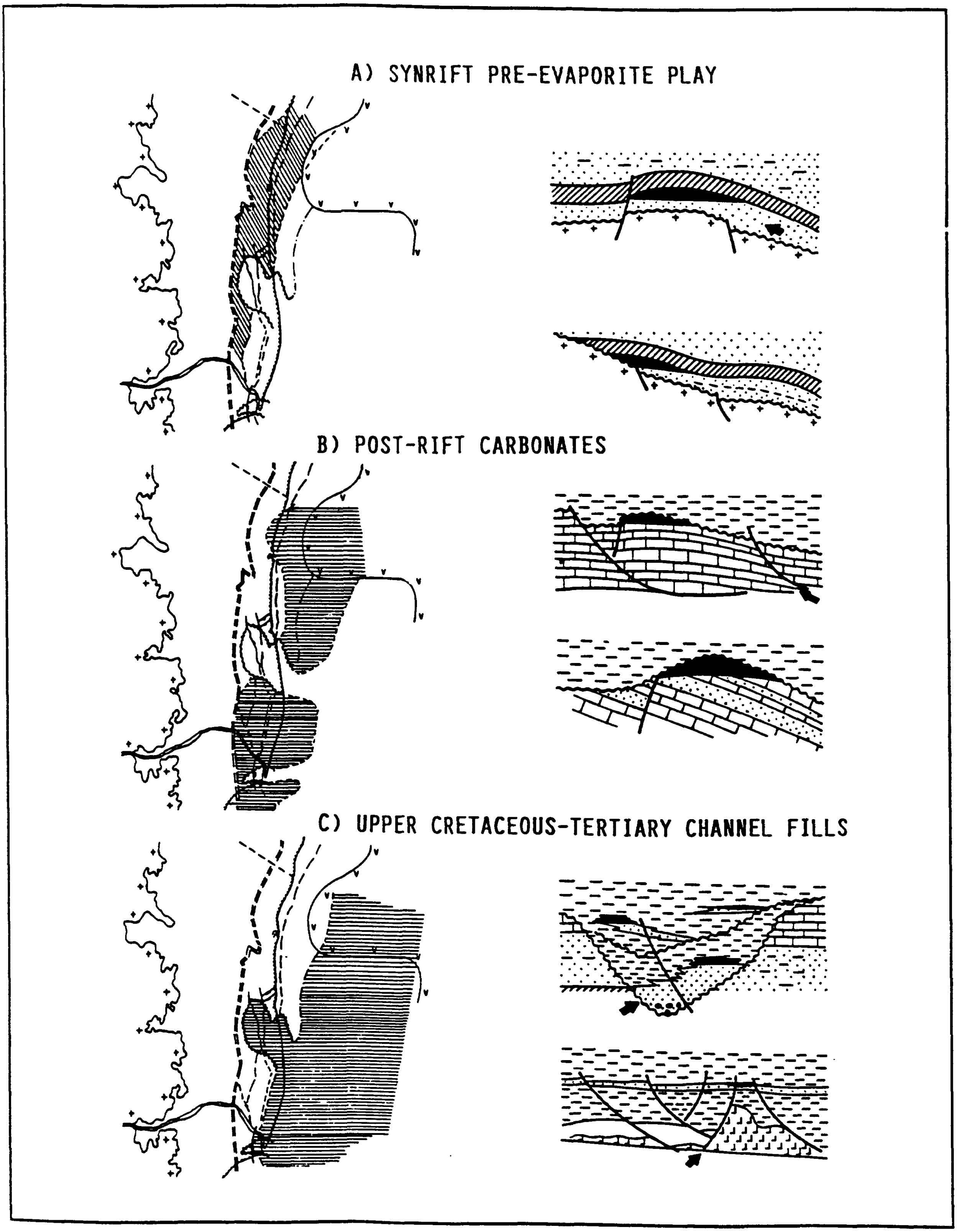


Figure 38 Maps showing areal distribution and accumulation models for the three main shelf plays of the Espirito Santo basin. A - synrift or pre-evaporite play, B - shelf carbonate and associated clastics play, and C - Upper Cretaceous-Tertiary turbidites and channel fill. Arrows indicate migration paths (modified from Blassusi, et al, 1990).

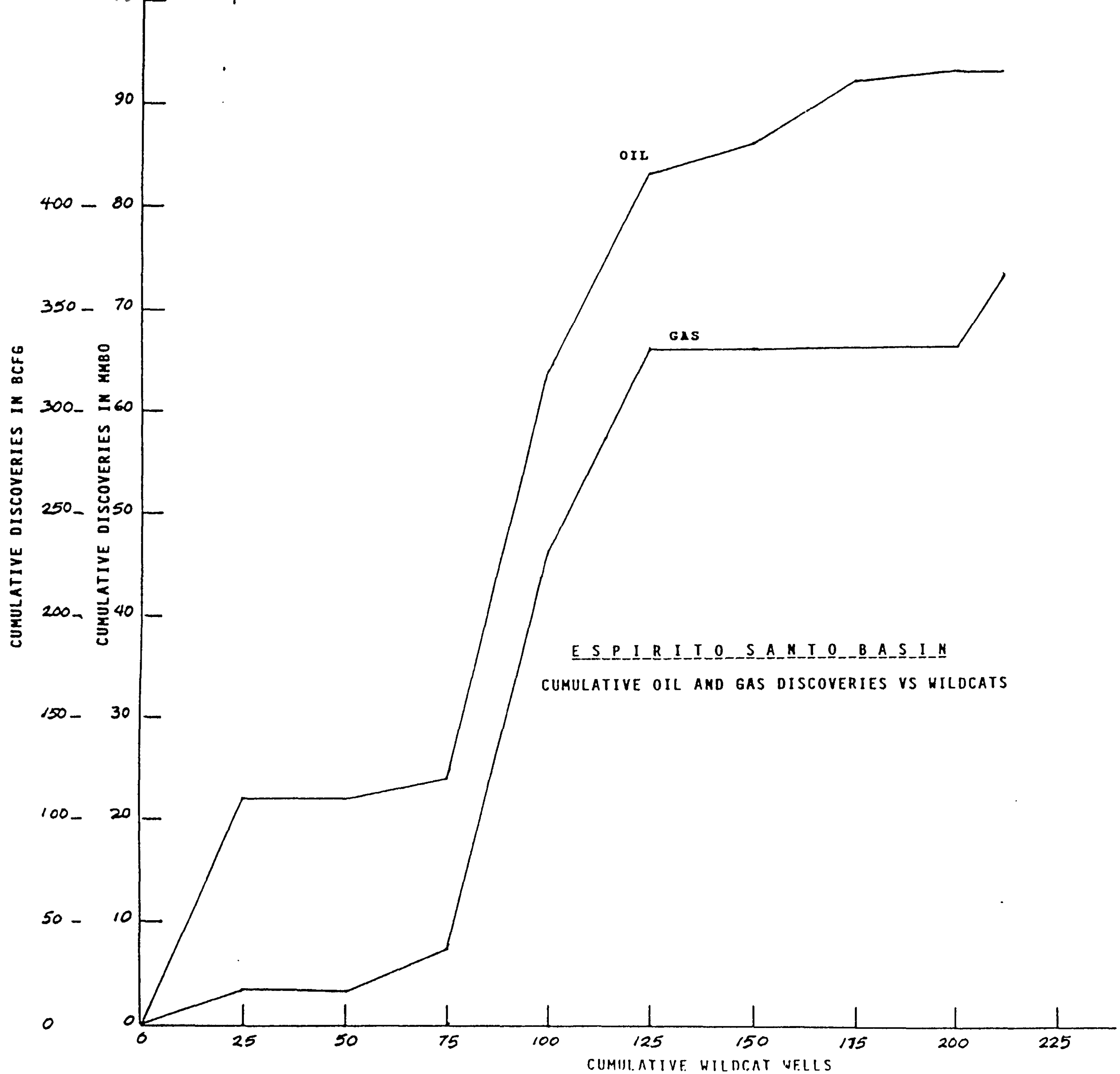


Figure 39 Graph showing the relation of cumulative discovered oil and gas quantity to the number of wildcats drilled in the Espirito Santo basin (data from Petroconsultants 1990, which may be incomplete).

time in reservoirs allowing longer exposure to leakage through shale seals, and 3), the poor discovery rate, this synrift analogy should be discounted to about a quarter, or about .079 BBOE. Assuming the same gas to oil ratio as of present Espirito Santo reserves (55 percent oil), the ultimate resources of the synrift play would be .043 BBO and .213 TCFG.

A curve relating the amount of discovered petroleum to the number of wildcats drilled (fig. 39) indicates that the discovery rate for all plays averages 0.12 MMB of discovered oil per wildcat. Assuming the same number of wells will eventually be drilled as were in the past, i.e. about 200, (exploration technology improvements counterbalancing increasing discovery difficulties) .024 BBO will be discovered. If half these discoveries are from synrift, versus postrift reservoirs, .012 BBO will be discovered. Using these same assumptions, .084 TCFG will be discovered. However, the Campos synrift fields are concentrated in one very limited area of unique geologic setting, (i.e., the Badejo syndepositional high), such as yet to be found in Espirito Santo basin and so this estimate, based only on discoveries to date may be too low and not entirely relevant; the first estimate based on a discounted areal analogy, i.e., .043 BBO and .213 TCFG appears to be more reasonable.

Postrift Shelf Play

The two principal postrift plays on the Espirito Santo continental shelf, the Cretaceous platform carbonates (38B) and the Cretaceous and Tertiary turbidites and channel fill (38C), are combined into a single shelf play for this study because of the lack of sufficient differentiating data. The closest analogy to this play is that of the combined Campos basin postrift shelf play which by areal analogy suggests resources of 1.481 BBOE. Based on the high incidence of gas in the basin, i.e. 45 percent, the petroleum resources are .815 BBO and 4.00 TCFG. This estimate should be discounted, however, for several reasons: 1) the lack of exploration success (10 percent versus approximately 40 percent in the Campos basin shelf), and the declining size of shelf discoveries (fig. 39), 2) the uncertain presence of Neocomian source shales, 3) the relatively early migration prior to some trap formation and causing longer exposure to leakage through Tertiary shales, 4) the relative lack of slope perhaps inhibiting turbidite development, 5) the apparent relative lack of listric faulting which provide primary migration paths, and tilted-block and roll-over closures. Accordingly, the straight analog estimate for the postrift shelf resources must be rather drastically discounted, probably to only 20 percent or .163 BBO and .800 TCFG.

Slope Turbidites

The little evidence available suggests that the Espirito Santo slope relative to the Campos slope is poorly developed (with a very approximate area of 1600 mi^2 (4100 km^2) owing to its occupation by massive volcanic material associated with Abrolhas Bank. The turbidites are also presumably less prevalent, owing to a less favorable slope and to the greater distance from the Serra do Mar clastic provenance. More importantly, it appears that migration may have started early before the bulk of the emplacement of the turbidites. (See Campos basin discussion on generation, migration and entrapment.) In view of these factors, the slope turbidite resources of the Espirito Santo basin are probably relatively minor, about 5 percent, on an areal basis, of those of the Campos basin, or some .104 BBO and .059 TCFG.

The essential petroleum resources of the Espirito Santo basin for all plays amounts to .310 BBO and 1.072 TCFG. Subtracting out present reserves, the estimated undiscovered oil and gas of the Espirito Santo basin are .202 BBO and .544 TCFG.

Bahia Sul Basin

Area: Total - 12,000 mi^2 (31,000 km^2)

Cumuruxitiba 8,000 mi^2 (21,000 km^2)

Jequitinhonha 4,000 mi^2 (10,000 km^2)

Shelf - 8,500 mi^2 (22,000 km^2)

Slope - 3,500 mi^2 (9,000 km^2)

Original Reserves:	Cumuruxitiba	5 MMBO	
	Jequitinhonha	16 MMBO	.001 TCFG
		.021 BBO	.001 TCFG

Description of Area: The Bahia Sul basin as defined here includes the Brazilian coast northwards from Abrolhos bank (at the Bahia-Espirito Santos provincial boundary) to about Latitude 13°30' South where it intersects the interior rift basin of Reconcavo. It is made of a number of sub-basins, which have been variously named by different authors. In this study they are grouped into two principal subbasins, the Cumuruxitiba and the Jequitinhonha subbasins (fig. 3, 40, and 41). (The sometimes referred to Mucuri subbasin is considered part of the Cumuruxitiba subbasin, and the Almada and Camamu subbasins part of the Jequitinhonha subbasin. The so-called Bahia Norte basin, the coastal area from Salvador City to the Sergipe-Alagoas basin, is narrow and considered to have little resources; it is not discussed further.)

The Bahia Sul basin extends from basement outcrops to the COB whose position is assumed to be at the contact of volcanics of the offshore Abrolhos and Royal Charlotte Banks and offshore uplifted blocks of continental basement in the Cumuruxitiba area and the

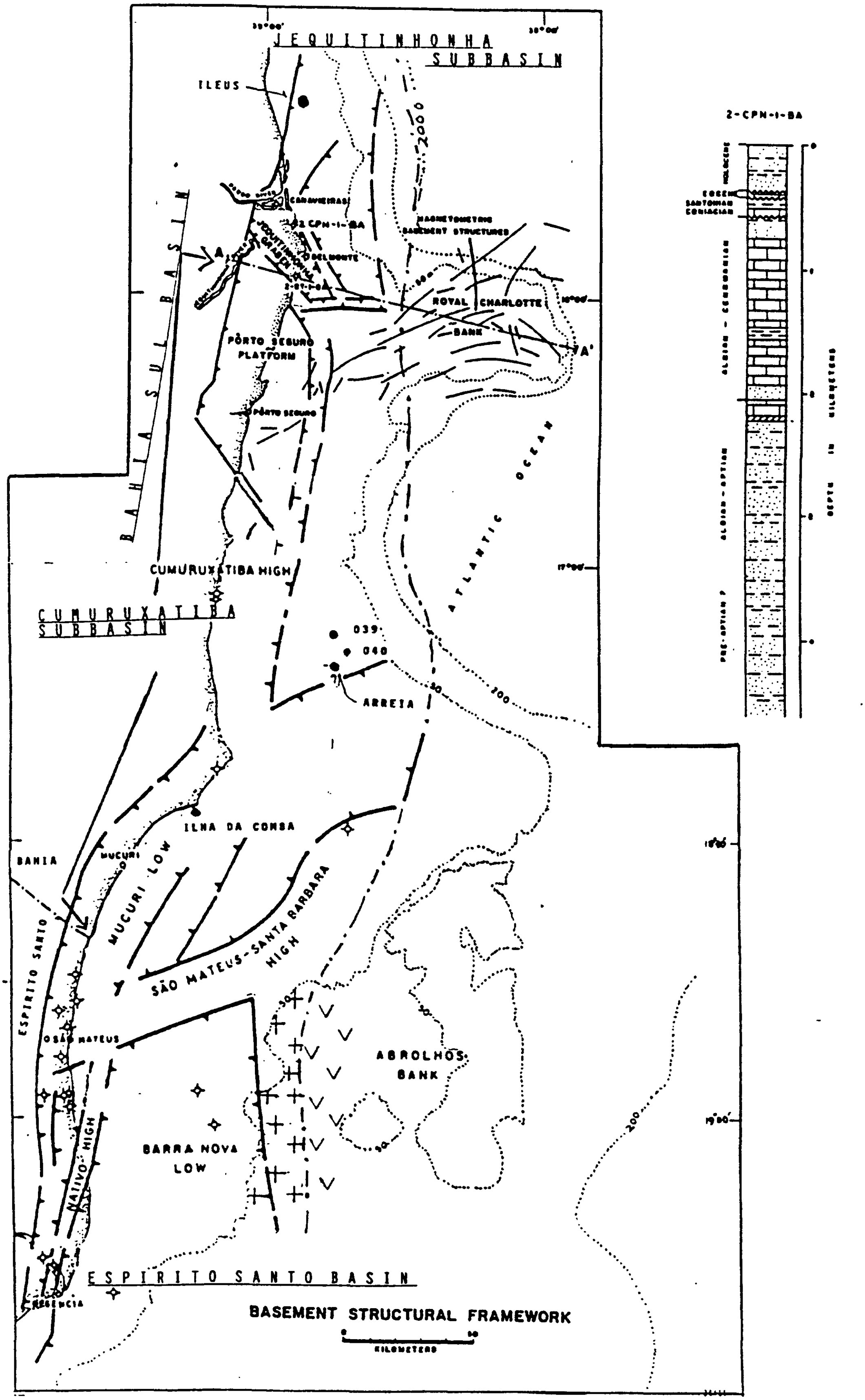


Figure 40 Schematic structure map of the Cumuruxatiba subbasin and portions of the adjoining Jequitinhonha subbasin and Espirito Santos basin showing the postulated position of the continental-oceanic crust boundary (dash-dot line), some wildcat dry holes and discoveries, and A-A' section of figure 42 (modified from Asmus and Ponte, 1973).

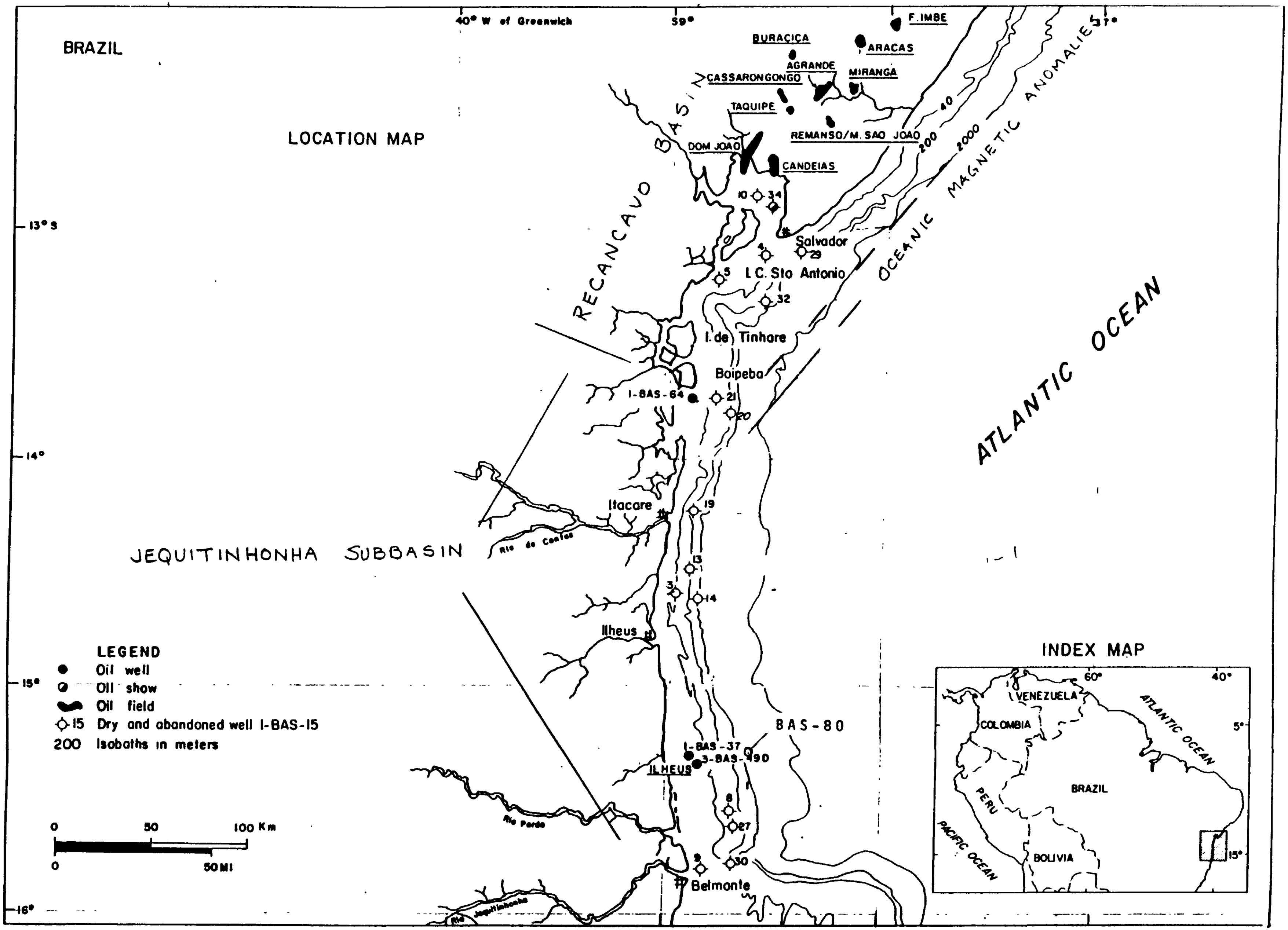


Figure 41 Index map of the Jequitinhonha subbasin showing some key wildcats, oceanic magnetic anomalies, and relation to Recancavo basin (after Petroconsultants, 1989).

2000 M isobath and oceanic magnetic anomalies in the Jequitinhonha area (figs. 3, 40, 41 and 42).

Stratigraphy:

The stratigraphy of the Bahia Sul basin is analogous to that of the adjoining on-trend Espirito Santos basin with the exception that it contains some prerift sediments and appears to contain less volcanic rock. The general stratigraphic section of the Bahia Sul basin begins with basal beds of the prerift Jurassic interior-sag, arid to fluvial deposits, confined to the northern Jequitinhonha subbasin. These are overlain by a synrift Neocomian nonmarine clastic sequence. These strata in turn are overlain by an Aptian transitional or restricted marine section containing evaporites. This sequence is followed by a postrift Albian section of platform carbonates, and an Upper Cretaceous to Tertiary section of clastics containing turbidites.

In the absence of data, it is assumed that source, reservoir and seal rocks are analogous to those of the adjoining Espirito Santos basin. That is, that the primary source is supposed by present Neocomian lacustrine shales downdip from drilling to date with a possibility of a minor source from Upper Cretaceous shales. The principal reservoirs are synrift sandstones, postrift platform carbonates and Upper Cretaceous and Tertiary channel fill and turbidite sandstones; and additional reservoir may be pre-rift Jurassic fluvial sandstones. Seals are Aptian evaporites and Cretaceous-Tertiary shales.

Structure:

The structure is also similar to the Espirito Santo and other rifted margin basins, the trap-forming structure being fault traps, tilted fault blocks and drapes in the lower rifted parts of the basin and salt-flow induced closures and perhaps some listric fault-associated tilted blocks in the upper postrift, post-salt parts. Pinchouts in channel fills and in turbidites provide stratigraphic closures.

Generation, Migration and Accumulation. Analogous to the Espirito Santo basin, migration began with petroleum generation in late Cretaceous-early Tertiary time, after synrift trap formation and synchronous or before some postrift trap formation. Reservoirs occur from Jurassic through Tertiary time. It appears that migration timing was reasonably favorable.

Plays. The plays are essentially the same as in the adjacent Espirito Santo basin, namely, (1) synrift, largely clastic, reservoirs in fault traps and drapes, (2) postrift carbonates in fault traps and drapes, (3) shelf turbidites and channel-fill sandstones, and (4) slope turbidites. The northernmost Jequitinhonha subbasin has an additional fault-trap play involving prerift reservoirs.

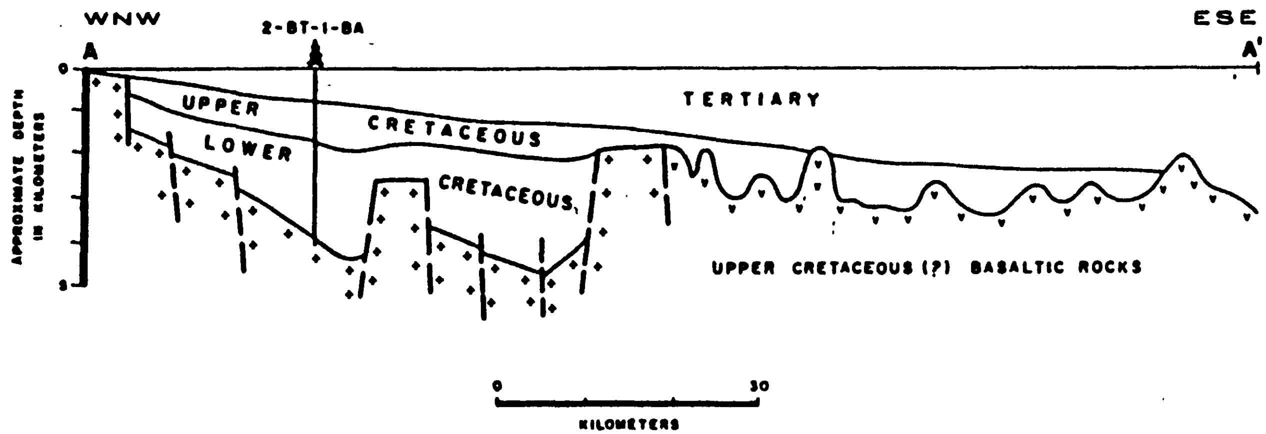


Figure 42 Geologic section across the Jequitinhonha subbasin. Location of figure 40 (after Asmus and Ponte, 1973).

Exploration History and Petroleum Occurrence. Exploration of the Bahia Sul basin has been fairly extensive, but relatively light compared to other basins and with minor results. According to Petroconsultants data (1989), out of 26 wildcats 7 discoveries have been made. Resulting reserves are estimated to be some 21 MMBO, 16 MMBO in the prerift play in Jurassic reservoirs of the northern-most Jequitinhonha subbasin and 5 MMBO from the postrift reservoirs of the Cumuruxitiba subbasin. The largest discovery, the BAS-64 wildcat, of 13 MMBO, is from Jurassic reservoirs in the Jequitinhonha subbasin at the boundary with the Recancavo basin (Fig. 41). Another field in the same subbasin is the Ilheous field. The reserves of the small fields of the Cumuruxitiba subbasin, BAS-039, BAS-044, Arrea and Ilha da Cacumba, are about 5 MMBO (fig. 40).

Estimation of Undiscovered Oil and Gas.

The closest analogy to the Bahia Sul basin is the adjacent on-trend Espirito Santo basin. Owing to lack of data in making a play-by-play comparison, all the plays are combined. On this basis a straight areal analogy with the oil and gas ultimate resources (reserves plus undiscovered) of the Espirito Santo basin would indicate ultimate resources of .523 BBO and 1.656 TCFG. However, the reserves of the Bahia Sul basin on an areal basis are only 6 percent of Espirito Santo basin in spite of a generally comparable exploration effort in both basins. In the absence of any more concrete data this lack of exploration success is taken as an indicator of the basins relatively lower petroleum potential. Accordingly, the straight areal Espirito Santo analog estimate is reduced to an approximately corresponding 10 percent indicating ultimate resources of .052 BBO and .166 TCFG. Subtracting the reserves, the undiscovered oil and gas amount to .031 BBO and .162 TCFG.

Sergipe - Alagoas Basin

Area: total 13,300 mi^2 (34,500 km^2)

Area: Land 4,700 mi^2 (12,000 km^2)

Offshore 8,500 mi^2 (22,000 km^2)

Shelf 4,700 mi^2 (12,000 km^2)

Slope 3,800 mi^2 (9,850 km^2)

Original Reserves: 0.499 BBO, 0.790 TCFG (Table V)

Petroconsultants estimated total .645 BBO and 1,026 TCFG.

Description of Area: The Sergipe-Alagoas basin extends northward along the western Brazilian coast approximately occupying the coastal and offshore areas of the Sergipe and Alagoas provinces.

It extends from approximately 30 mi (50 km) south of the city of Aracaju northward to 60 mi (100 km) north of the city of Maceio and from basement outcrops on the west seawards to the COB approximately at the 2000 M isobath on the west (fig. 43).

Stratigraphy

General. The stratigraphic section (fig. 44) is the most complete of the Brazilian rifted continental margins. The section is in six sequences: prerift, synrift, postrift transitional (i.e., restricted-marine interior sag) carbonate shelf, and shelf/slope clastics. It differs from the stratigraphy of most of the basins to the south (e.g. Campos basin) by having appreciable prerift reservoirs and containing large amounts of postrift restricted-marine source rocks.

Unlike the rifted margin basins further south (exclusive of the immediately adjacent Jequitinhonha subbasin) the Sergipe-Aloas basin contains prerift Permo-Carboniferous and Jurassic sequences. The Permo-Carboniferous sequence is a typical Gondwana section ranging upward from continental sediments to shallow marine. The Jurassic sequence contains fluvial sandstones, the Serrario and Candeeiro Formations, and shales that were deposited in an African-South American interior sag basin. With the beginning of rifting Neocomian synrift clastics were laid down in graben-lakes. They consist of lacustrine shales, syntectonic sands and conglomerates and coquina banks. At the end of rifting the area was covered by an Aptian narrow interior sag basin of restricted marine entry into which evaporites and anoxic shales were deposited. Continued subsidence lead to the deposition of extensive shallow-water Albian carbonate platform deposits and Upper Cretaceous and Tertiary clastics.

Source. As in the adjoining rifted marginal basins, an important petroleum source is the Neocomian synrift lacustrine shales, i.e., the Morro de Chaves, Coqueiro Seco, and Ponta Verde Formations. There is, however, an additional and more dominant source contribution from the Aptian postrift transitional sequence of restricted marine sediments, the Muribeca Formation, which contain evaporites and dark shales. Figure 45 shows the areas of petroleum generated from the lacustrine synrift Neocomian shales versus that from the restricted marine Aptian shales, and the related accumulations.

Reservoirs and Seals. There are three main groups of reservoirs: 1) fractured basement, occuring, for example, in the Carmopolis Field, Aracaju High (figs. 43 and 46B), 2) Jurassic sandstones, mainly of the Serraria Formation, occurring, for example, in the Platform of Sao Miguel do Campos (figs. 43, 46A),

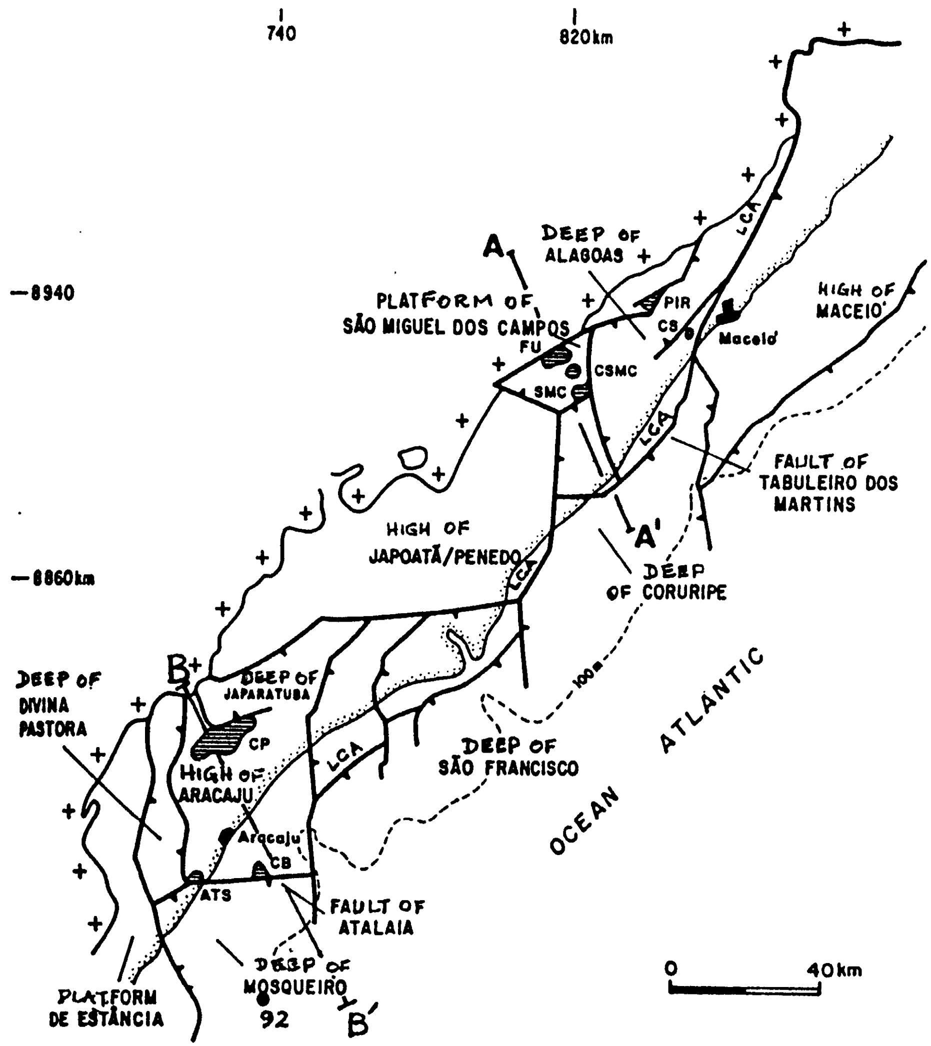


Figure 43 Map showing structural framework of Sergipe-Alagoas basin with key petroleum accumulations; Atalaia Sul-ATS; Caioba-CB; Carmopolis-CP; Cidade de Sao Miguel do Campos-CSMC; Coqueiro Seco-CS; Furado-FU; Pilar-PIR; Sao Miguel dos Campos-SMC. LCA=Aptial hinge line (Linha de Charneira Alagoas) (modified from Bruhn et al, 1988).

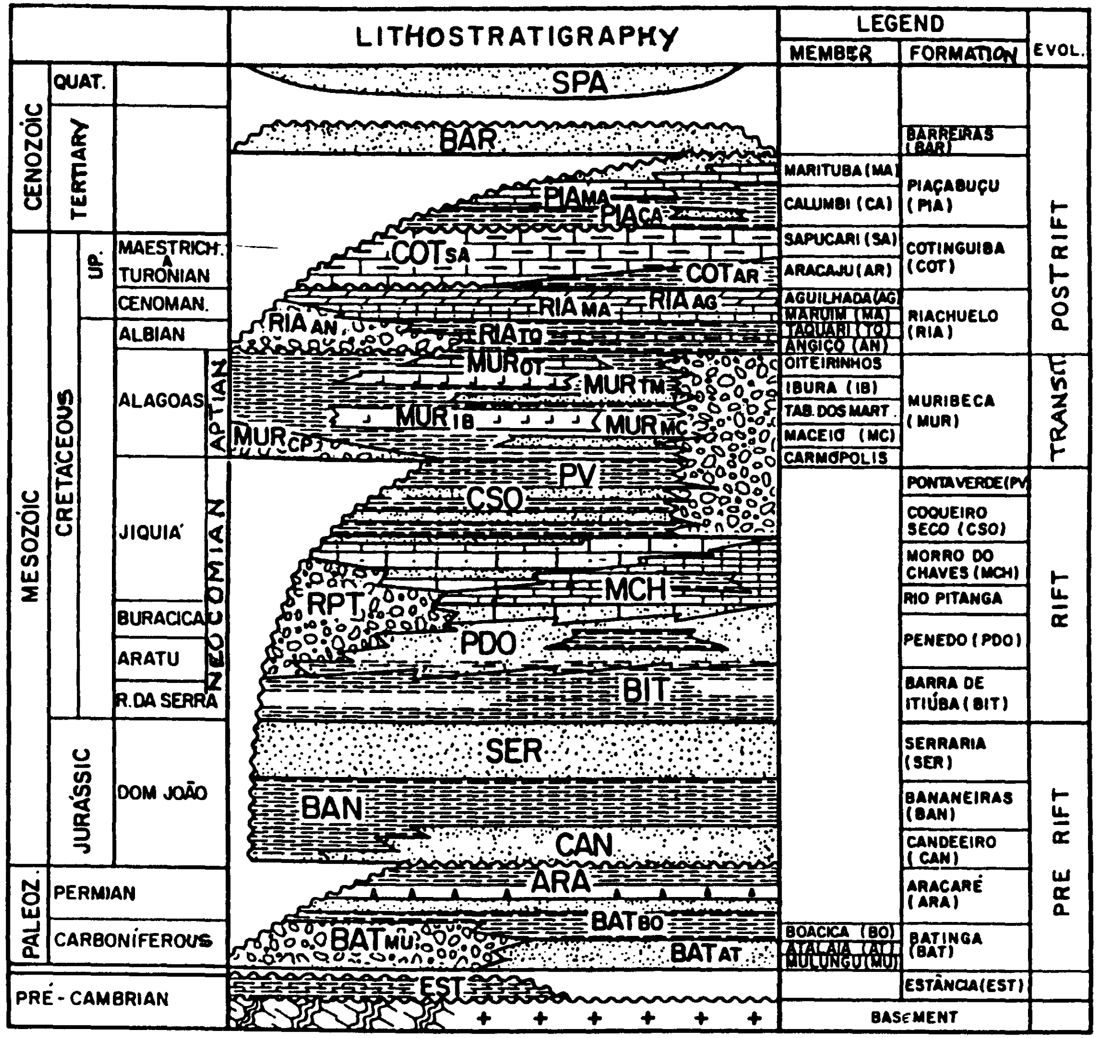


Figure 44 Stratigraphic column of the Sergipe-Alagoas basin (modified from Bruhn et al, 1988).

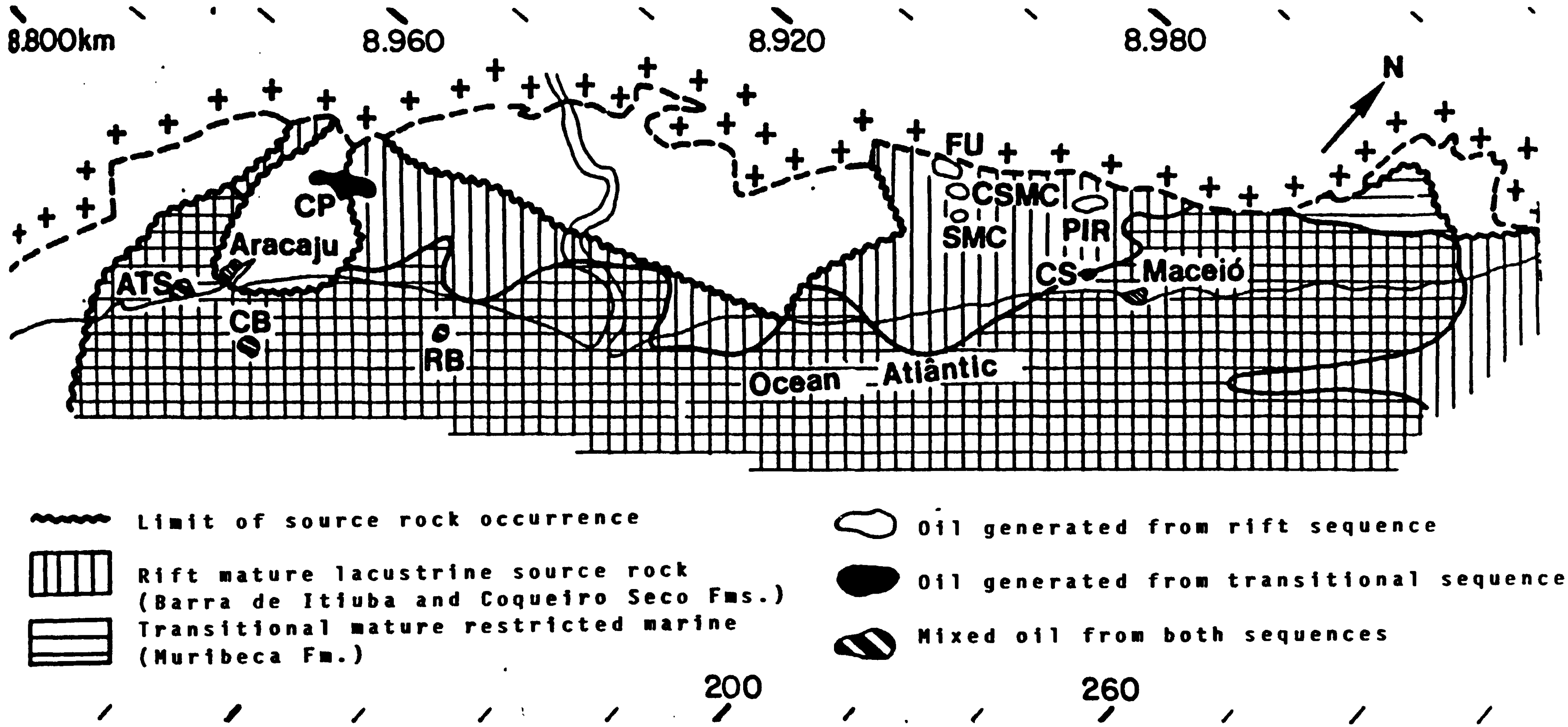


Figure 45 Map showing areas of petroleum generation in the Sergipe-Alagoas basin from synrift Neocomian lacustrine shales versus postrift interior sag restricted marine shales, and key accumulation of each type. Atalaia Sul-ATS; Caioba-CB; Carmopolis-CP; Cidade de Sao Miguel dos Campos-CSMC; Coqueiro Seco-CS; Furado-FU; Pilar-PIR; Robalo-RB; Sao Miguel dos Campos-SMC (modified from Bruhn, et al, 1988).

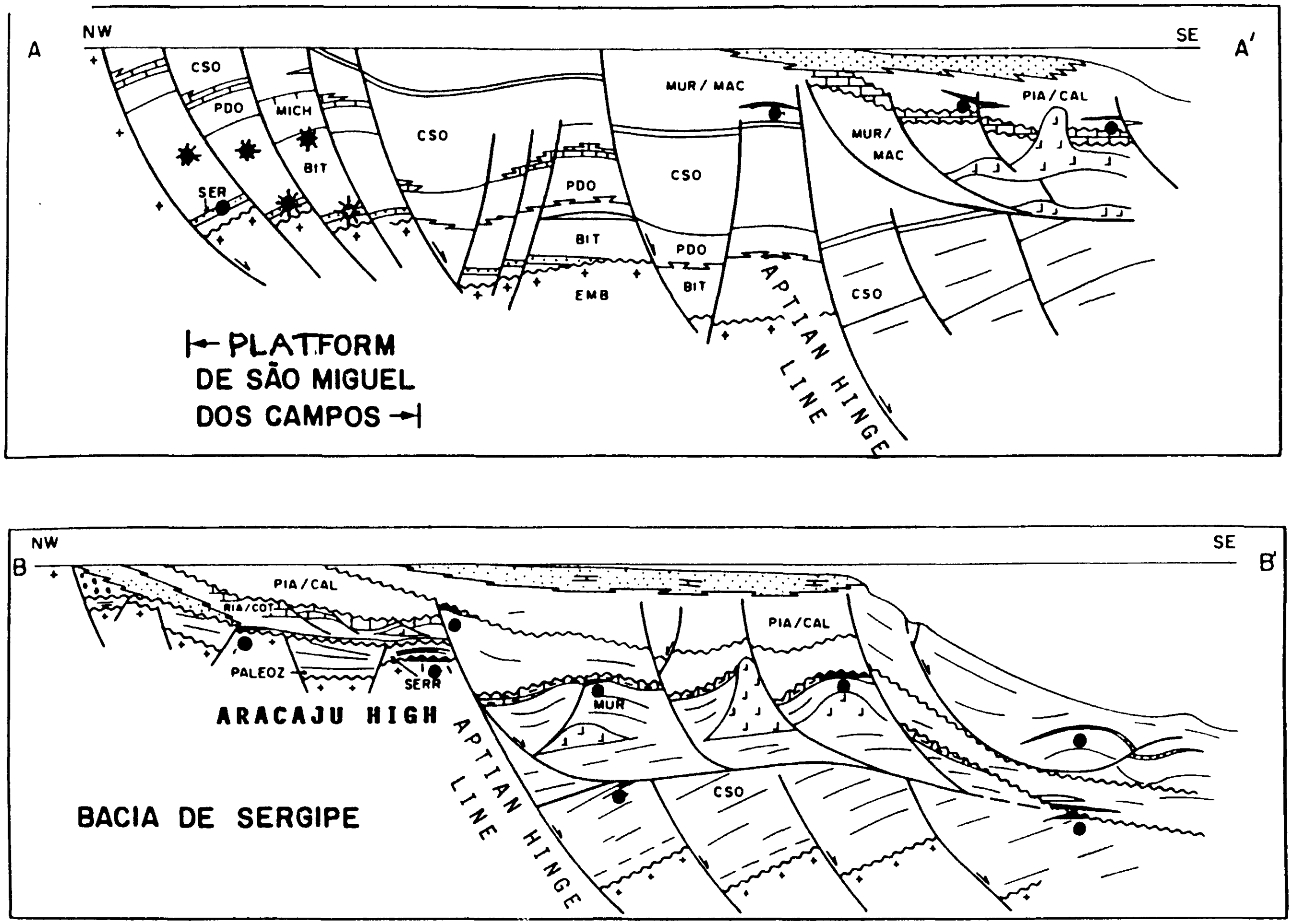


Figure 46 Schematic geologic sections across the Sergipe-Alagoas basin showing structural and stratigraphic relations, Section A-A′ across the Alagoas sector and B-B′ the Sergipe sector. Formation abbreviations same as in fig. 44. Black dots flag plays, Location figure 43 (modified from Van der Ven, 1989).

and 3) the Calumbi Member of mainly turbidite sandstone, which makes up some one percent of the volume of largely Tertiary Piacabucu Formation (fig. 44), occurring in the outer continental shelf and slope lenses of figure 46B.

The principal seals are upper Cretaceous and Tertiary shales which are deemed only moderately effective. The Aptian evaporites being discontinuous and downdip from the larger accumulations do not appear to be a significant factor in this basin.

Structure

The structure of the Sergipe-Alagoas basin is generally similar to the rifted continental basins to the south. However, the north-trending Neocomian rifting is overprinted by a northeast-trending Aptian down-to-the-basin normal fault system and hinge line generally parallel to the coast (line of Charneira Alagoas [LCA]) resulting in a mozaic of high and low fault blocks (fig. 43, 46 A,B). Of particular significance is the Aracaju high block which contains a major part of the oil reserves including the Carmopolis field which has over half the reserves of the basin. The structural closure are fault traps, drapes, salt domes, rollovers accompanying listric faulting (fig. 43, 46A,B).

Generation, Migration, and Accumulation. Judging from Ponte and Asmus (1976) subsidence curves and assuming a stable geothermal gradient, generation and migration began in the Tertiary, at which time all the traps except possibly some late Tertiary channel fills or turbidites had formed. Assuming the prerift and synrift reservoir porosity and permeability were to some degree preserved, as appears to be the case in at least in some instances, the migration timing is favorable.

Plays. Petrobras has defined some eight plays which are indicated in figure 46A and B. These plays, in the absence of sufficient data can be combined into four major plays, 1) prerift, 2) synrift, 3) postrift shelf and 4) postrift slope (Table V).

Exploration History and Petroleum Occurrence. Geophysical surveys began in 1935 and the first wildcat drilled in 1939. Extensive systematic exploration did not commence until 1954 with the founding of Petrobras. The first discovery was made in 1957. Carmopolis, the largest field in the basin (53 percent of the reserves), was discovered in 1963 (Figs. 43 and 45). Offshore exploration of the continental shelf began in 1968. In 1987 two wildcats drilled in water depths exceeding 3300 ft (1000 m) initiated exploration of the continental slope. Exploration success occurred in four phases. The first and, to date, most important phase was the onshore discoveries of the fields of the Aracaja High (fig. 43, 46B), Carmopolis and two other fields accounted for 65 percent of the cumulative production up to 1990. The second phase was the discovery of the Caioba field and three others in the fault block immediately offshore of Aracaja (figs. 43 and 46B). The third

TABLE V

SERGIPE-ALAGOAS BASIN PETROLEUM RESOURCES

	-1-	-2-	-3-	-4-	-5-	-6-	-7-	-8-	-9-
	RESERVES			UNDISCOVERED PETROLEUM RESOURCES					
PLAY				PLAY ANALYSIS			INDIRECT METHODS		
	BBOE(1)	BBO(2)	TCFG(2)	BBOE(1)	BBO(2)	TCFG(2)	BBOE(5)	BBO(6)	TCFG(6)
PRERIFT	0.069	0.055	0.087	0.040	0.032	0.050	0.037	0.012(3)	0.101(3)
SYNRIFT	0.120	0.095	0.150	0.111	0.088	0.139	0.062	0.021(3)	0.174(3)
POSTRIFT SHELF	0.441	0.349	0.553	0.182	0.144	0.228	0.230	0.077(3)	0.643(3)
POSTRIFT SLOPE	0	0	0	0.672	0.534	0.846	0.641	0.476(4)	0.990(4)
TOTAL	0.630	0.499	0.790	1.008	0.798	1.268	0.970	0.586	1.908

(1)Derived from Petrobras data and statements (Van der Ven et al 1989, and Aquino and Lana,1990).

(2)Separate oil and gas figures derived from columns -1-and-2- on the basis of the petroleum mix being 20.9 percent gas as estimated from Petroconsultants data.

(3)Cumulative discoveries versus wildcats on the shelf (including prerift, synrift, and postrift shelf plays) indicate some 0.123 BBO and 1.239 TCFG will be discovered on the shelf (text and fig.47) which is distributed to the three shelf plays in the same ratio as their reserves.

(4)Slope undiscovered petroleum estimate arrived at by assuming the Campos basin ratio of shelf to slope resources (3.9 for oil and 2.9 for gas) holds to some degree for this basin, but this estimate is discounted to 20 percent because of some factors relatively unfavorable to turbidite formation in this basin as compared to the Campos basin (see text).

(5)BBOE estimate derived from columns -8- and -9-.

(6)Based on discovery-versus-wildcat curve (see text).

phase was the onshore discoveries of the San Miguel dos Campos Platform and adjoining areas (i.e. Pilar field) (figs. 45, 46B. The fourth phase, which only began in 1990, included the slope with one significant turbidite discovery 1-SES-92 (southernmost wildcat of fig. 43). These four phases are indicated by abrupt increases in the cumulative discoveries on figure 47.

Onshore exploration is mature with little chance for further significant large discoveries. Offshore shelf discoveries will most likely continue as indicated by the curve of field-size discoveries against number of wildcats (fig. 47) (from Petroconsultants 1990 data). The curve (exclusive of the latest slope discovery) indicates an average oil discovery size, for the last 200 wilcats, of about .245 MMBO per wildcat. Gas discovery size per wildcat is much higher at 2.41 BCFG, perhaps indicating an increasing interest in gas.

Estimation of Undiscovered Oil and Gas

Estimates of reserves and undiscovered petroleum (on an oil-equivalent basis) of approximately the four plays may be gleaned from Petrobras publications (Van der Ven et al., 1989 and Aquino and Lana, 1990) (columns 1 through 4, Table V). Recoverable gas and oil, reserves and undiscovered oil and gas (columns 5, 6 and 9), are obtained from oil-equivalent estimates by assuming 20.9 percent gas (from the ratio of Petroconsultant oil and gas reserve estimates). Exactly how Petrobras estimated undiscovered petroleum is not known other than that play analysis was employed.

Column 8, Table V shows my estimates of undiscovered petroleum determined by less direct methods and based on assumptions derived principally from the exploration history, i.e., the cumulative discovered petroleum versus wildcats drilled in the case of the shelf plays (fig. 47), and from a discounted analogy to the geologically-similar Campos basin in the case of the slope play.

Assuming offshore shelf exploration can be economically sustained, at about the same discovery rate, (.245 MMBO and 2.41 BCFG per wildcat) for the same number of additional wildcats as those already drilled (450 wildcats), (newer technology counter-balancing increasing discovery difficulty) some 0.110 BBO and 0.918 TCFG in shelf discoveries may be expected. Distribution of these resources to shelf plays in the ratio of shelf reserves (Table V), the undiscovered resources for the prerift play amounts to .012 BBO and .101 TCFG, the synrift play .021 BBO and .174 TCFG, and the postrift shelf .077 BBO, .643 TCFG.

Slope exploration, indicated by the final ascent of the cumulative discovery per wildcat curve (figure 47) is still immature and shows no reliable discovery rate; however, an analogy to the Campos basin slope may be useful. The ratio of slope ultimate resources (reserves plus estimated undiscovered petroleum) to shelf ultimate resources in the Campos basin is 3.9 for oil and 2.9 for

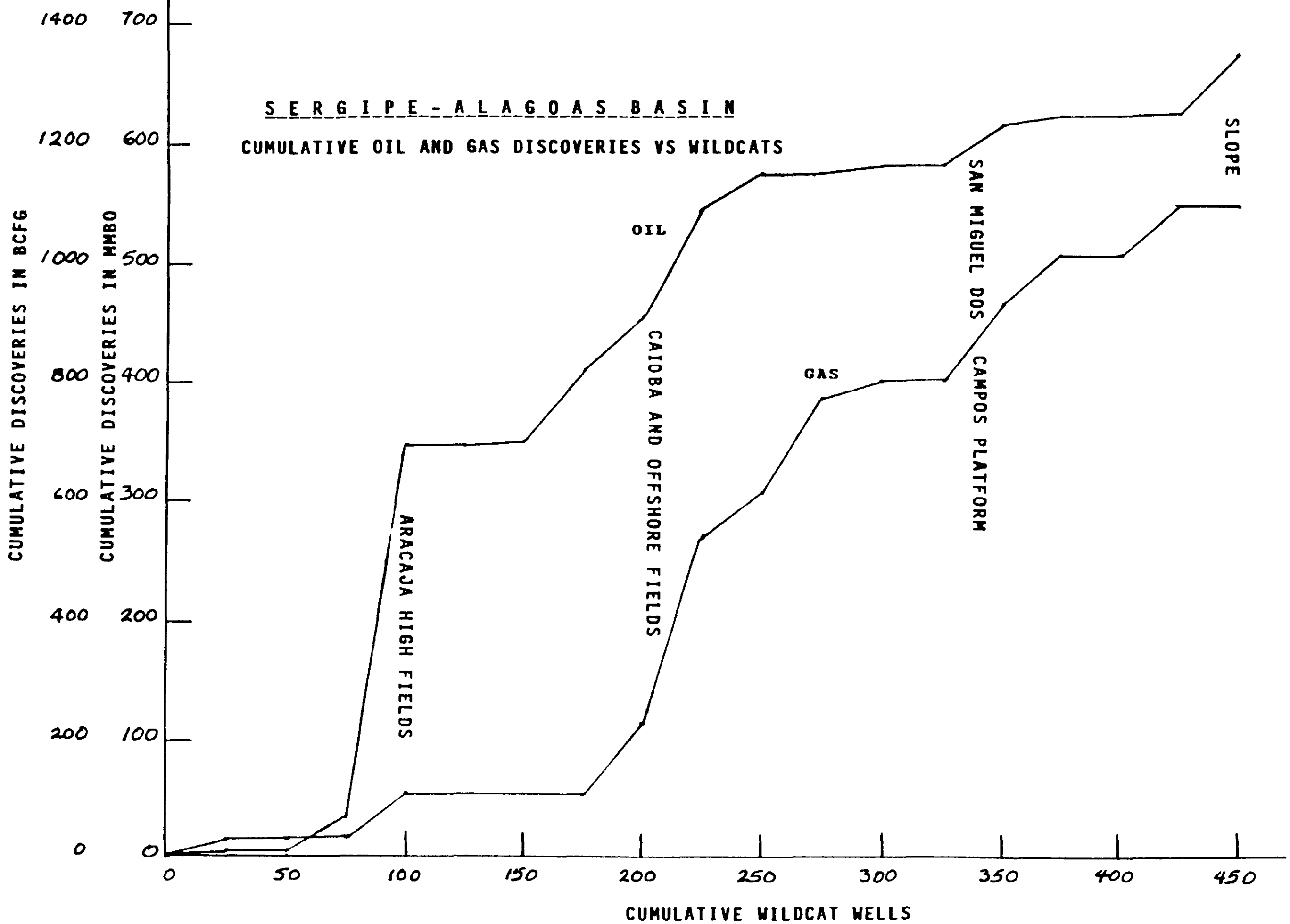


Figure 47 Graph showing the relation of cumulative discovered oil and gas quantity to the number of wildcats drilled in the Sergipe-Alagoas basin. Based on Petroconsultants data (1990) which may be incomplete.

gas. Applying these ratios to the shelf resources of the Sergipe-Alagoas basin, the slope resources would be 2.38 BBO and 4.95 TCFG. However, the slope of the Sergipe Alagoas basin slope is relatively narrow, an adjoining quartz provenance (such as the rising Serra do Mar range) is less evident, and the rapid post-Eocene Campos subsidence which may have caused turbidite formation is missing in the Sergipe-Alagoas basin (fig. 10). The Campos slope analog, therefore, can be discounted to 20 percent, or .476 BBO, and .990 TCFG.

The estimates of undiscovered oil and gas for the various plays of the Sergipe-Alagoas basin of this study are summarized and compared with those derived from the Petrobras play analyses in Table V. The estimates of this study, Indirect Methods columns 7, 8, and 9, compare closely with the Petrobras-derived estimates, i.e., columns 4, 5, and 6, as to total undiscovered petroleum resources on a BBOE basis, but indicate less oil and more gas than the Petrobras-derived estimates. This apparent discrepancy arises largely from the greater relative rates of gas over oil discoveries indicated by the cumulative discoveries versus wildcat curves (fig. 47), upon which the Indirect Method estimate partly hinges. Based on more data and knowledge of the basin, however, the Petrobras-derived estimates, i.e., 0.798 BBO and 1.268 TCFG (Table V) should be regarded as the best estimates of undiscovered gas and oil of the Sergipe-Alagoas basin.

Northeastern Rifted and Wrenched Margin

Figure 48 shows the physiography of the western equatorial Atlantic and the adjoining northeastern rifted and wrenched continental margin of South America. The fracture zones appear, at least to the extent they may affect the continental margin area, to be a series of regional sinistral wrench faults. This means that the structure of this margin has been influenced by oblique transpressional (and transextentional) forces in contrast to the southeastern rifted margin which was effected largely by perpendicular-to-the-coast, pull-apart extensional forces. The shape and distribution of the basins have also been influenced by these forces. Fig. 49 indicates the basins, within Brazil, which will be discussed.

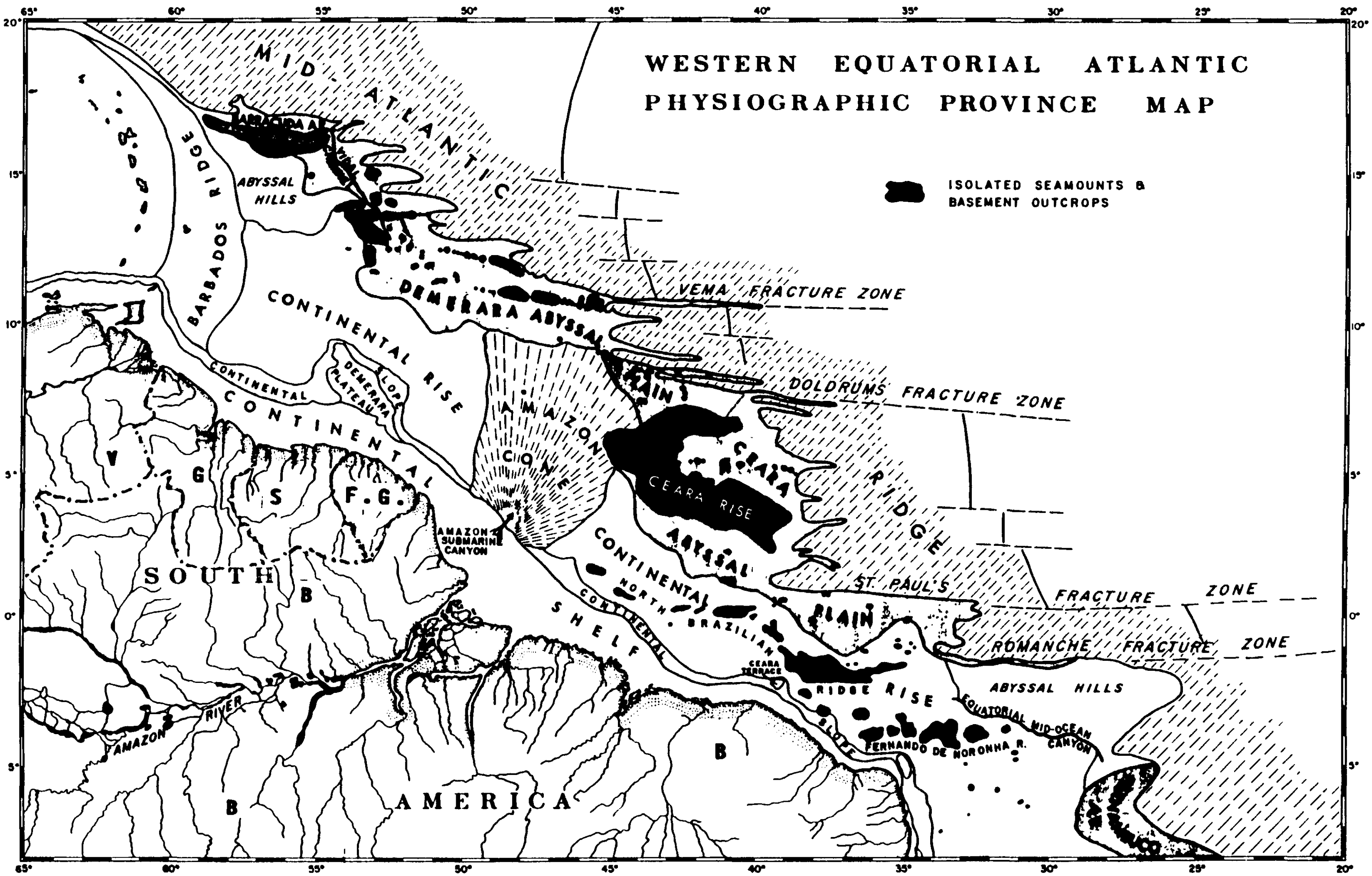


Figure 48 Map showing the physiographic provinces of the northwestern margin of the Brazilian craton area of South America. B=Brazil, V=Venezuela, G=Guyana, F.G.=French Guyana, S-Surinam (modified from Damath and Kumar, 1975)

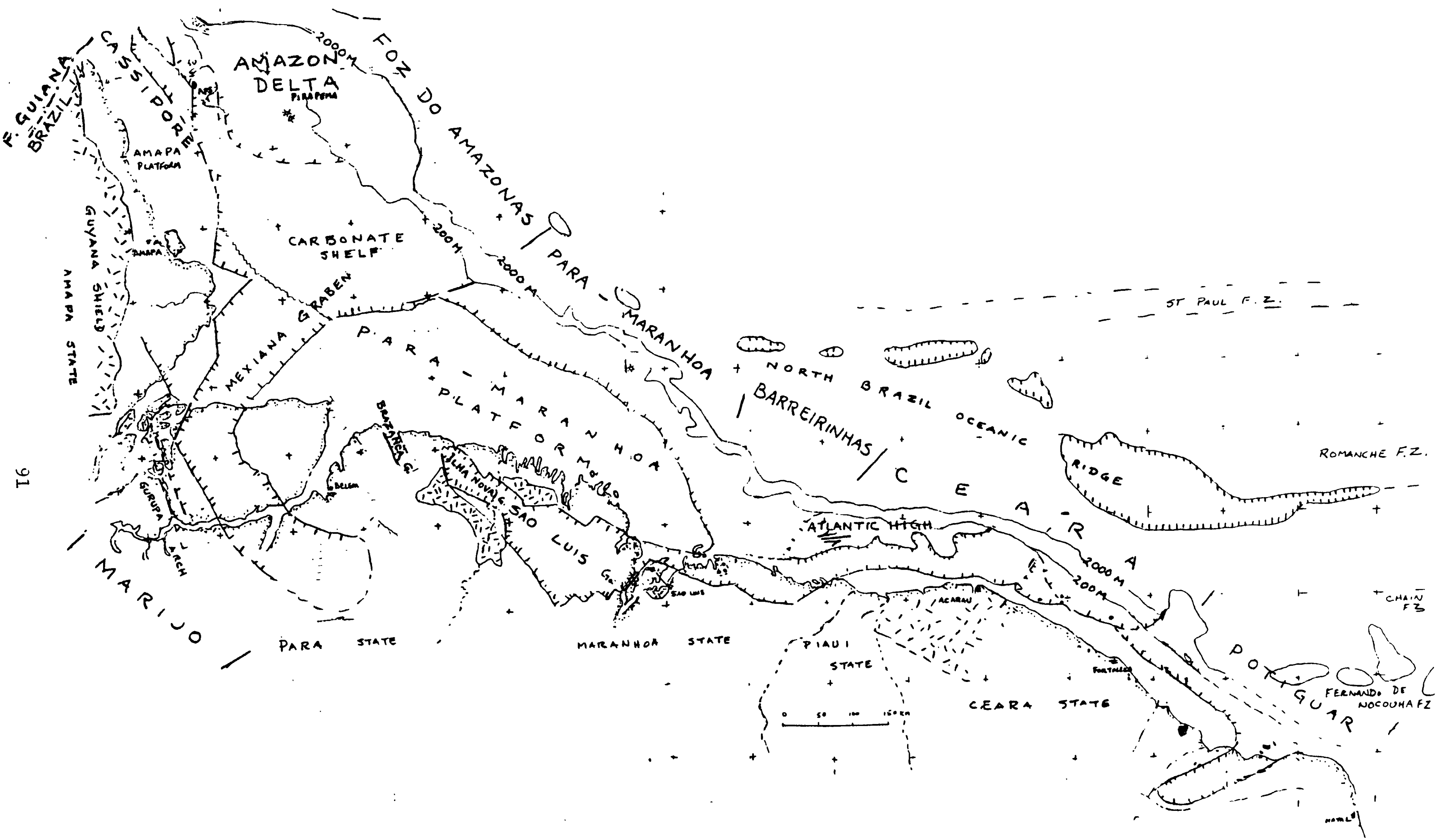


Figure 49 Sketch tectonic map of Brazilian northeast coast showing basins and structural elements.

Potiguar Basin

Area	mi²	km²
Deep Rift onshore	2,248	5,823
offshore	2,007	5,198
Marginal shelf	752	1,948
Slope (area very approximate)	4,789	12,404
Shallow Shelf onshore	5,679	1
offshore	4,759	12,326
Total	20,234	51,541
Total (Exclusive of shallow shelf)	9,796	25,371

Original Reserves .154 BBO onshore (Bertani, et al., 1987)

.066 BBO offshore (assumed to be very largely turbidites)

.220 BBO Total proven reserves(Taden and Coster)

Description of Area: The basin extends from basement outcrop to offshore COB and from the Touros High eastward to the Forteleza High (fig. 50). The deeper basin is "L" shaped, having two trends, a SW-NE-trending interior rift and sag trend, and a SE-NW-trending rifted continental margin trend. The basin has a large shallow shelf area onshore and offshore encompassing about 10,400 mi^2 (27,000 km) which is generally less than a kilometer in thickness but into which petroleum has migrated (e.g. the Fazenda Belem field, fig. 53); this outer shelf area is not considered in making areal comparisons of the Potiguar basin with analogous basins.

Stratigraphy

General. The Lower Cretaceous stratigraphy of the Potiguar basin, consisting of Neocomian continental rift-fill sediments (Pendencia Formation) overlain by Aptian restricted-marine to marine interior sag sediments (Alagamar Formation), which in turn are overlain by Albian shelf carbonate (Ponta do Mel Formation), is similar to that of the rifted continental margin basins of the Brazilian southeast coast (Fig. 51). The massive Upper Cretaceous carbonates (Jandaira Formation) also appear in the Sergipe-Alagoas basin, but are not particularly well developed in any of the other

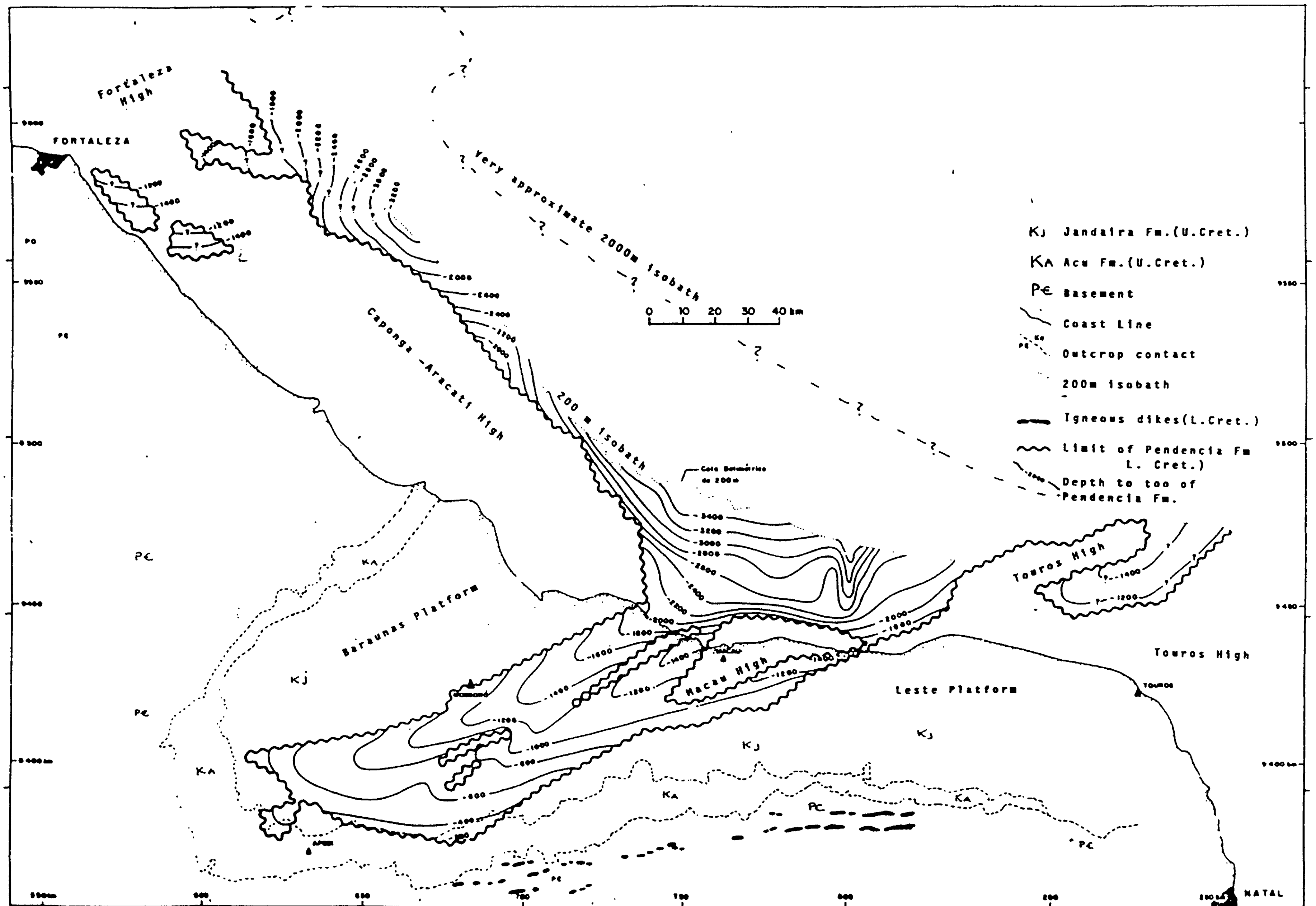


Figure 50 Structural map at top of synrift sediments showing the general structure of the Potiguar basin to the shelf edge (200 M). The approximate position of the base of the continental slope postulated to be at about the continental-oceanic crust boundary (modified from Francolin and Szatmari, 1987).

LITHOSTRATIGRAPHY

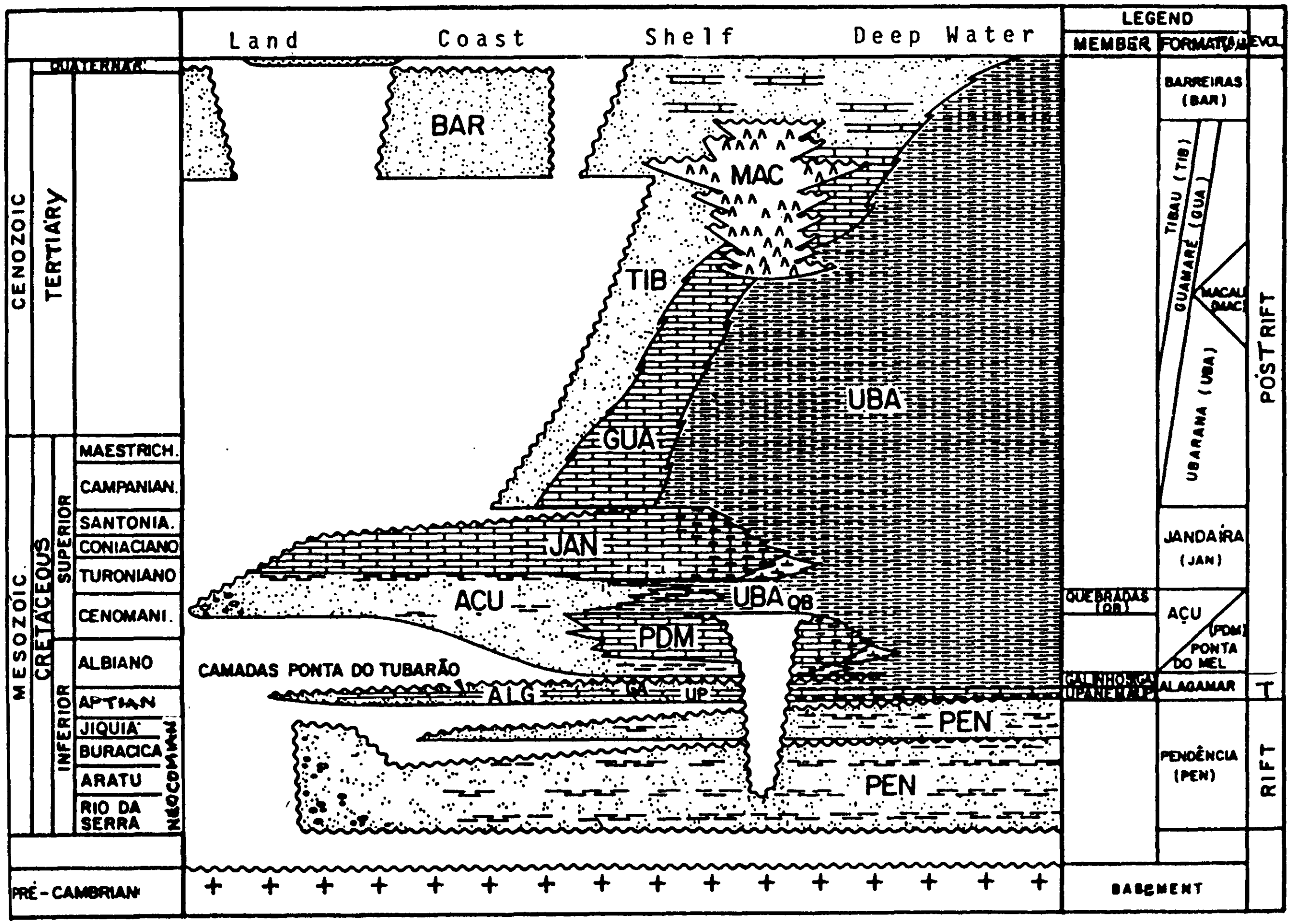


Figure 51 Stratigraphic column of the Potiguar basin (modified from Bruhn, et al, 1988).

basins. The stratigraphy of the Tertiary is similar to that of the Brazilean northeast coast, some of the formation names (e.g., Guamare, Tibau, and Uburana Formations, and Macau volcanics) being carried over into the next basin to the northwest, Caera basin.

Figure 52 shows the distribution of sedimentary strata in the flank of the interior rift and sag and in the area of the marginal rift and sag.

As in the other basins of the northeast margin, the Aptian salt of the southeast margin is missing.

Source. Source rocks are the lacustrine sediments of Neocomian continental beds (the Pendencia Formation) and the marine shales of the interior sag Aptian sediments (the Algamar Formation). Figure 53 shows the areas of these two sources and the oil fields in which the oils of these sources accumulated.

Reservoirs and Seals. Reservoirs apparently occur throughout the section, but may be divided into four groups 1) limited deltaic and syntectonic sands of the synrift stage (Pendencia Formation), 2) sandstones of the interior sag stage (Alagamar Formation), 3) porous zones in the platform carbonates (Jandaira Formation),and 4) Late Cretaceous to Tertiary sandstones (Acu and Uburana Formations).

The seals are generally shales, the Aptian evaporites of the southeast Brazilian continental margin being absent.

Structure

The structure is essentially of two types, a typical interior rift (fig. 50) intersecting with a rifted continental rifted margin. Rifting occurred through the Neocomian until early Aptian time when minor interior sagging began. In Late Cretaceous time the coastal part of the basin began substantial thermal subsidence and continued through the Tertiary as the continents drifted apart (fig. 52).

Traps in the Neocomian section, or rifted part of the basin, are principally fault trap and drape closures. In the interior sag phase traps are formed by drape closure, and in the thermal subsidence phase of the rifted margin, the traps are drapes, rollover and listric fault closures.

Generation, Migration and Accumulation. Generation and migration began in late Cretaceous-early Tertiary time when all the traps, except for some of the Tertiary listric fault associated closures, turbidites and possibly channel fills had been formed. The older synrift reservoirs appear to be at least in part preserved from diagenetic degradation and so the timing of migration appears to be moderately favorable.

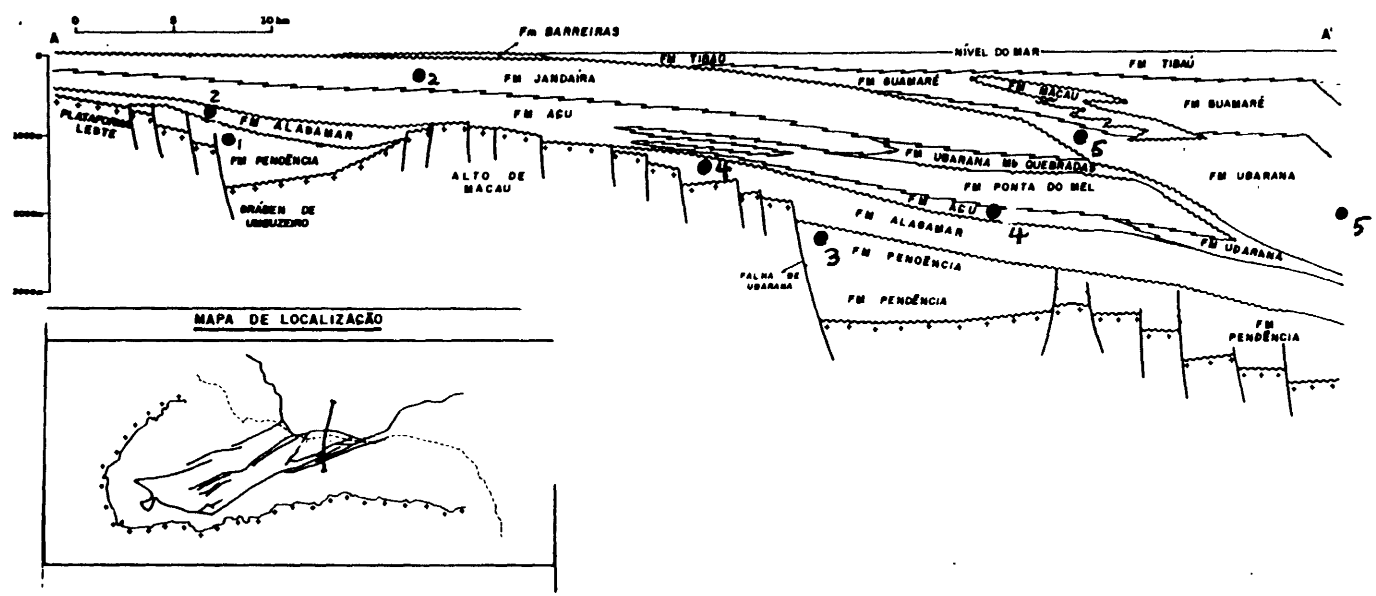


Figure 52 Geologic dip section across the interior rift and marginal rift parts of the Potiguar basin showing the distribution of plays: 1-synrift of the interior rift (Pendencia Formation) play, 2-interior sag play (Algamar and Acu Formations); 3-synrift of the marginal rift; 4-interior sag of the marginal basin; 5-turbidites largely in the rifted margin (modified from Francolin and Szatmari, 1987)...

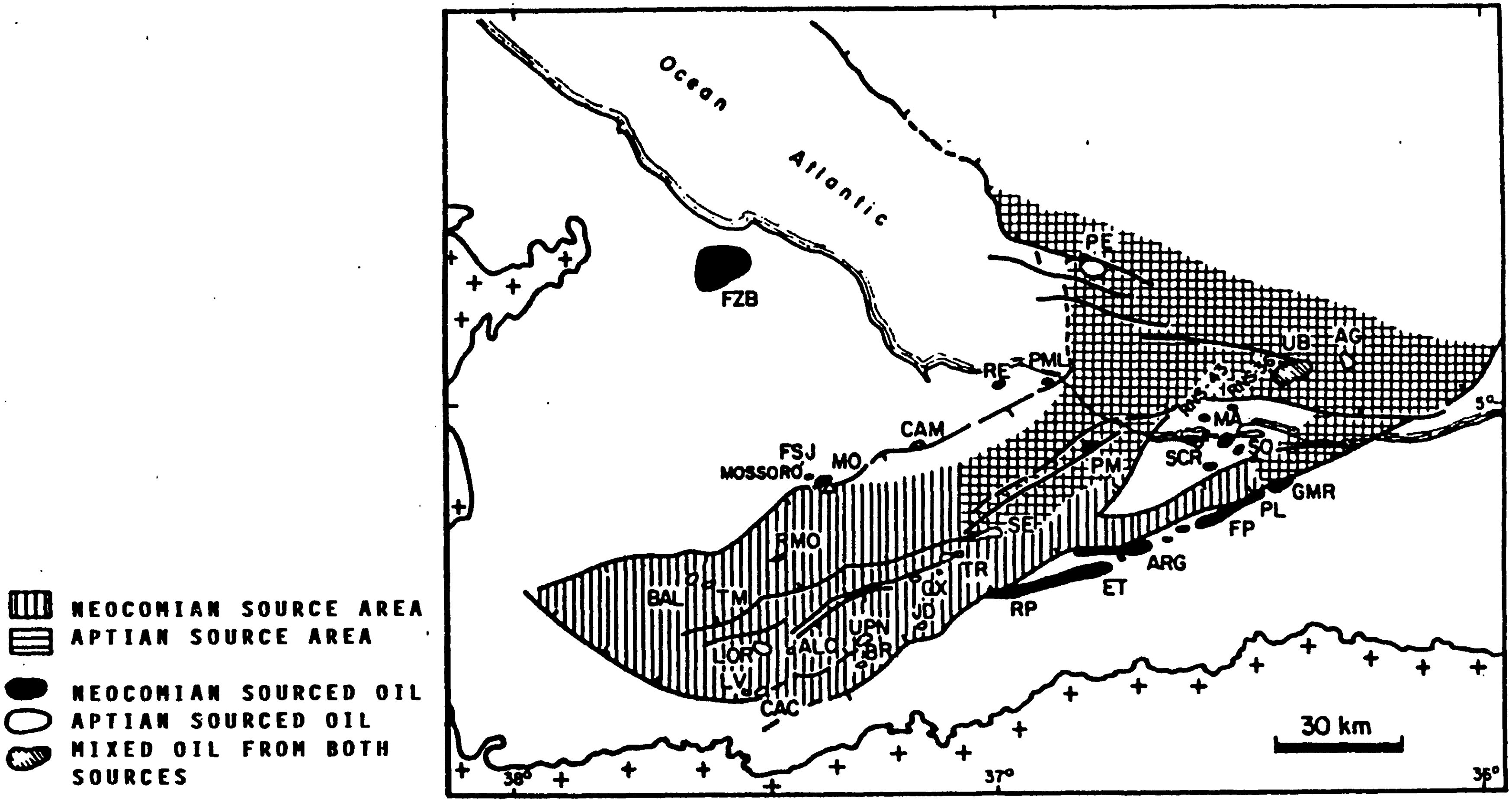


Figure 53 Potiguar basin map of petroleum generation areas of the synrift Neocomian lacustrine shales and of the postrift-Aptian restricted-marine shales, and the accumulations of petroleum from each source. The petroleum accumulations are: Agulha-AG, Allcrim-ALC; Alto do Rodriques-ARG; Baixa do Algodao-BAL; Brejinho-BR; Cachoeirinha-CAC; Canto do Amaro-CAM; Estreito/Rio Panon-ET/RP; Fazenda Belem-FZB; Fazenda Pocinho/Palmeira-FP/PL; Fazenda Sao Joao-FSJ; Guamare-GMR; Jandui-JD; Livramento-LV; Lorena-LOR; Macau-MA; Mossoro-MO; Pescada-PE; Ponta do Mel-PML; Porto do Mongue-PM; Soledade-SO; Trapia-TR; Tres Marios-TM; Ubarana-UB, Upanema-UPM plus indicated discovery well numbers (modified from Bruhn et al, 1988).

Plays. There appears to be a number of plays: 1) the interior synrift play with the deltaic and syntectonic reservoirs of the Pendencia Formation in drape or fault traps, 2) the interior sag play involving the sandstones of the Alagamar and Acu Formations and carbonates of the Jandaira Formation in drape traps, 3) the marginal synrift play involving the same reservoirs and type traps as the interior rift, 4) the marginal sag play involving same formations and traps as for the interior rift, and 5) turbidites, largely in the marginal rift shelf and slope area but most prospective on the continental slope; this play was the most potential of the plays. Figure 52 shows diagrammatically the position of the potential plays and Figure 54 particularly shows plays 3, 4, and 5.

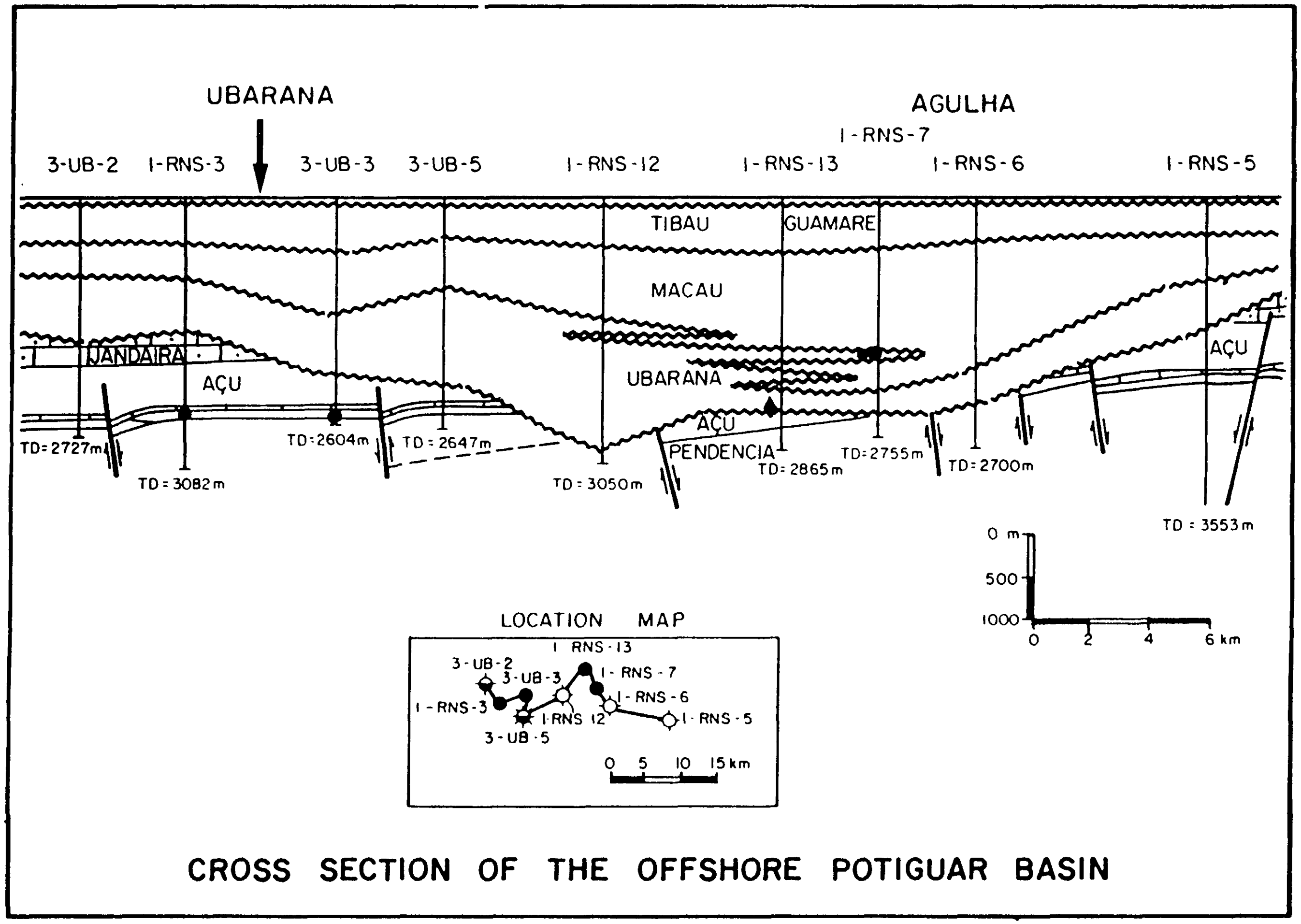
History of Exploration and Petroleum Occurrence. Exploration began in 1945 and was initially discouraging, but after the first onshore discovery in 1979, the onshore exploration increased with 93 wildcats being drilled in the 1980-81 period resulting in three more discoveries. In the following years until 1986, 16 more discoveries were made, with the emphasis moving towards deeper (synrift) discoveries in about 1984. In general, the onshore discoveries have been small, averaging 2 or 3 MMBO with the largest being 20 MMBO. In the offshore area, discoveries occurred earlier (1973-1975). They were few but larger than the onshore discoveries, e.g., the Uburana field having some 50 MMBO and 143 BCFG in Aptian reservoirs, and the only shelf turbidite field, the offshore Agulha Field, with reserves of 14 MMBO and 35 BCFG (fig. 54). Only some six wildcats were drilled in the marginal rift area north of the interior rift and its seaward extension (as of 1989) and they were dry. Figure 55 shows the cumulative millions of barrels discovered versus the number of wildcats drilled. The sharp ascent of the curve at 75 to 100 wildcats represents the offshore discoveries. Afterwards, the discovery rate of oil and gas appears to reach a slope of about .20 MMBO and .53 BCF per wildcat from 150 to 350 wildcats. This discovery rate indicates that the onshore interior rift trend where most of the wildcats have been drilled is near a mature stage. The continental shelf has only a few wildcats north of the interior rift area and the slope is yet to be drilled.

Location of the petroleum accumulations and their source areas are shown in Figure 53.

Estimation of Undiscovered Oil and Gas

If again as many wildcats are drilled as have already been drilled in the land and shelf portion of the basin (350), and if the discovery rate curve continues at about the rate of .20 MMBO and .53 BCFG per wildcat,.(assuming increased technology counterbalances increasing discovery difficulties), .070 BBO and .186 TCFG will be discovered exclusive of the slope.

The prospective shelf of the rifted margin trend is limited to a narrow 5 mile (10 km) strip, the remaining area being occupied by



After M B ARAÚJO, J B GOMES and S M SOUZA in Offshore Brazil, The Latin American Oil Show, 1978

Figure 54 Geologic cross section of the Potiguar through the Ubarana and Agulha Fields (UB and AG of figure 52) (from Petroconsultants, 1989).

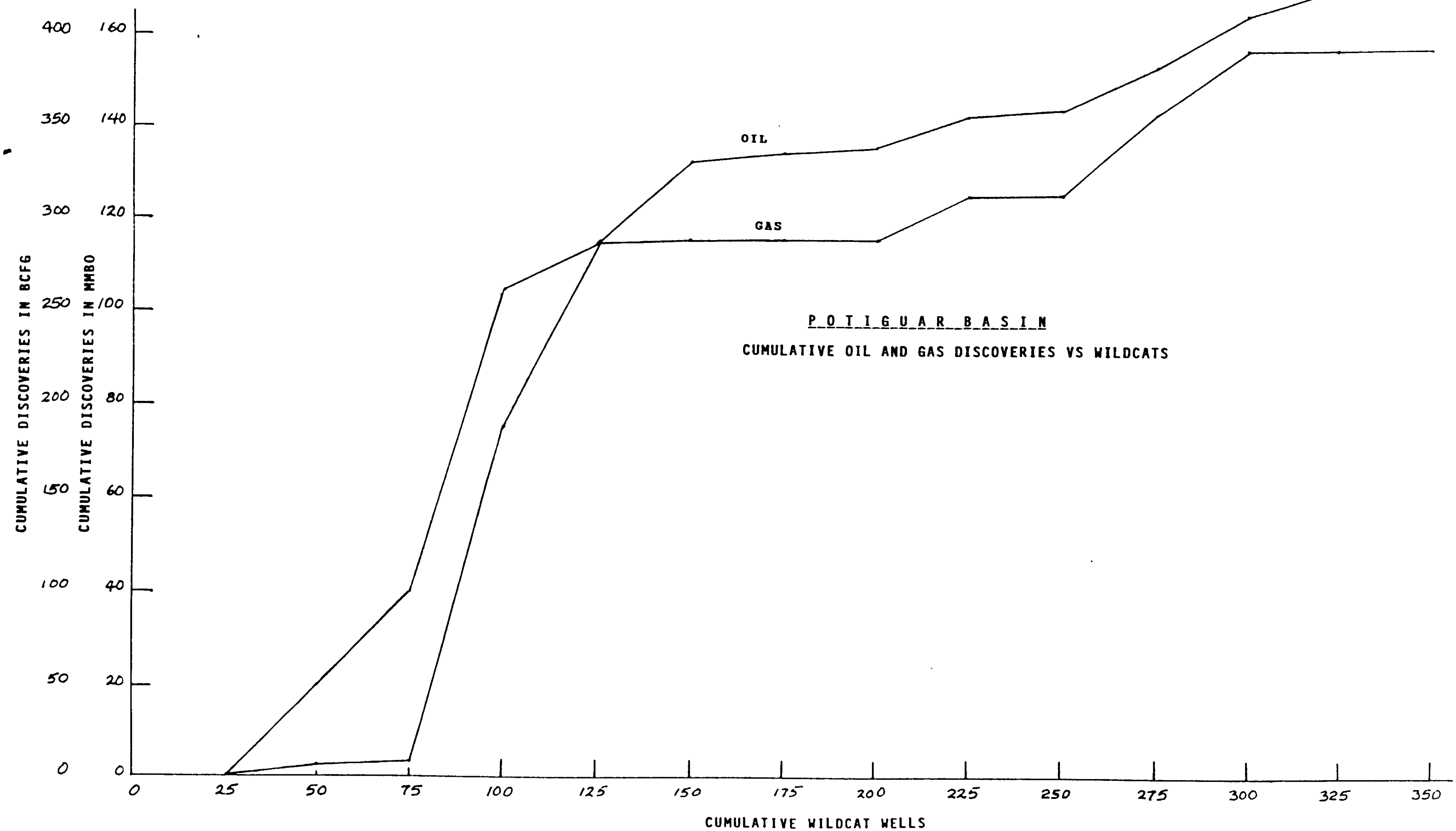


Figure 55 Graph showing the relation of the cumulative discovered oil and gas quantity to the number of wildcats drilled in the Potiguar basin (from Petroconsultants data, 1990 which may be incomplete.)

a shelf too shallow for petroleum generation. The six-mile-wide strip may be grouped with the slope for evaluation purposes. The nearest analog to the Potiguar slope is that of the adjoining Caera basin, which, as described, has a very similar Tertiary section and concerning which more rifted margin data is available. The Caera slope has not been drilled, but has estimated undiscovered resources of .324 BBO and .240 TCFG (this study). By areal analogy, the undiscovered resources of the Potiguar slope and adjoining narrow shelf would be .408 BBO and .302 TCFG. However, judging by the lack of success in the area, this estimate should reduce by about half indicating resources of .204 BBO and .151 TCFG. Altogether, the estimate of undiscovered oil and gas of the Potiguar basin amounts to .274 BBO and .337 TCFG.

Caera

Area: 13,300 mi^2 (34,500 km^2)

Caera Shelf		8,900 mi^2	(23,000 km^2)
Caera Slope		4,400 mi^2	(11,400 km^2)
Mundau Subbasin.	Shelf	1,300 mi^2	(3,400 km^2)
Mundau Subbasin.	Slope	1,400 mi^2	(3,600 km^2)

Original Reserves: .084 BBO .065 TCFG (Costa et al 1990)

.067 BBO .023 TCFG (Petroconsultants, 1989)

Description of Area: The Caera basin extends from the shallow-basement edge northwards to the estimated position of COB (about 2000 M batholith) and from the Fortaleza High (opposite Fortaleza City) westward to the Tutoia Estuary (just west of the Piaui-Maranhao boundary) (Fig. 56). Subbasins are Mundau, Icarai, Acarau and Camocin-Piaui. The Subbasin Mundau is the deepest and is open to the ocean. The other subbasins are shallower grabens, located in a more landward position behind a line of horsts or drag features of the Caera and Atlantic High trend. Although wildcats have been drilled in all the subbasins, only the deeper Mundau subbasin has produced petroleum.

Stratigraphy

General. The stratigraphy of the Caera basin is, in part, similar to that of the Potiguar basin (figs. 51, 57, 58, and 59). In both basins, the Lower Cretaceous up through lower Aptian strata are continental fluvial and lacustrine (Maudau Formation of the Caera basin) and the upper Aptian (lowest Abian) is transitional, i.e., restricted marine, with fluvial, deltaic and lacustrine

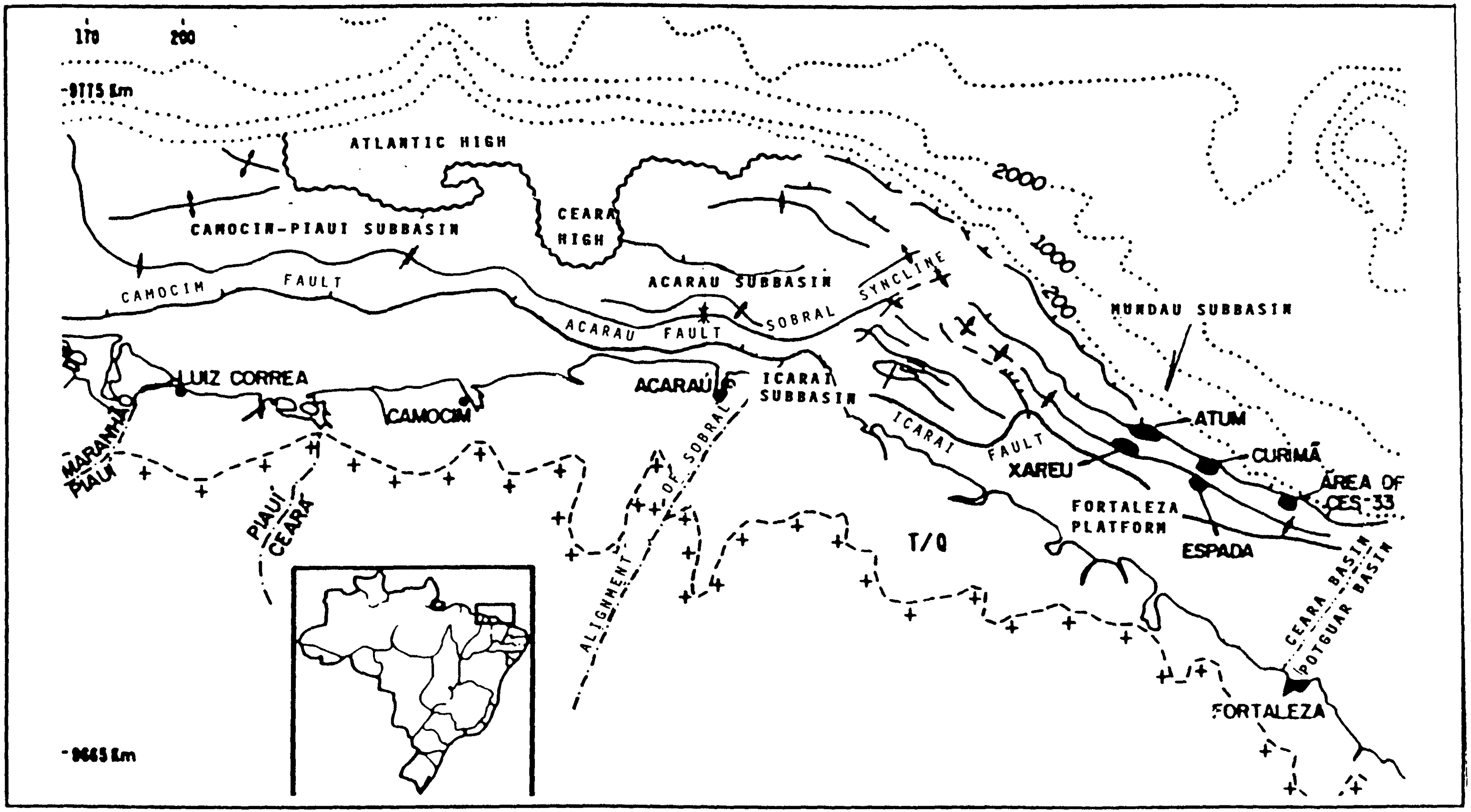


Figure 56 Location map and structural framework of Caera basin (modified after Costa et al, 1990).

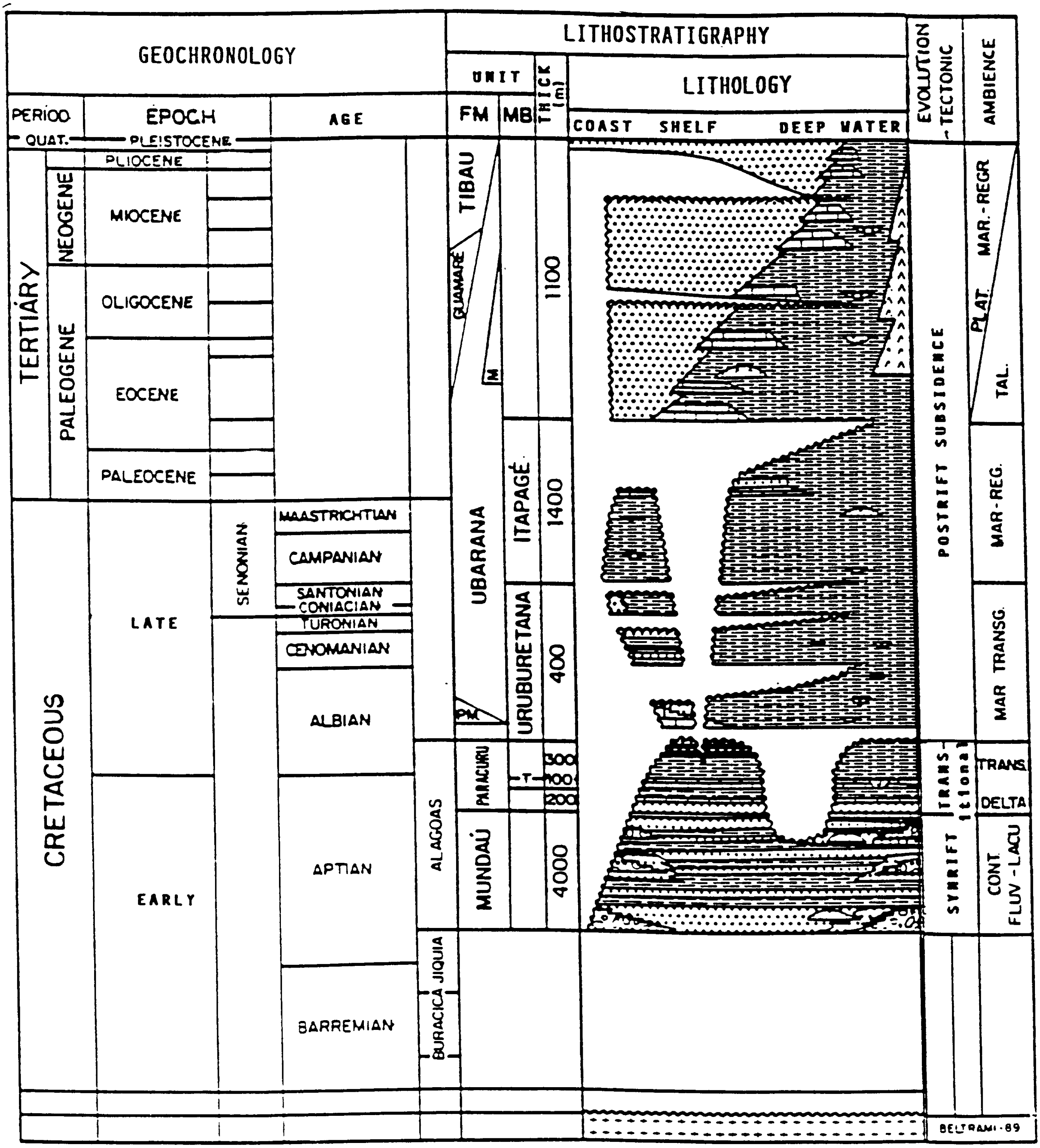


Figure 57 Stratigraphic chart of Mundau subbasin, Caera basin (modified from da Costa et al, 1990).

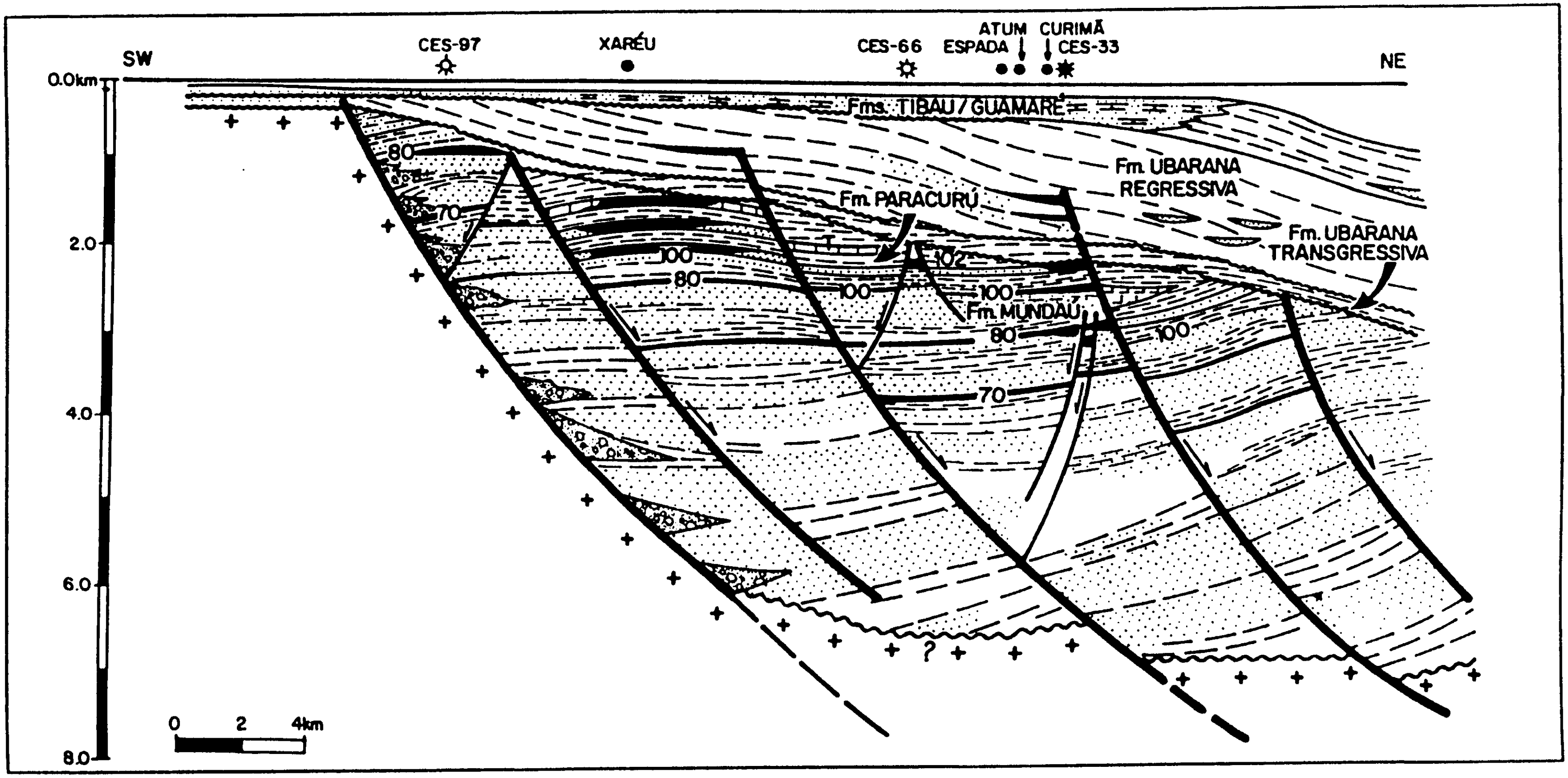


Figure 58 Structural dip section of Mundau subbasin indicating main plays (after da Costa et al, 1990).

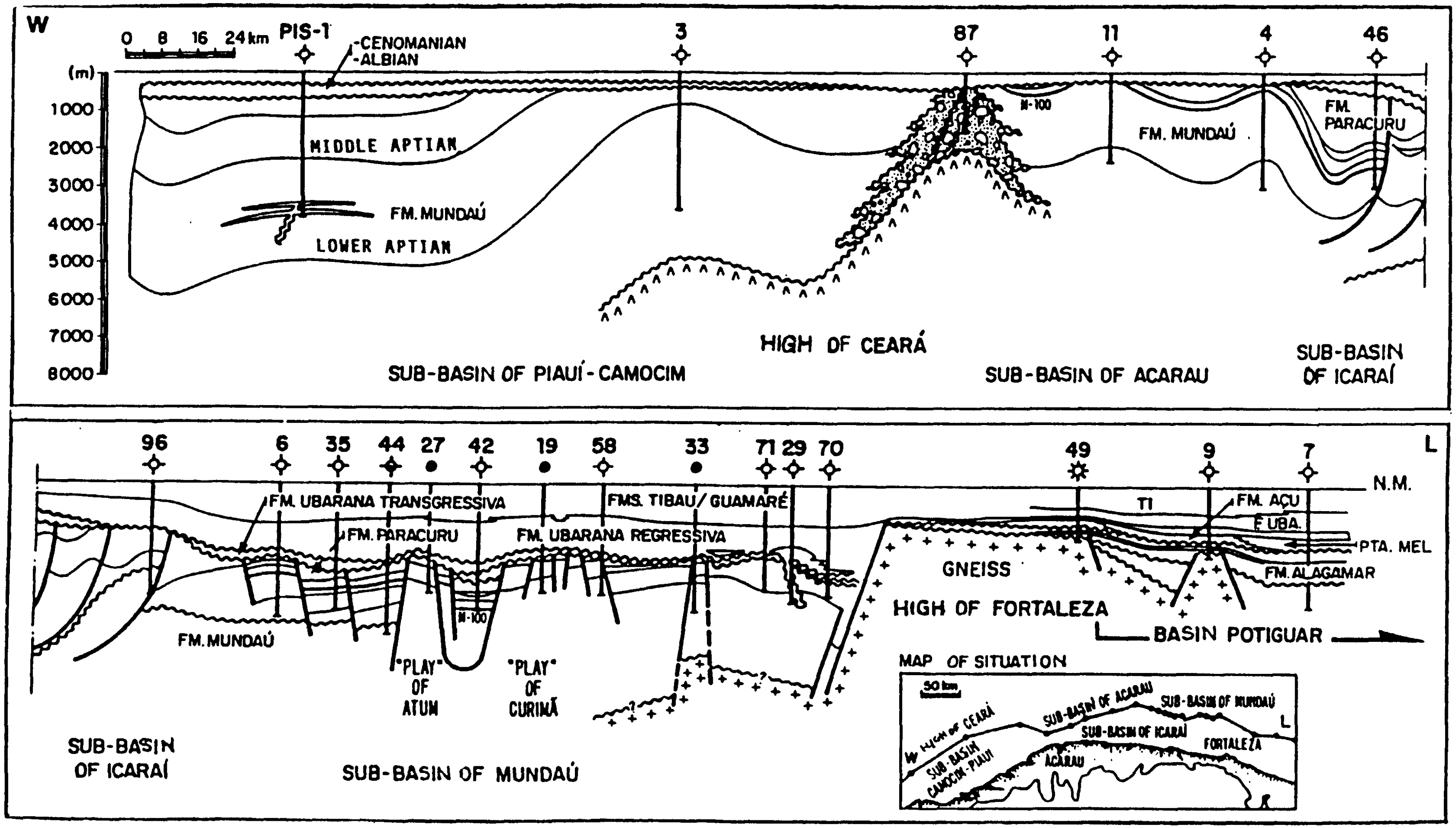


Figure 59 Geological strike section of Caera basin (Betrami, C.V. 1987) (modified from da Costa et al, 1990).

sedimentation (Paracuru Formation of Caera basin, Alagamar Formation of Poliguar basin). During late Cretaceous time, however, when deposition of the Potiguar basin was largely carbonates (Jandaira Formation), the Caera basin, or at least the Mundau subbasin, was largely filled with shale with some turbidites of the transgressive Uburana Formation (fig. 58). The Tertiary sequence is very similar in both basins and is represented by a regressive phase which lasted throughout the Tertiary. Both basins have mid-Tertiary volcanics (Macau Formation).

Source. In the Mundau subbasin, the Aptian Paracuru Formation (Figs. 57 and 58) is the principal source of petroleum in the Caera basin; it has a high TOC and is indicated to be an excellent source rock (Mello et al., 1984, Costa et al., 1990). The organic material is type I and II. The depth to the top of the Paracuru Formation approximately coincides with the top of the thermally mature zone of petroleum generation. The underlying sandy Mundau Formation also has some source rock potential, but is less rich and is, in a large part, overmature.

The Mundau subbasin may be the only subbasin of the Caera basin containing significant source rocks. Wildcat CES-46 (fig. 59) drilled through the Paracuru and upper Mundau Formations of the Icarai sub-basin without encountering any source rock of consequence (Costa et al., 1990). In the subbasins of Acarau and Piaui-Camocim the potential for oil generation appears to be generally low although some source beds of high total organic carbon content with some potential for generation were encountered in the Acarau subbasin. In the Piaui-Camocim subbasin organic material is moderately abundant and overmature. In the non-productive subbasins, the best source shales, the Paracuru Formation, may be too shallow for maturity and that the adjoining slopes also lack sufficient thickness and depth of sediment for maturity (fig. 59).

Reservoirs and Seals. Reservoirs appear to exist throughout the section. As indicated in Figure 58, petroleum has accumulated in sandstones of the Mundau Formation, in sandstones and carbonates of the Paracuru Formation and in sandstone lenses and turbidites of the Uburana Formation. The quality of the reservoirs appears to be good, the producing reservoir porosities averaging generally around 20 percent.

The only extensive seals are upper Cretaceous and Tertiary shales. Aptian evaporites are present, but only cover limited areas.

Structure

The structure of the Caera basin is complicated but is essentially that of a rifted continental margin which has been subjected to considerable dextral wrench faulting during and after the continental rifting (lower Cretaceous) and separation (mid-Cretaceous) of South America and Africa. The wrenching effects appear to have been largely transtensional in the normal faulted and dropped-down Mandau subbasin and transpressional in the thrusted and folded Icarai and other subbasins (fig. 56, 58 and 59). Wrench faults, indicated by flower structures, are common in the Acarau and Piani-Camocin subbasins (Costa et al., 1990).

Structural traps are formed by fault closures mostly related to the early Cretaceous rifting, but also to transtensional faulting, and by folding related to rotational faulting (i.e., rollovers). Minor traps occur in transpressional folds (i.e., dragfolds) (fig. 58).

Generation, Migration, and Accumulation. The top of the oil generating zone, as indicated by vitrinite reflectance of .6 percent, is shallow, ranging from 4,000 ft (1,400 m) at the updip side of the Mundau subbasin to over 9,200 ft (2,800 m) near the shelf edge (Mellow, et al., 1984). The shallow depth of the generating zone may be explained by Albian uplift and erosion prior to the Albian (Uburana Fm) marine transgression, as suggested by figure 58, or by an unusually high geothermal gradient. There is no available thermal data, but the adjoining Potiguar basin has the highest thermogradient of any Brazilian basins, averaging 1.81°F/100 ft (33°C/km) (Zembruscki and Kiang, 1989) which would probably put the top of the oil generation between 7,000 (2.2 km) and 8,500 ft (2.6 km). Perhaps the shallow oil generation zone may be explained as a combination of both factors.

Assuming a relatively high geothermal gradient generation, migration would have begun near the end of the Uburana transgressive subsidence phase or early Tertiary. By that time most of the traps were formed and depending on the preservation of porosity and permeability in the older reservoirs, the migration timing appears favorable for oil accumulation.

Plays. The plays in this basin can be related to the phases of a rifted continental margin basin combined with wrench tectonics. The principal plays as identified by Petrobras are shown in figure 58. The five principal plays are: 1) turbidite updip closures (as exemplified by the Espada Field); 2) unconformity traps (Curima Field); 3) rollover closures (Xaren Field); 4) fault closure, Paracuru Formation (Curima Field); 5) transpressional fold (CES-97) and 6) transtensional (CES-66).

History of Exploration and Petroleum Occurrence. Exploration of the Caera basin began in 1971. Ninety-five "exploration wells," of which 63 were wildcats (as of early 1990), discovered six petroleum fields and some subcommercial petroleum accumulations. Proved original reserves of some .084 BBO were established as of 1990 of which .038 BBO were produced by February 1986. Discoveries have been confined to the Mandau subbasin (Costa et al., 1990).

A curve relating the oil discovered versus the number of "exploration" wells drilled (fig. 60, from Petroconsultants data,

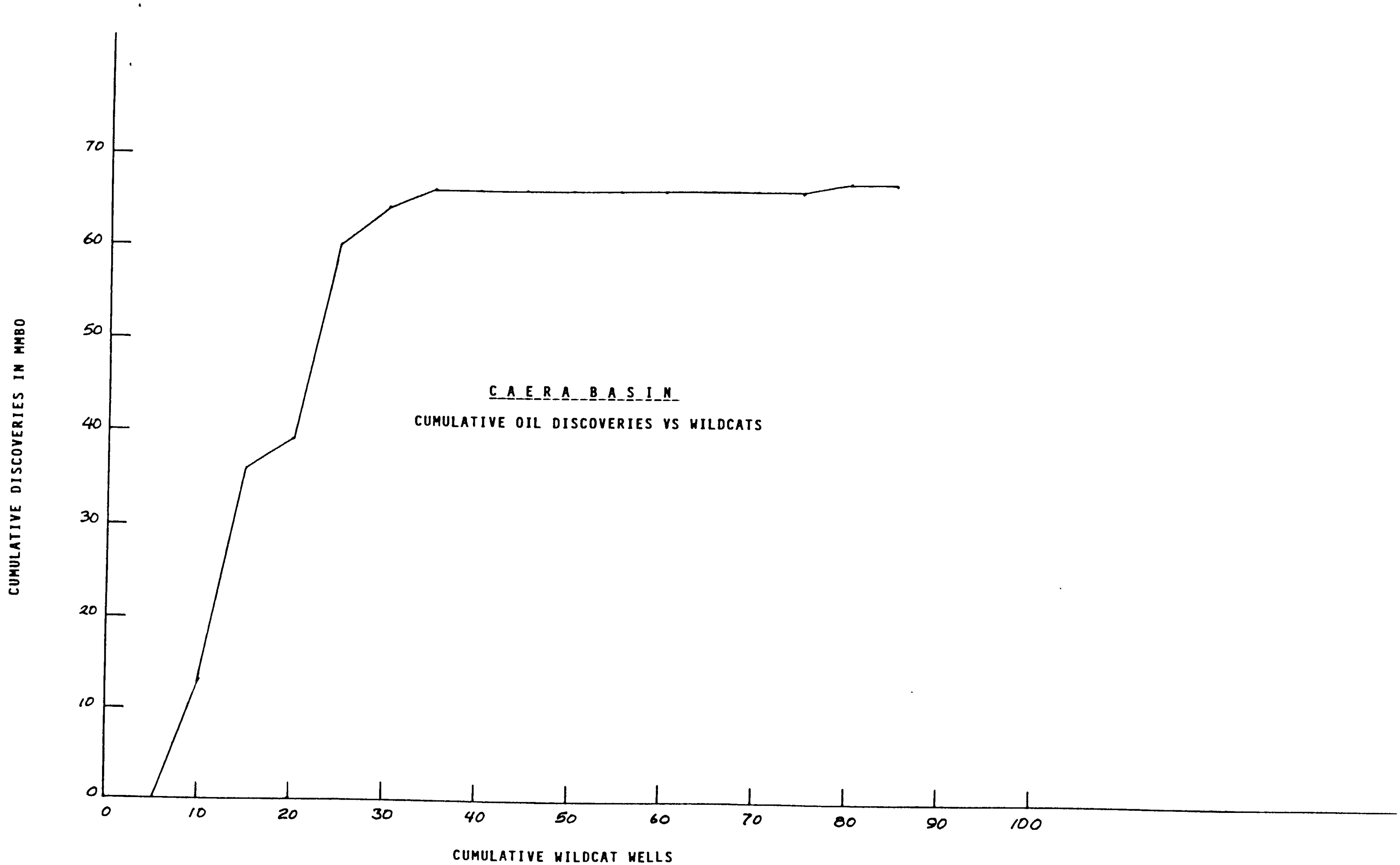


Figure 60 Graph showing relation of cumulative discovered oil quantities to the number of exploration wells drilled in the Caera basin (from Petroconsultants, 1989, data which may be incomplete).

1990) suggests that the area, at least in the Mundau subbasin, is in a mature stage of exploration; however, the drilling has been confined to the shelf, largely of the Mundau subbasin, and none have yet been drilled on the prospective continental slope.

The location of the oil fields is shown in Figure 56 and some additional oil and gas occurrences are indicated in diagrammatic sections figures 58 and 59.

Estimation of Undiscovered Oil and Gas

The projection of the curve of figure 60 indicates that only negligible amounts of oil will be discovered on the shelf.

There is no data on the undrilled slope, but if the ratio between slope and shelf oil resources is the same as that in the Campos basin (3.9), resources of .32 BBO may be expected in the Caera basin. From an average of other marginal basins, gas is 10 percent of the petroleum or .21 TCF.

Petrobras (Costa et al., 1990) have made their own assessment of the Caera basin based on play analysis. They have divided the prospects into eight plays on the basis of trap-type, age of reservoirs, and water depths. Their definitions and analyses of plays were based on a wealth of data, the details of which are unavailable. In summary, they estimate that .073 BBOE will be discovered in the shelf and .364 BBOE in the slope. On the basis of the oil/gas ratio of the reserves (89 percent oil), this indicates .065 BBO and .048 TCFG on the shelf and .324 BBO and .240 TCFG on the slope or .389 BBO, .288 TCFG for the entire Caera basin. This estimate is somewhat more optimistic than my estimate which envisions negligible oil and gas in the shelf and .32 BBO and .21 TCFG in the slope. The Petrobras-derived estimates, however, are regarded as the more valid since they are made on the basis of more data and knowledge of the basin. Petrobras estimate that 96 percent of the undiscovered petroleum will be in the Mundau subbasin and most of that in water depths of over 1,000 m.

Barreirinhas Basin

Area:	Barreirinhas half graben	2,300 mi^2	6,000 km^2
	Barreirinhas shelf	4,500 mi^2	11,000 km^2
	Barreirinhas slope	1,370 mi^2	3,500 km^2
Total		8,170 mi^2	21,100 km^2

Original Reserves: 4.4 MMBO (Petrobras, Bruhn et al., 1988)

(2.0 MMBO, Petroconsultants, 1989)

Description of area: The Barreirinhas basin extends westward along the north coast of Brazil from the west edge of the Tutoia high, which separates it from the Caera basin to the east, to a northeast-trending line through Sao Luis (the eastern area of the Ilha de Santana platform) (figs. 49 and 61). Extending through part of the onshore basin is a line of west-trending grabens, the western extension of which is the Ilha Nova, San Luis, and Brazanca grabens (the Sao Luis and on-line, more western Brazanca are not included in the Barreirinhas basin). The Barreirinhas basin extends northward from the shallow onshore Sobradinho Platform to the offshore COB which is taken to coincide with the 2000 M isobath.

The Barreirinhas basin as described here is made up of two elements: (1) an offshore rifted continental margin shelf and slope, and (2) an onshore west-trending half-graben (Sections B, C, D, fig. 62).

Stratigraphy

General. The onshore half-graben portion of Barreirinhas basin has Paleozoic, as well as lower Mesozoic prerift strata (fig. 63). The Neocomian sediments, which, in a synrift mode, provided the source for the marginal basins to the east and south, is thin or in part missing (Sardinha Formation).

The Aptian is represented, at least in the onshore by relatively thin marine and restricted shale and sandstone sections (Codo, Grajan, and Sobradinho Formations) which have source potential.

The Albian (Canarias Group) is a regressive sequence which is generally continental in the Ilha Nova and Sao Luis grabens landward of the Santana Platform, and continental or restricted marine, landward of the Tutoia--Atlantic highs, and open marine in the deeper offshore part of the Barreirinhas basin. The Albian onshore sandstones, Barro Duro, grade into offshore shales (Bom Gusto or Arpoador Formation) which contain sand bodies of probable turbidite origin.

After the Cenomanian which was a period of quiescent carbonate deposition, the sedimentation is regressive although the margin is subsiding (Caju and Humberto de Campos Groups). The furtherest offshore facies is shale, which apparently contain some turbidites. The Tertiary section is thin over the basin and, even in the outer shelf and slope where it is thicker, probably has less Tertiary turbidites than the other marginal basins.

Source. Little source rock information is available. The Paleozoic strata have some minor potential for gas; the TOC ranges from 2 to 4 percent and is deemed to have medium generation potential (3 to 6 kg HC/t rock). The organic material is type II and largely type III. Where examined in the adjoining Sao Luis

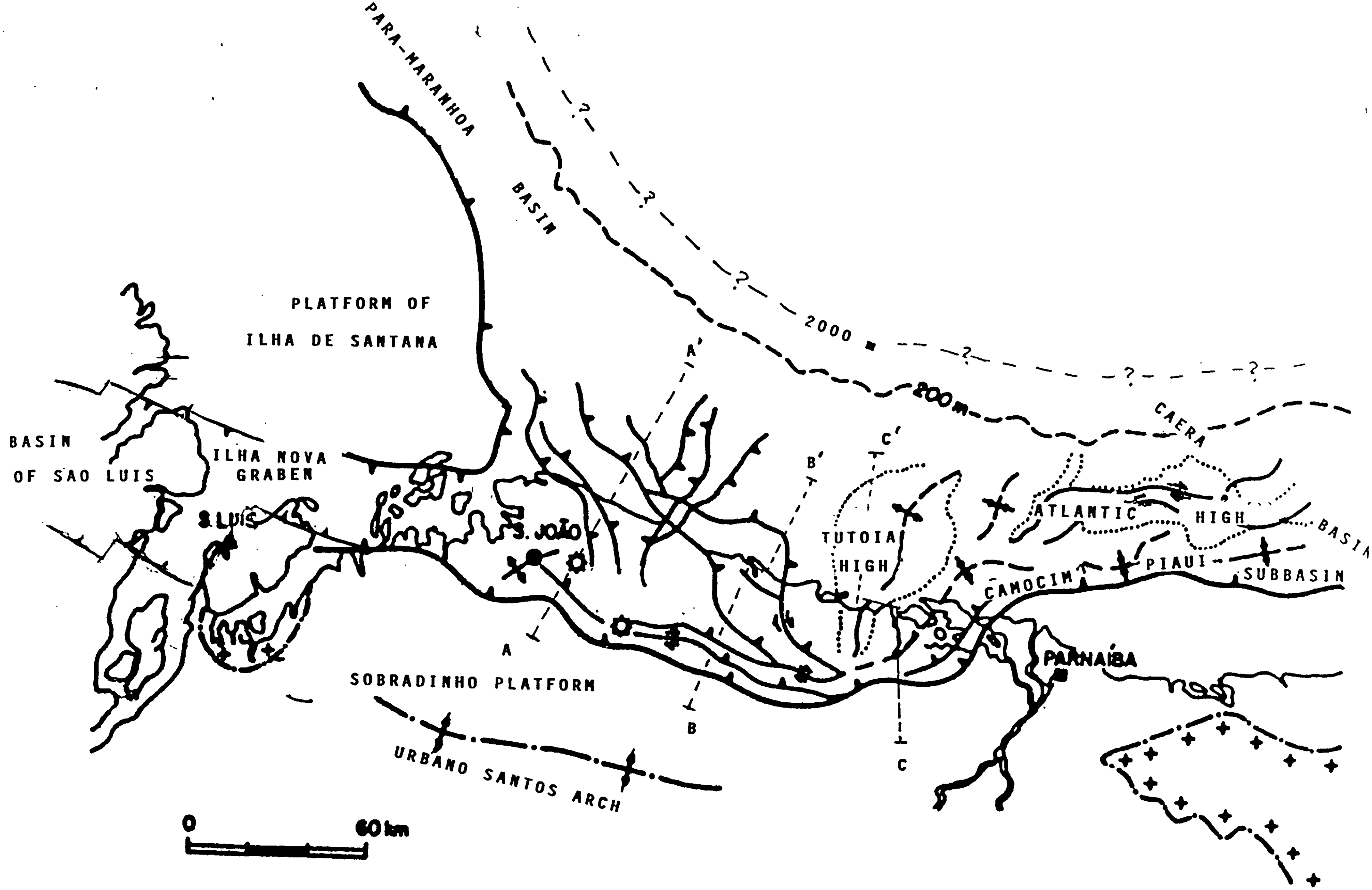


Figure 61 Map showing structural framework of its Barreirinhas basin (modified from Brun et al, 1988).

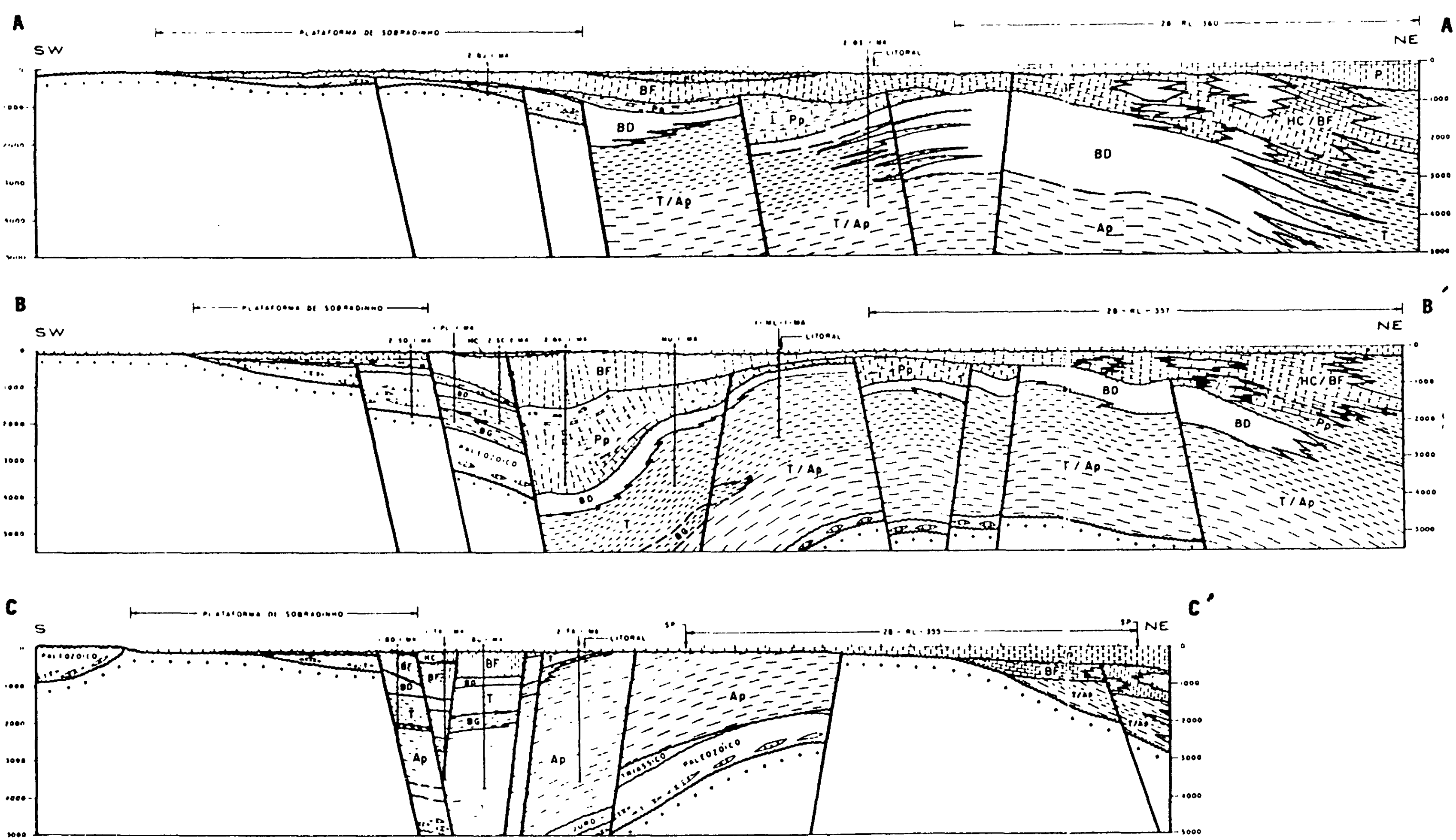


Figure 62 Geologic dip sections across the Barreirinhas basin; Ap-Arpoador Fm.; T-Tutoia Fm.; BD-Barro Duro Fm.; Pp-Peria Fm.; B.F. Bonfin Fm.; HC-Hamberto de Campos Group; and P-Pirabas Fm.; depths in meters. Locations figure 61 (from Rezenda and Arajo, 1970).

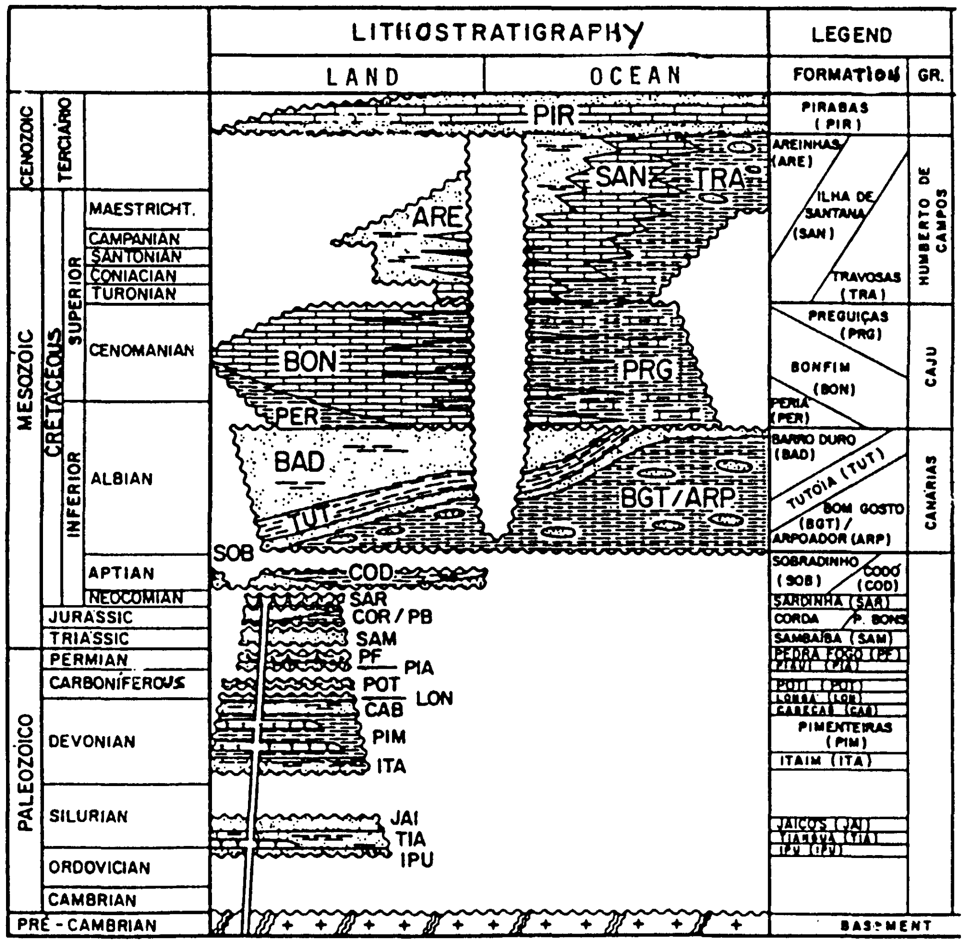


Figure 63 Stratigraphic chart of the Barreirinhas basin (modified from Bruhn et al, 1988).

graben, the upper Paleozoic is immature and the immediately underlying pre-Silurian is overmature (Cerqueira and Marques, 1985).

The marine shales of the Aptian Codo (and the subjoining Grajan Formation) have TOC ranging from 3 to 15 percent and high generation potential (6 to 90 kg HC/t) of Type I and II kerogen in the adjoining Sao Luis graben. These beds are relatively thin (150 to 500 ft, 50 to 150 m) where encountered (Cerqueira and Marques, 1985) but could be thicker in other parts of the basin.

No other source data are available but some of the overlying Bom Gusto and Arpoador shales may have source quality. These shales are sufficiently deep in the Barreirinhas onshore graben to be thermally mature and, apparently also in the outer continental shelf and slope.

Reservoirs and Seals. Reservoirs appear to be largely deltaic or turbidic sandbodies of the Albian Canarias Group, either in the Barro Duro Formation or in isolated sands in the largely shale (Bom Gosto/Arproador Formation). The overlying upper Cretaceous sequences contain carbonates and sandstones, some of which are probably of reservoir quality.

The seals are shale which, in general, are less effective shoreward.

Structure

The onshore portion of the basin appears to be a half-graben in line with the trough landward of the generally west-trending Tutoia and Atlantic complex highs or ridges on the east and the west-trending Ilha Nova and Sao Luis grabens in the west (Sections A, B, and C, fig. 61 and 62).There appears to be several ages of normal faulting, but it mostly centers around Cenomanian (fig. 62). In general, this interior rifting is younger than the rifted continental margin portion of the basin which is assumed to be typical of the other Brazilian north-coast basins where rifting is largely of Early Cretaceous age.

It appears that the effects of the late Jurassic and Neocomian pre-continental-separation rifting of the Brazilian northeast coast diminish, and are younger, and perhaps more restricted westwards along the north coast of Brazil; i.e., rifting in the Caera basin is of Aptian age (and perhaps, at sub-drilling depths, upper Neocomian) and in the Barreirinhas, faulting (rifting or wrenching) appears to extend through most of the Albian.

Except for the outer shelf and slope, there was only very little subsidence or structural deformation during the Tertiary which is represented by a thin, flat sequence, lying by profound unconformity over the Cretaceous (fig. 62).

The faults have a strong wrench component causing transpressional or drag folds in the onshore half-graben portion of the basin, e.g., the Sao Joao field (fig. 64). Other structural traps would be fault closures and drapes. The marginal shelf and slope may have some listric faulting and associated rollover structure as in other continental margins, but because of its apparent distal position and consequent relatively thin Tertiary wedge, such structure would be less developed.

Generation, Migration and Accumulation. From thicknesses of the Albian sections (fig. 62), it appears that potential source rock at the Aptian level subsided into the petroleum generation zone in late Cretaceous time, after trap formation. A few Tertiary listric fault and rollovers traps and turbidites of the outer shelf and slope may have deveoped after petroleum generation.

Plays. The principal plays of the basin appear to be: 1) block-fault related traps involving synrift sandstones; 2) post-rift Cretaceous drapes and turbides; 3) transpressional (drag) folds involving middle Cretaceous sandstones; 4) Tertiary listric fault and rollover traps of the outer shelf and slope; and 5) Paleozoic sandstones in fault traps.

Exploration History and Petroleum Occurrence. The onshore portion of the basin appears to be a rather maturely explored area. Drilling began in 1963 and the first discovery was the Sao Joao field in 1966. The success rate was about 10 percent; 50 wildcats discovered 5 small fields, 4 onshore and 1 offshore all within the Barreirinhas half graben area and none in the continental margin area. The total discovered reserves, however, are small--4.4 MMBO and 37 BCFG as abstracted from published Petronas data (Bertani et al.,, 1986), or 2 MMBO (from Petroconsultants data).

Estimation of Undiscovered Oil and Gas

In the adjoining Ceara basin the subbasins in line with the onshore Barreirinhas and landward of the Atlantic and Ceara Highs (i.e., the Piaui-Camocim and Acarau subbasins) have small reserves and are said to have a potential of less than 17 MMBOE (Costa et al., 1990). By areal analogy with these subbasins, the Barreirinhas half-graben should have reserves of about 13.8 MMBOE or about 12.4 MMBO and 8.3 BCFG.

By analogy,on an areal basis, to the entire Caera shelf, the resources of the Barrierinhas shelf has resources of 33 MMBO and 33 BCFG.

The Barreirinhas slope compared to the estimated undiscovered oil and gas of the analogous Caera slope or an areal basis would indicate 101 MMBO and 75 BCFG. Altogether the undiscovered resources of the Barreirinhas basin are .146 BBO and .116 TCFG.

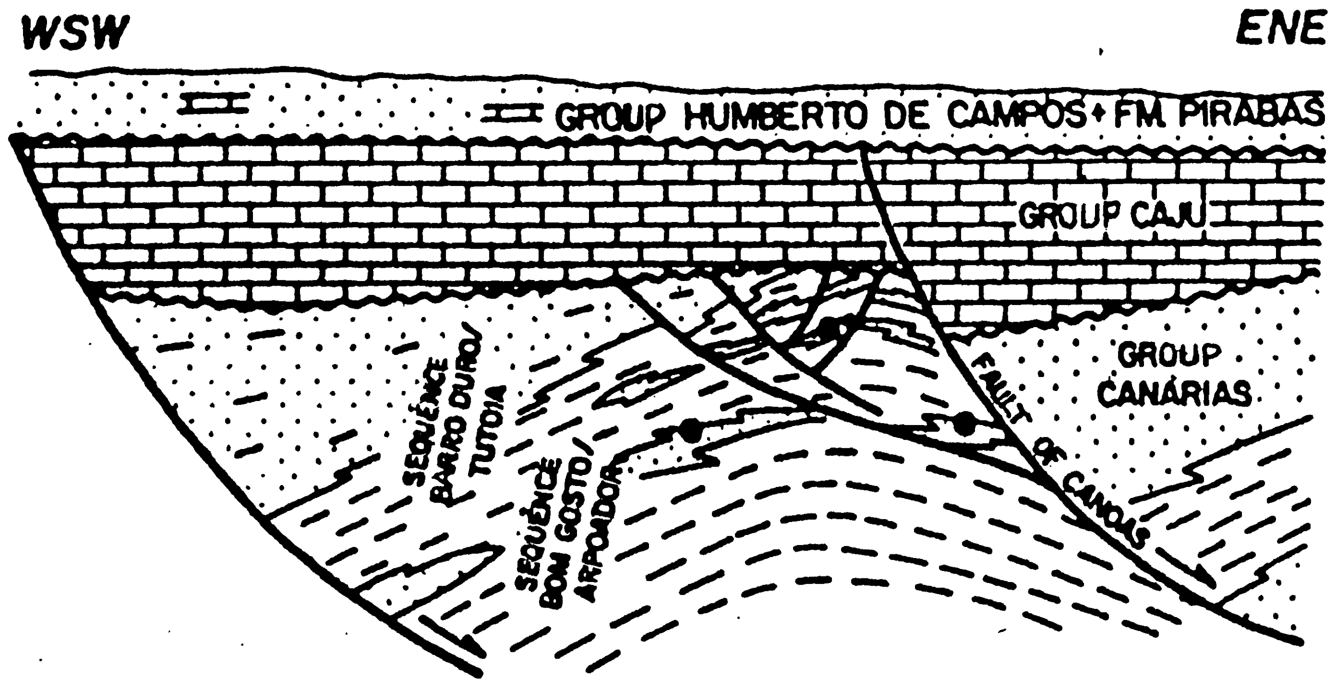


Figure 64 WSW-ENE geologic cross section across the Sao Joao Field, Barreirinhas basin. Location figure 61 (modified from Bruhn et al, 1988).

Para-Maranhoa Basin

Area: Shelf - 10,000 mi^2 (26,000 km^2)

Slope - 2,800 mi^2 (7,300 km^2)

Total - 12,800 mi^2 (33,100 km^2)

Original Reserves: 7 MMBO

Description of Area:. The Para-Maranhoa basin is offshore on the outer continental shelf and slope (fig. 49 and 65). It lies seaward of Para-Maranhoa or Ilha Santana Platform of shallow basement which occupies most of the continental shelf. The Para-Maranhoa basin extends westward from the eastern end of the platform at about 43°30'E to the Marajo Bay (at a rather arbitrary line perpendicular to general coastal trend through Belem) (fig. 65).

Stratigraphy

General. The stratigraphy is similar to the adjoining marginal basins to the east. The Neocomian is apparently missing, or at least not penetrated, the oldest observed sediments being an Aptian-early Middle Albian non-marine, evaporitic synrift and transitional sequence (fig. 66). This is overlain by a marine carbonate shelf late middle Albian sequence. A Turonian-Santonian marine transgression is represented by neritic sediments at the base and neritic/upper bathyal sediments in the upper part. Campanian to recent progradation followed although subsidence of the basin continued.

Source. No source rock data are available, but from an analogy to adjoining basins it would appear that the principle petroleum sources are the Aptian-lower Albian non-marine (possibly in part lacustrine) and evaporitic (restricted marine?) sequence. The organic richness of this probable source is unknown. The thickness and depth of the basin has been sufficient for maturation of the presumed source rock, assuming an average thermal gradient, since early Tertiary.

An indication of restriction of benthonic life during early middle Albian and Turonian suggests periods of anorobic preservation of organic material.

Reservoirs and Seals. Little reservoir information is available, the two discoveries of the western basin appear to be from fractured, low-porosity Tertiary limestones. By analogy to other Brazilian marginal basin some shelf and slope turbidite reservoirs may be expected though perhaps less developed in their offshore distal position beyond a very wide shelf.

The only seals are upper Cretaceous and Tertiary shales.

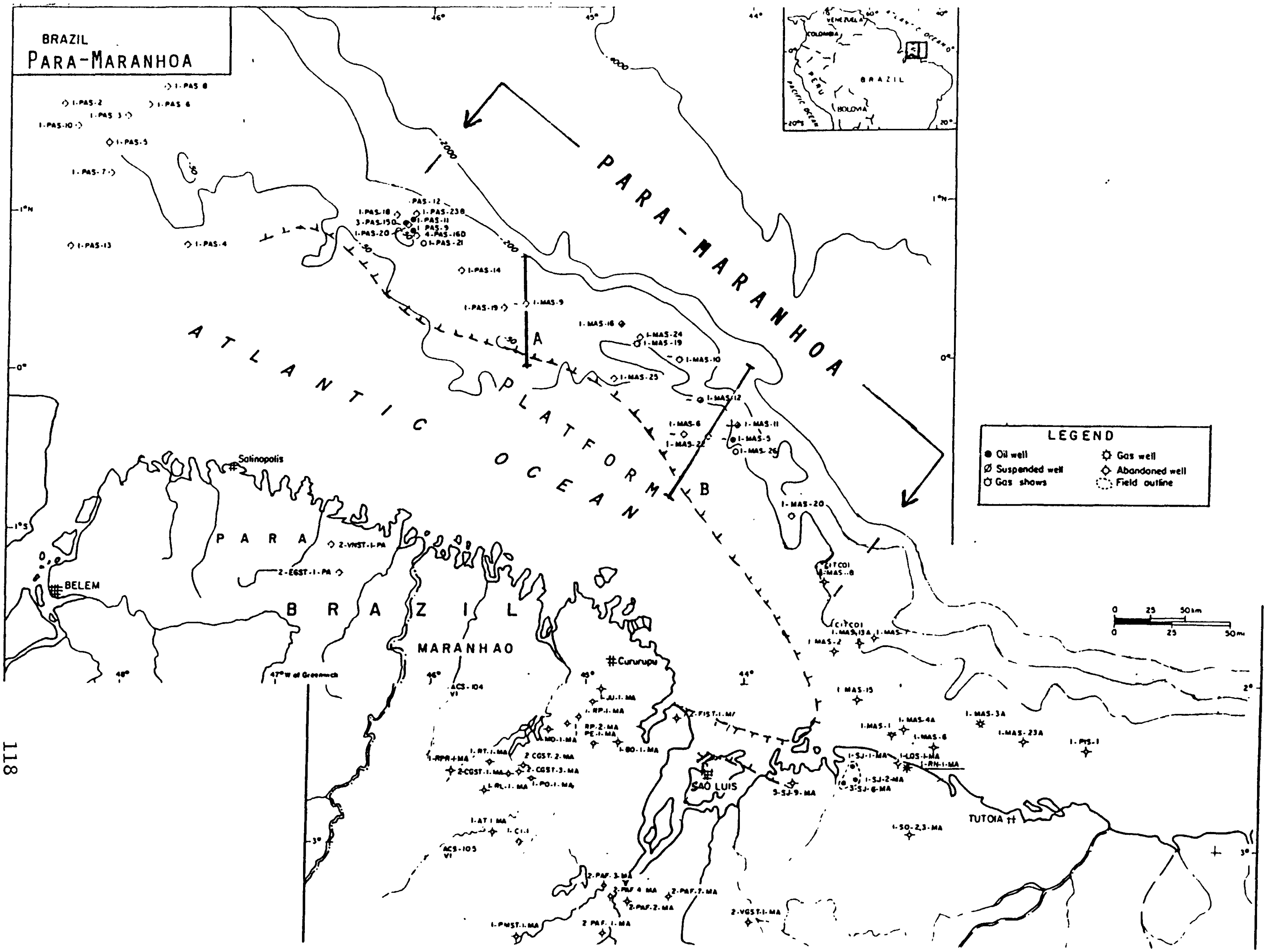


Figure 65 Index map of the Para-Marahoa basin (modified from Petroconsultants, 1989).

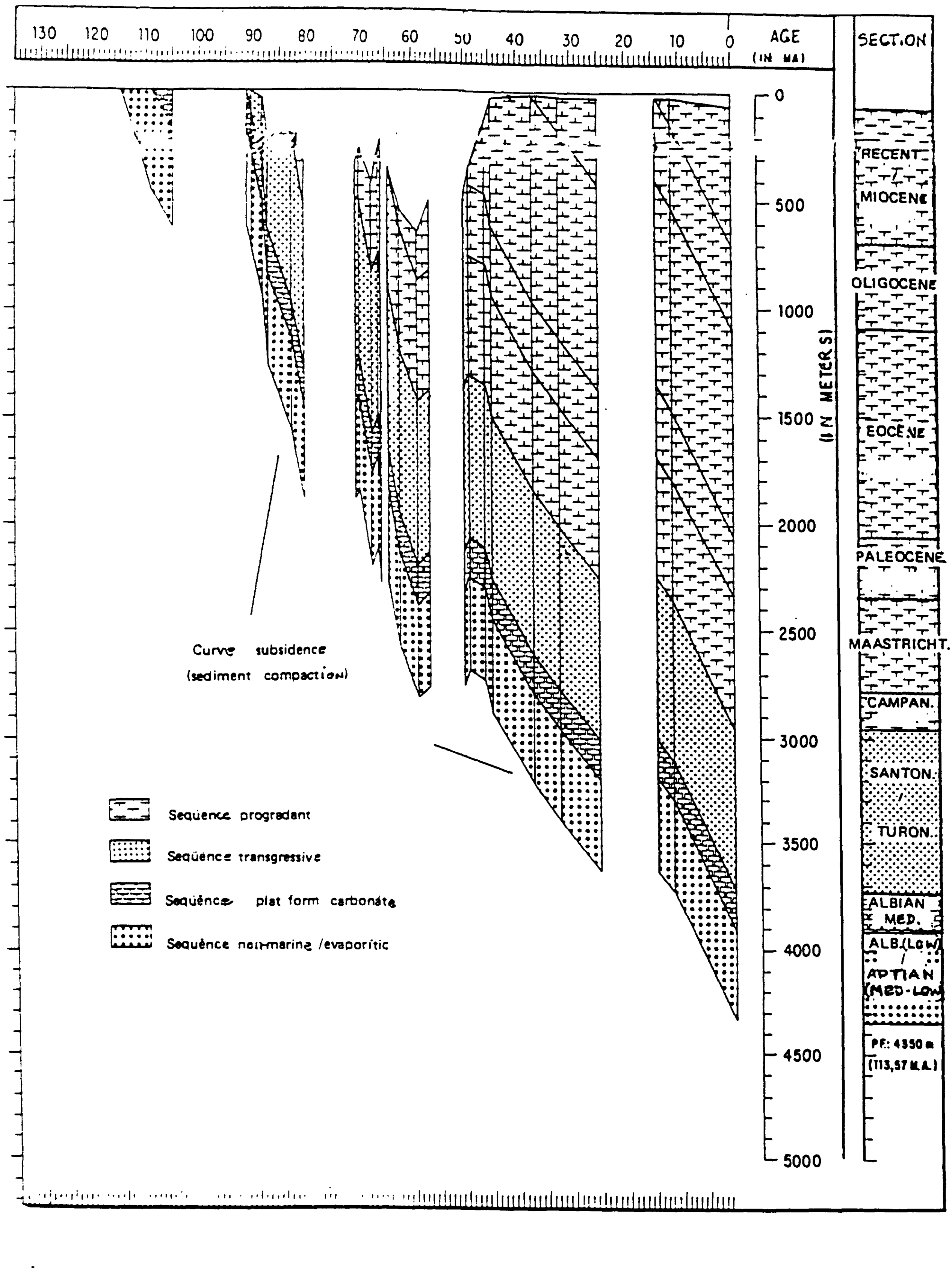


Figure 66 Diagrammatic sedimentary history at wildcat MAS-11. Location figure 65 (modified from Beurlen and Regali, 1987).

Structure

The Para-Maranhoa basin is essentially a north-dipping shelf extending from the shallow Para-Maranhoa Platform northward to the COB. It reaches a depth of over 5 kilometers. The shelf is extensively broken by normal faulting, resulting in horst and graben structure. Faulting is limited largely to Lower Cretaceous rocks, but some faults extend up into Upper Cretaceous rocks (fig. 67 and 68). Listric faulting is largely limited to the Tertiary part of the section and to the outermost shelf and slope. The normal faulting trends westward in the western part of the basin and northwestward in the eastern part. The two trends are separated by the north-trending Gurupi structural high. Another prominent structural high is the I-MAS-9 west-trending high of the western basin.

Potential structural traps include fault closures or drapes over tilted fault blocks and horsts, and listric-fault-rollover closures on the outer shelf and slope. Aside from structural traps, some syntectonic stratigraphic traps as well as turbidites on the slope may be expected.

Generation, Migration, and Accumulation. Assuming a moderate thermal gradient, as may be expected in a rifted continental margin, remained stable through the Upper Cretaceous and Tertiary, oil generation, and migration, would have begun in about the Eocene when the Aptian presumed source rock subsided to a depth of about 10,000 ft (3 km). By that time the fault traps and drapes had formed and listric faults of the outer shelf were forming. Some of the upper Tertiary turbidites had not yet been deposited, but the timing of the migration appears generally favorable.

Plays. The three major plays of the basin appear to be: 1) fault traps and drapes involving carbonate or sandstone reservoirs on the shelf, 2) listric fault associated closures, and 3) turbidites on the slope.

Exploration History and Petroleum Occurrence. Exploration appears to have been relatively light. In an area of 13,000 mi^2 there were only some 23 wildcats drilled as of 1987. The first discovery was in 1979 (I-MAS-5) (fig. 65) in the eastern basin, and in the early 1980's two more discoveries were made in the western part (I-PAS-9 and I-PAS-11) (fig. 65). These discoveries were small, amounting, in all, to reserveds of some 7 MMBO.

Estimation of Undiscovered Oil and Gas

The Para-Maranhao basin appears to be geologically analogous to the outer Barreirinhas and the Caera basin, but perhaps more distant from clastic provenances at least in Tertiary times.

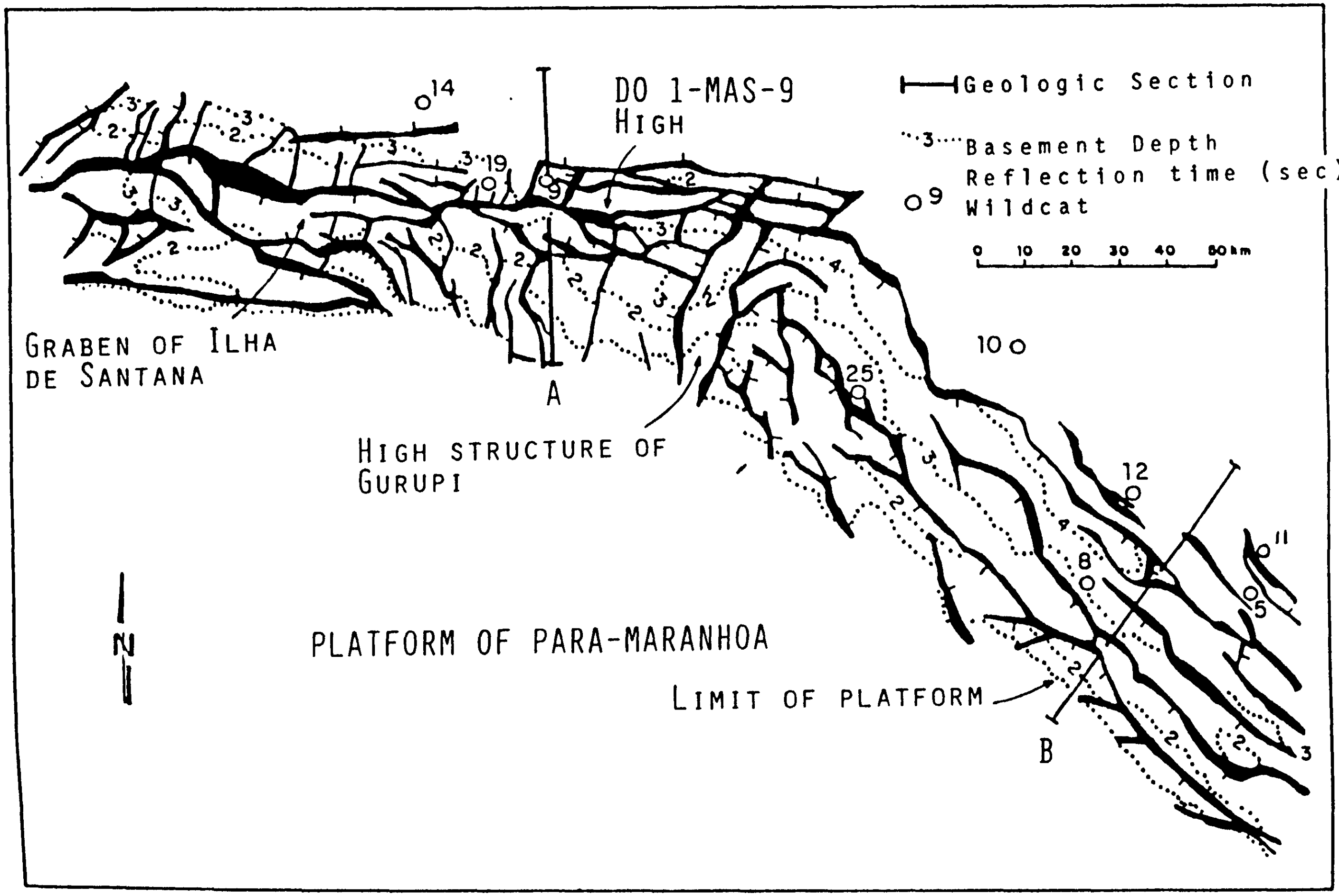


Figure 67 Depth to basement map of the Para-Maranhoa basin in seconds of reflection time, showing faulting and early wildcat locations (modified from Zanotto and Szatmari, 1987).

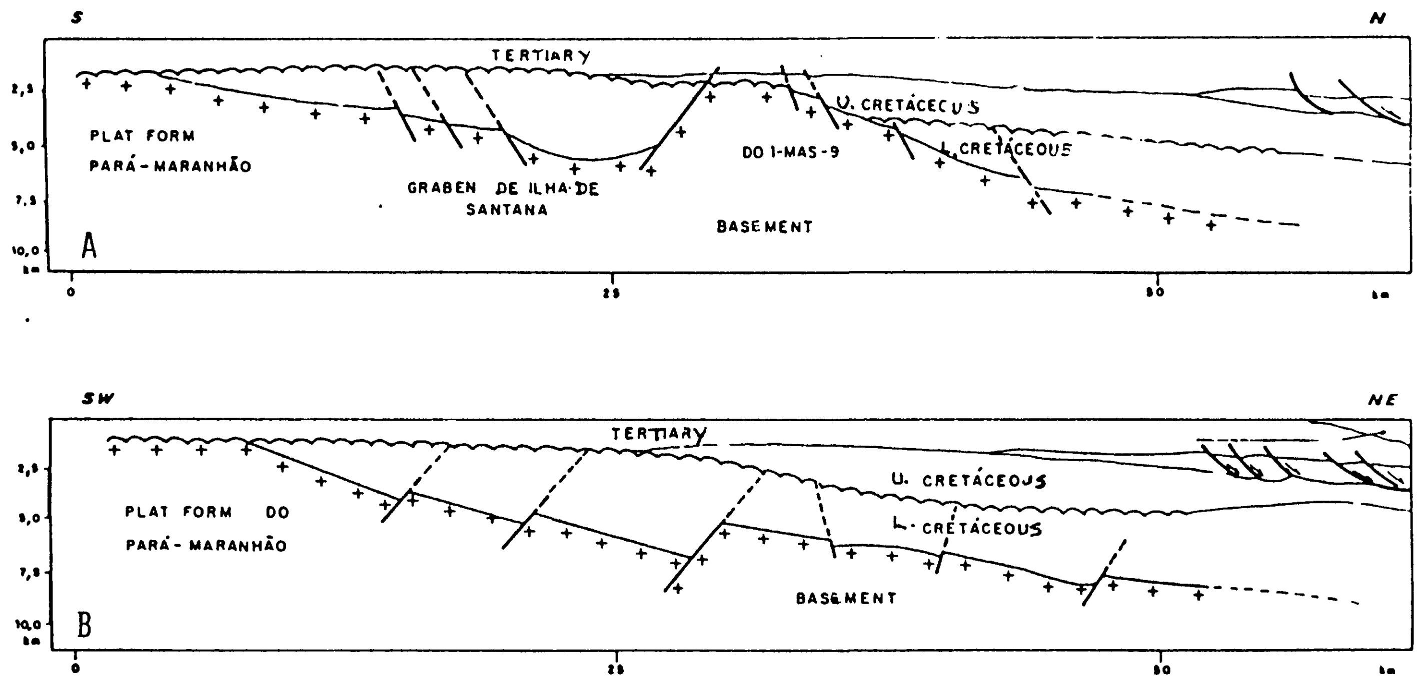


Figure 68 Schematic geologic dip sections across the western and eastern positions of the Para-Maranhoa basin. Location in figure 67 (modified from Zanotto and Szatmari, 1987).

The shelf play, by areal analogy, to the ultimate petroleum resources (reserves plus estimated undiscovered resources) of the Caera basin would have resources of .167 BBO and .145 TCFG. However, this figure should be discounted down to an aggregate of 28 percent on the following basis: 1) the Aptian (and possibly Neocomian) synrift source section of the Caera basin and, in particular, the Mandau subbasin, may not be present, or at least not particularly noted in available literature (discount to 75 percent), 2) the fold structures, drag and rotational, of Caera are not evident (discount to 75 percent), and 3) sandstone reservoirs exist but probably are thinner and less prevalent being further from the clastic provenance, and in the Tertiary separated from the provenance by the broad Para-Maranhao Platform (discount to 50 percent). On this basis the resources of the shelf are estimated to be .047 BBO and .041 CFG minus the discovered reserves of .007 BBO the undiscovered resources are .040 BBO and .041 TCFG.

The slope play on an areal analogy to the ultimate resources of the Caera slope are .202 BBO and .153 TCFG. However, this estimate would be subject to the same discounts as applied to the shelf plus the probability of slope turbidites reservoir volumes being reduced even more, being further from clastic provenances. Doubling the amount of reservoir discount so that in aggregate the discounted value is 14 percent, the slope resources amount to .028 BBO and .021 TCFG, indicating a total undiscovered petroleum of .068 BBO and .062 TCFG in the Para-Maranhau basin

Foz do Amazonas

This province is made up of four diverse structural and depositional elements usually not included in a single basin.

Area:	mi^2	km^2
1. Interior rift areas		
(exclusive of carbonate shelf)	27,500	71,200
2. Shelf		
Carbonate Shelf (exclusive Amazon deep and Cassipore grabens)	25,000	64,700
Amazon Deep (shelf delta)	6,000	15,500
Cassipore grabens	5,000	13,000

3. Delta (beyond slope)		8,900	23,000
(total delta - 18,700 mi^2 - 48,400 km^2)			
4. Slope		8,000	20,700
(under delta - 3,800 mi^2, 9,800 km^2)			
Total Province		80,400	208,200

Original Reserves: 0.880 TCFG

Description of Area: The interior rift and inner part of the Foz do Amazonas basin, i.e., the onshore and continental shelf, lies generally between the Para-Maranhao Platform on the east, the Amapa Platform on the west and Garupa Arch in the south (fig. 69). The main elements are: 1) the interior rift grabens (the Marijo or Limoeiro, and Mexiana Grabens); 2) the shelf, including the Tertiary carbonate platform and Amazon deep which overlies the intersection of the interior rift grabens and continental margin rifting, and 3) the grabens of the Cassipore area. The outer part of the Foz do Amazonas basin is the rifted slope; included in the area is the Amazon Tertiary delta and cone. It extends from the area of the Para-Maranhoa platform along the coast northwestwards to the Brazil-French Guiana border, and basinwards from the shallow Amapa and Para platforms to the COB (assumed to be at the 2000 m isobath) or the outer edge of the Amazon cone which extends onto the abyssal plain.

Stratigraphy

General. The stratigraphy varies widely over the province. The oldest unit is Lower Cretaceous (and Jurassic?) non-marine sedimentary rock filling the grabens adjoining the Amapa platform in the Cassipore area (fig. 69 and 70).

Fig. 71, section A-A', shows diagrammatically the lateral facies changes in the Mexiana interior rifts from onshore, at the juncture with the Marajo basin, to offshore at the Amazon delta. Section B-B' shows the lateral change across the Amazon Deep. The lowest unit, the Limoeiro Formation, is continental, largely in a sandy fan facies, changing westwards first to a deltaic-fluvial and then to a marine slope facies near the outer shelf; it ranges from Paleocene down to an unknown age, perhaps Albian. A cross-section of Bigarella (1973) (fig. 72) of the Marajo (Limoeiro) basin indicates a thick section of some 7,000 ft (2,200 m) of lower Cretaceous continental strata overlain by an equal thickness of lower Tertiary continental and marine strata.

Unconformably overlying the Limeiro Formation is an Eocene to Middle Miocene unit which is represented onshore by a fan-delta

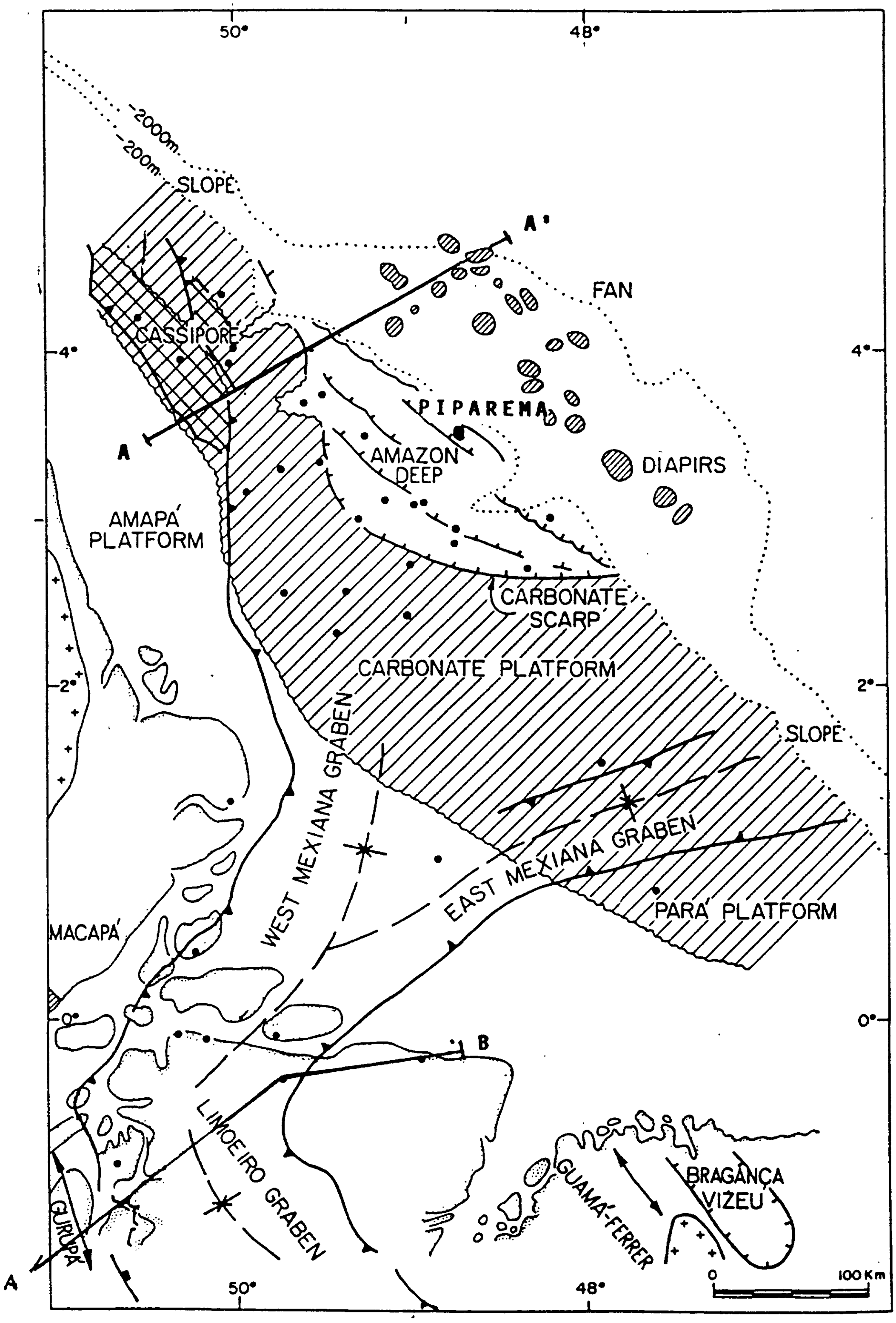


Figure 69 Structural framework of the Foz do Amagonas basin. Diagonal lines - carbonate platform, cross-hatch-Cassipore grabens (modified from Carozzi, 1981).

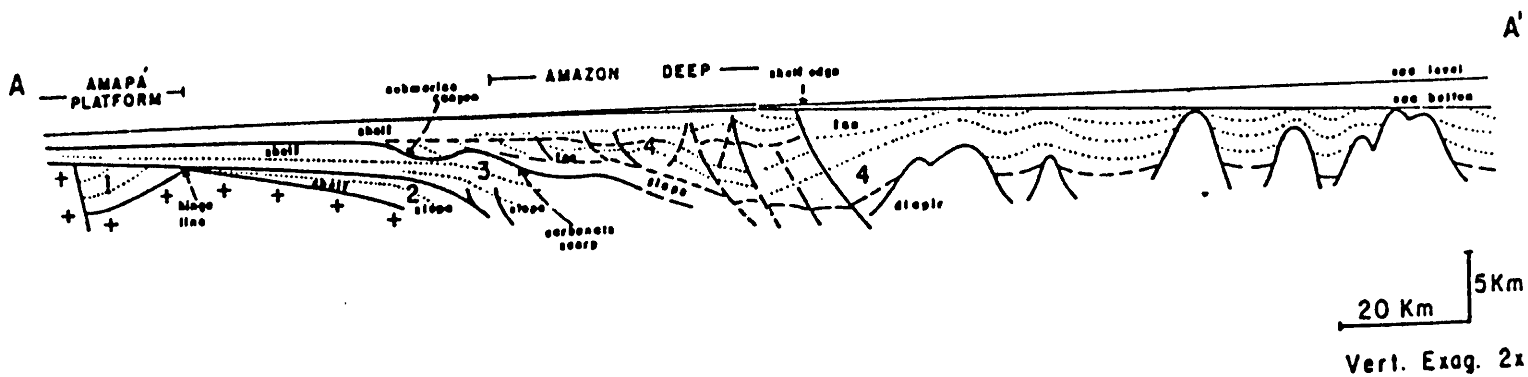


Figure 70 Geologic dip section across Foz do Amazonas basin drawn from seismic profiles. Dotted lines are reflectors. Dashed lines in sequence 4 are facies limits. 1=Lower Cretaceous/(Jurassic 2); 2=(Albian?) Paleocene; 3=Eocene - Middle Miocene; and 4=Middle Miocene to Quaternary. Location figure 69 (from Castro et al, 1978).

facies, and offshore by thick carbonates. These carbonates are the Amapa Formation which makes up the Carbonate Platform area of the basin. The Amapa Formation in turn changes to a slope shale facies at the lower Tertiary shelf edge (fig. 71). The overlying upper Tertiary and Quaternary fluvio-deltaic sediments change to submarine fan and slope deposits near the present shelf edge.

The mouth of the Amazon is not occupied by a delta where the river meets the sea; instead the delta and adjoining fan occupy a limited portion of the outer shelf and the slope (figs. 69, 70, 71). The Amazon delta and adjoining deep sea cone has a sedimentary thickness of up to 40,000 ft (13 km). The delta formed in the mid-Miocene, when uplift of the Andes reversed the flow of the Amazon River. The growth of the delta essentially ended in the Holocene when the rise in sea level accompanying the end of the last glacial period prevented the transportation of sediment across the broad, current-swept continental shelf. The sediments of the delta are assumed to be analogous to sediments of other great deltas, i.e., deltaic sandstones and shales.

Source. The traditional source rocks of the Brazilian rifted continental margins, the Neogene and Aptian, do not appear to be present in the interior rift part of the basin. Reportedly, Texaco drilled some deep wildcats (up to 18,000 ft or 5,500 m) in the deep Marijo (Limoeiro) Graben (fig. 72) and found a largely sandy section with no significant source rocks. The Aptian Codo Formation, which contains source shales in the neighboring Barreirinhas basin apparently thins northwestward and does not occur in the Marajo (Limoeiro) Graben (Zembrucki and Campos, 1988) or northwards. Two probabilities for source rocks occur, however, in the outer shelf and slope and in the Amazon delta and cone: 1) Aptian non-marine and evaporitic strata similar to source rocks in the Caera basin are penetrated in grabens in the Cassipore area of adjoining the Ampa Platform (figs. 69,70) and by deeper wells on the outer shelf of the adjacent Para-Maranhao basin, and 2) Tertiary shales of the Amazon delta are at sufficient depth for thermal maturity and, by analogy to the Niger and other deltas, should have source rock potential. The one discovery in the basin is gas, apparently sourced from deltaic shales.

Reservoirs and Seals. Deltaic and fluvial sandstone reservoirs may be found in the upper Cretaceous through Paleocene within the interior rift and in Tertiary over a somewhat wider area including the Amazon delta and submarine fan. Carbonate reservoirs are distributed over the Carbonate Shelf. The carbonate porosity is mainly secondary, the thickness of the porous zones decreasing basinwards towards the shelf edge, suggesting the effects of meteroric water and danger of flushing. Fractured carbonate are reservoirs in the Para-Maranhao basin to the immediate east.

Seal effectiveness varies over this basin of such diverse geology. Apparently, one of the principal reasons for the lack of petroleum in the Marijo graben may be the lack off sufficient shale

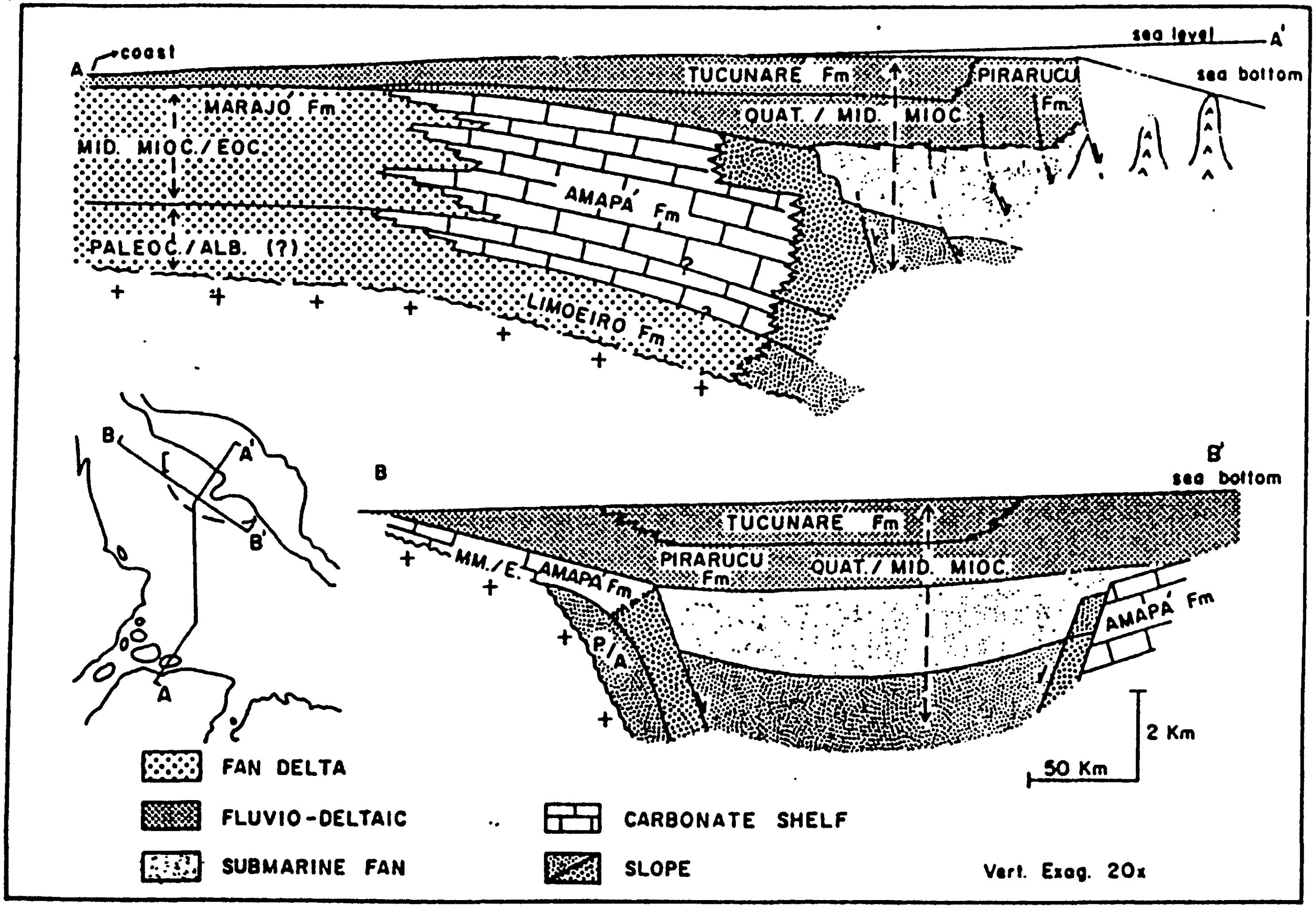


Figure 71 Dip and strike stratigraphic cross-sections of Foz do Amazonas basin (from Carozzi, 1981).

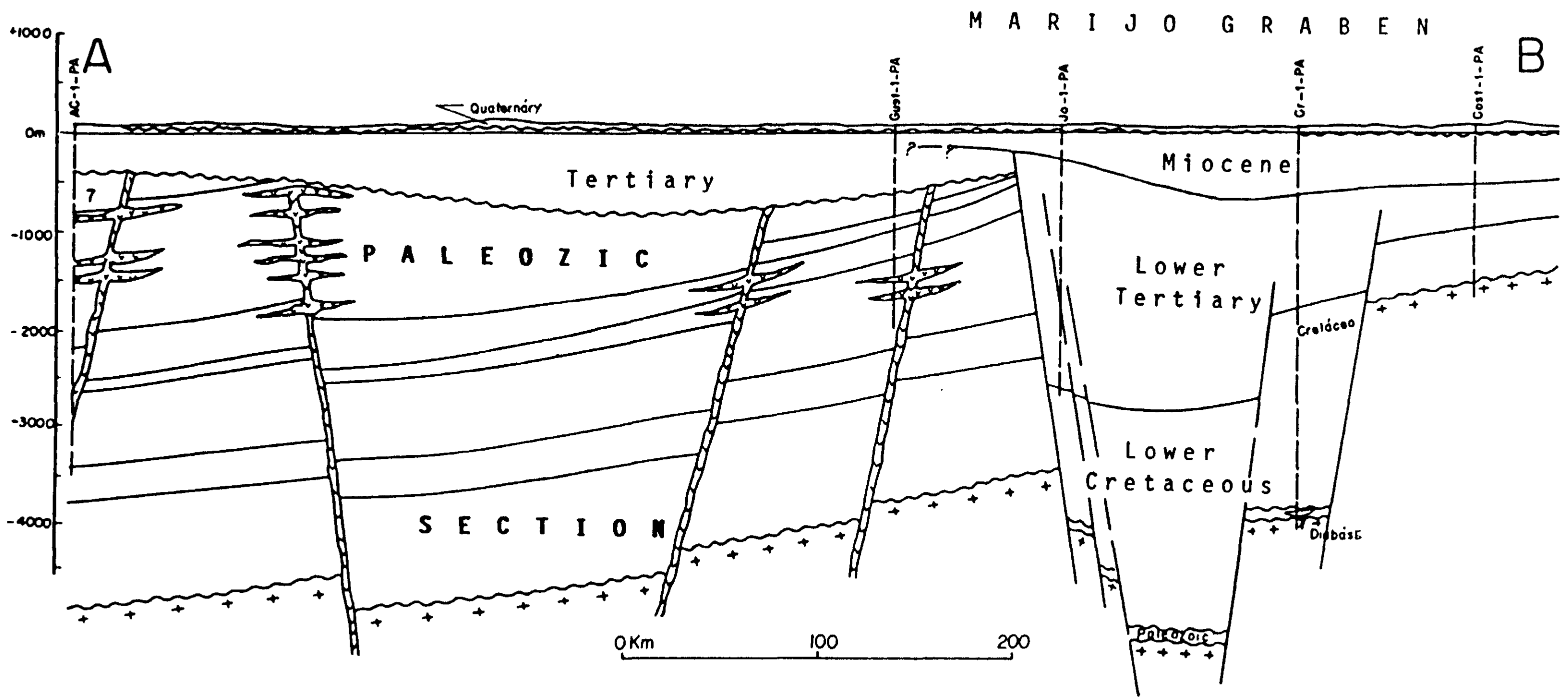


Figure 72 Geologic section across the Marijo (Limoeiro) basin. Location figure 69 (modified from Bigarella, 1973).

seal (another may be lack of source). Any traps of the other outer shelf areas and the Amazon delta would be sealed to some degree by Tertiary shales.

Structure

The structural framework of the basin consists of a generally northeast-trending Cretaceous to early Tertiary interior rift system intersecting a northwest-trending Early Cretaceous rifted continental margin (fig. 69). The interior rift system is made up of the Marijo (or Lumoeiro) Graben (fig. 72) and the Mexiana Graben which bifurcates into West Mexiana and East Mexiana as it intersects the rifted continental margin. The Early Cretaceous normal faults of the rifted continental margin are seen in map and profiles across the Para-Maranhoa basin to the east (fig. 67-68) and to the west they form large half-grabens or subbasins, the Cassipore troughs (figs. 69 and 70).

Structural traps within the interior rift areas as well as the rifted continental margin are fault closure and drapes over tilted fault blocks and horsts. In the Amazon delta deep and fan, and probably on the continental slope, typical listric faulting accompanied by rollovers occur. Diapir of shale (or salt?) occur further out on the Amazon cone (figs. 69 and 70).

Generation, Migration and Accumulation. The geology is varied over the basin, but in general, it appears that, except for the delta, the most likely source rocks are interval in the Aptian. These possible source strata subsided into the oil generation zone sometime in the Tertiary. At that time some of the traps of the Amapa shelf and carbonate platform may have been formed, but those of the Amazon deep (figs. 69 and 70)), as well as the slope and delta, had not yet formed. However, generation and migration has continued and the Tertiary traps and reservoirs were formed in time to receive some petroleum. The delta appears sufficiently thick to have generated gas and oil from middle Tertiary shales which may have charged some of the delta structures.

Plays. Plays in this basin of such diversified geology are numerous, but the main ones appear to be: 1) fault block and drape closures involving Lower Cretaceous graben-fill reservoirs of the Amapa Shelf; 2) fault block and drape closures in the Cretaceous to Tertiary sandstones of the Marajo and Mexiana grabens; 3) shelf listric fault closures, rollovers involving carbonates and sandstones; 4) shelf turbidites, 5) slope and delta listric fault closures, and rollovers; 6) slope turbidites; and 7) diapir traps in the Amazon delta area.

Exploration History and Petroleum Occurrence. Exploration in the region presumably began after World War II, the first deep, 13,000 ft (4,000 m) plus, onshore holes being drilled in the early 1950s, and the first offshore wildcats in the early 1970s. The only notable discovery, the Piparema gas field, was made in 1975 (fig.

69). Through 1988 approximately 72 wildcats have been drilled in the basin, of which about 35 were in the Amazon Deep. The discovery rate of the Foz do Amazonas basin appears to be 1.3 percent, and about 3 percent for the delta within the continental shelf. Total reserves are .88 TCFG. A recently drilled deep wildcat in the Marajo subbasin encountered shows at 18,100 ft (5,516 m) (Aptian?), but the operator, Texaco, has since given up its concession.

Estimation of Undiscovered Oil and Gas. The interior rifts, i.e., Marajo (Limoeiro) and Mexiana grabens, do not appear very prospective. By areal comparison to the geologically similar, parallel, onshore half-graben part of the Barreirinhas basin where Aptian source rock appears present, the petroleum resources could be .140 BBO and .069 TCFG, but in the apparent absence of such source rock, and the sand prone sequence found in Texaco's recent drilling, this estimate is reduced to half or .070 BBO and .035 TCFG.

The continental margin area on the other hand does appear to have Aptian source rock and the area, exclusive of the Amazon delta, appears geologically analogous to the other marginal basins of Brazil's northern margin. By areal analogy to the estimated ultimate resources of the shelf and slope of the adjoining Para-Maranhao basin, the resources would be .223 BBO and .062 TCFG which would be distributed in reservoirs along the marginal shelf and slope in traps involving delta sandstone and carbonate platform reservoirs, and in the slope in turbidites and in deltaic sandstones of the Amazon delta. The resources of the Cassipore grabens would be included in this estimate.

The petroleum potential of the Amazon delta and adjoining submarine fan cannot be presumed to be entirely analogous to large Tertiary petroleum producing deltas, such as the Niger and Mississippi, given its distal shelf and slope position, its short life (less than 10 million years), and the Quaternary intermittent periods of deposition (during oceanic low-stand, i.e., glacial, periods) when the Amazon currents were able to carry detritus across the broad continental shelf. Forty-eight percent of the delta-fan appears to be over oceanic crust and, therefore, lacking of any predelta source rock. Given these data along with low success rate, 3 percent for recent and presumably state-of-the-art exploration drilling, this delta is assumed to be only 10 percent as prospective, on an areal basis, as the somewhat analogous Tertiary Niger delta (ultimate resources of 33 BBO and 100 TCFG, Kingston, 1988) or 1.3 BBO and 4.0 TCFG or 2.0 BBOE. However, since the only discovery is nonassociated gas, the Amazon delta hydrocarbon is probably largely gas, perhaps about 90 percent; on this basis, the estimated basins resources amount to .20 BBO and 10.8 TCFG of undiscovered hydrocarbon. The estimate of aggregate undiscovered petroleum of the Foz do Amazonas basin is .423 BBO and 10.9 TCFG.

Guyana Basin

<u>Area</u>: Shelf 41,000 mi^2 (106,000 km^2)

Slope <u>11,000 mi^2</u> (28,500 km^2)

Total 52,000 mi^2 (134,500 km^2)

<u>Original Reserves</u>: .045 BBO

<u>Description of Area:</u> The basin spans the coastal and offshore area of the Guianas, being very approximately, 40 percent in Guyana, 50 percent in Surinam, and 10 percent in French Guiana. It extends westwards from the eastern Demerara Plateau (which occupies a major part of the Surinam and French Guiana offshore) to the base of the Barbados Ridge (approximately at the Venezuela-Guyana border) (fig. 48 and 73). The basin stretches northward from the basement outcrop to the COB assumed to be at the 2000 meter isobath (except at the shallower Demerara Plateau). Data indicating the complete outline of the basin is unavailable and position of east flank of the basin and shallow platform areas are only rough estimates indicated by dotted lines in figure 73. The shallow part of the Demerara Plateau and projections of the shallow areas of the Amapa platform (of Brazil) and the Pomeroon Rise are excluded from basin consideration.

<u>Stratigraphy</u>

<u>General</u>. The stratigraphy is similar to that of the rifted continental margin basins of northern Brazil (fig. 74). The Neoconian and lower Aptian synrift strata, have not been penetrated, but a synrift sequence is indicated by glimpses of rift faulting on some seismic lines (Lawrence and Coster, 1985). The lowest penetrated beds are a mid-Cretaceous platform sequence of Aptian postrift marginal marine clastics (Starbroek Formation). These are overlain by Aptian/Albian carbonates and shales (Potoco Formation) which in turn are overlain by transgressive organic rich shales (Canje Formation). Following a widespread late Cenomanian unconformity is a Turonian through Paleocene sandstone and shale unit deposited during two regressive cycles (New Amsterdam Formation) and a Paleocene transgressive unit (Georgetown Formation), as the basin subsided. The early Tertiary was a period of quiescence with deposition of carbonates and offshore shales similar to those of the Foz do Amazonas and the Para-Maranhoa basin of Brazil (Pomeroon Formation). Neogene strata are sandstones and shales (Corentyne Formation) deposited during marine regression.

<u>Source</u>. The shales of the Canje Formation have up to 7 percent by weight organic carbon. These high organic carbon contents in conjunction with pyrolysis yields of 21,000 ppm indicate good source rock. Pyrolysis characterization and visual examination of these shales indicate an oil prone source rock (Lawrence and Coster, 1985). These shales are the most significant source rock in the

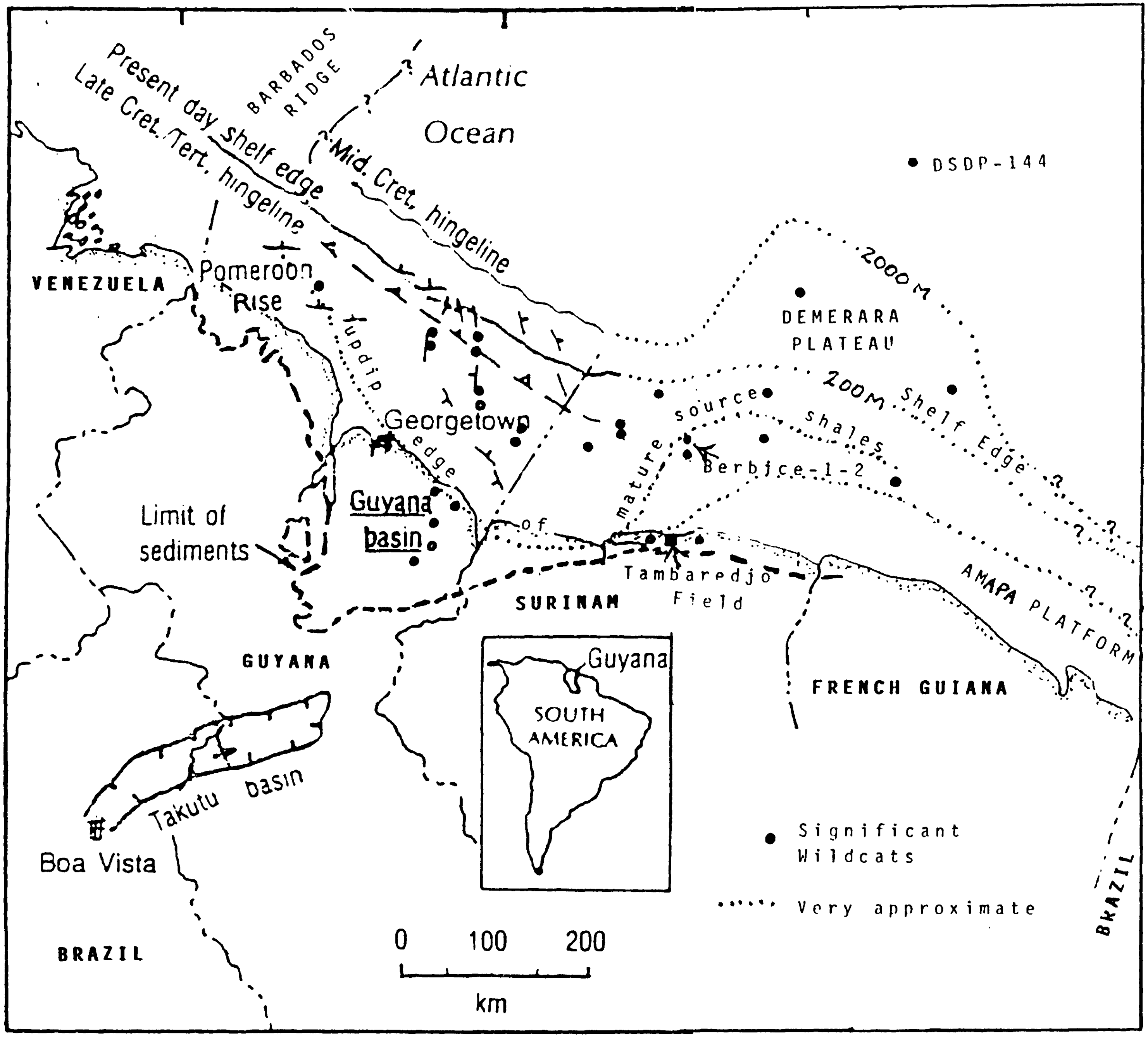


Figure 73 Sketch map of the Guyana basin showing structural elements and significant wildcat positions (heavy dots). Dotted lines are very approximate projections (modified from Lawrence and Coster, 1985)

basin; they correlate with the organically-rich Oceanic Anoxic Event-2 of the south Atlantic. DSDP site 144 drilled adjacent the Dermara Plateau (fig. 73) found Albian to Upper Cretaceous type III source shales of moderate source potential (1-5 metric tons of potential oil covering an area of 1 m^2) (Tessot et al., 1980). Other less-rich organic zones are recognized in the Tertiary (Lawrence and Coster, 1985), but are generally immature. The Cenomanian Conji Formation is within or below the zone of peak oil generation over most of the basin. Seismic profiles indicates the possible presence of a pre-Aptian synrift sequence which in other marginal basins contains source shales; because of their depth of burial, such a source would be gas prone.

Some oil is generated from unknown units as attested by onshore oil seeps.

Reservoirs and Seals. Good potential reservoirs are in the carbonates of the Potoco Formation which immediately underlies the Conji source shales and in which fair to good porosity has been identified in well logs. Porous carbonates are also seen in the Pomeroon carbonates. Thick coastal/paralic sandstones occur in the Toronian-Paleocene and Neogene clastic units (Lawrence and Coster, 1985). However, one wildcat, Berbice - 1 (11,199 ft., 3413 m) (figs. 73, 75) which penetrated most of the Tertiary, reportedly found no significant reservoirs.

The only seals are upper Cretaceous and Tertiary shales which become less effective shoreward. Onshore seeps indicate a certain degree of leakage.

Structure

The basin structure is that of a rifted continental margin. It is a low between the flanking promontories of the Demerara Plateau of volcanic origin and the Barbados ridge which, as part of the Caribbean orogenic province, marks the western limit of the Brazilian craton rifted margin. The lowest subsiding portion of the basin is the central one-third, eastern Guyana and western Surinian, the western, shallower part being largely occupied by the Pomeroon Rise and the eastern shallower part by the extension of the Amapa Platform (fig. 73). This subsidence pattern is thought to be inherited from earlier rift structure and transform adjustments (Lawrence and Coster, 1985). The pre-Aptian rift geometry of half-grabens and tilted fault blocks is suggested by deep partial reflection surfaces on some seismic lines. Block-faulting is prevalent up through mid-Cretaceous, cutting and displacing the mid-Cretaceous platform sequence (fig. 75). According to Lawrence and Coster, 1985, the COB corresponds to the edge of mid-Cretaceous platform, approximately the mid-Cretaceous hingeline of figs. 73 and 75. The Cretaceous/mid-Tertiary shelf-break of hinge-line is some 50 miles (80 kilometers) landward and is marked by seaward listric faulting and attendant rollovers. The continental shelf edge is

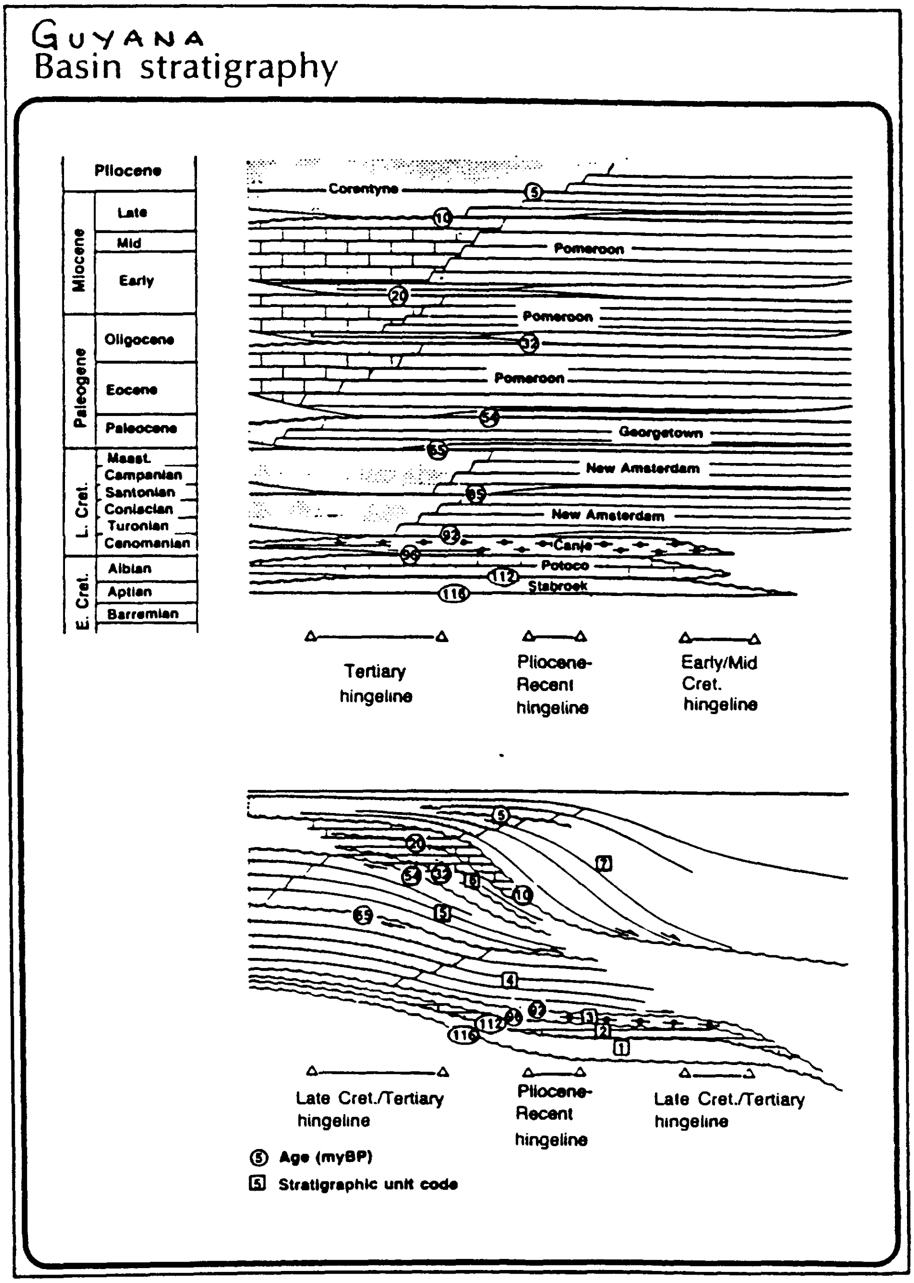


Figure 74 Stratigraphic column and dip section showing vertical and horizontal distribution of sedimentary units in the Guyana basin (from Lawrence and Coster, 1985).

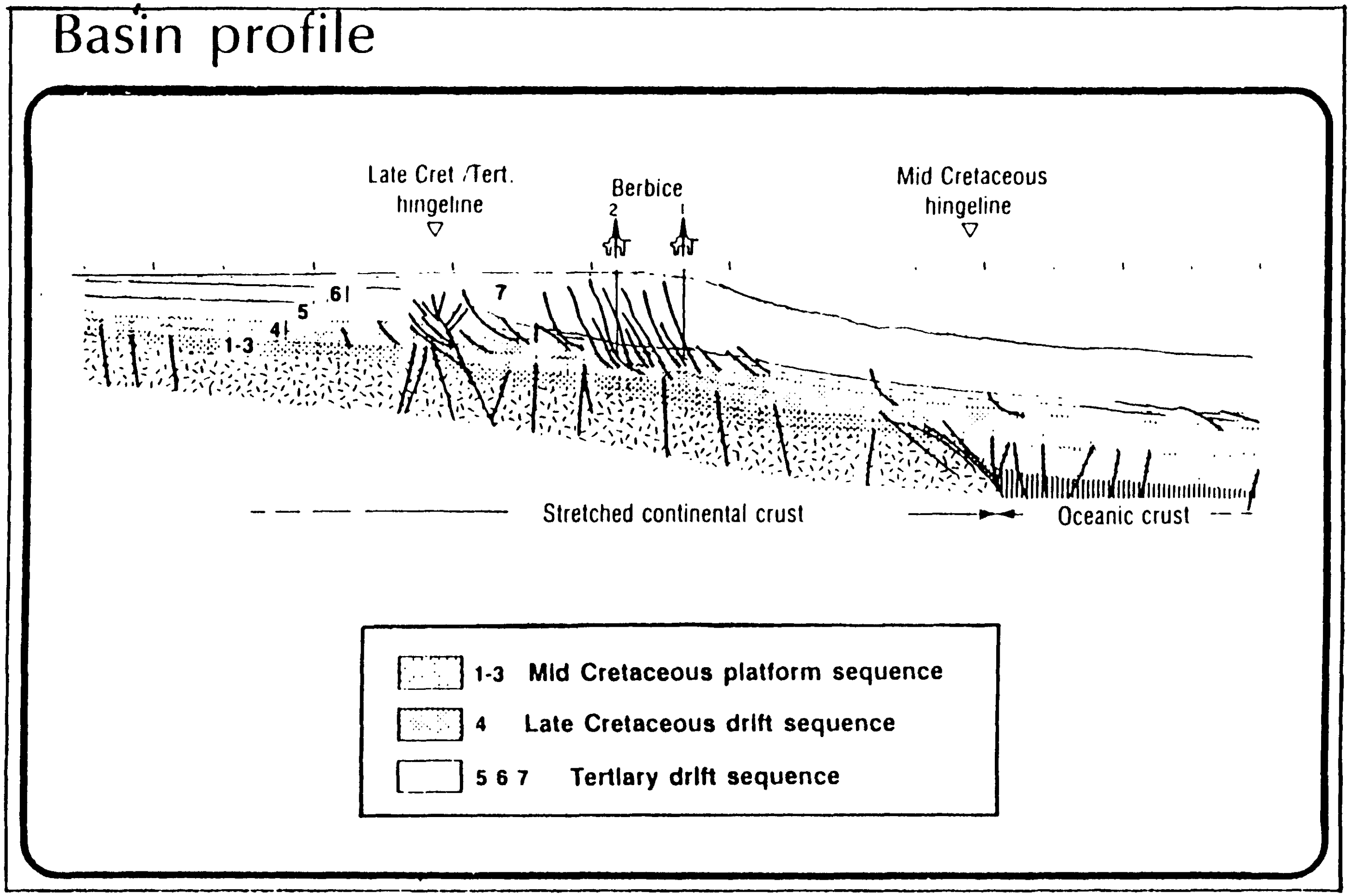


Figure 75 Geologic dip section across offshore Guyana basin (from Lawrence and Coster, 1985).

some 30 miles landward of the COB (fig. 75). Some west-trending wrench faults apparently transect the area.

Potential structural traps would be normal fault closures and drapes associated with the early rifting, especially the faulting involving the platform sequence. Other traps would be associated with shelf-edge and slope listric faulting and accompanying rollovers and perhaps drag folds associated with wrenching..

Generation, Migration, and Accumulation. According to Lawrence and Coster (1985) in the basin depocenter, offshore of eastern Guyana and western Surinam, oil generation and migration began in the Late Cretaceous and optimum expulsion began in mid-Tertiary time and continues to the present. The Cretaceous traps had already formed; the late forming Tertiary traps, i.e., listric faults and associated rollovers and turbidites, however, would also presumably receive at least part of the generated oil.

Plays. The principal plays appear to be: 1) block-faulted early to middle Cretaceous sandstones and carbonates; 2) low relief structures on the shelf, Tertiary involving carbonates and sandstones; 3) listric fault closures involving Tertiary sandstones; 4) rollover traps involving Tertiary sandstones; 5) Tertiary turbidites; and 6) drag folds.

Exploration History and Petroleum Occurrence. Shows of shallow, heavy oil was first observed onshore in the thirties and the first well drilled in 1941. Numerous shallow wildcats led to the discovery in 1981 of the small Tambaredjo field on the coast, 40 km west of Parimaibo with estimated reserves of some .045 BBO (fig. 73).

Offshore drilling began in 1967 and eventually resulted in some 18 wildcats, two of which were on the continental slope. Some shows were encountered (Berbice -1, fig. 73) but no discoveries were made.

Estimation of Undiscovered Oil and Gas

Oil exists in the basin as evidenced by heavy oil shows and one small oil field along the shore line and by shows in at least one offshore wildcat, Berbice-1. There may be, however, a lack of reservoirs. Berbice-1, which penetrated most of the Tertiary, found no reservoirs.

The best analog would be with the shelves and slopes of the adjoining Foz do Amazona and Para-Maranhao basins of Brazil. A direct areal analogy with the ultimate resources (reserves plus estimated undiscovered petroleum) indicates .192 BBO and .166 TCFG on the shelf and .113 BBO and .084 TCFG on the slope, making .305 BBO and .250 TCFG for the entire basin.

B. Brazilian Interior Rift Basins

There are a number of interior rifts within the Brazilian craton. Rift basins underlie the present interior sag basins, e.g. the Solimoes, Amazonas, Parnaiba and possibly the Parana basin. The Marajo and other grabens parallel to and near the coast, and included with this study's Foz de Amazonas and Barreirinhas basin discussions, might also be classified as interior rift basins. In this section, however, discussion is limited to the Recancavo, Tucano, and Jatoba basins which are in one rift trend, or aulacogen northbearing from the southern Bahia coast, and the relatively small, west-trending Tacutu rift basin in the northern part of the Brazilian craton on the Brazilian-Guyana border.

Reconcavo

Area: 3,860 mi^2 (10,000 km^2)

Original Reserves:

Oil	1.436 BBO (Petrobras 1988)
Associated Gas	2.196 TCFG
Non-associated Gas	.847 TCFG
Total Gas	3.043

Description of Area: The Reconcavo basin is onshore, extending northwards from Salvador of southern Bahia on the Atlantic coast of Brazil (fig. 76). It is part of the Reconcavo-Tucano-Jatoba rift or aulacogen formed in the early Cretaceous (fig. 76 inset). The northern end of the Reconcavo basin is placed at the Precambrian Apora high and the southern end at south of Itaparica Island opposite Salvador; it is bounded on the east by the Salvador High horst block and on the east by Precambrian rock outcrop.

Stratigraphy

General. The stratigraphy of the Reconcavo basin is made up of three sequences, the prerift, synrift and postrift (fig. 77). The prerift sediments, Jurassic and lowermost Cretaceous (zones RT-002 and 003, fig. 77) were deposited in a Africa-South America intracontinental setting. They are mainly continental red-beds, containing good reservoirs in the Sergi and Itaparica Formations and some lacustrine shales in the Itaparica Formation and in the base of the Candeias Formation (Taua Member). With the beginning of rifting deep lakes formed and thick clastic deposits flanked graben borders. This synrift sequence, especially the Candeias Formation, is claystone, interbedded with fresh-water ostracod carbonates associated with turbidite sandstones and with fans from the flanks, particularly the eastern flank. During the period of the Ilhas

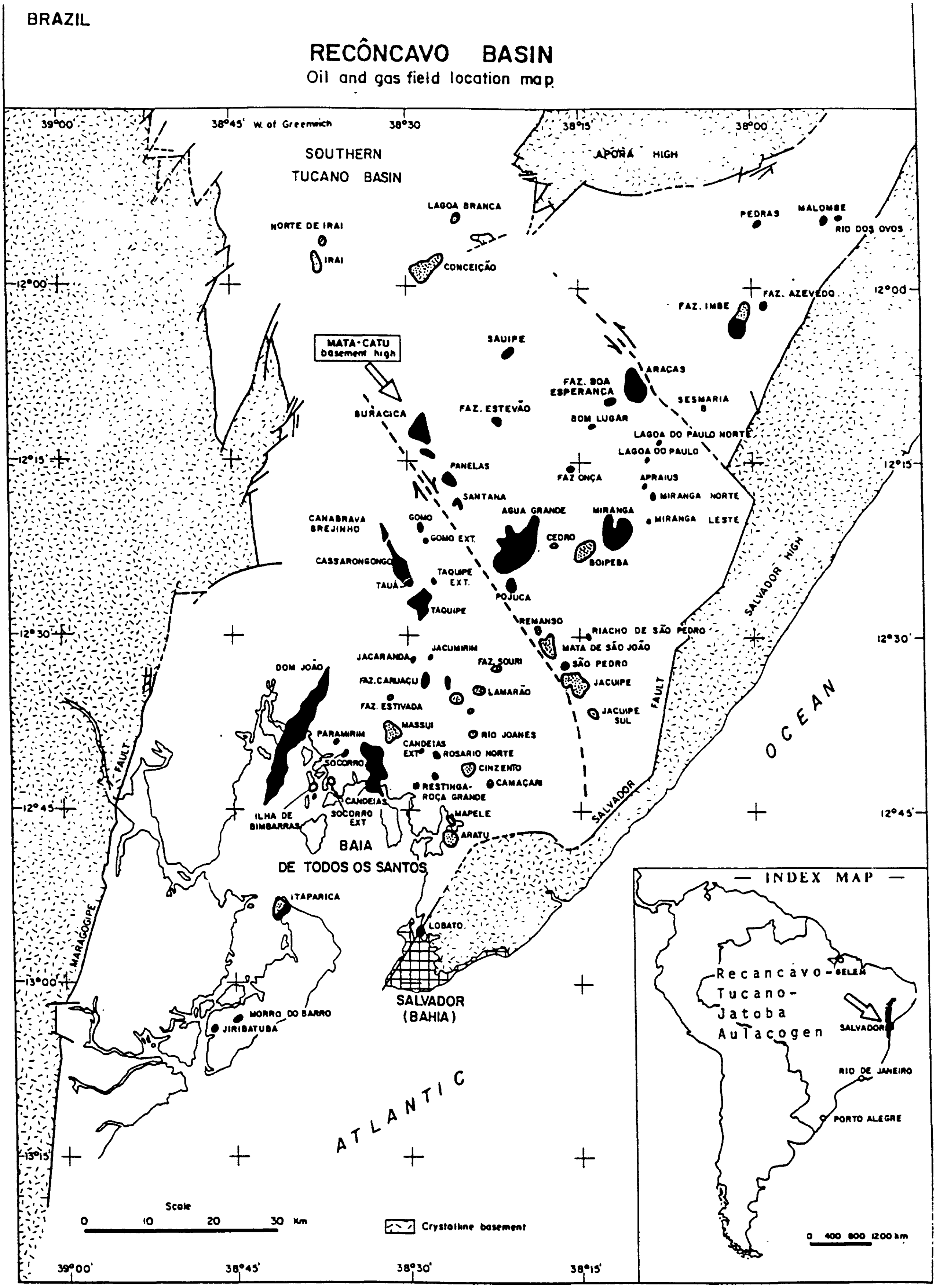


Figure 76 Index map of the Recancavo basin. Dashed northwest-trending lines show position of wrench zones compartmentalizing the Recancavo graben. Inset shows position of the Recancavo-Tucano-Jatoba aulocogen (from Petroconsultants, 1989).

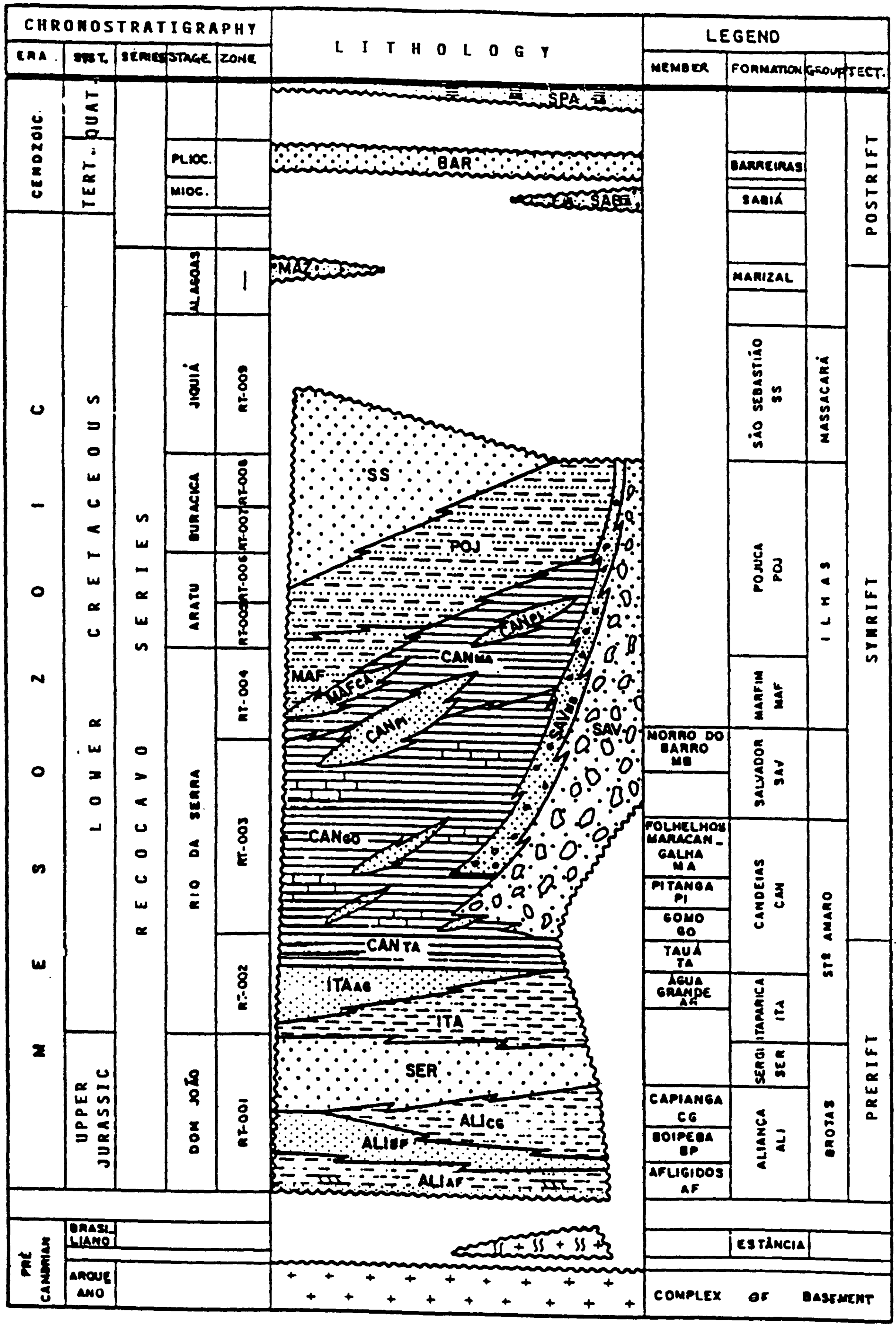


Figure 77 Stratigraphic column of the Recancavo basin (modified from Mato and Souza, 1988).

group sedimentation, tectonic activity was less and a cyclical deltaic system began allowing lithologic correlation across the basin. Rifting ceased in about the Alagoas (Aptian) stage with an erosional phase followed by alluvial formations. During the erosional phase, nearly 6,000 ft (1,800 m) of strata were removed as indicated by the shallow depth of the petroleum-generating thermal zone.

Source. The principal source rocks are the lacustrine shales formed at the end of the prerift and beginning of the synrift phases, the Taua and Gomo Members of the Candeias Formation. Average TOC value is 1 percent while the average residual generation potential is 5 kg HC/ton rock (moderate) reaching 10 kg HC/ton rock (good) in some strata (Santos and Braga, 1990). Type II organic matter prevails, although type I is also present. The younger, Pojuca, shales also have high potential values but are thermally immature except in local depocenters. Although the thermal gradient is average 1.54°F/100 ft (28°C/Km), the top of the petroleum generation mature zone is unusually shallow ranging from 900 ft (270m) on the flanks to 4,000 ft (1,200 m) in the depocenter (Daniel et al., 1989).

Reservoirs and Seals. Reservoirs exist throughout the stratigraphic column. More than half (55 percent) of the reserves are in the prerift Sergi and Itaparica (Aqua Grande Member) sandstones. The synrift reservoirs contain the remaining 45 percent of the oil which can be divided into two groups, those of the Candeias Formation (15 percent) and those of the Ilhas group (30 percent) (Santos and Braga, 1990). The sandstones of the Candeias Formation are largely discontinuous turbidites that form stratigraphic traps, while the overlying, more coherent, Ilhas sandstones form in rollover and drape closures.

Seals are deemed fair. The evaporites of the adjoining rifted marginal basins are absent and shales provide the only seals. The basin is characterized by abundant faulting which must have allowed appreciable leakage.

Structure

The principal structure of the Reconcavo basin is that of a northeast-trending half-graben, steep flank to the east indicated diagrammatically in figure 78. It is broken into three main compartments by two northwest transverse wrench faults (fig. 76), each compartment being progressively shallower to the north. Normal faulting is extensive with steep dips of around 70°, trending generally N30°E. The Reconcavo basin was apparently uplifted in late Neocomian time and has essentially remained high, receiving only minor amounts of Upper Cretaceous-Tertiary sedimentation. The shallow depth of relatively high vitrinite reflectance values indicate erosion of some 6,000 ft (1,800 m) of section in the northeastern part of the basin (Daniel, et al., 1989). The basin is part of the Reconcavo-Tucano-Jatoba aulacogen (fig. 76 inset).

Traps are normal fault closures and drape in the prerift and older synrift (1 of fig. 78) and listric fault closures, rollovers and shale diapirs in the younger synrift section (7 and 8 of fig. 78). Stratigraphic traps in the form of isolated turbidites (3, 4 and 6 of fig. 78), unconformity truncations (5 of fig. 78), fractured shales, and fractured basement are also present (2 of fig. 78). The traps, 1, 3 and 8 as diagrammed in figure 78, represent the principle fields of the basin and contain some 95 percent of the petroleum.

<u>Generation, Migration and Accumulation</u>. Generation and migration began at least 115 million years ago (Aptian) in the basal portions of the Gomo and Taua members in the northeastern sector of the basin (Daniel, et al., 1989) and probably earlier in the deep, subsiding southern parts of the basin. This timing appears favorable since by Aptian time the traps of the Reconcavo basin had formed. The quality of the older reservoirs were evidently at least partially preserved as evidenced by the fact that about half the oil is in Jurassic reservoirs.

<u>Plays</u>. The plays are well illustrated in figure 78. Of the eight plays shown, the principal plays are the prerift fault blocks, turbidites in the Gomo Formation and sand lenses in the Ilhas Formation.

<u>History of Exploration and Petroleum Occurrence</u>. Petroleum exploration began in 1939 when the small Lobato field near Salvador was discovered. By 1988, 958 wildcats had discovered 80 oil fields, establishing original reserves of 1.436 BBO, of which 1.140 BBO were produced. Figure 76 shows the major oil and gas fields of the Reconcavo basin.

<u>Estimation of Undiscovered Oil and Gas</u>.

Figure 79 (drawn on the incomplete data of Petroconsultants, involving 500 out of the 958 exploration wells drilled according to Petrobras) shows the advanced exploration maturity and size of fields discovered versus the number of wildcats drilled. The approximate curves appear to flatten at about .45 MMBO and .36 BCFG per wildcat. Assuming half the number of wildcats indicated as already drilled are drilled in the future (or 250 wells), .112 BBO and .090 TCFG will be discovered.

Petrobras (Santos and Braga, 1990) believe more petroleum will be found by focusing on turbidite and stratigraphic traps in general and by using more refined exploration techniques, 3-D seismic survey in particular. They estimate there is 40MM M^3 of oil equivalent yet to be recovered. Using the oil to gas ratio of the Reconcavo reserves, i.e., 74 percent oil, this translates into .186 BBO and .393 TCFG which fits generally with the field-size-derived estimate for oil, but indicates more gas. It is based on more complete data (e.g., twice as many wildcats) and is the best estimate of the Reconcavo basins undiscovered oil and gas.

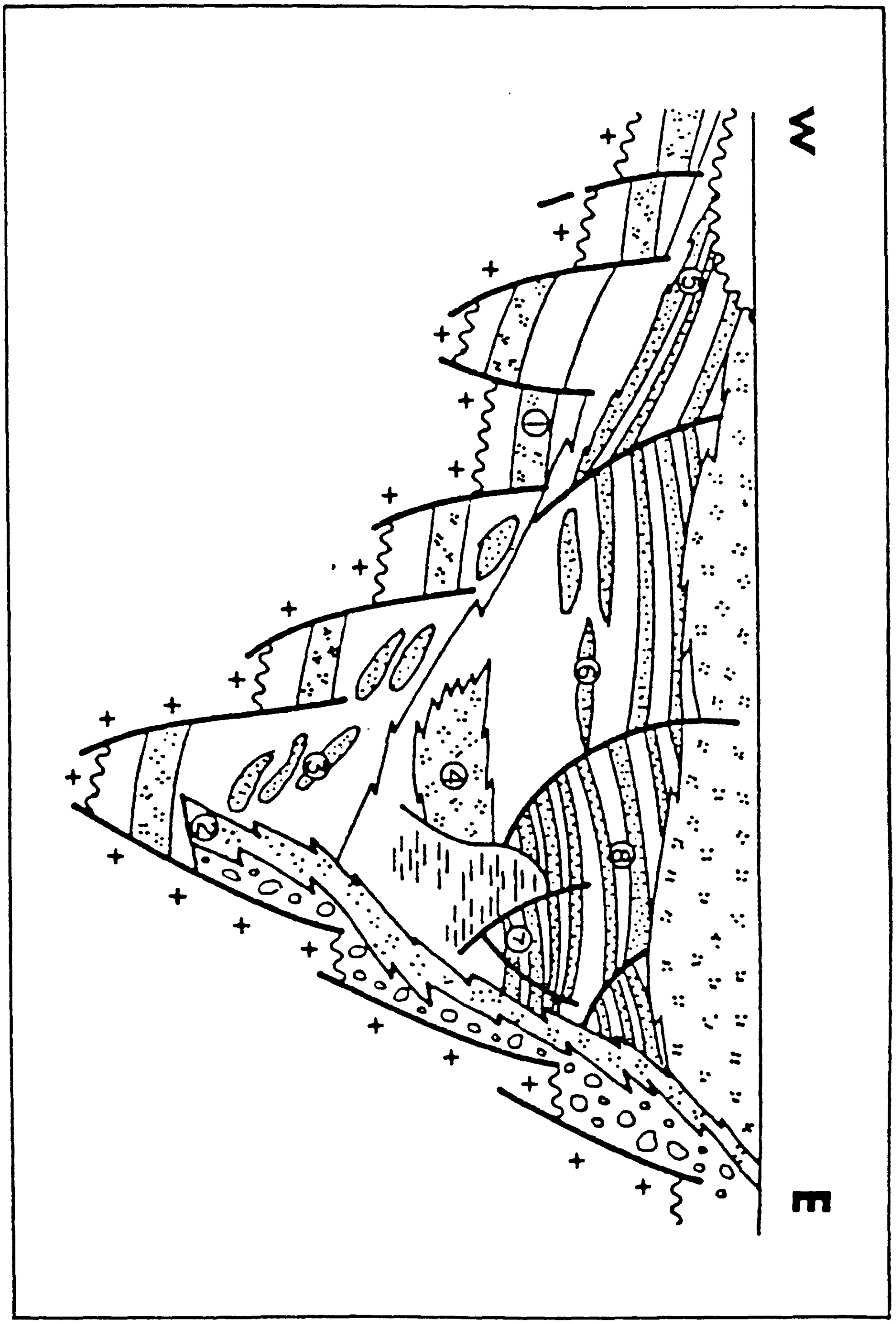


Figure 78 Schematic cross section of the Recancavo basin illustrating the various trap possibilities or plays. 1) pre-rift reservoirs in fault closures, 2) fracture reservoirs along basin perimeter, 3) lenses and turbidites in Gomo Formation, 4) tight-gas in fluxoturbidite reservoirs, 5) unconformity truncated reservoirs, 6) sandstone lenses, 7) truncation of sandstones by diapirs and faults, and 8) delta sandstones in rollovers (from Netto, 1985).

Tucano and Jatoba basins

Area:				
Area:	Tucano Sul	-	2,600 mi^2	6,700 km^2
	Tucano Central	-	4,000 mi^2	10,400 km^2
	Tucano Norte	-	3,000 mi^2	7,800 km^2
	Jatoba	-	2,000 mi^2	5,200 km^2
			11,600 mi^2	30,100 km^2

Original Reserves

.060 TCFG Petrobras 1988

(.036 TCFG Petroconsultants 1989)

Description of Area. The Tucano basin is a segment of the Reconcavo-Tucano-Jatoba onshore rift or aulocogen which extends northwards from the Brazilian coast at Salvador (fig. 76 inset). It is separated from the Reconcavo basin to the south by the Apora basement high and its extension (fig. 76 and 80) and from the Jatoba basin to the north by the Ico horst at the Rio San Francisco (fig. 81). The Tucano basin is divided into three subbasins, the Southern, Central, and Northern Tucano subbasins (81). The Jatoba basin is a northeast-trending segment at the north end of the aulocogen and is bounded by Precambrian basement.

Stratigraphy

General. The stratigraphy of the Tucano and Jatoba basins is similar to that of the Reconcavo basin except for the presence of a Paleozoic section (fig. 82). The Paleozoic section appears to be correlatable with the other interior basins of Brazil and is probably a remnant of an extensive interior sag basin. Above the Paleozoic rocks, and also a remnant of an interior sag basin, are the continental prerift Jurassic (Brotas Group) rocks of largely fluvial origin. During the period of early Candeias sedimentation, in the Neocomian, rifting began, but apparently less vigorously than in the Reconcavo basin. Lacustrine shales alternate with carbonate members in the central parts of the basin and coarser clastics members occur on the boundaries with turbidites extending into the lacustrine areas. Above the Candeias Formation is the Neocomian Ilhas Group of sandstones alternating with shales deposited in a fluviodeltaic environment. Above the Ilhas Group is the Neocomian fluvial Massacara Group of massive thick sandstones. Lastly, Aptian sandstones and conglomerates, the Marizal Formation, overlie the section by an unconformity in which, by analogy to the Reconcavo basement, some 6,000 ft (1,800 m) of section was removed.

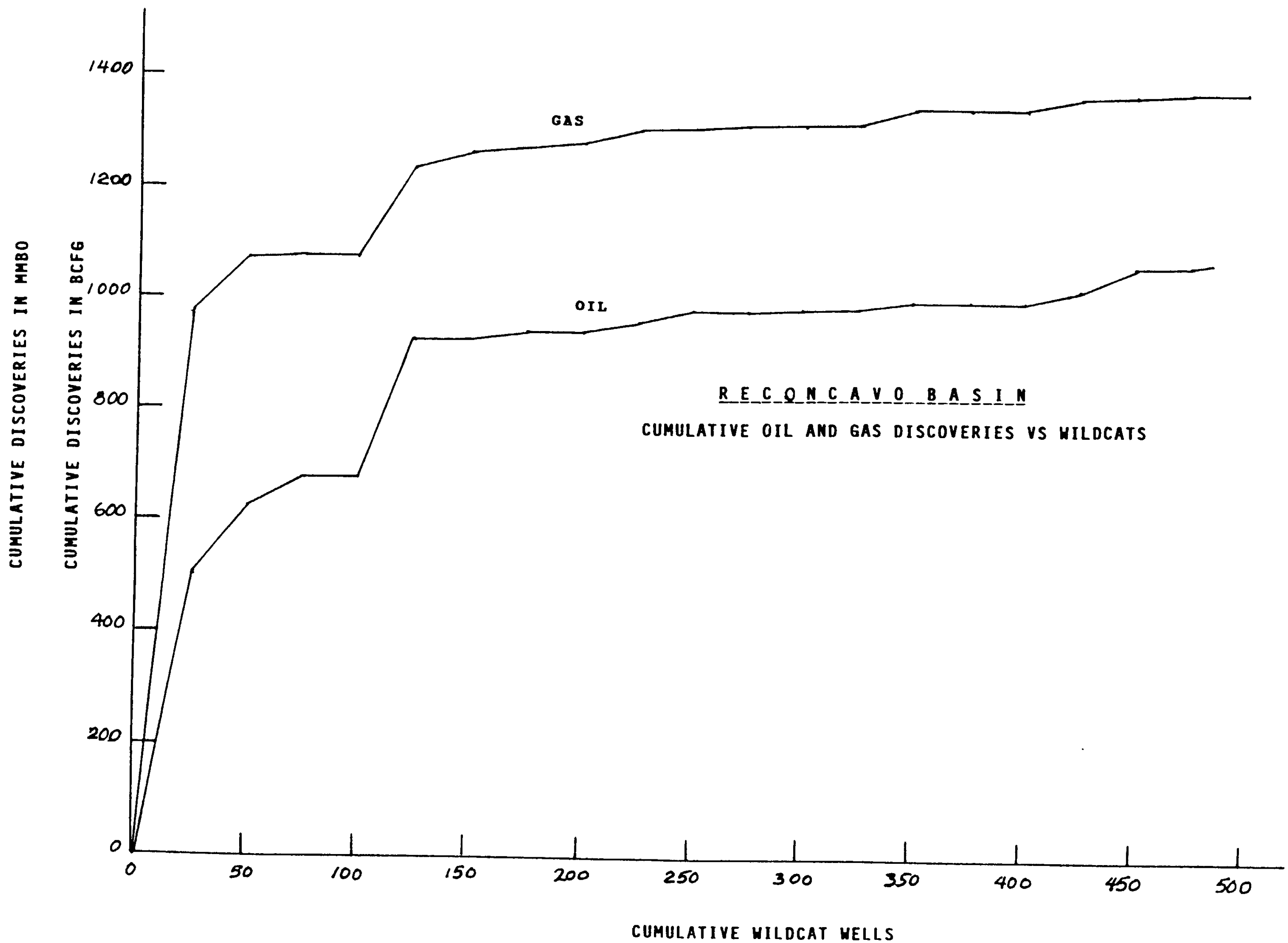


Figure 79 Graph showing relation of the cumulative amount of discovered oil and gas to the number of exploration wells drilled in the Recancavo basin. Based on Petroconsultants data (1990) which may be incomplete.

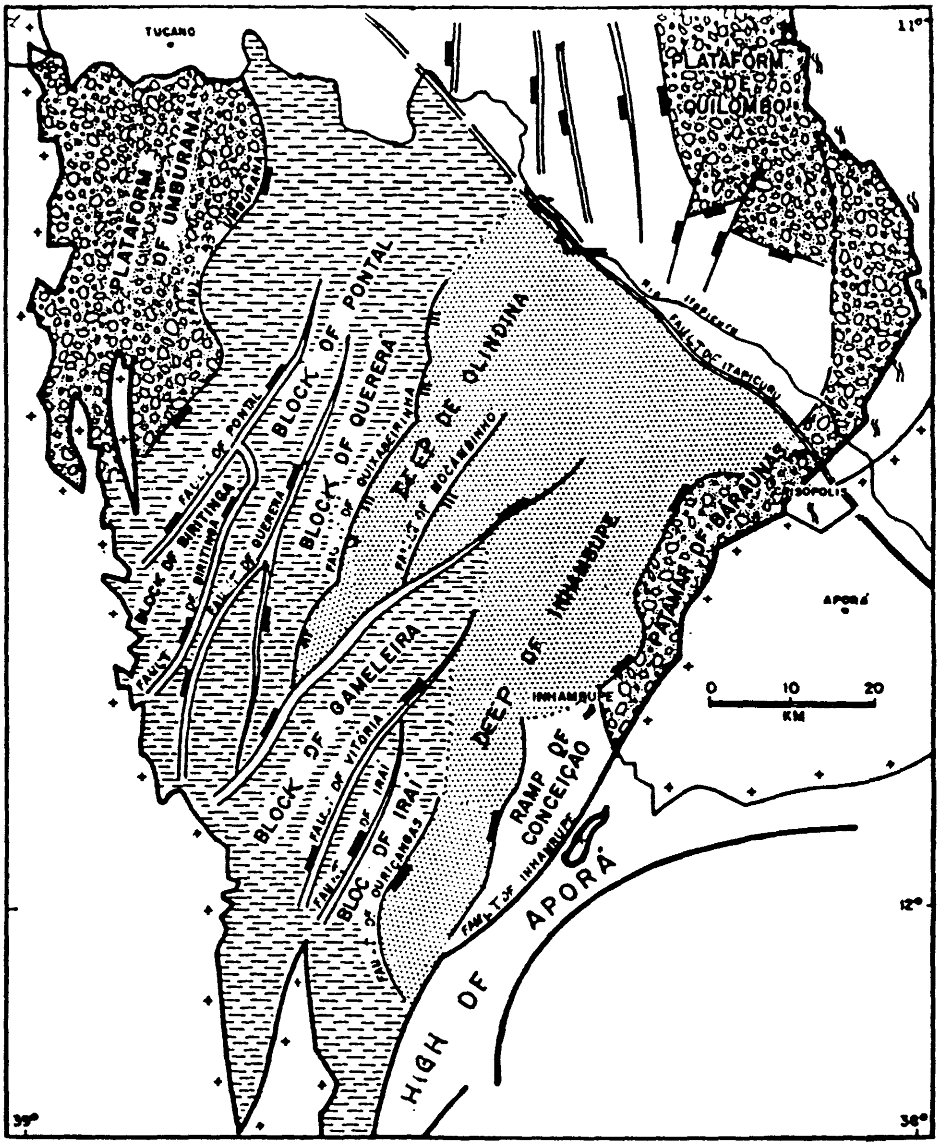


Figure 80 Tectonic map of the south Tucano subbasin (modified from Magnavita and Cupertino, 1987).

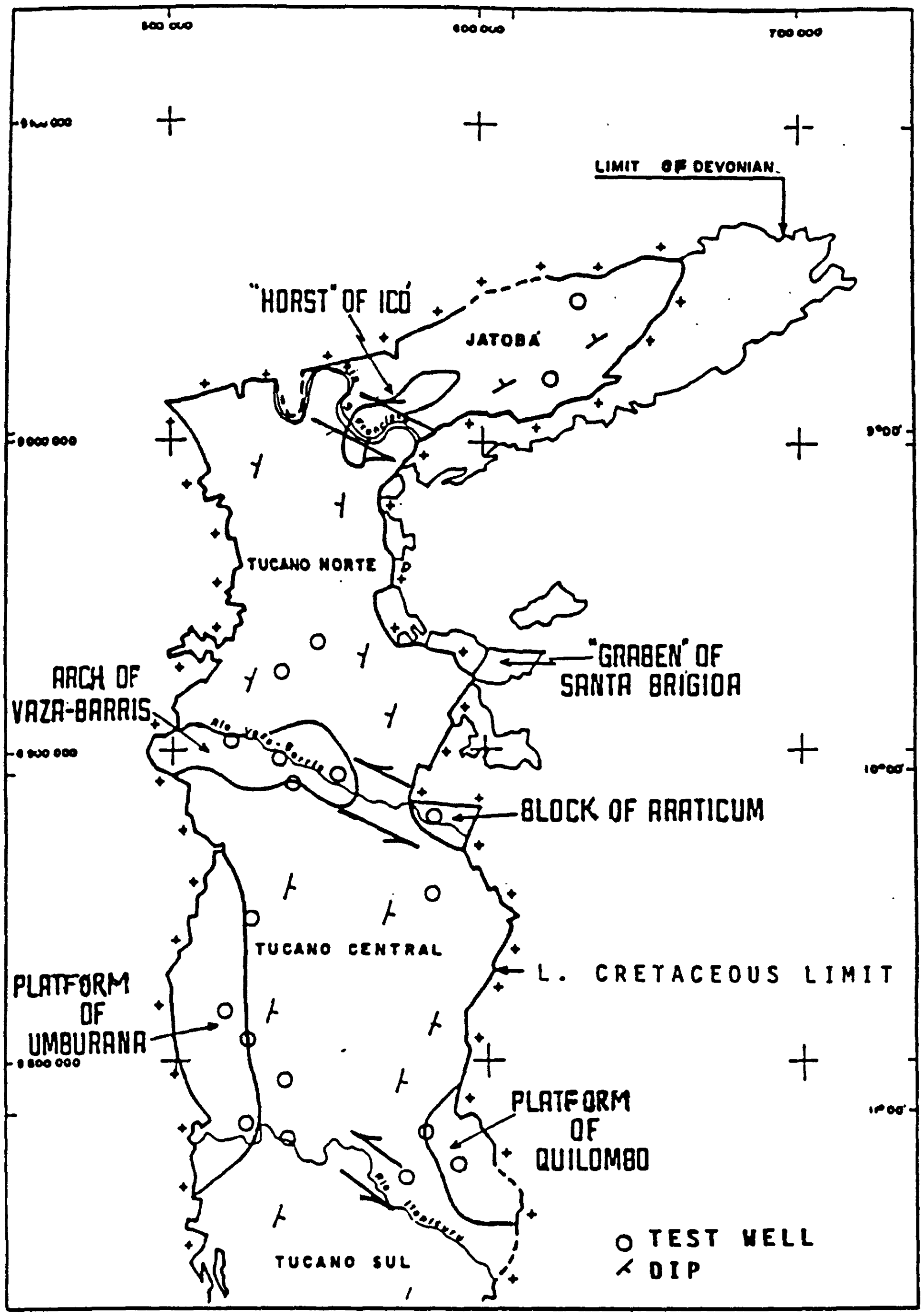


Figure 81 Structural element map of the Tucano and Jatoba basins showing the zones of sinistral wrenching and the reversal of dip direction at the wrench zone of the Rio Vaza-Barris (modified from Magnavita and Cupertino, 1987).

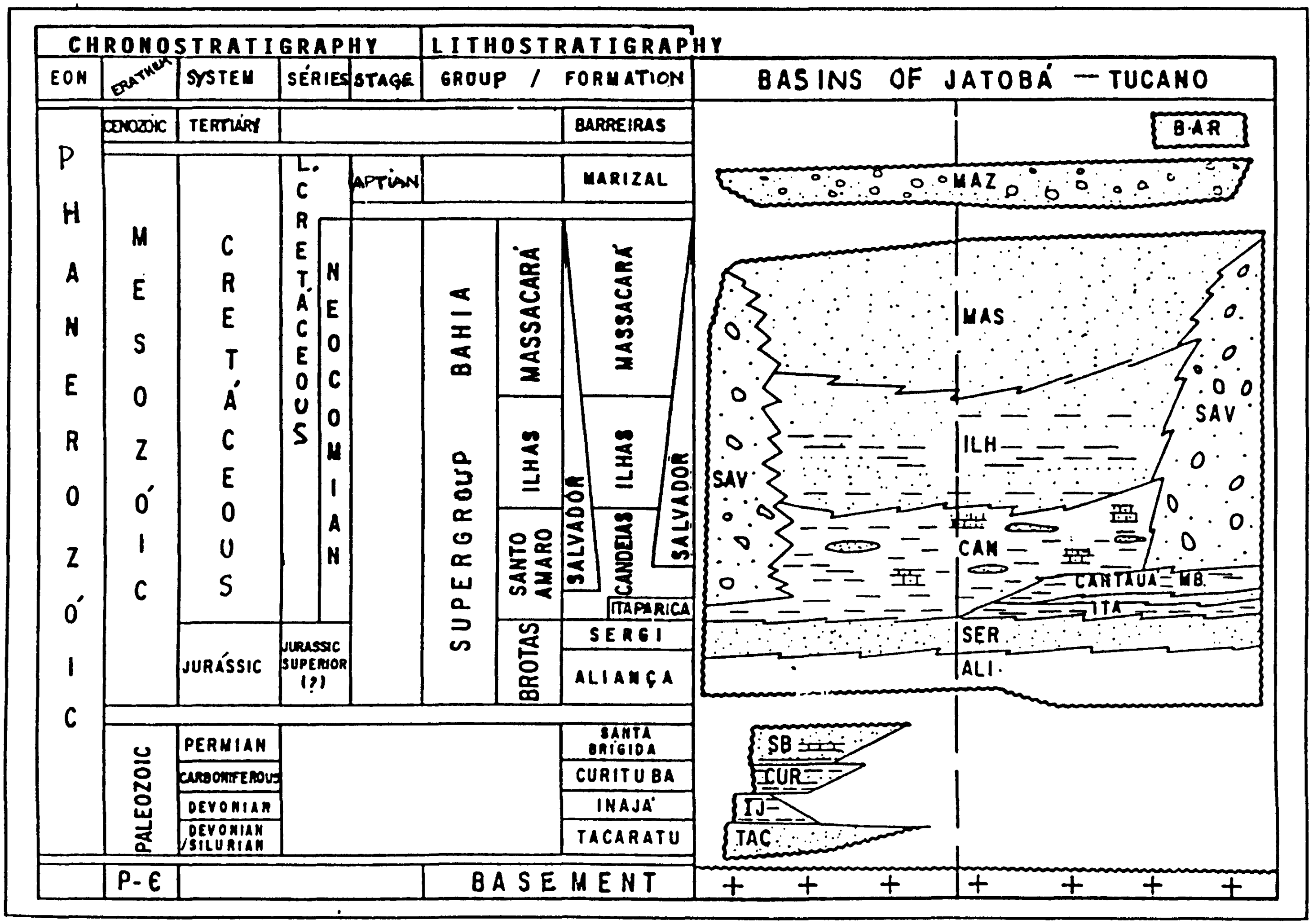


Figure 82 Stratigraphic column of Tucano and Jatoba basins (modified from Cupertino, 1990).

Source. The oldest potential source rocks are organic-rich shales of the Permian of the North Tucano subbasin. Where they have been sampled, however, they are thermally immature (Magnavita and Cupertino, 1987). The Cretaceous potential source rocks, particularly of the Southern Tucano subbasin, are in the same formations as in the Reconcavo basin, namely, the lower Candeias Formation and the base of the Ilhas Group, but especially the Candeias which appears to have had a more restricted depositional environment.

The source rocks in the Southern Tucano subbasin were determined to be gas prone (Magnavita and Cupertino, 1987) and discoveries have been only of nonassociated gas. Presumably, this condition exists to some extent in the other Tucano subbasins. Reportedly, some Ilhas Group shales of the Central Tucano subbasin were found to have good source characteristics, but are probably thermally immature. The Northern Tucano subbasin likewise has potential source rock, i.e., Candeias shale with TOC values of 2.0 and genetic potential of 3 kg HC/ton rock (moderate), but it is also immature (Magnavita and Cupertino, 1987). The Jatoba subbasin appears to be too shallow for sufficient source rock maturation.

Reservoirs and Seals. The main reservoirs are similar to those of the Reconcavo, that is, the prerift, the Sergi sands or their equivalent, the turbidites within the Candeias Formation, and the deltaic sandstones within the Ilhas Group.

The seals are shales. In these relatively shallow, much faulted basins, leakage may be a negative factor.

Structure

The structure of the Tucano and Jatoba basins are similar to that of the Reconcavo basin, being largely a half-graben rift with north and northeast-trending normal faults and horst and graben features. This northerly trend is transversed by a number of northwest trending wrench faults. Of particular note is a zone of sinistral wrench faulting at the Rio Itapicuru which divides the Central Tucano from the Southern Tucano subbasin (fig. 81) and the Vaza-Barris zone of wrench faulting (adjoining the Vaza Barris Arch, fig. 81) which separates the Central Tucano basin, where the dip of the strata is towards the deep east-side of the subbasin, from the North Tucano subbasin, where the dip is reversed so that it is towards the west side of the subbasin (fig. 81).

Fig. 83 is a cross-section approximately along the divide between the Central and Northern Tucano subbasin. From the data at hand the gravity induced structures, that is, listric faults, rollovers, and shale diapirs, which are prevalent in the Reconcavo basin, are not so significant in the shallower Tucano basin. Traps would be mainly fault-block and drape closures.

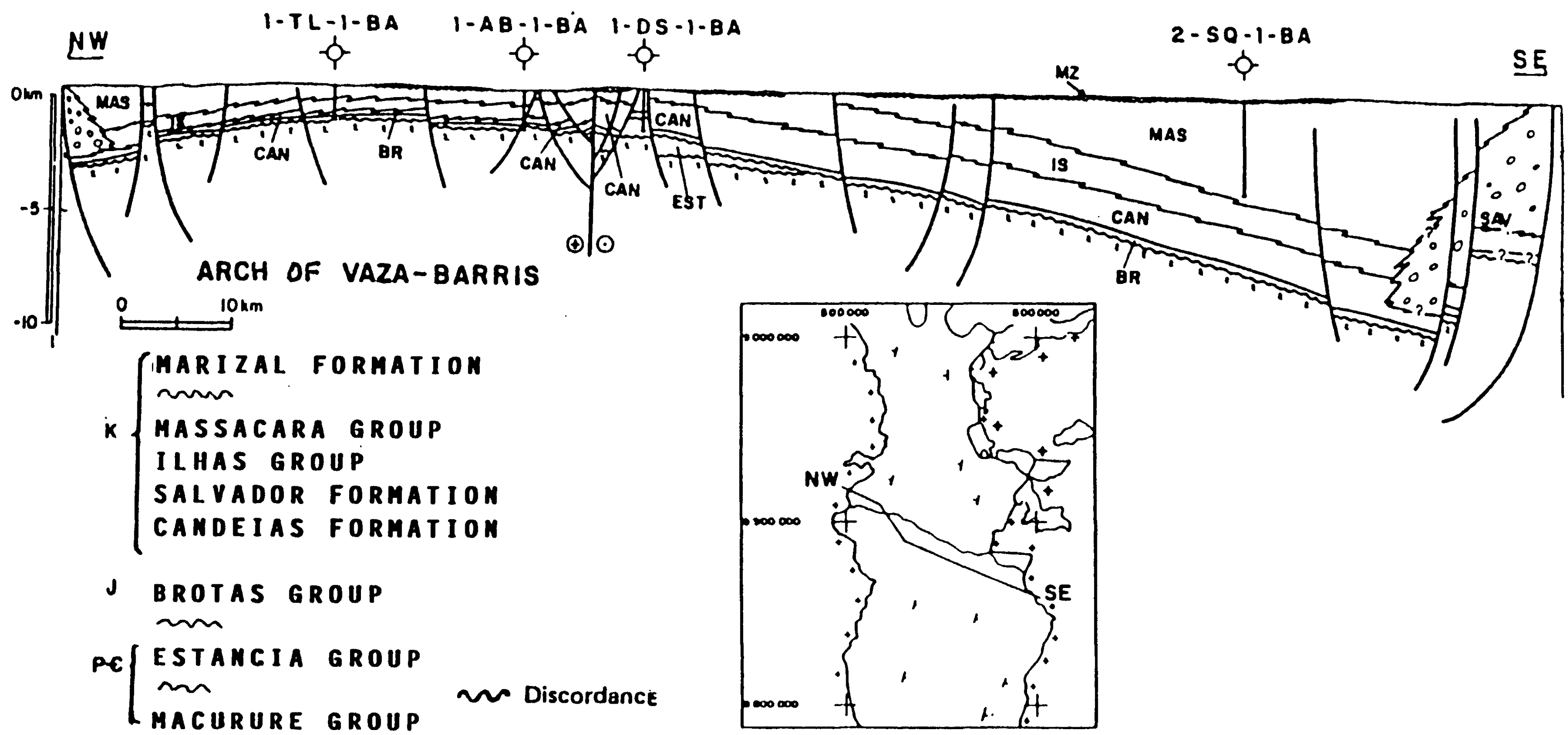


Figure 83 Geologic section across Tucano basin at Rio Vasa-Barris (modified from Magnavita and Cupertino, 1987).

Generation, Migration and Accumulation. Generation and migration appears to have begun about the late Neocomian when the sediments of the deeper parts of the Tucano basin were depressed sufficiently to enter the oil generating zone. These deep parts were largely confined to the southeastern side of the Southern Tucano subbasin where all the three gas fields are concentrated in Neocomian traps.

Plays. The plays are the same as those of the Reconcavo basin except that the fault-block closures involving prerift and synrift strata would probably dominate.

History of Exploration and Petroleum Occurrence. Exploration of these basins has been carried on since at least the 1950s to 1987 with the drilling of 106 wildcats, 87 in the Southern Tucano subbasin, 15 in the central Tucano subbasin, 2 in the Northern Tucano subbasin and 2 in the Jatoba basin. This exploration resulted in the discovery of three gas fields in the extreme south of the Southern Tucano subbasin (fig. 76).

Estimation of Undiscovered Oil and Gas

The Tucano subbasin and Jatoba basin appear to become progressively less prospective to the north. The Southern Tucano subbasin is the only basin to have petroleum accumulations (reserves .06 TCFG, Bruhn et al., 1988) and source rock data suggests the basin is gas prone (Magnavita and Cupertino, 1987). By areal comparison to ultimate petroleum resources of the analogous Reconcavo basin, assuming the petroleum was 90 percent gas, the resources of the Southern Tucano subbasin would be 7.99 TCFG and .148 BBO. However, the small amount of discovery,.060 TCFG after drilling 87 holes, along with the apparent lack of anything but fault and drape closures and the restricted volume of the Candeias source shales, suggests the Reconcavo analogy should be reduced to about 20 percent, indicating resources of .400 TCFG and .030 BBO.

The Central Tucano and Northern Tucano subbasins appear to be less prospective on the basis of the relative lack of exploration they have evoked. The Central Tucano subbasin, after 15 wildcats, has no production but has found some indications of source rock in the Candeias Formation and Ilhas Group. The Northern Tucano subbasin apparently contains no Cretaceous source rock, but does contain organically rich Permian shales which, where found, are immature. Other requirements for oil occurrence, i.e., thick section, reservoirs, and traps are present. On the assumption that the Central Tucano subbasin is only half as prospective on an areal basis as the Southern Tucano subbasin and the Northern Tucano subbasin half that of the Central Tucano subbasin, the resources of the central subbasin are .307 TCFG and .023 BBO and the northern subbasin .100 TCFG and .008 BBO. The petroleum resources of the Jatoba basin, because of its shallowness, are regarded as negligible. Altogether, the undiscovered oil and gas of the Tucano and Jatoba basins amount to .807 TCFG and .061 BBO.

Tacutu Basin

Area: 4,300 mi^2 (11,200 km^2)

(Approximately half in Brazil and half in Guyana)

Original Reserves: None

Description of Area: The Tacutu basin is a Mesozoic northeast-trending interior rift or graben of some 200 mi (300 km) in length and 30 to 50 mi (20-30 km) wide located in the center of the Guyana shield, at the border between Guyana and Brazil (figs. 2 and 84).

Stratigraphy

General. The sediments of the basin are essentially some 18,000 ft (5,400 m) of synrift sediments (fig. 85). The basin is floored by up to 3000 ft (950 m) of subaqueous basalt of Jurassic age (Apoteri Volcanic Formation). The synrift basal unit is up to 1000 ft (300 m) of the Upper Jurassic to Lower Cretaceous Manari Formation of lacustrine shales and limestones. Above the Manari Formation is the Lower Cretaceous Perara Formation of shales, siltstones, limestones and halites (up to 3,000 ft, 950 m) laid down in hypersaline lakes or restricted marine bays. At the same time fanglomerates of the Arraia Formation developed near the steep southeastern margin. The rift-fill was completed with the Upper Cretaceous deposition of the Tacutu Formation red beds and the overlying Tucano deltaic sandstones.

Source (Crawford et al., 1985) Only the sedimentary rocks immediately below the Pirara halite, the Pirara and Manari Formations have source rock potential. The TOC of the source shales range from 1.5 to 3.1 percent. The richer shales have a hydrogen index of 336 (oil prone) and petroleum genetic potential of 4,300 to 9,300 ppm (moderate to good source rock). Terrestrial plant kerogen is dominant, though kerogen of non-marine algae origin is also present. The average geothermal gradient of the area is 1.76°F/100 ft (3.2°C/100 m). The top of the thermal zone of oil generation varies over the basin, but averages between 5,200 and 6,900 ft (1,600 and 2,100 m) with optimum generation at about 11,500 ft (3,500 m) (Crawford, et al., 1985). Two of the four wildcats encountered good source rock within the zone of oil generation.

Reservoirs and Seals. Like other synrift sequences, the main problem for petroleum accumulation in the Tacutu basin is the uncertainty of sufficient reservoirs. The wildcat which penetrated the most reservoirs was the Petrobras Tacutu No. 1 (High of Tomba, fig. 84). In that well about 5 percent sandstone with 70 ft (20 m) of 10 to 15 percent porosity was penetrated in the post-salt

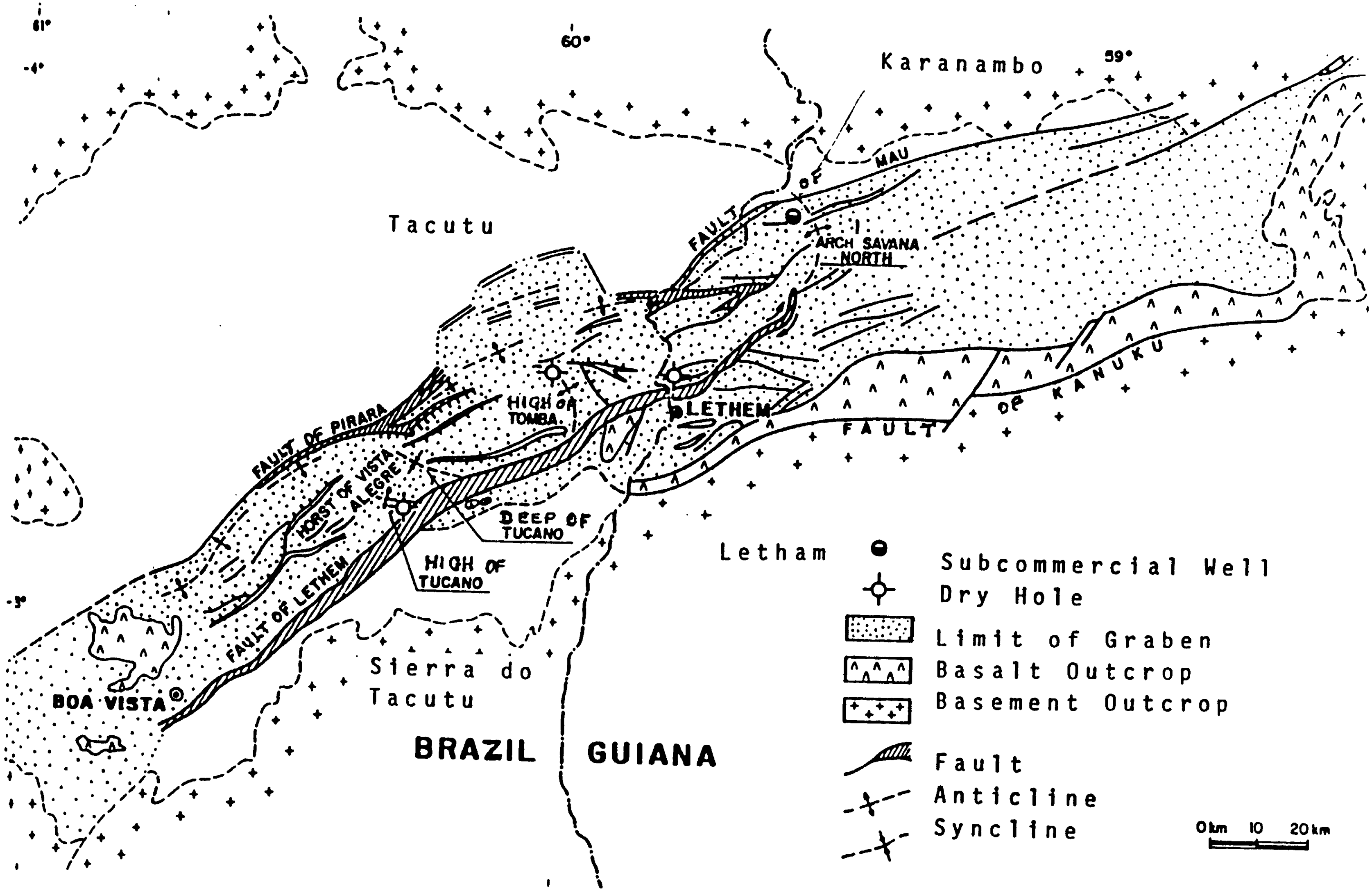


Figure 84 Map of structural framework of the Tacutu basin (modified from Eiras and Kinoshita, 1988).

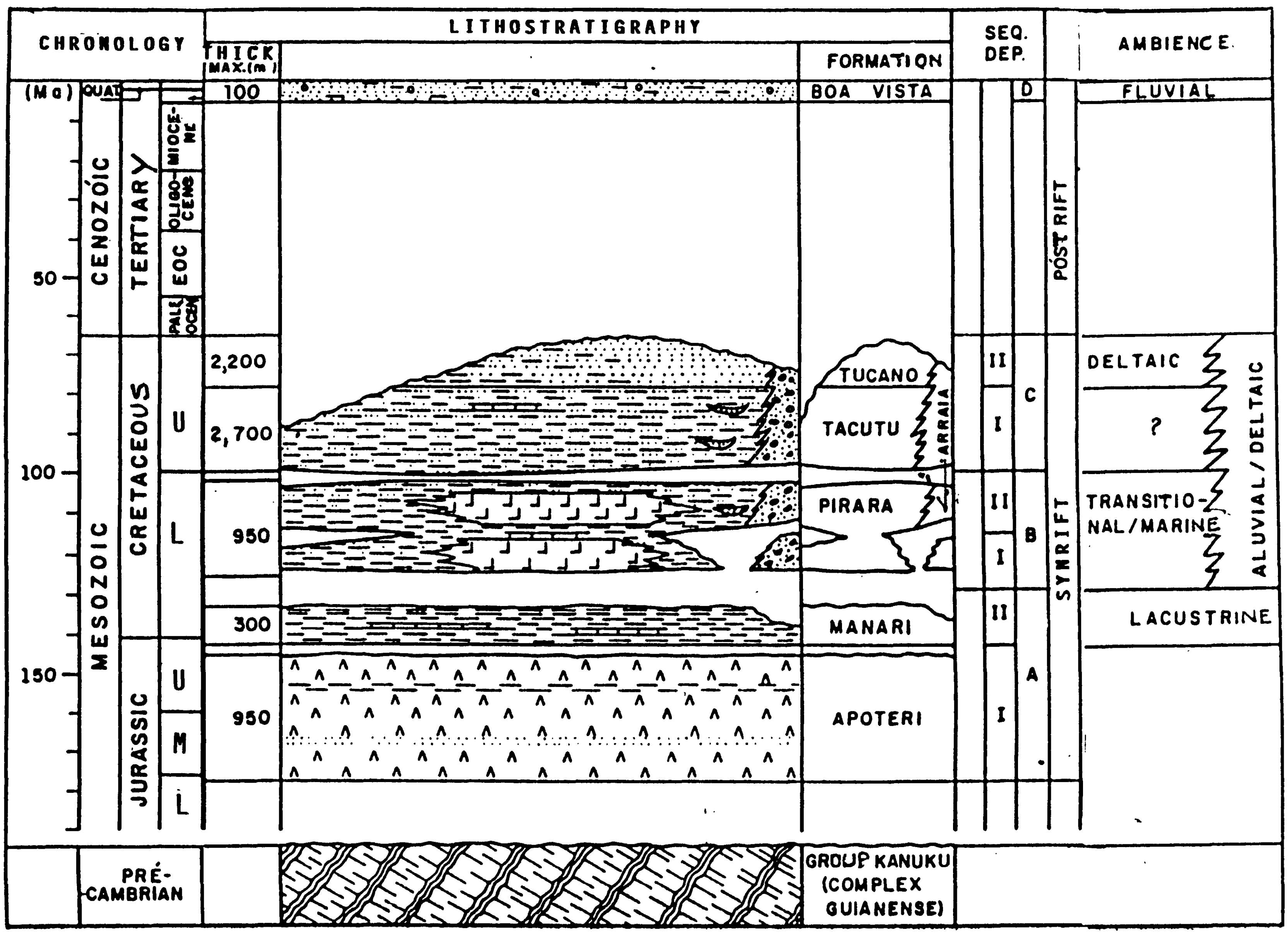


Figure 85 Stratigraphic column of the Tacutu basin (modified from Eiras and Kinoshita, 1988).

clastics. Thicker reservoirs should be encountered in deltas and fans along the steeper, southern and eastern sides of the basin. The only appreciable oil found to date is in the fractured volcanic basement reservoir at Karanambo (fig. 84).

Seals are the evaporites and accompanying shales. These seals, however, are absent or poorly developed on basin flanks where the best reservoir development may be expected.

Structure

The structure of the Tacutu basin is essentially that of a graben (fig. 86). Deformation was mainly tensional with abundant normal faults and horst/graben structural relief with attendant fault and drape closures. Only the larger faults cut the ductile salt-bearing Pirara Formation. Post-salt listric faults and attendant rollover and fault closures affect the younger formations. Salt structures in the form of domes, swells, or ridges are prevalent. Wrench faulting was active in postrift time (Tertiary?) as exemplified by the Lethem Fault (figs. 84 and 86). Drag folds may also be present.

Generation, Migration and Accumulation. Generation and migration probably began in the late Cretaceous when the lower source beds of the Pirara Formation reached a burial depth of about 10,000 feet in the deeper parts of the graben. At that time the principal traps were in place, i.e., fault traps and drapes. Generation and migration continued and was probably contemporaneous with the formation of salt and listric-fault-associated traps as well as possible transpressional traps, formed in the Cretaceous or Tertiary.

Plays. The principal plays are the fault- and drape-associated closures of the presalt, salt flow closures, listric-fault-associated features and possible transpressional closures of the postsalt. Stratigraphic traps on the flanks of the graben and of local horsts may have minor potential.

Exploration History and Petroleum Occurrence. The presence of the Tacutu basin was first detected by the airborne magnetometer in 1962-63. Later geophysical work outlined the basin in more detail. Between 1980 and 1982 four exploratory wells were drilled which, along with the preliminary seismic work, provides our present knowledge of the basin. One of these wells, Karanambo No-1 (fig. 84) tested 42° API, low sulfur, low wax crude oil from a 344 ft (105 m) sequence of fractured volcanic basement, shale, and carbonate, but of insufficient quantity (409 BOD) to be considered commercial (declining shut-in pressures suggested reservoir depletion) (Crawford et al., 1985). Reportedly, the other three wildcats failed to find significant reservoirs.

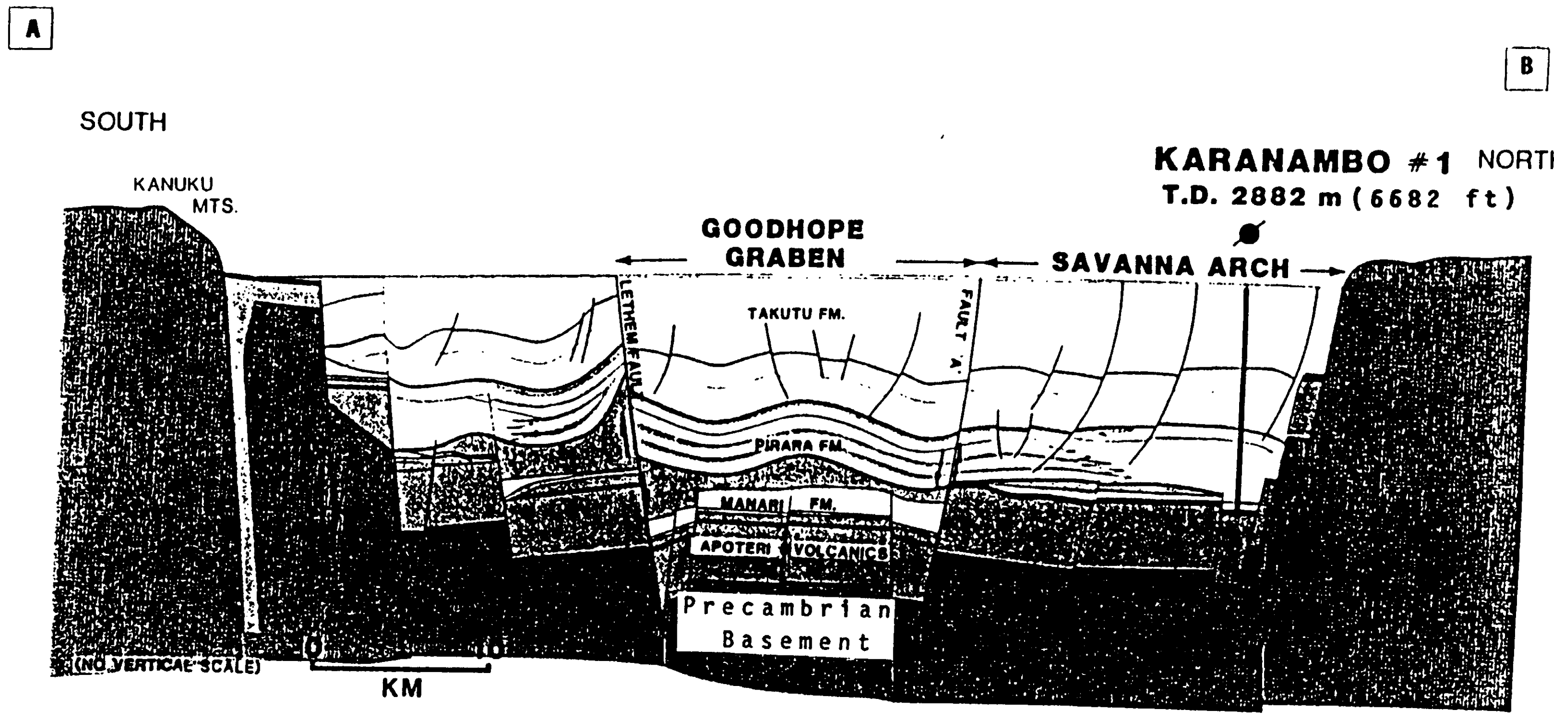


Figure 86 Schematic geologic section across the Tacutu graben (from Crawford et al, 1985?)

Estimation of Undiscovered Oil and Gas

There appears to be two main plays in the Tacutu basin: 1) petroleum resources in deltaic sandstones in fault, drape or stratigraphic traps around the perimeter of the basin and perhaps locally adjacent to horst blocks, and 2) fractured basement or volcanics adjacent to the pre-salt source shale sections.

The main play would be the deltaic sandstones. Mapped traps or leads in the play can be estimated from Crawford et al's 1985 maps to be some 140 mi^2 in area. It is assumed, however, that complete mapping would reveal about 200 mi^2 of closure area (about 5 percent of the basin area). It is further assumed that a 20 percent success rate for tests of these traps and that the traps have an average areal petroleum-fill of some 15 percent. Under these assumptions, if reservoirs are equal to that of the most favorable case encountered, that of the Tacutu No. 1 wildcat, i.e, 70 ft (21 m) of 10 to 15 porosity, the calculated oil resources would be about .022 BBO and .240 TCFG (assuming an average depth of 6,000 ft [2,000 m]). However, none of the mapped traps or leads are within the presalt delta areas, and only 20 percent are within the postsalt deltas, the two principal areas where reservoirs may be expected. On this basis the estimate of the amount of oil resources of the deltaic sandstones would be reduced to 10 percent or .022 BBO and .024 TCFG. The fractured basement/volcanics play would be minor play. By areal analogy to the synrift fractured volcanics play of the Campos basin, petroleum resources amount to .004 BBO and .011 TCFG. Estimated total undiscovered oil and gas for both plays amount to .026 BBO and .034 TCFG.

C. Brazilian Interior Sag Basins

There are four major interior sag basins in Brazil: Solimoes Amazonas, Parnaiba, and Parana (fig. 2). In contrast to the Mesozoic and Tertiary marginal and interior rift basins these basins are primarily Paleozoic basins. Although there has been considerable exploration drilling, only the Solimoes basin has produced gas and oil. The Parecis, Alti Tapajos and Soa Francis basins, which appear to have no or negligible amounts of petroleum, are not discussed. The Solimoes basin, where the most exploration has taken place and where there are the most data, is discussed first.

Solimoes

Area: 232,000 mi^2 (600,000 km^2) of which the play area is some 116,000 mi^2 (300,000 km^2), i.e. the extent of the Paleozoic strata (fig. 87).

Original Reserves: .037 BBO 2.0 TCFG (Estimated from Petrobras in-place reserves of .123 BBO and 2.505 TCFC)

Description of area: The Solimoes basin approximately occupies the southern side of the valley of the Solimoes River (Upper Amazonas River) between the Guyanas and Brazilian (or Guapore) Shields (fig. 87). It is separated from the Amazonas basin on the east by the transverse Purus Arch (some 60 mi [100 km] west of Manaus) and on the west from the Acre basin by the transverse Iquitos Arch (which passes through Iquitos, Peru). There are two subbasins, the Jurua subbasin on the east and the Jandiatuba basin in the west, separated by the Carauri syndepositional high.

Stratigraphy

General. The basin-fill's maximum thickness is 12,000 ft (3,600 m) of which one third (4,000 ft, 1,200 m) is composed of Jurassic (and Triassic) diabase sills. The largely marine sedimentary rocks (Ordovician through middle Carboniferous) transgressed into the basin from the Andean geosyncline to the west (fig. 88). The first transgression in the Lower Ordovician advanced a short distance into the basin. It is overlain by the principal transgression from the west, the Devonian to early Carboniferous wedge of sedimentary rocks, the major part of which is the Jandiatuba Formation largely of basinal dark shales which are very radioactive in the upper section. The lower section of the Jandiatuba Formation grades laterally into the basal sandstones, shales and phosphatic dolomites of the Bia Formation. The upper part of the Jandiatuba Formation, transgressing the Bia Formation, grades laterally into the Uere and Jaraqui Formations as well as basal sandstones of the Jurua (Monte Alegre) Formation. The Uere Formation (cherts and siliceous shales) and the overlying Jaraqui Formation (mudstones, shales, diamictite and dropstones) extend over Carauari High and the Jurua subbasin and become laterally more sandy (the Uruca Formation) as it approaches the distal part of the transgression at the Purus Arch. These formations of both subbasins are overlain by the regressive sandstones and interbedded siltstones and shales of the Lower Carboniferous Jurua (Monte Alegro) Formation which change to a continental, facies in the upper part. Overlying the Jurua Formation are evaporites and carbonates of a restricted marine environment, the Carauari (Itaituba/Nova Linda) Formation of the upper Carboniferous and Permian.

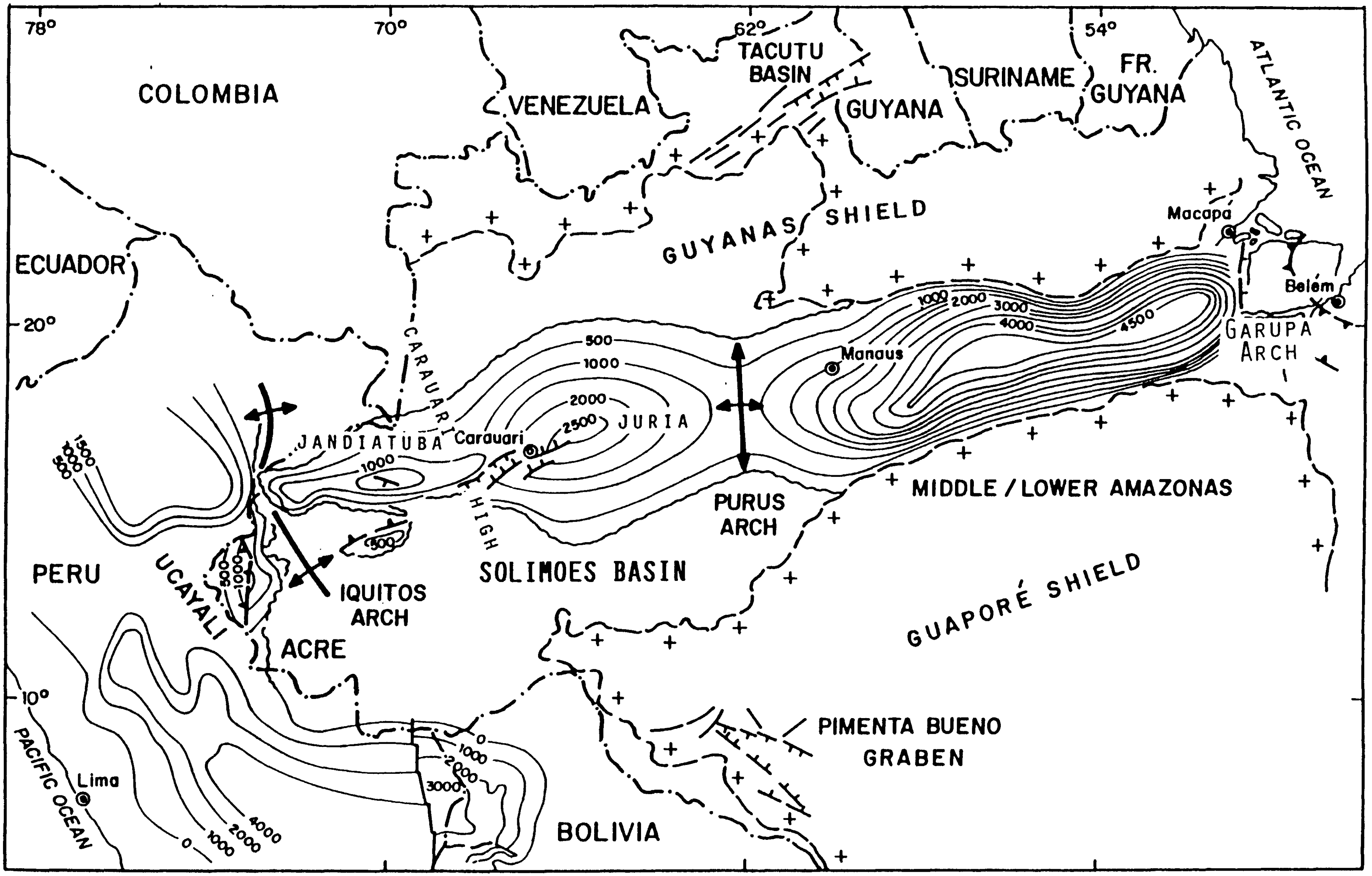


Figure 87 Structure map of the Solimoes and adjoining basins showing the Jandiatuba and Juria subbasins and separating Carauari high (modified from Neto and Tsubone, 1988).

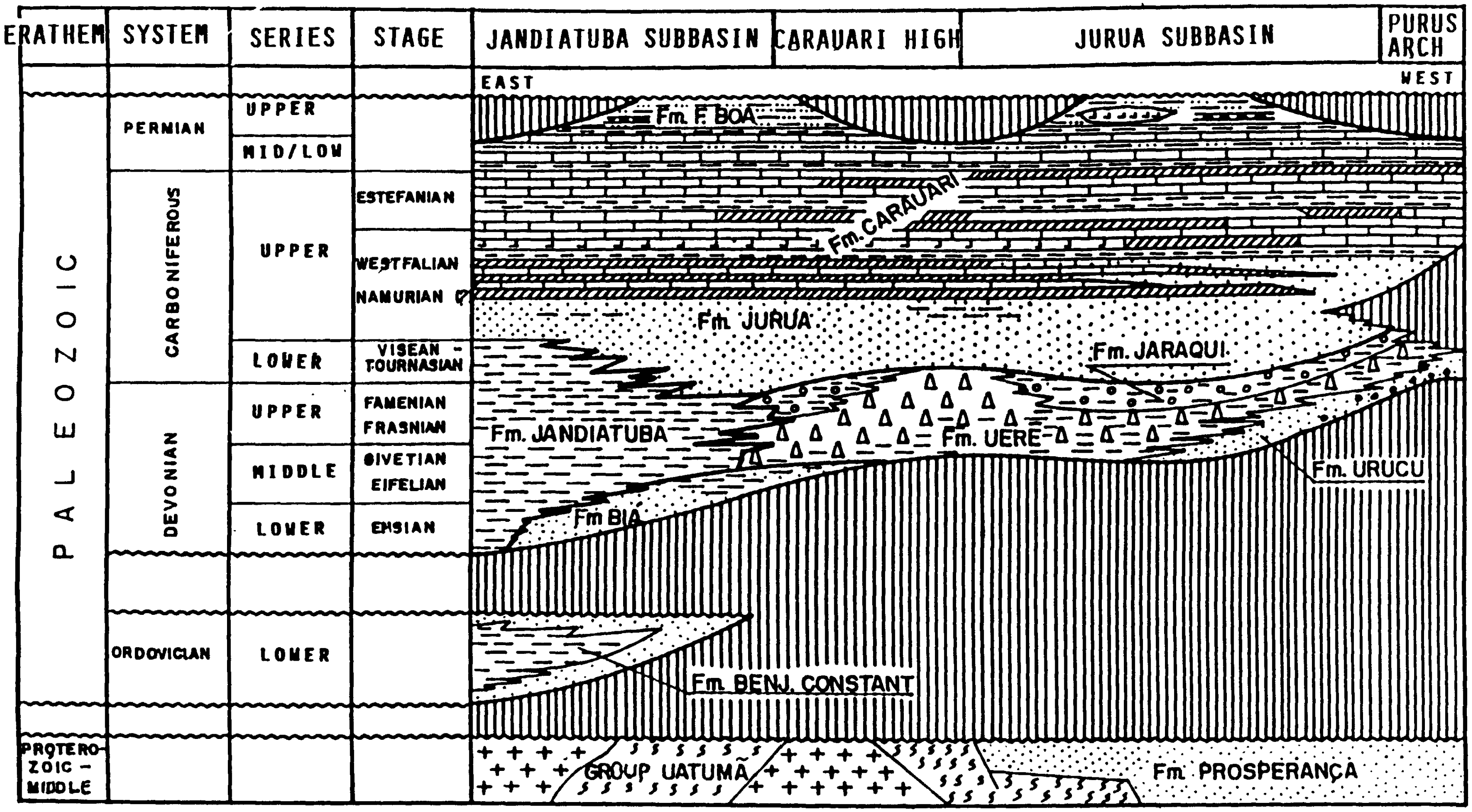


Figure 88 Stratigraphic column and lithostratigraphic chart of the Solimoes basin (modified from Castro and Silva, 1990).

Largely during the Jurassic there was a massive intrusion of diabase dikes and sills such that the total thickness of the sills make up one third of the stratigraphic section (not shown in the Figure 88 stratigraphic section). Overlying the Paleozoic basin, and overlapping extensively on to the basement is a thick middle to upper Cretaceous and Tertiary sequence of fluvial and lacustrine sediments.

Source. The main source section is the Devonian shales. In the Jandiatuba subbasin there is 230 ft (70 m) of radioactive Devonian Jandiatuba shales with an average TOC of 5 percent ranging to 8 percent (Brazil, 1990). These organically rich shales in the equivalent Uere and Jaraqui Formations, extend over the entire Solimoes basin.

The relatively shallow source shales of the Solimoes basin appear to be either thermally mature or senile, as surmised from available literature, indicating a thermal zone of oil generation too shallow given the usually low thermal gradient for interior sag basins. The probable explanation is a post Jurassic-pre Aptian period of uplift and erosion (see Structure) which presumably removed some thousands of feet of strata. The massive diabase intrusives also affect the thermal maturity of the sediments and are a key factor in determining the oil versus gas generation capability of the source shales. The Solimoes hydrocarbon production is limited to the Jurua Subbasin where it is in two trends; the gas-producing western Jurua trend and the gas and oil producing eastern Urucu trend (fig. 89). The principal difference in the geology of these two areas is that the strata of the gas-bearing Juria trend is intruded by a up to 800 ft (250 m) thick deep sill just above the main potential reservoirs (Juria or Monte Alegre Formation) (fig. 90) while the section of the oil and gas bearing Urucu trend is not (compare figures 90 and 91, see also figure 92). Figure 93 shows in some detail the increase in methane in the hydrocarbon and the increase in thermal maturation from mature to senility (i.e. oil-prone to gas-prone) within 1,800 ft (550 m) below a massive sill. This dependance of maturation, and therefore gas or oil generation, on the distribution of intrusives adds another variable to exploration of the Solimoes as well as other Brazilian Paleozoic interior sag basins. Because of the unknown amount of probable post-Paleozoic, pre-Late Cretaceous erosion and the effects of intrusives on the source rock maturation it is difficult to determine the time of generation and migration, but it probably occurred before the pre-Late Cretaceous unconformity and therefore approximately contemporaneous with the formation of the primary structural closures.

Of special concern is the presence of H_2S in the sandstones interbedded with the evaporites at the base of the Carauri Formation which is ascribed to the thermal action of the intrusive diabase sills on the anhydrite (Castro and Silva, 1990). Significantly the H_2S has only been encountered in the Juria trend and Carauari High where the deepest diabase sill adjoins the

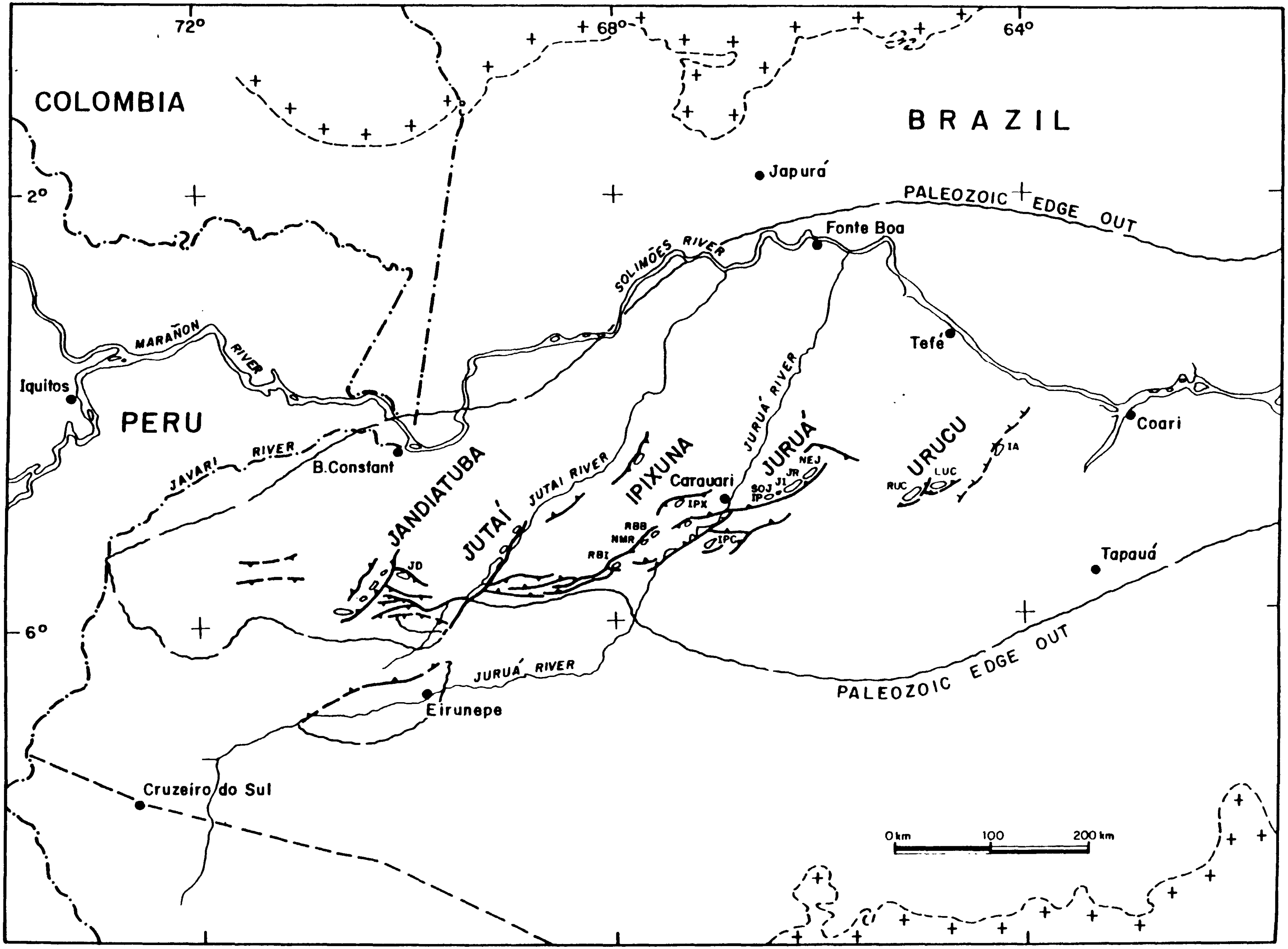


Figure 89 Map of the Solimoes basin structural framework showing the major wrench zones with some of the accompanying transpressional folds and reverse faults (from Neto and Tsubone, 1988).

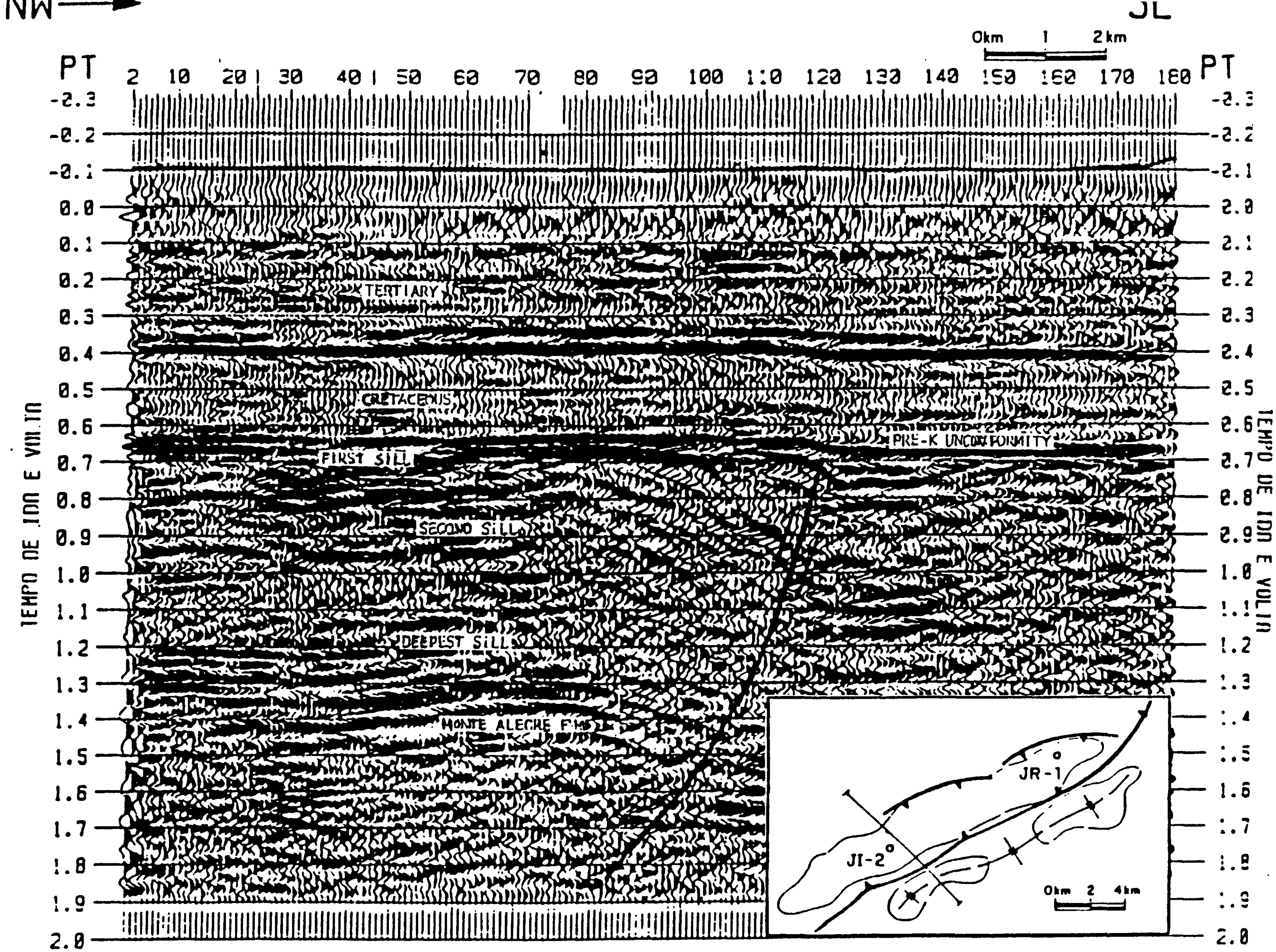


Figure 90 Seismic profile across the gas-bearing Jurua trend of the Solimoes basin showing the pre-Cretaceous transpressional structure and the deepest diabase sill adjacent the Monte Alegre (Jurua) Formation reservoirs (from Neto and Tsubone, 1988).

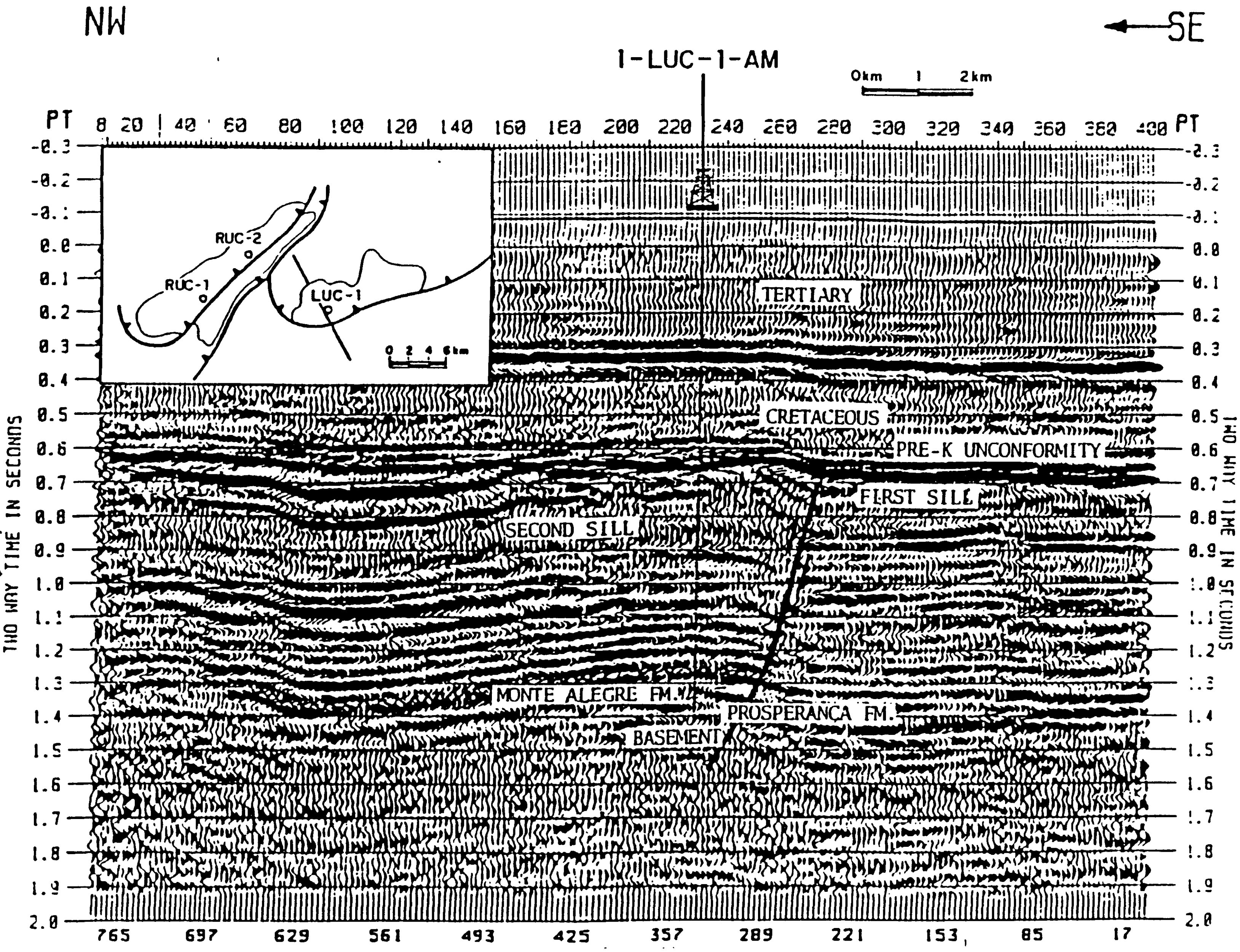


Figure 91 Seismic profile across the oil and gas-bearing Urucu trench of the Solimoes basin showing the pre-Cretaceous transpressional structure, the diabase sills and the principal reservoirs of the Monte Alegre (Jurua) Formation (from Neto and Tsubone, 1988).

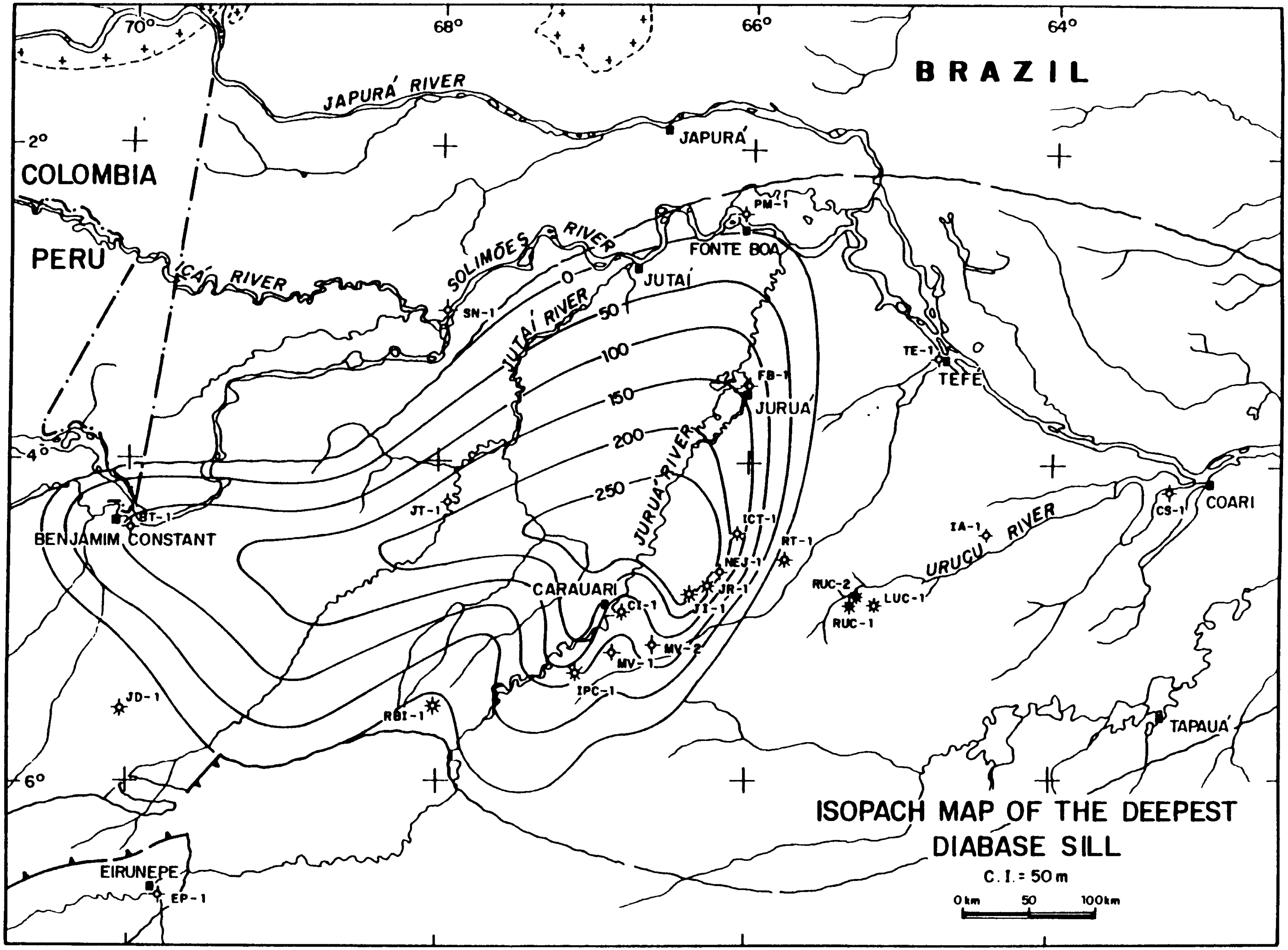


Figure 92 Isopach map of the deepest diabase sill of the Solimoes basin showing its relation to the gas-bearing Jurua trend versus the oil and gas-bearing Urucu trend (from Neto and Tsubone, 1988).

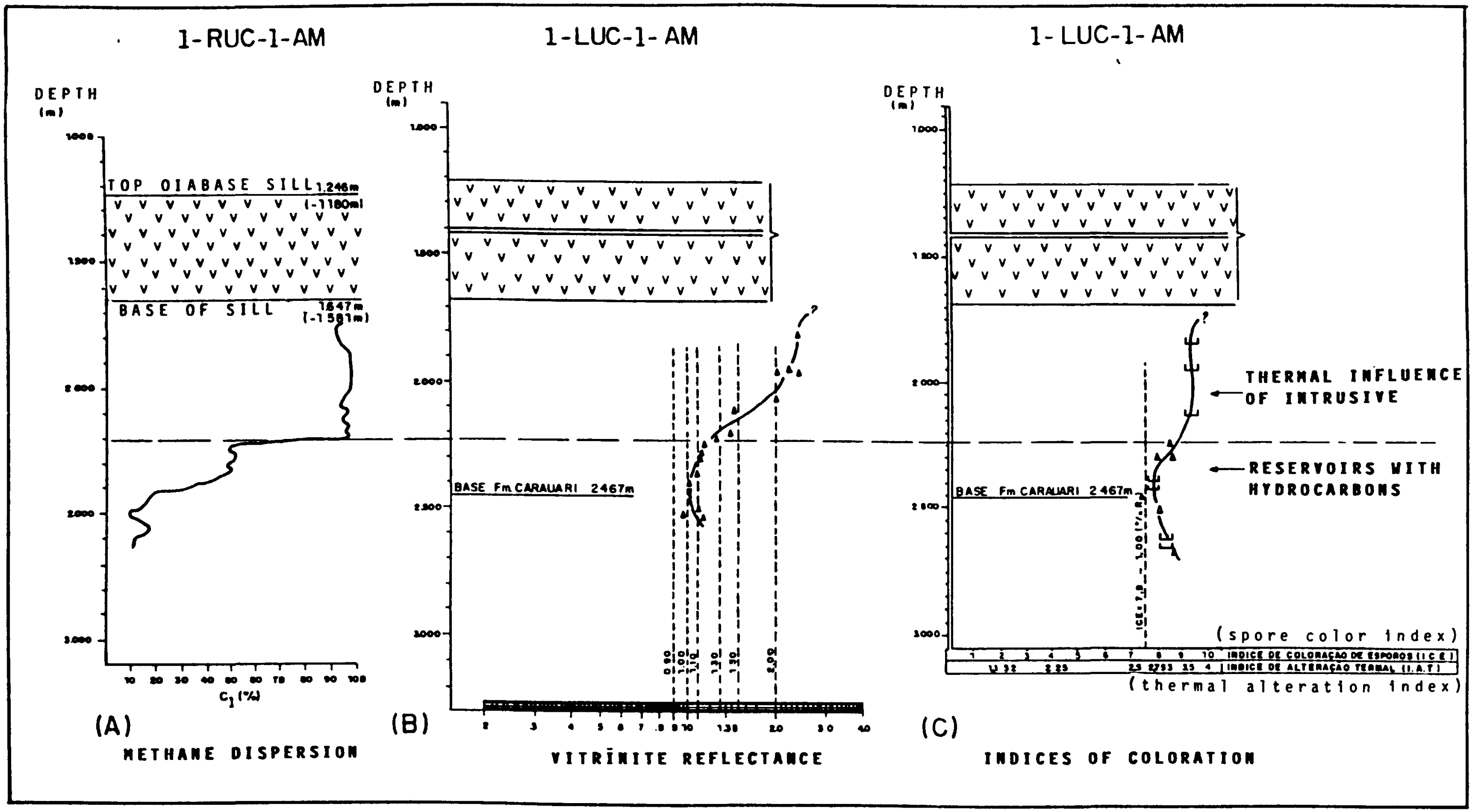


Figure 93 Diagram showing the thermal effects of Solimos basin diabase sills (A) methane dispersion, (B) vitrinite reflectance, and (C) coloration indices (from Castro and Silva, 1990).

principal reservoirs of the Jurua (Monte Alegre) Formation (figs. 90 and 92).

Reservoirs and Seals. The principal reservoirs are in the Jurua (Monte Alegre) Formation and the lower part of the Carauari Formation. The reservoirs are sandstones of continental origin which in the Urucu area typically occur at depths of 8,000 ft (2,400 m) with pay thicknesses averaging 80 ft (25 m). Porosity ranges from 15 to 22 percent, permeability ranges from 60 to 2,100 md. Reservoir drive is gas cap and water influx (OGJ, 1990).

The seals are composed of shales that are interbedded with the reservoir sandstones in the Jurua Formation and evaporites of the Carauari Formation.

Structure

The Solimoes basin is part of an east-northeast trending elongate sag which extends across Brazil approximately coincident with the Amazon River valley. The basin's elongate pattern suggests that it is formed over a rift zone. The Solimoes basin is separated from the rest of the sag trend by transverse arches in the west and east, referred to as the Iquitos and Purus Arches respectively (fig. 87). The Paleozoic sedimentary rocks, especially the Permo-Carboniferous section, are closely correlatable to those in other Brazilian sag basins and it appears that these sedimentary rocks were, at least in part, a coherent marine platform deposit extending over the Brazilian shield and that most of the sag subsidence must postdate the Paleozoic (Permian) and predate continental Cretaceous (Aptian) strata which truncates the low-dipping Paleozoic strata flanking the sag. During this hiatus there appears to have been a period of uplift and deep erosion indicated, not only by the missing Paleozoic strata from the basin flanks, but by the absence of the Jurassic surface flows one would expect to accompany the massive Jurassic diabase intrusives. Such flows are very thick in other interior sags of Brazil, e.g. the Parana basin. This uplift and deep erosion during the post-Jurassic-pre-Aptian appears to be supported by a shallow, perhaps pre-erosion-established, thermal zone of petroleum generation.

Probably during this period, coeval with the final rifting prior to the continental separation, regional wrenching with accompanying transpressural folding and faulting occurred, possibly in accommodation to the inequalities of the continental extension, during the early Cretaceous after the diabase intrusive and prior to the Aptian (figs. 90 and 91). There is good evidence, however, that some wrenching tectonics continued up through the Tertiary. This wrenching is of particular importance to the petroleum prospects of the Solimoes basin. Discovered to-date are five northeast to north-northeast-trending, mainly right-lateral wrench fault zones (Jandiatuba, Jutai, Ipixuna, Jurua, and Urucu) extending diagonally through the basin (fig. 89). They are accompanied by transpressional en echelon drag folds and reverse faults (figs. 89, 90, 91) which are the traps of the basin. Two of the five trends have produced hydrocarbon: the Urucu trend, as of 1990, 5 oil and gas discoveries and the Jurua trend, 10 gas discoveries (Brazil, 1990). The fold structures average 4 mi^2(10 km^2) in areal extent with an average vertical closure of 400 ft (120 m) (OGJ, 1990).

Generation, Migration and Accumulation. It appears that generation, and migration must have begun in the early Cretaceous, when the basin was deeper, prior to the post-Jurassic-pre Aptian uplift and deep erosion, as evidenced by the shallow vitrinite-reflectance-indicated thermal zone of petroleum generation. Migration, therefore, would be somewhat contemporaneous or prior to the main wrenching which formed the transpression traps of the Solimoes basin in the post-Jurassic-pre Aptian period.

Plays. The primary, and perhaps only viable, play of the Solimoes basin is the folds and fault closures associated with the east-northeast trending wrench system through the basin. Other plays of relatively minor potential are fault blocks and drapes on the flanks and possibly in the pre-Devonian rift phase.

Exploration History and Petroleum Occurrence. Some exploration began in 1917, but in the late fifties and early sixties a more sustained exploration led to the drilling of 16 stratigraphic holes along the rivers; results were discouraging and exploration was suspended. In the early seventies exploration was resumed using improved seismic techniques which led to the 1978 discovery of the Jurua gas trend and the 1986 discovery of the Urucu oil and gas trend. The Jurua gas trend (as of 1990) (fig. 89) had estimated reserves of 1.07 TCFG and the Urucu trend .037 BBO and .932 TCFG (estimated from Petrobras in-place reserve figures, Brazil, 1990).

Estimation of Undiscovered Oil and Gas

On the basis of the immature exploration, to date, with large unexplored areas, and the likelihood of more north-northeast-trending wrenches being found on both sides of the basin, it is assumed that the equivalent of two more wrench zones similar to the Jurua and Urucu trends will be discovered. On this assumption, undiscovered oil and gas should amount to .04 BBO and 2.0 TCFG.

Amazonas Basin

Area: 200,000 mi^2 (500,000 km^2)

Original Reserves: nil

Description of Area: The area occupies the central stretch of the Amazon River valley between the transverse Purus arch (100 mi, 160 km, west of Manuas), separating it from the on-trend Solimoes basin to the west and the transverse Garupa Arch separation from the Foz do Amazonas basin (figs. 87, 94).

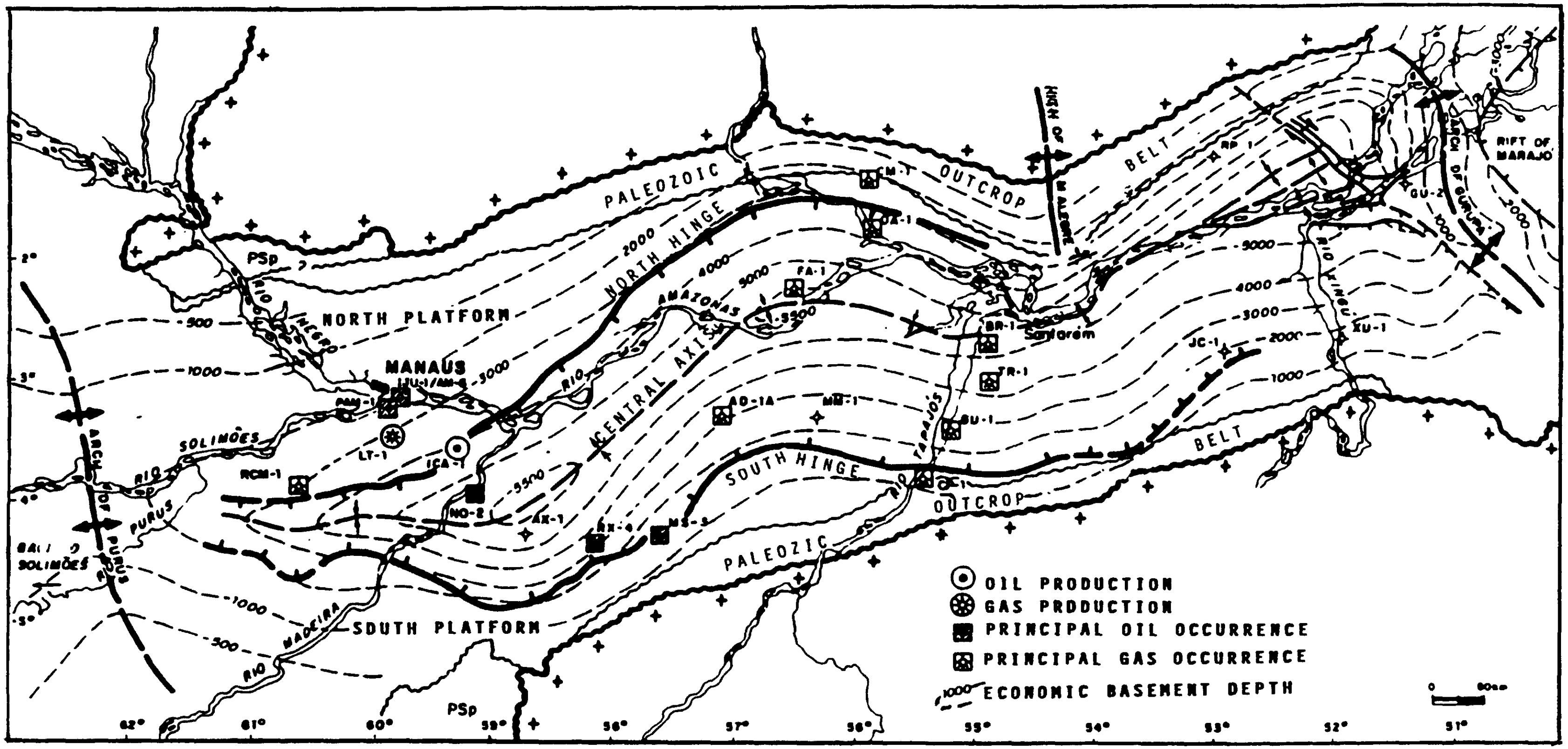


Figure 94 Simplified depth-to-economic basement map of the Amazonos basin showing the main hydrocarbon occurrences (modified from Neves, 1990).

Stratigraphy

General. The stratigraphy (fig. 95) is very similar to that of the Solimoes basin to the westwards (and seawards in Paleozoic time). The stratigraphic column may be divided into four sequences. The pre-Devonian sequence is 3,000 ft (1,000 m) of alternating fluvial, marine and glacial clastics (largely missing in the Solimoes basin).

The Devonian-early Carboniferous sequence is a wedge of sediments which is an eastward onlapping continuation of the transgressive sequence of clastics well-displayed in the Solimoes basin (fig. 88). The sequence is shallow marine becoming deltaic eastwards with some marine-glacial beds and contains up to 850 ft (260 m) of organically rich radioactive shales, Curua Formation, Barrierinhas Member (equivalent to part of the Jandiatuba and the Jaraqu Formations of the Solimoes basin).

These formations are overlain by a late Carboniferous/Permian sequence of fluvial clastics, eolian sandstones and shallow marine in the basal portion, the Faro and Monte Alegre Formations (equivalent to the Jurua Formation of the Solimoes basin). A system of predominantly evaporites and fluvial and lacustrine shale are near the top of the sequence.

Unconformably overlapping the Paleozoics and basement is a sequence of Cretaceous and Tertiary continental sediments.

As in the Solimoes basin, a great portion of the Paleozoic sedimentary column is occupied by massive Jurassic diabase sills.

Source: The principal source rocks in the basin are carbonaceous black marine shales, the Devonian Barrierinhas member of the Curua Formation. The areal limit of source shales is shown in figure 96. The principal organic material is amorphous type II kerogen. The TOC ranges from 3 to 8 percent by weight (Neves, 1990). The thermal maturity of the source shales varies over the basin, ranging from immature on the flanks of the western basin, mature further basinwards, and senile over the eastern two thirds of the basin (fig. 96). Diabase intrusions, which locally influence the maturation of the source shales, are in greater concentration in the eastern basin contributing to elevated levels of maturity and its proneness to gas, while the western region is prone to both liquid and gas accumulations.

Reservoirs and Seals: The principal reservoirs of the basin are sandstones within the Monte Alegre Formation (Jarua Formation of the Solimoes basin). These continental sandstones change upwards into a thick (over 3,000 ft [1,000 m]) evaporite-bearing sequence. The Monte Alegre Formation ranges in thickness up to 460 ft (140 m) in the axial part of the basin, and thins towards the flanks where the better reservoir sandstones are concentrated (fig. 97). No

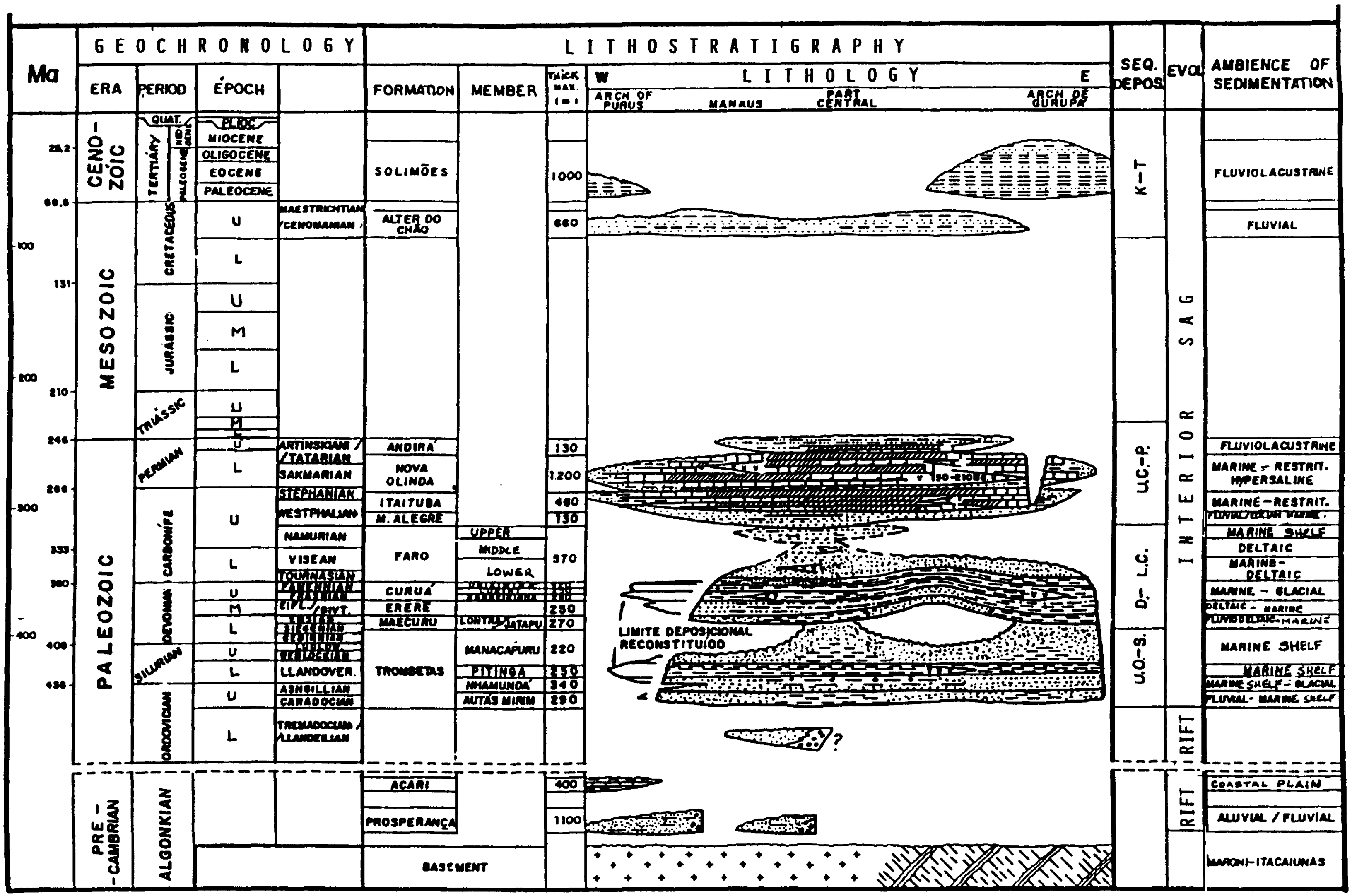


Figure 95 Stratigraphic chart of the Amazonas basin (from Neves, 1990).

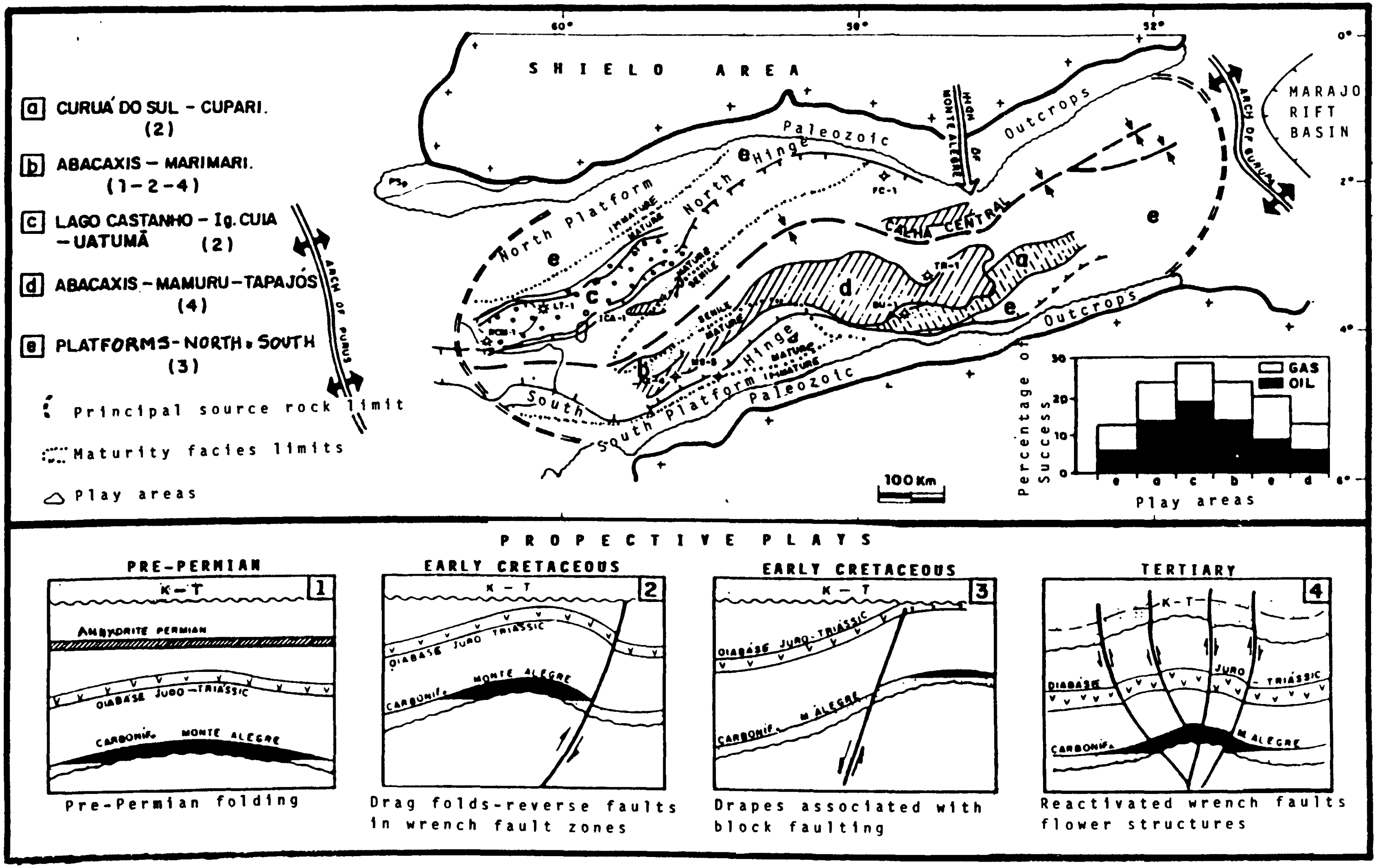


Figure 96 Map of Amazonas basin showing distribution of mature petroleum source rock and exploration plays plus a diagrammatic representation of the four main trap types (modified from Neves, 1990).

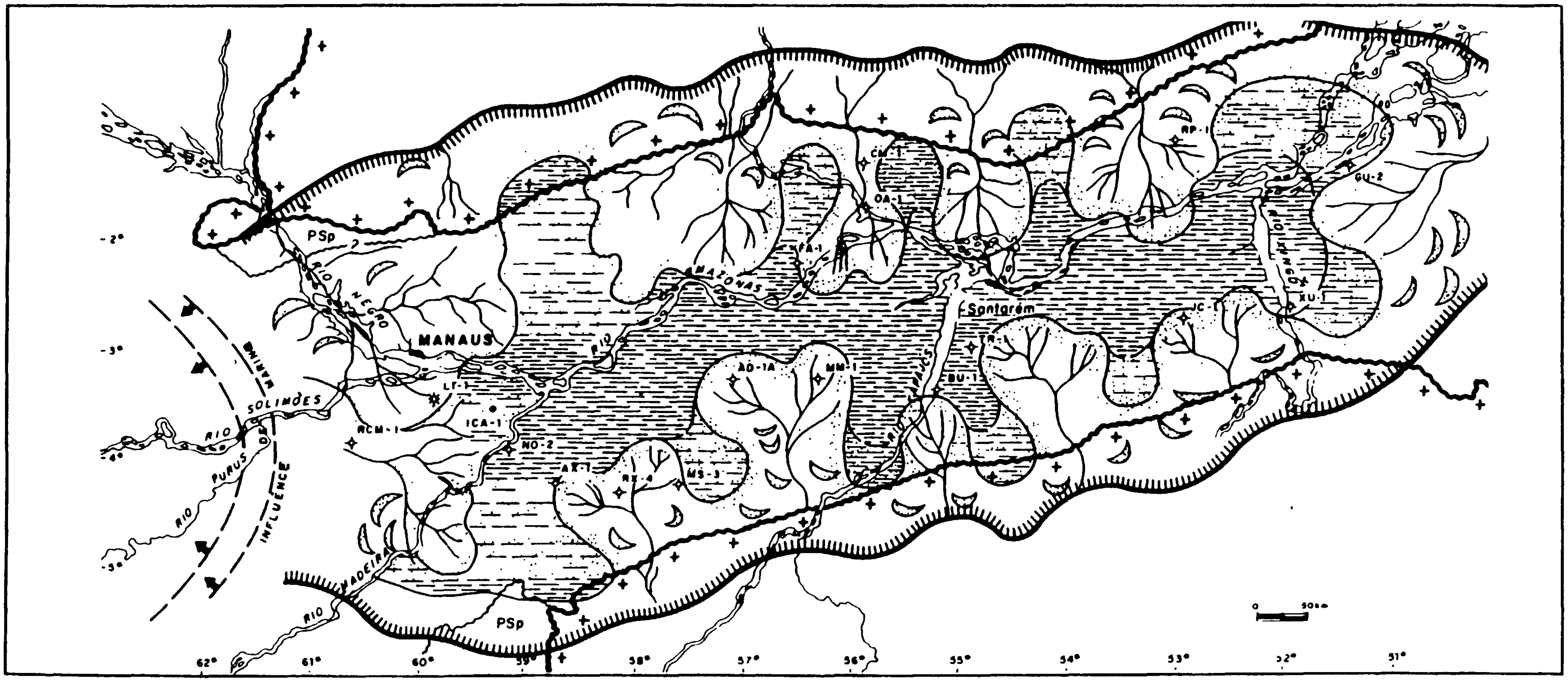


Figure 97 Paleoenvironmental map of the Amazonas basin indicating the probable location of better sandstone development in the main reservoir objective unit, the Monte Alegre Formation (modified from Neves, 1990).

reservoir parameters are available but equivalent sandstones in the Solimoes basin producing areas have pays averaging 80 ft (25 m), porosities of 15 to 22 percent and permeabilities of 60-2,100 mds. Reservoir drive is gas cap and water influx (OGJ, 1990).

Structure

The structure is similar to the on-trend Solimoes basin; it is an elongate, east-northeast-trending interior sag basin, probably following an earlier rift system. The transverse Purus and Gurupa Arches separate it from the Solimoes and Foz do Amazonas basin respectively (figs. 94 and 96). The central portion depth averages over 10,000 ft (3 km) ranging to over 18,000 (5.5 km). The eastern part of the basin tended to uplift and the western part to subside from early Carboniferous time. There is a wide (to 90 mi [150 km]) platform on either side of a central trough (figs. 94, 96).

According to Neves (1990) there are four types of traps in the basin: 1) Pre-Permian folds, 2) Early Cretaceous drag folds associated with reverse faults, 3) Early Cretaceous domes or drapes associated with normal fault blocks, and 4) Tertiary closures associated with wrenching. Areas of the basin in which these traps occur is shown in figure 96). Pre-Permian closures, as well as the Early Cretaceous domes or drapes of the southern and northern platforms, hold little promise based on success to date. The areas of transpressure, i.e. drag folds and associated faults are "a", "b", "c", and "d" of figure 96 where wrench faults or structures associated with wrenching have been detected by seismic surveys (Neves, 1990) are more prospective.

On the south side of the basin, areas "a" and part of "b", have typical post-Paleozoic-pre-middle Cretaceous drag folds and associated faults which are similar to producing fields of the Solimoes basin. Closure areas and heights vary from an average of 8 mi^2 (20 km^2) and 165 ft (50 m) in area "a" to 4 mi^2(10 km^2) and 150 ft (45 m) in area "b". The intervening area "d" is also a wrench zone but the age of the wrenching or reactivated wrenching extends into the Tertiary (Neves, 1990).

On the north side of the basin area "c" is another zone of transpression with the development of drag folds. Area "c" is considered the most attractive, since it is entirely within the area where the source shales are in the thermally mature zone. Furthermore, some non-commercial oil and gas discovery wildcats, 1CA-1 and LT-1 (fig. 94), were drilled in the area. The eastern three fourths of the basin is in the area of senile source shales so that only gas may be expected.

Generation, Migration, and Accumulation. Figure 96 suggests that in the eastern two-thirds of the basin, the relatively shallow source shales are thermally senile, indicates, as in the case of the Solimoes and other interior sag basins, that thousands of feet of section must have been removed prior to the middle Cretaceous sedimentation. This would presumably include thick Jurassic flows one would expect accompanying the massive Jurassic diabase intrusives. This shallow senility is also due in part to the very pervasive diabase intrusives. Probably the source shales reached generation burial depth in post Jurassic-pre-middle-Cretaceous time and migration began. Trap formation, as discussed, ranges from the pre-Permian to the Tertiary, but the traps of highest potential, the wrench associated folds and faults, appear to have formed about contemporaneously with the beginning migration, that is post Paleozoic-pre-Middle Cretaceous. It seems that the migration timing in relation to trap formation was optimum.

Plays. The principle plays all involve the same reservoir zone, the Carboniferous Monte Alegre Formation, the only variable being the type of structural trap. These four types are discussed under structure and shows diagrammatically in figure 96.

Exploration History and Petroleum Occurrence. After initial surveys, wildcat drilling began in 1953. By 1990 200 wells had been drilled of which 90 were wildcats. One oil and one gas non-commercial discoveries were made (1-CA and LT-1, figure 94). Five significant oil shows and seven gas shows were encountered.

Estimation of Undiscovered Oil and Gas

The Amazonas basin is analogous to the Solimoes basin in many respects, but may be somewhat less prospective and more gas prone since: 1) it appears to have a lower volume of marine source shales; 2) the source shale appears to senile over about two-thirds of the basin, and 3) judging from the wildcat pattern, similar trends to the Jurua and Jandiatuba have not yet been found. An estimate arrived at by an areal analogy to the Solimoes basin should be therefore discounted down to 50 percent for oil and to 60 percent for gas indicating the resources of the Amazonas basin to be .035 BBO and 2.07 TCFG.

Parnaiba

Area: 230,000 mi^2 (600,000 km^2)

Original Reserves: Nil

Description of Area:

This interior sag basin is located in northeastern Brazil south and inland of the Barrierinhas basin, bordered on the east by the ranges forming the eastern watershed of the Parnaiba River and approximately on the west by the Tocantins River. Its southern boundary is about latitude 11 degrees south) (fig. 98).

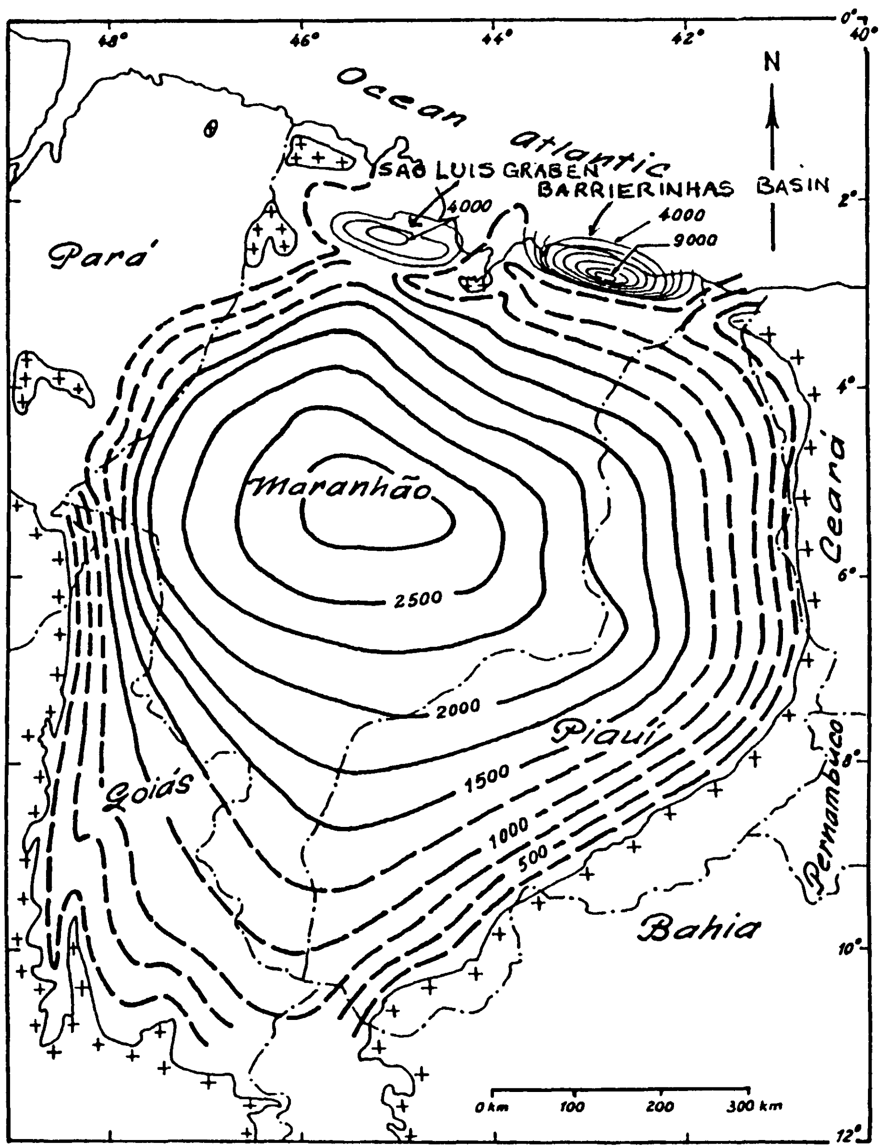


Figure 98 Isopach map of the total thickness of the Parnaiba basin and of the adjoining Barreirinhas basin and Sao Luis graben (modified from Bigarella).

Stratigraphy

General. The Paleozoic stratigraphy is similar and very correlatable to that of the Solimoes, Amazonas, and Parana basins indicating that during Paleozoic time (from Silurian onwards) Brazil was covered by a single platform of deposition.

The earliest sediments were pre-Silurian continental strata filling north-trending grabens under the sag (fig 99, 100). The basal unit of the sag sequence is the Silurian Serra Grande Group which consists of fluvio-deltaic, changing upwards to shallow marine, sediments. Sandstone reservoirs of the Ipu and Jalcos Formations of this group are secondary drilling objectives of the basin, the interbedded Tiangua Formation shales providing the source. Disconformably overlying the Serra Grande Group is the Devonian marine Candinde Group. The group consists of four alternating sandstone and shale formations, i.e. the Itaim sandstones, the Pimenteiras shales, the Cabecas sandstones, and the Longa shales. The potential sandstone reservoirs of the Itaim and Cabecas Formations are the principal drilling objectives of the basin and the adjoining Pimenteiras Formation contains the principal source shales of the basin. The Caninde Group lithology corresponds to the Devonian group of formations in the Amazonas and Solimoes basins. Conformably overlying the Caninde Group is the marine, changing upward to continental, Poti Formation of sandstone with some shale. Disconformably overlying the Poti Formation is the Balsas Group of mixed continental and restricted marine sediments. It has a lower section of continental fluvial to eolian sands (Piaui Formation), an intermediate section of interbedded dolomites, evaporites and eolian sands of upper Piaui, Pedra de Fogo, and Motuca Formations, and an upper section of continental fluvial-eolian sandstones (the Triassic Sambaiba Formation). The pre-Triassic portion of this group closely resembles the Carboniferous-Permian Monte Alegre-Itaituba-Nova Linda-Andera group of formations of the Amazonas basin and the Carboniferous-Permian upper Jurua and Carauri Formations of the Solimoes basin.

Thick (up to 500 ft [150 m]) Jurassic basalts cover a west central portion of the basin and Jurassic diabase sills of up to a combined thickness of 1300 ft (400 m) intrude the sediments, constituting about an eighth of the total section. Aptian restricted marine and marine sediments (Codo Formation), containing some dark, bituminous shales, cover by unconformity the northern part of the basin, thickening northwards to 1,600 ft (500 m).

Source. The principal potential source rocks of the basin appear to be the shales of the Devonian Pimenteiras Formation (of the Caninde Group) which reaches a thickness of over 1600 ft (500 m). As in the equivalent Devonian shales of the other interior sag basins these shales are highly radioactive. The TOC values are up to 6 percent. The type of kerogen is predominantly type II and III (Goes et al, 1990). A secondary potential source include the

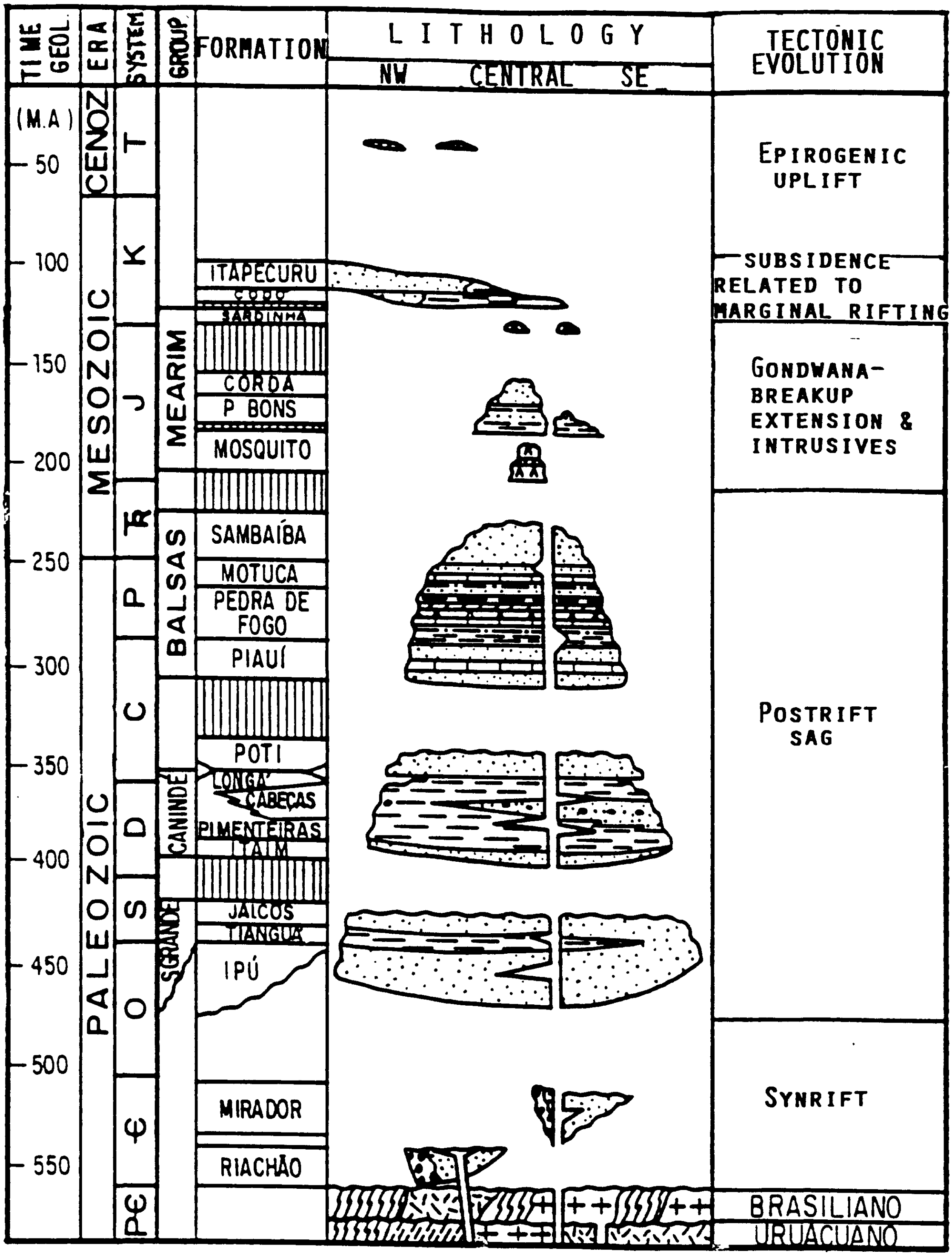


Figure 99 Stratigraphic column of the Parnaiba basin (modified from Goes et al, 1990).

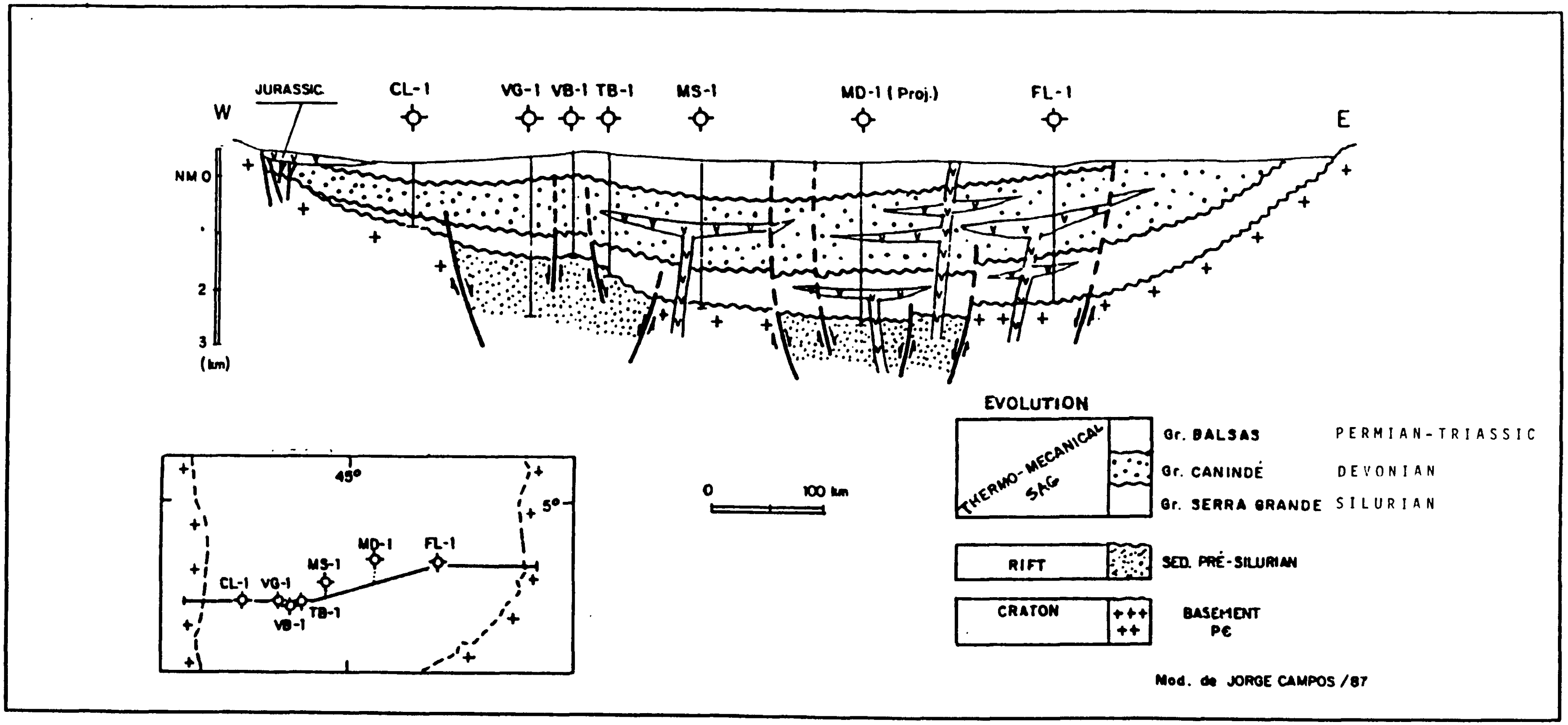


Figure 100 East-west geologic section across the Parnaiba basin (modified from Goes et al, 1990).

Tiangua shales of the Serra Grande Group and the Longa shales of the Caninde Group. A third organically rich shale of the Aptian Codo Formation is too shallow for sufficient maturity. As in the other Brazilian interior sags, the basin does not appear deep enough, given the low thermal gradient (1.07 degrees F/100 ft, 19.4 degrees C/Km, Zembruscki and Campos, 1988), to bring about sufficient thermal maturity to generate petroleum from the source shales. It appears that the basin may have once been deeper and that several thousand feet of sediment, including a thick volcanic sequence similar to that in the Parana basin, were removed by pre-Cretaceous erosion. The thermal maturity of the source shales is also strongly influenced by the presence of Jurassic diabase sills which can cause maturation or senility of the source shales. Figure 101 (Goes et al, 1990) indicates that more of the thermal maturity of the potential source rock may be caused by the heat of the diabase intrusives than by depth of burial. Figure 101 also indicates that the basin area underlain by thermally mature or senile source shale is only about 62,000 mi^2 (160,000 km^2), about 27 percent of the total basin area.

Reservoirs and Seals. The principal objective reservoirs of the Parnaiba basin are in the Caninde Group sandstones, that is in the Cabecas and Itiam Formation and in sandstone lenses within the Pimenteiras Formation. No reservoir parameters are available, but similar reservoirs in the only nearby sag basin where production is obtained, Solimoes, have pay thicknesses averaging 80 ft (25 m), porosity ranges of 15-22 percent, and permeabilities of 60-2,100 md. Reservoir drive is gas cap and water influx (OGJ, 1990). A secondary objective is the sandstones of the largely Silurian Serra Grande Group.

Seals are provided by the shales of the Longa Formation and perhaps by evaporites of the Permian Balsas Group which appear less developed than in the Solimoes basin.

Structure

The basin is essentially a Paleozoic interior sag slightly elongated in a northerly trend positioned over an earlier pre-Silurian northerly-trending rift zone (fig. 100 and 102). The sag began in early Silurian (or late Ordovician) with the deposition of the Serra Grande Group, followed by the Caninde Group.

After this deposition an Early Carboniferous deformation resulted in a number of east to northeast trending faults and closures such as exemplified by the structure traversed by seismic line 218RL-01 (figs. 102 and 103). In pre-Aptian time, probably Neocomian, northwest-trending high-angle wrenching or reverse faulting was mapped as exemplified by structure shown in seismic line 59RL-115 (figs. 102 and 104). These structures, however, may not have a similar origin to the long, regional, east-north east trends of wrench associated folds and reverse faults of the Solimoes and Amazonas basins.

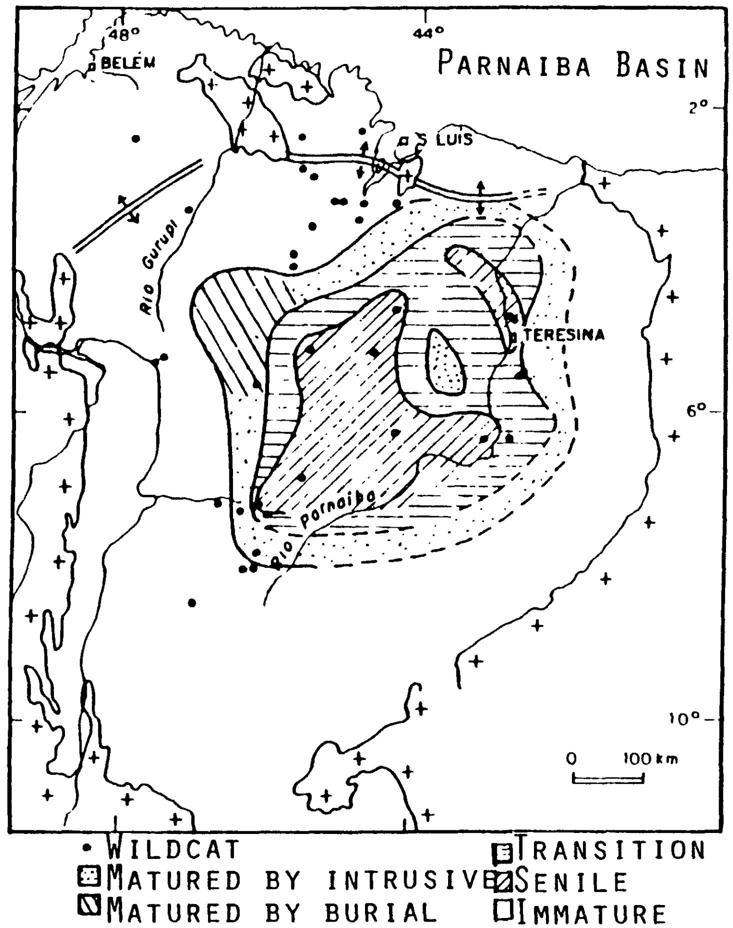


Figure 101 Maturation map of the Pimenteiras Formation of the Parnaiba basin (modified from Goes et al, 1990).

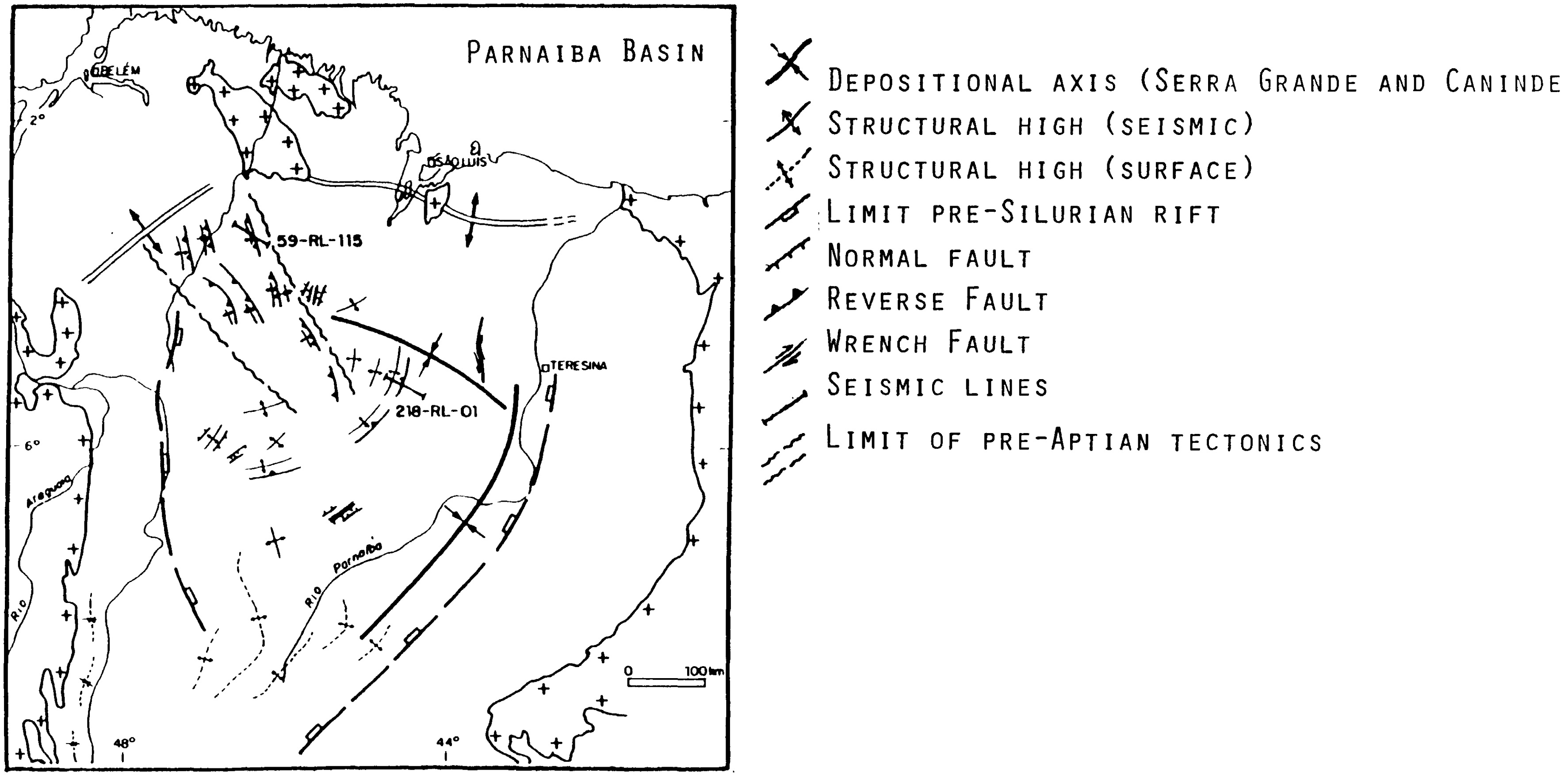


Figure 102 Map of the main structural features of the Parnaiba basin (modified from Goes et al, 1990).

Generation, Migration, and Accumulation. Petroleum generation and migration began prior to the post-Jurassic pre-Middle Cretaceous uplift and erosion, probably in the early Cretaceous. The times of the principal potential trap formation appear to be early Carboniferous and pre-Middle Cretaceous (figs. 102, 103 and 104). Thus, the temporal relationship between petroleum generation and structural trap formation is optimum for the pre-middle Cretaceous features, but possibly too late for the early Carboniferous potential traps.

Plays. In this basin where traps appear to be the limiting factor to any significant petroleum accumulation, the plays are restricted to two trap types, early Carboniferous structures, and pre-middle Cretaceous (figs. 102, 103 and 104). The pre-Middle Cretaceous traps appear more promising by analogy to the producing traps of the Solimoes basin and because they formed contemporaneously with migration.

Fault and drape closures occur in the pre-Silurian rift phase of the basin, but the source and reservoir capability of the associated strata are unknown and, in any case, the source rock would be significantly overmature.

Exploration History and Petroleum Occurrence. Exploration of the basin, began in the fifties with surface geology, gravity survey, local seismic surveys and 22 wildcats, detecting some oil and gas shows. The work was interrupted in 1966 and began in 1975 with more comprehensive seismic and drilling programs; by 1990 a total of 36 holes had been drilled of which 31 were wildcats, but only six involved the use of seismic control. Trap detection appears to be the principal exploration problem. Various indications of oil and gas were found including one sub-commercial gas discovery and one significant gas show and one significant oil show, but locations are unavailable (Goes et al, 1990).

Estimation of Undiscovered Oil and Gas

The stratigraphy and to a lesser extent the structure of the Parnaiba basin is similar to that of the Solimoes basin, but there are some differences that tend to downgrade any analogy as to the petroleum resources of the Parnaiba basin in respect to the Solimoes basin:

1) Significant shows in the Parnaiba basin have been so far limited to the Devonian sediments, none having been found in the Carboniferous sandstones, which are the main reservoirs of the Solimoes basin. The evaporite seals of the Solimoes appear to be absent or much less developed.

2) Exploration to date has been unsuccessful after some 31 wildcats. Before this stage had been reached in the Solimoes basin, the Jurua gas trend appears to have been discovered.

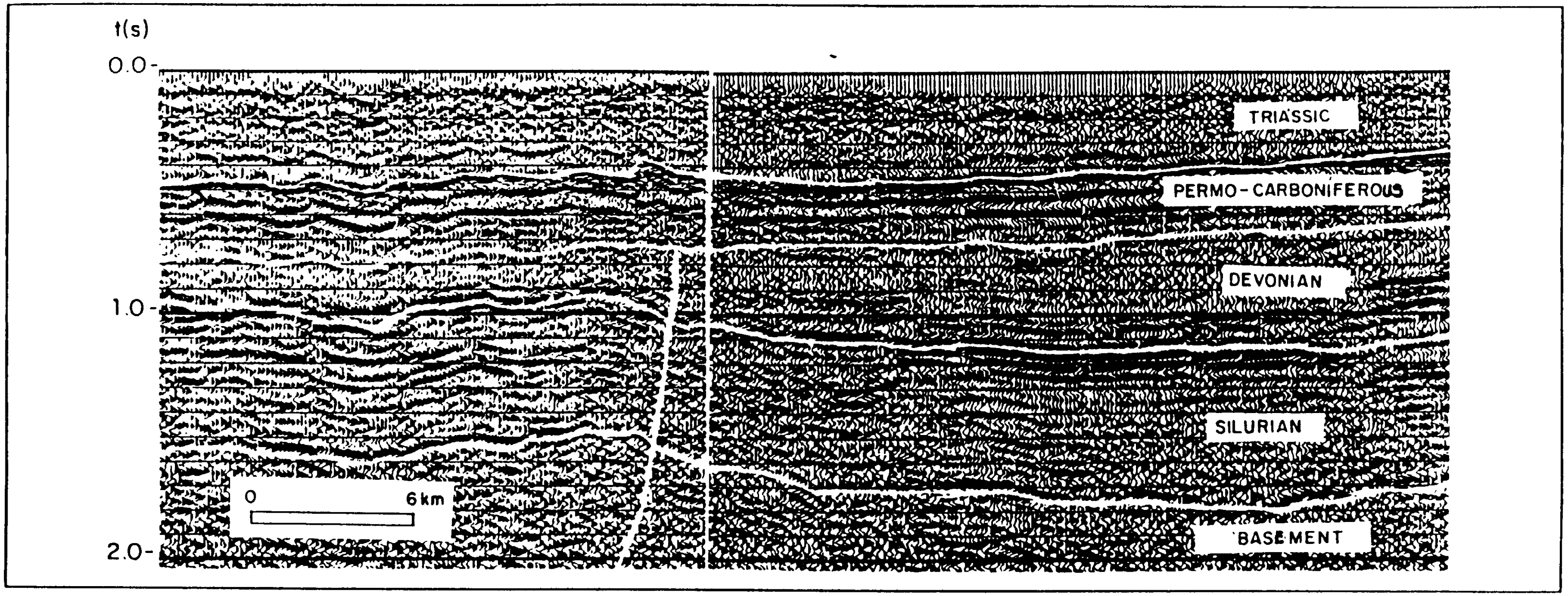


Figure 103 Northwest-southwest seismic profile 218-RL-01, in the Parnaiba basin showing Early Carboniferous tectonics. Location figure 102 (modified from Goes et al, 1990).

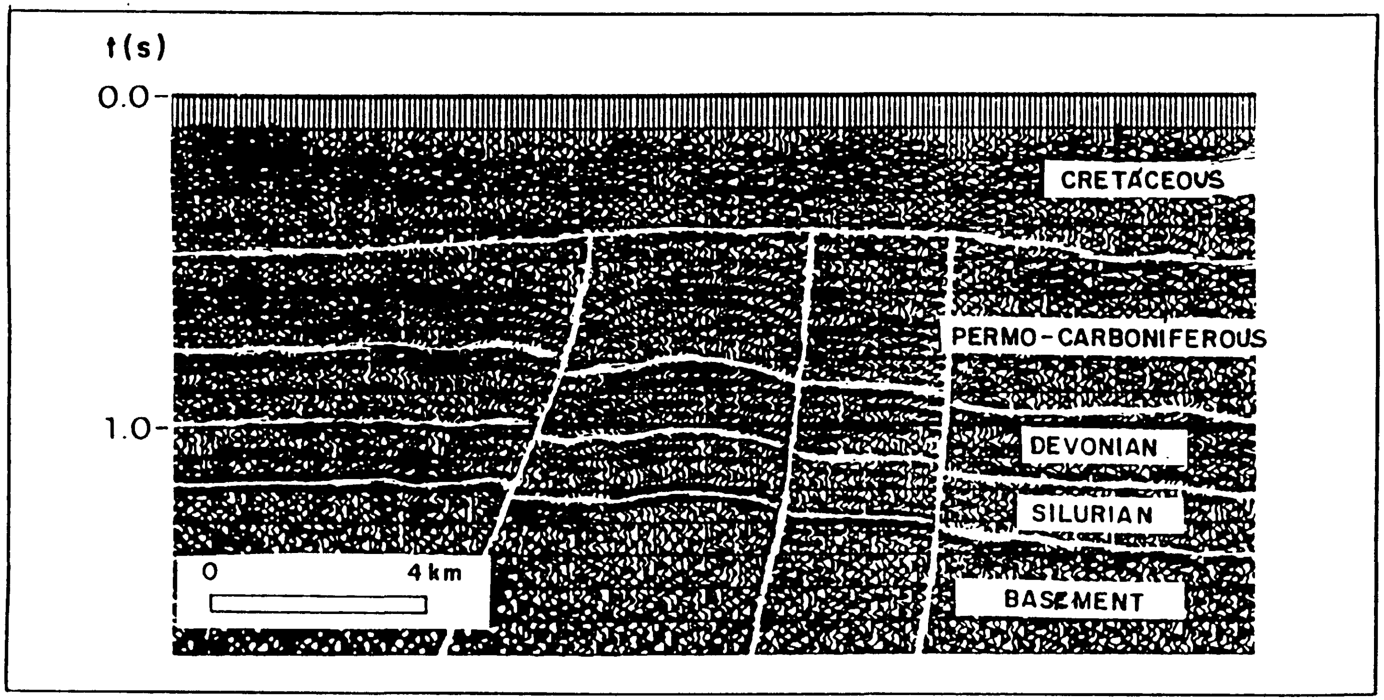


Figure 104 Northwest-southeast seismic profile 59-RL-115 in the Parnaiba basin showing post-Paleozoic - pre-Middle Cretaceous tectonics. Location figure 102 (modified from Goes et al, 1990).

3) No extensive (up to some 300 mi, 500 km) regional, straight zone of wrenching with accompanying folds and thrusts such as those mapped in the Solimoes basin appear present.

4) The principal source rock is immature over about 73 percent of the basin while source rock of the Solimoes basin is mature or overmature over most of the basin, excepting the flanks.

On these bases, an areal analogy to the petroleum resources of the Solimoes basin should be discounted or reduced by probably 25 percent for lack of similar favorable trap structure, by another 25 percent for less thermal maturity of the source rock, and by an additional 15 percent for the probable lack of comparable Permian seals. Application of these reductions to the areal analogy to the Solimoes basin, indicates that the petroleum resources of the Parnaiba basin are .037 BBO and 1.9 TCFG.

Parana Basin

Area: Total 620,000 mi^2 (1,600,000 km^2)

Brazil 390,000 mi^2 (1,000,000 km^2)

Argentina 160,000(?) mi^2 (415,000[?] km^2) indefinite boundary

Paraguay 30,000 mi^2 (75,000)

Uruguay 40,000 mi^2 (100,000)

Original Reserves: Nil

Description of area: The Parana basin approximately coincides with the watershed of the upper Parana River, occupying the southeastern corner of onshore Brazil (about 1 percent of Brazil), the eastern 20 percent of Paraguay, the northwestern 50 percent of Uruguay, and the northeastern corner (4 percent) of Argentina (fig. 105). The Parana basin joins the shallow Chaca basin of Argentina in the southwest; the lower Parana River is rather arbitrarily taken to be the boundary between the two basins.

Stratigraphy

General. The stratigraphic section is up to 23,000 ft (7,000 m) thick including thick sills and volcanics (fig. 106, 107). The stratigraphy is similar in some respects to the other Brazilian continental sag basins in that the prospective section is largely Paleozoic clastics.

The Paleozoic stratigraphy of the Parana basin is divided by unconformities into three groups: a Silurian, a Devonian, and a Permo-Carboniferous sequence. These are approximately equivalent to the Serra Grande, Caninde and Balsas groups of the Paranaiba basin

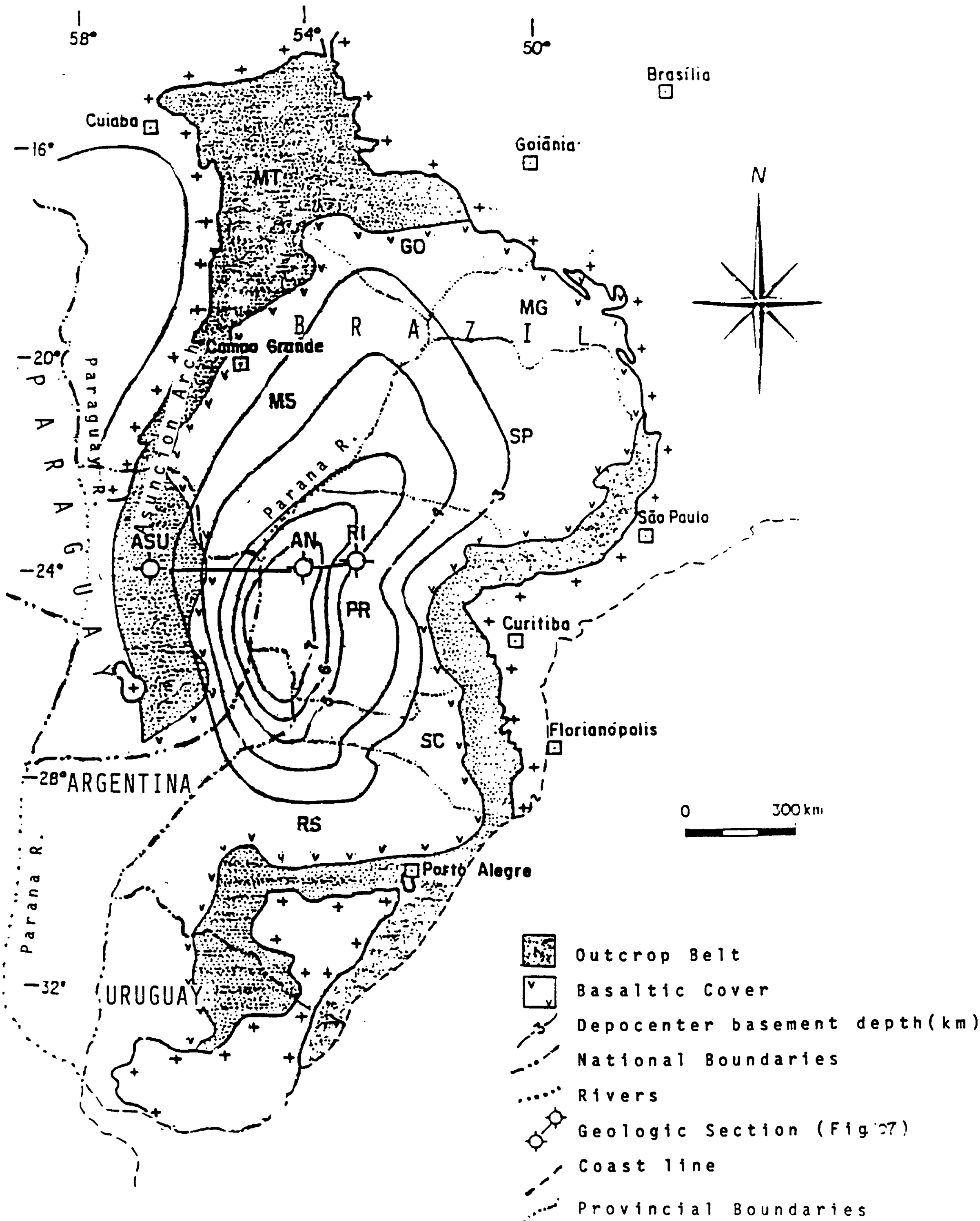


Figure 105 Location map of the depocenter area of the Parana basin (modified from Milani et al, 1990).

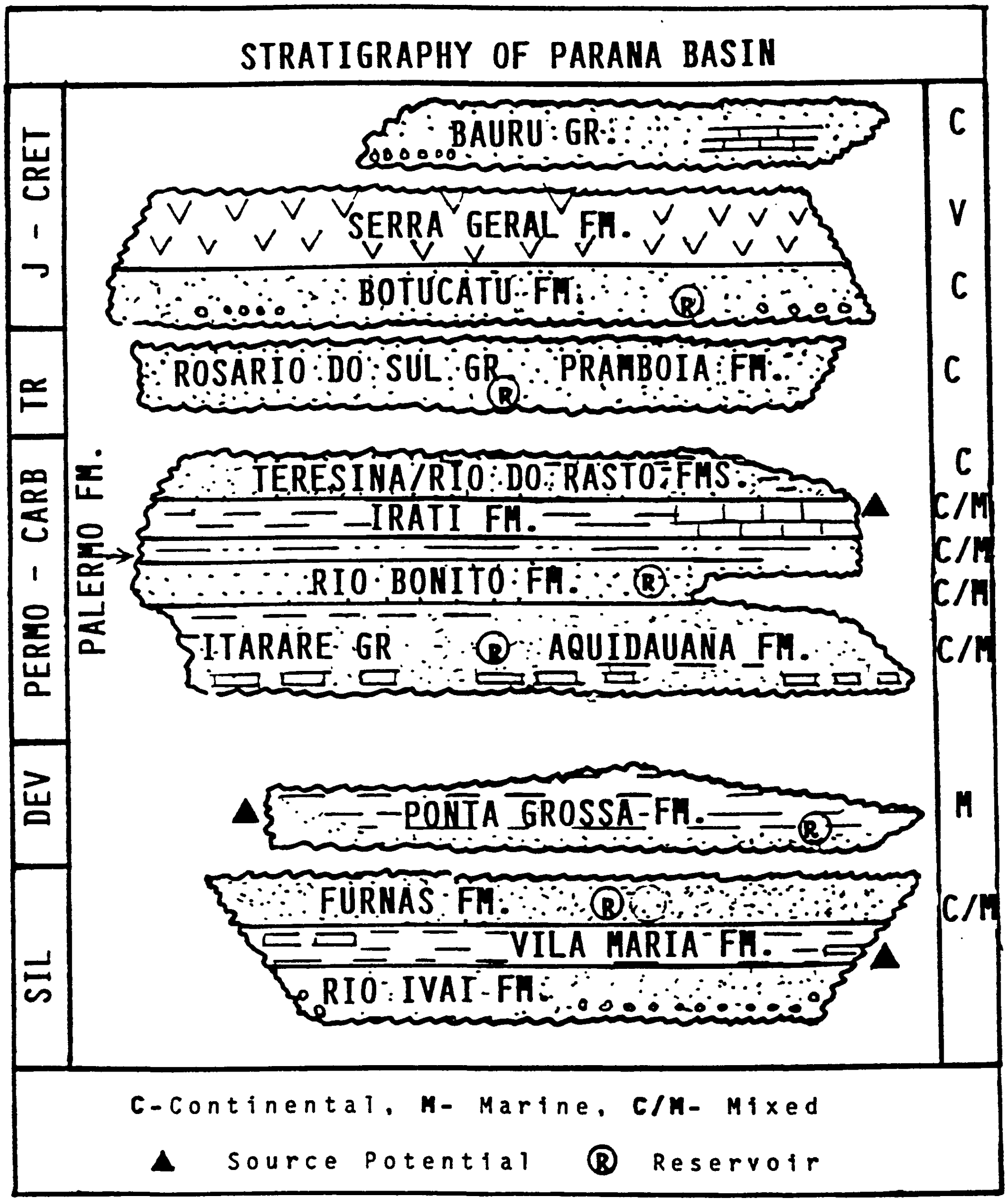


Figure 106 Stratigraphic column of the Parana basin (from Milani et al, 1990).

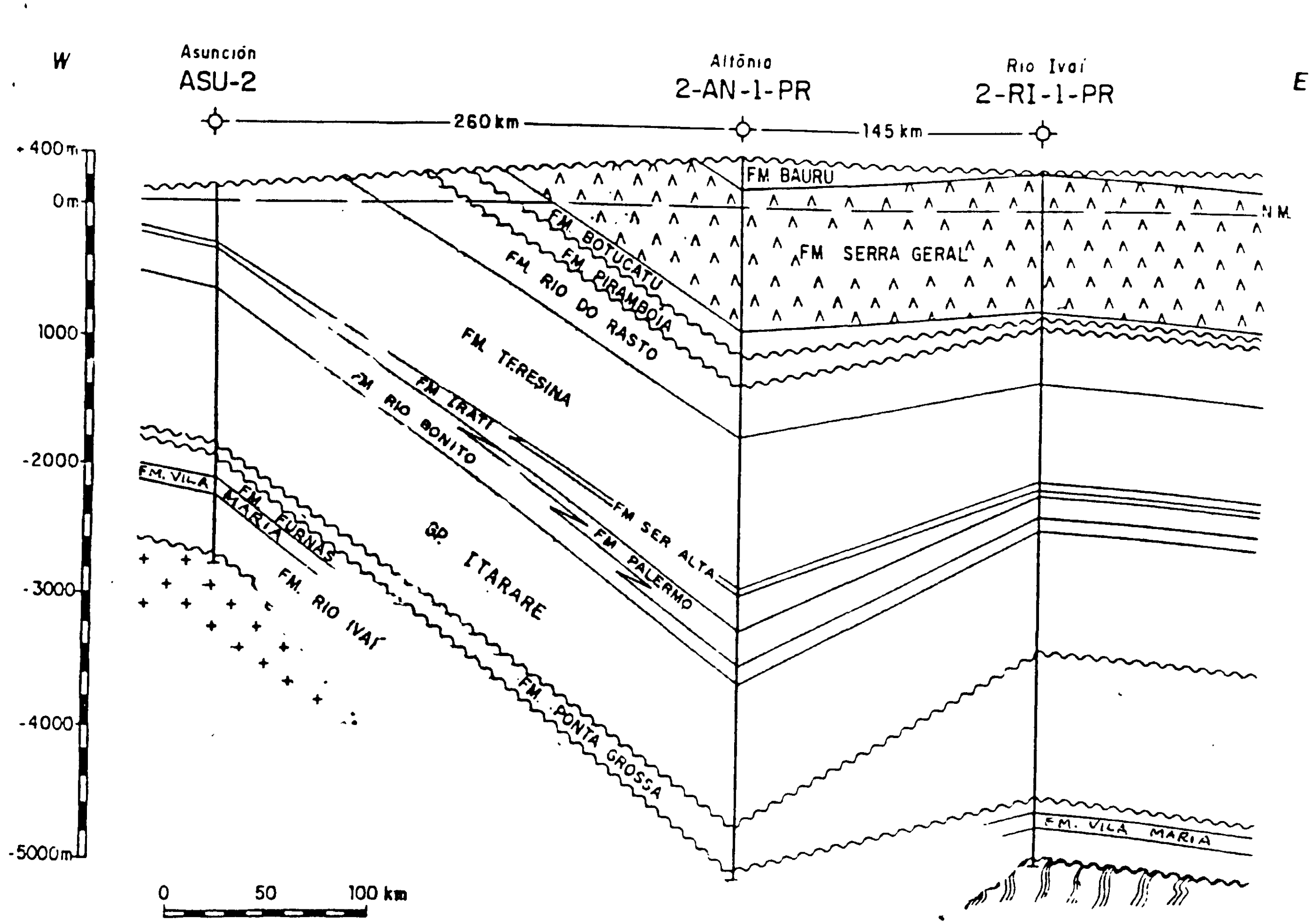


Figure 107 Regional correlation section from Paraguay (wildcat ASU-2) eastward through the depocenter (wildcats 2-AN-1-PR and 2-R1-PR) of the Parana basin. Massive diabase intrusives not indicated. Location figure 105 (modified from Milani et al, 1990).

(fig. 99) which in turn appear related to the Late Carboniferous-Permian, the Devonian-Early carboniferous, and the Late Ordovician-Silurian depositional sequences of the Amazonas basin (fig. 95).

The Silurian group, of mixed continental and marine origin, is made up of three units. The basal, largely sandstone Rio Ivai Formation, the predominantly shale Vila Maria Formation, and the largely sandstone Furnas Formation. The Devonian group, the Ponta Rossa Formation, is made up of marine siltstones and shales. The Permo-Carboniferous sequence makes up most of the stratigraphic thickness of the basin in some six formations and groups. It is largely a sandstone and shale sequence of mixed origin ranging from neritic marine and lagoonal to deltaic, fluvial and lacustrine. It contains tillites and some carbonates.

The post Paleozoic strata are all of continental origin and shallow. The most prominent unit is the up to 5,000 ft (1,550 M) thick Serra Geral Formation which is mainly basalts and volcanics with some sandstones near the base. The largely sandstone formations directly underlying the Serra Geral basalts have some reservoir potential.

The whole stratigraphic section is intruded by Jurassic diabase sills which make up a good portion of the basin thickness and influences the thermal maturation of the sediments.

Source. There are three shale sequences which appear to be potential source rock (fig. 106) (Milani et al, 1990). The first sequence, the Silurian Vila Maria Formation shales (Vargas Pena shales of Paraguay) are the source of significant oil and gas shows in Paraguay. The shales have an average TOC value of 2 percent. The second sequence, The Devonian Ponta Grossa Formation shales have an average TOC of 3 percent and are the source of gas and condensate shows on wells of the eastern flank of the depocenter. The third, and principal potential source rock of the Parana basin is the shale sequence of the Late Permian Irati Formation which contains organic matter with TOC values up to 23 percent, averaging 8 percent, and a kerogen type prone to liquid hydrocarbon.

According to Milani et al (1990) the depth to the top of the oil generation zone in the center of the basin (i e, wildcat 2-R1-1 PR is about 6500 ft (2,000 M) (fig. 107). This depth appears shallow given the usual low thermal gradients for interior sag basins, but as indicated by figure 107 considerable post-volcanic erosion has taken place. Temperature may have been raised by the massive Jurassic intrusives (not indicated in figure 107). The depth to the oil generation window precludes the relatively shallow principal source shale of the basin (the Irati shale) from maturation over all of the basin except for deepest part, about 10 percent of the basin area (figures 105 and 107). The deeper, but much leaner, source shales could, however, produce some gas and oil. Maturation is complicated by the effects of the diabase intrusives which, on one hand, may raise the thermal ambience of a source shale to maturity and, on the other hand, may overmature or even destroy a source shale. Figure 108 shows the depletion of the source capability of the Irati shale by diabase sills.

Reservoirs and seals. There are potential reservoir sandstones throughout the section. The older and deeper potential reservoirs, the Rio Ivai and Furnas sandstones of the Silurian sequence and the Itarare sandstones of the Permo-Carboniferous sequence, have relatively low porosities ranging from 6 to 16 percent. The shallower Permian Rio Bonito Formation sandstones have good reservoir characteristic having some 500 ft (150 M) of porosity in the order of 20 percent even at depths of 13,000 ft (4,000 M) in the central part of the basin (Milani et al, 1990).

Seals appear to be relatively poor; the evaporitic section of the Solimoes and Amazonas basin is missing, and the section except for the shale source intervals is predominantly coarser clastics. The Serra Gerral volcanics may be a seal in some parts of the basin. Flushing of reservoirs by meteoric water on the flanks of the basin is a problem, as indicated by biodegraded oil shows; however in the depocenter area hypersaline connate water indicates hydrocarbon preservation from this flushing.

Structure

The structure of the Parana basin is that of an interior sag, probably, as in the case of the other Brazilian interior sags following earlier rifting. A regional sag probably came into existence about the Carboniferous although sedimentation over a South American-African platform must have continued intermittently since Silurian or Ordovician time. The basin reached its present configuration in post-Bauru (early Cretaceous?) time (fig. 107). All regional dips are low and the only local structure are confined to block-faulting which may have occurred generally during subsidence, but especially in the period of regional extension and massive diabase intrusion of the Gondwana Jurassic-Early Cretaceous breakup period. Some of these faults are indicated by lineations mapped by aerial magnetometer surveys. It would appear, however, that any local fault-associated closure in this interior sag basin would be of a very low amplitude. Exploration for such traps is severely hampered and probably under the present state of geophysically technology largely negated by the up to 5,000 ft (1,500 M) thickness of Jurassic basalt flows overlying most of the basin. Although no viable closures have yet been mapped, there remains the good possibility that in this huge area some wrench zones exist with accompanying transpressional drag folds and reverse faults such as are indicated in the closely analogous but relatively volcanic-free Paranaiba interior sag basin and such as the productive structures in the Solimoes interior sag basin.

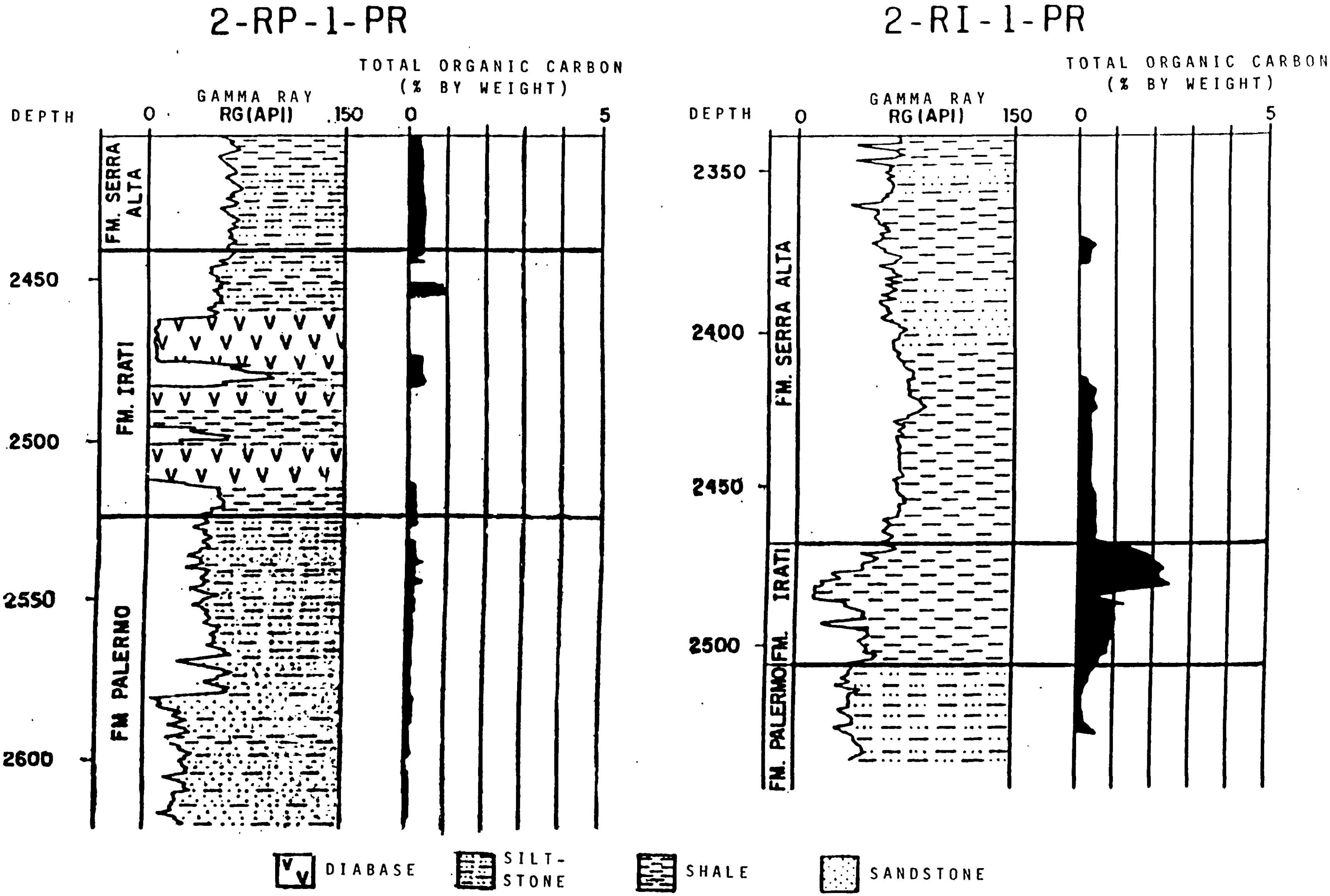


Figure 108 Detail of Irati Formation interval in two Parana basin wildcats showing the depletion of TOC (total organic carbon) by the thermal efforts of diabase intrusion (modified from Milani et al, 1990).

Generation, Migration and Accumulation. The main generation, and migration began when the principal source shales of the Irati Formation subsided into the oil window which probably occurred at the end of Jurassic or early Cretaceous time, after the thick volcanic flows. Closure formation in the form of fault traps may have occurred during: 1) the Jurassic period of extension accompanying diabase intrusion and volcanic flows, and 2) by analogy to the other interior sag basins, in the form of wrench associated traps in the pre-Middle Cretaceous. Migration timing should be opportune for both periods of trap formation. Reservoir quality, especially in the older reservoirs, may have been downgraded by the heat of Jurassic intrusives.

Plays. Plays are limited to possible trap occurrences which appear to be Jurassic extension fault-associated closures and possible pre-Middle Cretaceous wrench related features.

Exploration History and Petroleum Occurrence (In the Brazilian portion) From 1892 to 1953 government and private companies, motivated by the abundant oil seeps emanating from the shallow or outcropping sandstones, drilled several shallow dryholes along the eastern outcrop belt. In 1953 a more intensive exploration was initiated, including geophysical surveys and the drilling of some deep stratigraphic test holes. However, seismic resolution through the thick basalt was not very successful and only a few subcommercial discoveries were made. After an exploration hiatus from 1975 to 1978 the basin was opened to risk contractors. Thirty-three wells were drilled and only two were sub-commercial gas discoveries. In 1985 Petrobras took over the exploration of the basin and applied advanced seismic and other technologies. The cumulative work in the Brazilian portion of the Parana basin was 13,600 miles (22,000 kms) of seismic lines and 107 wells, as of 1990 (Milani et al, 1990). The deep drilling resulted in the discovery of a few barrels of oil and some subcommercial gas from the Permian Rio Bonito formation in the Santa Catarina province (SC, fig. 105) on the eastern flank of the depocenter. Gas tested up to 1.8 MMCFG/day from the Itarare Group sandstone at Chapeu do Sol, Parana (PR, fig. 105) at Cuiaba Paulista, Sao Paulo (SP, fig. 105), and also on the eastern flank of the depocenter.

Estimation of Undiscovered Oil and Gas

The closest analog to the Parana basin in Parnaiba basin with an overall area of 230,000 m^2 (600,000 km^2) with estimated resources of .037 BBO and 1.9 TCFG. On a straight areal analogy basis the Parana basin would have .10 BBO and 5.08 TCFG.

Chaco Basin

Area: 200,000 mi^2 (510,000 km^2)

Original Reserves: Nil

Description of Area. This irregularly-shaped, relatively shallow platform is regarded as a significant petroleum basin by only some authors, its areal extent depending on one's definition of the basin. Very generally, it extends eastward from the Pompayan (Pompean) Range to the Asunsion Arch and the Parana River which is somewhat arbitrarily taken as the boundary between the merging Chaco and Parana basins (figs. 2, 105, and 153).

Geology. The tectonic classification of the extensive Chaco basin is uncertain as it may be regarded mainly as an interior sag in the east but resembling a pericratonic foreland basin in the west. The closest analogy to the Chaco basin is the adjoining relatively well-explored Parana basin. In the Parana basin the principal source rocks are in the Late Permian Irati Formation. Other source rocks are in the Devonian Ponta Grossa Formation and in minor amounts in the Silurian Vila Maria Formation. In the Chaco basin, as indicated in fig. 109, all these source rocks are less than two kilometers (6,500 ft) deep. The oil generation zone in the analagous Parana basin is below this depth (Milani et al, 1990) and, accordingly, these source rocks are probably immature. While there are abundant seeps in the Parana basin, none are reported in the Chaco basin.

On the assumption that the Chaco basin is half as prospective on an areal basis as the Parana basin, it would have resources of .016 BBO and .82 TCFG which is a negligible amount in such an extensive area.

D. Subandian Foreland

Acre Basin

(Note: The Acre basin is the only Brazilian basin of the Subandean foreland; more logically it should be discussed along the other Subandian basins in another section of this report, but is placed here so as to complete the Brazilian inventory of undiscovered petroleum possibilities).

Area: Total is 60,000 mi^2 (150,000 km^2) including a thin Cretaceous platform.

The actual play area, underlain by Paleozoic and thick Cretaceous, is estimated to be 13,000 mi^2 (34,000 km^2)

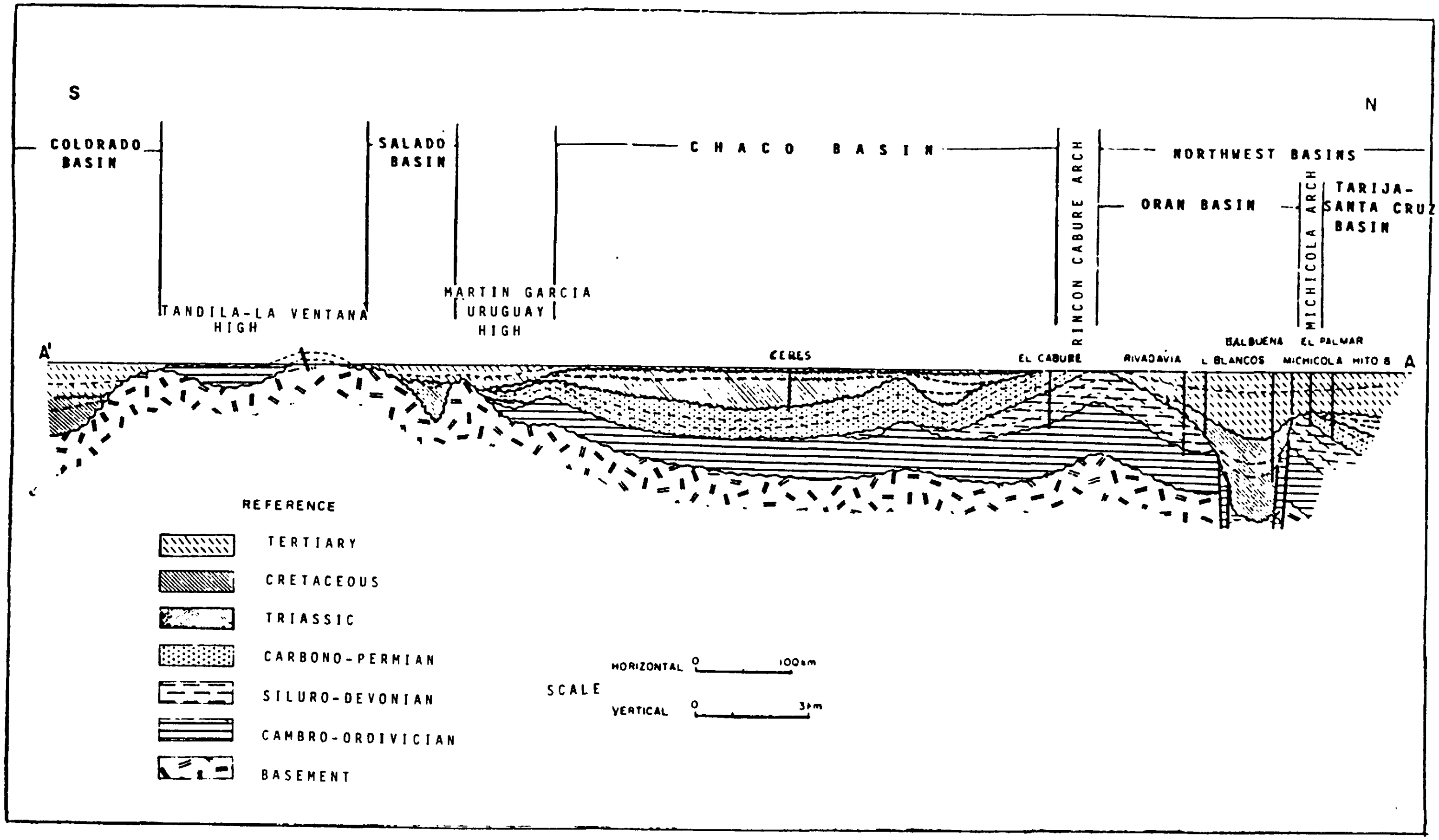


Figure 109 South to north geologic cross-section across the Choco basin (modified from Russo et al, 1980).

Original Reserves: Nil

Description of Area. The Acre basin occupies the westernmost tip of Brazil (figs. 2 and 110). It is separated from the interior sag, Solimoes basin by the Iquitos Arch on the northeast and from the foreland Ucayali basin of Peru by a ridge (Topiche or Utoquina Arch, or Divisor Range) which runs along the Brazil-Peru boundary.

Stratigraphy

General. The stratigraphic column of the Acre basin, is shown on figure 111 which compares it to that of the Andean foreland basins of Peru. The oldest sequence of consequence in the Acre basin consists of marine-continental Late Carboniferous-Permian carbonates and shales. The Devonian and older Paleozoic rocks, although present in the adjoining Peruvian foreland basins (fig. 111) and in the Brazilian interior sag Paleozoic basins, appear to be missing in the Acre basin. The Late Carboniferous-Permian strata are in part overlain by Triassic continental strata which in turn are overlain by thick continental Cretaceous and Tertiary coarse clastics. The Cretaceous and Tertiary shales which occur in Peru apparently becoming more sandy in the Acre basin. As indicated in figure 112 the petroleum-producing Paleozoic rocks of the Solimoes basin thin considerably into the Acre basin region and the thick Jurassic diabase-sill intrusive rocks of the Solimoes and other Brazilian interior sag basins do not occur in the Acre basin (nor any of the Andean foreland basins). In contrast, the Cretaceous and Tertiary strata thicken into the foreland Acre basin as a consequence of the Andean orogeny and accompanying foredeep.

Source. The shales of Late Carboniferous-Permian sequence appear to be the principal source rocks of the basin, as indicated by the La Colpa-1 well (drilled in the adjoining Ucayali basin but near its boundary with the Acre basin [Alves 1989]). These shales are also the main source of the oil in the adjoining Ucayali basin. The principal source rocks of the southern Subandian foreland, i.e., southern Peru, Bolivia and northern Argentina are the Devonian and Ordovician sequences, which are missing. The principal source of oil in the more northern foreland basins of northern Peru, Ecuador and southern Columbia (where the Paleozoic strata are generally overmature) are Cretaceous shales, which appear to be undergoing a facies change into sandstone in the Acre basin (fig. 111). Petroleum generation probably began in the Tertiary when the Paleozoic source shales were depressed into the thermal zone of oil generation.

Reservoirs and Seals. Potential reservoirs are largely in the Cretaceous sequence where most of the sandstones are concentrated. The producing reservoirs of the adjoining foreland basins of Peru are practically all Cretaceous sandstones. Efficient seals appear to be somewhat lacking, the Cretaceous and Tertiary shales thin from Peru into the Acre basin.

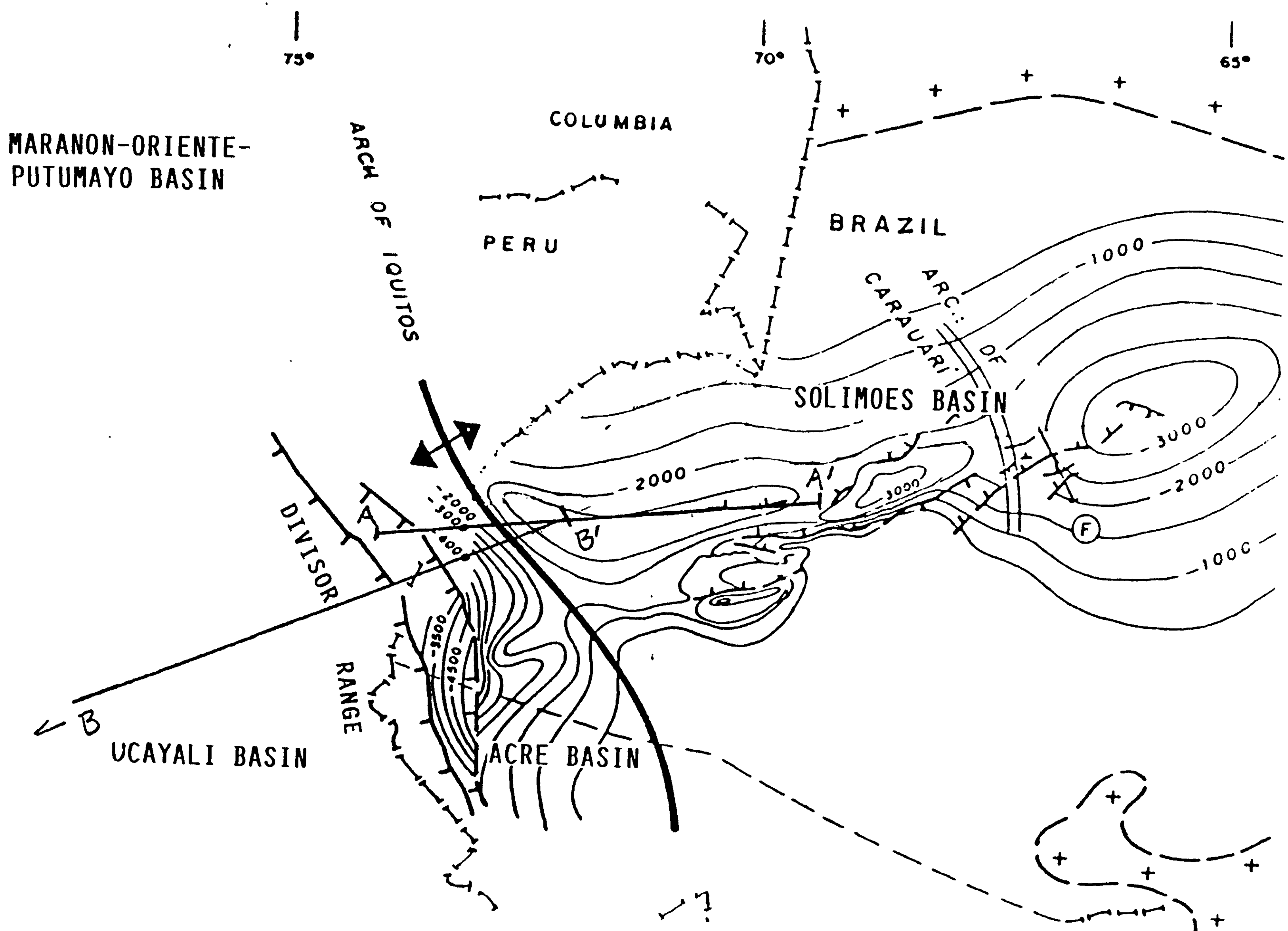


Figure 110 Sketch depth-to-basement map of Acre basin, separated from the adjoining Solimos basin by the Arch of Iquitos and from the Ucayali basin by the Divisor Range. Contours in meters. Section A-A, figure 112; Section B-B', figure 174 (from Caputo, 1985).

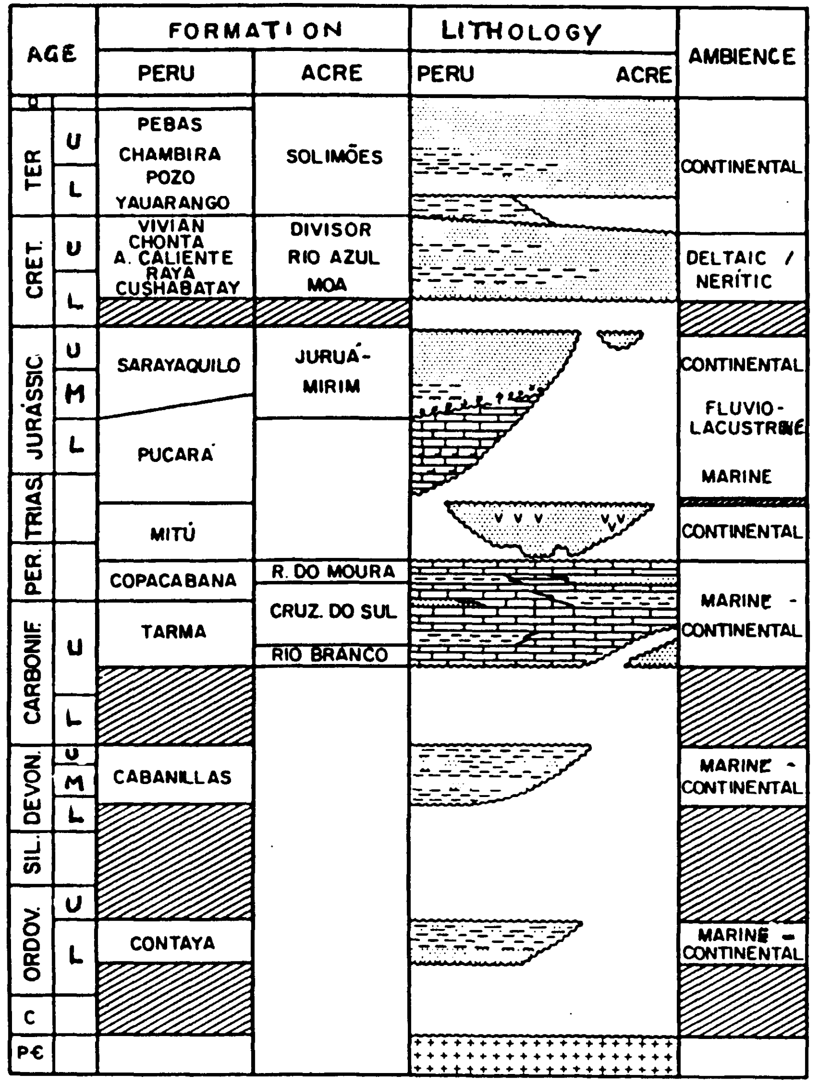


Figure 111 Stratigraphic columns of the Acre basin of western Brazil and the adjoining Maranan subbasin of eastern Peru (modified from Alves, 1988).

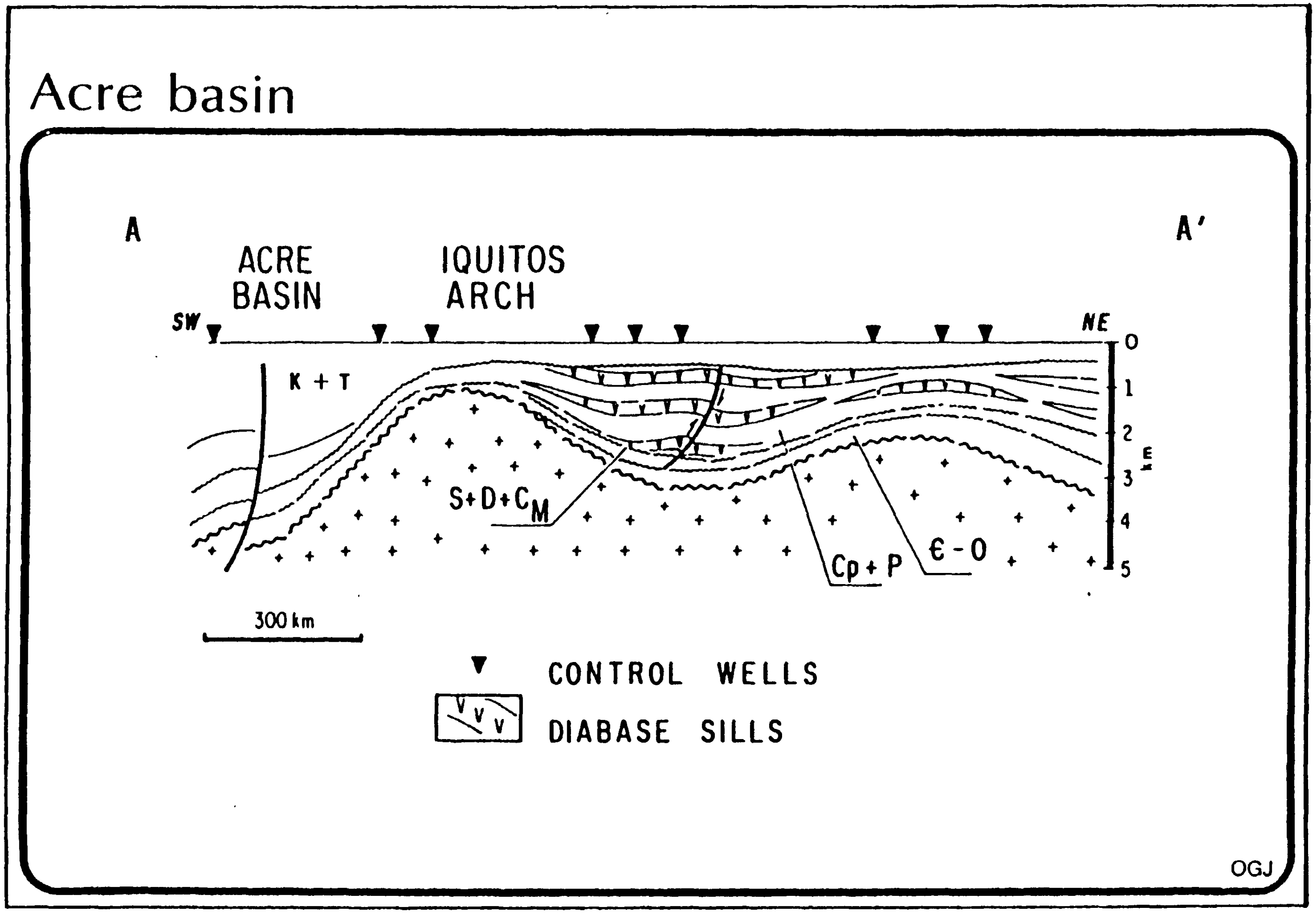


Figure 112 Diagrammatic west-east geologic section from the Acre basin into the Solimoes basin. Location figure 109 (modified from Porto and Szatmari, 1983).

Structure

The Acre foreland basin in the only basin of Brazil that does not lie within the Brazilian craton or its rifted margin. It is far enough west as to be part of a string of foreland basins which fringe the craton facing the Andes Mountains. The basin is elongate parallel the Andes and cut by several north-trending faults which are thought by some to originally have been normal faults but were later transformed into reverse faults by Andean movements (Porto and Szatmari, 1983) (fig. 110 and 112). In any case the structure is similar to the upthrust foreland blocks of the adjoining Ucayali and Maranon-Oriente-Putumayo foreland basins.

There is no data concerning individual structural closure, but the situation appears analogous to the adjoining Ucayali basin where closures appear associated with upthrust block faulting, yielding fault and drape closures. The age of the upthrusting is late Tertiary.

Generation, Migration, and Entrapment. Petroleum migration would have begun with it generation in the Tertiary Andean foredeep subsidence. This timing is most favorable being contemporaneous with any closure formation associated with the upthrusting along the western side of the basin. The most likely reservoirs would be Cretaceous sandstones which are the principal reservoirs of the adjoining basins of northern Peru and Ecuador. Some Tertiary reservoirs may also have received petroleum.

Plays. The principal play, as in the adjoining subandian basins of eastern Peru and Ecuador, involves Cretaceous, and possibly younger, sandstones in foreland upthrust block closures. Other plays would be low amplitude foreland normal fault-block closures and stratigraphic traps. Paleozoic traps such as wrench-associated transpressional closures of the Solimoes basin are a possibility.

Exploration History and Petroleum Occurrence. This rather inaccessible, hostile basin has been only sparsely explored. Apparently only some half a dozen wildcats have been drilled in the seventies and eighties with no success.

Estimation of Undiscovered Oil and Gas

The closest analogy to the Acre foreland basin is the adjoining Ucayali foreland basin of Peru which has an area of some 36,000 mi^2 (93,000 km^2). The Ucayali foreland basin, excluding the overthrust belt which has no counterpart in the Acre basin, has estimated ultimate resources of 0.531 BBO and 8.077 TCFG. An areal analogy with the Ucayali basin indicates that the Acre basin has resources of .19 BBO and 2.92 TCFG.

III Patagonian Accreted Region

A. Foreland/Interior Rift Basins

This superprovince encompasses the area of the southern South American continent accreted in the Precambrian and early Paleozoic, coinciding with most of Argentina and a small area of southeastern Chile, i.e., Patagonia exclusive of the Andes, which are affected by the Pacific subduction tectonics. The boundary with the northern craton area of Brazil and Uruguay extends from the north Salado basin northwest to the north of the Cuyo basin (fig. 113). Included in this superprovince is the rifted Atlantic margin and the Malvinas basins.

The region has a northwest-trending northeast-trending structural grain, apparently reflecting old lines of weakness or sutures between the accreted continental blocks. These lines appear to have localized zones of faulting developed during the Mesozoic rifting which accompanied the breakup of Gondwana. This northwest to northwest structural trend is superimposed on the west by the north-bearing effects of the Andes subduction trends along the Pacific side of the continent, and on the east by north-northeast-trending rifting along the Atlantic continental-oceanic margin.

Most of the sedimentary provinces are rift basins following the northwest to northeast trending lines of weakness, but affected by foredeepening in the west near the Andes; the Magallanes and Malvinas basins are more dominantly foreland basins.

The Magallanes basin along with adjoining Malvinas basins will be discussed first, then the basins along the Atlantic coast and finally those basins along the west side of the superprovince adjoining the Andes. Only the major basins of the Patagonia region are discussed, i.e., those of reasonably large volume, with areas of more than 15,000 mi^2 (40,000 km^2) and depths of 13,000 ft (4 km). Ten such basins are evaluated.

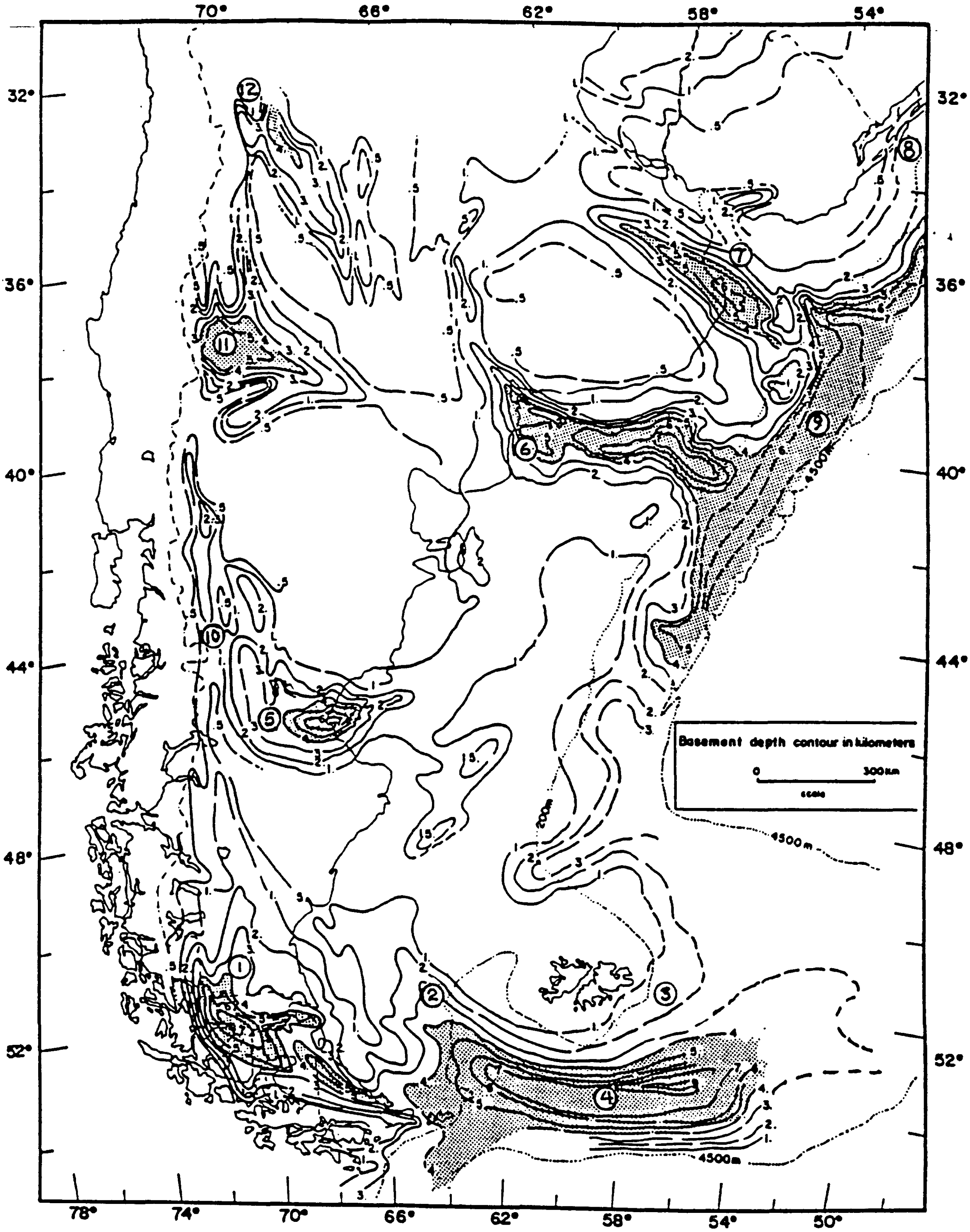


Figure 113 Depth to "technical basement" (seismic velocities greater than 15,000 ft/sec (4.5 km/sec) map of the Patagonia area showing the major basins. Area of greater depth than 16,400 ft (4 km) are stippled basins are: 1-Magallanes; 2-Malvinas; 3-Malvinas Plateau; 4-Malvinas Trough; 5-San Jorge; 6-Colorado; 7-Salado; 8-Pelotas; 9-East Patagonia; 10-Nirihuau; 11-Neuquen; 12-Coyo (modified from Urien and Zambrano, 1973).

Magallanes (Austral) basin

Area: Total 71,600 mi^2 (185,000 km^2)
(Argentina area - 48,700 mi^2 [126,100 km^2])

(Chile area - 22,900 mi^2 (59,300 km^2])

Foreland Play area - 57,400 mi^2 (148,700 km^2)

Argentina - 40,240 mi^2 (104,200 km^2)

Chile - 17,134 mi^2 (44,400 km^2)

Foldbelt - 14,200 mi^2 (36,800 km^2)

Largely Chile

Original Reserves:

Chile:	.323 BBO	8.513 TCFG	1.742 BBOE
Argentina:	.440 BBO	5.715 TCFG	1.3925 BBOE
	. 763 BBO	14.228 TCFG	3.134 BBOE

(Petroconsultants 1990)

Description of Area: The Magallanes basin is essentially a foreland basin, bounded on the west, southwest and south by the curving Andes orogene and its southeastern extension. To the north it laps onto the Deseado Massif and on the northeast onto the long-standing basement high, Rio Chico-Dungeness Arch (figs. 113 and 114).

Stratigraphy

General. The stratigraphy is shown in figure 115, a north-south stratigraphic section through the Magallanes basin (Biddle et al 1986). In general the Cretaceous sediments are derived from the east and northeast, i.e., the Rio-Chio-Dungeness Arch, and the Tertiary sediments largely from the west and southwest, i.e., the rising Andes mountains (fig. 116). The basin-fill is rather unique in that aside from the sandy Springhill Formation and southwestern Tertiary strata, it is dominated by shaly rocks. The basal unit, the Jurassic Tobifera Formation, is a heterogeneous mixture of silicic volcanic and non-marine volcaniclastic rocks which covers vast areas of southern South America and is associated with the extension resulting in the breakup of Gondwana. Its thickness varies from nothing over faulted basement highs to some 7,000 ft (2,000 m) in the lows. Although there are some interbedded sediments and isolated sediment-filled grabens below the Tobifera Formation, it is considered as economic basement.

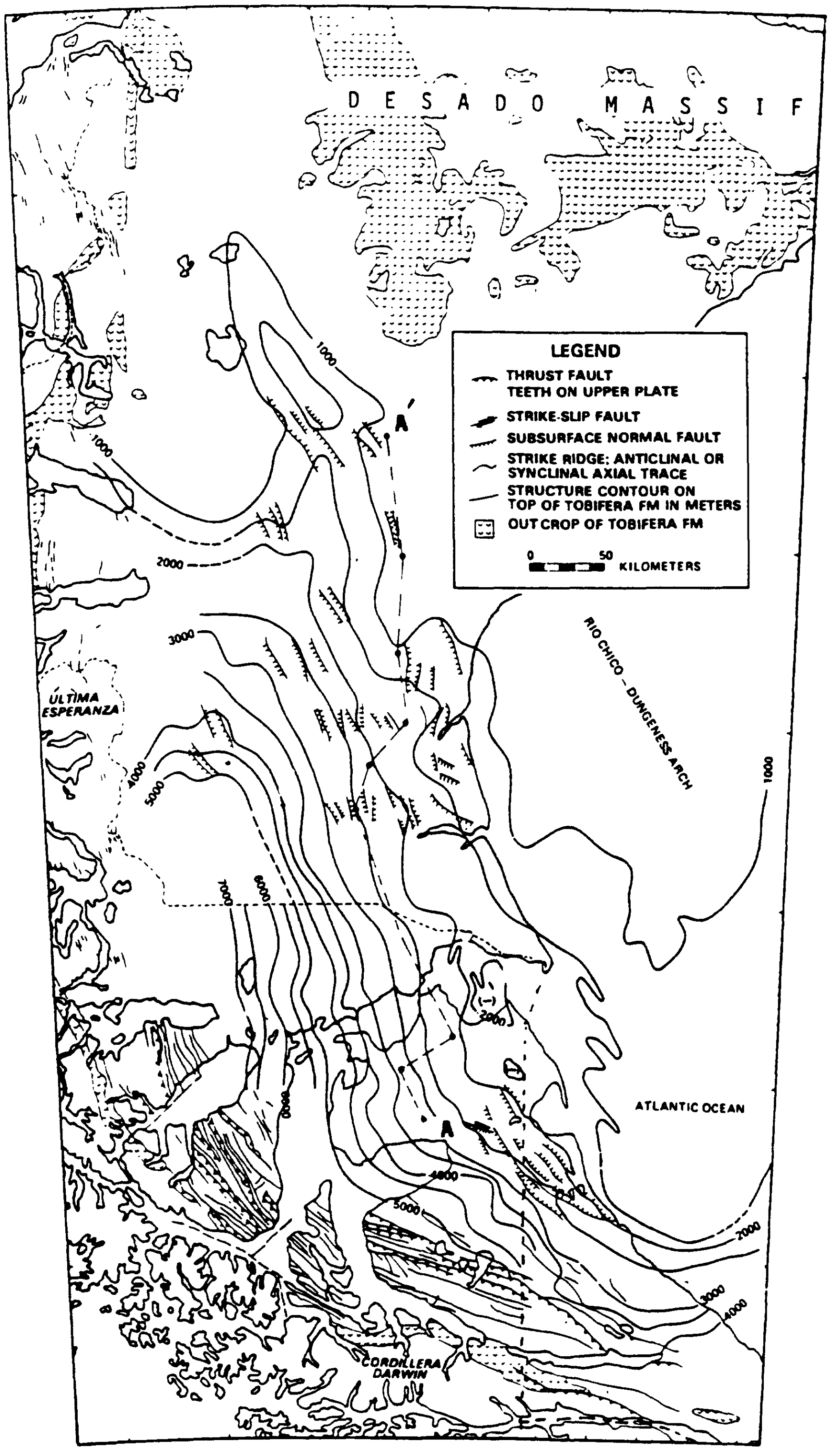


Figure 114 Structure contour map of top of Tobifera volcanic rocks, Magallanes basin. Dashed lines between dots (wells) is location of stratigraphic section A-A (fig. 115). Fine dashed line boundary between Chile and Argentina (Chile to west) (modified from Biddle et al, 1986).

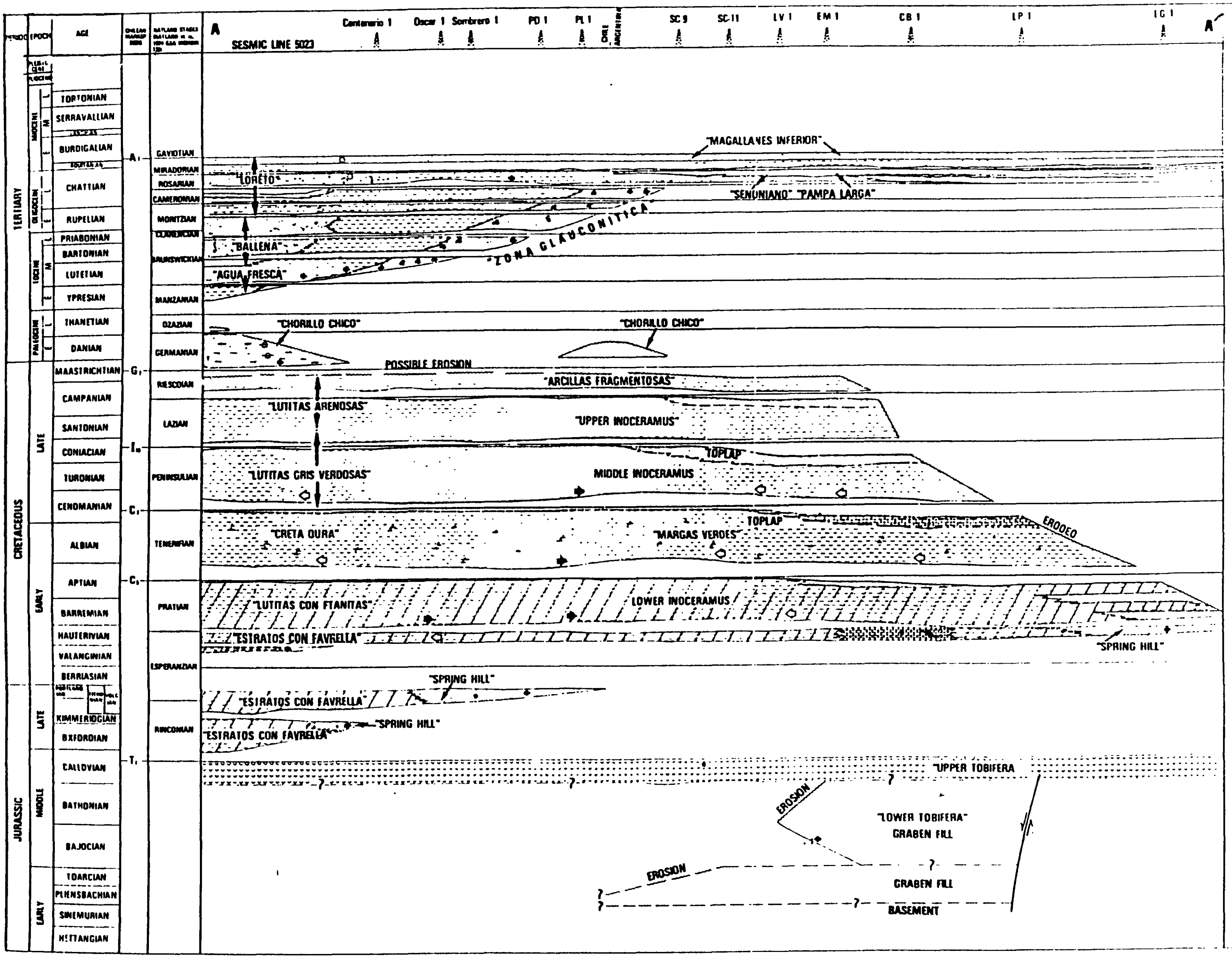


Figure 115 South to North stratigraphic section through Magallanes basin. Location figure 114 (Biddle et al. 1986).

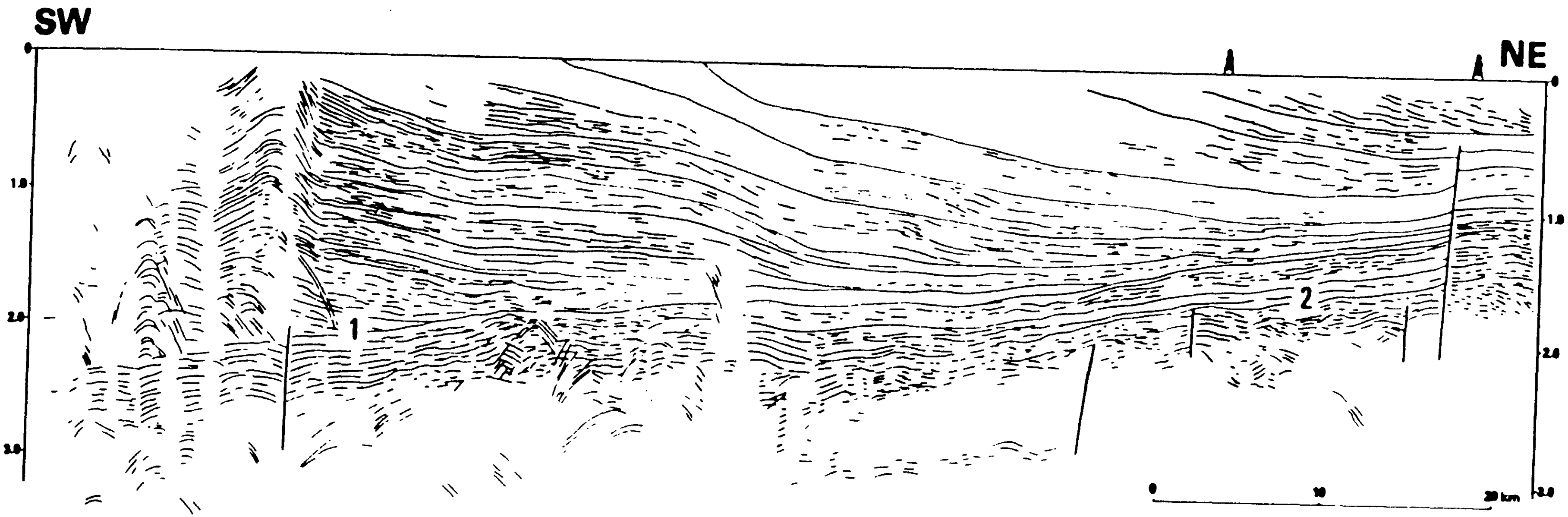


Figure 116 Sketch of seismic southwest-northeast dip section of the Magallanes basin from frontal folds of the Chilean fold and thrust belt to the edge of the Dungeness Arch. Location 1 shows the onlap of the Andean derived Tertiary sediments over near-top-of-Cretaceous strata. Location 2 shows the approximate top of the Tobifera volcanic rocks (Biddle et al, 1986).

Transgressively overlying the Tobifera Formation is the Upper Jurassic-Lower Cretaceous Springhill and "Estratos con Favrella" Formations. The Springhill Formation is largely a succession of retrogradational fluvial, shoreline, and shallow marine sandstones which are the petroleum reservoirs of the Magallanes basin. The sandstones are absent over Tobifera/basement highs and thicker in the lows. Equivalent basinward and downdip, i.e. west and southwestwards, strata are marine shales (locally "Estratos con fig Favrella") which are poor to fair source rocks in some areas. The downdip extent of the retrograding Springhill sands lessens with time but is approximately limited by the shelf edge indicated by the steepening at about the 4000 meter contour on the top of the Tobifera volcanic rocks (fig. 114).

Overlying the Springhill-Estratos con Favrella sequence is the Early Cretaceous Lower Inoceramus Formation which forms a broad, prograding wedge which onlaps the Dungeness arch to the east and thickens to the west and southwest, reaching a thickness of some 2600 ft (800 m). The formation consists of dark claystones and shales deposited in part under an aerobic condition. The lower, largely anoxic part of these shales are the principal source rock of the basin. The paraffinic composition of the oil indicates terrestrially derived organic material.

The overlying Cretaceous formations generally follow the same depositional pattern as the Lower Inoceramus Formation, that is a northwest-trending shaly wedge thinning onto the Dungeness arch reflecting continuing passive, low-energy subsidence.

Uppermost Cretaceous and Tertiary units, derived from the rising Andes and their southeastern extension, show a progressive onlap geometry from west to east over a profound regional composite unconformity (fig. 116). Coarser Paleogene sediments are found only in the southern end of the basin. Abundant glauconite points to a certain degree of sedimentary starving in the more northern parts of the basin (fig. 115).

The above stratigraphy (Biddle et al, 1986) mainly concerns the eastern or foreland part of the basin where deposition was in a low energy environment with little relief and where the Tertiary coarser Andean material was isolated from the area by a narrow zone of deep water, the abundance of glauconite in the Paleogene sediments suggesting low deposition rates. By contrast the stratigraphic section of the Andean fold belt is very thick, indicating high rates of sedimentation. More than 30,000 ft (9000 m) of Cretaceous and Tertiary sediments were deposited in the deepest part of the Magallanes basin (Winslow 1982). Derived from the rising Andean magmatic and deformed Lower Cretaceous sedimentary rocks, continuous sedimentation began with upper Cretaceous turbidites in deep-water shales, then lower Tertiary shallow marine sediments and finally Miocene-Pliocene tuffs and littoral sandstones. The relative lack of petroleum potential and structural complexity of the fold and thrust belt has inhibited the detailed study such as was applied to the foreland stratigraphy.

Source. The principal source rocks of the basin are the lowermost shales of the Lower Cretaceous Lower Inoceramus Formation. These shales were deposited in relatively deep water under anoxic conditions in the center of the basin; they immediately overly the Springhill Formation reservoirs (fig. 115). Biddle et al, (1986) state that these shales are the best source rocks in the basin. Other source rocks include the basinward equivalent shales to the Springhill Formation, the Estrados con Favrella Formation.

Reservoirs and Seals. There appears to be only one significant set of reservoirs, the Springhill sandstones. The reservoirs are quartzitic sandstones interbedded with green and black carboniferous shales. The medium to coarse-sized grains are crystalline with hard to soft kaolinite cement. The reservoirs appear to range from shoestring type sandstones on a mature flood plain near the base of the formation to more blanket-like nearshore marine sandstones in the upper interval. The Springhill Formation is as thick as 500 ft (150 m) and averages about 160 ft (30 m) thick (Urien, 1981). The porosity ranges from 15 to 20 percent (Petroconsultants, 1980-1990).

The sealing of petroleum in the foreland portion of the basin appears good, as the section is largely shale. In the fold and thrust belt portion of the basin, where there is much faulting and coarse clastics, sealing may be a problem.

Structure

The basin may be divided into two structural provinces: an eastern, gently westward dipping, normal-faulted, relatively stable foreland platform, making up two-thirds of the basin, and a western and southwestern belt of Andean folds and thrusts, with sinistral wrenching in the south, making up one third of the basin. Jurassic and Early Cretaceous rifting accompanying the breakup of Gondwana and emplacement of the Tobifera volcanics, is the principal structure of the foreland, producing an irregular horst and graben surface and forming the fault and drape traps which contain the hydrocarbon of the basin (fig. 116). The structures of the western third of the basin, the fold belt, consists of long sinuous folds in an area of basal Tertiary decollement where thrust faults cut upward to higher stratigraphic levels. Structural traps are prone to being rather strongly deformed and only negligible accumulations have been found.

Generation, Migration and Accumulation. Maturation of the source shales was probably limited to the deeper western portion of the basin. Assuming average heat gradients and progressive subsidence through the Tertiary with westward deepening and tilting of the basin the top of the oil window is at a depth of about 10,000 ft (3000 m) i.e., west of the 3,000 m contour of figure 114. Maturation, and consequently migration, began further downdip towards the Andean foredeep when the source rock's burial depth first reached 10,000 ft (3,000 M) in about the mid-Tertiary, so that the initial lateral migration distance was further than at present.

It appears that as the basin tilted westwards, the flood of lateral updip migration was largely in the Neogene to present and through thin Springhill sandstone conduits from the downdip source kitchen to the oil fields.

Plays. There appears to be two principal plays, one of which seems to be a minor to negligible play in the fold and thrust belt of the Andean foothills since there appears to be little possibility of encountering good reservoirs or sizable closures. The other play is the single viable play of the Magallanes basin, that is, petroleum accumulations in fault traps and drape closures involving reservoirs of the Springhill Formation.

History of Exploration and Petroleum Occurrence. Exploration began in 1917 with the drilling of eight test wells. Seven tests were drilled between 1930 and 1942. In 1942 a more comprehensive exploration began resulting in the first discovery in 1945 of the Manantiales field. Although exploration began in the fold belt, only negligible petroleum accumulations were found there, and as larger accumulations appeared unlikely, subsequent exploration was confined to the foreland platform. Curves of cumulative oil and gas discoveries versus cumulative wildcats (figures 117 and 118) shows that after the first surge of discoveries in both Argentina and Chile, involving the first approximately 125 definitively recorded wildcats in each country, there was an abrupt levelling-off of the discovery rate for both oil and gas. A second surge for oil occurred when first Argentina and then Chile began offshore drilling at about 250 and 325 wildcats respectively. After this surge the curve levels off; for the last 50 wildcats the discovery rate for oil is .060 and .88 MMBO per wildcat for Argentina and Chile respectively. Gas on the same basis is 1.30 and 1.16 BCFG per wildcat. These low yields indicate the basin to be in a mature stage of exploration.

Estimation of Undiscovered Oil and Gas

The undiscovered oil and gas, except for negligible amounts in the fold belt, is in the foreland part of the basin and in a single play, the drape and fault traps involving the Springhill sandstones. Given the relatively simple geology and the mature stage of exploration only little potential remains. Assuming that eventually the total number of future wildcats drilled will be about half the number already drilled (i.e. 542 for Argentina and 474 for Chile by the end of 1988) and that the average discovery rate for the last 50 wells for both countries remains constant (increasing finding difficulty balanced by increasingly improved exploration technique) .016 BBO will be discovered in Argentina and .208 BBO in Chile, totalling .224 BBO for the basin. Using the same assumptions in regard to gas the undiscovered gas of Argentina amounts to .352 TCF and of Chile .275 TCF amounting to .627 TCF for the entire basin.

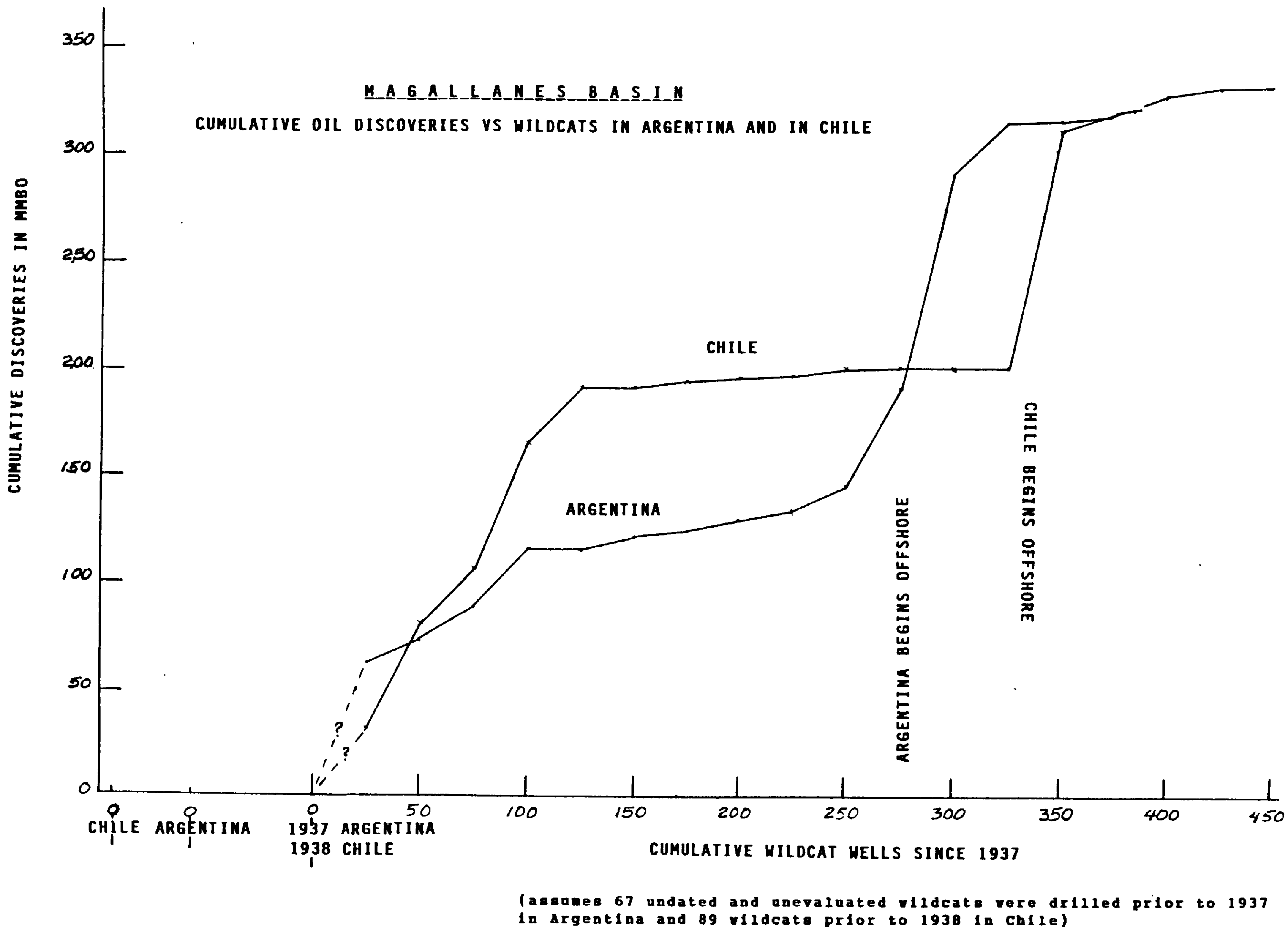


Figure 117 Graph showing relation of the cumulative amount of oil discovered to the number of wildcats drilled in the Argentina and Chile portions of the Magallanes basin. Based on Petroconsultants data (1990) which may be incomplete.

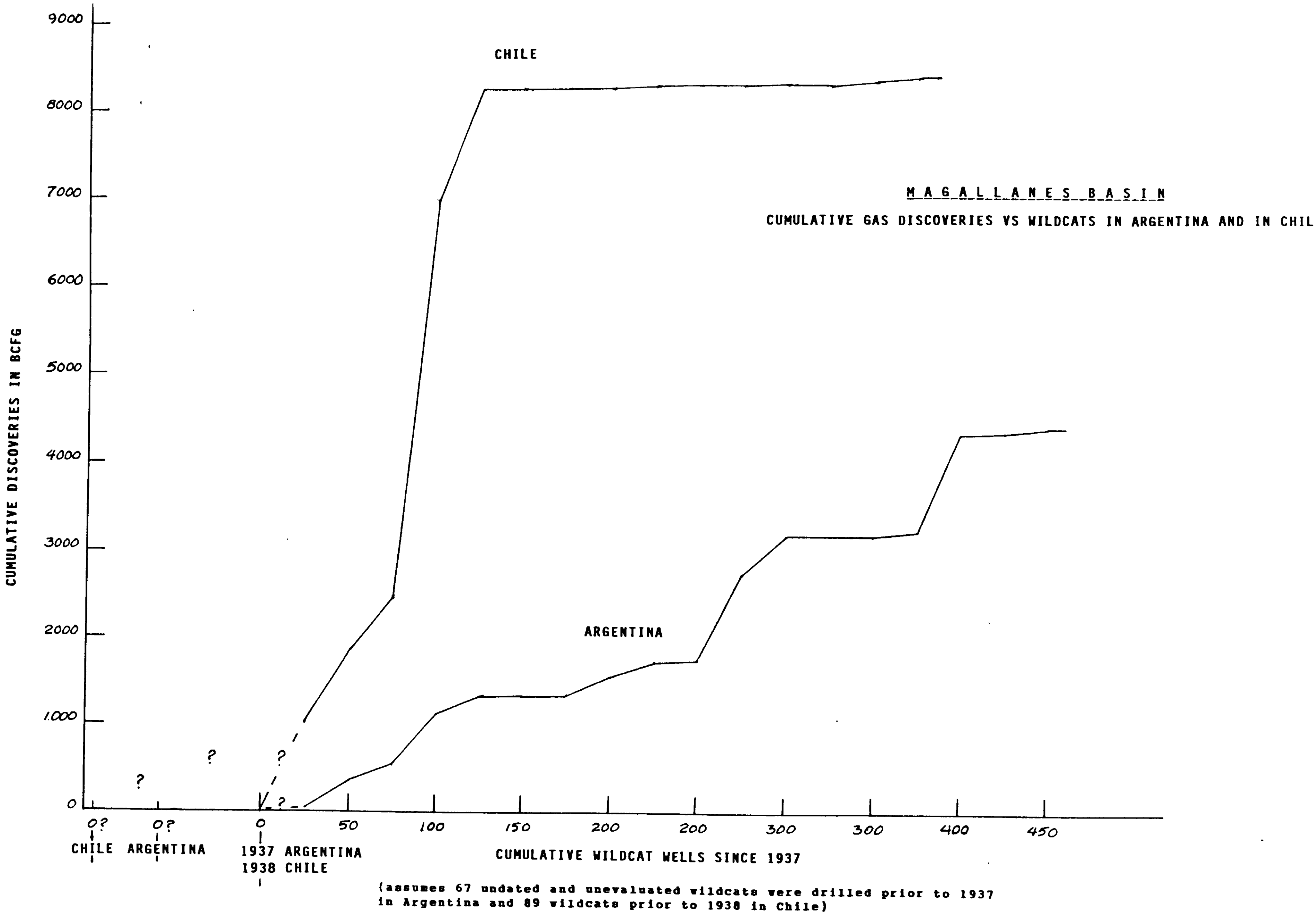


Figure 118 Graph showing relation of the cumulative amount of gas discovered to the number of wildcats drilled in the Argentina and Chile positions of Magallanes basin. Based on Petroconsultants data (1990) which may be incomplete.

Malvinas Basin

Area: 25,000 (64,750 km^2)

Original Reserves: (probable): .010 BBO, .075 TCFG

Description of Area: The Malvinas basin is assumed to be primarily a foreland basin separated from the Malvinas Trough (figs. 119, 120). As assessed here, it is bounded on the west by the axis of the Dungenes Arch and its southward extension. On the south it is bounded by the Scotia Ridge. On the southeast it is bounded by an approximate hinge line between it and the Malvinas Trough at about the 3.5 km sedimentary isopach of fig. 119, and, on the north and northeast by the Malvinas Plateau. The basin is all offshore and in an area of unfavorable weather conditions.

Stratigraphy

Figure 121 isopach map and sections show a thick wedge of Cretaceous sediments thickening off the old, long-standing, south-plunging Dungenes arch and extending around the south plunge of the arch from the Magallanes basin into the Malvinas basin. The Cretaceous rocks of the Malvinas basin were apparently derived from the west, that is, the Dungenes Arch and also from the Malvinas Plateau which appears to have been high during the Cretaceous (fig. 122). The only available details of Malvinas basin stratigraphy are reports that wildcat Ciclon 1 (fig. 121) encountered the Albian-Aptian Margas Verdes Formation at 12,467 ft (3,800 M) and the Neocomian Springhill Formation sandstones at 13,976 ft (6,260 M), and that the wildcat, Salmon X-2, encountered sandstone reservoirs in the Springhill Formation at 8,613 ft (2,625 M) (Petroconsultants 1981, 1982). From this information it is assumed that the stratigraphy of the Malvinas basin is closely similar to that of the adjoining Magallanes basin. The Magallanes basin, except for the Andes-derived Tertiary rocks, is largely a shale basin but with a basal, largely sandstone-bearing unit, the Springhill Formation. The Springhill Formation, as defined by sandstones, is limited to the Magallanes foreland platform changing to shale basinward beyond the platform edge, which is assumed to be the analog for the Malvinas basin, the Springhill equivalent sandstones shaling out towards the Malvinas Trough.

Source. Source shales, as in the Magallanes basin, may be those shales overlying the Springhill-equivalent formation or down-dip in the deeper, central part of the Malvinas basin or in the Malvinas Trough vicinity, where thermal maturity of the source shales may be expected.

Reservoirs and Seals. Reservoirs are Springhill-equivalent basal sandstones thinning southeastwards. Two, and probably three wildcats, have penetrated the Springhill-equivalent sandstones, and in one wildcat, Ciclon 1, five pay zones of 217 ft (66 m) with an indicated flow capability of 9,400 BOPD (but declared "sub-

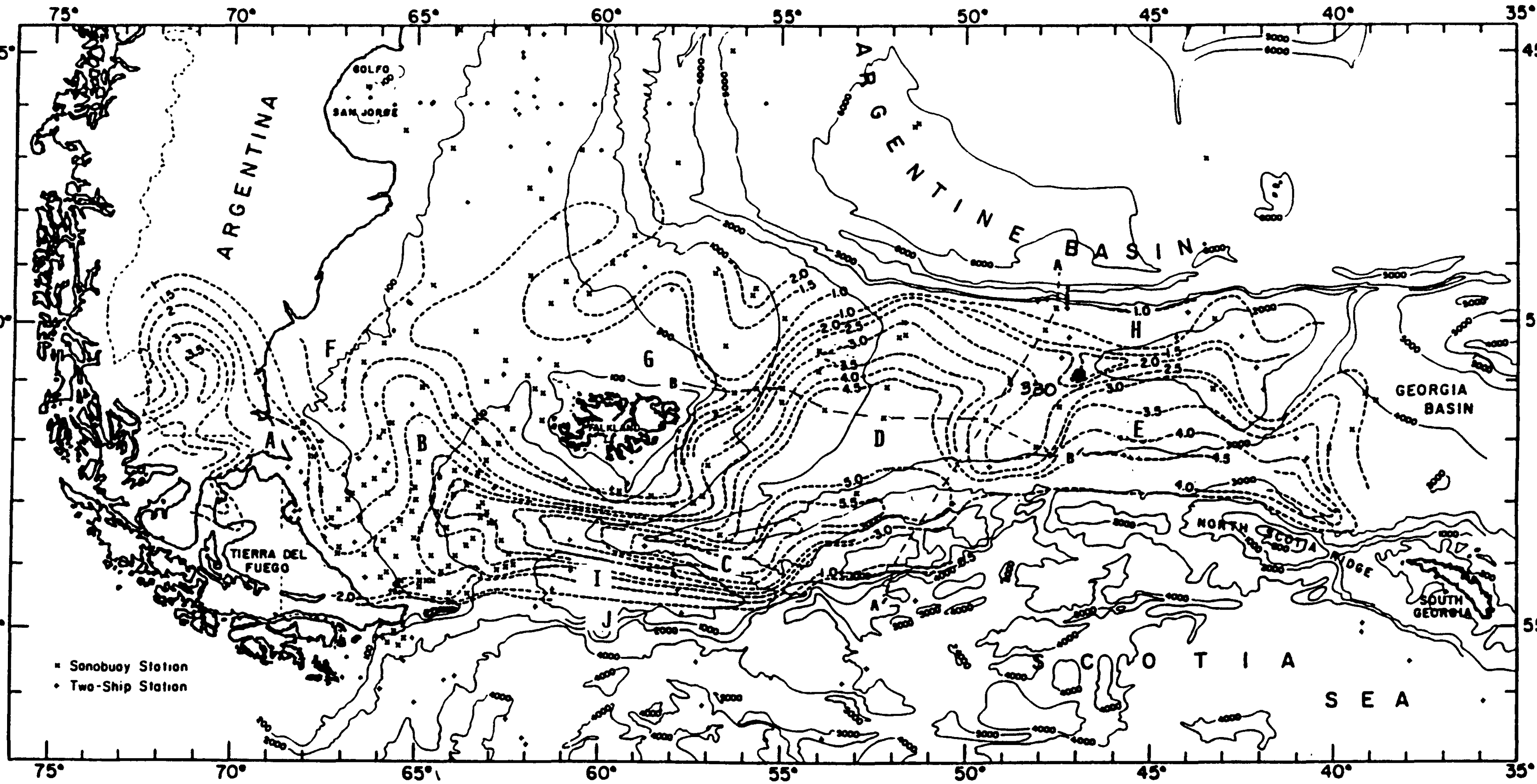


Figure 119 Tentative isopach map (dashed contour line in meters) of sediments of seismic velocity less than 4.2 km/sec covering the Malvinas (Falkland) platform and vicinity (modified from Ludwig et al, 1978). Isobath solid line in meters. A-Magallenes (Austral basin; B-Malvinas basin; C-Malvinas (Falkland) Trough; D-Malvinas (Falkland) Plateau; E-Eastern Basin; F-Dungenes Arch (high); G- Falkland (Malvinas) platform; H-Ewing bank (Falkland High); I-Burdwood Bank; J-North Scotia Ridge, 330=JOIDES borehole, Sections A-A′ and B and B′ shown in figure 123; black dot refers to JOIDES borehole 330 (modified from Ludwig et al, 1978).

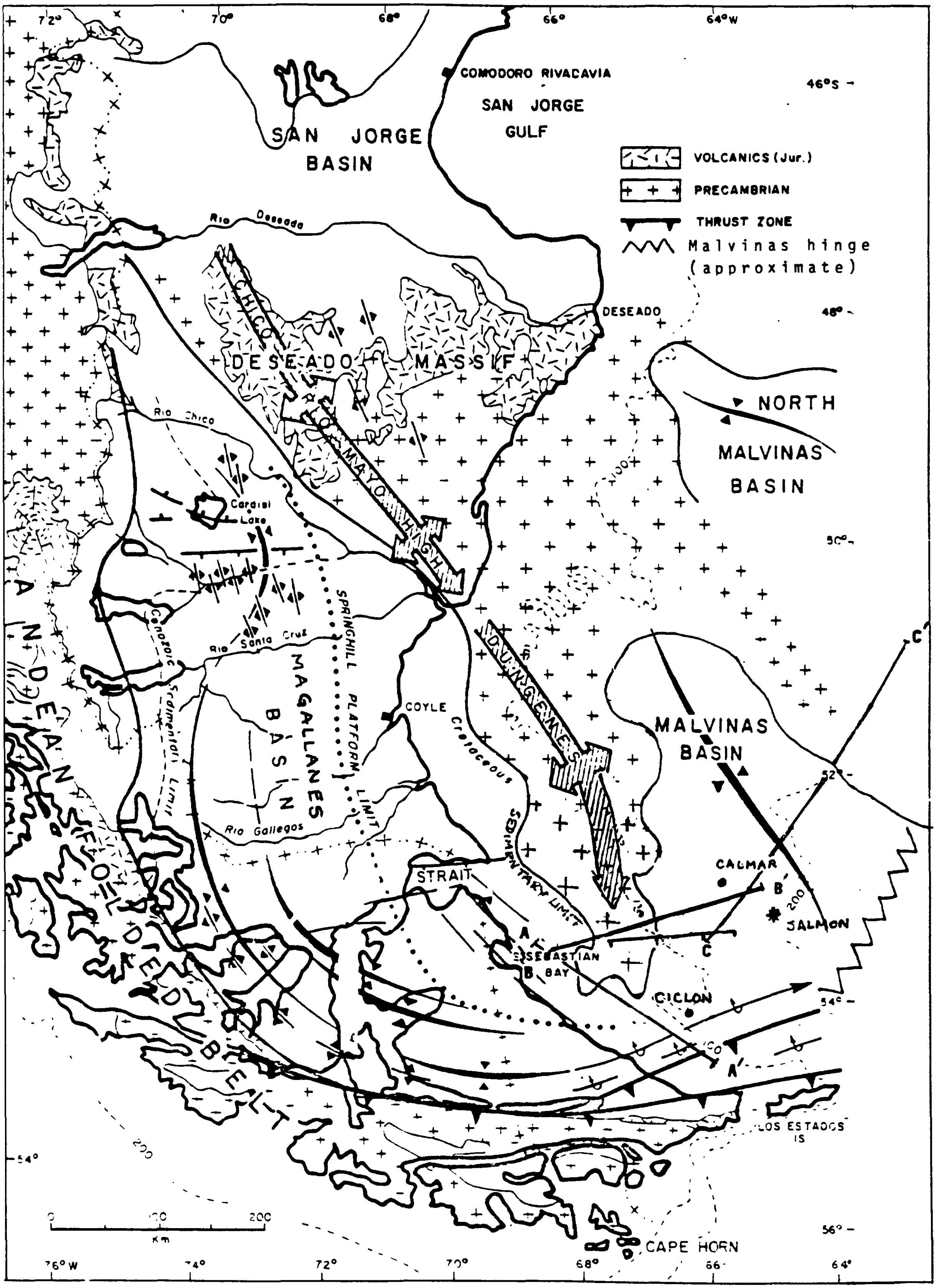


Figure 120 Tectonic element map showing the relation of the Malvinas Basin to the Magallanes Basin (modified from Urien, 1981).

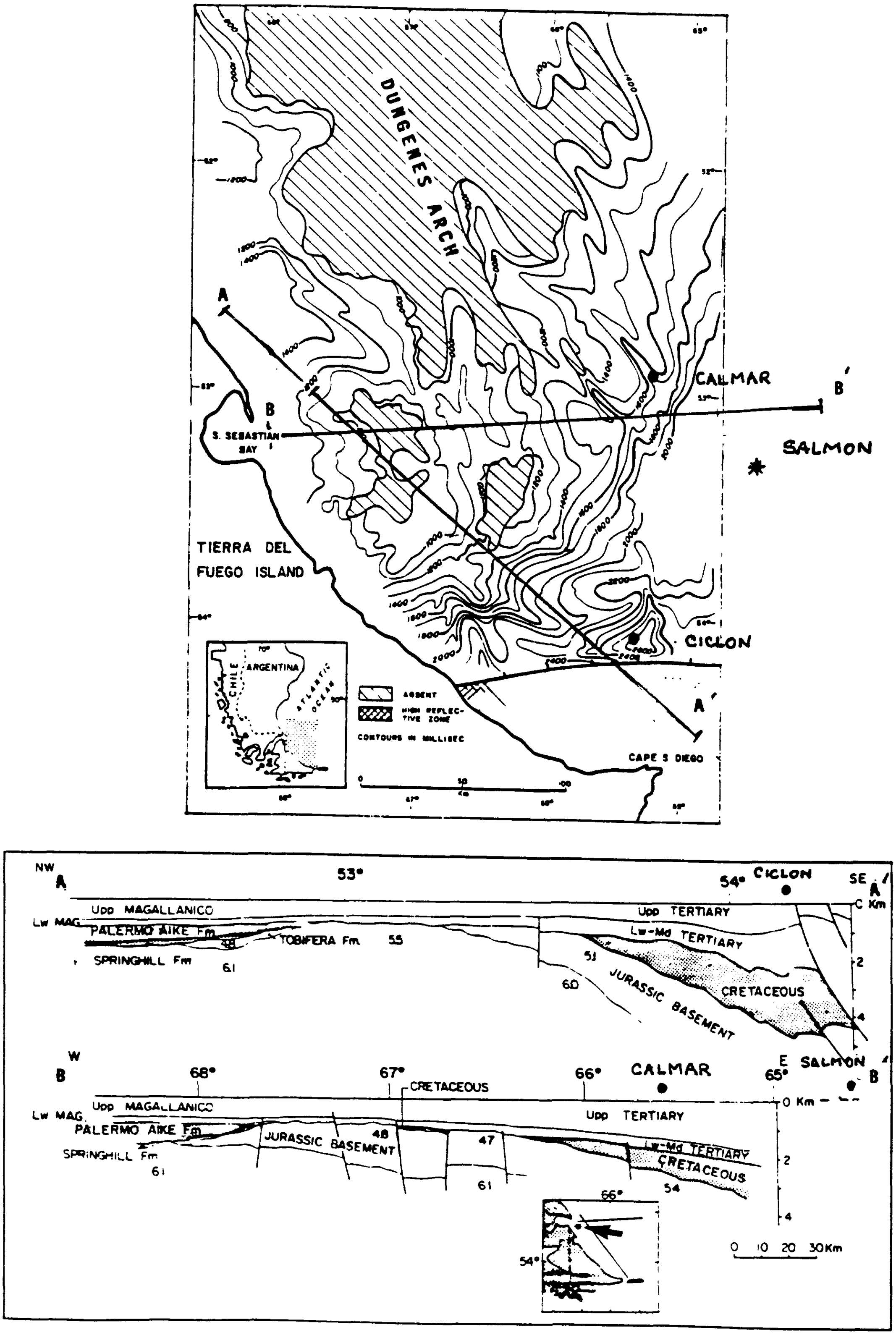


Figure 121 Time isopach map of the Cretaceous sediments adjoining the Dungenes Arch in the Magallanes and Malvinas basins and cross sections across the Dungenes Arch (from Petroconsultants, 1988).

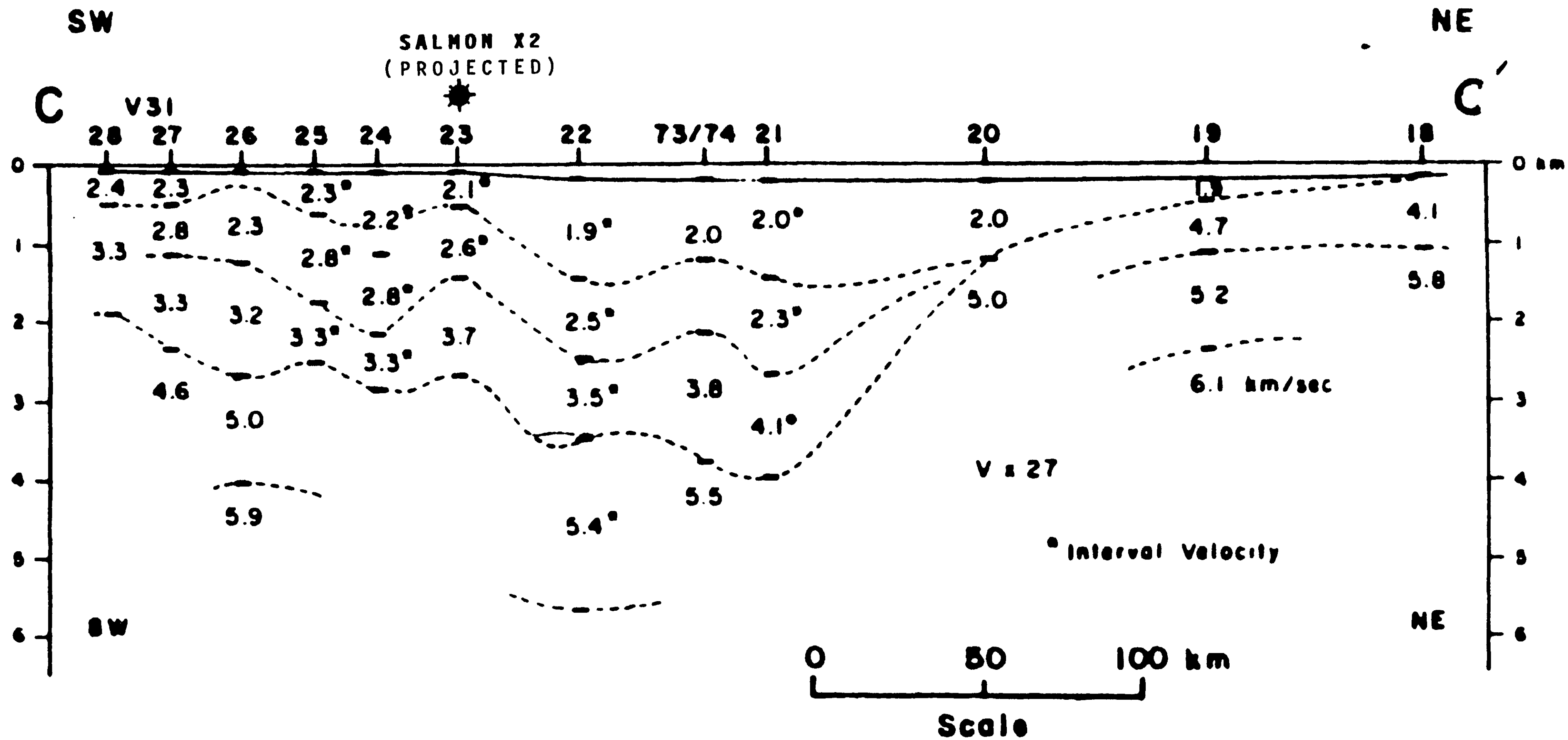


Figure 122 Seismic structure section across the Malvinas basin showing refraction velocities of stratigraphic intervals. Units having seismic velocities less than 4.2 kilometers per second assumed to be sediments. Location figure 120 (from Ludwig et al, 1978).

commercial") were found. Another wildcat, Calmon X2, flowed 20,000 MCFGD + 600 BCPD. A third wildcat in the basin had a flow rate of up to 3,100 BOPD probably from Springhill sandstones (Petroconsultants 1981, 1982).

By analogy to the Magallanes basin a thick shale section in the upper Cretaceous should provide ample seal.

Structure

The structure of the western part of the Malvinas basin is deemed analogous to the Magallanes basin which lies in an equal position vis-a-vis the Dungenes Arch (Figs. 119, 120, and 121). Figure 122 is a seismic structure section across the Malvinas basin indicating its general shape. While the western, Dungenes Arch, flank is a low-dipping, irregular slope, the eastern, Malvinas Plateau, flank is steep and probably faulted.

It is assumed that, like the Magallanes basin foreland, the Malvinas basin is a stable shelf effected by the same degree of normal faulting as effected the Magallanes basin. From this analogy Jurassic and Early Cretaceous rifting provides the principal structure, producing an irregular horst and graben surface and forming potential fault and drape traps.

Generation, Migration, and Accumulation. Continuing the analogy with the Magallanes basin, and assuming similar thermal history, it appears that the source shales which adjoin the Lower Cretaceous Springhill-equivalent sands would have reached thermal maturity at about 10,000 ft (3 km) in the Malvinas Trough, and perhaps the axial part of the Malvinas basin, during Tertiary time. The Early Cretaceous sandstone reservoir quality, as indicated by the flows from the few penetrating wildcats and by analogy to those of the Magallanes basin, is assumed to be largely unaffected by diagenesis and of good reservoir quality.

Plays. As in the case of the Magallanes basin, there appears to be only one significant play that is the petroleum accumulated in Springhill-equivalent basal sandstone trapped in fault block structures and in drapes over an irregular surface.

Exploration History and Petroleum Occurrence. Exploration extended from the Magallanes basin to the Malvinas basin leading to the drilling of some 11 wildcats from 1980 to 1982 (Petroconsultants, 1989). Apparently little further exploration was accomplished as a result of the Falkland war although the prospects appeared somewhat promising. Of the 11 wildcats, 3 were declared discoveries, i.e., Calamar, Ciclon and Salman 2x, with estimated total reserves of .01 BBO and .075 TCFC according to Petroconsultant (fig. 120, 121).

Estimation of Undiscovered Oil and Gas

The primary play is limited by the shelf area of appreciable reservoir (Springhill sandstone) thickness. This shelf sandstone area is assumed to extend eastwards from the Cretaceous pinch out on the Dugenes Arch (fig. 121) to the steep (faulted?) edge on the Malvinas Platform. It is limited to the southeast by the Malvinas Trough (fig. 119) where it presumably shales out (at about a line joining the southern tip of South America to the western tip of the Falkland Islands). Altogether the play area encompasses an area of some 25,000 mi^2 (65,000 km).

By a straight areal analogy to the ultimate petroleum resources of the Springhill Formation-covered foreland shelf of the Magallanes with an area of 57,400 mi^2 (148,700 km^2), the resources of the Malvinas basin is .430 BBO and 6.470 TCFG. However, because of the uncertainty as to the extent and quality of reservoirs and source rock, this estimate should be reduced by about half to .215 BBO and 3.235 TCFG.

Malvinas Plateau

Area: 40,000 mi^2 (140,700 km^2)

Original Reserves: 0

Description of Area: The province occupies an elongate east-west plateau extending eastward from the Falkland islands some 620 mi (1,000 km). More specifically, it is east of the Falkland (Malvinas) Platform (58° E) and south of the North Malvinas fracture zone, or Falkland Escarpment, separating it from the Argentine basin (49° S). It is west of the Ewing Bank, (or Falkland high) (49° E) and its southwest nose, and north of the Malvinas Trough (53° N) (fig. 119).

Another on-trend small basin, the so-called Eastern basin exists to the east of the Ewing Bank area, but is deemed unlikely to have sufficient reservoirs or depth, and is not discussed further.

Stratigraphy

The known stratigraphy of the Malvinas Plateau is based on a group of three JOIDES bore-holes, drilled in the northeast up-dip corner of the province, and on interpretation of refraction seismic surveys of Ludwig et al (1978). On the assumption that the seismic velocity of sediments generally average less than 4.2 km/sec and that Tertiary sediments are less than 2.0 km/sec, the sedimentary section in the center of the basin is 4.5 km (14,800 ft) (fig. 119) and the thickness of the Mesozoic section reaches at least 3 km (10,000 ft) (fig. 123). The stratigraphically deepest of the bore-

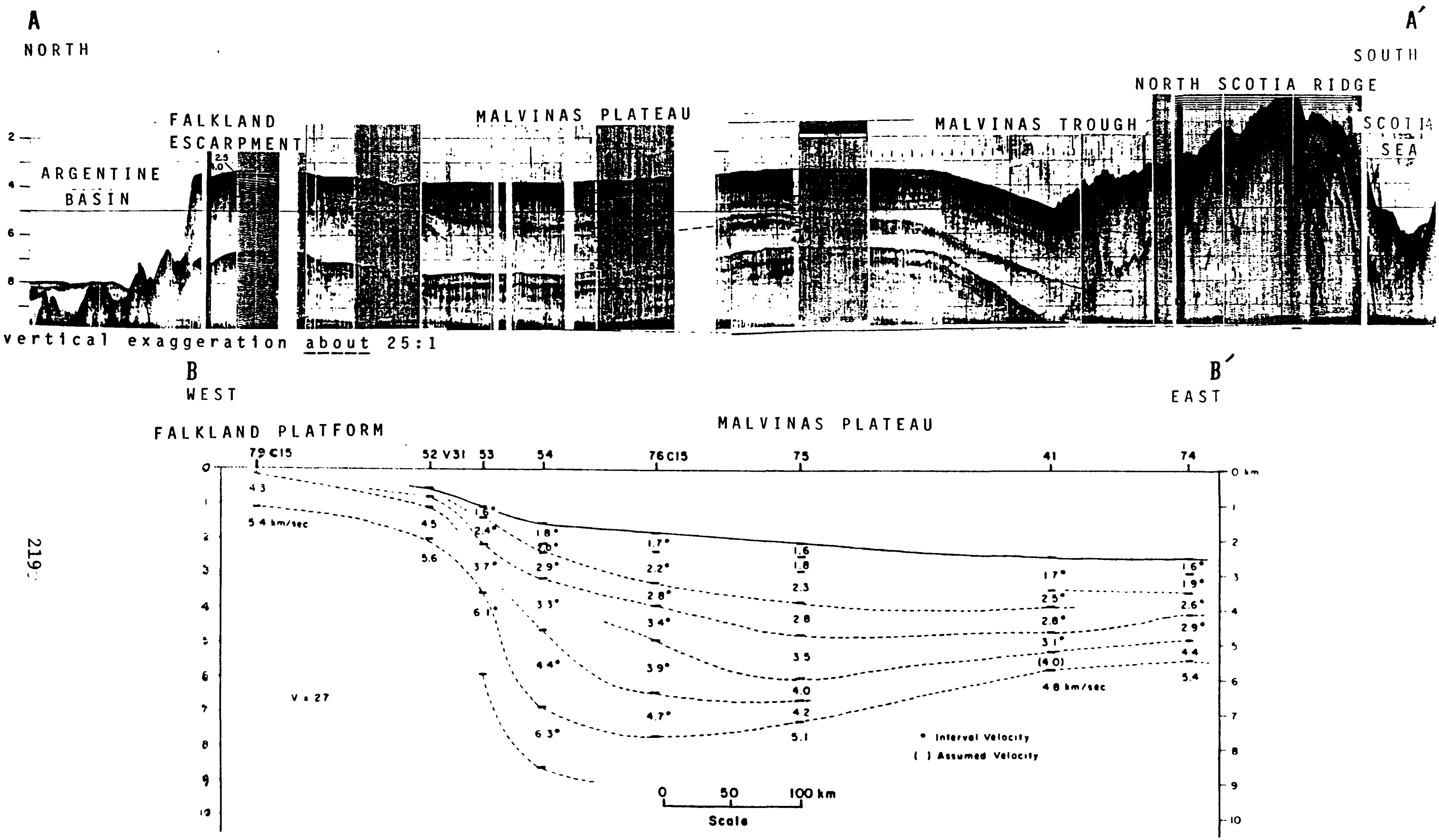


Figure 123 A seismic reflection section A-A′ north-south across Malvinas Plateau and B-B′ a seismic refraction section west-east across Malvinas Plateau. Locations figure 119 (from Ludwig et al, 1978).

holes, 330 (fig. 119) of 1,887 ft (575 m) revealed the following: 1) a basal, fluvial sandstone overlain by marine silts and clays representing continental to shelf deposition in a transgressive mode, 2) beginning in Upper Jurassic and extending through the Aptian dark euxinic claystones were deposited, representing a restricted marine condition, and 3) in Albian time open marine sedimentation began, represented by oozes and clays, which continued up through the Tertiary (Scientific Staff, 1974).

Source. The Upper Jurassic-Lower Cretaceous euxinic claystones are potential source rocks; the organic content averages 3 to 4 percent and increases upwards to nearly 6 percent in the Aptian claystones (Scientific Staff, 1974). The color of the organic matter is yellowish brown suggesting a thermal maturity near the top of the oil window despite the present shallow depth of 660 ft (200 m) to 1,300 (400 m). An oil show in the basal sand (Urien, 1981) indicates either adjacent or down-dip petroleum source.

Reservoirs and Seals. Reservoirs appear to be very limited on the basis of available information. Only the basal sandstones encountered in the JOIDES bore-hole 330 have reservoir possibilities and these are poorly sorted in the lower part and clayey in the upper part; only a basal beach sandstone of less than 20 ft (7 m) thickness may have potential. In what appears to be a dominantly shale basin, seals are not a problem.

Structure

The general structure of the Malvinas Plateau basin is shown in figures 119 and 123. It is essentially a part of a continental crust fragment lying between two major regional wrench or transform features, the Falkland Fracture Zone, and attendant Falkland Escarpment on the north and the North Scotia Arc or Ridge and attendant Falkland trough on the south (fig. 123). In cross-section (A-A′, fig. 123), the floor of the basin slopes southward from the Falkland scarp, flattens, or sags, over most of the basin and then steepens into the Falkland Trough. Along strike (B-B′, fig. 123) it has a relatively steep (faulted?) western flank with the Falkland (Malvinas) Platform and rises gradually eastwards towards the Ewing Bank area.

There is no available information concerning structural traps. The most likely would be fault trap and drape closures associated with foreland-type normal faulting, such as occur in the Magallanes foreland and are thought to occur in the Malvinas basin.

Generation, Migration, and Accumulation. Surveys by Ludwig, et al (1978) indicate that the thickness of the sedimentary rocks in the center of the basin is 4.5 km (14,800 ft) (fig. 119) of which the Mesozoic section is as thick as 3 km (10,000 ft) at its deepest point. Assuming an average foreland thermal gradient (1.4° F/100, 25.5° C/km) and a burial depth of 10,000 ft (3 km) required for peak oil generation, only little oil would have been generated before mid-Tertiary time. Oil would have been generated earlier and perhaps in greater volume in the adjoining-to-the-south, thicker, presumably more shaley, Malvinas (Falkland) Trough (fig. 123). However, the apparent lack of sandstone for conduits and reservoirs would preclude much lateral migration from the trough or, indeed, within the Malvinas Plateau. Trap formation would be mainly in the form of normal fault-associated closures in Early Cretaceous time and the reservoirs would probably be of Jurassic or Early Cretaceous age. Since it appears migration would be much later than trap or reservoir formation and since the section is largely shale, effective migration, and particularly lateral migration, would be difficult and large accumulation would be inhibited.

Plays. There seems to be only one major play, i.e., basal sandstones involved in normal fault-associated closures.

History of Exploration and Petroleum Occurrence. No petroleum exploration has been carried out in this offshore, remote area of deep-water and hostile weather.

Estimation of Undiscovered Oil and Gas

The Malvinas Plateau basin is regarded as a largely foreland basin and, as such, is analogous to the Magallanes and Malvinas basin. By a straight areal analogy to the Malvinas basin, the petroleum resources amount to .69 BBO and 10.35 TCFG. However, the apparent lack of appreciable reservoirs would downgrade the prospects of this basin to only 10 percent of the Malvinas basin, indicating petroleum resources of some .07 BBO and 1.0 TCFG.

Malvinas (Falkland) Trough

Area: 32,800 mi^2 (85,000 km^2)

Original Reserves: None

Description of Area:

The Malvinas Trough extends eastwards between the North Scotia Ridge on the south, and on the north, the Malvinas Basin, the Falkland Platform or Massif, the Malvinas Plateau and the Eastern Basin, which together may be considered a foreland to the trough (fig. 119, 123). The Malvinas trough includes the Burdwood Bank.

Stratigraphy

The stratigraphy is unknown, but seismic data (fig. 123) indicate that the stratigraphic units of the Malvinas (Falkland) Plateau extend into the north side of the Malvinas Trough. It is assumed that analogous to the situation in the on-trend Magallanes basin, the Cretaceous section becomes more shaly away from the shelf. The Magallanes very thick, relatively sandy, Tertiary section, however, is largely of sediments derived from the bordering fast-rising, batholith-containing Andes, while the Malvinas Trough's bordering, relatively low, North Scotia Ridge probably delivers only minor sediments to the trough (fig. 123).

Structure

The Malvinas Trough lies between the North Scotia Ridge and a platform or foreland, made up of the Malvinas Platform, the Falkland Massif, the Malvinas Plateau and the Eastern basin. The North Scotia Ridge appears to be a transpressional ridge along a sinistral wrench zone along which there is a component of southward subduction. The Malvinas foreland dips under the ridge in a manner similar to the oblique subduction on either flank of the docking Indian subcontinent as it moved northward past the adjoining Asian blocks (section A-A′, fig. 123). As may be seen in section A-A′ of figure 123 (vertical exaggeration about 25:1), the northern side of the trough is low-dipping Mesozoic and Tertiary Malvinas sediments possibly cut by some normal faulting, while the southern side is made up of "an upper zone of highly deformed sediments which do not return coherent reflections" (Ludwig, et al 1978) (fig. 123).

Structural closures may be 1) normal fault traps involving the south-dipping strata of the north flank, and 2) more complicated transpressional fault and fold trap on the south flank.

Generation, Migration and Accumulation. Analogous to the adjoining basins, generation and migration did not begin until some time in the Tertiary when sufficient burial depth was reached. Available traps are speculated to be normal fault traps on the north flank and fault and fold closure in the structurally complicated south flank.

Exploration History and Petroleum Occurrence. No petroleum exploration has been carried out in this offshore area of deep water and hostile weather conditions.

Plays. There are two plays, 1) possible fault traps in the north flank and 2) any appreciably-sized fault or fold closure on the complicated south flank.

Resource Evaluation. The north flank monoclinal dip on the northern half of the trough, as seen in section A-A′, figure 123, appears to be stratigraphically similar to the Malvinas Plateau, but would presumably be somewhat more shaly and, therefore, have less reservoirs and less prospects. On the assumption that the Malvinas Trough has only 25 percent of the reservoir volume of the Malvinas Plateau, on an areal basis, the undiscovered petroleum resources would amount to .007 BBO and .1.03 TCFG. The highly deformed southern half would have no commercially-sized accumulation, especially in this offshore area of deep-water and hostile weather.

San Jorge Basin

Area: 48,000 mi^2 (124,000 km^2)
(onshore - 35,000 mi^2, 90,000 km^2)

Original Reserves: 3.45 BBO and 2.67 TCFG, Fitzgerald et al, 1990

South Flank 1.38 BBO and 1.07 TCFG,
North Flank 2.07 BBO and 1.60 TCFG
(4.098 BBO and 5.050 TCFG, Petroconsultants, 1989)

Description of Area. The San Jorge Basin is directly onshore of the San Jorge Gulf, but with about one-third of its area lying northwards so that it is approximately between the Chubut and Deseado Rivers (or between latitudes 44° and 47°S). It extends eastward from the Andes to the Atlantic offshore about as far as the 100 m (330 ft) isobath (fig. 124).

Stratigraphy

The San Jorge Basin is an extensional basin which began to form in the early Mesozoic. Although the basin was open to marine incursion from the west in the early part of its history, i.e., Jurassic, the sediments are largely fluvial and lacustrine rock. These Mesozoic, dominantly nonmarine strata, are divided in four sequences (Fitzgerald et al, 1990) (fig. 125) related to tectonic phases, that is, 1) a Middle to Late Jurassic early rift phase, 2) an Upper Jurassic-Lower Neocomian late rift phase, 3) an Upper Neocomian early sag phase, and 4) an Aptian through Upper Cretaceous late sag phase.

The Middle to Late Jurassic early rift phase sediments consist of dark marine to nonmarine shales and sandstones preserved in minor, poorly known grabens, the marine strata being laid down during marine incursions from the west. These strata are overlain by the predominantly volcanic Lonco Trapial (Tobifera) sequence which, in most places, is considered effective basement (A, fig. 125).

The Upper Jurassic-Lower Neocomian late rift phase sediments are deposited in the waning phase of the rifting. They appear to be largely marine shale with syntectonic sandstones and fan-glomerates deposited on the fringes of the grabens (B, fig. 125).

The Upper Neocomian early sag phase sediments are largely lacustrine shales in the central part of the basin (the D-129 Formation) and dominantly red beds and tuffs (Mate Siete Formation) in other parts of the basin. The D-129 Formation shales are the principal source rocks of the basin (C, fig. 125).

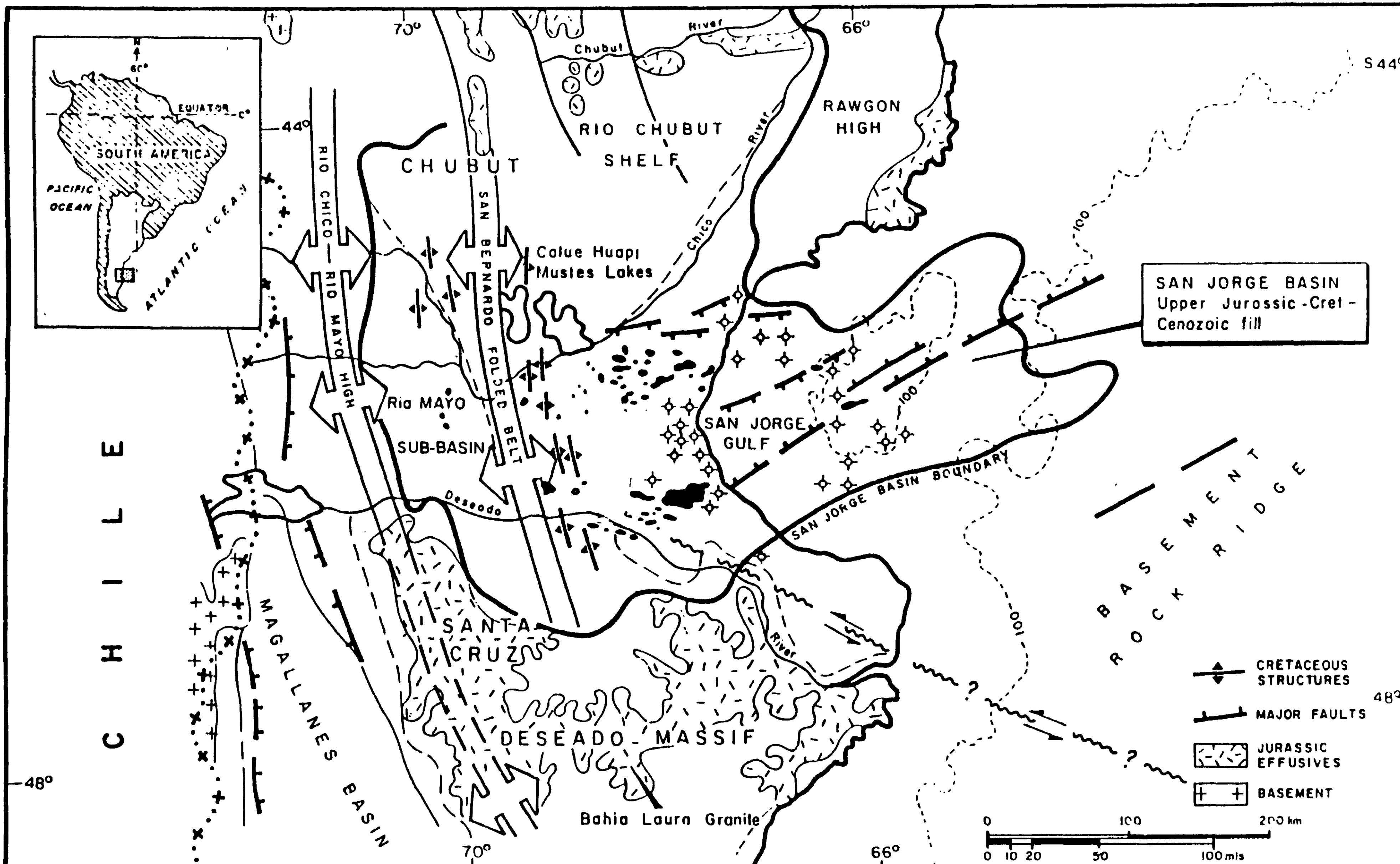


Figure 124 Structural sketch map of San Jorge basin (from Petroconsultants, 1988 after Urien, 1981).

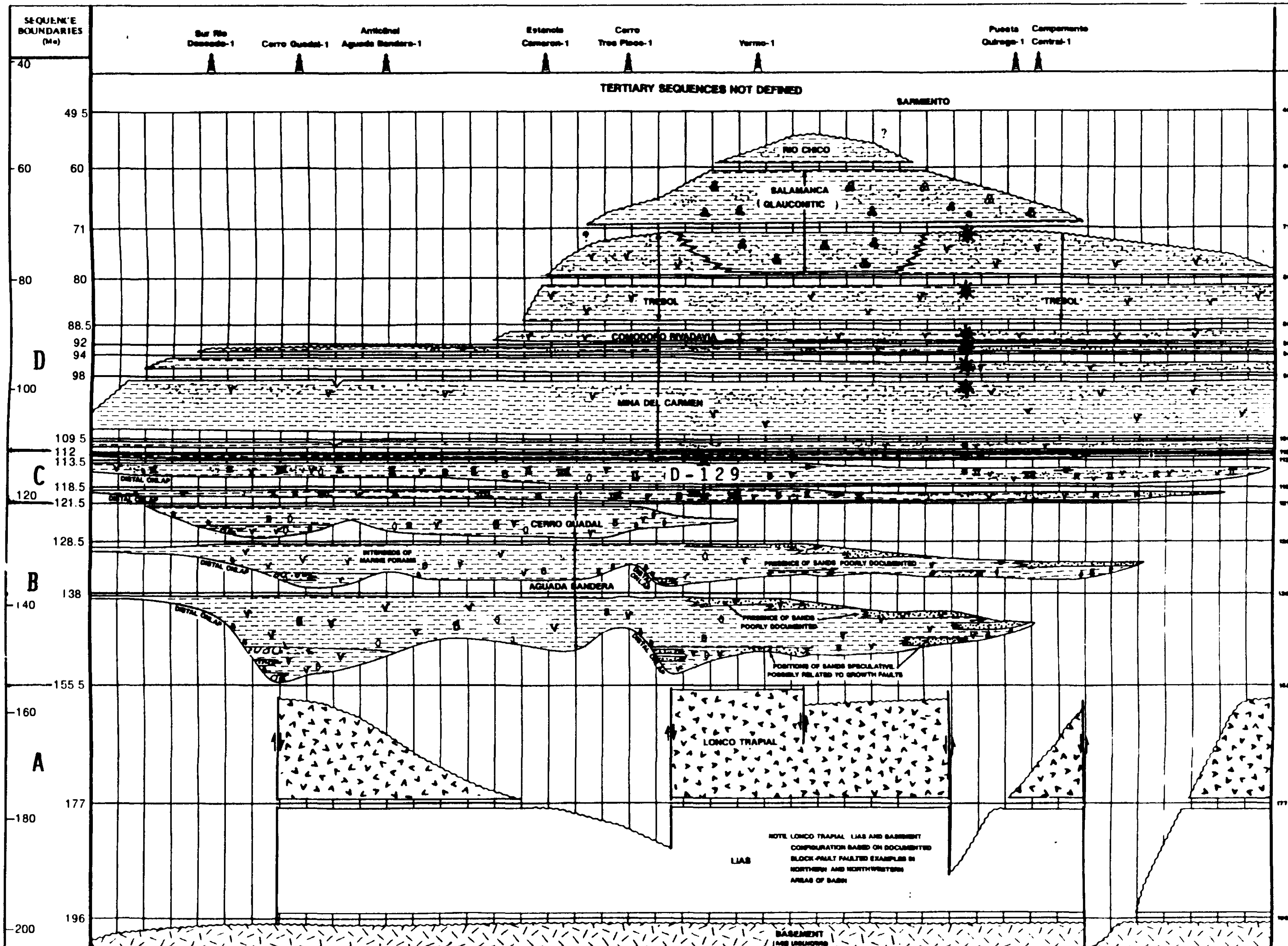


Figure 125 Chronostratigraphic chart, basin on a northeast-trending cross-section of the San Jorge basin (modified from Fitzgerald et al, 1990). Oil and gas-producing horizons are indicated. A-sequence of early rift tectonic phase, B-late rift phase sequence; C-early sag phase sequence, and D-late sag phase sequence.

The Aptian through Late Cretaceous late sag sediments were laid down in a more stable, less subsiding environment, the lacustrine setting giving way to a mostly fluvial late sag environment. Depositional sequences include the Mina del Carmen, Comodoro Rivadavia, and Trebol sequences of the Chubut Group. The Comodoro Rivadavia contains reservoir sandstones which are the major producers of the basin. The sandstones of the Mina de Carmen are also significant producers (D, fig. 125).

Source Rock. Early rift-fill dark marine and lacustrine shales of limited areal extent may be potential source rock (A, fig. 125), but are now overmature throughout most of the basin. The principal source rock of the basin is the widespread, organic-rich, dark shales and mudstones of the D-129 Formation which were deposited in a stratified anoxic lake setting in the center of the basin during the early sag phase of basin development. The shales are thick and moderately organic-rich (0.5 to 4.0%). That these shales are lacustrine rather than marine is supported by the paraffinic, low-sulphur oil produced in the basin. The kerogen type is a mixture of mostly amorphous kerogen, type I and II dominating. The oil proneness increases towards the basin center. The gas oil ratio is low, averaging about 150 (Fitzgerald et al, 1990).

Reservoirs and Seals. Reservoir sandstone are largely in the late sag stage sequences, mostly in the Comodoro Rivadavia Formation, but also in the underlying Mina del Carmen Formation (fig. 125). These stacked fluvial to shallow lacustrine sandstones are regionally persistent. The reservoir quality of the coarse to fine quartz-lithic sandstones tends to be rather poor, because of pyroclastic components, the porosity ranging 15 to 30 percent, averaging 22% with an average permeability of 100-200 MD. The sandstones are in thick fluvial sheets, porous channels, and isolated lenses (Fitzgerald et al, 1990).

The reservoirs are confined by thick shale-tuff seals, but late Cretaceous and Tertiary faulting, very probably, provided some avenues for escape of petroleum.

Structure

Extension and subsidence in the San Jorge basin began during the early Mesozoic as a series of grabens and half grabens with a northwest to northeast trend subparallel to the regional trend of the Patagonian accreted region (fig. 113). The faults may have formed along old sutures between continental fragments accreted in Paleozoic and pre-Cambrian time and may coincide with similar rifting in the Cuyo and Neuquen basin to the northwest. A second Middle to Late Jurassic episode of extension, difficult to distinguish from earlier extensional events, lead to the extrusion of the Lonco Trapial (Tobifera) volcanics which cover most of central and southern Patagonia.

As normal faulting ceased in the Early Cretaceous, the rift system evolved into a broad interior sag which had an early depositional phase (Hauterivian-early Aptian) of lacustrine source rock and fluvial sandstone reservoirs and a later phase (late Aptian-Paleogene) of fluviable reservoir sandstones, but with lean source rocks. During this late phase, in latest Cretaceous time, some further extension occurred and normal faults with apparent strike-slip displacements, formed in alignment with the South Atlantic transform faults. Most of the hydrocarbon-producing traps are fault-related closures developed in this period (Fitzgerald et al, 1990).

Finally, Tertiary uplift and compression accompanying the Andean orogeny, or regional transpressional movement, caused the north-trending San Bernardo fold belt. Figure 124 shows the west- trending graben shape of the San Jorge basin being abruptly interrupted by this north-trending San Bernardo fold belt.

San Jorge basin ceased being an individual depocenter in the Tertiary.

Traps. The most common structures are west to northwest-trending normal fault-related traps. Faulting was at its peak during Jurassic-early Cretaceous time, coinciding with the principal time of basin. However, the majority of the hydrocarbon-producing structures were formed later, during latest Cretaceous and early Tertiary time. Two major types of normal faulting are common: 1) reactivation of basement involved faults, and 2) detached, normal listric faults. Figure 126 is a cross-section showing these two types of latest Cretaceous faulting and associated rollover structure fields. Figure 127 shows three fault trends: 1) the presumably older northwest trend in the northwest, 2) north-trending reverse faults of the San Bernardo fold belt, and 3) latest Cretaceous early Tertiary west-trends of the eastern, largely offshore, part of the San Jorge basin. The most common producing traps are listric-fault-associated lowside rollovers, although highside rollovers and fault closures occur. It appears that the faults provide avenues of migration between source and reservoir rocks.

North-trending compressional Neogene anticlines are significant in the San Bernardo trend (fig. 124). Despite their favorable geometry these folds hold only a small fraction of the hydrocarbon found in the basin since their prospective Cretaceous section is often partially breached by erosion, the reservoirs are poor, and trap growth was largely after the main phase of hydrocarbon migration (Fitzgerald, et al, 1990).

Generation, Migration and Accumulation. Hydrocarbon generation in the principal source shales of the D-29 Formation probably began in the Late Cretaceous when they first subsided into the oil generating zone, the top of which, assuming stable Cretaceous-Tertiary conditions, would be at 2 to 4 kilometers (5,000 to 13,000 ft) (fig. 128). The D-29 shales have now largely subsided through the oil generation zone into gas generation zone, but the low gas-oil ratio (150) of present oil production suggests that much of the migration had already taken place before the Tertiary part of the subsidence. Formation of the fault-related hydrocarbon-producing traps was largely in the latest Cretaceous and early Tertiary. The better reservoirs are largely in the

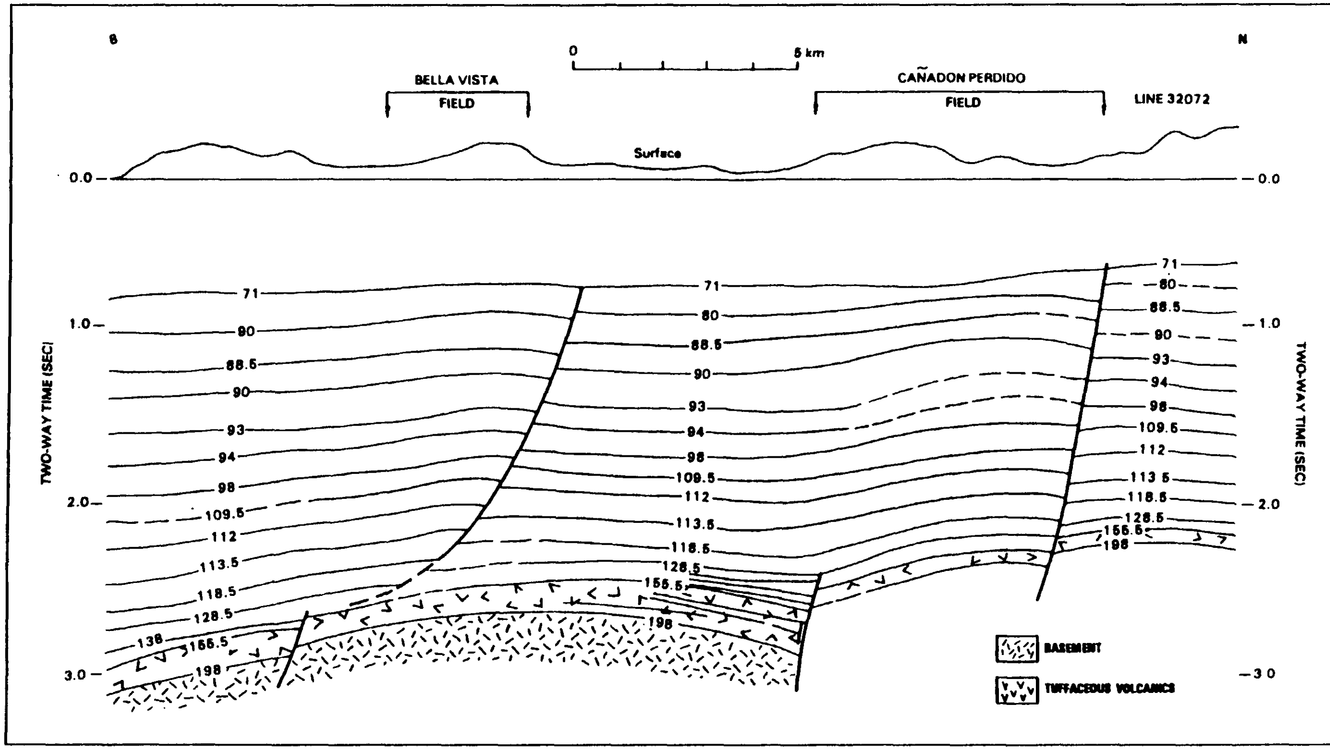


Figure 126 Cross-section of Bella Vista and Canadon Perdido Fields showing two styles of normal faults and relation of fields to faulting reflection horizon. Numbers are in millions of years before present. Location in figure 129 (from Fitzgerald et al, 1990).

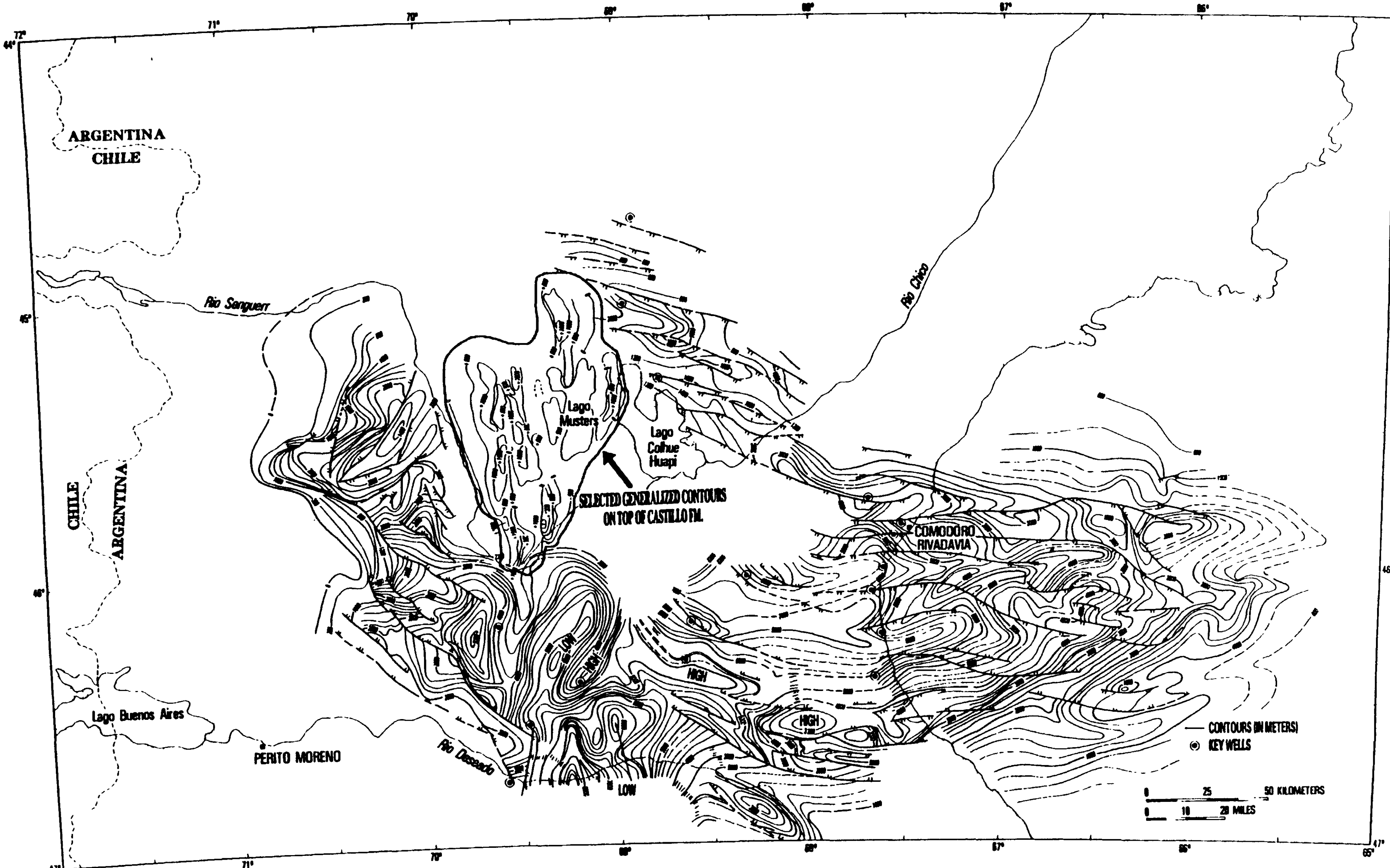


Figure 127 Structure contour map on the top of the Lonco Trapial volcanics of the San Jorge basin showing the fault block structure typical of the basin (Fitzgerald et al, 1990).

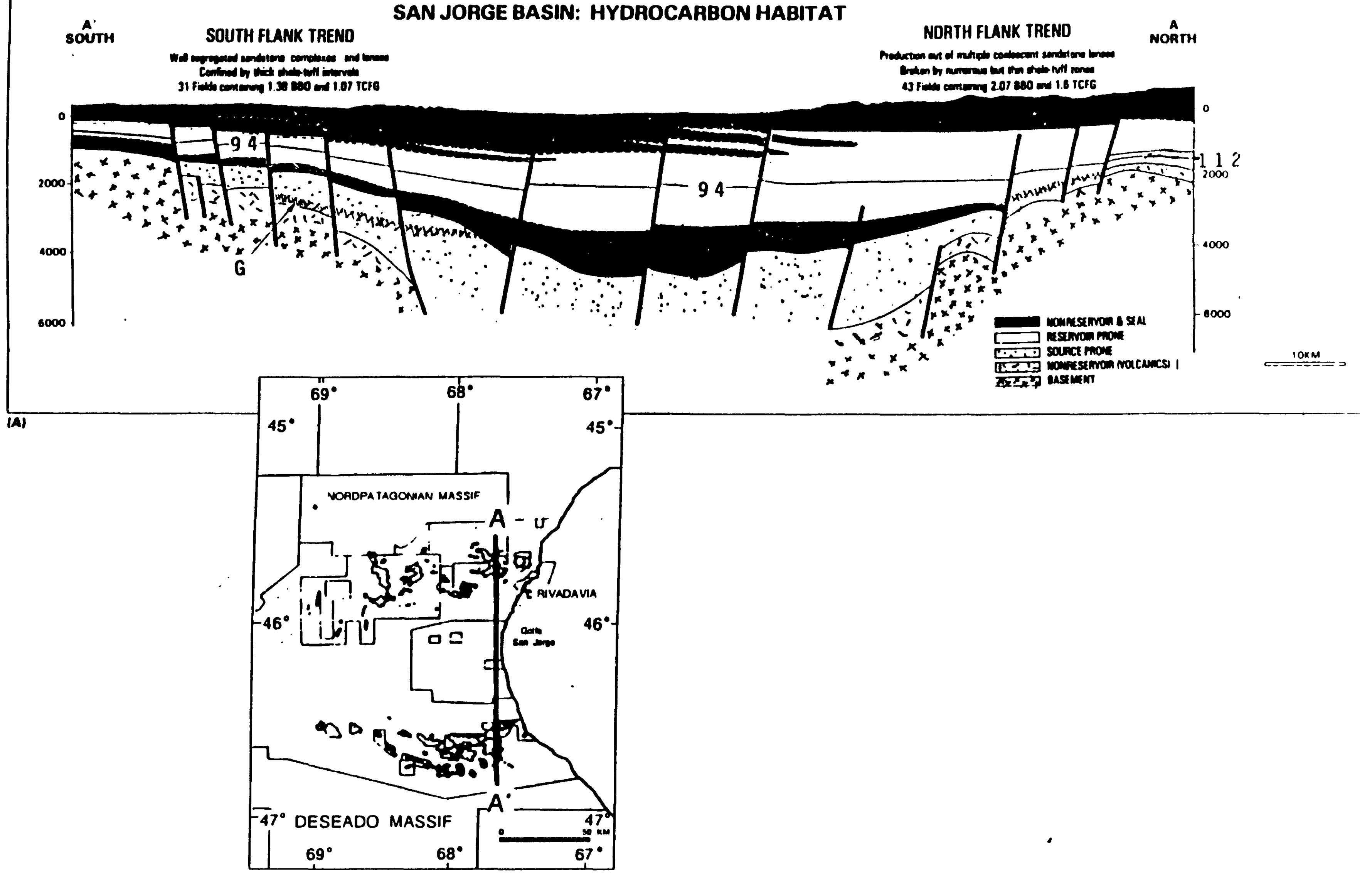


Figure 128 Cross-section of the San Jorge basin showing the source-prone, reservoir prone and non-reservoir and seal parts of the basin stratigraphy. G=onset zone of oil to gas conversion. Numbers are million years before present (Fitzgerald et al, 1990).

Upper Cretaceous and some in the Middle Cretaceous sequences. It appears, therefore, that traps and reservoirs formed and were in place during the migration period.

Plays. There are essentially two plays both involving largely Upper Cretaceous sandstones (Chubut Group) in 1) fault traps, rollovers, and drapes, and 2) folds and thrust fault-traps of the San Bernardo trend. The first of these plays is of paramount importance, the second appears to have negligible potential.

History of Exploration and Petroleum Occurrences. Oil was first discovered in 1907 and the basin has been under exploration ever since. The wildcat success rate was about 24 percent according to Petroconsultant data. Figure 129 shows the distribution of oil fields in essentially two bands flanking the depocenter of the basin. A graph of cumulative discovered oil and gas against cumulative discovery wildcats show the history of exploration (fig. 130). The early wildcat results are not available but after 15 discoveries, in 1916, some 520 MMBO and 2,180 BCFG had been found. Work done after the early 1950's benefited from systematic field mapping, intensive and deeper drilling, and geophysical surveys, as indicated by the steep rise of the cumulative discovery curve from 35 discoveries onwards. The rising curve flattens at about 75 wildcats for oil and 65 for gas and thenceforth rises at a low, rather uniform rate, indicating small-sized fields in a maturely explored basin.

Evaluation of Undiscovered Oil and Gas

The only available data regarding discovery size versus the number of consecutive wildcats are from Petroconsultants. The data are incomplete owing 1) to the omission of completion dates for 70 wildcats (but which are assumed to be the older wildcats, prior to 1916?), 2) to the lack of coordination of the successful wildcat designations with eventual field names, and 3) to undefined reserves of recent discoveries. The flattening of the steeply rising curve of cumulative oil discovery size versus wildcats at about 75 wildcats indicates a fairly uniform rate thereafter of 1.9 MMBO per discovery (95 MMBO/50 discoveries). Similarly, the gas curve, which flattens at about 65 discoveries, rises at a rate of about 6.23 BCFG per discovery (374 BCFG/60 discoveries). It is assumed that: 1) these low flat rates persist into the future, 2) that the wildcat success rate of .24 remains constant (increasing finding fig 129 difficulty offset by increasing technological improvements), and 3) that, given the somewhat complex geology, the same number of wildcats (i.e. 427 as of 1989) will be drilled in the future as in the past. Under such assumptions, about .195 BBO (427 x .24 x 1.9), and some .638 TCFG (427 x .24 x 6.23) will be discovered in the San Jorge basin.

Unaccountably, from the data at hand, only a few wildcats appear to have been drilled on the two flank trends within the

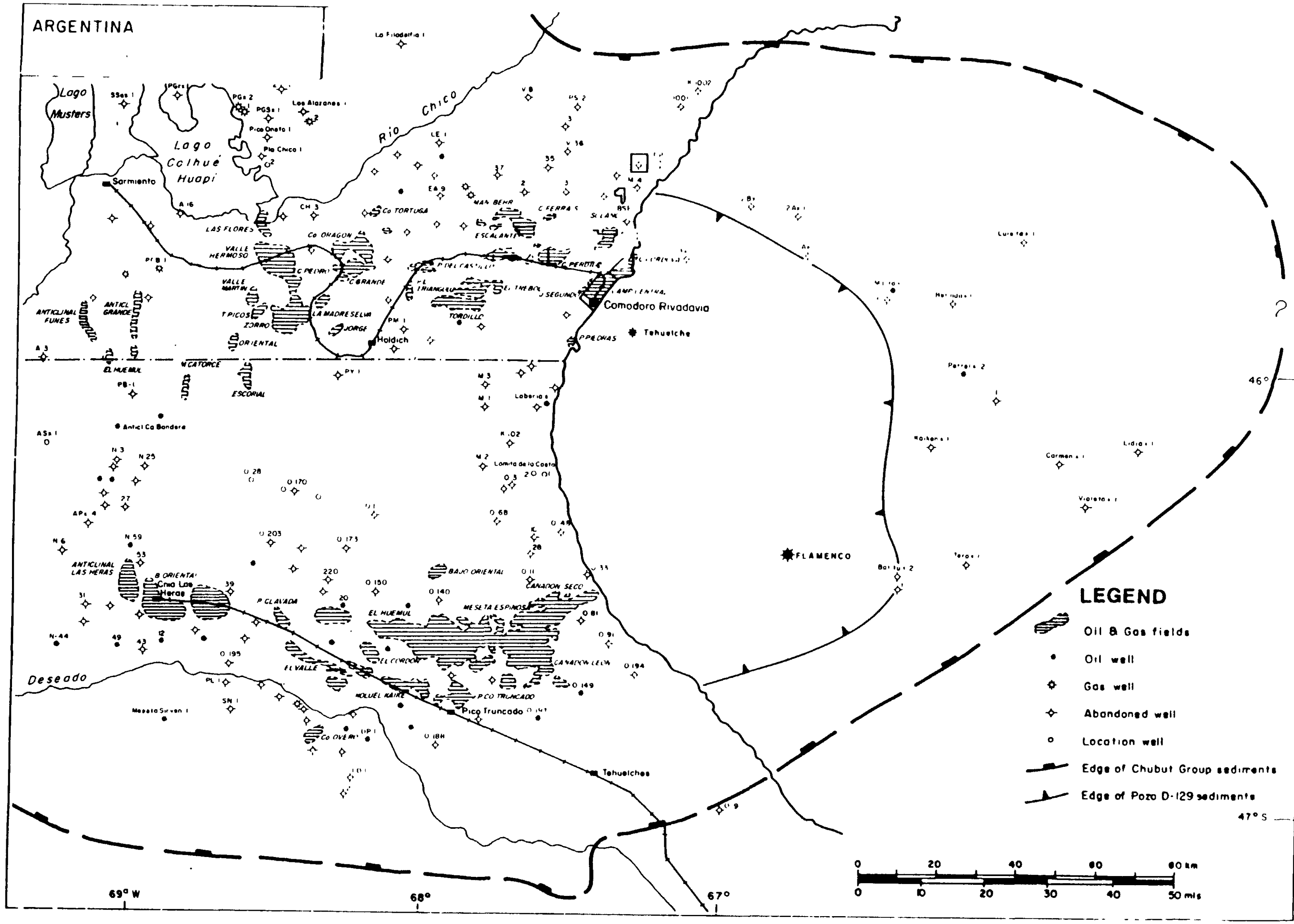


Figure 129 Map of the San Jorge basin showing the oil and gas field distribution as of about 1980, the limits of the Chubut Group (Upper Cretaceous reservoirs) and the offshore limits of the D-129 Formation (principal source) (Petroconsultants, 1980).

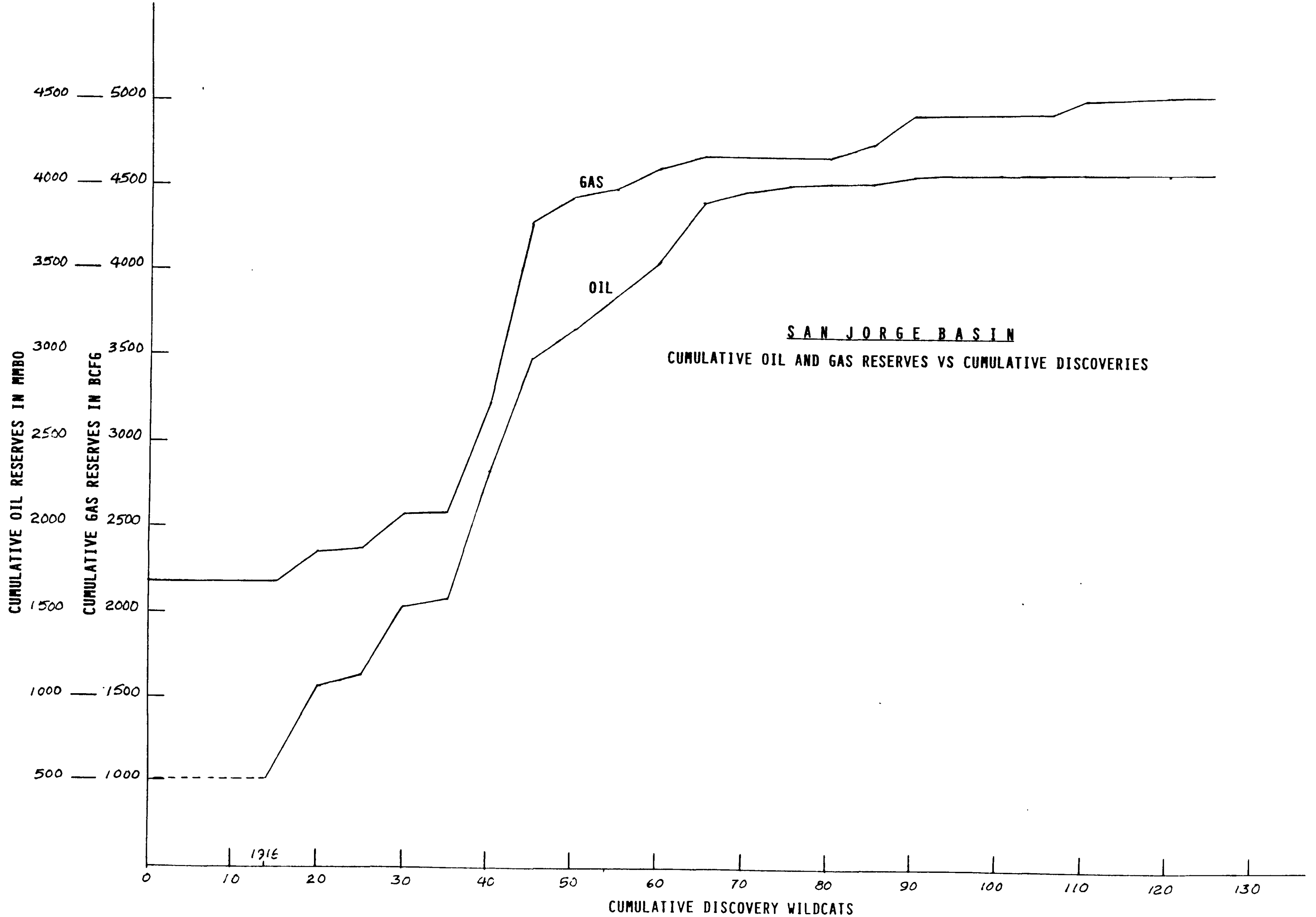


Figure 130 Graph of cumulative oil and gas discoveries versus cumulative wildcat wells drilled from 1916 to 1989 in the San Jorge basin (from Petroconsultant data). Oil curve indicates the basins exploration reaching maturity by a flattening at about 75 wildcats and a low uniform rise (1.9 MMBO per discovery) from there. Gas shows a similar flattening at 65 wildcats and from there a rise of 6.23 BCFG per discovery. Based on Petroconsultants data (1990) which may be incomplete.

offshore inner San Jorge Bay area (fig. 129). The area is underlain by source rock (D-29 shale) and the principal reservoir formations (Chubut Group) of the basin (fig. 129). Figure 127 indicates structure is present. If only one-twentieth of the present basin petroleum reserves are found in this apparently underdrilled, but prospective area, it would raise the estimate of undiscovered petroleum by .17 BBO and .13 TCFG to .365 BBO and .671 TCFG.

Colorado (Bahia Blanca) Basin

Area: 27,000 mi^2 (70,000 km^2)

Reserves: 0

Description of Area: Basin is an east-west elongate, largely offshore basin whose axis intersects the coast at the mouth of the Colorado River (fig. 131).

Stratigraphy

The Colorado basin is an extensional rift zone which apparently began to form during the Cretaceous or Jurassic (C.M. Urien, 1981) Late Cretaceous non-marine sediments, where encountered in an updip position, (e.g. wildcat La Bollena, figs. 131 and 132) overlie basement. The basal unit is largely shale with some mudstone, micritic limestone, anhydrite and sandstone, the Fortin Formation. The age of the Fortin Formation based on palynology is Cenomanian according to Urien (1981), but Uliana and Biddle (1987) believe it to be Middle to Upper Jurassic, (apparently based on work of Lista et al., 1978).

This sequence is overlain by another, perhaps more sandy, flood-plain sequence (the Colorado Formation). These sequences appear analogous to the Chubut Group of the San Jorge basin which contains the principal reservoirs. Seismic data suggests limestone intercalations towards the center of the basin.

Further down dip to the east, the above described beds appear to be underlain by older sediments (of 4.7-5.4 km/sec. velocity sediments, figs. 132 and 133). If the Fortin Formation is indeed Cenomanian, these higher velocity sediments may be Lower Cretaceous. If the Fortin Formation is Middle to Lower Jurassic, the high velocity sediments could be of Paleozoic age.

Overlying the Cretaceous strata are Tertiary, mainly marine shales or claystones and sandstones, which grade into non-marine beds westwards.

Source. No source rock has been penetrated. If the Fortin Formation is late Cretaceous age, by analogy to the San Jorge basin, the down-dip strata below the Fortin Formation may be Lower

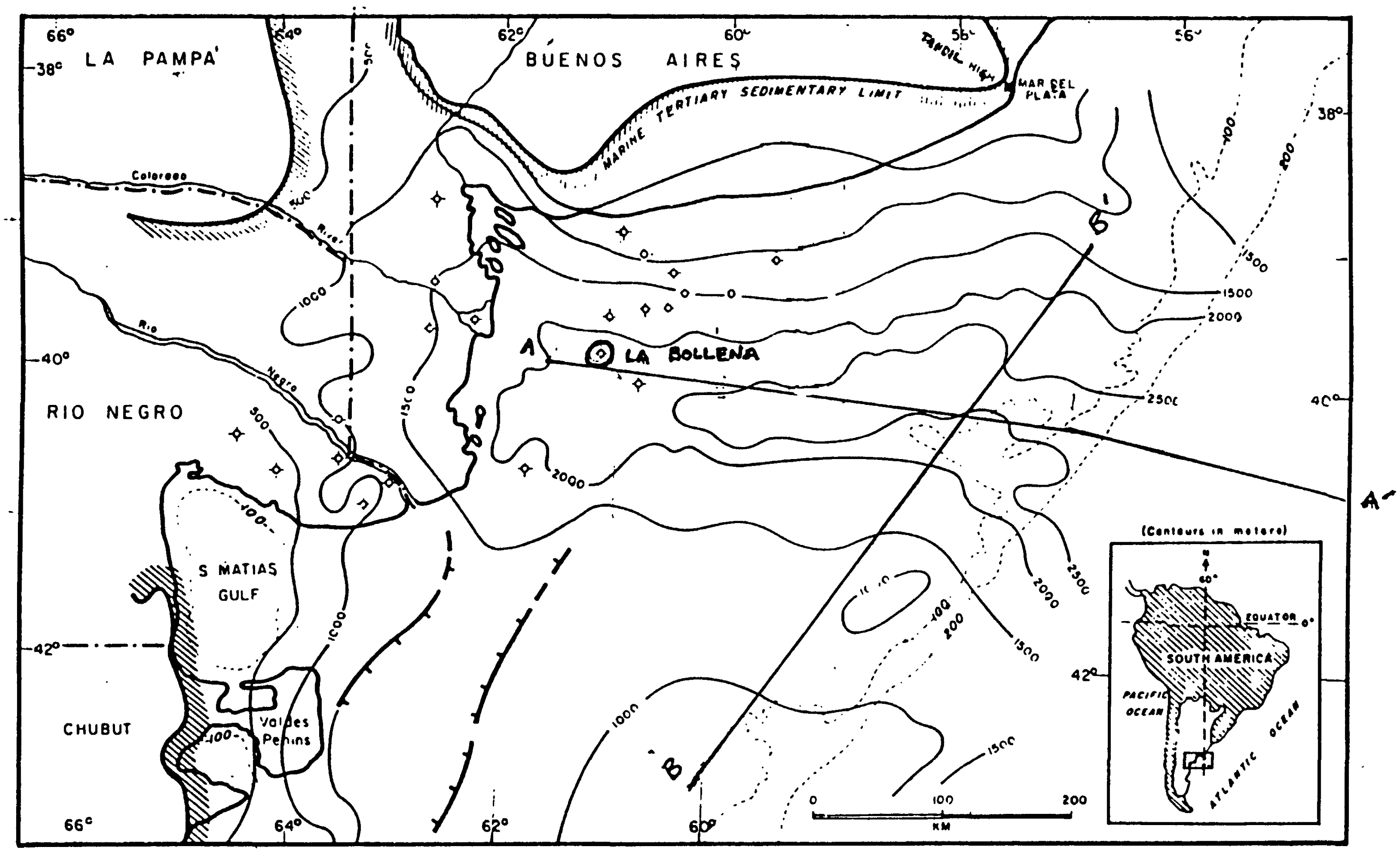
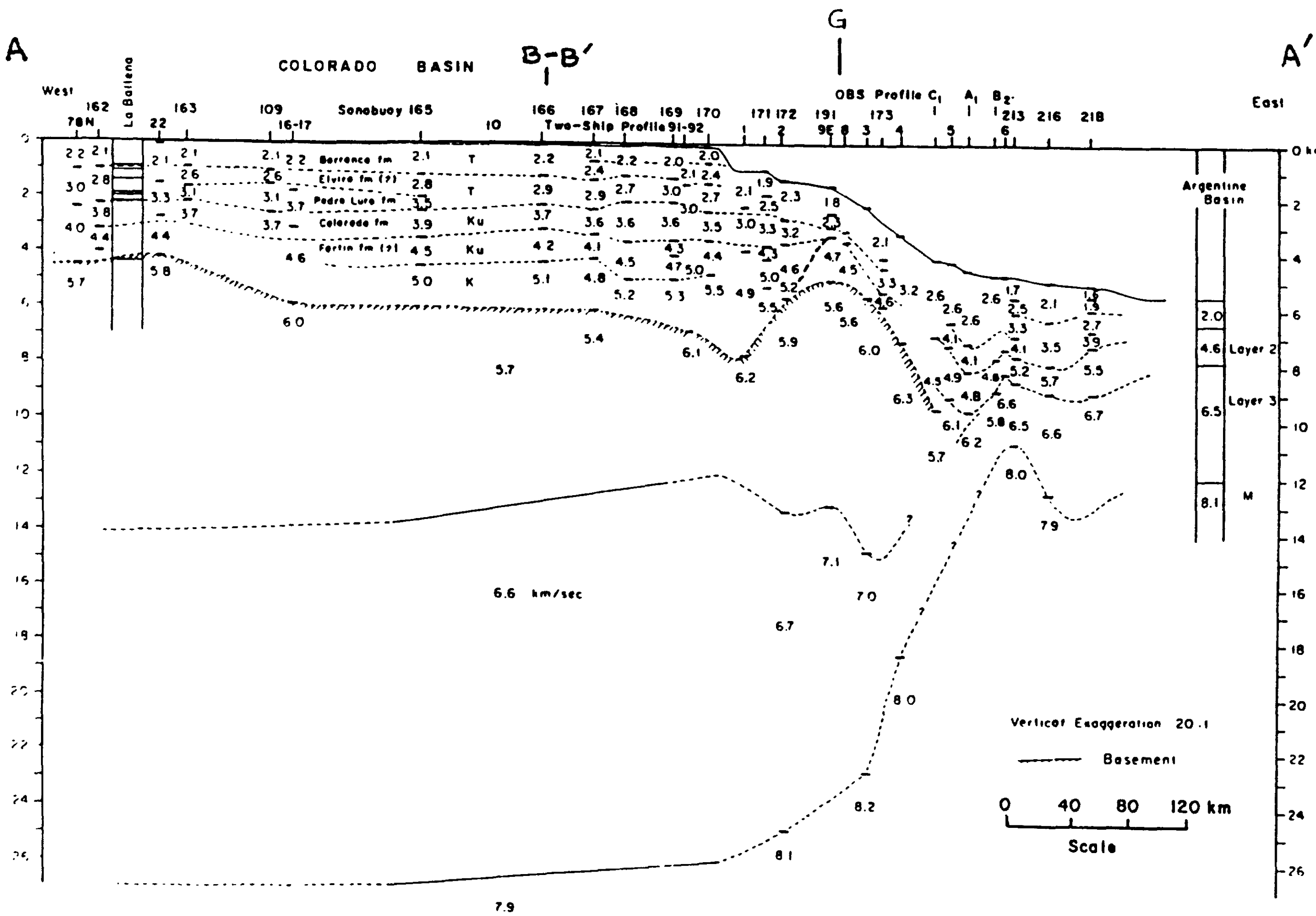


Figure 131 Generalized isopach map of the Cretaceous sediments of the Colorado basin (modified from Urien, 1981).



	Age	*Formation*	*Velocity (km/sec)*
Marine	Quaternary and Tertiary	Belen (Rio Negro) / Barranca Final / Elvira/Ombucta	1.8–2.7
	Early Tertiary (Paleocene-Maestrichtian)	Pedro Luro	2.1–3.2
Continental	Late Cretaceous (Maestrichtian)	Colorado	2.8–4.0
	Late Cretaceous	Fortin	4.0–4.5
	Early Cretaceous (with Jurassic?)	Basement(?)	4.7–5.4
	Pre-Cretaceous	Basement	5.9

Figure 132 Schematic west-east structure section along the strike of the Colorado basin. G is the interpreted boundary between the continental and oceanic crusts. Location figure 131. (after Ludwig et al, 1978).

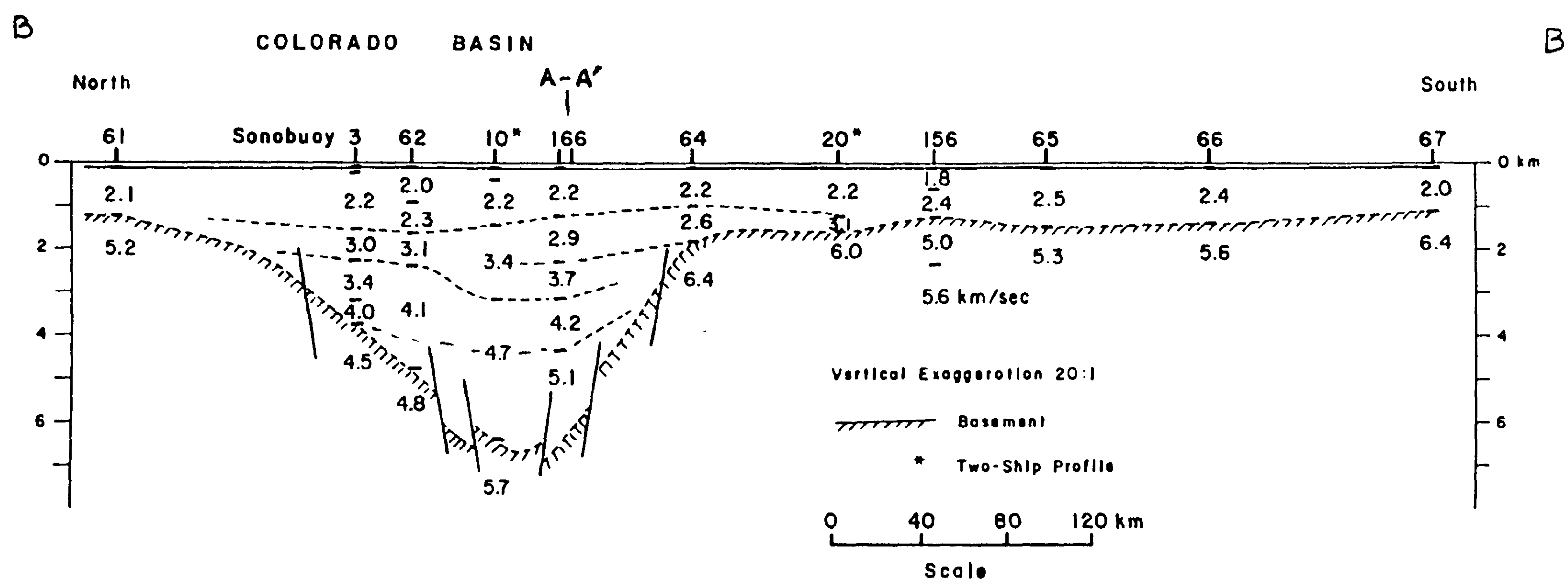


Figure 133 Schematic north-south structure section across the Colorado basin. Location figure 131. (after Ludwig et al, 1978).

Cretaceous and contain the organically rich lacustrine source shales of the D-129 Formation. If the Fortin Formation is of Jurassic age as suggested by some, the presence of lacustrine source shales is less likely. The Colorado Formation is reported to have some lenses of euxenic shales, but they are probably of small volume. The Tertiary sequence contains some dark colored shales, but these rocks, as well as the Colorado Formation, appear too shallow to be thermally mature.

Reservoir and Seals. Sandstones in the Upper Cretaceous and in the Tertiary would provide reservoirs. The Tertiary sequence is predominantly shales and claystones and therefore provide some seal.

Structure.

The Colorado basin is an east-trending graben (Urien, 1981) (figs. 131, 132 and 133). The dominant east-west trending set of normal faults have displacements of up to 10,000 ft (3,000 m). The most active faulting appears to have been largely limited to the Lower Cretaceous or older rock (fig. 133). The pattern and timing of the Colorado basin tectonics appears analogous to that of the San Jorge basin except that the Colorado basin is somewhat shallower. Traps appear to be fault closures or drapes.

Generation, Migration and Accumulation. Generation could have only taken place in the deepest and easternmost part of the basin, where Lower Cretaceous source shales may exist and where the shales would be sufficiently deep for thermal maturity. Any source shales would only reach sufficient depth in late Tertiary time. Migration of petroleum, therefore, would have occurred during Tertiary time from any deep source beds to Upper Cretaceous reservoirs.

Plays. There appears to be only one play and that is for Upper Cretaceous sandstones in fault traps or drapes.

History of Exploration and Petroleum Occurrence. Little is known concerning the exploration of the Colorado basin prior to 1970 except that Yacimientos Petroliferos Fiscales (YPF) and Shell had drilled some onshore dry holes. Following the granting of concessions to foreign oil companies in 1968, 12 wildcats were drilled in 1970, and 1 in 1977. They were all dry, apparently never finding any older sediment than the continental Upper Cretaceous (or Jurassic?) Fortin Formation.

Evaluation

The geology of the Colorado basin appears somewhat analogous to the San Jorge basin except that the Lower Cretaceous source section is either limited to the deeper part of the basin or is missing altogether. The maximum area containing source rocks is less than 7,500 mi^2 (19,500 km^2) in contrast to about 11,500 m^2

(30,000 km^2) for the San Jorge basin. The probability of the presence of any source rock at all is deemed to be 25 percent. On this basis a straight areal analogy to the San Jorge basin would indicate .627 BBO and .567 TCFG. However, the lack of proven reservoirs, the relative shallowness, and absence of shows indicates a much less favorable basin and, therefore, these resource numbers are further discounted to 10 percent, indicating .06 BBO and .06 TCFG.

Salado Basin

Area: 29,000 mi^2 (74,000 km^2)

Original Reserves: nil

Description of Area: The Salado basin is essentially a graben which trends north-westwards intersecting the Atlantic coast just south of the Rio de la Plata and Buenos Aires of Argentina (134).

Stratigraphy

The Upper Jurassic and Lower Cretaceous Serra Geral (Lonco Trapial, Tobifera) basalt underlies part of the Salado basin near the outcrops and is considered to be economic basement (fig. 135).

Similar to the Colorado basin, the oldest sediments penetrated are Upper Cretaceous nonmarine flood-plain shales and sandstones, coarsening southwestwards. A thickness of unknown sediment exists in the basin. However, where in the Colorado basin it may be speculated that Lower Cretaceous source rock, equivalent to that of the San Jorges basin, may exist in deeper eastern parts of the basin, a shallow basement ridge under the central area of the Salado basin (fig. 134) indicates a lesser possibility of a significant volume of source rock. It should be pointed out, however, that the small adjoining Santa Lucia subbasin (fig. 134) does have a Lower Cretaceous section of largely shale, presumably lacustrine, and partly bituminous.

The first marine transgression was in the Maastrichtian from the Atlantic and during the Tertiary further transgressive marine sequences interfingers with flood plain deposits. The Tertiary sediments are largely shale and sandstone with some tuffs, carbonates, and anhydrites.

Source. No source rock has been recognized in the Upper Cretaceous and Tertiary sediments and there appears to be limited space for any underlying Lower Cretaceous which by analogy to the San Jorge basin may be expected to contain source rock.

Reservoirs and Seals. The Upper Cretaceous sequence has sandstone beds which by analogy to the San Jorge basin may be of

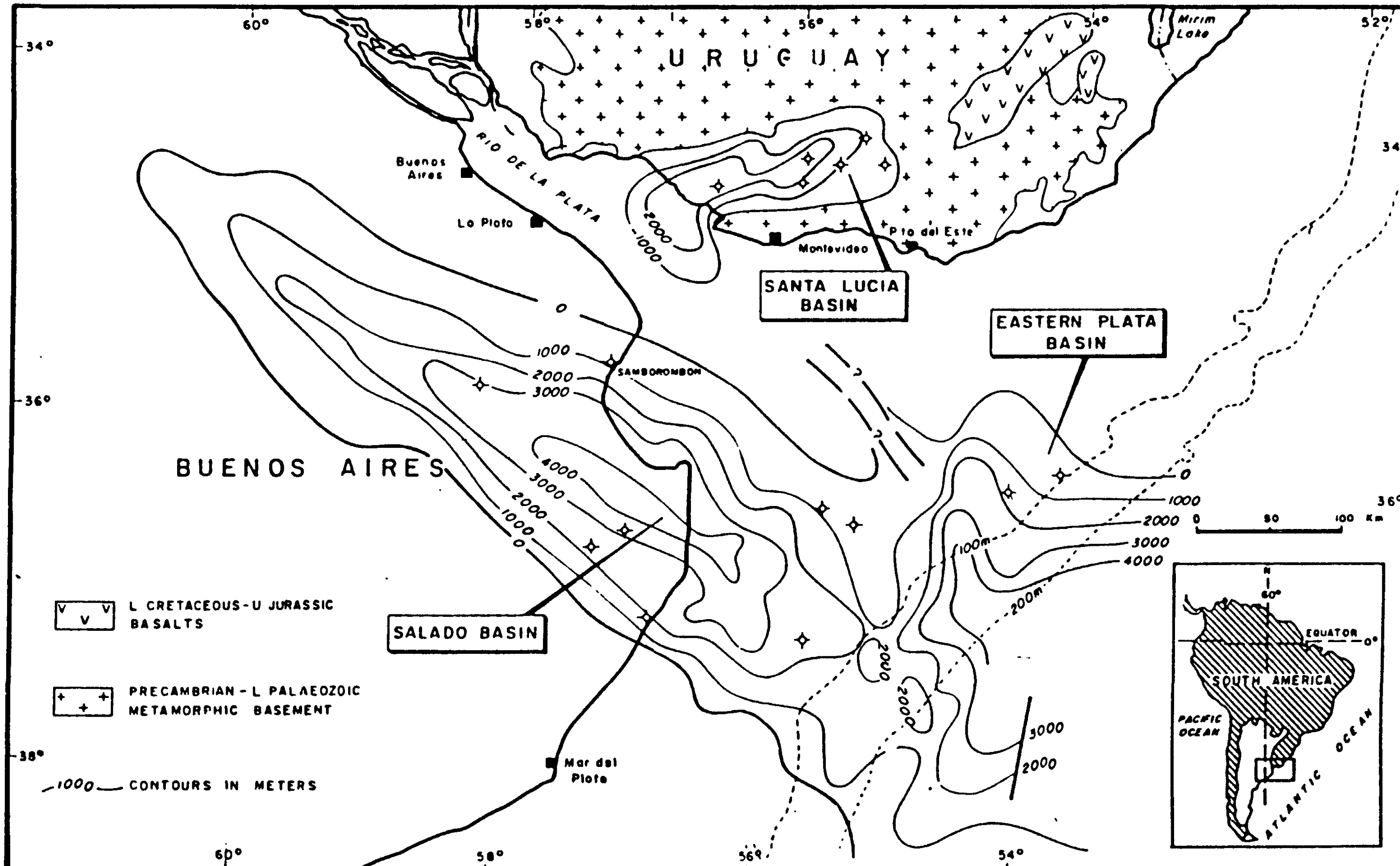


Figure 134 Generalized isopach map of the Cretaceous sediments of the Salada basin (after Urien, 1981).

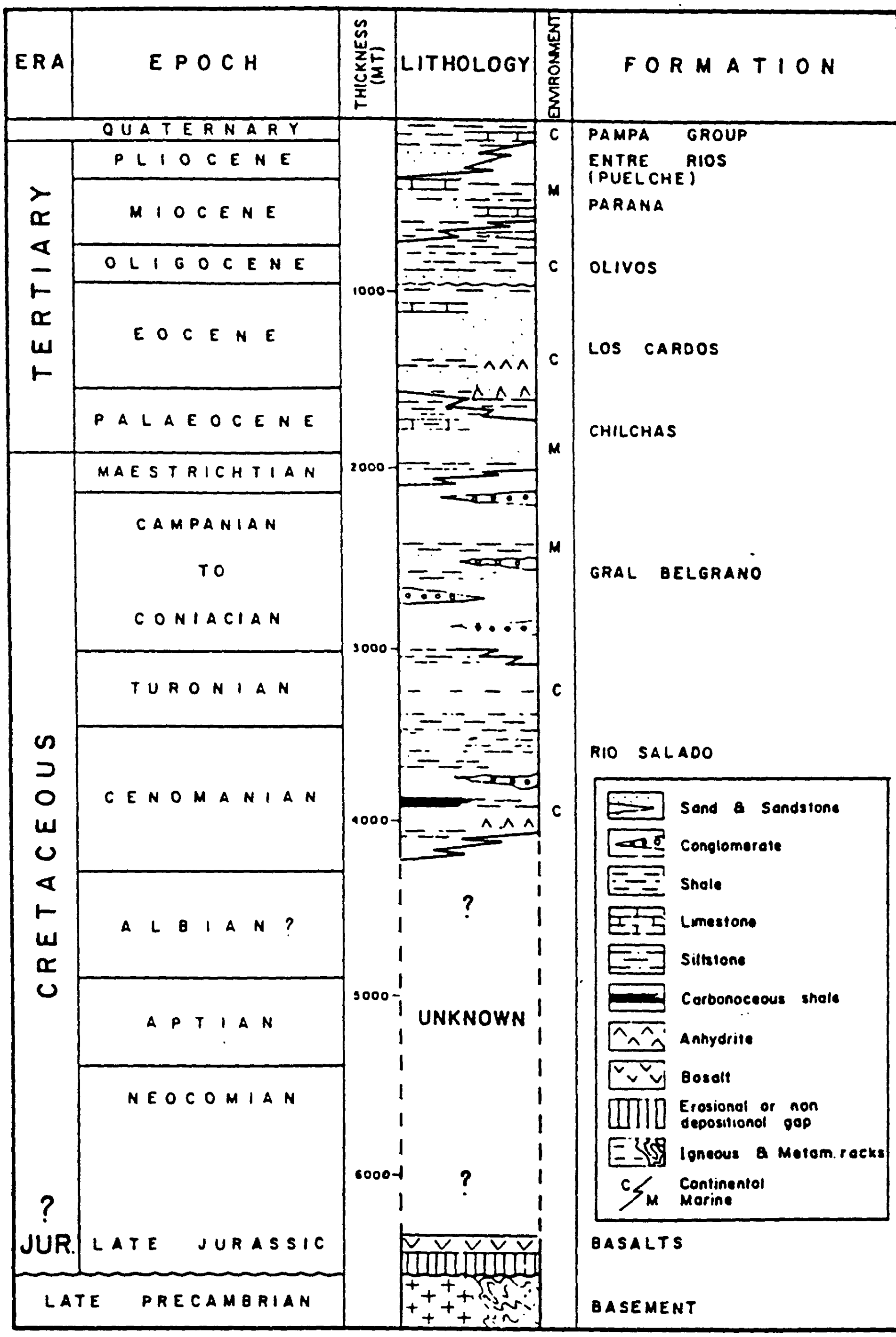


Figure 135 Stratigraphic column of the Salad basin as revealed in outcrops and in updip-positioned wildcats, leaving the deeper downdip section unknown (after Urien, 1981).

reservoir quality. Similarly, the Upper Cretaceous shales may be adequate seals.

Structure

The Salado basin is essentially southeastern trending graben with a maximum sedimentary thickness of 20,000 ft (6,000 m) (figs. 134 and 136). Its northeast side is a horst (Martin-Garcia High-Plata Horst) northeast of which is a wrench zone (Martin Garcia Wrench Zone) which separates the Patagonia accreted region from the Brazilian shield region. The southwest basin boundary is taken at the Cretaceous pinchout as the sediments thin towards the Tandil Highs. The basin is separated from the rifted continental margin basin (East Patagonia basin) by a northeast trending basement ridge. There are two minor peripheral subbasins, the Santa Lucia and Eastern Plata local depocenters.

Traps. In such a graben as the Salado basin, expected traps would be fault closures or drapes.

Generation, Migration, and Accumulation. Assuming the presence of source rock in the deepest parts of the basin generation and migration would be in the Tertiary. Fault trap or drapes would be of Cretaceous age and available to any petroleum, provided diagenesis had not impaired the reservoirs during the intervening time.

Plays. The principal play would be Upper Cretaceous sandstone reservoirs involved in fault traps or drapes.

Exploration History. Exploration on land prior to 1968 resulted in only dry holes. In 1968, concessions were granted to foreign companies under a new Petroleum Law and 5 holes were drilled in 1969, 1 in 1970, 2 in 1971, and 1 in 1973. All holes were dry and the concessions were given up.

Evaluation

The basin is generally analogous to the San Jorge and Colorado basins except that it is less likely to contain the Lower Cretaceous source rock present in the San Jorge and possibly present in the Colorado basin. By straight areal analogy to the Colorado basin, the undiscovered petroleum of the Salado basin amount to .06 BBO and .06 TCFG, but, in view of the more probably absence of source, is discounted by half to .03 BBO and .03 TCFG.

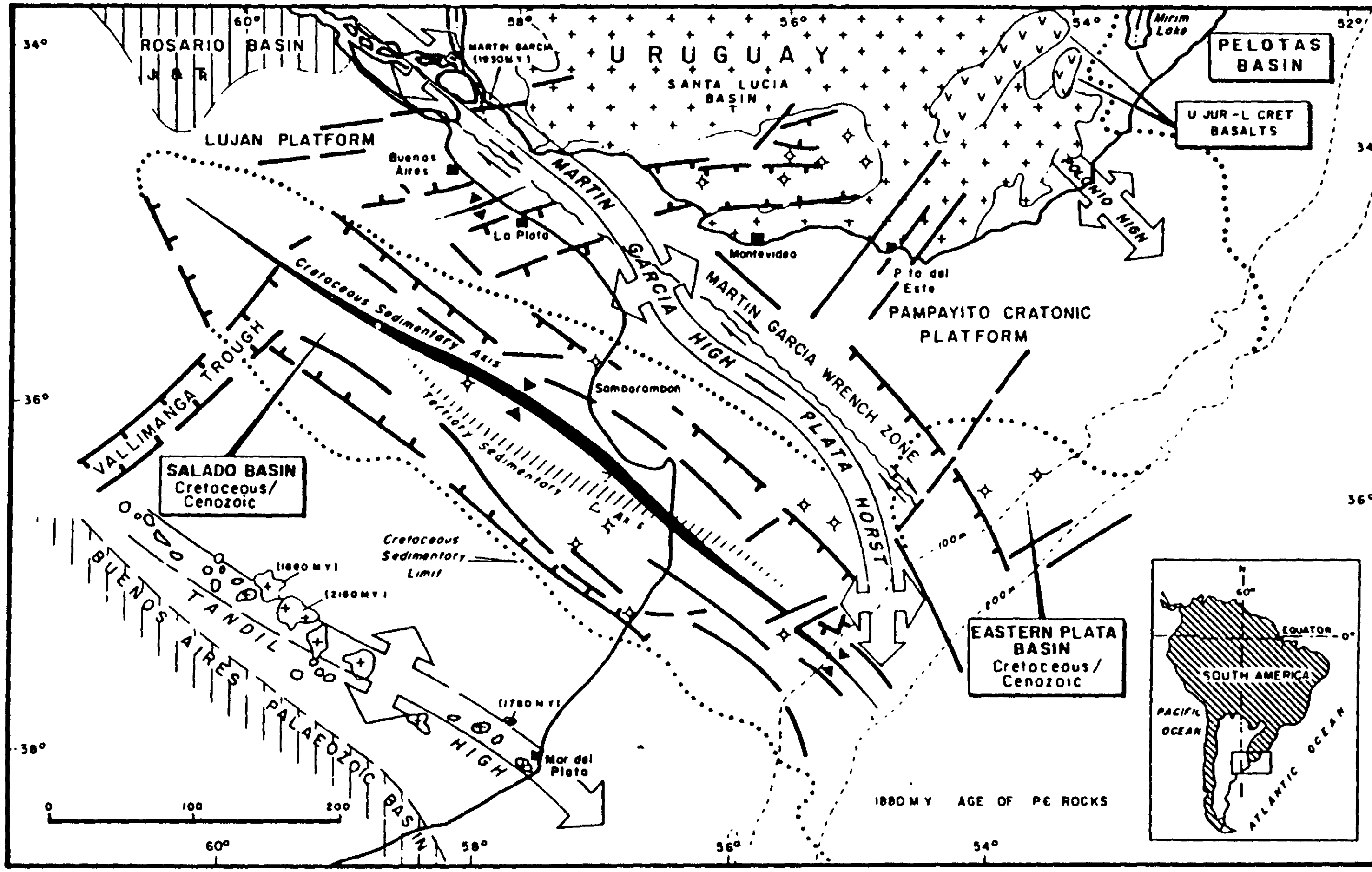


Figure 136 Sketch structure map of the Salada basin (after Urien, 1981).

Nirihuah Basin

Area. 2,500 mi^2 (6,400 km)

Original Reserves: Nil

The small, back-arc basin is in the Andes foothills of Argentina some 50 mi (80 km) northwest of the western edge of the San Jorge basin (fig. 113). It is a narrow, faulted trough which filled with up to 10,500 ft (3,200 m) of volcaniclastic fluvial and lacustrine sediments during the Lage Oligocene to Lage Miocene time. Three exploration wells were dry. The deepest and primary potential source shale, Early Miocene deep lacustrine shale was found to be thermally immature. The petroleum potential of the basin appears negligible. This minor basin only included because of evident interest by some.

Neuquen Basin

Area: 48,000 mi^2 (125,000 km^2)

Foldbelt: 21,000 mi^2 (55,000 km^2)

Platform: 27,000 mi^2 (70,000 km^2)

Original Reserves: 1.95 BBO, 18.21 TCFG (Marchese, 1985)

1.997 BBO, 24.61 TCFG (Petroconsultants, 1989)

Description of Area:

The Neuquen basin is in west-central Argentina at the foot of the Andes Mountains in the drainage area of the Neuquen, Colorado, and Lamay Rivers. It is located within the Neuquen, Mendoza, Rio Negro, and La Pampa provinces. The basin may be divided into 1) a north-trending fold belt on the west edge and 2) a platform exhibiting a north to northwest trends of rifting (fig. 137) on the east side of the basin. The fold-belt is largely in the Mendoza province (often called the Malargue subbasin) and the platform largely in the Neuquin province.

Stratigraphy

The Neoquen basin strata essentially represent a Mesozoic marine encroachment from the west or Pacific Ocean area (fig. 138). The sedimentation may be divided into three phases. The initial phase (first marine cycle) early Jurassic to Kimmeridgian marine, restricted-marine, and nonmarine clastics, with subordinate carbonates and evaporites towards the top, were deposited in an essentially rifted basin. During Late Jurassic and Early

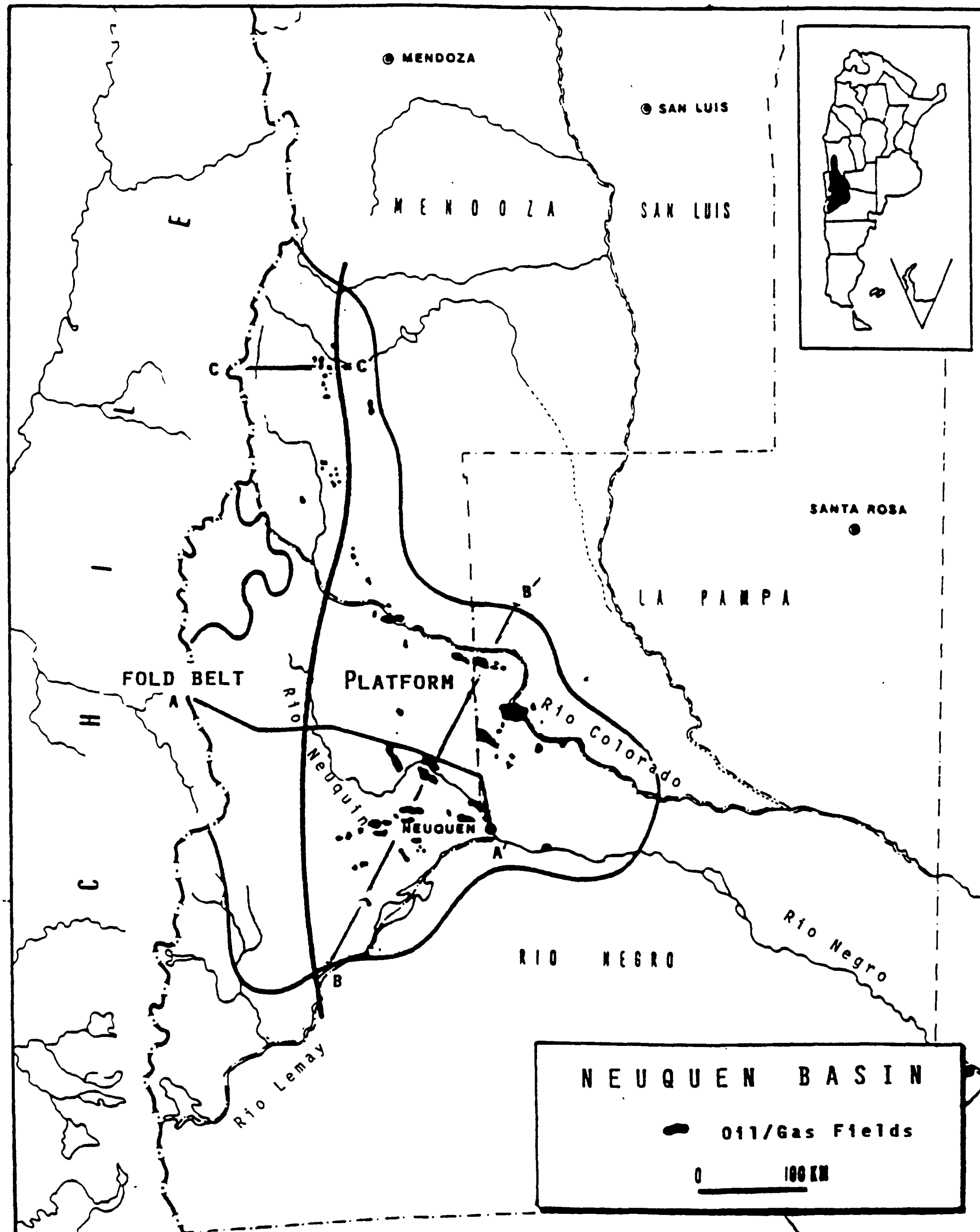


Figure 137 Index map of the Neuquen basin showing basin location, the fold belt and platform elements, trends of petroleum accumulations, and geologic cross sections (modified after Marchese, 1985).

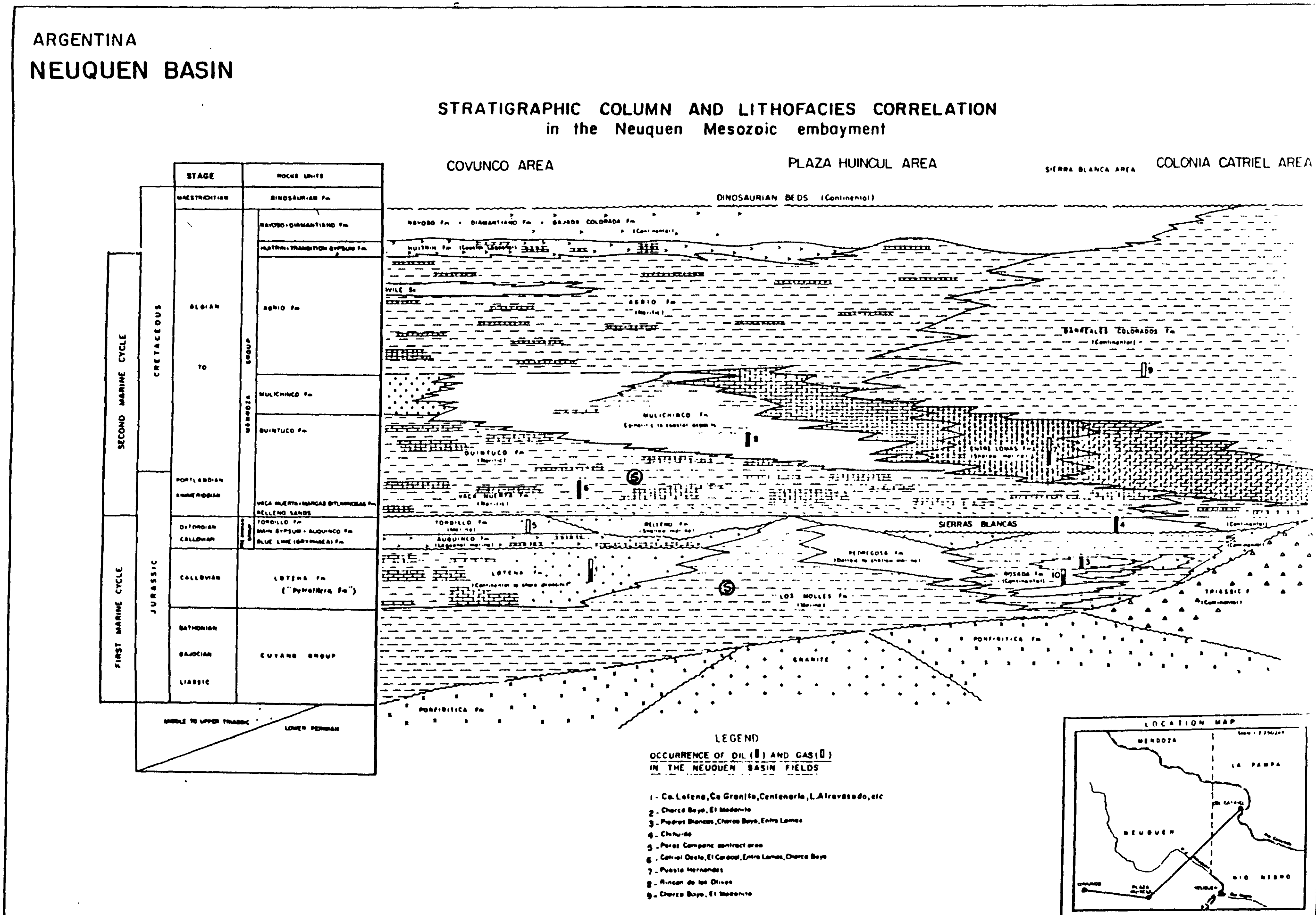


Figure 138 Stratigraphic cross section of Mesozoic sediments of the Neuquen basin (Circled S = source shales and vertical bars reservoirs (from Petroconsultants, 1977).

Cretaceous time (second marine cycle), the basin entered a sag phase, and carbonates, shales and sandstones were deposited under conditions of constant slow subsidence. In Late Cretaceous time a thick unit of red beds (Rayosa Formation) was deposited in a late sag phase, followed by Tertiary sediments derived from the rising Andes on the west.

Both marine sequences become shaley westward representing a more basinal facies. For instance, fig. 139 shows this facies change in the upper part of the second marine cycle which is sandy in the Neuquen province in the west and black shale in the Mendoza province (or Malargue subbasin) in the east.

Source Rock. There are two main source rock sequences. The lower sequence is the Jurassic marine Los Molles Formation, of the first marine cycle (fig. 138), which contains richly organic, black shales. The strata were apparently deposited in a marine embayment which became restricted. The second sequence is the Upper Jurassic-Lower Cretaceous Vaca Muerta Formation, of the second marine cycle (fig. 138), which also contains organically rich black shales, which were preserved in a restricted marine sedimentary environment.

Reservoirs and Seals. Almost all reservoirs contain some petroleum somewhere in the basin, but the two major reservoir zones are 1) in the Jurassic Las Molles, Lotena, Rosada and Tordillo Formation sandstones of the first marine cycle, and 2) in the Upper Jurassic Quntuco and Loma Montosa (Entre Lomas) carbonates of the second marine cycle (fig. 138). The carbonate reservoirs have primary porosity plus fracture porosity. A third type of reservoir is in fractured "economic basement," the Permo-Triassic (Choiyoi Formation) volcanics, which, in one field has reserves of 93 MMBO.

Each of the two marine cycles end up with a restricted marine or lagoonal phase (Auquinco and Huitrin Formations) conducive to evaporite formation and providing locally important seals. The Huitrin evaporites are particularly important seals, holding in the light oils; oils that escape around the seal or through faults are found shallow and highly viscous (fig. 139). Elsewhere, the main seals are shales which are not so effective as attested by the high-density, high viscosity shallow oil found in the platform of the northern basin.

Structure

The early (Late Triassic) structure of the Neuquin basin was that of a rifted basin, the exact configuration of which is not known, but, as indicated in the eastern, unfolded part of the structure map of the basin (fig. 140) and cross section B-B', (fig. 141) it had a west to northwest trend. This basin gradually opened and deepened towards the Pacific Ocean as indicated by the westward thickening, shaling, and more marine aspects of the sediments (fig. 138). The west to northwest trend of the eastern Neuquin basin is

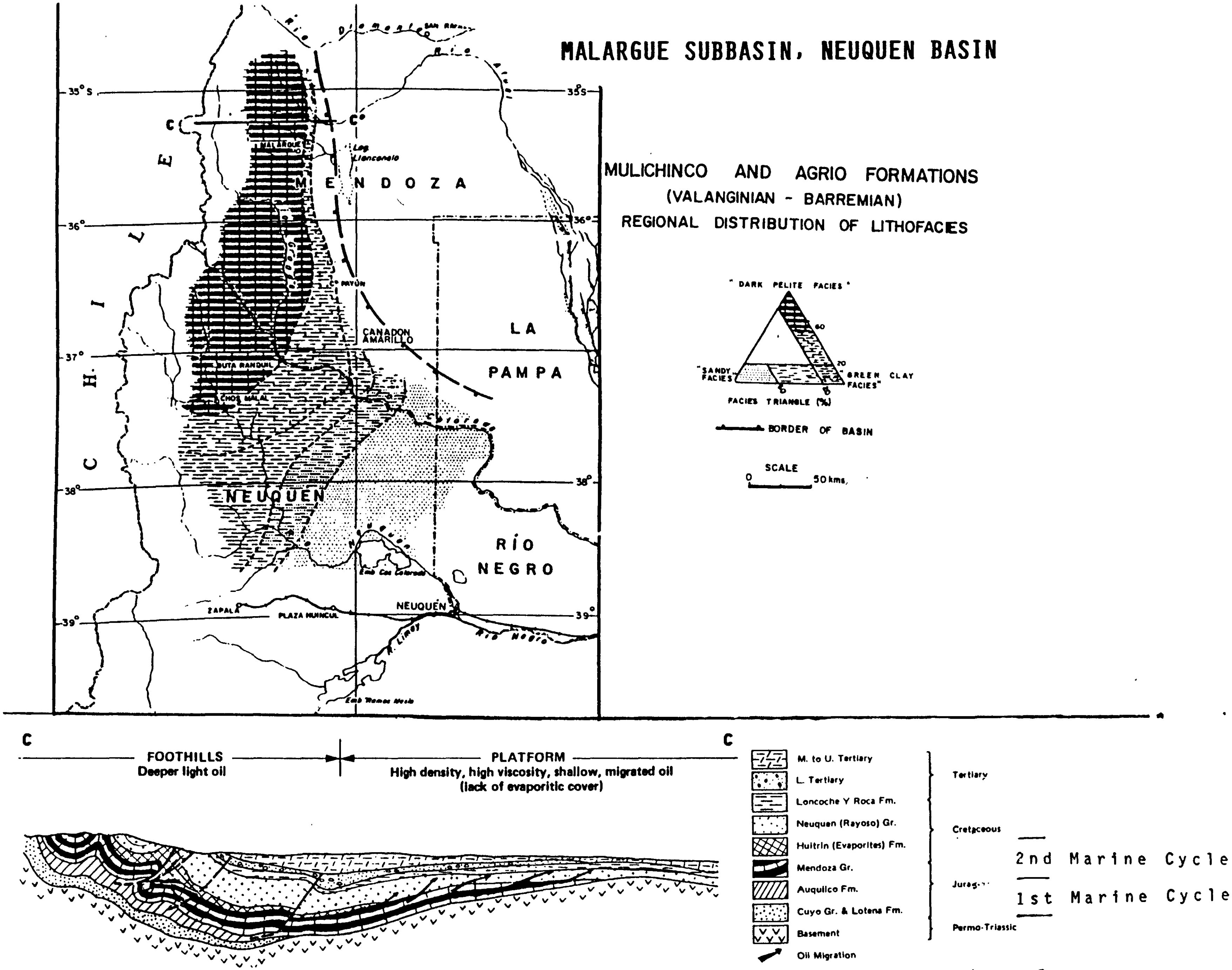


Figure 139 Map of North Neuquen or Malargue subbasin showing westward shaling of Lower Cretaceous formations and cross section of the subbasin showing the division between fold belt and platform and effects of the evaporites on petroleum migration (from Petroconsultants, 1977).

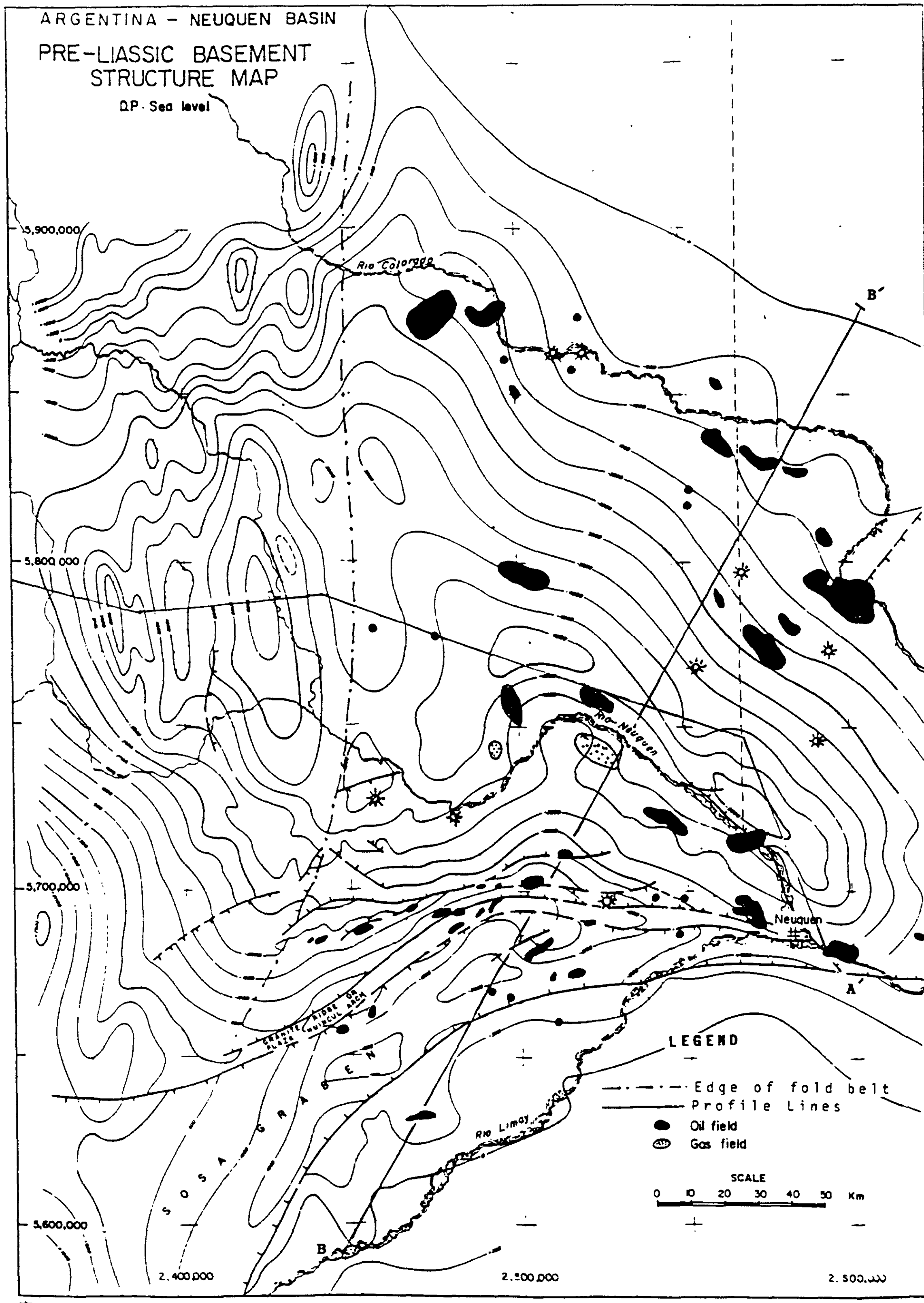


Figure 140 Structure map of the southern, or largely platform, portion of the Neuquen basin drawn on the top of basement showing the trends of petroleum accumulation, the edge of the fold belt and position of profile lines (Line A-A' only approximate) (from Petroconsultants, 1977).

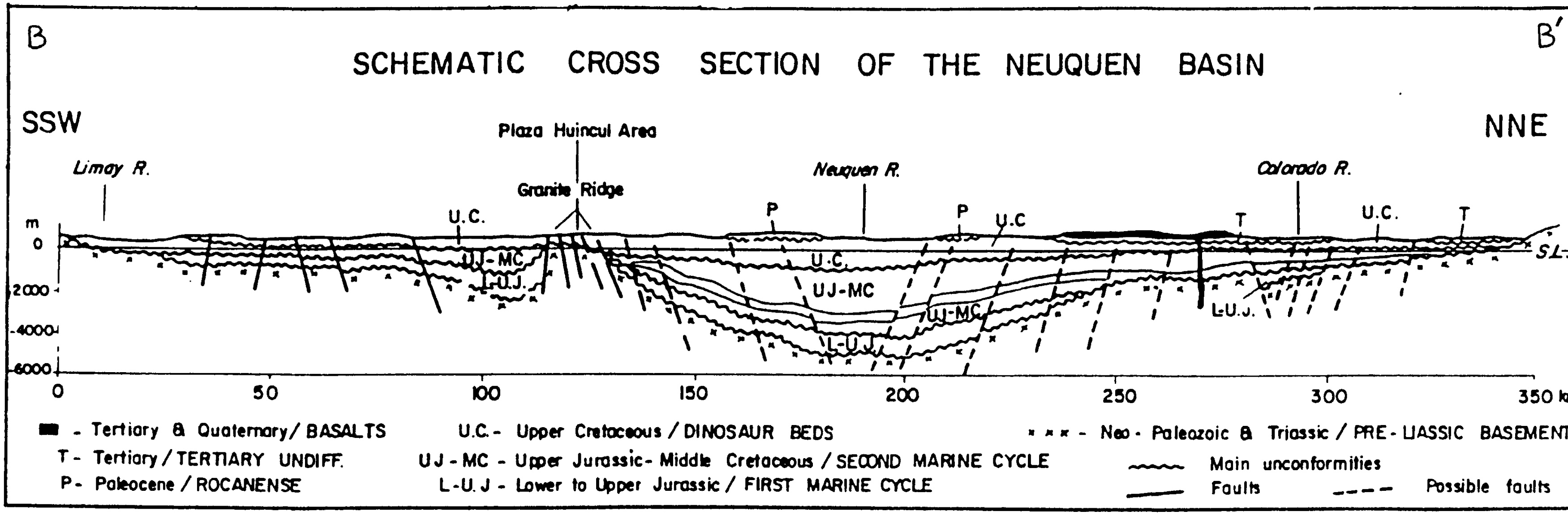


Figure 141 Schematic southwest-northeast cross section of the platform portion of the Neuquen basin. Location on figures 137 and 140 (from Petroconsultants, 1977).

subparallel to an old Paleozoic grain as well as other Mesozoic basins, e.g., the Colorado, Salado, and Cuyo basins, and appears to be following Pre-Cambrian and Paleozoic faults and sutures between accreted continental fragments of the Patagonia region. The Triassic-Jurassic faulting which initiated the basin has been reactivated through geologic time, many faults being active up to the end of Middle Cretaceous and a lesser number through the Tertiary as the basin continued to sag or subside (fig. 141). Superimposed on this structure is that of the Tertiary Andean orogeny which folded and thrusted the western third of the basin (fig. 139, 140, and 142).

Most of the petroleum traps occur in the unfolded or platform portion of the basin where the traps are relatively extensive in contrast to the folded and faulted traps of the fold belt which are small and structurally complicated (fig. 142).

<u>Generation, Migration and Accumulation</u>. Assuming an average geothermal gradient for this combined rift and sag basin of 1.4°F/100 ft (or 25.5°C/km), petroleum generation, and accompanying migration, from the Jurassic Los Molles source shales would have begun in Early Cretaceous time when the oldest source shales of the subsiding basin reached a burial depth of some 10,000 ft (3 km). At that time the rift-associated traps and the Jurassic reservoirs of the first marine cycle and lower reservoirs of the second marine cycle were in place and available. The shallower source shales in the Vaca Muerta Formation probably did not subside into the oil generation zone until the Tertiary or latest Cretaceous at which time all reservoirs, particularly those immediately adjacent to the source shales, were available.

<u>Plays</u>. There are two main plays: 1) the west to northwest trending pre-Andean Mesozoic normal fault and drape traps of the platform area (figs. 140, 141, and 142), and 2) the north-trending Tertiary folds and thrust closures of the Andean orogeny (figs. 139, 140, 142).

<u>History of Exploration and Petroleum Occurrence</u>. The first official oil discovery was made in 1918, but the first substantial field, Pampa Palanco in the fold belt, was not discovered until 1941. Some 686 wildcats were drilled by about the end of 1988 (Petroconsultants, 1989) (1,283 "exploration holes" by 1985, Marchese, 1985). Of the 686 wildcats, some 191 were discoveries indicating a wildcat success rate of 28 percent. Of the 686 wildcats about one-eighth (12 percent) were drilled in the folded belt and the rest on the platform. Of the basins reserves, about 11.6 percent of the oil and 6.5 percent of the gas is in the fold belt and the rest in the platform.

The most significant discovery was that of the Loma de la Lata gas and condensate field discovery in 1977 which holds almost all the gas reserves of the basin, some 13.2 TCFG.

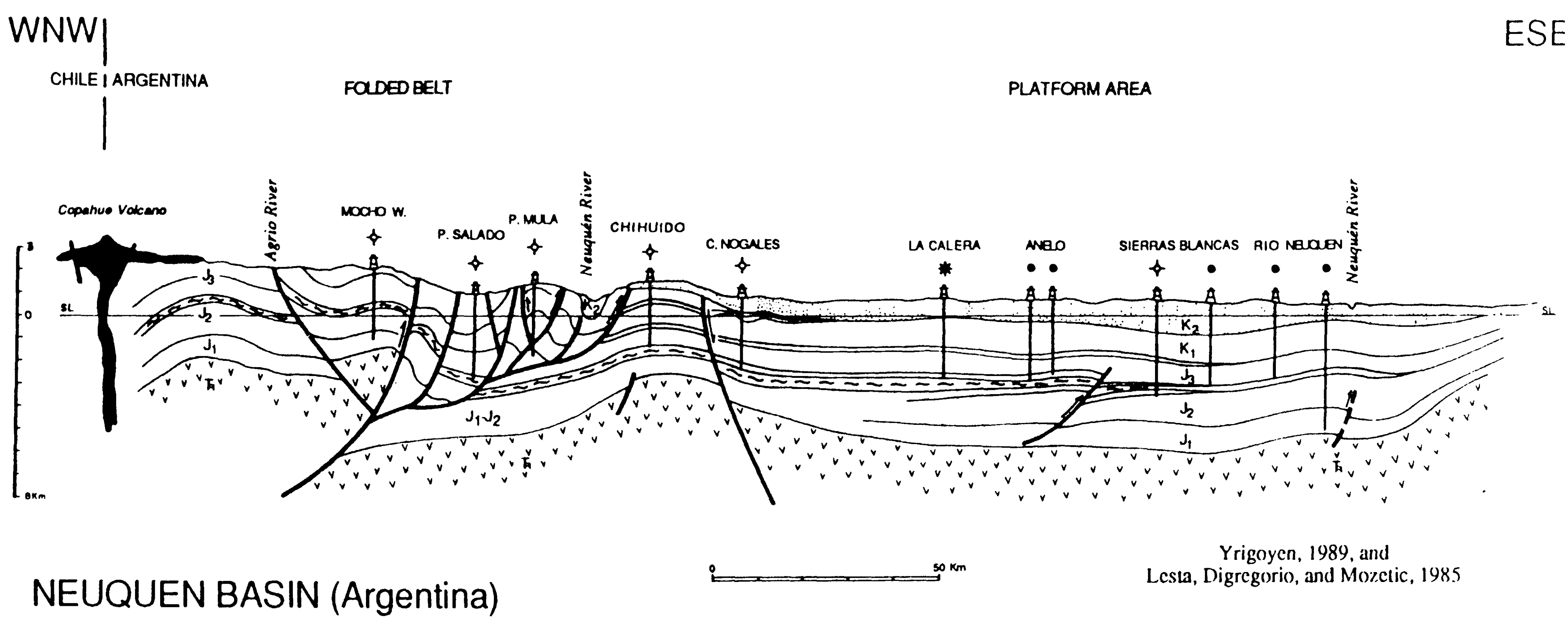


Figure 142 Schematic west-east cross section to the Neuquen basin. Approximate location figure 140 (from Yrigoyin, 1991).

As indicated in Figure 143 most of the oil discoveries were made in the first 225 wildcats, after which the amount of oil discovered versus the number of wildcats declined so that for about the last 200 wildcats the discovery rate was about .25 MMBO per wildcat. The curve showing the amount of gas discovered versus number of wildcats (fig. 144), follows a similar declining discovery pattern as for oil, except for the rather anomalous Loma de la Lata giant gas discovery (wildcat 283, causing the sudden ascent of the curve. The declining discovery curve for gas flattens for the last 200 wildcats to an average of 1.71 BCFG per wildcat.

Evaluation of Undiscovered Oil and Gas

The basin appears to have reached a mature stage in exploration as indicated in figures 143 and 144, and the discovery of another giant-sized field appears unlikely. Assuming that as many wildcats will be drilled in the future as have been drilled in the past (686 by Petroconsultants data), and that the present average discovery rate and field-sizes remains constant at .25 MMBO and 1.71 BCFG per wildcat, new technology balancing increasing finding difficulties, 171 BBO and 1.173 TCFG will be discovered.

Cuyo (Cuyanas) basin

Area: 14,300 mi^2 (37,100 km^2)

Original Reserves: 1.115 BBO and .216 TCFG

Description of Area: The basin is an elongate, northwest-trending area situated in northeast Mendoza province (fig. 145).

Stratigraphy

This basin is unique compared to other Patagonian basins in that it has a substantial thickness of Triassic strata. The strata are nonmarine clastics containing source shales--the Cacheuta Formation, and reservoir sandstones-- the Potrerillos and Rio Blanco Formations (fig. 146).

The Triassic sequence is overlain by a thin blanket of Jurassic-Lower Cretaceous basalt and volcanics Punta de las Bardas Formation, correlative to the Tobifera, Lonco Tropia, and other widespread Jurassic-Lower Cretaceous volcanic formations covering most of Argentina and southern Brazil. In other Argentinian basins, these volcanics are usually considered to be effective basement.

Unconformably overlying the volcanics is a relatively thick sedimentary fill of Tertiary and Quaternary shales and sandstones

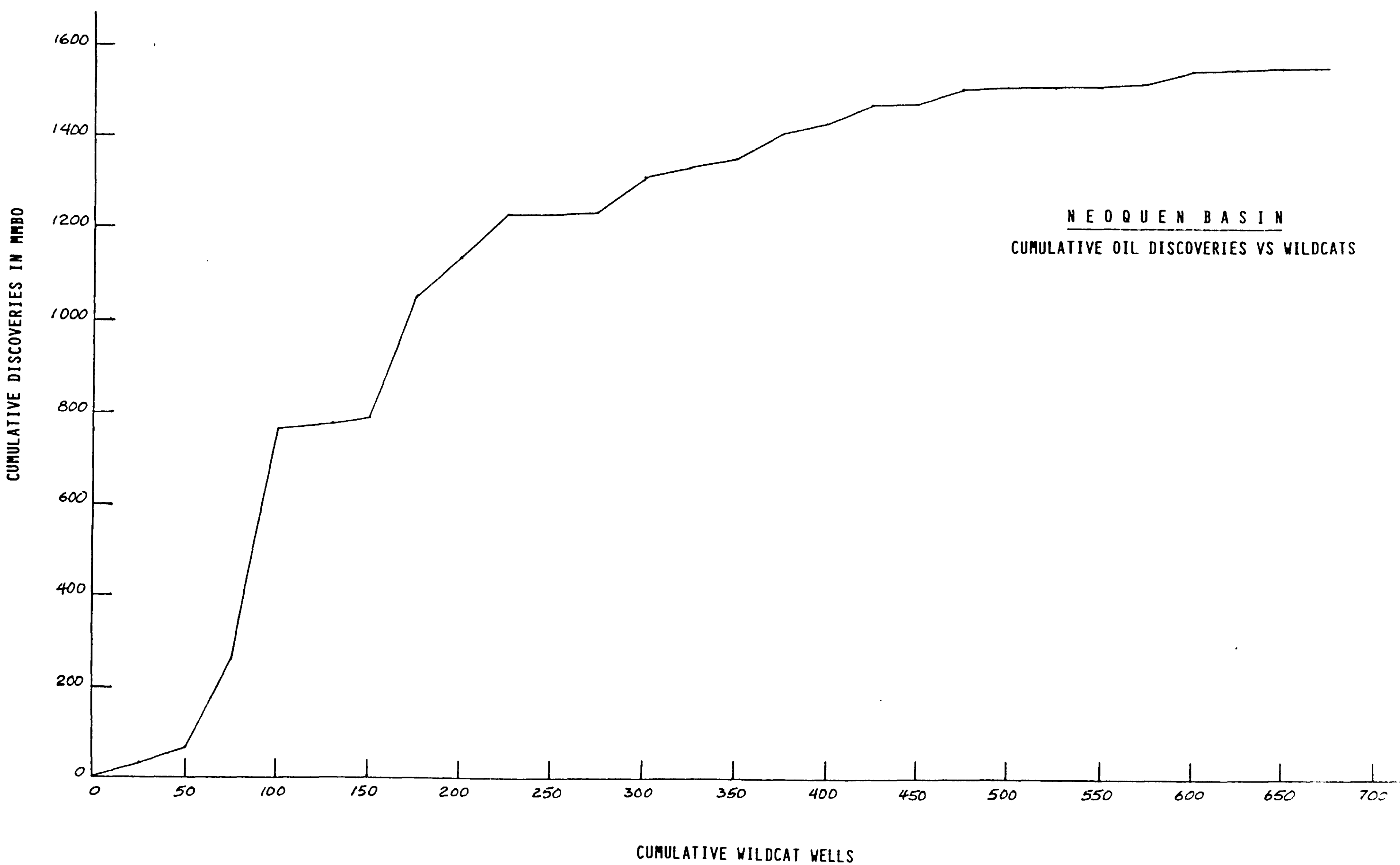


Figure 143 Graph showing the cumulative amount of discovered oil (in MMBO) versus the cumulative number of wildcats in the Neuquen basin. Curve indicates exploration reached maturity after about 225 wildcats when the amounts of discovered oil levelled off so that the last 200 wildcats had a discovery note of about .23 MMBO/wildcat. Based on Petroconsultants data (1990) which may be incomplete.

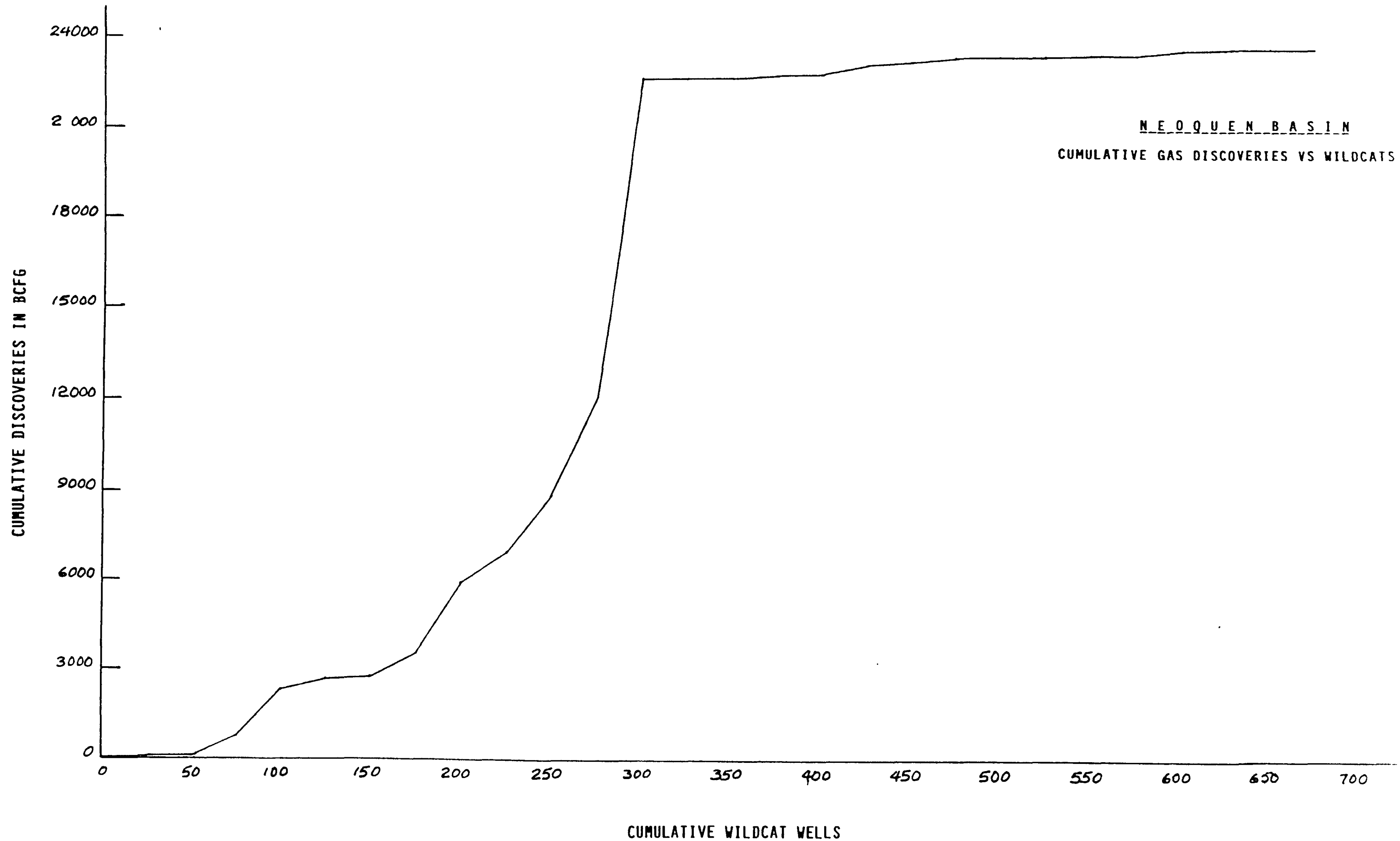


Figure 144 Graph showing the cumulative amount of discovered gas (in BCFG) versus cumulative number of wildcats in the Neuquen basin. Curve indicates early exploration reached a climax at wildcat 283, Loma de Lota, where 13.2 TCFG was discovered and after which the discovery rate declined so that for the last 200 wildcats the discovery rate was 1.71 BCFG/wildcat. Based on Petroconsultants data which may be incomplete.

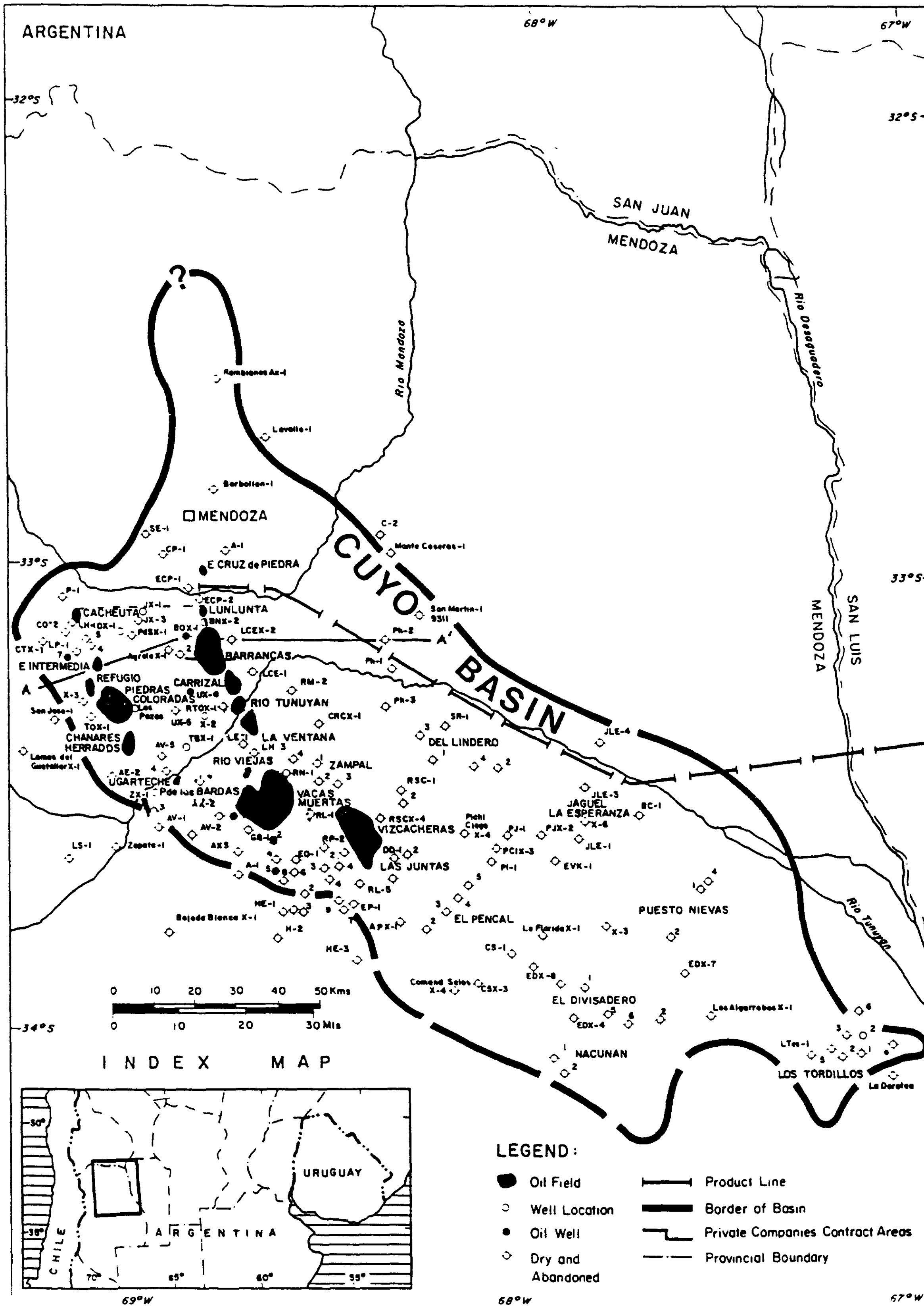


Figure 145 Index map of the Cuyo basin showing trends of petroleum accumulations (Petroconsultants, 1980).

(figs. 146 and figs. 147). The basal part of the Tertiary sequence, the Papagayo Formation, contains some productive reservoirs.

Source. The principal source rocks are the black lacustrine shales with abundant organic material of the Triassic Cacheuta Formation. Shales of the lower part of the overlying unit, the Rio Blanco Formation, also contributed as a source.

Reservoirs and Seals. All the sandstones of the basin appear to be potential reservoirs. Many fields produce from multiple reservoir horizons. The shales associated with the sandstones provide some seal. Probably the best seal is the volcanics (Punta de las Bardas Formation) since only little petroleum is found in the overlying Tertiary sandstones.

Structure

The basin, at least in its early phase, was probably an interior rift basin which filled with Triassic sediments. However, the structure is unique to the other Patagonian basins in that it is completely dominated by folds that trend north-northwest parallel to the Andes created by the same compressional forces which raised the Andes in the Tertiary. There are three fold trends in the western half of the basin (fig. 147). Closures along the fold trend are anticlines associated with reverse faulting. The eastern half of the basin is relatively flat, but with low-amplitude fault traps and drapes (fig. 147). There appears to be two principal ages of faulting; one period of normal faulting occurred in Jurassic to Cretaceous time, probably associated with the regional extension at the time of the Gondwana breakup. The second period of folding occurred in the Tertiary. This period of faulting is characterized by reverse and probably wrench faulting associated with the Andean compressional forces.

Traps. The principal traps are the anticlines and associated fault traps of the three compressional fold trends and traps associated with low-amplitude faults and drapes of the unfolded eastern part of the basin (fig. 147).

Generation, Migration, and Accumulation. Subsidence sufficient for the Cachueta source shales to reach the oil-generating thermal zone, estimated to be between 10,000 ft (3 km) and 18,000 ft (5.5 km), could only have occurred in the rather late Tertiary. The block-fault-related, Jurassic-Early Cretaceous traps of the foreland platform may be somewhat early for Tertiary generated oil and gas, but the Tertiary folds and associated reverse faults were very timely, forming just before and during the oil migration.

Plays. There appears to be two plays both primarily involving Triassic sandstones: 1) Tertiary anticlinal folds and associated thrusts in the western part of the basin, and 2) Jurassic-Early

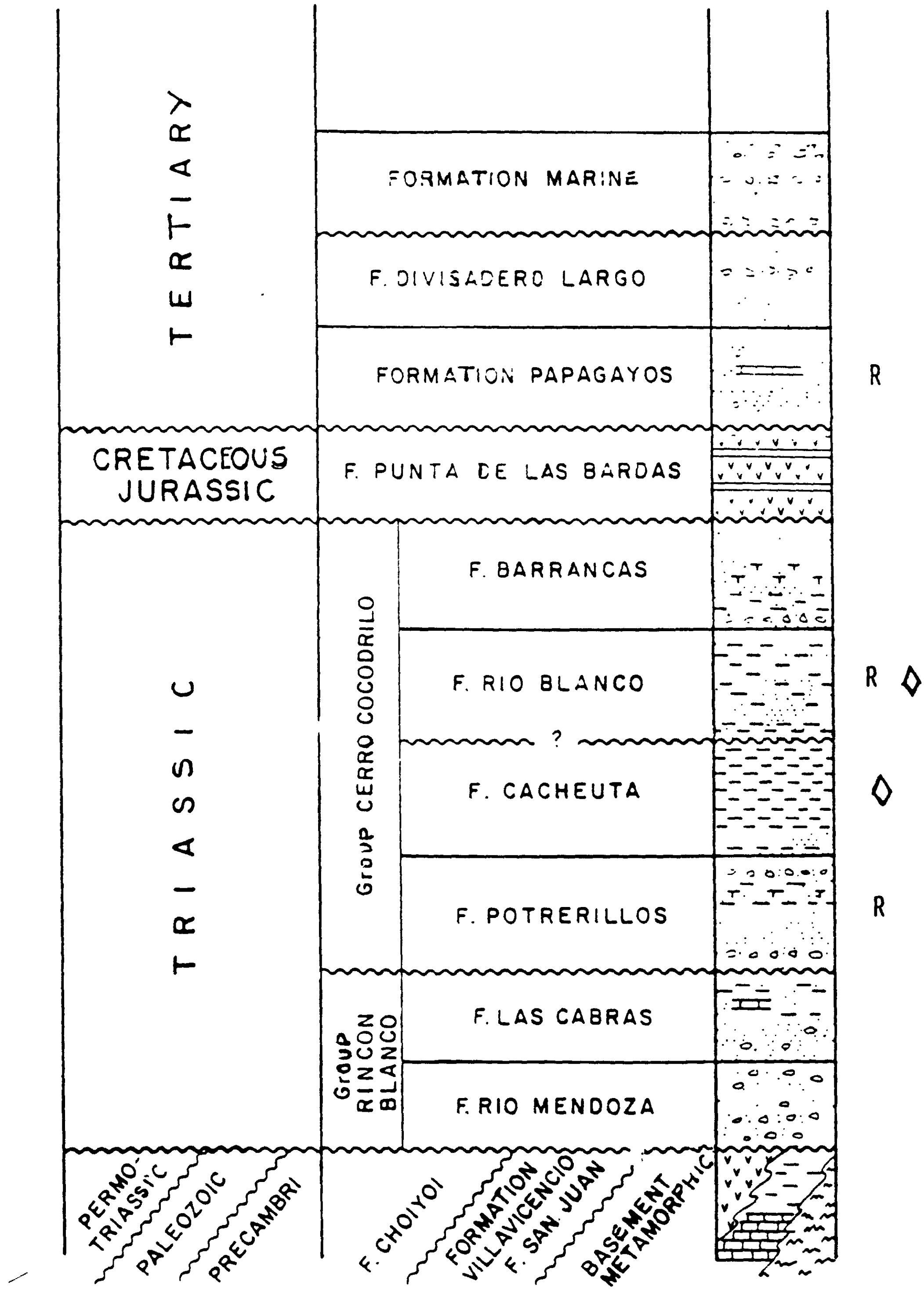


Figure 146 Stratigraphic column of Cuyo basin; R = Reservoir rock, Diamond = source rock (Lesta et al, 1985).

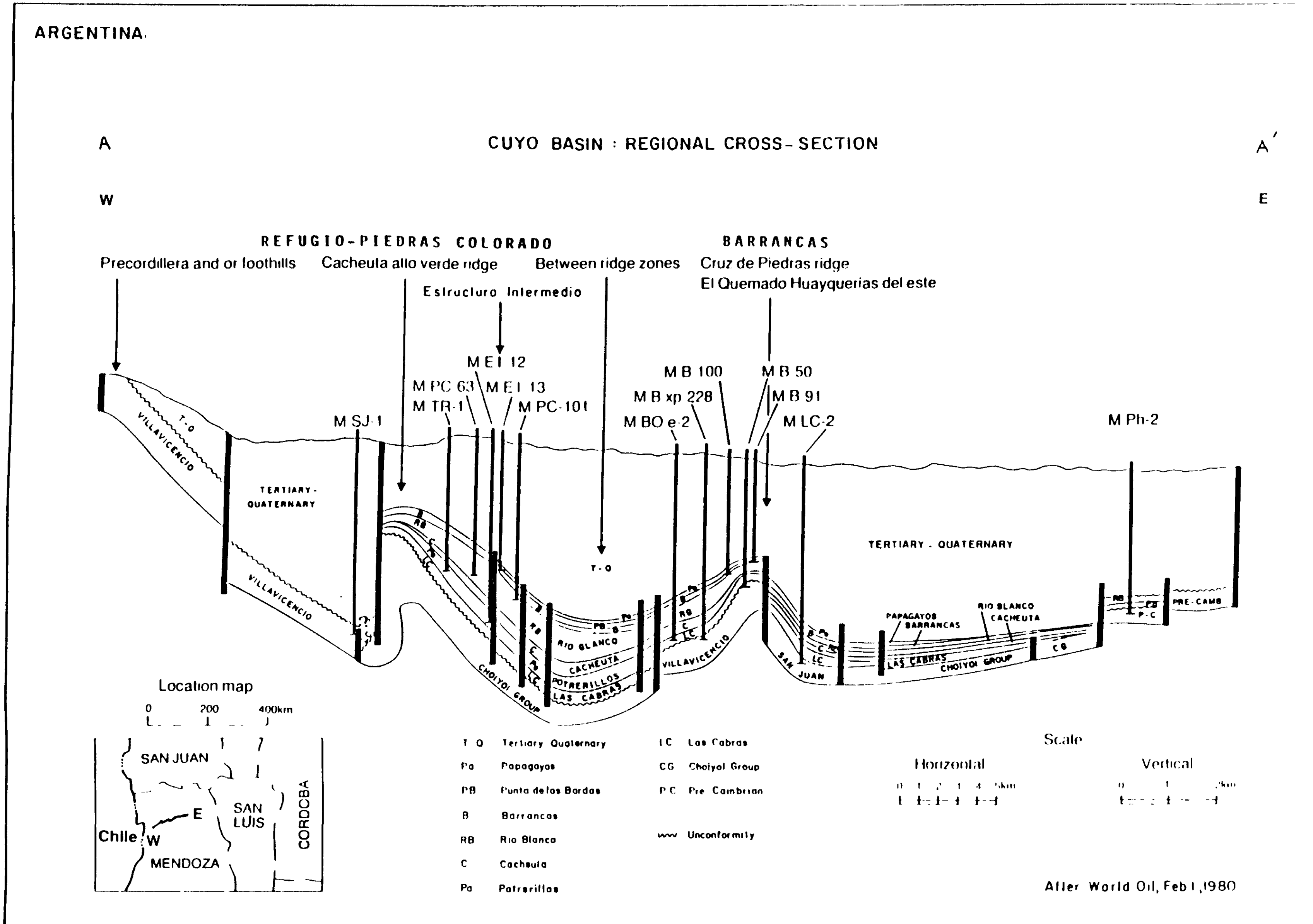


Figure 147 Geologic section across Cuyo basin showing principal structural trends and sedimentary sequences. Location on figure 145 (from Petroconsultants, after World Oil, 1980).

Cretaceous low-amplitude fault and drape closures on the eastern part of the basin.

History of Exploration and Petroleum Occurrence. The Cuyo basin exploration has reached a mature stage (figs. 148 and 149). Early exploration information is lacking, but incomplete wildcat records (Petroconsultants, 1989) indicate that over 95 percent of the present reserves were discovered in the first 125 wildcats by 1963. Since that time the field size and success of wildcatting has diminished so that for the last 200 wildcats the discovery rate was .25 MMBO and .06 BCFG per wildcat. As of 1988, some 354 wildcats have been drilled (Petroconsultants 1989).

Evaluation

Exploration history indicates that there is probably only limited amounts of undiscovered petroleum remaining in this small, maturely explored basin. Assuming that the present low level of exploration success (.25 MMBO and .06 BCFG) does not diminish further and that half again as many wildcats will be drilled (i.e. 175), the undiscovered oil would amount to .044 BBO and undiscovered gas to .011 TCFG.

B. Rifted Continental Margin Basin

East Patagonia Basin

Area: 100,000 mi^2 (260,000 km^2)

Reserves: nil

Description of Area: The East Patagonia basin area is far offshore, 150 to 350 mi (240 to 560 km), approximately corresponding to the continental slope area, i.e., between the 200 and 2500 isobaths. It extends southwards parallel to the coast from the northern Argentine border (i.e., the Patagonia accreted region--Brazil shield boundary, to the Malvianas Escarpment and Platform (fig. 150).

Stratigraphy

No wildcats have penetrated the sediments of this basin; however, interpretations of seismic data indicates considerable thicknesses of Cretaceous as well as Tertiary sediments extend on to the continental slope. Fig. 151 shows a dip-section from the San Jorge basin eastwards to the continental margin; on the basis of seismic refraction velocities an estimated maximum thickness of some 23,000 ft (7.000 m) of sediment, 10,000 ft (3,000 m) of Cretaceous and 13,000 ft (4,000 m) of Tertiary strata has been interpreted.

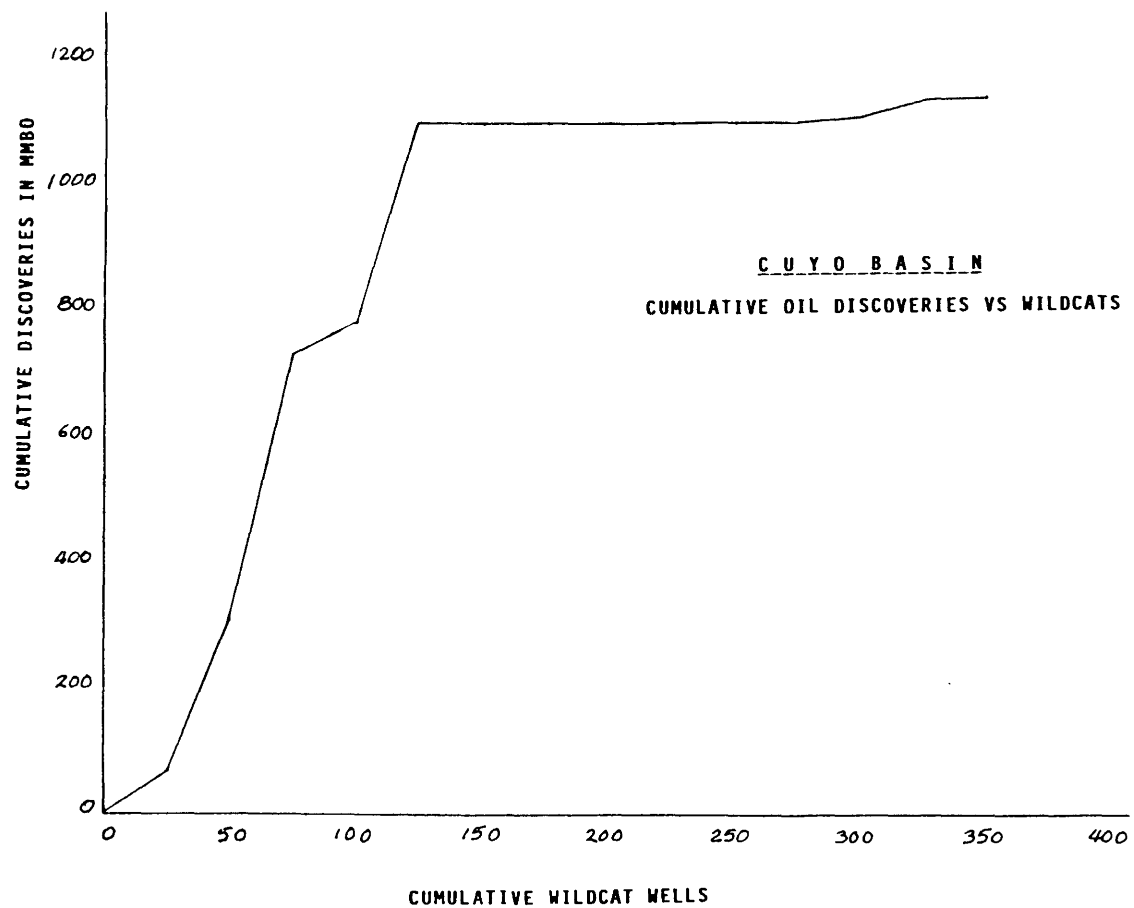


Figure 148 Graph of oil discovery rate in the Cuyo basin showing the amount of cumulative oil discovered (MMBO) per cumulative number of wildcats. Curve indicates exploration for oil reaching maturity at about 125 wildcats, the discovery rate declining to 0.25 MMBO for the last 200 wildcats. Based on Petroconsultants data (1990) which may be incomplete.

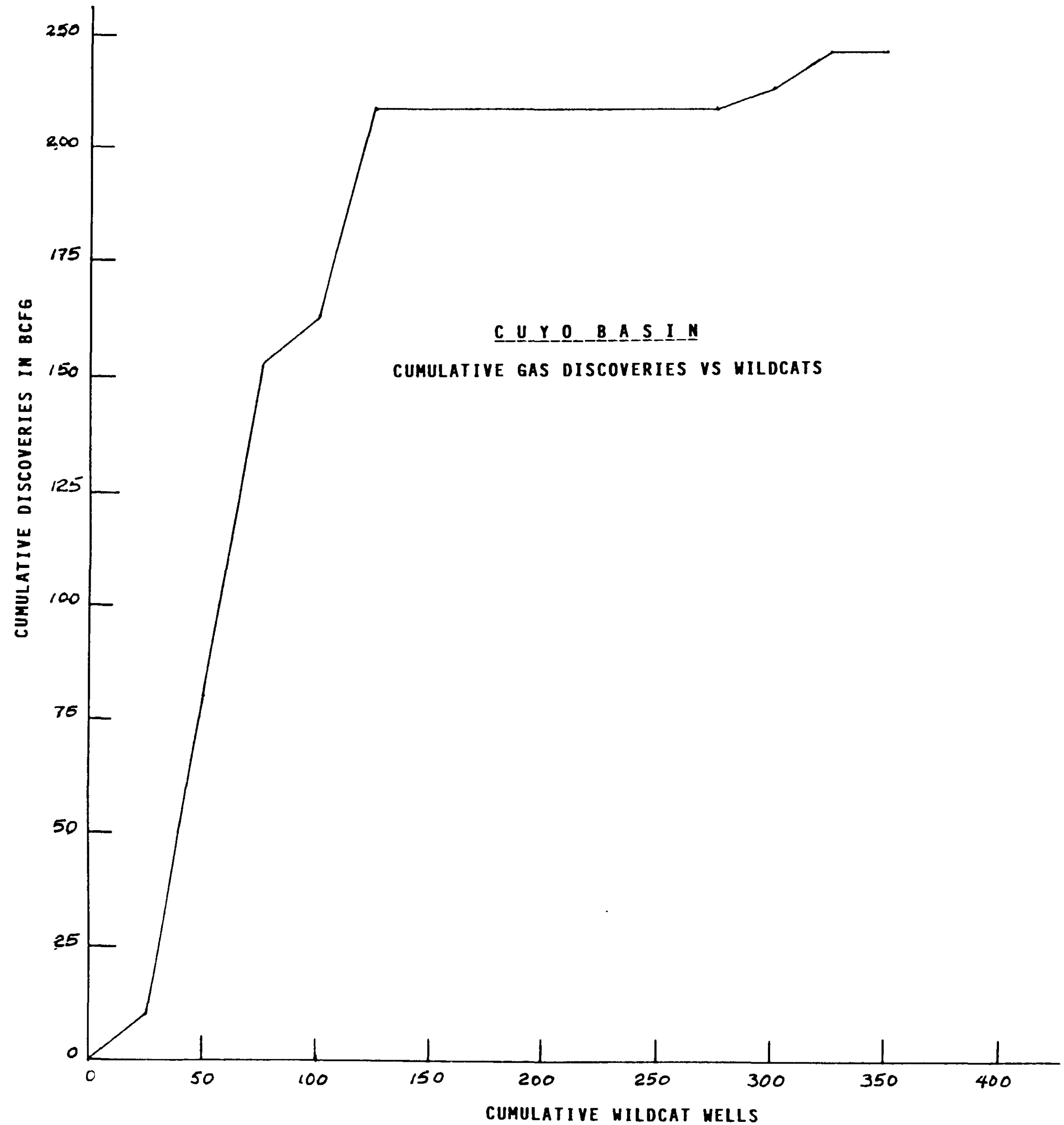


Figure 149 Graph of gas discovery rate in the Cuyo basin showing the cumulative amount of gas discovered (BCFG) per cumulative number of wildcats. Curve indicates exploration for gas reached maturity at about 125 wildcats, the discovery rate declining to 0.06 BCFG for the last 200 wildcats. Based on Petroconsultants data (1990) which may be incomplete.

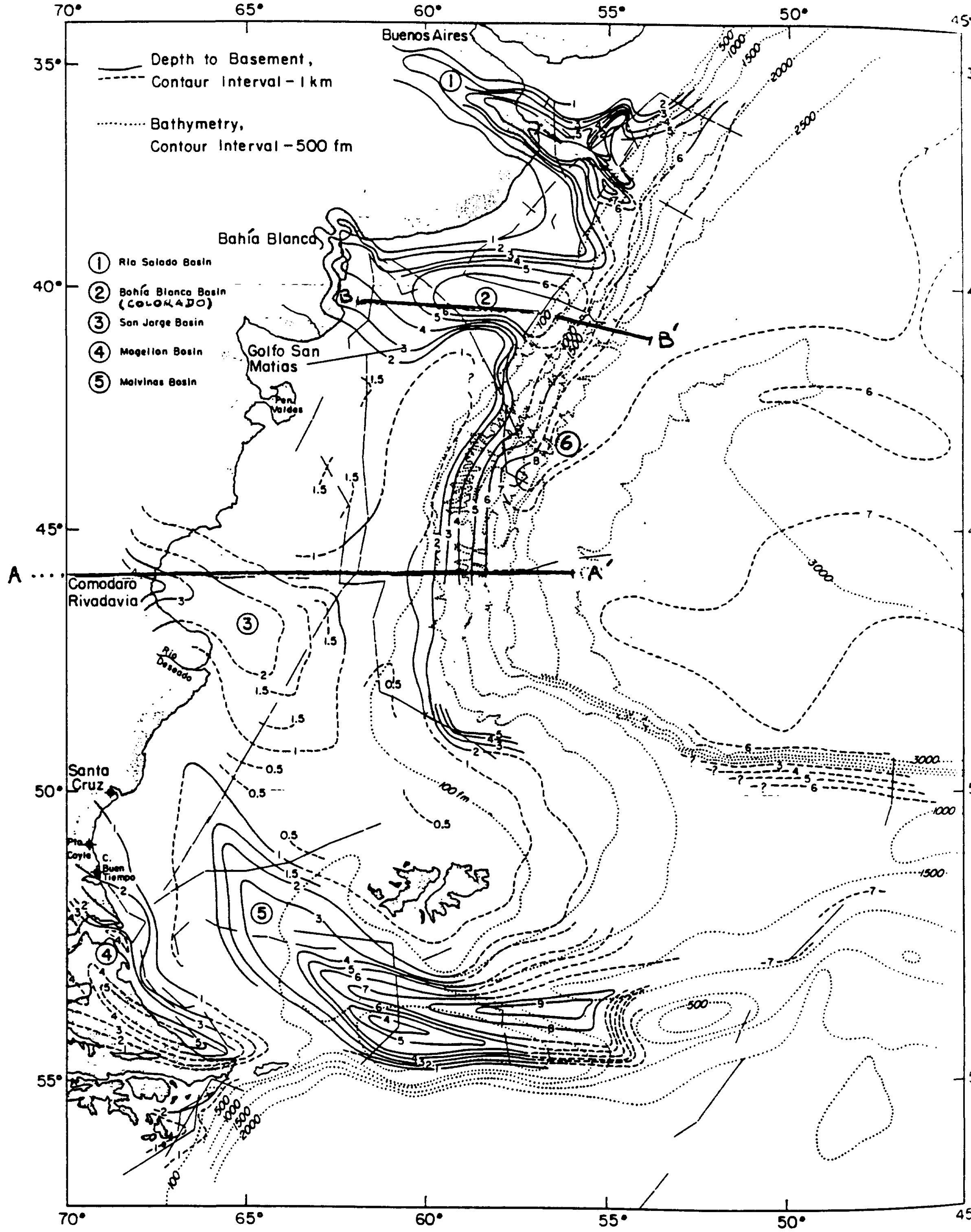


Figure 150 Generalized subsurface structure map of the Argentine continental margin. Datum at the top of the 5.9 km/sec velocity layer in the Buenos Aires province and top of 4.5 - 6.4 km/sec layer elsewhere. 1 = Salada basin, 2 = Colorado basin, 3 = San Jorge basin, 4 = Magallanes basin, 5 = Malvinas basin, 6 = East Patagonia basin (modified from Ludwig et al, 1968).

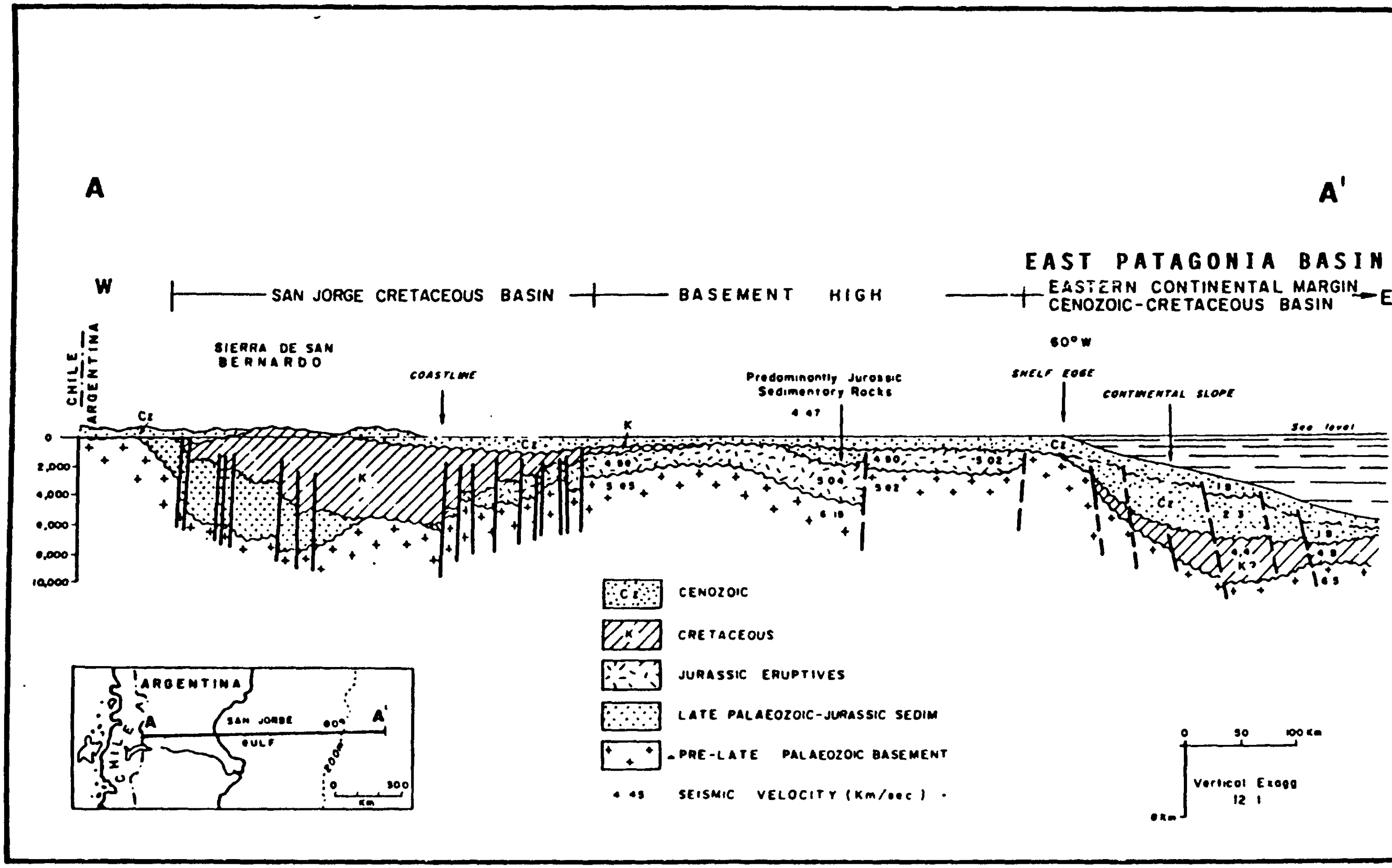


Figure 151 West-east cross-section from San Jorge basin to across the East Patagonia basin at the continental margin (Urien, 1981).

Figure 152, a dip section from the Colorado basin, indicates the possible presence of Lower Cretaceous sediments in the basin. Other seismic-based profiles also indicate thick sediments in the East Patagonia basin.

More detailed stratigraphy of the East Patagonia basin may be surmised from adjoining analogous basins. The Jurassic sediments by analogy to the on-trend, adjoining Pelotas basin to the north are largely volcanics and the Lower Cretaceous sediments may also be largely volcanic; but by analogy to other rift continental margins further north and to the San Jorge basin, Lower Cretaceous sediments may contain lacustrine source shales. Upper Cretaceous and Tertiary turbidites are probably present.

The basin is also geologically similar to the Orange basin of the rifted continental margin of South Africa and Namibia, which once adjoined it prior to separation in mid-Cretaceous (Kingston, 1988). This basin is also largely unknown, but by analogy to on-trend neighboring African rifted continental margin basins, e.g., the Congo basin, it is thought to possibly have some Neocomian Cretaceous source shale. (However, in the only place this sequence was penetrated, on the pinchout edge, the sequence was volcanic.) As indicated by DSDP 361 hole Aptian-Abian source shales are also a possible source by analogy to other African rifted continental margin basins; reservoirs averaging some 70 ft (21 m) were estimated.

<u>Source.</u> The source shales would be by analogy to other rifted continental margins of the South Atlantic 1) possibly in synrift Lower Cretaceous lacustrine shale, and 2) in Aptian-Albian restricted-marine shales. A third possibility is the Middle Cretaceous organic-rich shale of the South Atlantic anoxic event (AE2).

<u>Reservoirs and Seals</u>. Reservoirs may exist in the form of synrift, Lower Cretaceous carbonates and sandstone, but more likely in Upper Cretaceous and Tertiary sandstones largely in the form of turbidites.

Seals would be accompanying shales, the more effective evaporites of the northern South Atlantic are missing.

<u>Structure</u>

The structure is typical to that of rifted continental margin, providing rift-phase horst and graben structure with fault traps and drapes and postrift marginal sags with listric faults and accompanying rollover closures.

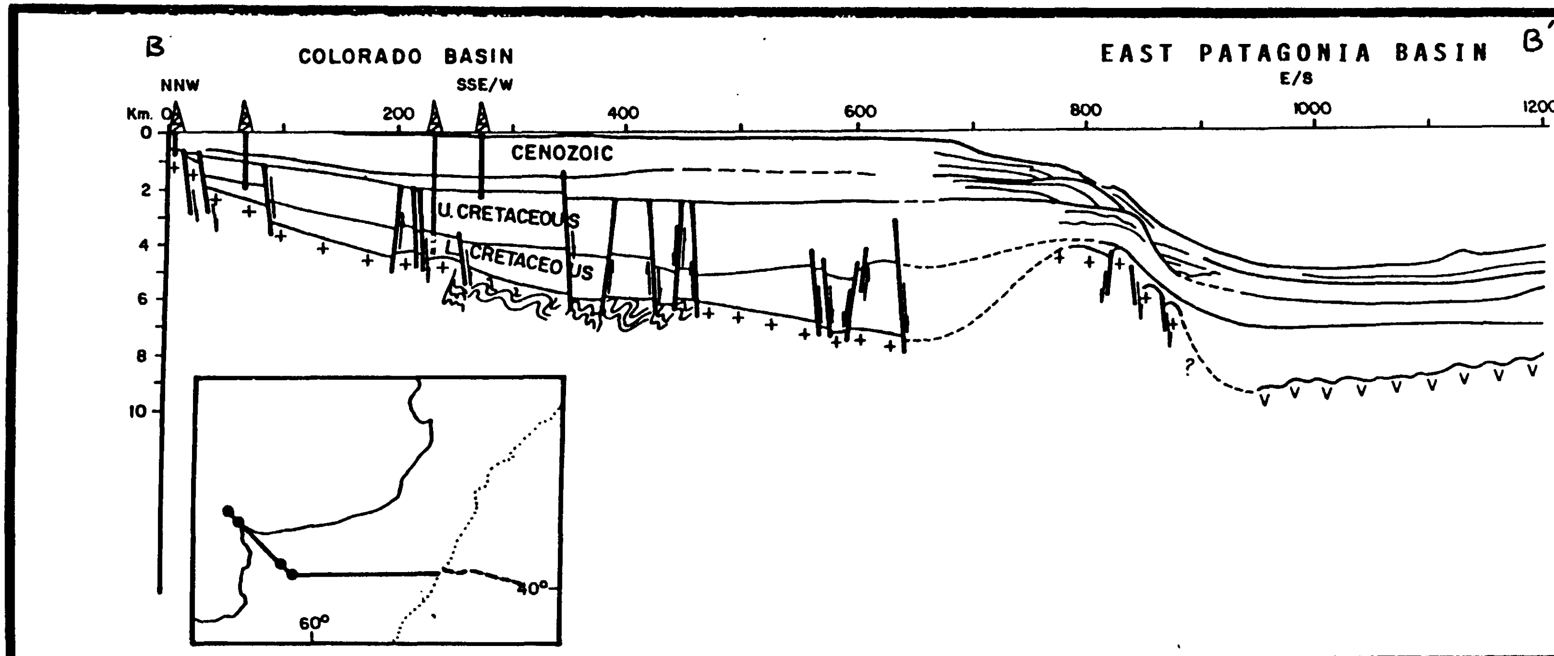


Figure 152 West-east cross-section from Colorado basin across East Patagonia basin at the continental margin (well penetration into lower Cretaceous is shown dashed since although Urien's original figure shows penetration, it is not indicated in his accompanying text) (Urien, 1981).

Generation, Migration, and Accumulation. Generation and migration would be fairly late, in Tertiary, when sufficient burial depth would have been reached by any source shale. Structure involving normal faulting probably was at its peak in the Early Cretaceous but continued into the Late Cretaceous. Listric faulting and rollovers are probably largely of Tertiary age; reservoirs, by analogy to adjoining basins, principally of Late Cretaceous age. Petroleum migration, therefore, would be some time after much of the trap formation and reservoirs deposition, but probably are contemporaneous or precede the listric fault and rollover traps.

Plays. There are essentially two plays: 1) Cretaceous sandstones involved in normal-fault traps or in drapes, and 2) Upper Cretaceous sandstones involved in listric faulting and rollovers.

Assessment

In view of the lack of drilling and other data, the best assessment can be made by comparison to the estimated petroleum resources of the geologically most similar province, the slope area of the on-trend Pelotas basin to the north. By straight areal analogy to the Pelotas slope and estimated resources, .175 BBO and 1.066 TCFG are indicated.

IV. Subandean Basins

The third tectonic region or superprovince of South America, as defined here, is the Subandian foreland region which includes the basin associated with the Andean orogeny. The basins in this region include the following: 1) the foreland basins fringing the adjacent Brazilian craton on the east, 2) the intermountain basins, and 3) the Pacific forearc and associated intra-arc basins on the west (fig. 153). The superprovince is essentially limited to northeastern Argentina and Chile, Bolivia, Peru and Ecuador. The continuation of the Andes orogeny and associated basins, northward into Colombia and Venezuela, comes under the influence of Tethyan geology and is considered part of the Tethyan Collision superprovince of South America, discussed in other studies. Although southern Patagonia (southern Argentina and Chile) is also affected by the Andean orogeny in the eastern and major part of Patagonia, the dominant and unifying geology is that of faulted, accreted continental crust under extension and the associated, northwest-trending basins. The Andes and the Pacific-facing forearc, associated intra-arcs, and intermontane basins from Colombia to the southern tip of South America, including western Patagonia, are dominantly of Andean orogenic origin and are discussed here.

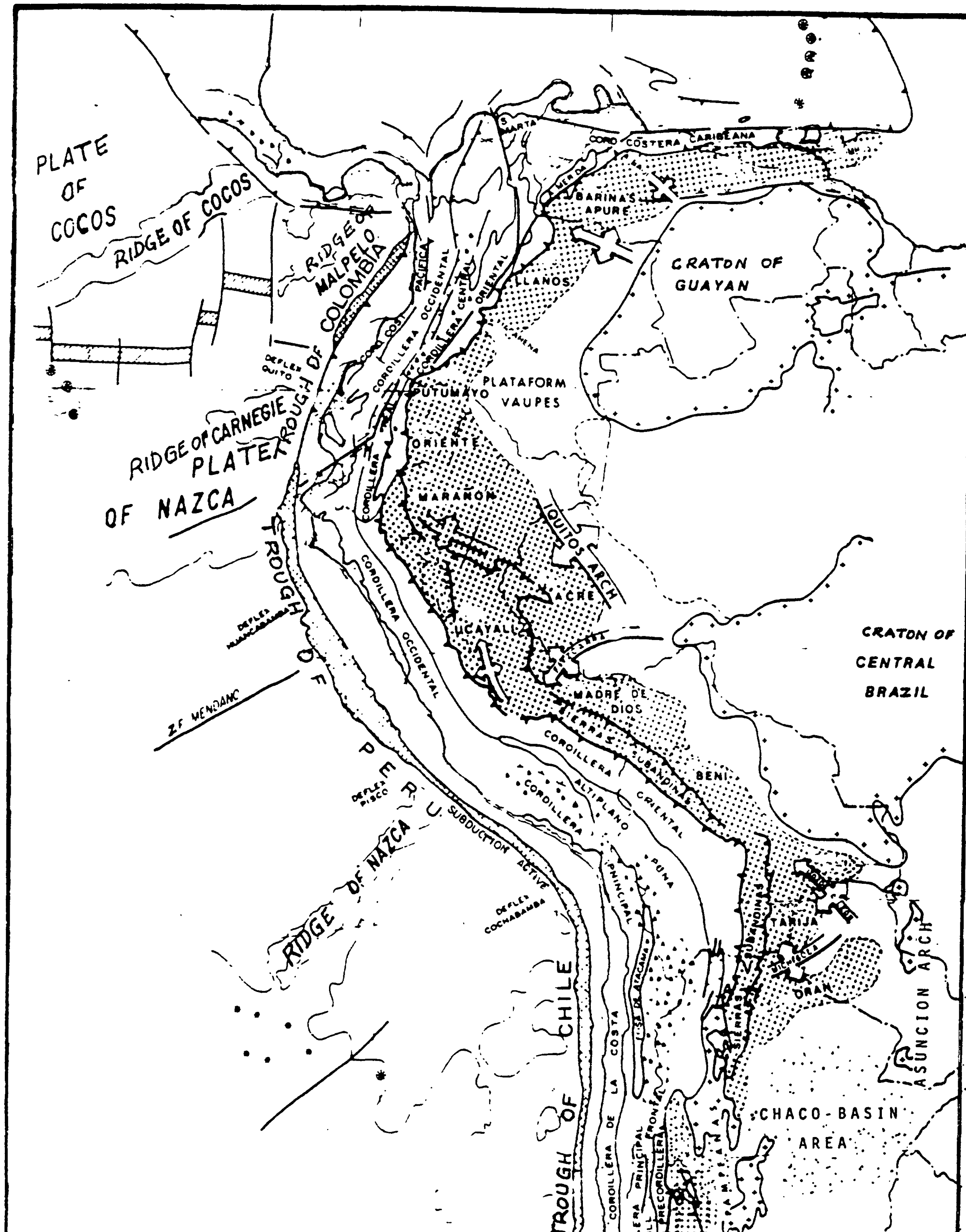


Figure 153 Sketch map of northwestern South America showing the foreland Subandian basins (stippled) and their relation to the Andes orogeny. Area of study extends from the Pampeanas in the south to, but not including, the Llanos and other basins of the northeast and east trending orogenic system of Colombia and Venezuela. Chaco-basin area dotted (modified from Urien et al, 1985).

A. Foreland Basins

General. The foreland basins of the Subandean superprovince are in a north-trending zone between the Brazilian craton to the east and the overthrust and fold belt of the Andes Mountains to the west (fig. 153). The adjoining overthrust and fold belt in some regions has been conventionally defined as a separate province from the foreland or platform portion of the basin, and in other regions the two tectonic elements are combined as a single province. For the sake of uniformity of treatment, and because of their related stratigraphy and their sometimes indistinct boundaries, the discussion of each foreland basin will be coupled with that of the adjacent fold and thrust belt, where it exists.

The foreland basins have westward-dipping, early Paleozoic platforms covered by upper Paleozoic platform rocks. The basins generally contain a thick, Upper Cretaceous section but the Triassic, Jurassic and Lower Cretaceous strata are missing or thin, although the section is thickening westward. The Paleozoic and Cretaceous were derived from the craton to the east. Molasse-type Cenozoic and latest Cretaceous rocks, derived from the rising Andes, complete the fill of the basins.

Structure in the foreland basins, as here defined, is limited to drapes, fault-closures, and up-thrust, "thick skinned" positive features. The fold and thrust belts which extend along the entire length of the Andes, along the west side of the foreland basins, largely involve the same rocks as in the foreland basins. The principle difference is that the structure of the fold and thrust best is dominated by low-angle, often decollement, thrusts, and associated steep-limbed anticlines in contrast to the less complicated structure of the foreland. Northward along the strike of the foreland basins, the style of the foreland structure changes. In the south, the Pampeanas ranges of northern Argentina are compressional, upthrust foreland blocks which separate the intermediate small basins (fig. 153); further northward in northernmost Argentina and in Bolivia (the Oran, Santa Cruz-Tarija, Beni and Madre de Dios basins) no such upthrust features occur; further north, however, in Peru and Ecuador (the Ucayali and Maranon-Oriente-Putumayo basins) compressional upthrust foreland blocks are again the predominant structural feature of the forelands. The presence of the foreland upthrust blocks has been related to the seismically-established lower angle of the subduction plane in those particular segments of the Andean subduction zone. These segments of upthrust features are further distinguishable from the adjacent steeper-dipping subduction-segments by the absence of Quaternary, and perhaps Neogene, volcanic rocks (Jordan et al, 1983).

Pampeanas Basins Area

Area: 174,000 mi2 (450,000 kms) (includes entire province of many subbasins (comprising about 10 percent of the area), and intervening mountain ranges

Original Reserves: Nil

Description of area: The Pampeanas basin area is made up of a number of small basins within the Sierra Pampeanas area (Pampeanas Ranges), a province of mountains and basins in west central Argentina between 26°30'W. It consists of about 12 major elongate, north-trending, up-thrust mountain blocks and intervening basins, four of which are indicated in Figure 154. The province lies at the southern end of the Subandean belt and adjacent foreland basins which extend northwards along the east side of the Andes (figs. 153 and 154).

Stratigraphy

During the late Paleozoic there was extensive erosion of largely igneous and metamorphic rock from the area. At that time a series of non-marine to marine sedimentary basins were formed. Late Carboniferous-Permian strata (the Pagonzo Group) are typically 3,300 to 6,600 ft (1,000 to 2,000 m) thick in the northern and western Sierras Pampeanas reaching depocenter thickness of 13,000 ft (4,000 m) and missing or thin to the south and in other areas (fig. 155A). The Triassic strata thicknesses are also localized in individual depocenters, mostly in the western Sierras Pampeanas (Jordan and Allmendinger, 1986), and in the extreme southwest constitute the main fill of the adjoining petroliferous Cuyo basin. The thickest sequence of the basins are Cenozoic sediment shed from the rising adjacent blocks. Data from the Bermejo subbasin (sometimes called the North Cuyo basin) suggests that there are 6,600 ft (2,000 m) to 26,250 (8,000 m) of Cenozoic and Upper Paleozoic strata (Section A-A', fig. 155).

Source. No source rock information is available. However, by analogy to the immediately adjoining Cuyo basin, Triassic lacustrine shales may provide such a source. According to Jordan and Allmendinger (1986) Triassic strata occurs in those basins to the west, presumably west of the Valle Fertil Range.

Reservoirs and Seals. From the brief rock descriptions available, and by analogy to adjoining on-trend basinal areas to the south and north, i.e., the Cuyo and Oran basins, Upper Mesozoic and Tertiary continental sandstones appear to be adequate reservoirs, but may be of reduced potential because of rapid, poorly-sorted deposition and volcanic content. Interbedded tuffaceous shales should provide effective seals.

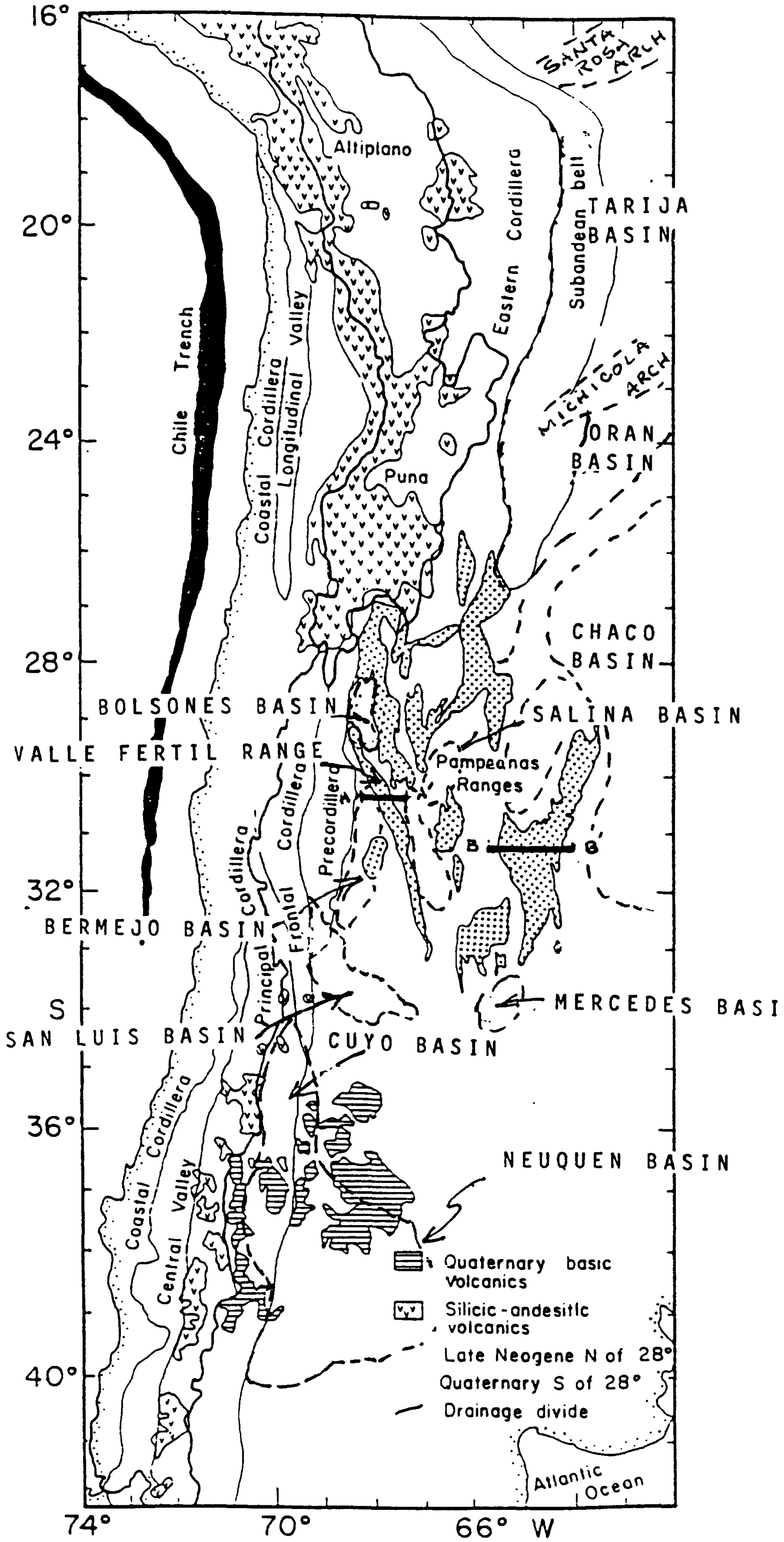


Figure 154 Map of west-central South America showing the Pampeanas Ranges (Sierras Pampeanas) area and its relation to the Andes orogeny, the Subandean basins to the north, and some of the Patagonian basins to the south (modified from Jordan and Allmendinger, 1986).

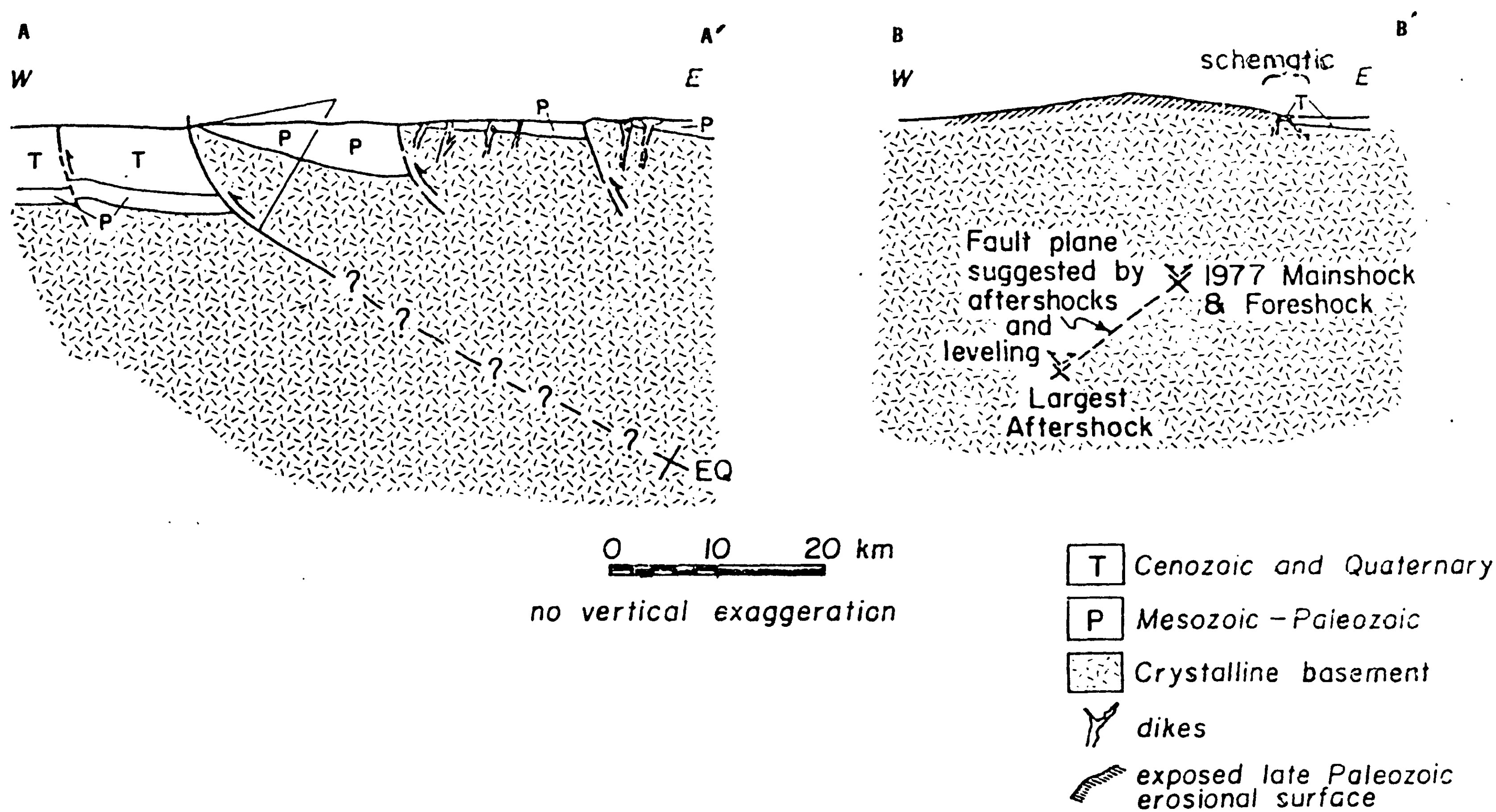


Figure 155 Cross-sections of the Pampeanas Ranges (Sierra Pampeanas) showing fault geometry of up-thrusted blocks and stratigraphy of the Bermejo subbasin (west end, section A). Location of sections on figure 154 (modified from Jordan and Allmendinger, 1986).

Structure

General. The structure of the Sierras Pampeanas province is a series of north-trending, upthrusted blocks lifted along reverse faults in the Late Tertiary and Quaternary (fig. 155). The fault-bounded mountain-blocks are generally asymmetric, tilting either to east or west. The intervening valleys are flat and broad, the central parts of the valley-basins showing only minor faulting or folding of Cenozoic strata. Figure 155 shows the upthrust nature of the boundary between an upthrust block (northern part of Sierra de Ville Fertil) and the Bermejo valley to the west.

The upthrust block, "thick-skinned" tectonics of the Sierra Pampeanas area, in contrast to the "thin-skinned" overthrusts of the Subandean belt to the north, are ascribed to compression associated with a relatively shallow, flat-dipping subducting plate (Jordan et al, 1983).

Traps. Potential traps would be either fault closures or drapes.

Generation, Migration, and Accumulation. Any generation and migration could only occur in the Tertiary when the basinal areas were depressed sufficiently so that any source rock would reach thermal maturity. This would be after or contemporaneous with the formation of fault traps or drape closures and therefore of favorable timing.

Plays. There is probably only one principal play and that would be the possible accumulations in Upper Mesozoic or Tertiary sandstones involved in Cenozoic fault trap or drape closures.

Exploration History and Petroleum Occurrence. Although there are indications in the literature that some exploration, including the drilling of wildcats, has taken place in the subbasins of this province, no details are available. It appears that exploration has been light and that no discoveries were made.

Estimation of Undiscovered Oil and Gas

From the little data at hand it appears that in the west, presumably west of the Valle Fertil Range, i.e., the Bermejo or North Cuyo basin, Triassic source strata are more likely to occur.

However, lack of discovery, and even exploration activity, indicates the area is less prospective than the adjacent Cuyo basin. The Triassic source rocks of the Cuyo basin may be thin or missing in the Triassic sequence of the Bermejo or Northern Cuyo; for evaluation purposes, it is estimated that, on an areal basis,only one-tenth the petroleum of Cuyo basin is present or .070 BBO and .014 TCFG, and it is limited to the western half of the Pampeanas area.

Oran Basin

Area: 55,000 mi^2 (140,000 km^2), 15,000 mi^2 (40,000 km^2) in the overthrust and fold belt and 40,000 mi^2 (100,000 km^2) in the platform area. About one-quarter of the platform is in Paraguay, the remainder in Argentina.

Original Reserves: .108 BBO and .360 TCFG (Petroconsultants 1990)

Description of Area: The Oran (or Cretaceous, or Pirity) basin of northern Argentina (and of a portion of northwestern Paraguay) is in two trends: 1) an east-northeast-bearing graben system incised into a shallow west-dipping foreland and 2) a north-bearing overthrust and fold belt overprinting the graben system on the west (fig. 156, 157). The Oran basin is separated from the essentially Paleozoic Santa Cruz-Tarija basin to the north by the Michicola (Tomasito) Arch, and thins southward towards an arch (Rincon Cabure) separating it from the Chaco basin.

Stratigraphy:

General. The basal portion of the sedimentary section in the Oran basin consists of Middle and Lower Devonian, along with some Silurian, strata which predate the basin formation, extending far beyond its present confines over the craton to the east and the Chaco plain to southeast. Carboniferous, Permian, and lower Mesozoic rock are missing by nondeposition or erosion, so that Upper Cretaceous rests directly on Middle Devonian strata (fig. 158, 159).

Little consideration is given to the pre-Cretaceous rock, but some questionable petroleum source rock, potential reservoirs, and minor shows are reported in Middle and Lower Devonian rocks.

The base of Upper Cretaceous rocks is the non-marine red-bed Pirgira Formation which covered an extensive area beyond the present basin boundaries. These strata are overlain by marine Campanian to Maastrichtian strata of the Bulbuena Subgroup of predominantly carbonates and shales with more sandy beds towards the edges of the basin. This subgroup contains the principal source and reservoir rocks of the basin. As shown on figure 160, the Bulbuena Subgroup is largely missing from the platform. Overlying the Bulbuena Subgroup is the marine Maastrichtian Santa Barbara Subgroup of vari-colored marls, shales and minor evaporites, but with some sand-bodies. This subgroup, while also extensively deposited over the region, is the principal sequence whose relatively thick depocenter defines the Oran basin. Thick Andes-derived Tertiary clastics blanket the region including the Oran basin.

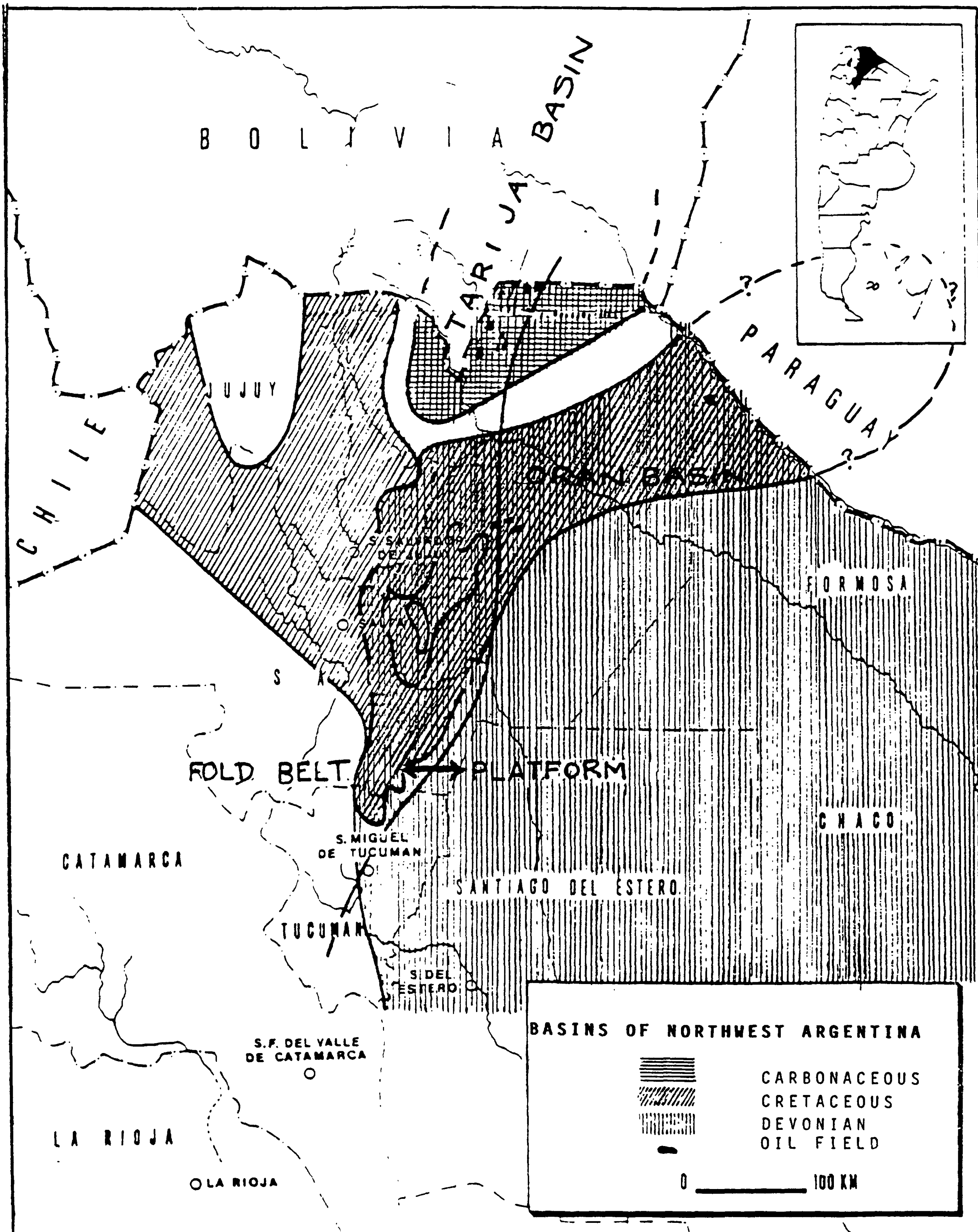


Figure 156 Map of northern Argentina showing the Oran basin and its fold belt and platform elements (modified from Lesta et al, 1985)

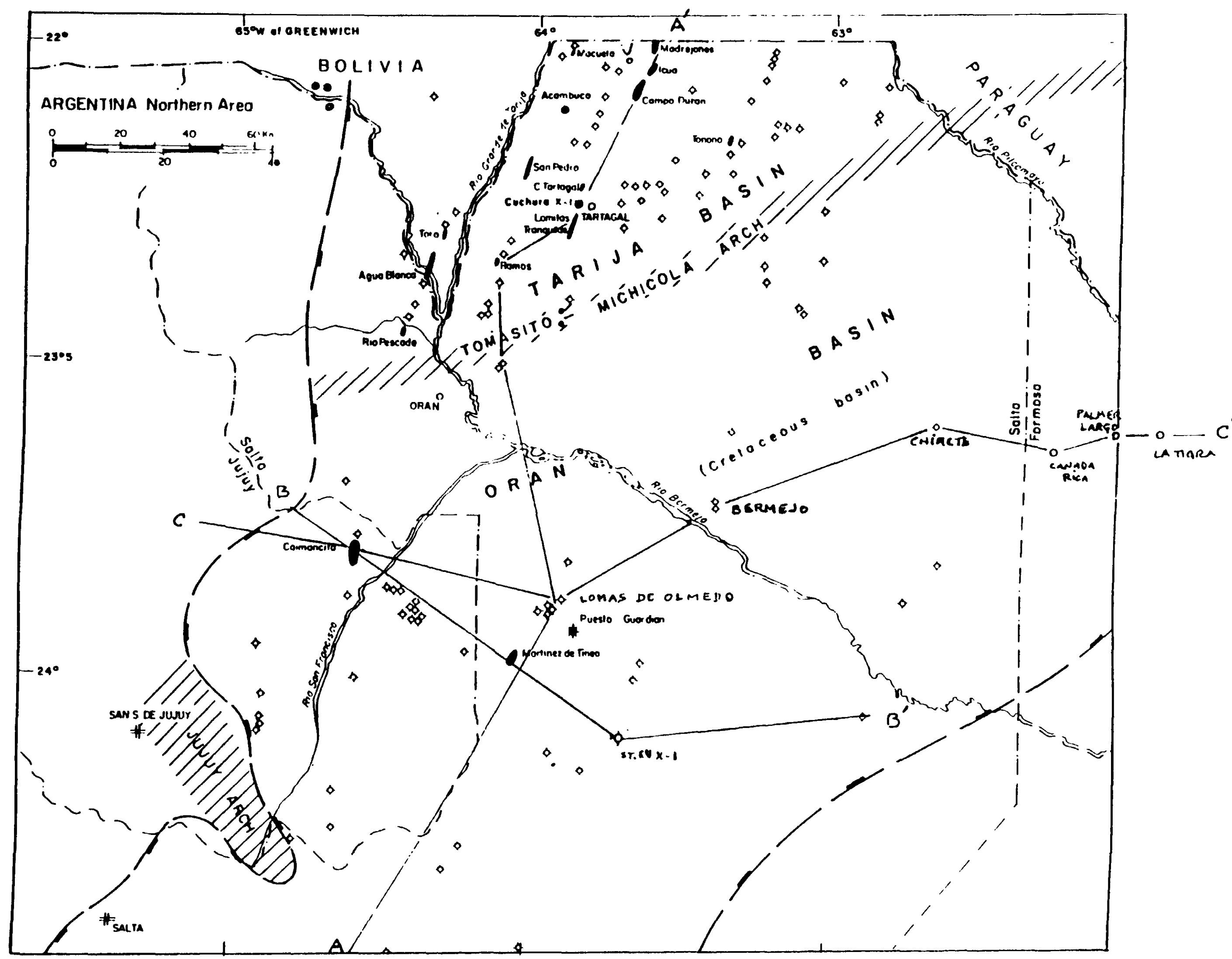


Figure 157 Map of central Oran basin and southern Santa Cruz-Tarija basin showing principal oil and gas fields, significant wildcats, and profile positions (modified from Petroconsultants, 1989).

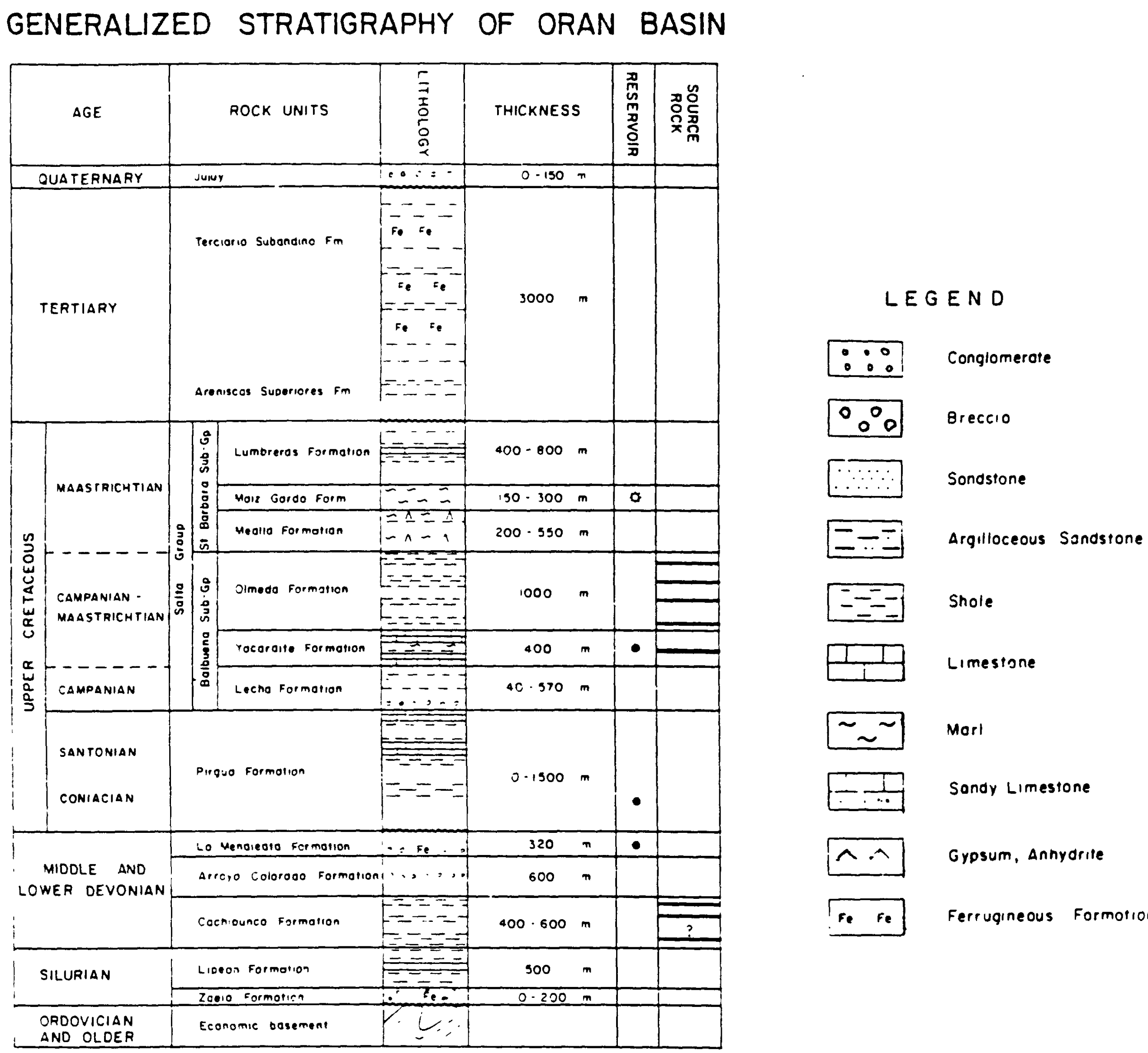
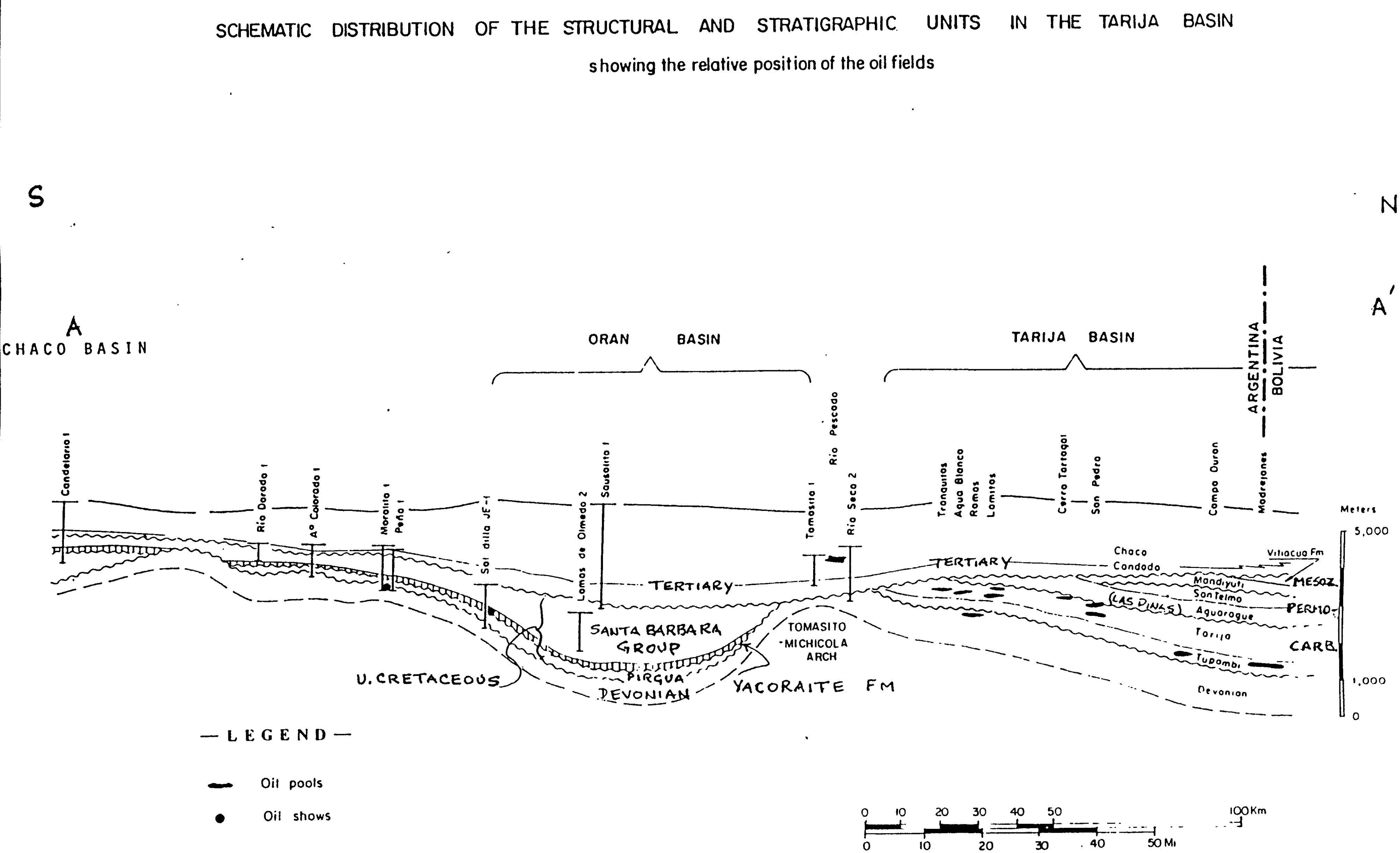


Figure 158 Stratigraphic column of Oran basin showing lithology and reservoir and source rock formations (from Petroconsultants, 1990).



ARGENTINA (RIO PESCADO)

Figure 159 South to north stratigraphic section showing stratigraphic relation of the mainly Cretaceous Oran basin to the mainly Paleozoic Santa Cruz-Tarija basin; location figure 157 (modified from Petroconsultants, 1990).

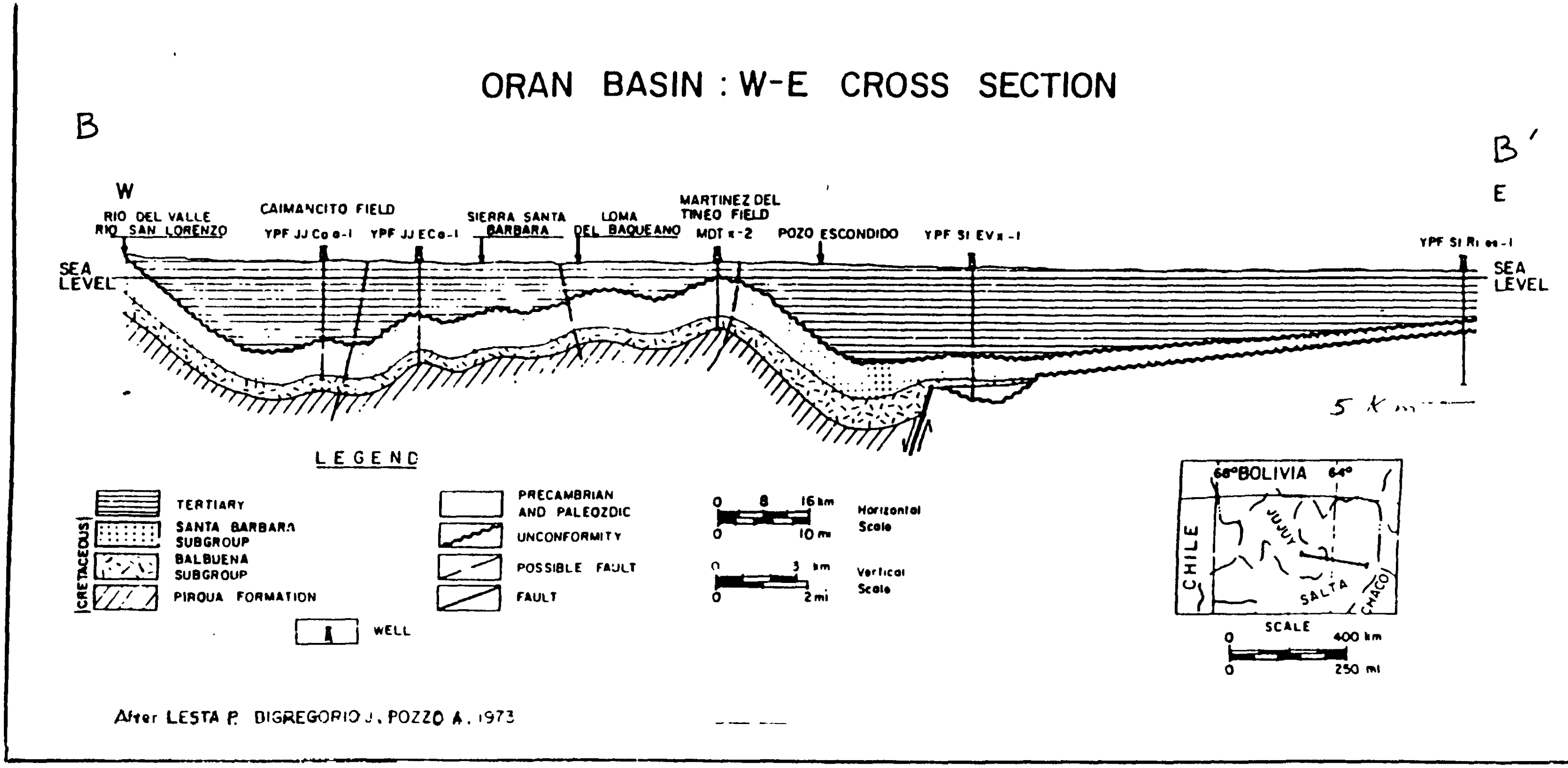


Figure 160 West to east stratigraphic section of the Oran basin showing the thinning and absence of the principal oil and gas generating and reservoiring Balbuena subgroup; location figure 157 (from Petroconsultants, 1990).

Source. The principal source rocks in the basin are the dark shales of the Olmeda Fm. of the Bulbuena Subgroup (Upper Cretaceous) which contain abundant organic material deposited in a reducing environment. Some dark shales of the underlying Yacoraite Formation and dark marls of the Santa Barbara Subgroup may also be considered as source rocks.

Reservoirs and Seals. The principal reservoir rocks of the Oran basin are the carbonates of the Yacoraite Formation (fig. 158). These rocks have secondary porosity developed by fracturing and some primary porosity in sandier facies. The reservoirs are only of fair to poor quality e.g., 15 percent porosity with 40 percent water saturation in 66 ft (20 m) net pay in the largest field, Caimancito. Some of the sandstones of the Olmeda Formation and Santa Barbara Subgroup have reservoir capability.

Seals are provided by interbedded shales and marls of the Yacoraite and Olmeda Formations. Other potentially important seals include evaporites in the overlying Mealla Formation.

Structure

The Oran basin platform is part of an extensive foreland that slopes westward from the Brazilian craton towards the Andes. It reached its present, more limited, configuration during the Upper Cretaceous when sediments were deposited in a transverse basin, apparently down-faulted along a line of east-northeast trending rifts. The rifting may be related to the Jurassic-Lower Cretaceous break-up of Gondwana. Superimposed on the western end of this rift basin is the north-trending foredeep and thrust and fold belt of the Tertiary Andean orogeny (fig. 161).

Most of the traps are anticlines in the overthrust and fold belt portion of the basin. The few traps which have been found in the other part of the foreland appear to be east-northeast-trending, low-amplitude fault closures.

Petroleum Generation and Accumulation. The thermal gradient of the region appears to be low, as indicated by determinations in the nearby Tarija basin, so that the top of the oil window may be as deep as 5,000 m (16,400 ft). The principal source interval, i.e., the Olmeda Formation reaches this depth in only the deeper parts of the basin, e.g., the foredeep extending north-northeastwards from near S. Miguel de Tucuman to the Michicola (Tomasito) Arch (fig. 156). The reservoirs, largely fractured carbonates, though deposited in the Late Cretaceous time, developed secondary porosity only in the Tertiary. At approximately the same time, migration began and structural closures formed.

Plays. Two plays have been developed in the basin: 1) anticlinal and fault closures in the overthrust and fold belt involving principally the Bulbuena Subgroup reservoirs, and 2)

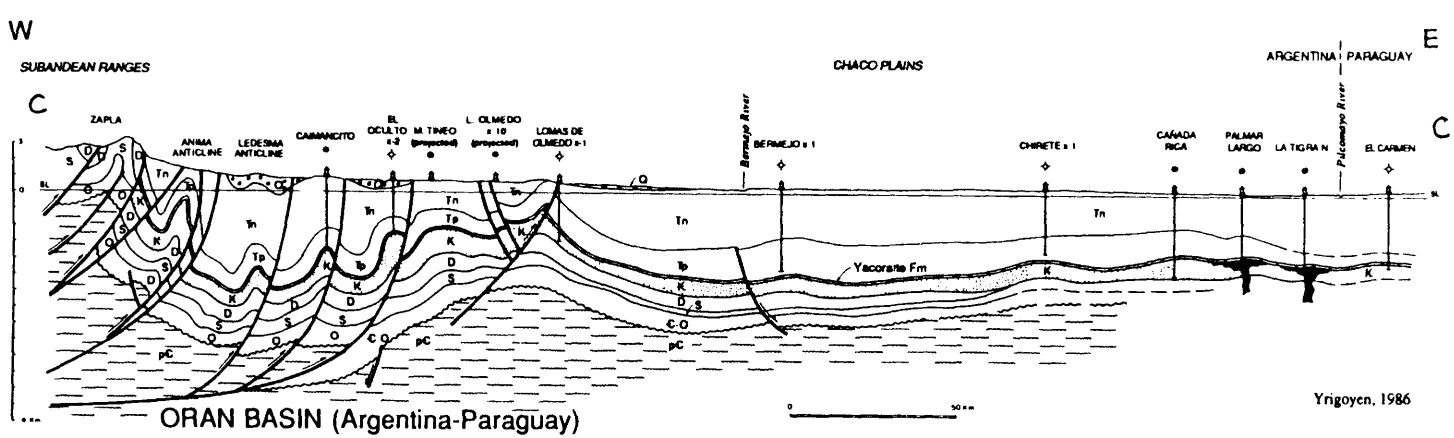


Figure 161 West to east structural cross-section of the Oran basin (Lesta et al, 1985).

normal-fault closures on the platform portion of foreland, involving a much thinner section of reservoirs and source rock. A third play which is important in similar foreland Cretaceous basins of the Rockies (Powder River and Denver basins), is stratigraphic traps. This play may have potential in the Oran basin.

Exploration History. Exploration began in the twenties, but with only limited initial success. However, the 28th wildcat discovered the Caimancito Field with reserves of some 64 MMBO and 164 BCFG (Petroconsultants data, 1990). This field, so far, is the largest accumulation in the basin. Other discoveries, as indicated on figure 162, are few, much smaller, and diminishing in size as exploration continues. The success rate appears to be about 11 percent based on Petroconsultants data.

Estimation of Undiscovered Oil and Gas

The Oran basin is essentially a Cretaceous foreland basin somewhat analogous to the on-trend Maranon-Oriente-Putumayo Cretaceous foreland basin of Peru, Ecuador and Columbia or the Cretaceous foreland Powder River basin of the United States. By straight areal analogy to the resources of these basins, each of which is considered to have oil resources of about 55 MBO per mi^2, the Oran basin has resources of about 3.0 BBO. However, it is estimated that only about 30 percent of the Oran basin is underlain by sufficiently mature source rock and the reservoirs are poor, with perhaps only 50 percent of the capacity of the Maronon-Oriente-Putumayo reservoirs. Furthermore, the traps are smaller and more broken up by faulting, reducing the analogy by another 50 percent.

These considerations reduce the estimated resources of the Oran basin to .227 BBO. Since .108 BBO has been found, .119 BBO is left to be discovered.

Using the same rationale and assuming the same undiscovered oil to gas ratio as its present reserves, the Oran basin has .757 TCFG of which .360 TCFG have been discovered, indicating .397 TCF of undiscovered gas.

As a check to this estimate, figure 162 shows a curve representing the cumulative amount of oil being discovered for the number of wildcats drilled. The curve appears, rather tenuously, to flatten for the last 100 wildcats for oil to a rate of about .43 MMBO per wildcat and the last 40 wells for gas to a discovery rate of 1.475 BCF per wildcat. If the same number of wildcats are drilled in the future as in the past (160), assuming the rate remains constant (new technology balancing increasing finding difficulty), .069 BBO and .236 TCFG will be discovered. However, the drilling to date has largely targeted structural traps and the resulting projection is considerably lower than the .119 BBO and .397 TCFG arrived at above by the analogy to basins perceived to have considerable stratigraphic oil potential. The estimate arrived at by analogy seems to be the more probable since it appears that,

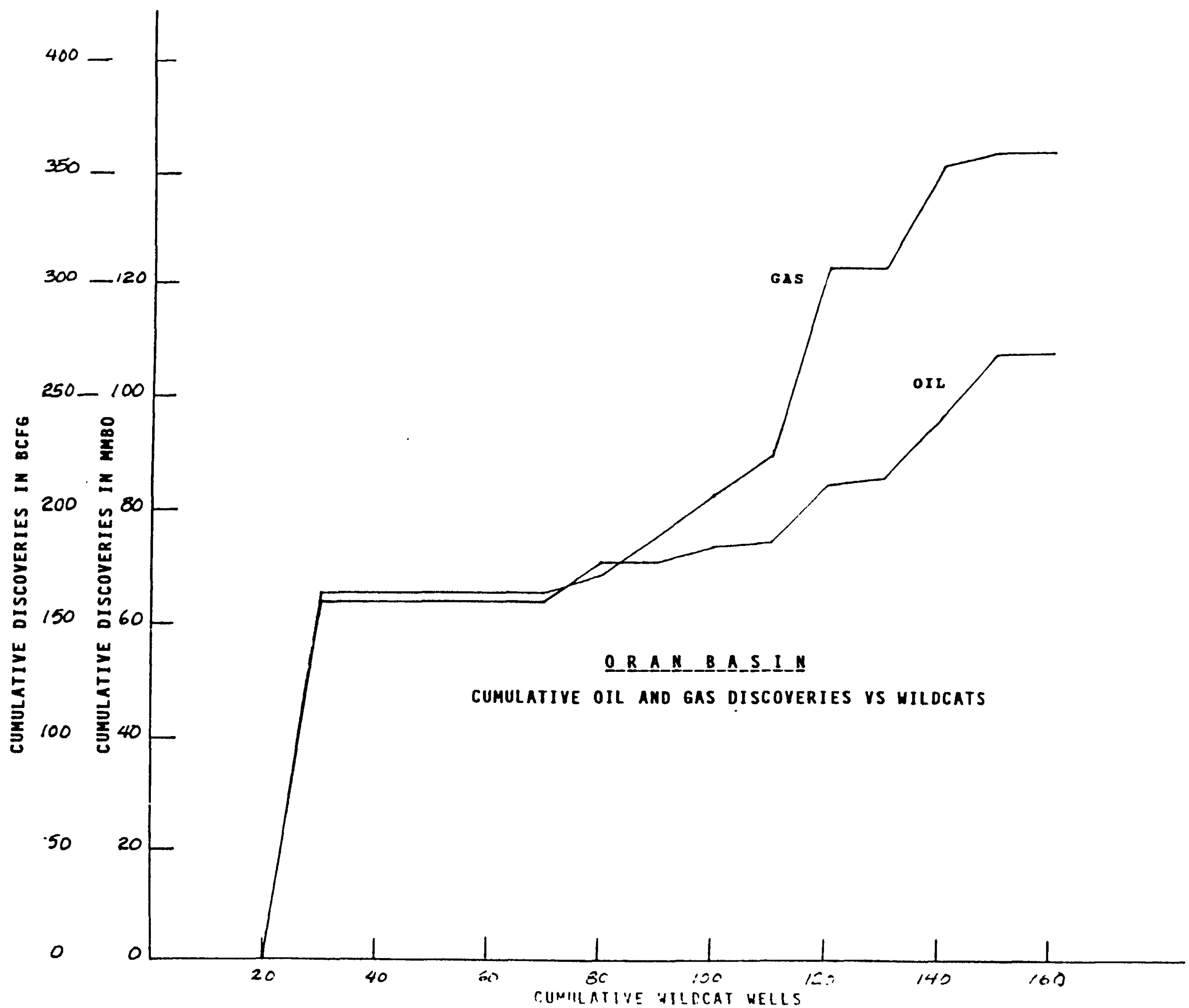


Figure 162. Graph showing the cumulative amount of oil and gas discovered in the Oran basin versus the cumulative number of wildcats drilled. Based on Petroconsultants data (199) which may be incomplete.

given the possible conduits, e.g., the Santa Barbara Subgroup sand bodies, the stratigraphic trap potential of the Oran basin may not as yet been fully investigated.

About one-quarter of the platform is in Paraguay. The platform is of low potential, especially in the updip area of Paraguay; the section is thinning and the most prospective unit, the Bulbuena Subgroup appears to be missing from the entire platform. By analogy to the adjoining Santa Cruz-Tarija basin only 6 percent of the basin's petroleum may be expected on the platform. On this basis the amount of undiscovered oil in Paraguay would be less than 1.5 percent of the basins ultimate oil resources, or .003 BBO. Gas would be neglible.

The Santa Cruz-Tarija basin

Area: 77,000 mi^2 (200,000 km^2), of which 73,000 mi^2 (190,000 km^2) is in Bolivia and 4,000 m^2 (10,000 km^2) in Argentina. Area of the unfolded platform is 44,000 mi^2 (114,000 km^2) of which 42,000 mi^2 (109,000 km^2) is in Bolivia and 2,000 mi^2 (5,000 km^2) is in Argentina. The area of the folded foothills plus overthrust and fold belt (including the Subandean Range and the adjoining low foothills) is 33,000 mi^2 (85,500 km^2) of which 31,000 mi^2 (80,300 km^2) is in Bolivia and 2,000 mi^2 (5,200 km^2) is in Argentina (fig. 163).

Original Reserves

Total:	.492 BBO	10.56 TCFG
Argentina:	.012 BBO	3.36 TCFG (Petroconsultants, 1990)
	(.359)	(6.427) (Yrigoyen, 1990)
Bolivia:	.480 BBO	7.20 TCFG (Yacimentos Petroliferous Fiscales, Bolivianos)
	(.655)	(6.684) (Yrigoyen, 1990)

Description of area: The Santa Cruz-Tarija foreland basin, including the platform and overthrust and fold belt elements, lies between the Brazilian craton on the east and the Andes Mountains on the west. It extends northwards from the transverse Tomasito-Michicolo Arch in northern Argentina to the Santa Rosa Arch of central Bolivia where the overthrust and fold belt narrows (fig. 163).

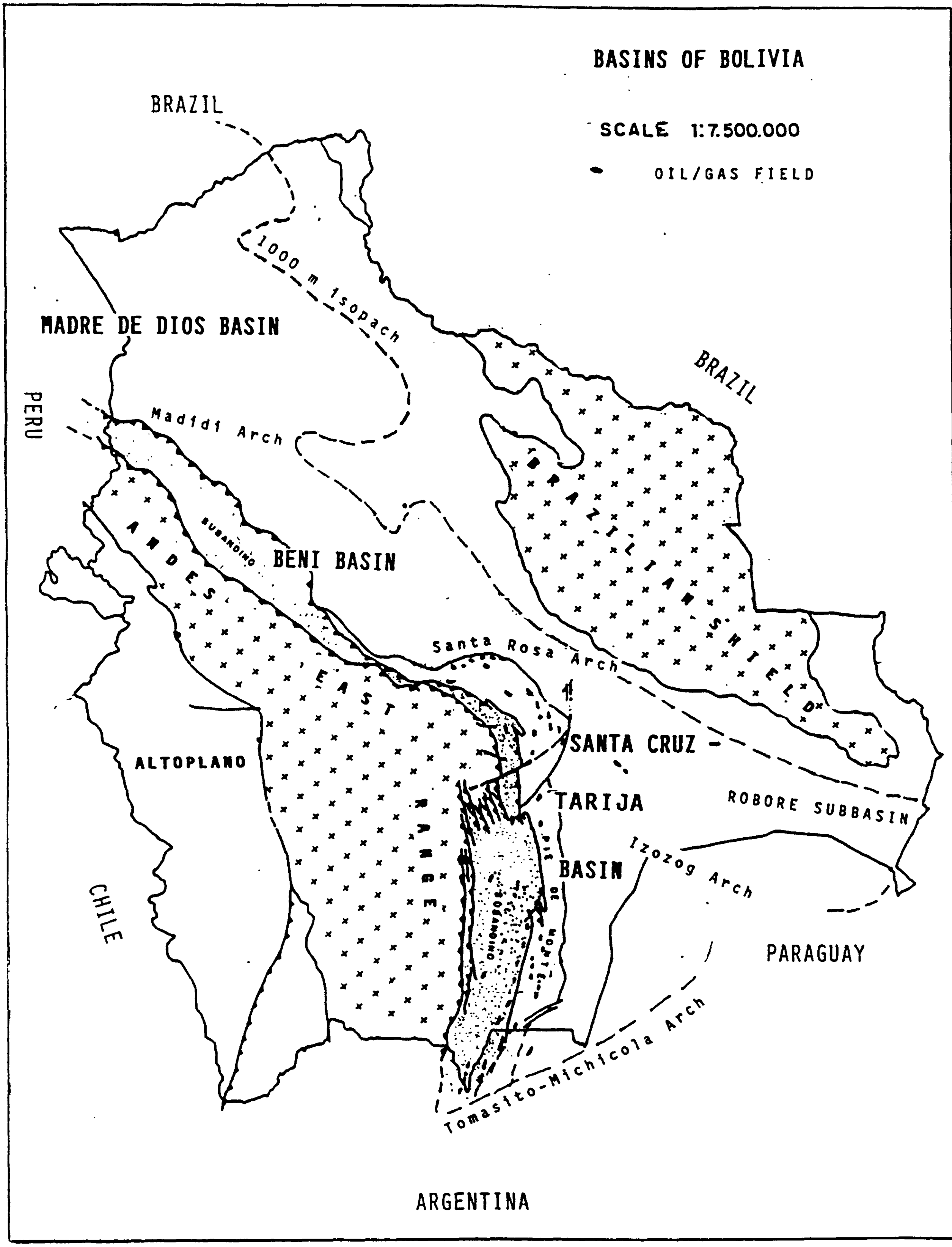


Figure 163 Tectonic map of Bolivia showing the Santa Cruz-Tarija basin, along with the ontrend Beni and Madre-de Dios foreland basins and the Subandino and Pie de Mont overthrust and fold bests (modified from Paulsen, 1988).

Stratigraphy

General. Unlike the Mesozoic basins of Argentina the Santa Cruz-Tarija basin is essentially a Paleozoic basin even though the present basin has become more restricted in size owing to the Tertiary Andean orogeny. Figure 164 shows the stratigraphic section as seen in the southern part of the basin. It should be noted that ages and correlations of Carbonaceous and younger strata, which are of Gondwana and/or continental facies and generally lacking in index fossils, are poor, varying from place to place and author to author; the problem is compounded by local formation designations.

The present depocenter of the Siluro-Ordovician sequence, or so-called Cordilleran Cycle, rather closely conforms to the configuration of the Santa-Cruz-Tarija basin, lying along the Andes front between the Michicola and Santa Rosa transverse arches, and not extending onto the foreland platform (Chaco Plain). It reaches a thickness of over 23,000 ft (7,000 m) (fig. 165). Not much is known of the deeper, seldom penetrated part of the sequence, assumed to be Silurian, but appears to be largely dark shales and sandstones (Lipeo-Kirusillas and older formations). The Devonian section consists of a basal, 1,000 ft- (300 m-) sandstone (Santa Rosa or Ramos Formation) overlain by 3,300 to 10,000 ft of marine, organic, black shales (Los Monos or Tonono Formation) with intercalations of siltstone and sandstone (fig. 166) which become predominant along the western side, perhaps indicating an ancestral Andes.

A second cycle includes the Carboniferous through the Triassic, sometimes called the Gondwana Group, or the Subandean Cycle. The Carboniferous may be divided into four formations (or five by some authors) (fig. 164). The basal unit is the Tupambi Formation, of some 700 ft (200 m) thickening southwards, of predominantly medium to coarse grained white sandstones with black shales, the upper part being more shaly (sometimes designated the Itacuami Formation). This is overlain by a 300 to 1,200 ft (100 to 400 m) sequence of fanglomerate sandstones, shales and diamictites, thickening southwards, laid down in a glacial front lake or sea, the Tarija Formation. The lower Carboniferous (Tupambi and part of the Tarija?) appears to be largely limited to the Santa Cruz-Tarija basin (fig. 167). Overlying the Tarija Formation is a thick (up to 1,150 ft (350 m) sandstone formation, containing some shales and diamictites, the Las Penas Formation. The top Carbonaceous unit, the San Telmo Formation, is up to 1,200 ft (360 m) of varicolored fanglomerates, sandstones, shales and diamictites.

Permian strata appear missing from the basin.

Overlying the Paleozoic strata by unconformity is the Mesozoic section, the Triassic strata confined to the depocenter of the basin and the Cretaceous more widespread, but not uniformly covering the basin. The Mesozoic section is relatively thin and made up of sandstones, shales, and some carbonates and topped by some basalts.

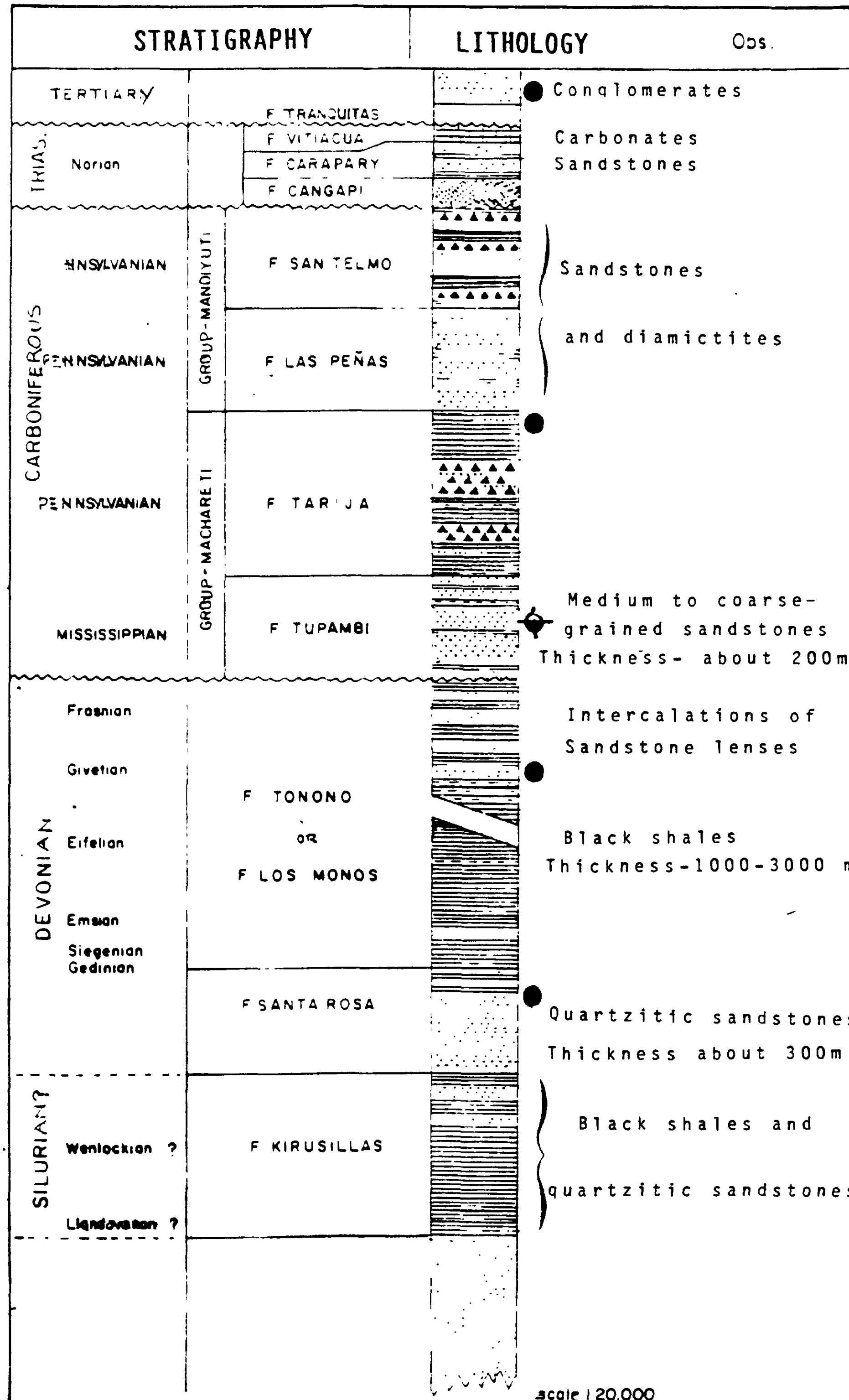


Figure 164 Stratigraphic column of the Santa-Cruz-Tarija basin showing oil and gas occurrence (modified from Lista et al, 1985).

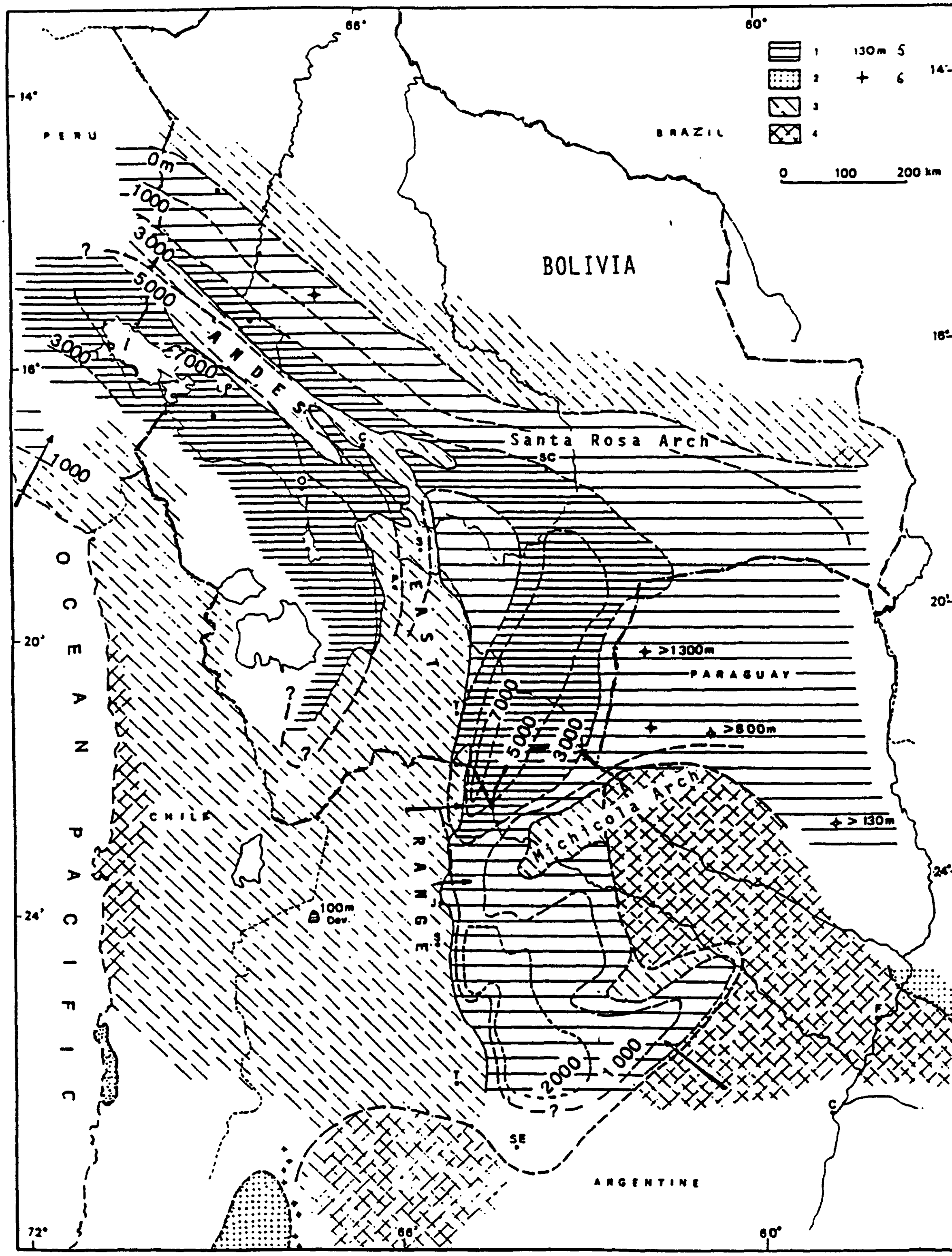
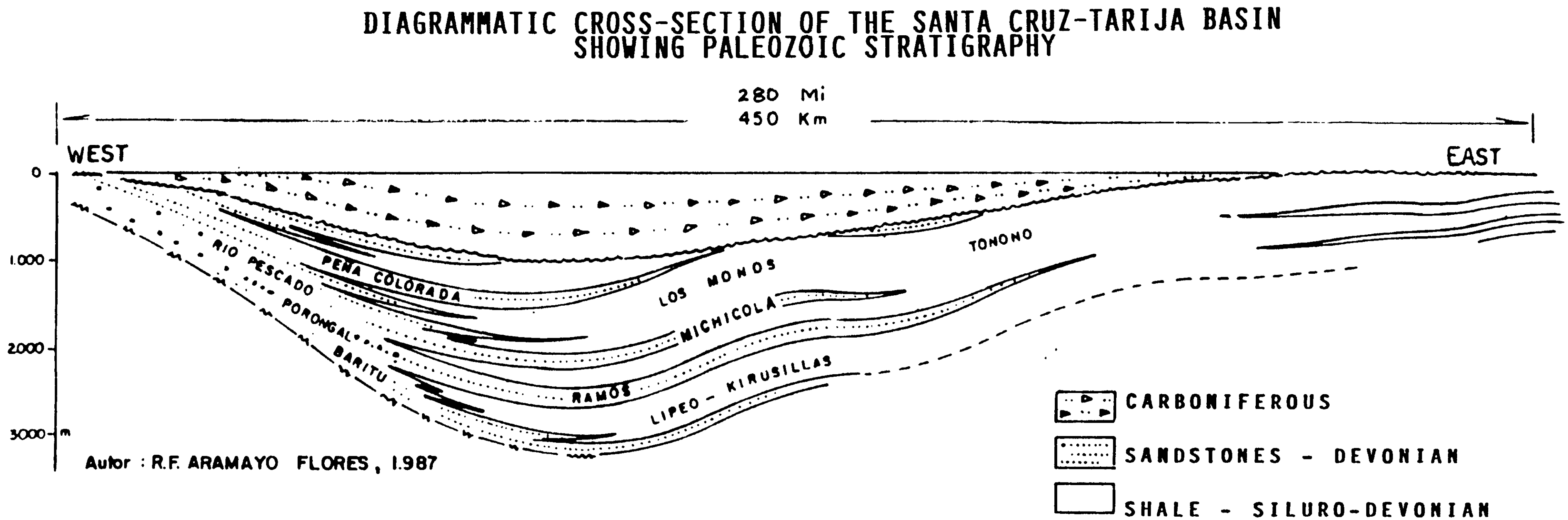


Figure 165 Map of southern Bolivia and adjoining countries showing isopach and extent of the Siluro-Devonian sequence in the Santa Cruz-Tarija basin. 1) = marine grey-shale facies; 2) = continental facies, 3) = positive eroded areas; 4) = positive emergent areas; 5) = thickness values, and 6) = wildcats which penetrated sequence. Dast-dot lines = international boundaries (modified from Martinez, 1980).



ARGENTINA	BOLIVIA
Fm Los Monos	Fm Los Monos
Fm Michicola	Fm Huamampampa
Fm Tigre	Fm Icla
Fm Ramos	Fm Santa Rosa
Fm Lipeo	Fm Kirusillas

Figure 166 Diagrammatic cross-section of the Santa Cruz-Tarija basin showing the westward sandstone increase in the Siluro-Devonian sequence (modified from Aramayo, 1988).

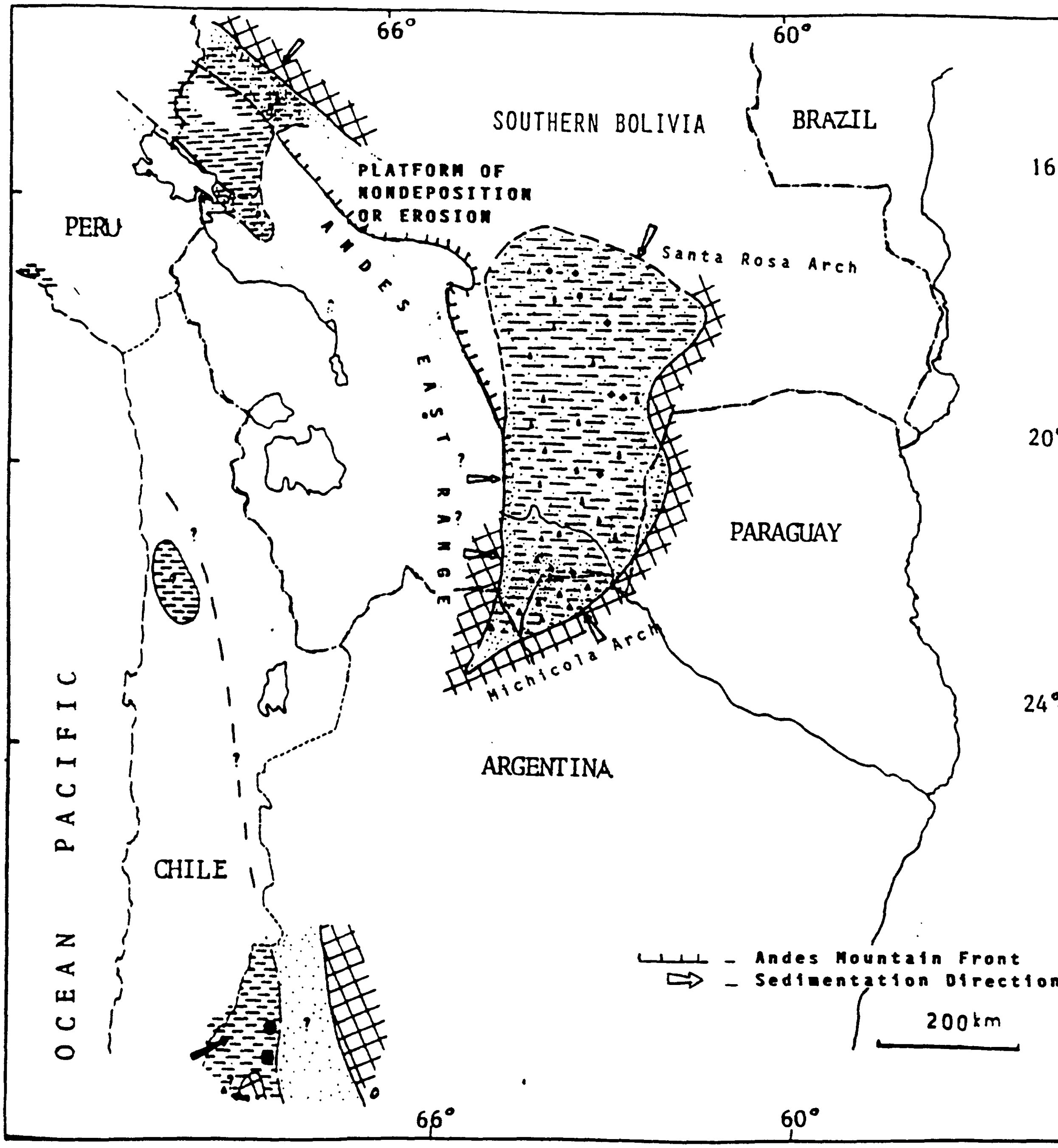


Figure 167 Map of southern Bolivia and adjoining countries showing the extent of the Lower Carboniferous, the Tupambi (and part of Tarija?) formations in the Santa Cruz-Tarija basin vicinity (modified from Martinez, 1980).

Overlying the Mesozoic is a thick section of Andes-derived Tertiary molasse.

Source. The principal source of the basins petroleum is the Devonian dark organic shales, particularly those of the Los Monos Formation; dark shales of the Silurian and Ordovician strata may have also contributed.

The basin appears to have an unusually low thermal gradient so the liquids, rather than gas, are generated at depths as deep as 16,400 ft (5,000 m).

Reservoirs and Seals. All the sandstone intercalations in the section appear to be potential reservoirs (fig. 164).

The lowest reservoirs are sandstones of the Lower Devonian Santa Rosa formation which have low primary porosity (about 4 percent) but good secondary porosity producing gas and condensate. Other higher lenticular reservoirs in the Devonian section have increasingly better primary porosity.

The most prominent reservoirs are the medium-grained quartzose sandstones in the Tupambi Formation at the base of the Carboniferous ("Gondwana Group"). Other reservoirs are in the Carboniferous Tarija Formation and in the basal Tertiary.

The only seals available are the shale over and interbedded with the reservoir sandstone sections. Of critical value would be the shales of the Tarija Formation which are closely associated with the principal reservoirs. Flushing appears to be a serious problem in the northern part of the basin, perhaps limiting the prospective traps to the lower thrust or foot-wall blocks.

Structure

The structure of the Santa Cruz-Tarija basin has been divided into three elements: (1) the platform, (2) the mildly folded, Tertiary-covered foothills (Pie de Monte Andino), and (3) the folded and overthrusted belt (Subandino) of pre-Tertiary ridges and Tertiary synclines (figs. 163 and 168).

The platform dips gently westwards from the Brazilian craton; it generally has only few features of very low amplitude. It is transected by a number of Cretaceous-Tertiary or older, low amplitude, generally transverse arches which have influenced the sedimentation, e.g., the Tomasito-Michicolo, the Santa Rosa and the Izozog Arches. Between Izozog Arch and the Brazilian craton is a local deep, the Rabore subbasin (fig. 163). These transverse structures are unrelated to the Andes orogeny (fig. 163). Only 6 percent of the basin's oil, in only 3 traps, has been discovered to date on the platform.

The Tertiary-covered foothill (or Pie de Monte Andino) belt occupies a north-trending zone of up to 35 mi (60 km) wide (fig. 163). The structure is relatively low amplitude folds and high-angle reverse faults (figs. 163 and 168). The folding and faulting are post-Tertiary and probably still active. These structures provide traps for 44 percent of the Bolivian oil production. Perhaps significantly, this zone of folding does not extend northward in the Beni foreland basin of northern Bolivia where oil is yet to be found (fig. 163).

The Subandean Range (Subandino) zone is distinguished by ridges of pre-Tertiary, largely relatively steep dipping, Paleozoic rock where thrusting is the dominant mode (fig. 168). This zone contains 55 percent of the basin's Bolivian oil and 95 of the basin's Argentine oil.

<u>Generation, Migration, and Accumulation</u>. Generation and migration began in major proportions when the Devonian source shales, Las Monos, subsided into the thermal zone for oil generation of the Andean foredeep during the Tertiary. Structural traps were formed concurrently during the same Andean orogeny so that migration timing appears favorable. The principal reservoirs range from Devonian to Permo-Carboniferous to the basal Tertiary section and, therefore, subject to varying degrees of reservoir diagenesis deterioration from oldest to youngest. The youngest, Tertiary, reservoirs, though perhaps of better quality, are further from the principal source in the Devonian strata. The presence of adequate reservoirs does not appear to be a limiting factor.

<u>Plays</u>. Since reservoirs exist at several horizons and source rock underlies the basin, plays are constrained by trap distribution. There are essentially two plays, the traps of the overthrust and fold belt and low-amplitude fault and drape features of the platform in which stratigraphic closure may play a part.

<u>Exploration History and Petroleum Occurrence</u>. Exploration by American companies began in the early twenties and the first oil field, Bermejo, was discovered in 1924. The area has reached a mature stage of exploration. In Bolivia, according to Yacimientos Petroliferos Fiscales Bolivianos, 403 wildcats discovered 53 fields, a success rate of 13 percent and in Argentina, according to Petroconsultants, 101 wildcats found 16 fields, a success rate of 16 percent. Figure 169 shows the cumulative amounts of discovered oil and gas per wildcats drilled for the Bolivian and Argentina portions of the basin. The rate of oil discovered for the last 100 wildcats appears to have leveled off at about .12 MMBO per wildcat in both Bolivia and Argentina. The rate for gas in the last 50 wildcats leveled off at 5.30 BCFG per wildcat in Bolivia and 3.62 BCFG per wildcat in Argentina.

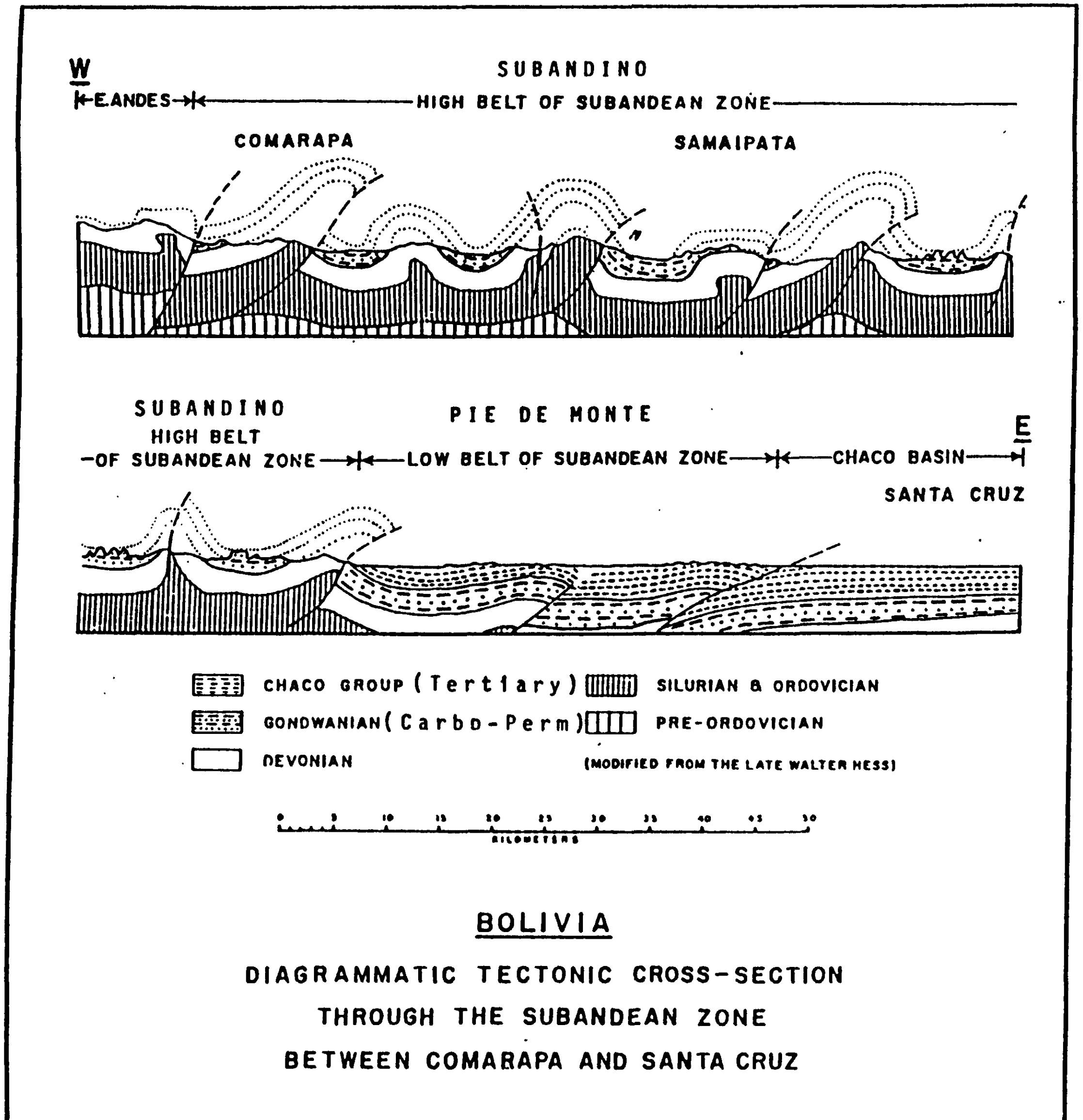


Figure 168 West to east diagrammatic cross-section across the Subandino high thrust belt and the Pie de Monte low belt of folding and reverse faulting, Santa Cruz-Tarija basin (modified from Lamb and Truitt, 1963).

Estimation of Undiscovered Oil and Gas

Assuming that the present low discovery rate at the "tail end" of the oil and gas discovery curve (fig. 169) continues for a long period (advancing technology balancing increasing discovery difficulty), and that the same number of wildcats drilled to date (250 in Bolivia and 100 in Argentina) will be drilled in the future, .030 BBO will be discovered in Bolivia and .012 BBO in Argentina, making .042 BBO for the basin. On the same assumptions, 1.33 TCFG will be discovered in Bolivia and .36 TCFG in Argentina, making 1.69 TCFG in all.

Beni Basin

Area: 47,000 mi^2 (121,000 km^2)

Platform: 31,000 mi^2 (80,000 km^2)

Overthrust and fold belt: 16,000 mi^2 (41,000 km^2)

Original Reserves: Nil

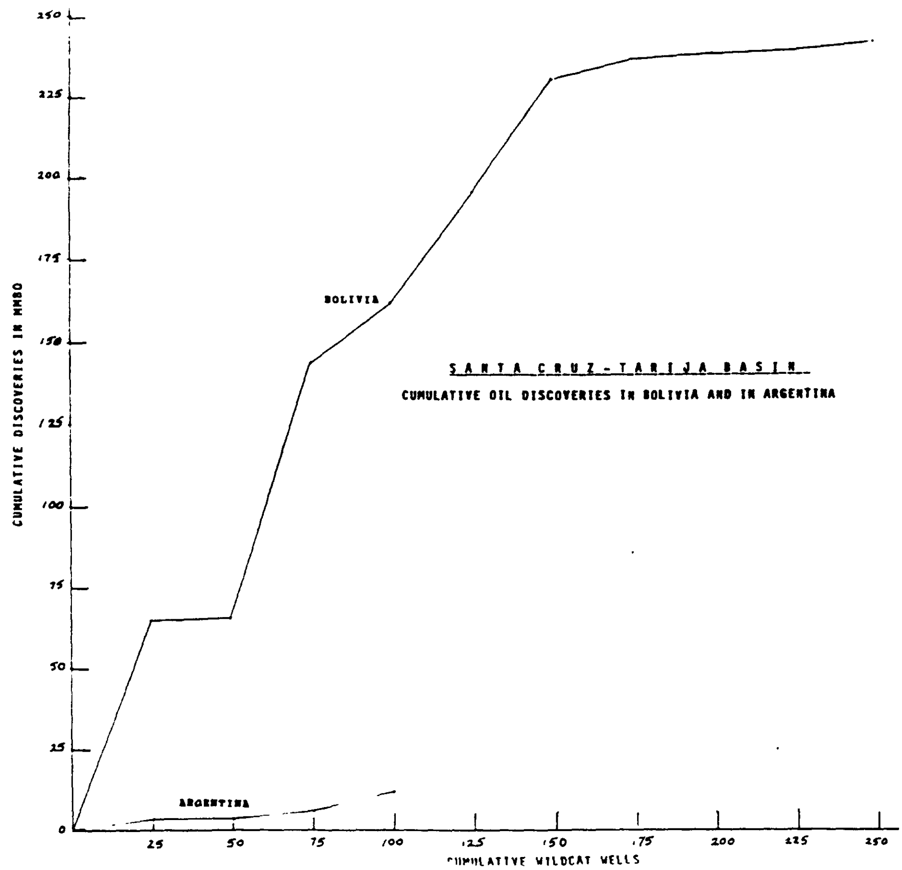
Description of Area: The Beni foreland basin is located in central Bolivia between the Brazilian shield and the Andes Mountains (fig. 170). It is taken to include the west sloping platform and the overthrust and fold belt, referred to as the Subandino Range. It is separated from the Madre de Dios foreland basin to the north by the Madidi Arch and from the Santa Cruz-Tarija foreland basin to the south by the Sata Rosa Arch (fig. 170). The basin is entirely within Bolivia.

Stratigraphy

Stratigraphic information is sparse. Presumably, the stratigraphy is similar to that of the adjoining on-trend basins, the Santa Cruz-Tarija basin to the south and the Madre de Dios basin to the north.

The Siluro-Devonian sequence appears to abruptly thin north of the Santa Rosa arch from a thickness of up to 23,000 ft (7,000 m) in the Santa Cruz-Tarija basin to about 10,000 ft (3,000 m) in the Beni basin (fig. 165). Further north in the Madre de Dios basin its thickness is reported to be 2,123 ft (647 m) (Sanz, 1985). The Siluro-Devonian sequence is largely dark colored, marine organic shales with interbedded siltstones and sandstones; it is considered to contain the principal source rock of the Santa Cruz-Tarija basin and contains the main potential source rocks of the Madre de Dios basin. The reservoirs are also good and are being productive in the Santa Cruz-Tarija basin.

The Lower Carboniferous strata which include the main reservoirs of the Santa Cruz-Tarija basin are missing or thin in the



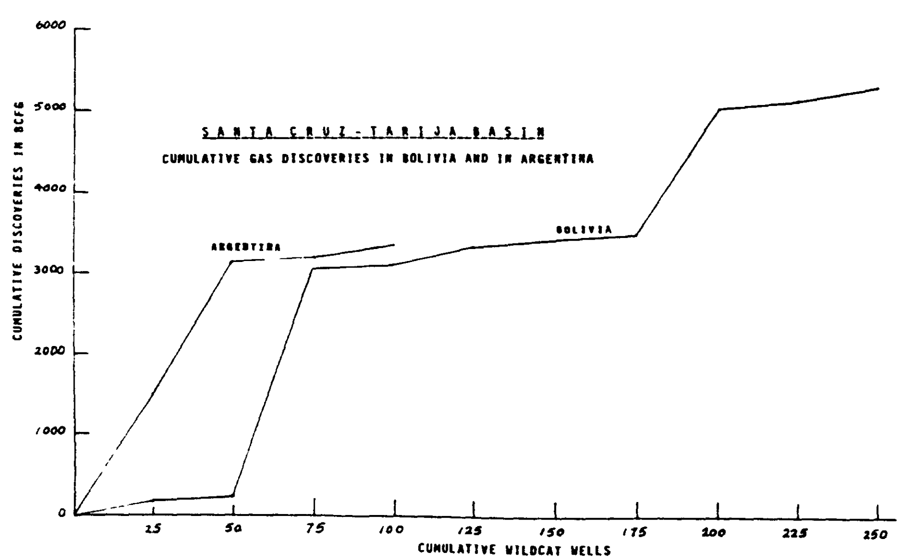


Figure 169 Graphs showing the cumulative amounts of oil and gas discovered in the Santa Cruz-Tarija basin versus the number of wildcats drilled. Based on Petroconsultants data (1990) which may be incomplete.

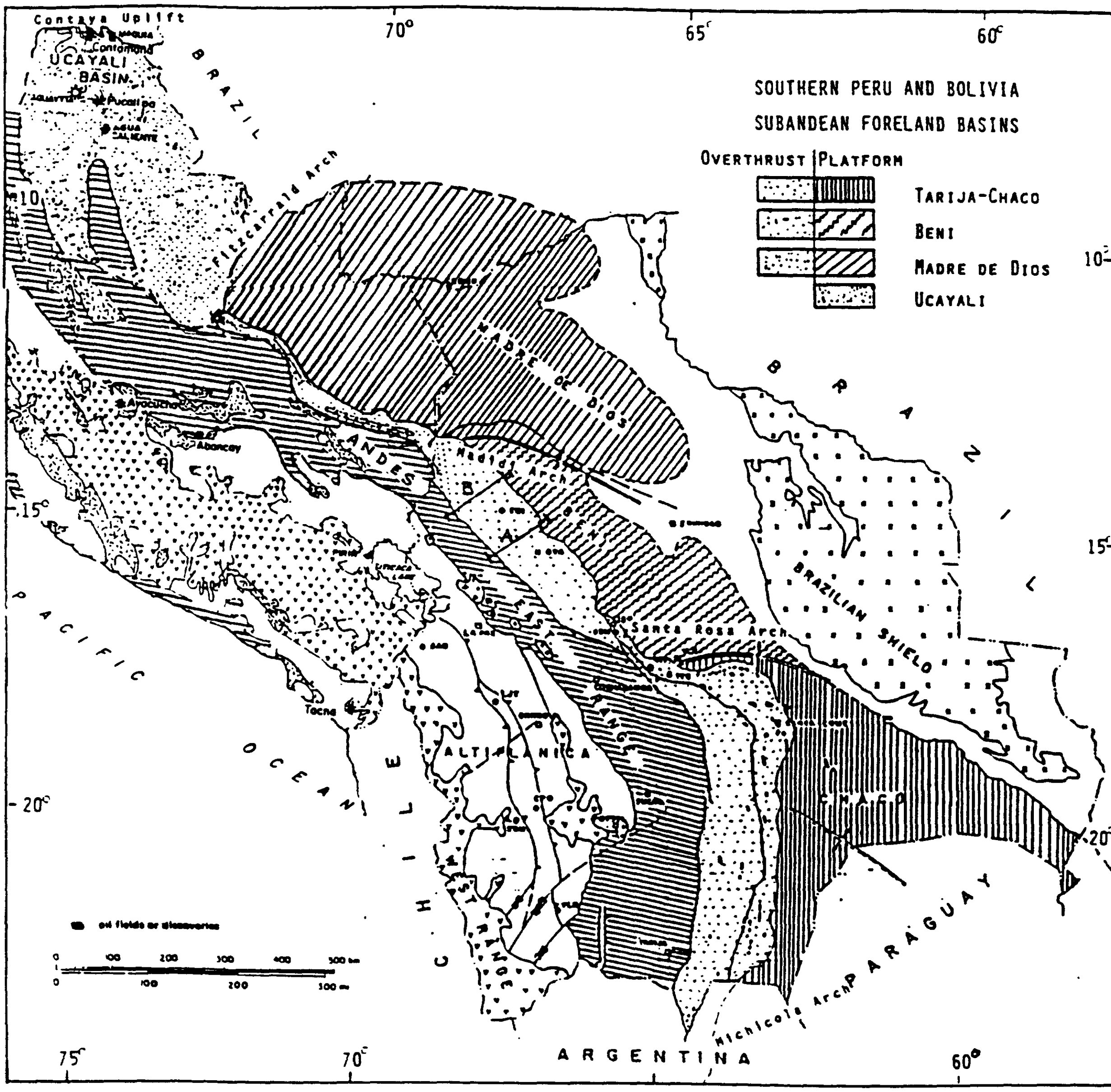


Figure 170 Tectonic map of Bolivia and southern Peru showing the Beni and other subandian foreland basins.

Beni basin (i.e. north of the Santa Rosa Arch, fig. 167). The continental Upper Carboniferous sequence also thins from the Santa Cruz-Tarija basin to the Beni basin (Martinez, 1988).

During the Permian, there was a marine transgression occupying the Peru area and extending a presumably limited, but unknown distance southward into the Beni area. This sequence, the Copacabana Formation consists of limestone, dolomite, shale, and lesser amounts of sandstone and siltstone. In the basins of Peru it has good source rock and reservoir potential. These carbonates are overlain by the Permian Mitu Formation of continental beds which thicken southwards into the Beni basin from the Madre de Dos basin.

The Mesozoic rocks are thin. Triassic and Jurassic rocks are thin or missing and the Cretaceous strata, consisting of sandstones and shales, are less than 2,600 (800 m) thick (Zuniga et al, 1974).

The Tertiary strata are thick continental molasse deposits derived from the rising Andes.

Source. The thickness of the Devonian-Silurian sequence which contains the principal source rocks (as well as some reservoirs) of the analogous Santa Cruz-Tarija basin is reduced to less than half in the Beni basin and the source rock potential of the basin is probably equally reduced. The Permian Copacabana Formation while having good source rock potential to the northwest, in the Madre de Dios basin, appears to be of limited extent and thickness in the Beni basin.

Reservoirs and Seals. The reduced thickness of the Siluro-Devonian section in the Beni basin compared to the Santa Cruz-Tarya basin, where it contains good reservoirs, indicates proportionately less reservoirs in the Beni basin. The absence of Lower Carboniferous strata which in the Santa Cruz-Tarija basin contain the principal Tupambi reservoirs, along with the thinning of the reservoir-containing Upper Carboniferous units, reduces the reservoir capability of the Beni basin in respect to the Santa Cruz-Tarija basin still further.

The only potential seals are shales sequences throughout the section of unknown thickness. Since it appears that most of the trap potential is limited to the complicated and faulted overthrust and fold belt in which structures are often found flushed, effective sealing may be a serious limiting factor.

Structure

The structure of the Beni basin is analogous to that of Santa Cruz-Tarija basin except that it does not appear to have the zone of Tertiary-covered, folded and thrusted foothills, "Pie de Monte," between platform and the overthrust and fold belt, which contains 44 percent of the Santa Cruz-Tarija basin reserves (figs. 163, 168).

The traps, therefore, appear to be largely confined to the very complicated overthrust and fold belt, the Subandino Range (fig. 163). At least two of these traps have been tested with negative results (fig. 171), but it is doubtful that exploration has yet proceeded to the point where the overthrust and fold belt can be considered to be evaluated.

By analogy to the Santa Cruz-Tarija basin, low-amplitude fault- and drape-closure traps probably exist on the platform.

Generation, Migration and Accumulation. Generation and migration probably began in the Tertiary when the Devonian source rocks subsided sufficiently deep (about 10,000 ft, 3 km^2) into the foredeep oil window. This is the same time when the structural traps would have formed. The age of the reservoirs range from Devonian to Tertiary. It is not known whether the older reservoirs have preserved their porosity and permeability. Since most of the traps appear to be in the faulted overthrust and fold belt, sealing versus migration is another unknown factor. By analogy to the Santa-Cruz-Tarija basin some accumulation may be expected.

Plays. There appear to be only two plays. One is in the traps of the overthrust and fold belt and the other in low-amplitude fault or drape closure on the platform portion of this foreland basin. By analogy to the more maturely explored Santa Cruz-Tarija basin, all but 6 percent of the petroleum will be found on overthrust and fold belt.

Exploration History. Exploration has been sparse. Reportedly, only half a dozen wildcats have been drilled in this vast, remote, and inhospitable area, 4 wildcats were drilled in the overthrust and fold belt and 2 wildcats were drilled on the platform.

Estimation of Undiscovered Oil and Gas. An estimate of the undiscovered petroleum of the Beni basin may be made by areal comparison to the resources of the analogous adjoining on-trend more maturely explored Santa Cruz-Tarija basin but limited to the producing area (i.e., not including the low-prospective, less distinct platform areas). Such a comparison would indicate the petroleum resources of the Beni basin to be .26 BBO and 5.94 TCFG. However, this analogy must be discounted by about half because of the lower volume of source and reservoir rock; the volume of the principal source-containing Siluro-Devonian sequence is less than half that of the Santa Cruz-Tarija basin, and the Lower Carboniferous sequence which contains the main Santa Cruz-Tarija reservoirs is missing. This accordingly discounted estimate (.13 BBO and 3.0 TCFG) should be further reduced since the more gently folded thrusted belt (Pie de Monte) which contains 44 percent of the petroleum in the Santa Cruz-Tarija basin is missing. Reducing the estimate by this percentage indicates the undiscovered petroleum in the Beni basin to be .073 BBO and 1.66 TCFG.

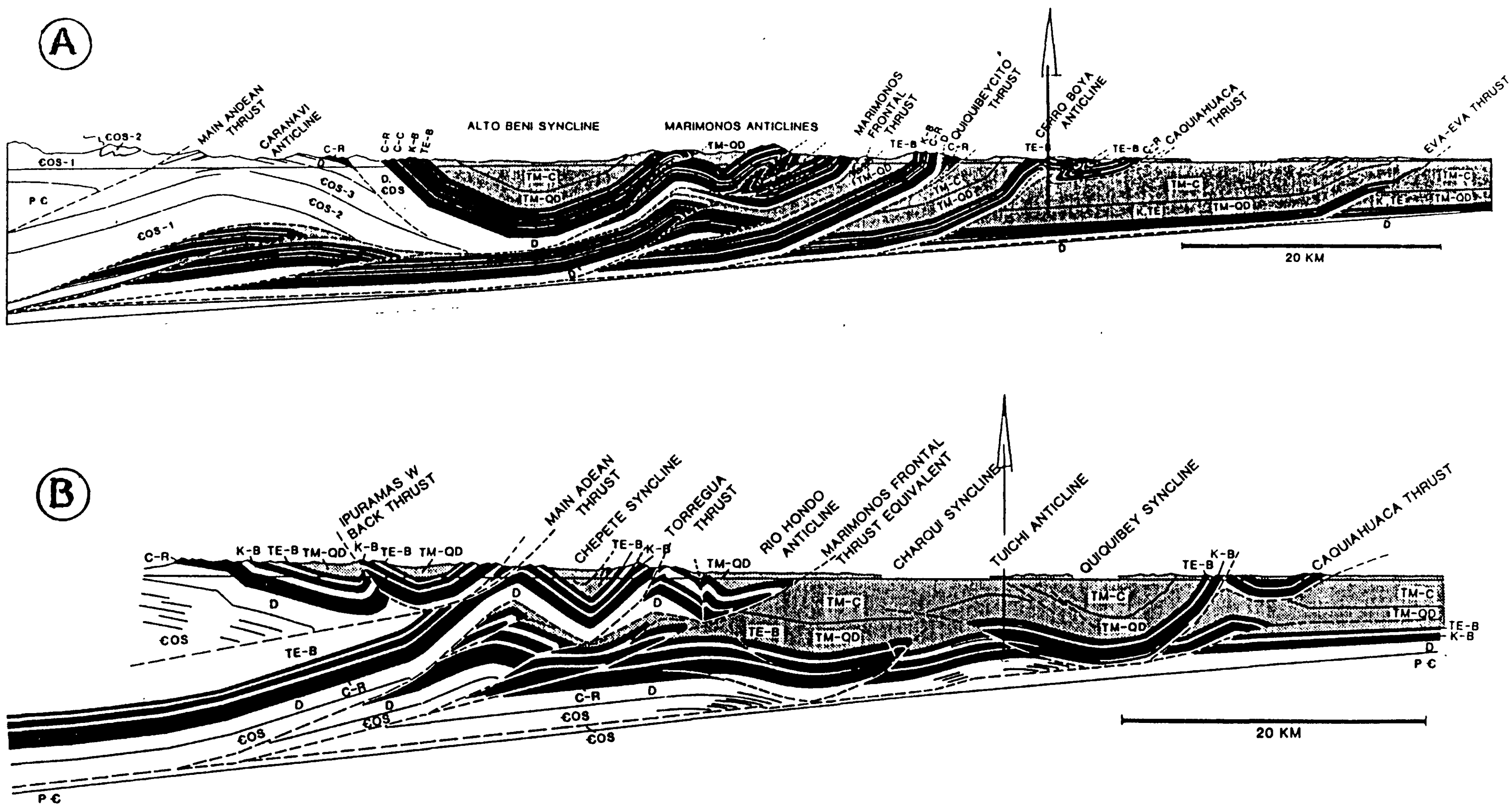


Figure 171 Geologic cross-sections across the sub-Andean overthrust and fold belt of the Beni basin located on figure 170. Solid areas are Eocene to Westfalian units. Dotted areas are foredeep fill. ЄOS = preCambrian to Silurian, D = Devonian, K - Cretaceous, TE = Eocene, TM = Miocene, Q = Quaternary, other letters refer to local formation names. Sketch rigs indicate two reported tests of anticlinal traps (modified from Rolder, 1988).

The Madre de Dios basin

Total Area: 112,000 mi^2 (290,000 km^2)

Overthrust and fold belt: 6,000 mi^2 (15,000 km^2)

Total platform: 106,000 mi^2 (275,000 km^2)

In Peru: 25,000 mi^2 (67,000 km^2)

In Bolivia: 48,000 mi^2 (124,000 km^2)

In Brazil: 23,000 mi^2 (59,000 km^2)

Original Reserves: Nil.

Description of area: This foreland basin, as defined here, includes the west-sloping platform of northern Bolivia, southeastern Peru and southwestern Brazil immediately adjoining the Andean overthrust and fold belt extending from the Madidi transverse arch in the south to the Fitzcarrald transverse arch in the north (fig. 170).

Stratigraphy

Figure 172 is a composite stratigraphic column for eastern Peru and represents the stratigraphy of the Madre de Dios basin which contains a sedimentary sequence of some 36,000 ft (11,000 m) of Paleozoic, Mesozoic and Tertiary strata (Touzett and Sanz, 1985).

The lowest Paleozoic sequences are the Ordovician Contaya Group of some 4,600 ft (1,400 m) of indurated dark fossiliferous calcareous shale and overlying 600 ft (170 m) of Silurian turbidite sandstones and breccias. These rocks are considered unprospective (Zuniga, et al, 1976). The oldest prospective sequence consists of over 2,120 ft (647 m) of marine, fossiliferous dark shales and interbedded sandstones and carbonate lenses of the Devonian Cabanillas Group. Incomplete sections are up to 2,120 ft (647 m) thick to the north of the area, thinning southwards towards the Madre de Dios basin. The group has good potential source rocks and fair reservoirs. After a prolonged period of erosion the Mississippian Ambo Formation was deposited north of the Madre de Dios basin; it consists of some 1,050 ft (320 m) of marine and deltaic grey sandstones and dark shales and coalbeds which thins southwards and may, or may not be represented in the Madre de Dios basin.

After a period of uplift and erosion there was deposited north of the Madre de Dios a 4,000 ft (1,213 m) section representing an extensive Permian marine transgression. The lower deposited strata are greenish grey sandstones and carbonates, the Tarma Formation, followed by grey micritic limestone and dolomite intercalated with black to greenish grey shales, the Copacabana Formation. These formations thin and grade upwards into redbeds, the Mitu Formation, toward the Madre de Dios basin.

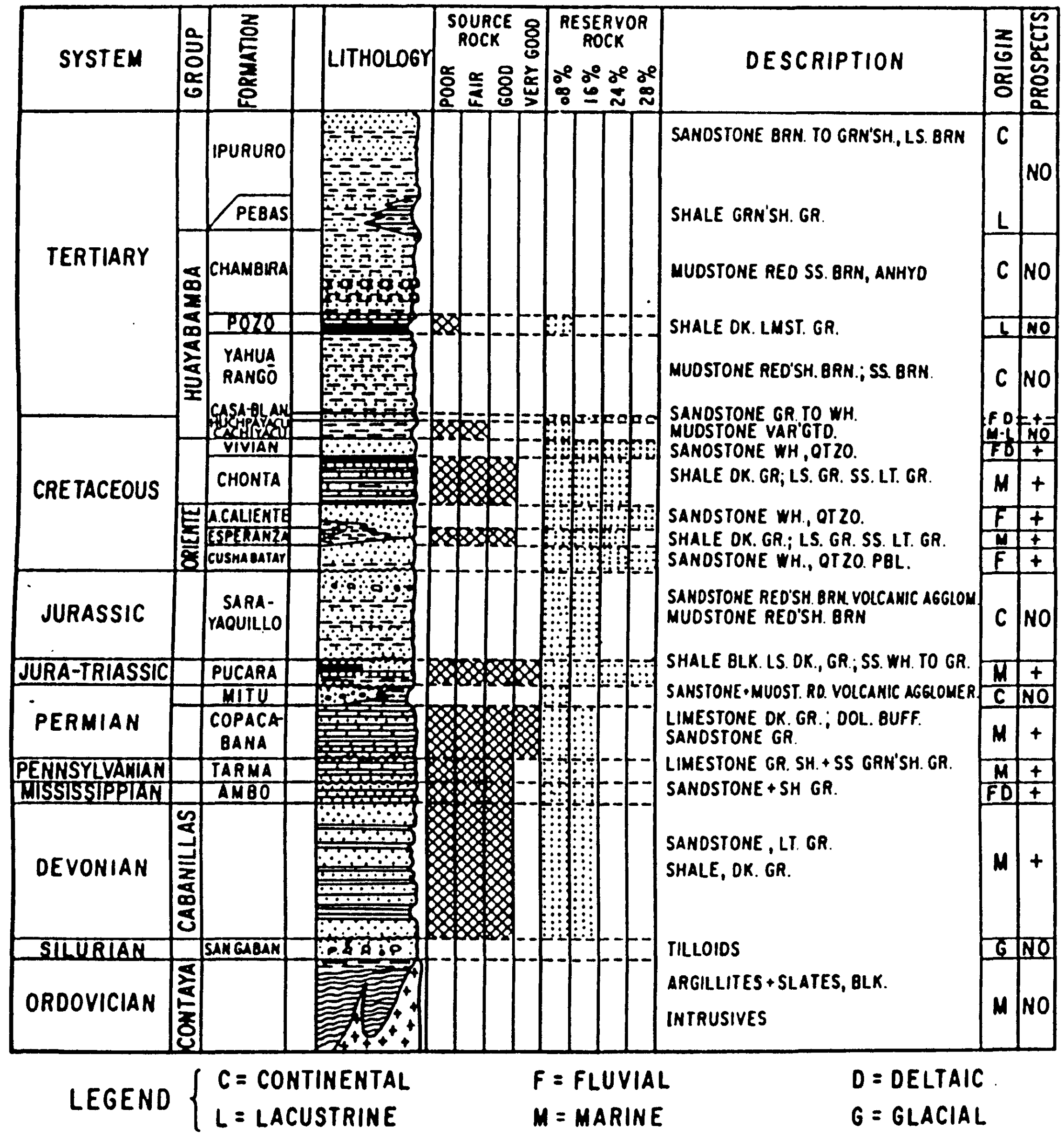


Figure 172 Composite stratigraphic column of eastern Peru showing lithology and source and reservoir potential including permeability and porosity (from Zuniga Rivero et al, 1976).

No Triassic or Jurassic strata of consequence occur. The Cretaceous is represented by at least 1,300 ft (400 m) of continental undifferentiated light-colored to red sandstones with some intercalations of shale and mudstone. From Campanian time onwards, Andes-derived sediments were prominent. Late Cretaceous sandstones (along with Early Permian reservoirs) are the reservoirs of the Cashirieri discovery of the Ucayali basin to the north.

The Tertiary is represented by a monotonous sequence of continental red-bed sandstones and shales derived from the rapidly rising Andes.

Source. The Devonian Cabanillos and Carboniferous-Permian Tarma-Copacapona Formations contain good to very good source shales with the TOC ranging from .75 to 1.97 percent (Touzett and Sang, 1985). The kerogen is largely amorphous with some obviously terrestrial types. The source of nearby giant gas/condensate discovery of Cashiriari is thought to be Carboniferous "coaly shale" (Mohler, 1989)--the coal-bearing Ambo Formation? The Carboniferous and Permian source units are thin or missing in the adjoining Beni basin to the south. Comparisons of chromatographic analyses of Madre de Dios basin oils with those of Paleozoic-generated oil of the Santa Cruz-Tarijo basin and the Cretaceous-generated oil of the Marnon-Oriente-Putumayo basin indicate that the Madre de Dios basin oil is largely Paleozoic-derived (Touzett and Sanz, 1985).

Reserves and Seals. The principal potential reservoirs appear to be the sandstones of the Cabanillas Formation (Devonian), the Ambo Formation (Early Carboniferous), the carbonates of the Copacabana Formation (Permian), and the sandstones of the Cretaceous (the Cushabatay, Agua Caliente, and Vivian Formation), the Cretaceous reservoirs being the more promising with substantial thickness and good to excellent porosities.

Seals are provided by the many shale sequences of the stratigraphic section; however, sealing may not be good in parts of the highly faulted overthrust and fold belt.

Structure

The structure of the foreland Madre de Dios basin has two elements, the westwards sloping foreland platform and the zone of overthrusting and folding. The platform is essentially a plan except for minor low-amplitude normal faults features. The absence of success in exploration on the platform may be due to the lack of sufficient closure. The overthrust and fold belt on the other hand is highly deformed and analogous to the overthrust and fold belt of on-trend basins to the south (figs. 161, 168, 171). Structural traps are much faulted anticlinal and fault closures largely formed in the Neogene.

Generation, Migration, and Entrapment. Hydrocarbon generation and migration began in the Tertiary when the Andean orogeny depressed the Paleozoic source shales into the foredeep and the thermal window of petroleum generation. Given the good reservoir-conduit sands of the Cabanillas Formation (Devonian) the Ambon Formation (Early Carboniferous), the Tarma Group (Mississippian) and especially the basal to middle Cretaceous sandstones, updip migration onto the platform may have occurred, suggesting the possibility of stratigraphic traps. Structural entrapment on the foreland, however, appears minimal given the apparent lack of tectonic features.

The Tertiary traps of the overthrust and fold belt have promise as evidenced by the nearby giant gas/condensate discovery of Cashiriari (10.8 TCFG, .725 BB condensate) of the adjoining Ucayala basin to the northwest. The timing of trap formation appears favorable, being contemporaneously with the beginning of petroleum generation and migration.

Plays. There are two, and probably three, plays: 1) the fold and fault closures of the overthrust and fold belt involving Devonian through Cretaceous reservoirs, 2) low-amplitude fault and drape closures on the foreland platform involving the Devonian through Cretaceous reservoirs, and possibly 3) stratigraphic traps on the foreland basin involving Cretaceous sandstones such as are found in the maturely explored foreland platforms of the United States, e.g., the Powder River and Denver basin where 50 to 100 percent of the petroleum reserves are in Cretaceous sandstone stratigraphic traps.

History of Exploration. This vast, remote, inhospitable area is in the immature stage of exploration. Reportedly, only some 8 valid wildcats have drilled 4 in the overthrust belt and 4 in the platform.

In the late 1980's significant finds were made in the overthrust belt at nearby Cashiriari and San Martin in the extreme south of the adjoining Ucayali basin, amounting to 10.8 TCFG and .750 BB condensate.

Estimating Undiscovered Oil and Gas

Exploration is in an immature stage over the vast area of the Madre de Dios basin. It appears, however, that given the exploration on-trend successes of the overthrust and fold belt on either side of the basin, i.e., the Santa Cruz-Tarija basin and especially the immediately adjoining Cashiriari discovery of the Ucayali basin, some undiscovered oil and especially gas can be expected in the basin. It may be logically surmised that additional Cashiriari-type discoveries will be made in the overthrust and fold belt of the Madre de Dios basin amounting at least to half that discovered at Cashiriari or 5.4 TCFG and .375 BB condensate or oil. By analogy to the structurally similar and maturely explored Santa

Cruz-Tarija basin, 6 percent of the total petroleum resources of the basin are in the foreland platform. On that basis .32 TCFG and .023 BB oil or condensate may be expected in the platform; however, allowing for postulated Cretaceous sandstone stratigraphic traps this platform estimate might be doubled to .64 TCFG and .045 BB oil or condensate, indicting in all 6.0 TCFG and .42 BBO oil or condensate.

This is a much higher estimate than that derived for the structurally analogous Santa Cruz-Tarija and Beni basins to the south, which, however, apparently do not have (1) the rich Carboniferous and Permian source rock nor good reservoirs which apparently extend from the northwest to some degree into the Madre de Dios basin, and (2) the good Cretaceous reservoirs.

Ucayali Basin

Area: 36,000 mi^2 (95,000 km^2)

Original Reserves:

Total: .786 BB oil or condensate, 11.74 TCFG

Upthrust play: .036 BBO, .937 TCFG

Overthrust and fold play: .75 BB condensate, 10.8 TCFG

Description of area: The Ucayali basin is a foreland basin located between the Brazilian craton on the east and the Andes Mountains on the west (fig. 173). It is separated from the Madre de Dios basin, on the south, by the Fitzcarrald arch and from the Maranon-Oriente-Putumayo basin, on the north, by the Cushabatay and Contaya uplift. The eastern boundary is along the Brazil-Peru border at the Tapache-Utoquinea (Sierra Divisor) Arch and the western boundary is the Andes Mountains (except in the northwest where a broad band of associated overthrusting and folding has been designated as a separate basin, the Huallaga basin).

Stratigraphy:

The oldest really prospective sedimentary strata of the Ucayali basin are the Devonian Cabanillas Group. The Cabanillas Group consists of fossiliferous black shales interbedded with gray sandstones and lenses of limestone which measure up to 2,600 ft (800 m) (fig. 172). These marine rocks were probably deposited in a wide area over the foreland platform. In the foothills of the Andes (in Ecuador) they are found to be metamorphosed. In the Santa Cruz-Tarija basin of southern Bolivia equivalent strata are productive.

After a long period of erosion, fluvial and deltaic sandstones, shales, and coal beds of the lower Carboniferous Ambo Formation were deposited. Their thickness ranged from 1,000 to 1,600 ft (300-800 m)

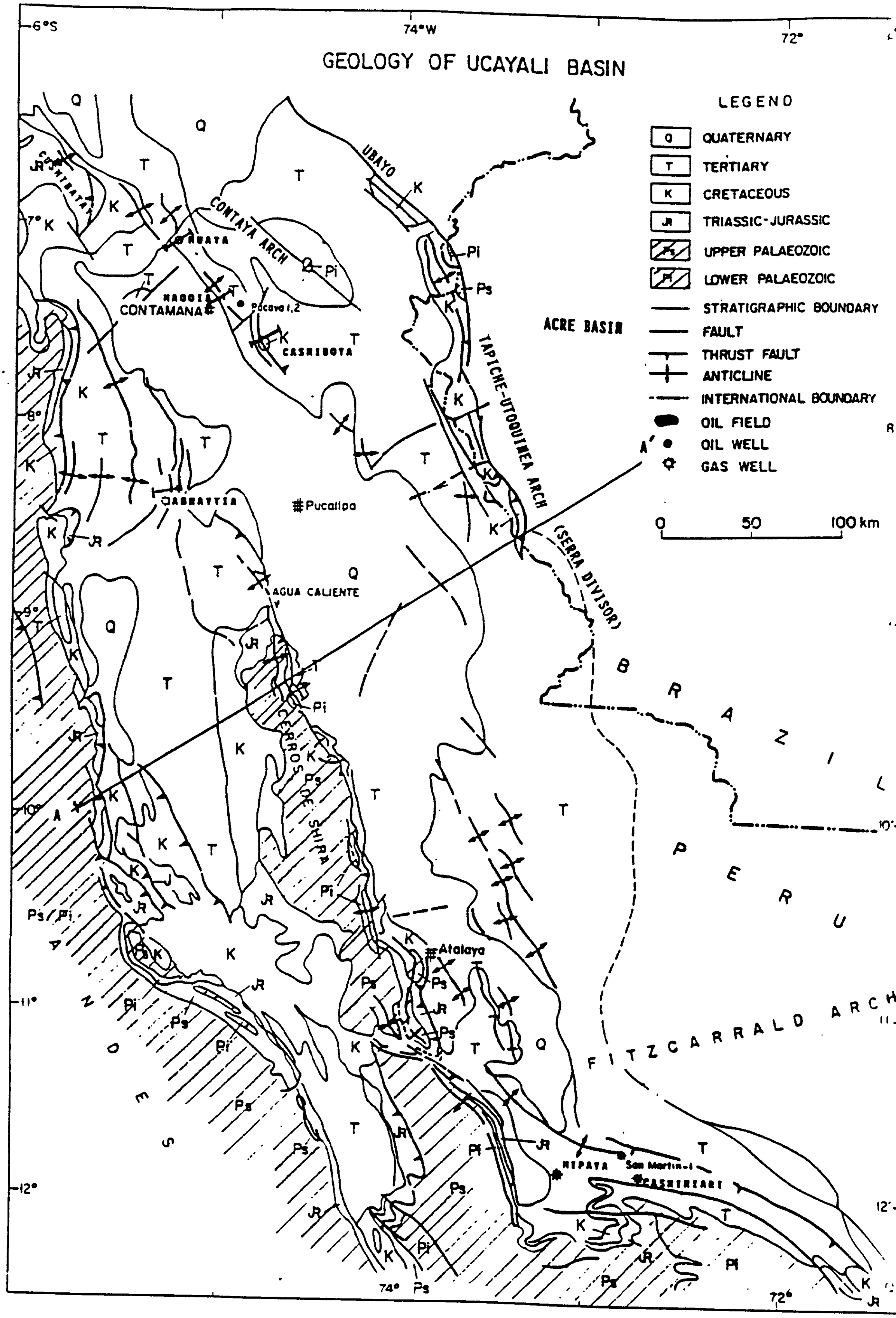


Figure 173 Geologic map of the Ucayali basin showing petroleum occurrence and cross-section location (modified from Petroconsultants, 1989).

A late Carboniferous (Middle and Late Pennsylvanian) marine transgression resulted in 1,000 ft (300 m) of greenish grey sandstones and subordinate limestones (Tarma Formation). This formation apparently contains some of the productive reservoirs of the Cashiriari and San Martin gas/condensate fields.

The Carboniferous is unconformably overlain by 600 to 2,300 ft (200 to 700 m) of Permian marine limestone, dolomite and black shale with lesser amounts of sandstone and shale (the Copacabana Formation). The Copacabana Formation is overlain by an upper Permian section of sandstone shale and carbonate, called the Piriquen Formation (not shown in figure 172). Southeastwards, toward Bolivia, the upper Permian section undergoes a facies change into continental red beds, referred to as the Mitu Formation.

After an erosional period through most of the Triassic, up to 9,000 ft (2,700 m) of marine strata of predominantly limestone with dolomite, evaporite and marine shales (Pucara Formation) were deposited. The Pucara Formation is overlain by a thick sequence of Jurassic red beds (Sarayaquillo Formation). These Triassic and Jurassic formations are largely limited to the western side of the basin.

Cretaceous sedimentation began at the end of the Neocomian and covered the entire basin and is characterized by frequent changes in facies and in thickness, ranging from 2,000 to 3,400 ft (590 to 1,040 m). The basal unit of fluvial-deltaic sandstones (Cushabatay Formation), originating from the Brazilian Shield. Overlying the Cushabatay Formation is the Esperonza Formation, a transgressive unit of largely marine shales. This was followed by the Agua Caliente Formation, a regressive unit in the Cenomanian representing fluvial deltaic conditions. This cycle (Oriente Group) was followed by the Chonta Formation, consisting of marine shale and carbonates interbedded with sandstones. Near the Bolivian border the Chonta Formation interfingers with red beds. The upper part of the section is a sequence of largely sandstones (upper Cretaceous (Vivian Formation) which were apparently derived from the Andes rather than the Brazilian shield as was the case with the previous stratigraphic units. These fluvial and deltaic Cretaceous formations appear to have stratigraphic trap potential in the foreland platform area. The analogous Powder River and Denver basins of the United States have 50 to 100 percent of their resources in such a play.

The overlying Tertiary sediments are largely Andes-derived red-bed molasse.

Source. One of the principle petroleum sources appears to be the black shales and limestones of the lower part of the Permian Copacabana Formation. The source of the Cashiriari gas and condensate is reported to be the Carboniferous "coaly shale" (Mohler 1989) (the Ambar Formation?). The Cretaceous shales are marginally organic rich with TOCs of 1 to 2 percent and the kerogen is largely of continental origin.

Chromatographic analysis indicates the oil of the Maquia Field, at the northern perimeter of the Ucayali basin (fig. 173), is similar to that of the adjoining Maranon-Oriente-Putumayo basin which is a Cretaceous-derived oil. However, the oil of the more southern field, Agua Caliente, in the center of the Ucayali (fig. 173), is different, perhaps indicating pre-Cretaceous-sourced oil. It appears that the Cretaceous shales, the principal source rock of the Maronon-Oriente-Putumayo basin, may not be as great a contributor to the Ucayali basin accumulations and that the principal source is the Permian shales. These shales, being deeper, may be the reason the Ucayali basin is so much more gaseous (71 percent) than the Maranon-Oriente-Putumayo basin (3 percent).

Reservoirs and seals. The principal producing reservoirs of the Ucayali basin are the Cretaceous sandstones, that is, of the Cushabatay, Agua Caliente, and Vivian Formations, with porosities ranging up to 20 percent and permeabilities up to 2,000 md. The Permian lower Copacabana Formation has porosities ranging up to 21 percent and the upper Carboniferous Tarma Formation has porosites ranging to 18 percent. Other potential reservoirs are in the Triassic-Jurassic Pucara Formation (porosity 5 to 20 percent) and possibly in the Tertiary formations, although porosities are reportedly low.

The prolific gas/condensate producing reservoirs of the Cashiriari and San Martin fields are evidentially the Cretaceous sandstone formations and Permian Copacabana Formation sandstones and carbonates.

Seals are provided by shales which may not be entirely effective in the overthrust and fold belt or in some of the faulted upthrust traps.

Structure

The Ucayali foreland basin formed in its present shape between the Brazilian craton and the Andes Mountains during the Tertiary. The structure is dominated by Neogene foreland upthrust blocks (figs. 173 and 174). The Subandean overthrust and fold belt of the Madre de Dios and other basins to the south appears to extend into the Ucayali basin only a relatively short distance as a major tectonic feature, as indicated by the thrusting shown in figure 173 and 174. Minor thrusting exists in a relatively narrow zone extending northward along the west boundary of the basin until it widens into a broad band of overthrusting and folding northwest of the Ucayali basin where it is defined as a separate basin, the Huallaga basin.

Many of the potential traps of the Ucayali basin are associated with upthrust fault blocks (fig. 174). These traps are similar to

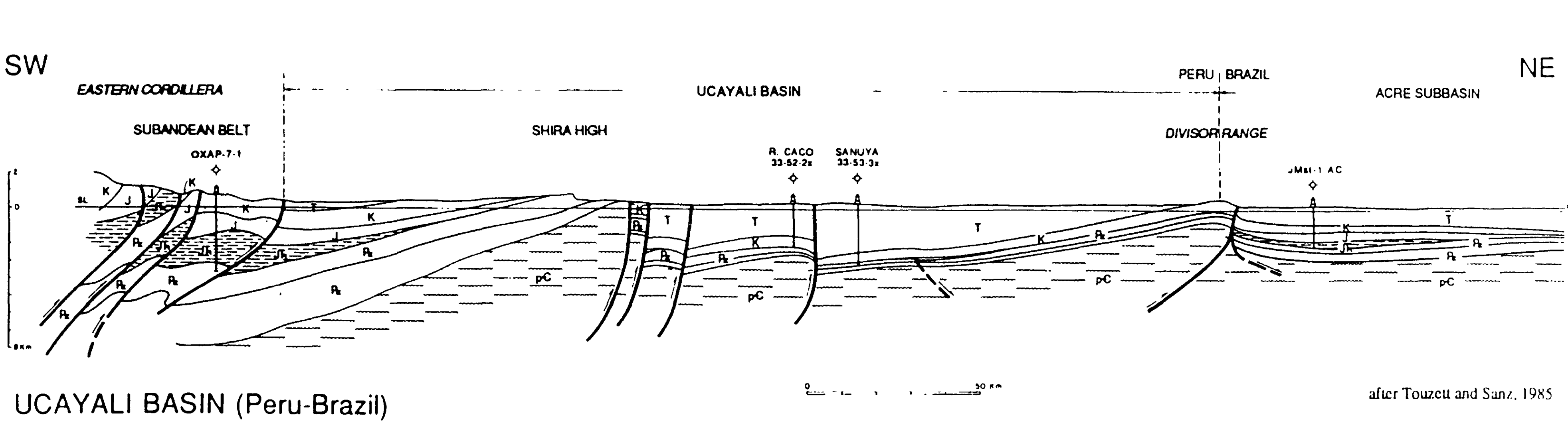


Figure 174 Diagrammatic west to east geologic section through the Ucayali basin of eastern Peru and the Acre basin of western Brazil. Location in figure 173 (from Yrigoyen, 1991).

those of the more prolific petroleum accumulation of the adjoining structurally analogous foreland basin to the north, the Maranon-Oriente-Putumayo basin, but have greater relief. Figure 175A is a section through the Aguaytia gas field showing the up-thrust geometry with the reverse fault on the east side; figure 175B is a section through the Cashiboya upthrust structure with the reverse fault on the west side.

Although the overthrust and fold belt is of limited extent, its major development being largely confined to the southernmost part of the basin, the traps associated with it have significant potential since they contain the major portion of the basin reserves. A cross-section of this belt would be similar in many respects to those of the overthrust and fold belt further south (figs. 168, 171, 174).

Aside from these major structural elements, there is a suggestion of transpressional or drag folding along a northwest-trending line of faults which may be a wrench fault zone through the Maquia oil field and Huaga structure (figs. 173, 176).

Minor potential traps are formed by salt flowage of Triassic salt largely limited to the west side of the basin. Such a salt pillow is indicated in the axial part of Aguaytia structure (fig. 175A).

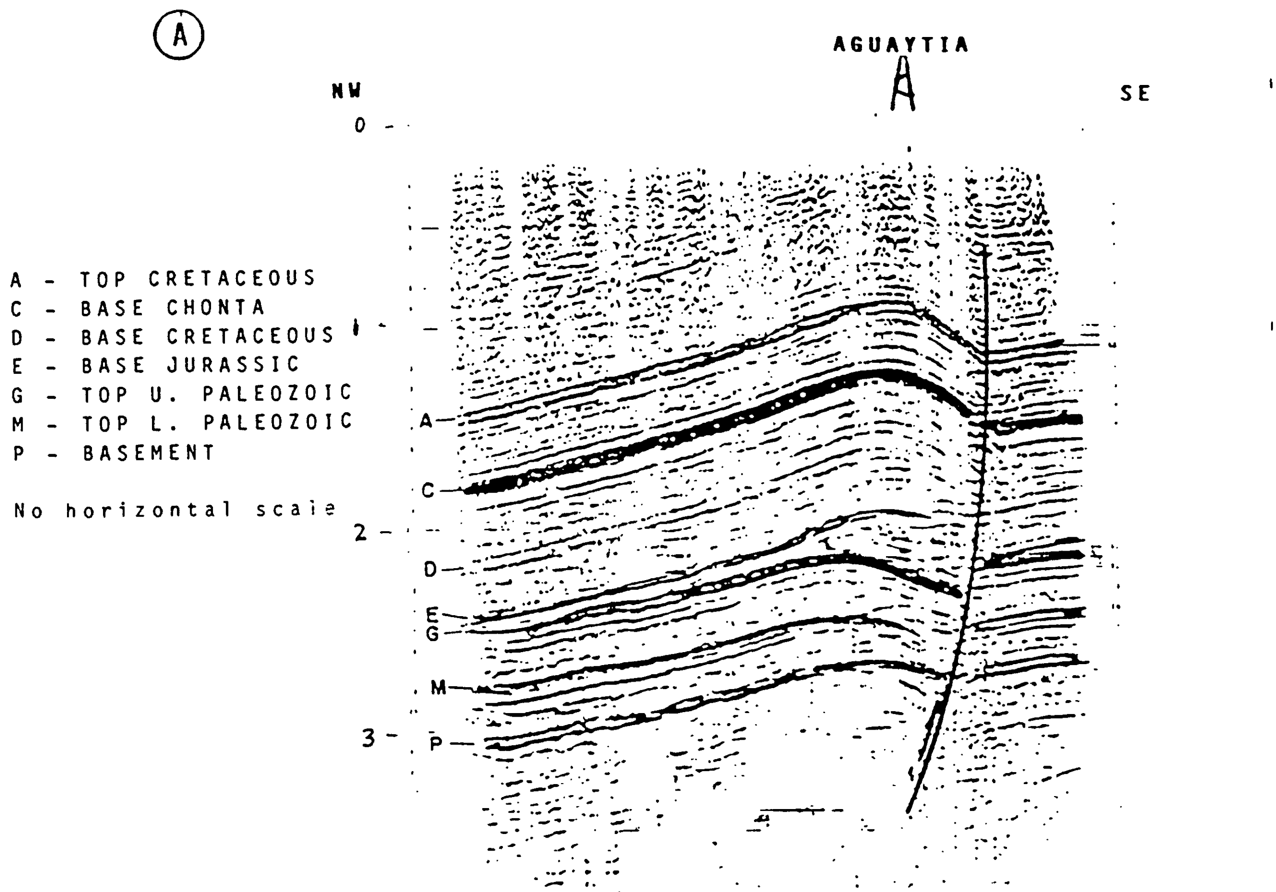
The transverse Fitzcarrald and Cushabatay-Contaya uplifts (fig. 173) which border the basin, although of unknown initial age, appear to have been active up through the Pliocene, influencing the sedimentation of at least the younger rocks.

Aside from structural traps it appears that there are good possibilities for stratigraphic traps involving Cretaceous sandstones, given the fluvial deltaic conditions of sedimentation. In analogous basins, e.g., the Powder River and Denver basins of the United States, such traps contain from 50 to 100 percent of the petroleum. In the present, immature state of the Ucayali exploration, such traps are apparently yet to be sought.

Generation, Migration and Entrapment. Generation and primary migration of petroleum began when the Paleozoic and Cretaceous source rock subsided into the thermal petroleum-generating zone in the Tertiary (and perhaps late Cretaceous in the extreme west). At about the same time, the traps associated with the foreland upthrusting and with overthrusting and folding were forming.

Because of the high relief of the upthrust blocks, structural entrapment in the Ucayali is probably not as complete as in the Maranon-Oriente-Pulumayo basin where the upthrust structures are covered by a thick section of Cretaceous and Tertiary shales.

The average depth of the faulted, up-thrust and fragmented Ucayali basin is less than half that of the broad low-relief



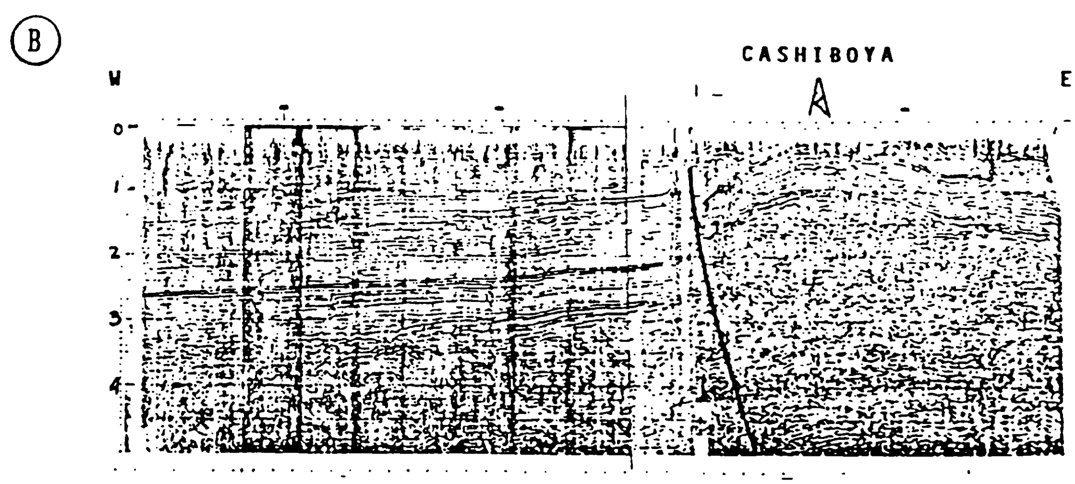


Figure 175 (A) Seismic cross-section through the Aquaytia gas field. Ucayali basin, showing 1) a reverse-faulted east flank of an east-facing upthrust block and 2) a Triassic salt pillow (at base of Jurassic).

(B) Seismic cross-section through the Cashiboya structure, Ucayali basin showing a reverse-faulted west flank of a west-facing upthrust block. Locations figure 173 (from reproduced seismic lines, Touzett and Sanz, 1985).

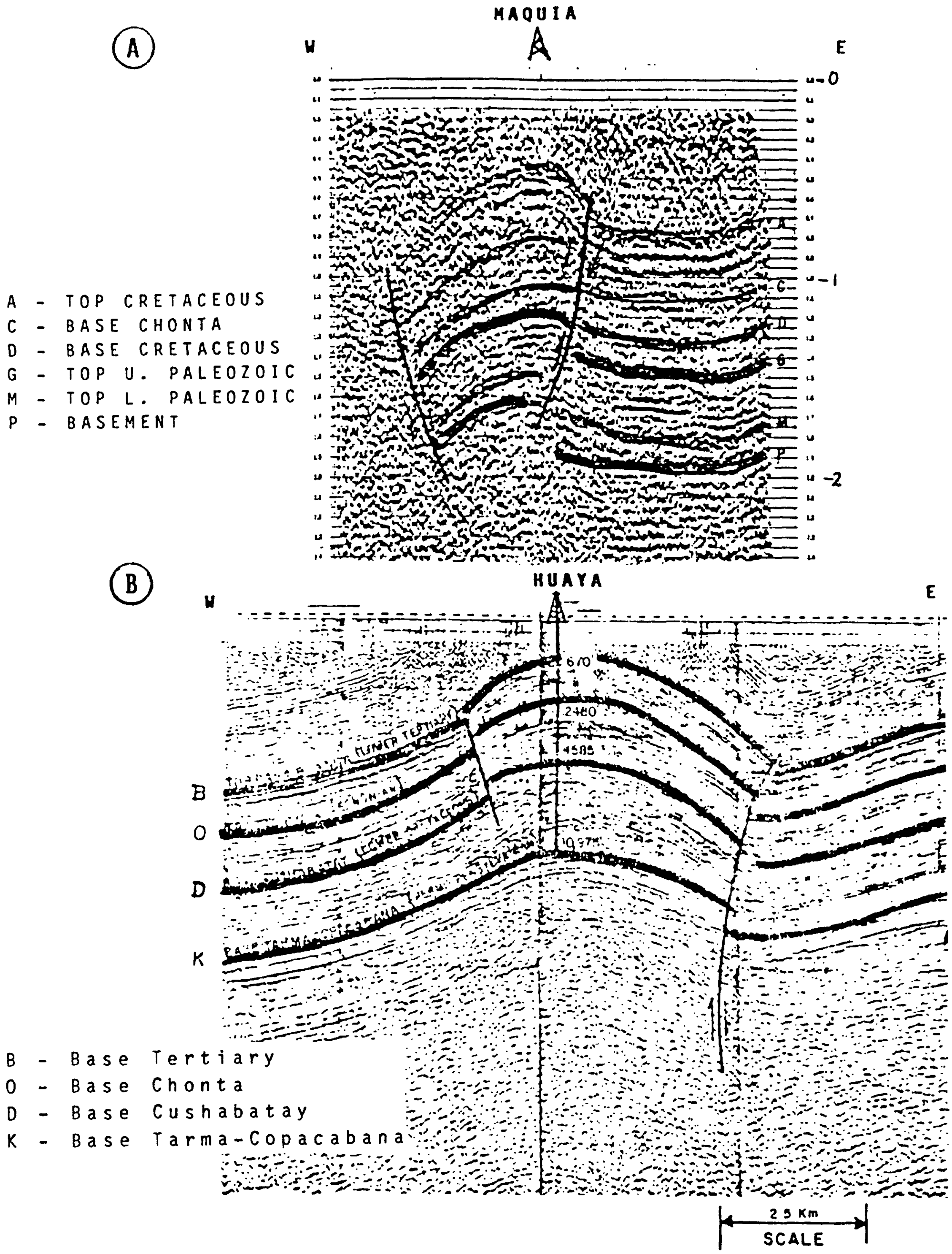


Figure 176 (A) Seismic cross-section through the Maquia field high-angle reverse (possibly strike-slip) faulting. (B) Seismic section through Huaya structure showing high-angle reverse (possibly strike-slip) faulting. Location figure 173 (from reproduced seismic lines, Touzett and Sanz, 1985).

Maranon-Oriente-Putumayo basin. The maximum depth to the base of the Cretaceous strata is about 10,000 ft (3,000 m) in the Ucayali versus 33,000 ft (10,000 m) in the Maranon-Oriente-Putumayo basin. This may indicate that the principal source rocks of the Cretaceous shales of the Maranon-Oriente-Putumayo basin are not, on the average, sufficiently deep and mature in the Ucayali basin to contribute as substantially to potential accumulations. There would also be, on the average, less trap cover in the Ucayali basin.

The timing of migration in the overthrust and fold belt was ideal and the closures were accessible to the hydrocarbon from deep-seated, mature Paleozoic and Mesozoic source shales.

Foreland platform structural and stratigraphic traps are more shallow and dependent on conduits from the mature potential source shales of the downdip, deeper foredeeps to the platform. Such conduits would be Paleozoic and Mesozoic sandstones, but particularly, the widespread Cretaceous formations which cover extensive areas of the platform.

Plays. The Ucayali basin potential petroleum occurs in several habitats which may be divided into five plays:

1) Fault traps originating in Neogene upthrust and tilted fault blocks, involving Carboniferous through Tertiary reservoirs;

2) Anticlinal and fault traps of the overthrust and fold belt in the southern part of the basin involving Carboniferous up through Cretaceous reservoirs.

3) Possible transpressional or drag folds along wrench zones involving Carboniferous to Cretaceous reservoirs.

4) Low amplitude fault closures and drapes in the foreland platform probably involving Carboniferous to Cretaceous sandstones.

5) Stratigraphic traps on the foreland platform probably involving the fluvial-deltaic Cretaceous formations.

Exploration History and Petroleum Occurrence. The first successful wildcats of the Peru Subandean basins were drilled in the Ucayali basin: the Agua Caliente field in 1938 (18 MMBO), the Maquira field in 1958 (15 MMBO), and the Aguaytia gas field and condensate in 1962 (.500 BBOE). By 1970 the reserves had reached 10.6 million barrels of oil (the gas was not considered). Discoveries in the adjoining Maranon-Oriente-Putumayo basin were not initially made until 1971. After 1970 no further discoveries were made in the Ucayali basin until the 1987 huge gas and condensate discoveries (10.8 TCFG and .75 BB condensate) in the overthrust and fold belt in the southern part of the basin in the Cashiriari vicinity.

Estimation of Undiscovered Oil and Gas. The closest analog to the Ucayali basin is the adjoining on-trend Maranon-Oriente-Putumayo basin, especially in regard to the first play, the upthrust-block related play. By a straight areal comparison to the petroleum resources (reserves plus estimated undiscovered petroleum) of the Maranon-Oriente-Putumayo basin, the petroleum resources of the Ucayali upthrust block play would be 2.18 BBOE. Assuming the same oil to gas ratio as the Ucayali upthrust block reserves, this amounts to .41 BBO and 10.69 TCFG. However, because of 1) the supposed lesser amounts of sufficiently deep, mature Cretaceous source and 2) less well-sealed trap-cover, this analogy should probably be discounted by half for each unfavorable factor resulting in an estimate of petroleum resources amounting to .101 BB and 2.67 TCFG. Subtracting out present reserves, the undiscovered resources of the upthrust block-associated play would be .07 BBO and 1.73 TCFG.

The second play, the overthrust and fold belt play, contains the principal discoveries of the basin, the San Martin and Cashiriari fields (10.8 TCFG and .75 BB condensate). The areal northward extent of the overthrust and fold belt play into the southern Ucayali basin is not exactly known, but appears to be quite limited, and possibly has been rather thoroughly explored, given the significant Cashiari discovery. It is estimated, however, that 25 percent additional petroleum, or 2.7 TCFG and .19 BB condensate or oil, will be discovered in this play.

The third play, of possible drag folds along wrench faults, is considered to be of minor potential. The one discovery which may be in this play, Maquia oil field, has reserves of 15 MMBO. Perhaps one or two such further discoveries will be made indicating undiscovered oil of perhaps some 25 MMBO. Gas, on the basis of the percentage gas in the upthrust block play, would amount to .60 TCFG.

The fourth play, the platform structural play, by analogy to the Santa Cruz-Tarija basin, would contain about 6 percent of the basins total resources in structural traps, or .10 BBO and 1.7 TCFG.

The fifth and most difficult-to-assess play is that of the stratigraphic traps. The stratigraphic trap play of the on-trend geologically similar Maranon-Oriente-Putumayo basin has estimated resources of 4.3 BBO and .8 TCFG. By areal analogy the resources of the Ucayali basin's stratigraphic play would be 1.17 BBO and .22 TCFG. However, both the potential reservoir and potential source of the Maranon-Oriente-Putumayo stratigraphic play would appear to be almost entirely of Cretaceous age while the Ucayali basin contains a much smaller volume of Cretaceous strata which are shallower and would be largely thermally immature. It is estimated Ucayali stratigraphic traps, therefore, would, on an areal basis, be only 20 percent as prolific as those of the Maranon-Oriente-Putumayo or about .234 BBO and .04 TCFG.

Putting the plays together, the undiscovered oil and gas in the Ucayali basin amounts to .619 BB undiscovered oil/condensate and 6.77 TCF undiscovered gas.

Maranon-Oriente-Putumayo Basin

Area: 132,600 mi^2 (343,400 km^2)

87,200 mi^2 (225,800 km^2) in Peru (Maranon)

31,600 mi^2 (81,844 km^2) in Ecuador (Oriente)

13,800 mi^2 (35,700 km^2) in Colombia (Putumayo)

Original Reserves:

Total:	4.30 BBO,	.8 TCFG (Petroconsultants, 1990)
Ecuador:	3.275 BBO,	.672 TCFG
Peru:	.756 BBO	.093 TCFG
Columbia:	.267 BBO	Gas unknown (.033 TCF?)

(Putumayo, Colombia .80 BBOE, Salazar, 1990)

Description of Area: The Maranon-Oriente-Putumayo Province is a single foreland basin lying between the Andes Mountains and the Brazilian craton and extending from northern Peru, through Ecuador into Colombia (fig. 177). In each country that portion of the basin has a separate designation, i.e., Maranon in Peru, Oriente (or Napo) in Ecuador, and Putumayo in Colombia. This foreland basin, as described by previous authors, does not always include the discontinuous overthrusted and folded margin, which in Peru, for instance, is in part designated as separate provinces, e.g., the Huallaga and Santiago basins.

Stratigraphy

Although the stratigraphy is fairly uniform throughout the Maranon-Oriente-Putumayo basin, an integrated study is hindered by the use of local formation designations in the different countries. Figure 178 shows the correlation of the various units in the three countries of this basin as well as with the previously discussed, i.e., Ucayali and Madre de Dios, basins. There are some disagreements, additional formations, and later refinements in local areas, but, in general, this summary, along with the composite lithologic column of eastern Peru (fig. 172), is adequate for this discussion.

The Maranon-Oriente-Putumayo is essentially a Cretaceous basin as concerns the oil potential. The composite stratigraphic column

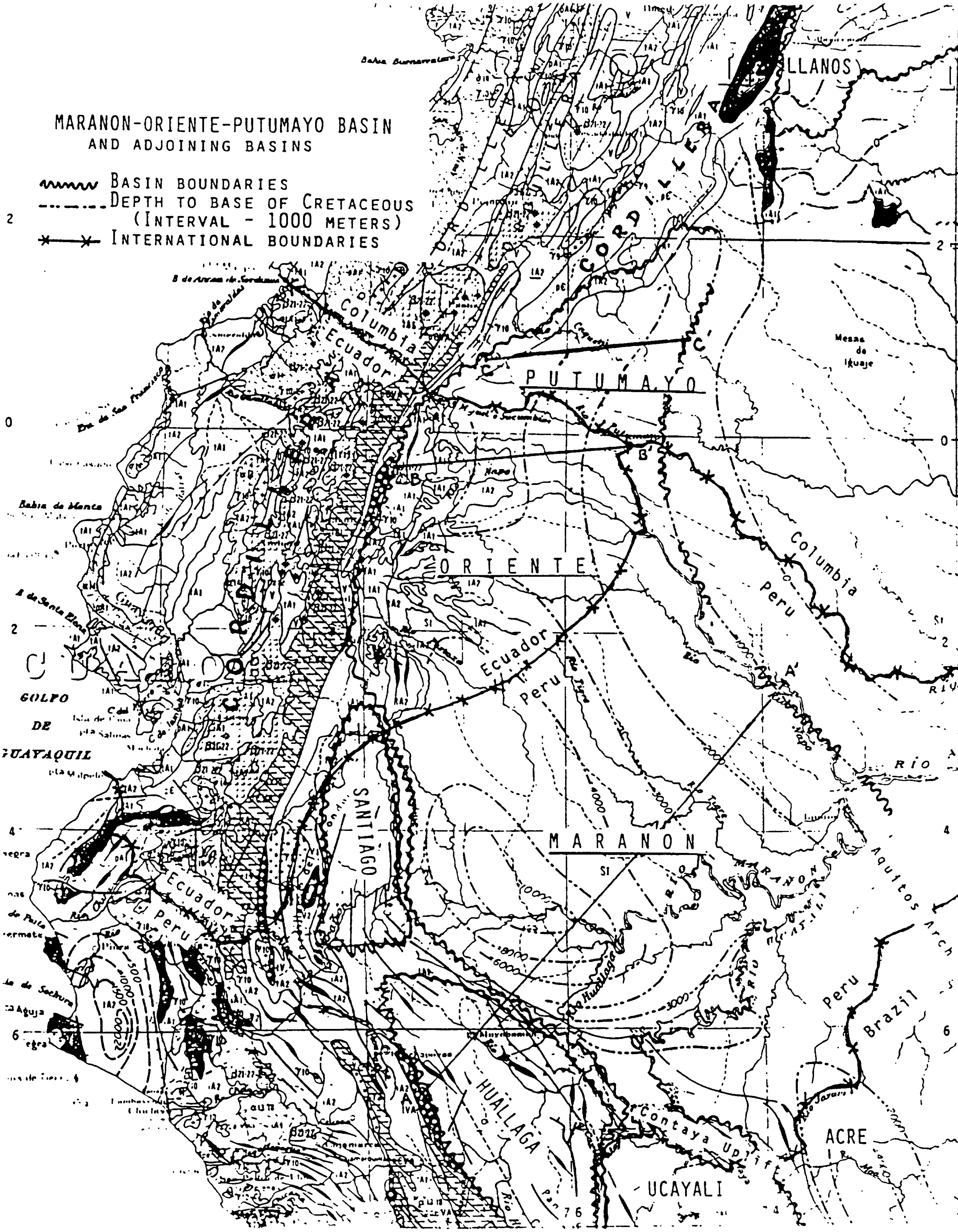


Figure 177 Structure map of the Maranon-Oriente-Putumayo basin indicating the basin boundaries, the depth to the base of Cretaceous sediments, and the international boundaries between Peru, Ecuador, and Colombia (modified from de Ameida, Tectonic map of South America, 1978).

(fig. 172) shows the lithology of the Paleozoics in eastern Peru. However, in the Maranon-Oriente-Pulumayo basin the Paleozoic strata are more indurated and thermally mature (and does not have the Paleozoic prospects indicated in figure 172). The Paleozoic strata are considered part of the economic basin in the northern part of the basin and a dry gas source in the south; they are generally lumped with the basket term, "pre-Cretaceous." The only pre-Cretaceous of some potential is the Jurassic Sarayaquilla Formation of the Maranon portion of the basin (the Chapiza and Motema Formations further north). This formation is largely nonmarine sandstone, mudstone, and volcanics, but has fair reservoir potential (Zunigy y Rivero, 1976). All together, the pre-Cretaceous offers only minor additional petroleum potential.

The principal source and reservoir rock of the Maranon-Oriente-Putumayo basin are in the Cretaceous sequence. The basal Cretaceous strata throughout the basin contain the principal reservoirs. In the Maranon (Peru) portion of the basin the basal sequence, an Aptian-Albian transgressive unit, is made up of a lower formation (Cashabatay Fm) of fluvial-deltaic sandstones, an intermedia unit of brackish-marine shales (Esperanza or Raya Fm), and an overlying fluvial-deltaic sandy formation (Agua Caliente Fm). In the Oriente and Putumayo portions of the basin, the intermediate marine shales (Esperanza or Raya Fm) is missing and the Aptian-Albian unit is represented by a largely sandstone sequence, the Hollin Formation in the Oriente, and the Caballos Formation in the Putumayo portion of the basin.

Overlying these Aptian-Albian largely transgressive formations is an Albian-Santonian section made up in the Maranon part of the basin of two formations; (1) the Chonta Formation, a sequence of marine shaly and calcareous rocks interbedded with sandstones, containing a greater proportion of carbonate to the northwest and of sandstone eastwards towards its source, the Brazilian craton, and 2) the Vivian Formation largely of non-marine sandstones, deriving from the initial rise of the Andes. In the Oriente and Putumayo sections of the basin these two formations are the equivalent of a single formation designated the Napo Formation in the Oriente and the Villeta Formation in the Putumayo part of the basin. The Napo formation in the Oriente, as seen at the Sacha Field, is about 3,000 ft (915 m) thick and thinning northeastward. It is a series of black marine shales and limestones, and sandstones. Two of the sandstones, "T and U," in the lower third of the formation are the important reservoirs of the Oriente part of the basin. The black marine shales and limestones are organically rich and believed to be the main source of the Oriente petroleum. The Villeta Formation of the Putumayo sector correlates and appears very similar, except thinner, 780 to 2,000 ft (300 to 750 m).

Overlying these strata by a strong unconformity is a non-marine Maastrichtion to recent molasse section originating from the rising Andes.

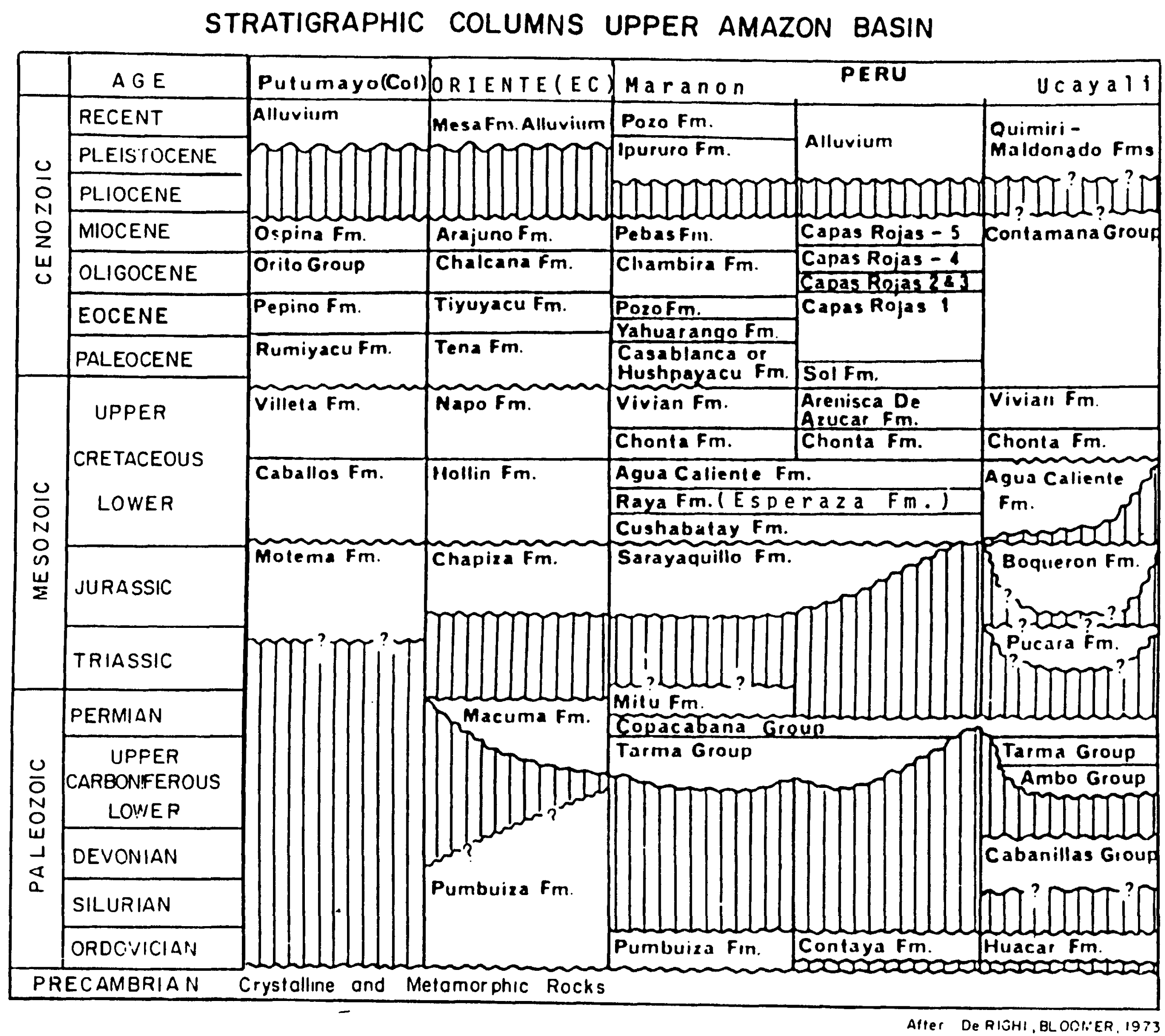


Figure 178 Stratigraphic columns upper Amazon foreland basins extending southward from the Putumayo sector of the Maranon-Oriente-Putumayo basin to the Ucayali basin (modified from Petroconsultants, 1989).

Source. Paleozoic dark organic shales occur in southern Peru and may extend northwards into parts of the Maranon-Oriente-Putumayo basin, but generally, these rocks are well-indurated and overmature for oil or gas. In the southeastern part of the basin where the Paleozoic rock was drilled, vitrinite reflectance of 2.0 to 3.0 percent were encountered. Reflectance of 1.5 percent was found at the base of the Cretaceous (Touzett and Sanz 1985). It appears, therefore, that Paleozoic shales is largely limited as a source for gas only.

The principal source rock for oil and gas of the basin is the organic shales of the Esperanza (or Raya) and Chonta Formation of Maranon, the Napo Formation in Oriente, and the Villeta Formation in Putumayo.

The area of source is limited to the deeper parts of the basin, approximately within the 10,000 ft (3,000 m) depth contour at the base Cretaceous, where the Cretaceous source shales have subsided into the oil generating zone (figs. 177 and 179).

Reservoirs and Seals. Potential reservoir sandstones may be found throughout the stratigraphic section, but in the absence of seals, are probably ineffective in the Tertiary molasse section. The Paleozoic reservoirs being largely below the oil-generating thermal zone are, therefore, largely inaccessible to any generated oil, but could contain gas. Destructive diageneses at depth is also a limiting possibility. The principal reservoirs are essentially limited to the Cretaceous formations: the eastern-derived Cushabatay, the Agua Caliente, the Chonta, and the western-derived Vivian Formations of Maranon sector, The eastern-derived Hollin and Napo Formations of the Oriente sector, and the eastern-derived Caballos and, in part, western-derived Villeta Formation of Putumayo. As perhaps maximal examples of these Cretaceous reservoirs are those in the Sacha Field of the Oriente sector, 90 percent of the reserves are in the main Hollin sandstone which has an estimated pay thickness of around 130 ft), with porosities averaging 16 percent, and an estimated primary recovery factor of 30 percent. The other Sacha reservoirs, making up to other 10 percent of the reserves, the upper Hollin sand, the "U" and "T" sands of the Napo Formation, and the Tena Formation sands, are relatively thin and discontinuous. While the better-developed Cretaceous reservoirs of the Oriente and Putumayo sectors sandstones are in the basal Hollin and Caballos formations, further south in the Maranon sector the better developed reservoirs are higher in the section in the Chonta and Vivian Formations.

Structure

The Maranon-Oriente-Putumayo basin is essentially a foreland basin formed between the Brazilian craton in the east and the Andes Mountains in the west (fig. 177). Figures 180, 181, 182,and 183 show in more detail the structure of each of the Maranon, Oriente, and Putumayo sectors of the basin, respectively, including the

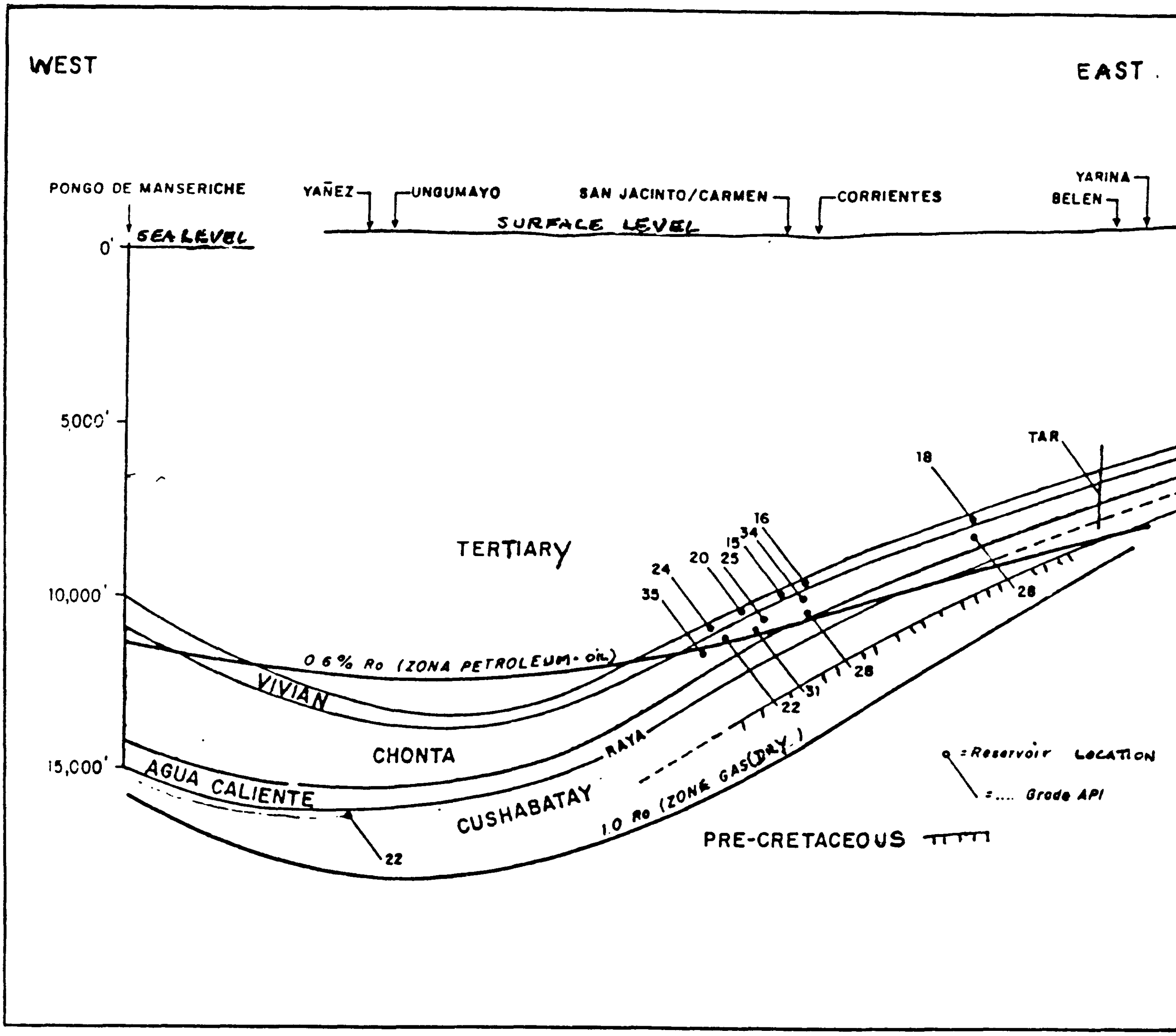


Figure 179 Schematic section across the Maranon sector of the Maranon-Oriente-Putumayo basin showing the relation of the oil window to basin structure and to the source and reservoir formations. It also shows the position of the oil in the reservoirs and the API gravity values (from Touzett and Sanz, 1985).

location of the principal petroleum structures, trends, and some geology and structure contours. The basin as it has been defined is a westward sloping platform ending abruptly on the west against an overthrust and fold belt (the Huallaga and Santiago basins) in the Maranon sector (figs. 177 and 183C) and against upthrust blocks in the Oriente and Putumayo sections (figs. 181, 182, and Sections A-A' and B-B' of 183) raising Oligocene and younger rock above the upper Tertiary and Quaternary plains.

This foreland basin is broken by upthrust blocks which not only form the uplifted Andean foothills, the Cutucu and Napo uplifts of the Oriente sector (figs. 181 and Section B-B' of 183) and the Sector Occidental of the Putumayo sector (figs. 181 and Section A-A' of 182), but also are the principal trap-forming structures of the basin. They are north-south elongate traps of low amplitude with one side or both controlled by faults. Figures 182 and Section A-A' of 183 indicates the upthrust-block structural style of the principal fields of the Putumayo. Figure 184 is a seismic section across a giant structure of the Oriente sector, the Shushufindi Oil Field, indicating apparent normal fault uplift in the pre-Cretaceous followed by post-Napo upthrusting along a steep reverse fault on the east flank which appears to be a reactivation of the pre-Cretaceous normal fault. Figure 183, Section A-A' shows that some of the upthrusting in the Putumayo sector is younger, apparently effecting most of the Tertiary strata.

<u>Generation, Migration and Accumulation</u>. The primary source rock of the basin are the middle Cretaceous marine organic shales within the Cushabatay-Vivian interval in the Maranon sector, the Hollin-Napo interval in the Oriente sector and the Caballos-Villeta interval of the Putumayo sector. Assuming no change in thermal gradient, generation and migration began sometime in the Tertiary, probably Neogene, when these source shale subsided into the oil window, approximate below about 10,000 ft (3,000 m) (figs. 177 and 179). By this time, the pre-Cretaceous potential source rock had subsided into or below the gas window.

The presence of extensive middle Cretaceous sandstone, e.g., the Cushabatay, Agua Caliente, Hollis and Caballos sandstones, indicates the opportunity for widespread lateral secondary migration. Some of the Oriente oil fields are in areas where the immediately underlying source shales are so shallow and therefore immature, that lateral migration from deeper parts of the basin must be called for. The oil fields of the Maranon sector are distributed in a ring or zone of intermediate depth along the eastern foreland slope of the basin (approximately between the 2,000 to 3,500 m [6,600 to 11,500 ft] top-Cretaceous contours in figure 180). A very similar distribution where oil occurrence parallels the structural contours is evident in the Powder River basin (fig. 9, Dolton et al, 1988). The accumulations of this zone are updip of the source-rock depocenter and of the intersection of the source strata and the top of the oil window, indicating updip lateral migration (fig. 179). The reason for the apparent absence of oil accumulations in the west

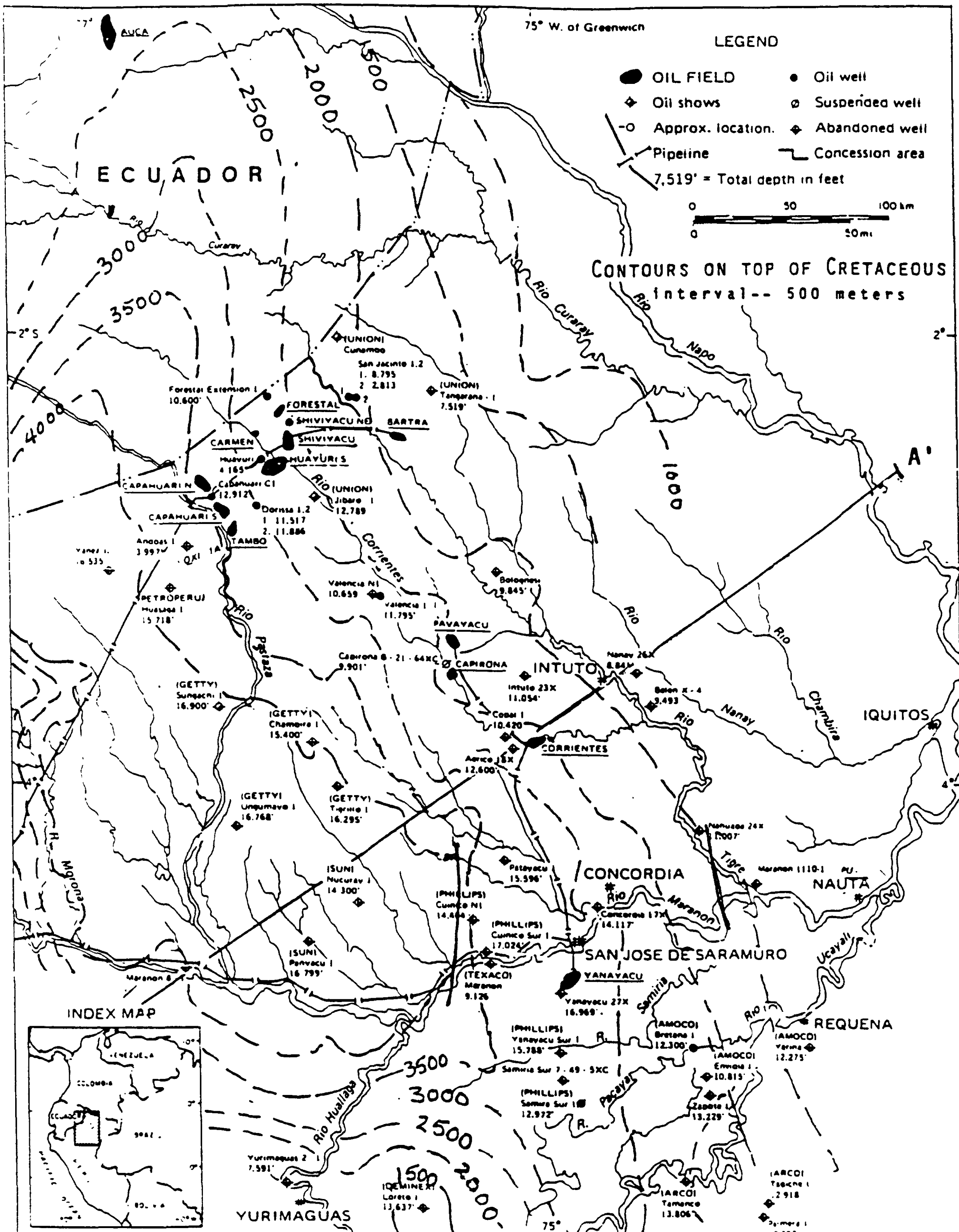


Figure 180 Structure map of the Maranon sector of the Maranon-Oriente-Putumayo basin showing structure at the top of the Cretaceous, oil fields and principal wildcats (from Petroconsultants, 1989).

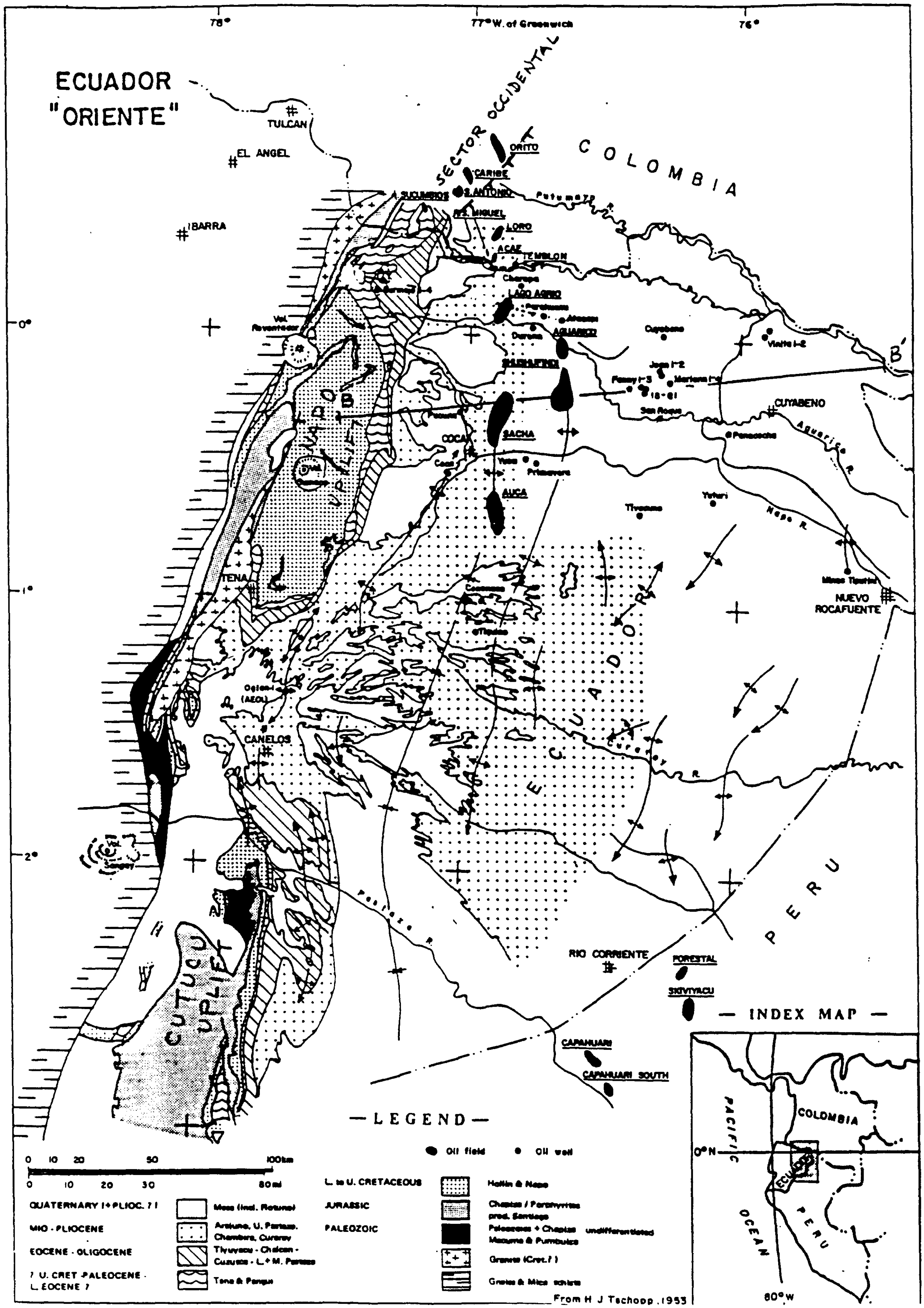


Figure 181 Structure map of the Oriente sector of the Maranon-Oriente-Putumayo basin showing geology, oil fields, and principal wildcats (modified from Tchapp, 1953).

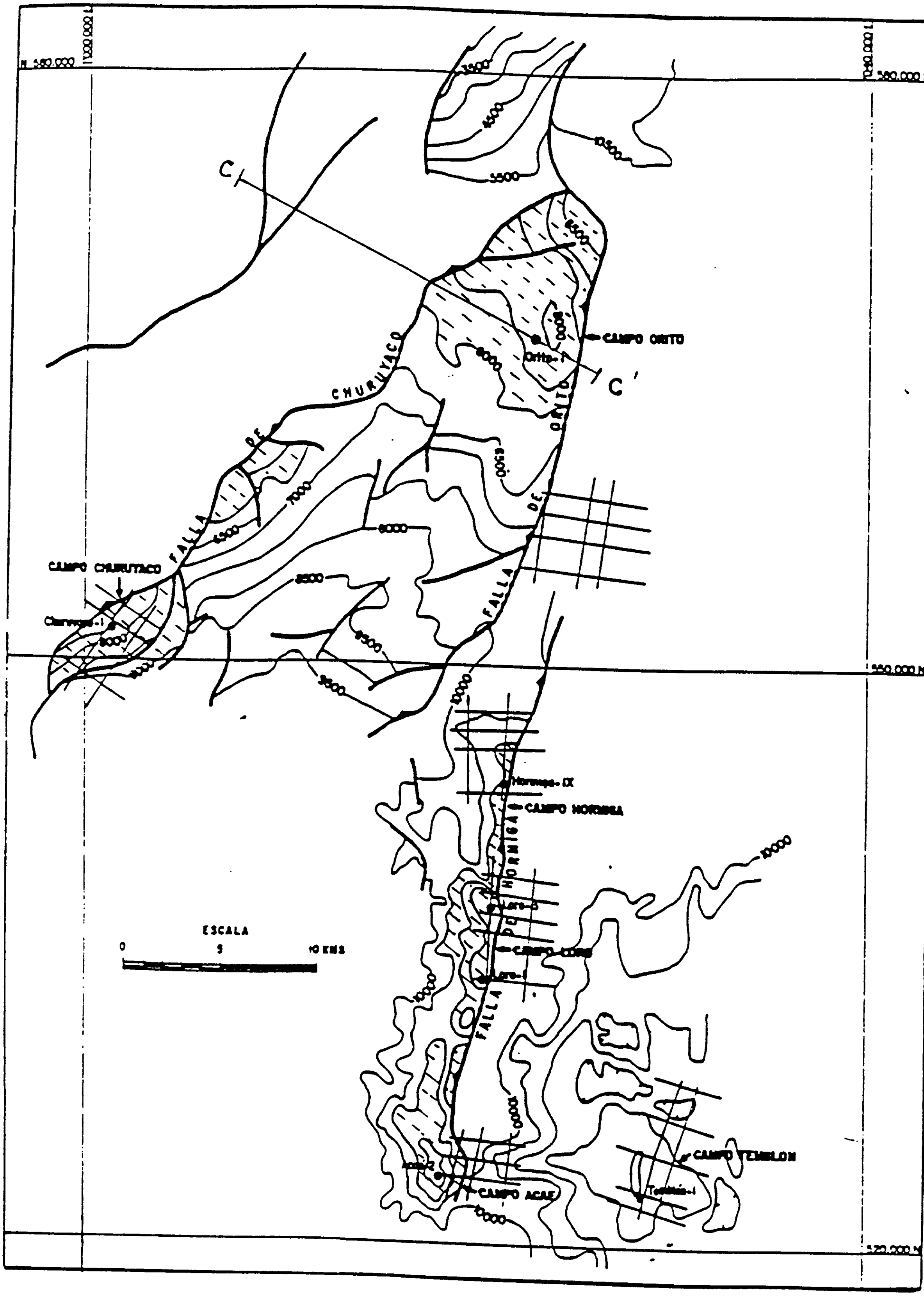


Figure 182 Structure map of a portion of the Putumayo sector of the Maranon-Oriente-Putumayo basin showing the structure at the top of the Caballos Formation and some of the oil fields hatchered (modified from Calderon and Margfay, 1985).

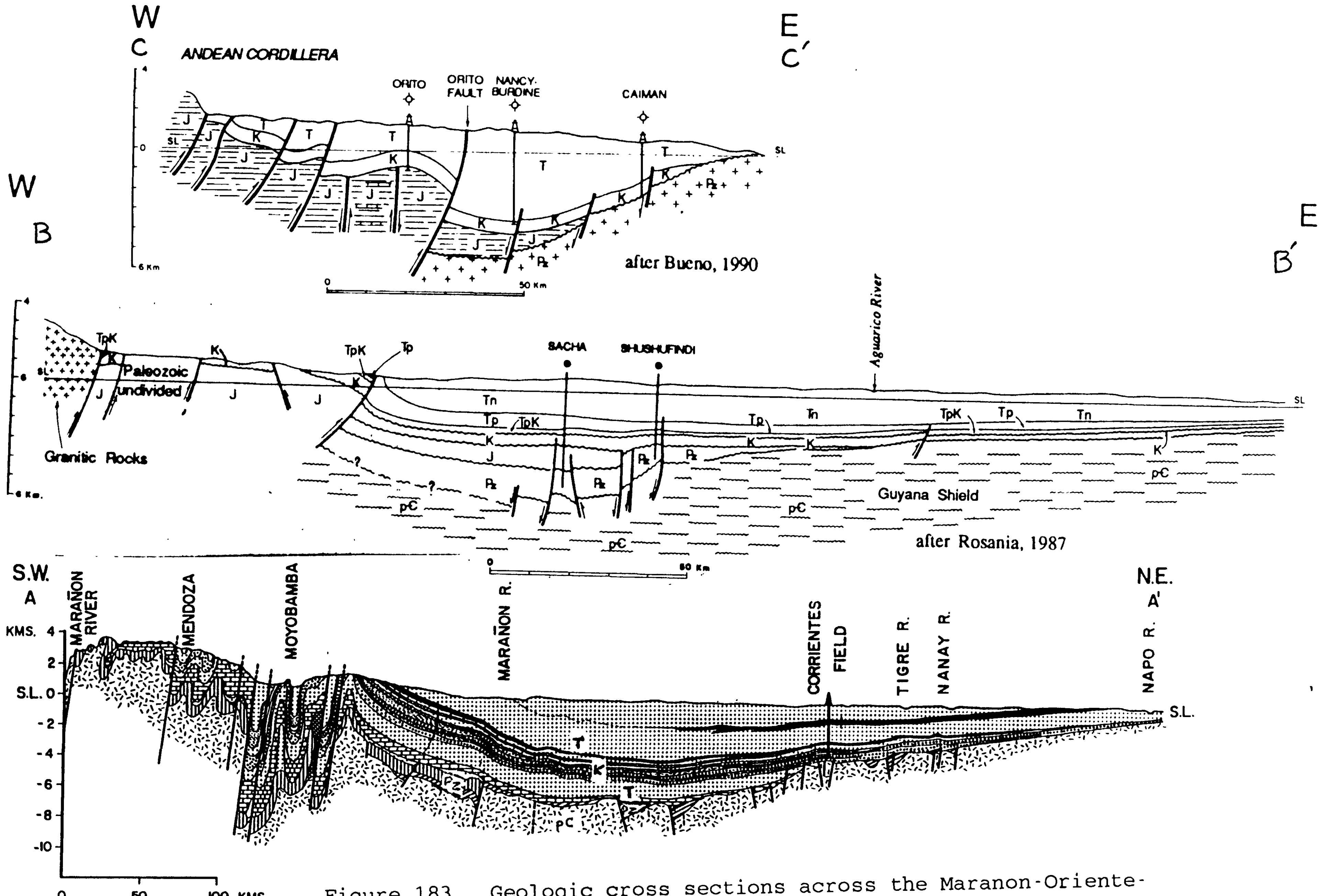


Figure 183 Geologic cross sections across the Maranon-Oriente-Putumayo basin. A-A' section across the Putumayo sector through the Orito Field (from Yrigoyen, 1991), B-B section across Oriente sector (from Yrigoyen, 1991) and C-C section across the Maranon sector (after Zuniga and Rivera et al, 1974) (Locations on figures 177, 180, 181, 182).

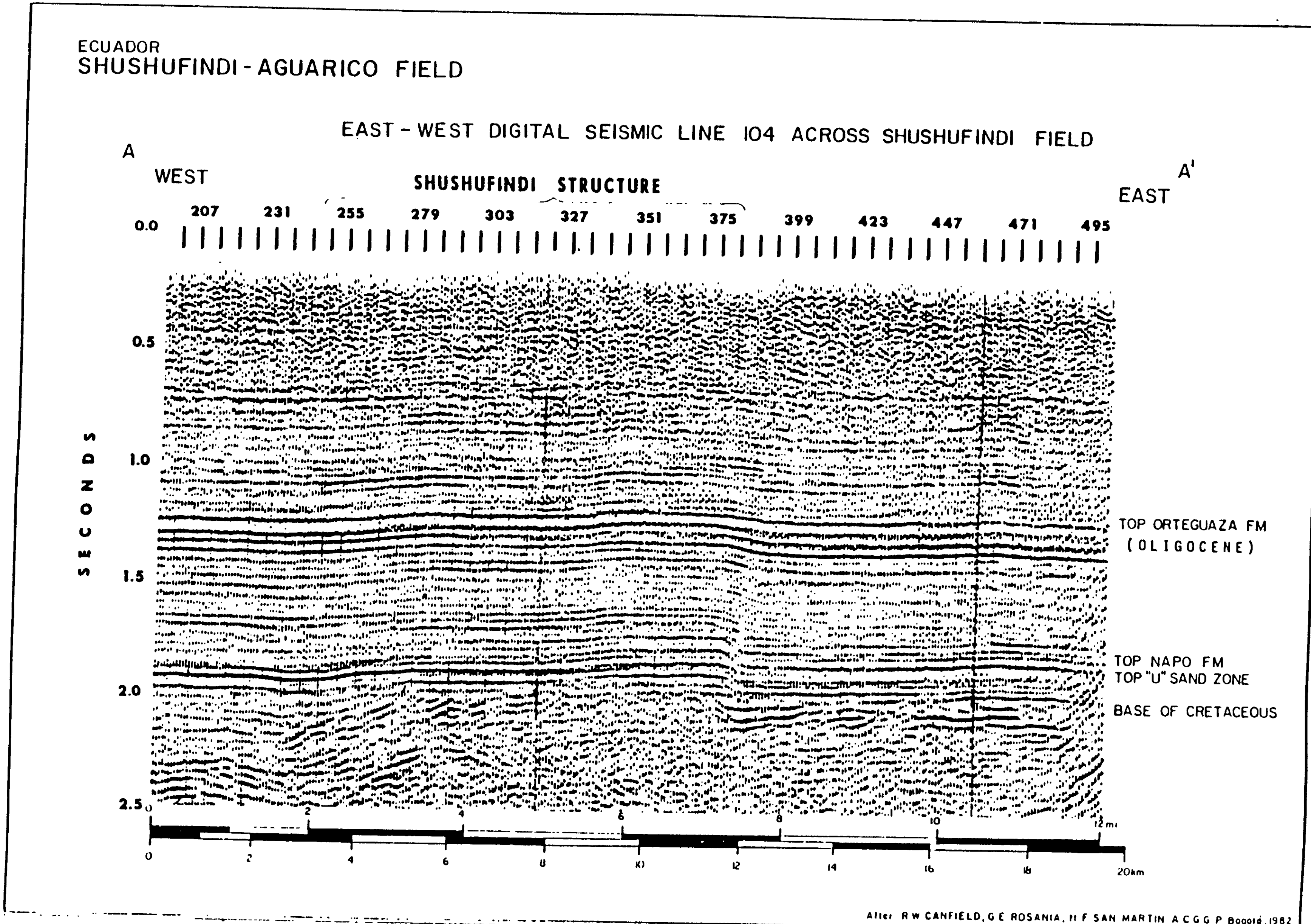


Figure 184 Seismic section across the Shushufindi field of the Oriente sector of the Maranon-Oriente-Pulumayo basin indicating the pre-Cretaceous apparent normal movement on flank faults and the reverse up-thrusting movement on apparently reactivated faults cutting through top of the Napo Formation (lower Tertiary-uppermost Cretaceous) (from Petroconsultants, 1989).

central basin area is unknown, but it may be due to strong cooling and flushing action of meteoric water from the rising Andes as evidenced by flushed reservoirs found in the foothill drilling of the Oriente sector. Flushing on the eastern, craton side of the basin updip from the zone of accumulations is also present as is evidenced by the tar in eastern wildcats, e.g., Belen (fig. 179, 180). It is estimated that flushing around the perimeter of the basin reduces its effective area by about 40 percent, or to 80,000 mi^2 (200,000 km^2).

This evident widespread lateral secondary migration, along with the character of the Cretaceous conduit sandstones, similar in some respects to the Cretaceous sandstones of the Powder River foreland basin, U.S.A., e.g., marine estuary to deltaic facies, leads one to expect the presence of stratigraphic traps. In the Powder River basin about half the petroleum reserves are in stratigraphic traps.

The percentage of gas to oil in the basin is generally low, only about 2 or 3 percent. This low ratio is probably not primarily due to the nature of kerogen, but more to the lack of gas-tight seals given the Cretaceous conduit sands and the coarse molasse cover of the Tertiary.

Plays. There are essentially three plays: 1) potential accumulations in the small part of the western overthrust and fold belt not included in the Huallaga and Santiago basins, 2) the major play to-date, accumulations in fault traps or drapes associated with compressive upthrust foreland blocks and involving Cretaceous sandstones, and 3) stratigraphic traps involving Cretaceous sandstones. Of these three plays, the first is of minor potential, the second is, so far, the only producer of this prolific basin, the third play, however, by analogy to the Powder River and Denver basins of the American Rockies (where petroleum is 50 percent and 100 percent respectively from stratigraphic traps) could be the most prospective for large amounts of undiscovered petroleum.

Exploration History and Petroleum Occurrence. First petroleum exploration in the Maranon-Oriente-Putumayo basin was in Ecuador in 1921, encouraged by the subandian discoveries in Venezuela and numerous oil and gas seeps. This exploration intensified in 1938 when Shell Company began operations which resulted in the drilling of five wildcats in the Andean up-thrust foothills which only found some shows of heavy tarry oil combined with fresh to brackish water indicating flushing. In 1950 Shell gave up their holdings and in 1964 Texas and Gulf acquired substantial acreage in the northwestern part of the Ecuador portion of the Maranon-Oriente-Putumayo basin and in 1967 made the first discovery (Lago Agrio, fig. 181) followed 2 years later by the discovery of the giant Shushufindi field (1.213 BBO). Some 123 wildcats (1990) in Ecuador have discovered 3.275 BBO and .672 TCFG (Petroconsultants) largely in the deeper parts of the basin.

Oil exploration began in the Putumayo (Colombia) sector of the basin in 1937 and intensified in 1963 when Texico/Gulf made the first discovery, Orito (figs. 181 and 182). Since then, until 1971, some 62 foothill wildcats discovered some 10 fields of minor production. Beginning in 1973, 13 wildcats discovered 3 small fields in stratigraphic traps on the platform.

Early oil exploration in eastern Peru concentrated in other parts of the subandian area, mainly the Ucayali basin, and it was not until 1971 that the first wildcat (Corrientes X-1, fig. 138) was drilled in Maranon basin and it was a discovery. Since then some 84 wildcats (1990) were drilled in the Maranon sector, discovering .762 BBO and .094 TCFG in some 30 fields.

<u>Estimation of Undiscovered Oil and Gas</u>. The uniformly, continuously rising curve of cumulative amounts of discovered oil against the number of wildcats drilled (fig. 185) suggests that, for oil at least, the basin's exploration is still in an immature stage. Since the initial surge of large-field discoveries (about the first 50 wildcats) the average discovery rate has been 7.52 MMBO per wildcat. If the number of wildcats 276 (Petroconsultants 1990), is eventually doubled and the discovery rate remains constant (new plays and techniques counterbalancing growing discovery size and difficulty, some 2.0 BBO will be discovered. Gas is considered of minor importance, and based on present reserve estimates, is assumed to be about 3 percent of the oil or about .36 TCFG. This oil and gas estimate, however, is probably low since, largely based on structural drilling, it cannot fully take into account the stratigraphic-trap play potential which, in my opinion, may be considerable.

The Maranon-Oriente-Putumayo basin is, in many respects, very similar to Rocky Mountain basins. Excepting the relatively minor pre-Cretaceous section, the Powder River basin, for instance, is similar in that it has: 1) a foreland basin with the same east-west asymmetric profile, 2) upthrusting compressive structures, 3) most of the oil prospects depend on middle and lower Cretaceous source shales and reservoir sandstones deposited in a mixed marine-flood plain-deltaic and generally transgressive environments, 4) oil generated in the foredeep part of the basin and migrated up the foreland platform, and 5) gas is only a minor component of the petroleum. In the Powder River basin stratigraphic-trap oil is equal in amount to structural-trap oil and Cretaceous oil amounts to 75 percent of the basin oil (Dolton et al, 1990). Significantly, in the exploration of the Powder River basin most of this structural-trap oil was discovered many years before the stratigraphic trap play became the main target of exploration. If the Maranon-Oriente-Putumayo is fairly analogous to the Powder River basin, an amount of petroleum equal to that found in Maranon-Oriente-Putumayo structural traps to date will eventually be found in yet undiscovered stratigraphic traps, so that the total undiscovered petroleum would amount approximately to 4.0 BBO and 0.7 TCFG.

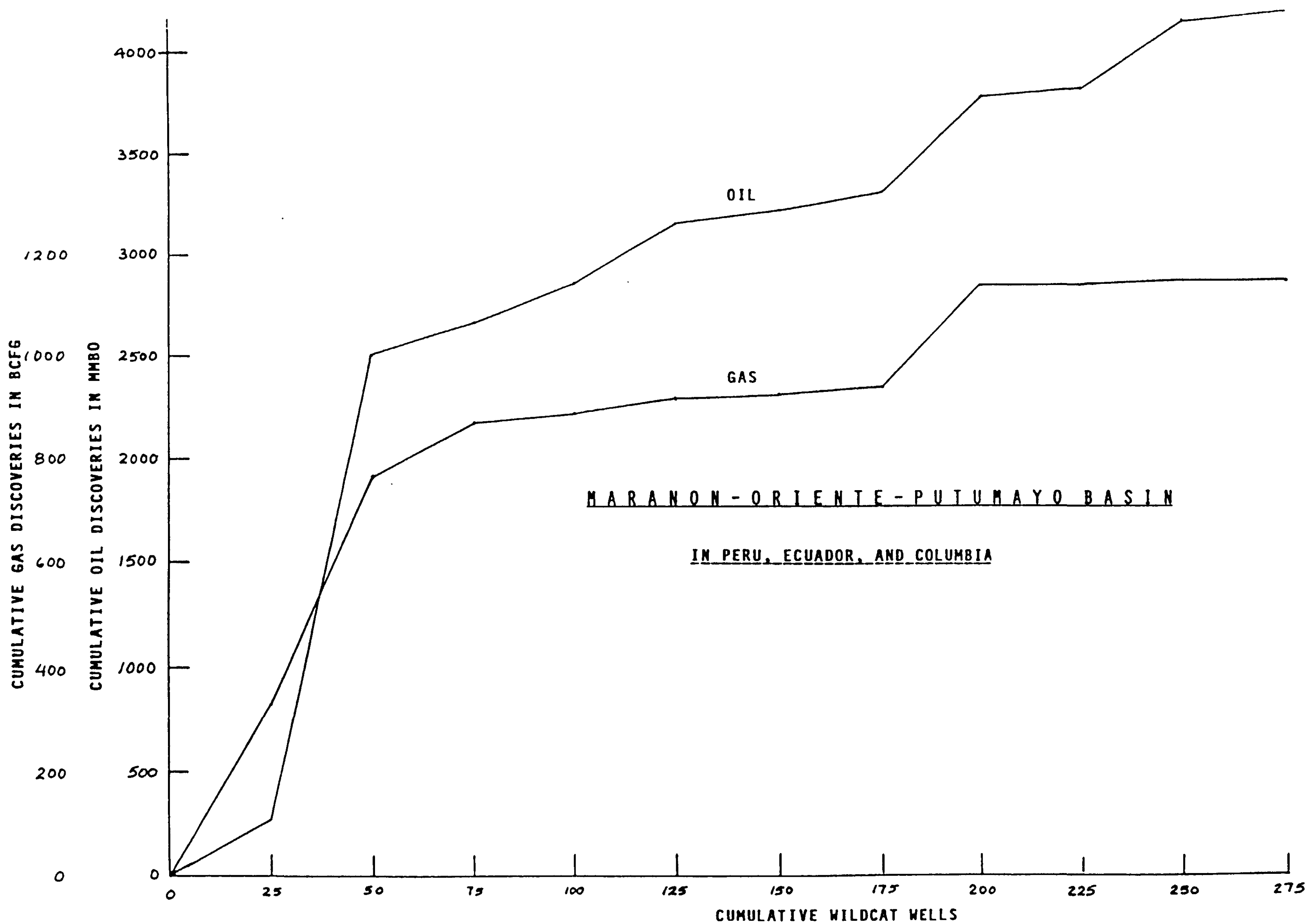


Figure 185 Graph showing Maranon-Oriente-Putumayo cumulative oil and gas discoveries versus number of wildcat wells, continually ascending oil curve indicating basin exploration still in an immature stage. Based on Petroconsultants data (1990) which is probably to some extent incomplete.

Another approach to the Powder River analogy is on a yield-per-area basis. The maturely explored Powder River basin has original reserves of some 2.5 BBO, of which 75 percent are in Cretaceous plays (Dolton et al, 1990) and expected undiscovered oil of 2.0 BBO (mean value estimate) (Mast, et al, 1989), of which 75 percent is also presumably in Cretaceous plays, giving ultimate resources of 4.5 BBO; of which approximately 75 percent, or some 3.4 BBO, are in Cretaceous plays (Dolton et al, 1990). The sedimentary area of the Powder River basin is some 34,000 mi^2 (87,000 km^2) (Varnes and Dolton, 1982). Straight areal comparison with the effective area of the Maranon-Oriente-Putumayo Cretaceous basin (80,000 mi^2, 200,000 km^2) suggests oil resources of 8.0 BBO of which 4.3 BBO has been discovered leaving undiscovered 3.7 BBO. Gas would be 1.40 TCF, assuming 3 percent of petroleum mix is gas; subtracting present reserves (.8 TCFG) indicates .6 TCF of undiscovered gas. These values of 3.7 BBO and .6 TCFG are comparable to thesomewhat higher estimate of 4.3 BBO and .8 TCFG (which was primarily based on the supposition that the amount of potential stratigraphic oil would equal discovered structural oil). On the basis of the more conservative 3.7 BBO and .6 TCFG, the distribution of the undiscovered resources to the three sectors on an areal basis are: Maranon (Peru) 2.43 BBO, .39 TCFG, Oriente (Ecuador) .88 BBO, .15 TCFG, and Putumayo (Colombia) .38 BBO, .06 TCFG.

B. Overthrust and Fold Belt Basins

Usually the Subandean foreland basins, as defined in the literature, includes the adjoining overthrust and fold belt. However, where that segment of the overthrust and fold belt becomes quite broad adjoining the Maranon-Oriente-Putumayo foreland basin and, in part, the Ucayali foreland basin, the overthrust and fold area has been separated in the literature from the foreland basins and divided into two basins, The Huallaga and Santiago basins, defined by structural lows (fig. 186).

Huallaga basin

Area: 10,000 mi^2 (26,000 km^2)

Original Reserves: Nil

Description of Area: The Huallaga basin is a structural low in the Subandean overthrust and fold belt defined by thrust ridges which separate it from the Maranon-Oriente-Putumayo and Ucayali basins on the east, and by the Cordillera Oriental of the Andes on the west. Its sediments thin northwards towards the high area separating it from the Santiago basin. Its relation with the adjoining basins is shown in figure 186 and its area in figure 187.

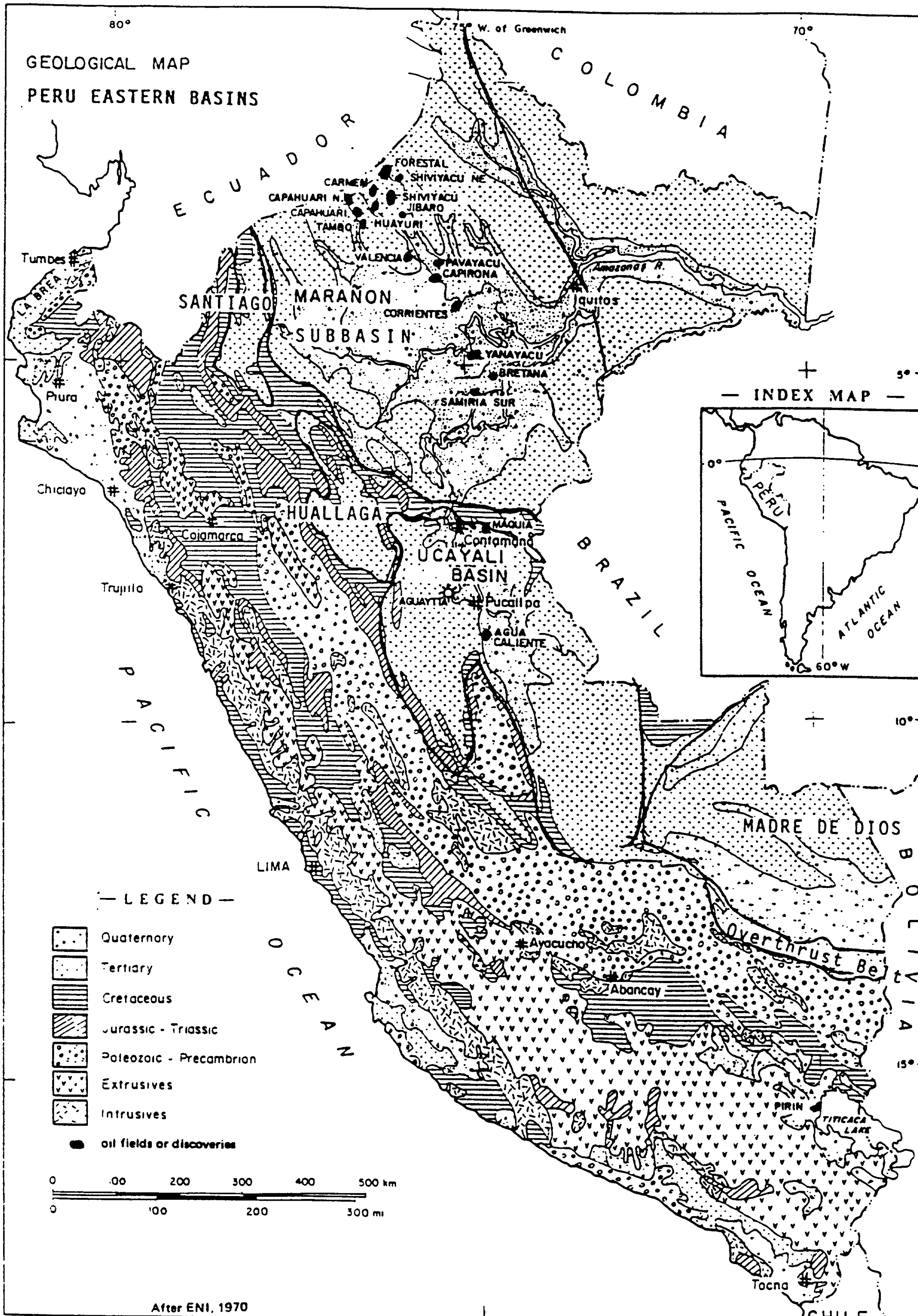


Figure 186 Geologic map of Peru, showing principal sedimentary basins east of the Andes (modified from Petroconsultants, 1989).

Stratigraphy

There is some 33,000 ft (10,000 m) of Paleozoic through Cenozoic rock exposed in the basin (fig. 188). In general, most of the stratigraphy is similar to that of the adjoining Maranon-Oriente-Putumayo basin except for two key differences. Firstly, the Cretaceous is of a somewhat more marine facies. Secondly, there is a western-thickening of the Triassic and Jurassic section as indicated in figure 174. The Triassic and lower Jurassic is represented by the Pucara Formation. It is more than 5,000 ft (1,500 m) thick and is made up of dark, bituminous micritic carbonates with interbedded black, fossiliferous shales; salt and other evaporites occur in some sectors. The upper Jurassic (the Sarayaquillo Formation) is represented by more than 8,000 ft (2,500 m) of a red-bed sequence of sandstones and mudstone. Evaporites appear at its base.

Source. The potential source rocks appear to be the shales of the Triassic-Jurassic Pucara Group and the Middle Cretaceous shales, the Paleozoic potential source rock probably being over-mature. Analysis of the Pucara Group shales have revealed TOC content of up to 5 percent, but generally less than 3 percent; the TOC of the carbonates ranges from .25 to .79 percent. The TOC of the Cretaceous shales apparently average around .67 to .88 percent (Vargas, 1988).

Vitrinite reflectance values from the base of the Cretaceous indicate the southern part of the basin to be in the oil window, the northern third being over-mature (Touzett and Sanz, 1985). The Pucara Group shales and older potential source rock may be largely over-mature for oil.

Oil and gas shows occur in basin, emanating largely from the Agua Caliente Formation. The oil is high gravity and correlates with oils of Cretaceous origin in the Ucayali basin (Vargas, 1988), figs. 187 and 188.

Reservoirs and seals. The reservoirs appear to be of the same lithology and potential as those of the same formations in the Maranon-Oriente-Putumayo basin, that is, the Vivian, Agua Caliente, and Cushabatay Formations. Where sampled, the reservoir porosities ranged from 15 to 25 percent (Varagas, 1988).

In a structurally complex area such as this, the effectiveness of trap seals come into question. In this area only drilling will answer the question, but two factors indicate that sealing may be effective: 1) the presence of Triassic-Jurassic evaporites and the salt domes indicate that, at that level, sealing may be fairly efficient and 2) on trend in the overthrust and fold belt of southern Peru, the closure of the giant Cashiriari gas field of the Ucayali-Madre de Dios border area holds 10.8 TCFG and .725 BB condensate.

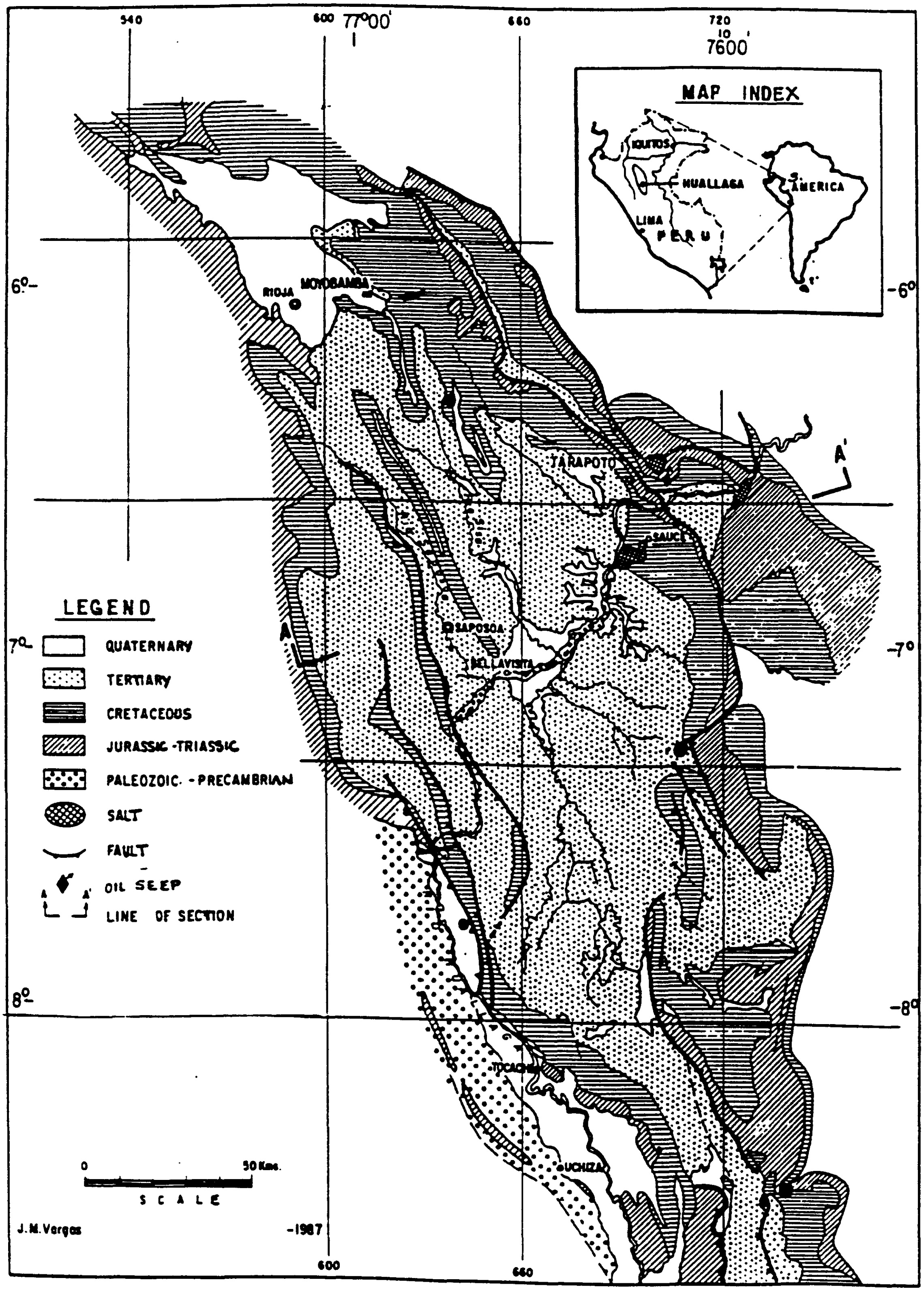


Figure 187 Geologic map of Huallaga basin (from Vargas, 1988).

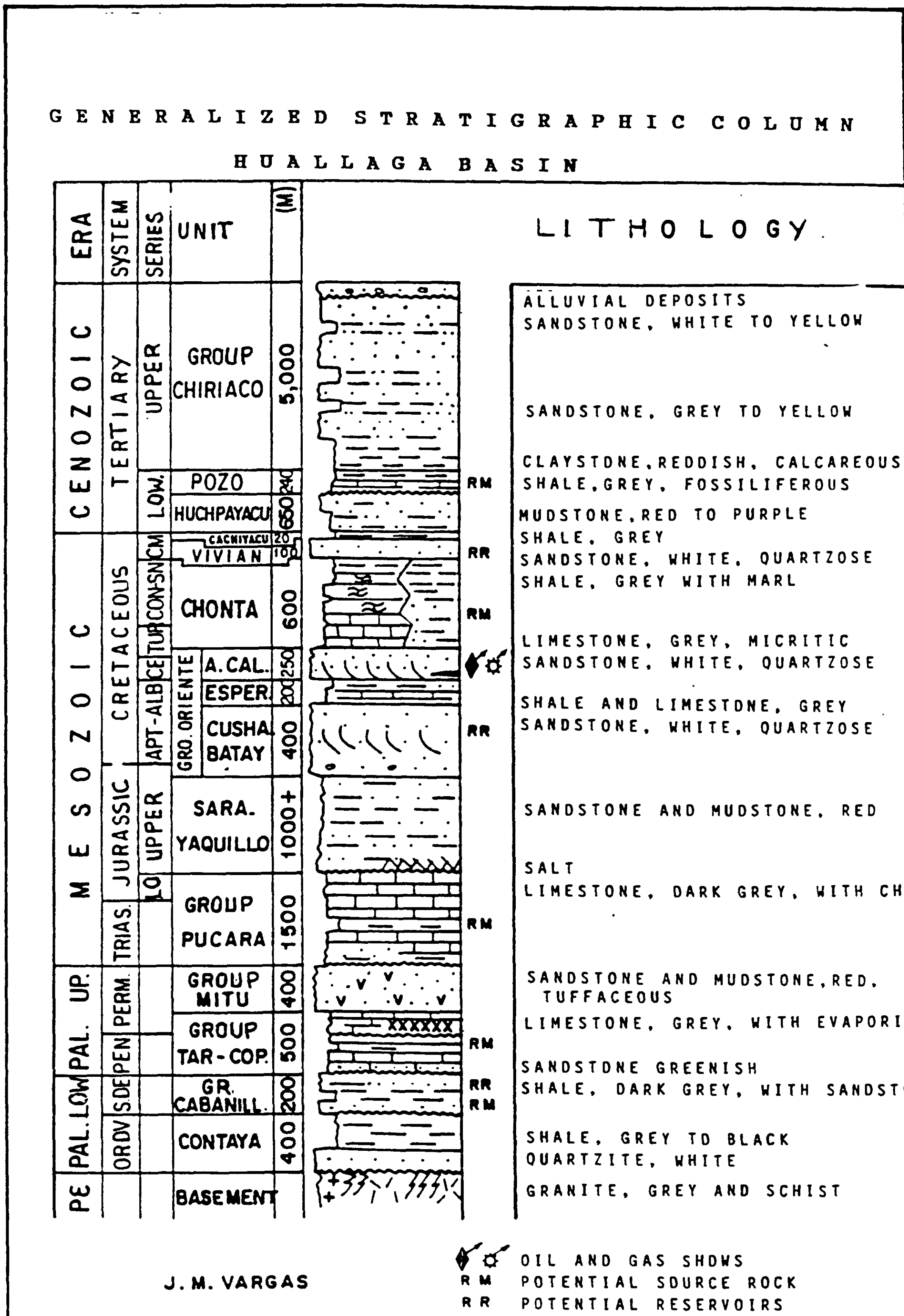


Figure 188 Generalized stratigraphic column of Huallaga basin (modified from Vargas, 1988).

Structure

As part of the Subandean overthrust and folded belt this province is structurally complex. There is a large variety of structural closures, including anticlines, fault blocks, drapes, salt domes and thrust-fault related closures (figs. 187 and 189). Surface mapping has indicated 40 structures, 15 of which are more highly regarded, 9 with Cretaceous objectives and 6 with pre-Cretaceous objectives (Vargas 1988).

Generation, Migration and Entrapment. Generation and migration from principal Mesozoic source shale began in the Neogene when they were depressed during the Andean orogeny. This would be contemporaneous to the trap formation associated with the trusting and folding.

However, the indicated thermal maturity of the sediments is high indicating the source shales probably were buried deeper prior to the Neogene orogeny in the Andean area. The pre-Cretaceous strata are largely overmature and those of the Cretaceous appear over-mature for oil generation (i.e., vitrinite reflectance over 1.35 percent) in the northern one-third of the basin.

Plays. There appears to be two main plays in the basin both involving Cretaceous reservoirs. One is possible closures around small salt domes, some five of which are shown in figure 187 and in section in figure 184. The second play, and the one with some promise of more substantial potential, is closures caused by overthrusting and folding (figures 187 and 189).

Exploration History and Petroleum Occurrence. This is no petroleum production and no wildcats have been drilled, though parts of the basin have been covered by surface geology and aeromagnetometer, gravity meter, and photographic and radar imaging surveys.

A few oil and gas shows, and at least one oil seep, occur in the basin (fig. 187 and 188).

Estimation of Undiscovered Oil and Gas. By straight areal analogy to the nearest on-trend portion of the Subandean overthrust belt, that is, the overthrust portion of the Ucayali basin would contain some 2.5 BB oil or condensate and 37 TCFG. However, since none of the pre-Cretaceous source rock (the principal source of the Ucayali basin) and only two-thirds of the Cretaceous source rock appears to be in the oil window, the analog-estimate is reduced to about one tenth, or .25 BB oil or condensate and 3.7 TCFG.

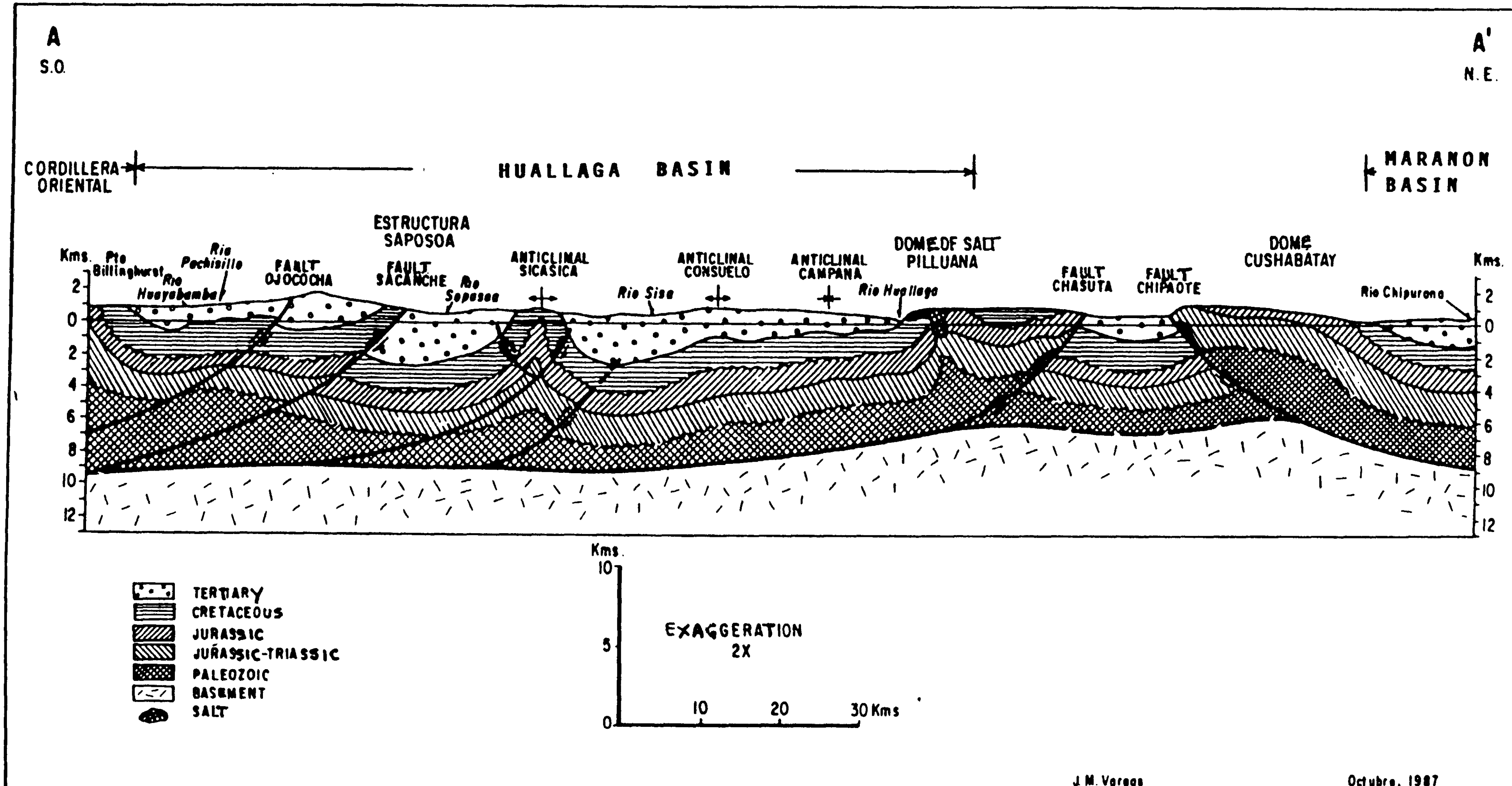


Figure 189 Geologic cross-section Huallaga basin. Location in figure 188 (from Vargas, 1988).

Santiago Basin

Area: 5,500 mi^2 (14,000 km^2)

Original Reserves: Nil

Description of Area: This basin is a tectonic depression along the Subandian zone of overthrusting and folding at the north boundary of Peru, separated from the Huallaga basin to the south by a structural high. The basin is bordered on the east by frontal anticlines of the Subandian overthrust and fold belt and on the west by the basement rock of the Andes (fig. 186 and 190).

Stratigraphy

The stratigraphy is similar to that of the adjoining basins and especially the on-trend overthrust and fold province of Huallaga to the south (fig. 188).

Source. The main potential source rocks are of the same formations as those in the adjoining basins, namely, the Pucara Group and the Middle and Upper Cretaceous (Cushabatay and Cachiyacu Formations) shales (fig. 188). The older rocks are probably being over-mature, at least for oil.

The Cushabatay and Cachiyacu shales have TOC concentrations (from outcrop samples) of 0.5 to 2.0 percent. The Eocene-Miocene marine strata, the Pozo Formation, has TOC concentrations as high as 4.0 percent, but may not be sufficiently mature in most areas (Touzett and Sanz, 1985).

Reservoirs and Seals. The primary reservoirs of the Santiago basin are the same as those of the adjoining basins, namely, the sandstones of the Cretaceous, Aqua Caliente, Vivian, and Cushabatay Formations. In addition, some of the Tertiary sandstones may be good reservoirs as indicated by two of the three wildcats drilled up to 1968. Porosity and permeability values are unavailable but assumed, by analogy to the Huallaga basin, to be reasonably good.

Two factors indicate sealing may be effective to some degree in this highly faulted province: 1) the presence of Triassic-Jurassic evaporites, and 2) the giant on-trend Cashiriari gas field trapped under the unknown favorable geologic conditions.

Structure

The predominant structure is associated with compressional overthrusting (fig. 190) similar to that of other parts of the subandian thrust and fold belt, particularly that of the Huallaga basin (fig. 187, 189). Movement of Jurassic salt probably began prior to the largely Pliocene overthrusting, therefore substantially affected the overthrust movements and closures.

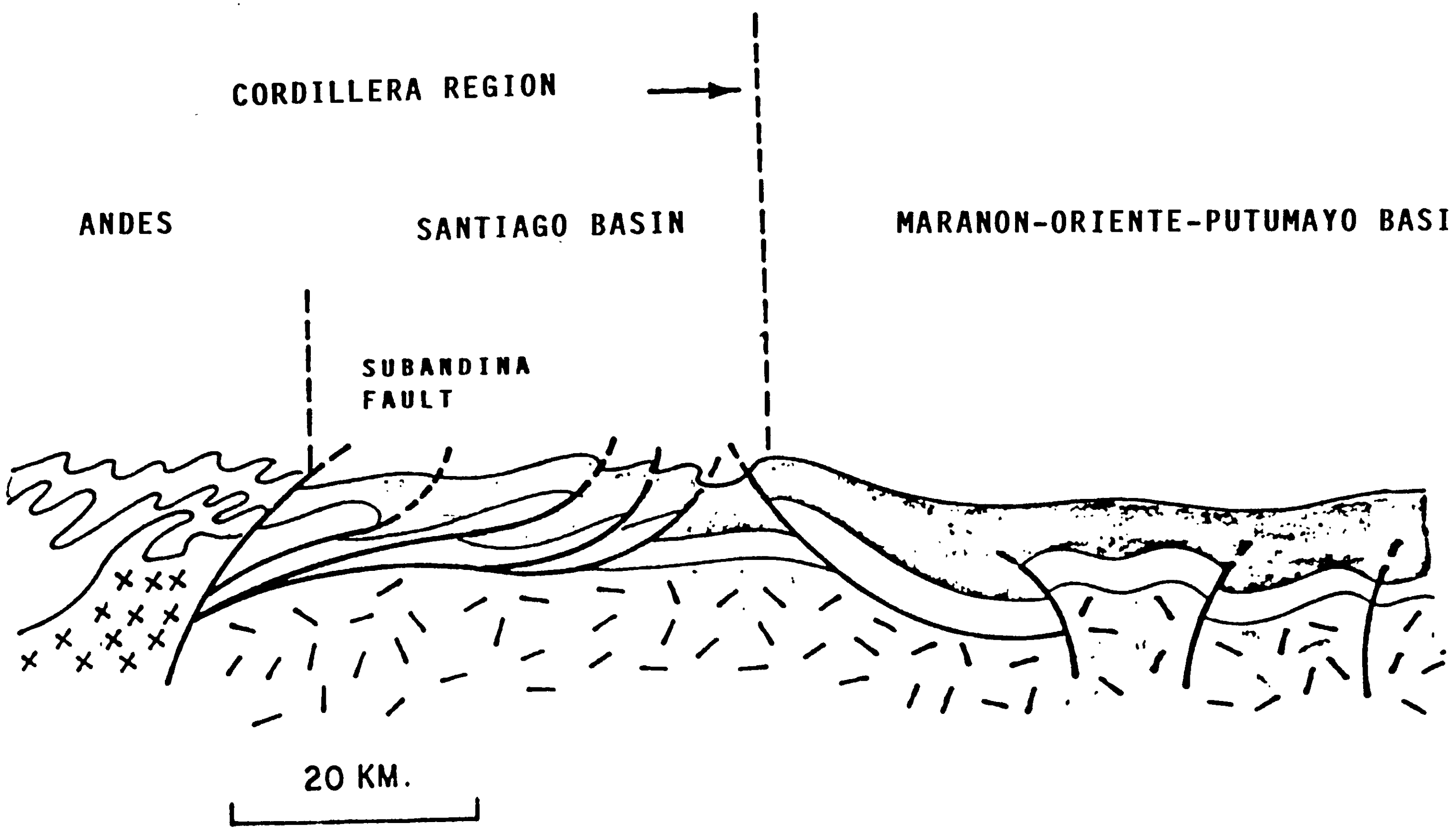


Figure 190 Regional east-west cross-section of northeastern Peru showing diagrammatically the structural style of the Santiago basin versus the Maranon-Oriente-Putumayo basin (from Touzett and Sanz, 1985).

Potential traps include the following: compressional folds, overthrust fault traps, drapes and salt diapirs.

Generation, Migration, and Entrapment. Generation and migration probably began in the Neogene when the Cretaceous source shales subsided into the oil window during the Andes orogeny. Concurrently trap formation associated with overthrusting began. Traps associated with salt flowage may have begun somewhat earlier. The Cretaceous reservoirs are assumed to have been available with adequate porosity and permeability.

Plays. As in the Huallaga basin there are two principal plays both involving Cretaceous reservoirs. The first play, with the more potential, involves closures associated with overthrusting and related folding, and the second and least important play is that of closures around salt intrusions of Jurassic-Triassic salt.

Exploration History and Petroleum Occurrence. No reserves have been established. Approximately three dry holes have been drilled in 1968 to depths suggesting Cretaceous reservoirs were the objectives. Oil shows were encountered in all three wildcats in Cretaceous and Eocene sandstones. Oil seepage from Eocene rock occurs.

Estimation of Undiscovered Oil and Gas. There is only little data on the Santiago basin but it appears to be closely similar to the on-trend Huallaga basin about which there is more information. The Huallaga basin's resources, on the basis of a discounted analogy to the overthrust and fold belt of the Ucayali basin, as previously discussed, were estimated to be .25 BBO and 3.7 TCFG. By a straight areal analogy to the Huallaga estimated resources, the undiscovered resources of the Santiago basin are estimated to be .14 BBO and 2.0 TCFG.

C. Andean Intra-arc Basins

There are a number of intra-arc basins within the Andes but only one, the Altiplano basin, is deemed to be large enough to have any appreciable petroleum prospects (fig. 191). Small intra-arc basins west of the Andes and adjoining the coastal forearc basins in Ecuador, Peru and Chile are discussed under Pacific Coastal Forearc and Intra-arc Basins.

Altiplano Basin

Area: 27,000 mi^2 (70,000 km^2)

Bolivia: 18,000 mi^2 (47,000 km^2)

Peru: 9,000 mi^2 (23,000 km^2)

Original Reserves: .0003 BBO

Description of Area: The area is a high plain located between the main or western range of the Andes (Cordillera Principal or Occidental) and the eastern range (Cordillera Oriental). It extends northward from about the Bolivia-Argentina border, through Bolivia into Peru at about latitude 15° south in Peru (fig. 191). The northern, largely in Peru, part of the basin is sometimes referred to as the Titicaca subbasin and the southern part, largely in Bolivia, as the Puna subbasin.

Stratigraphy:

The Paleozoic and Mesozoic stratigraphy is similar to, and correlates with, that of the adjoining Subandean basins (fig. 172, 178) since the intervening Cordillera Oriental did not begin to rise until late Cretaceous.

The oldest sedimentary unit is a very thick sequence of Silurian-Devonian (and Ordovician?) largely dark colored shales with lesser amounts of sandstone. This unit is in part metamorphosed to slate and mica schist. In any case, it appears to be presently largely overmature for the generation of oil, and probably also gas.

The overlying Carboniferous section is up to 3,300 ft (1,000 m) thick at the Peru-Bolivia boundary and thins southward. It is made up of a paralic succession of fluvial deltaic, grey, plant-bearing sandstones and shales with minor coal. It is correlated with the Tarma and Ambo formations of the Peruvian foreland basins (figs. 172 and 178) (Helwig, 1972). The carbonates of the Tarma Formation are evidently limited to the northern perimeter of the basin.

At the beginning of the Permian a major marine transgression from Peru deposited the Copacabana Formation and extended over the northern part of the basin. The formation consists largely of carbonates with tuff and shale interbeds, the shales becoming more prominent northwestwards. Near Lake Titicaca the lower part of the Permian consists of black, calcareous, bituminous shale. Overlying the Copacabana Formation is the Mitu Formation, a sequence of red beds of largely unfossiliferous sandstone and evaporites which may be Permian in age (fig. 192). Both the Carboniferous and Permian sections thin southeastwards and are not present in the southern Altiplano basin.

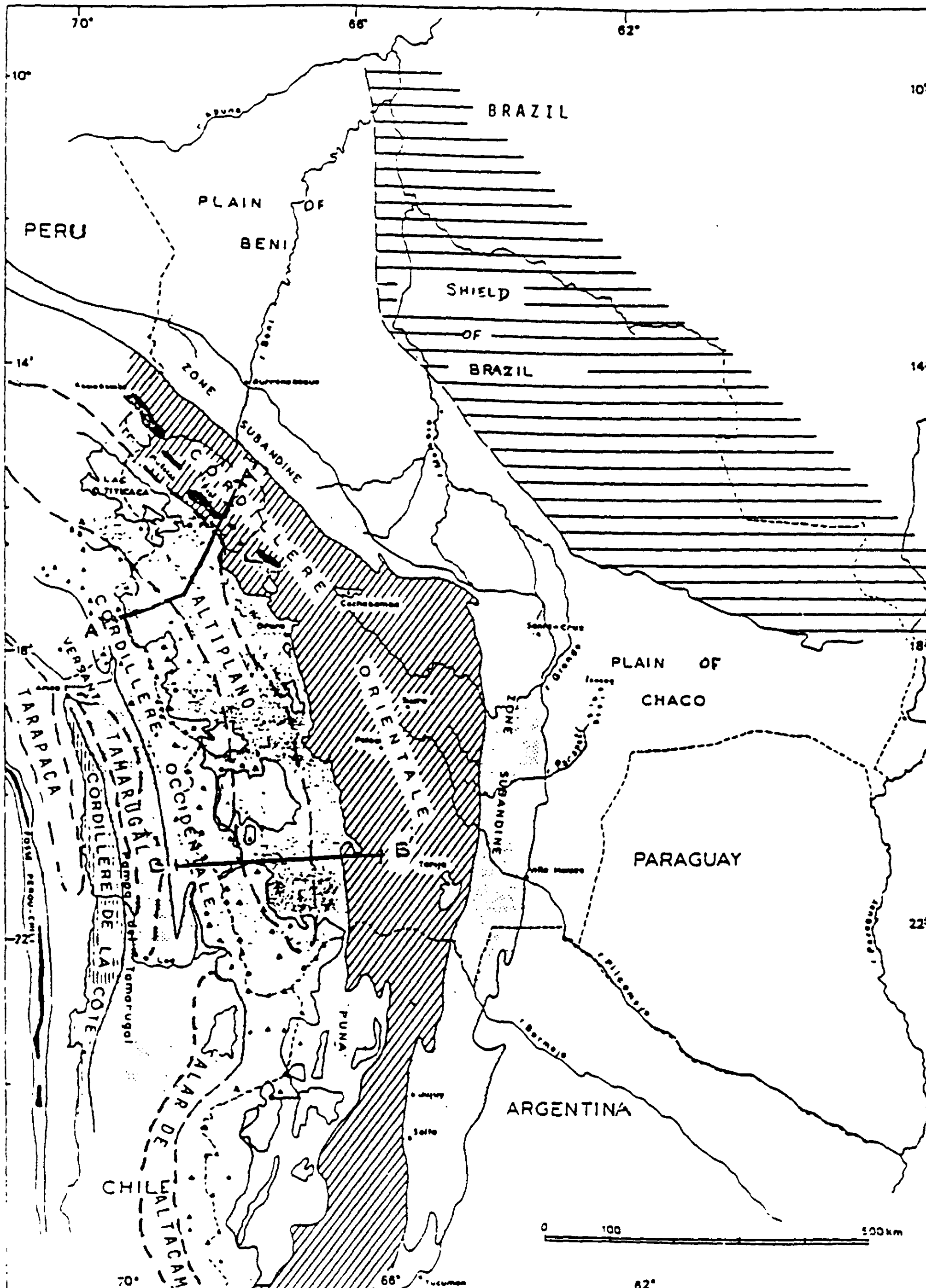


Figure 191 Map of the central Andes showing major tectonic provinces and, in particular, the position of the Altiplano and other basins (outlined by dashed line) (modified from Martinez, 1988).

No Triassic rocks are known, and strata of Jurassic age of unknown lithology reportedly occur in the basin in presumably minor thicknesses.

The basal part of the Lower and Middle Cretaceous Titicaca Group contains limestone beds which are probably equivalent to the Oriente Group of the Peruvian foreland basins. The rocks become more marine westwards (fig. 192 and 172). The younger Cretaceous and Tertiary sequences are largely coarse continental clastics interbedded with volcanics (fig. 192).

Source. The presence of some source rock is indicated by the presence of oil seeps and the small Perin oil field. The source of the oil is not known, but it may be from thermally mature Devonian dark shales which escaped metamorphism or overmaturation. The Carboniferous is largely in a red-bed facies as is the Permian except for the marine tongue, the Copacabana Formation. The Copacabana Formation contains source rock in the Peru Subandean basins. Most of the Mesozoic and Tertiary are largely in a red-bed facies with some marine interbeds in the lower Cretaceous. The presence of quantities of organic-rich source rock, sufficient to supply commercial-sized petroleum accumulations, appears to be one of the factors limiting the potential of the basin.

Reservoirs and seals. No detailed descriptions of potential reservoirs are available, but there appears to be a reasonable amount of potential reservoir sandstones and their quantity would not be a limiting factor for any potential accumulations. Potential Tertiary reservoirs are low quality because of their tuffaceous content.

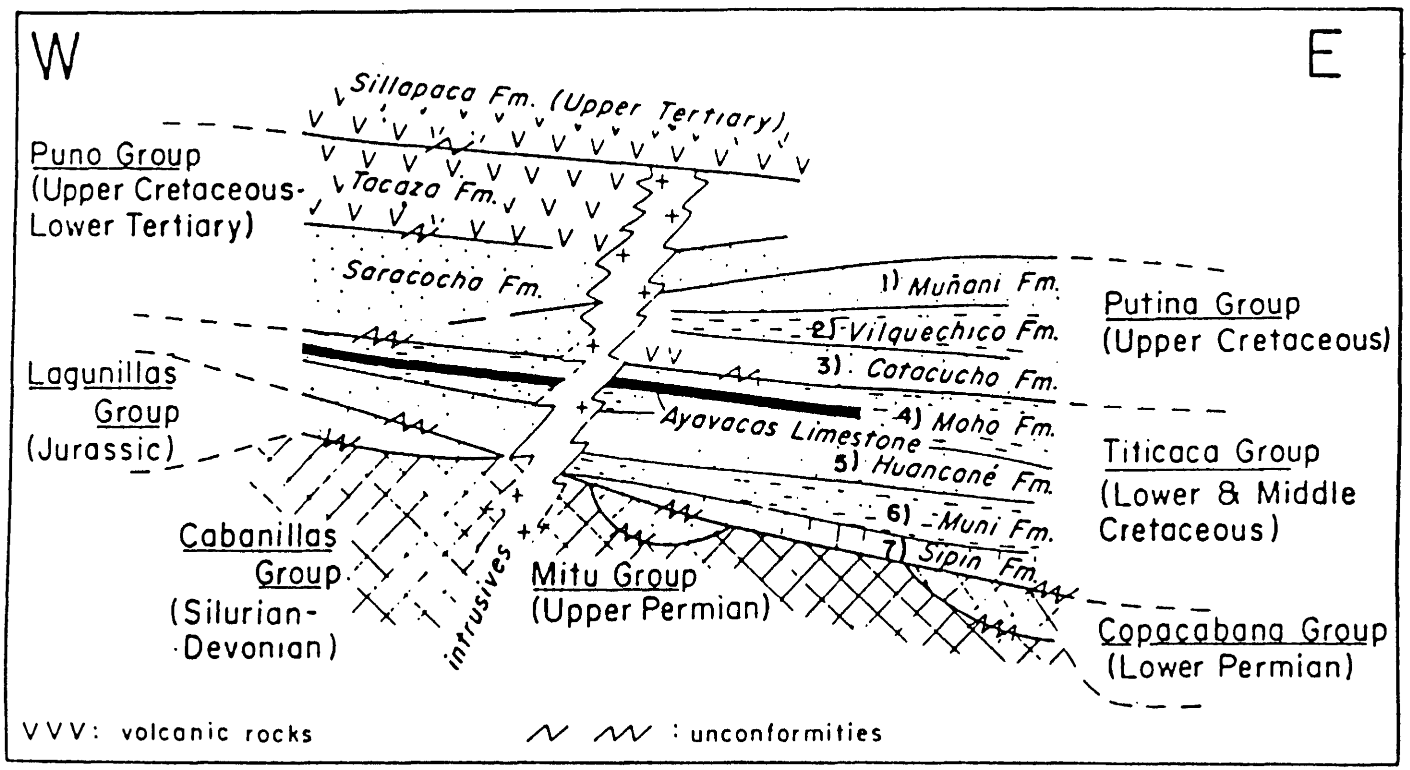
Seals may be a problem in this area of relatively coarse clastics and much faulting.

Structure

The Altiplano basin is cut by a great number of Neogene, north to northwest trending, normal and reverse faults resulting in a horst and graben terrain (fig. 193). Some salt flow structures are evident. In any case, structural closure in the form of fault traps, fault associated folds, and flow structures appear to abound, but may be small and complicated. Structural closure of sufficient size may be a limiting factor in this remote area.

Generation, migration and accumulation. There was not the Tertiary foredeep subsidence similar to the Subandean region which triggered petroleum generation, but, judging by the metamorphism of some of the Devonian strata, any petroleum generation and migration would have probably begun during an earlier and deeper subsidence. Traps evidently only formed in the Neogene in association with the Andean orogeny. Given the possible time-lapse between migration from any Paleozoic source rock and Neogene trap formation, and given

DIAGRAM OF STRATIGRAPHIC UNITS IN TITICACA AREA



1) Red sandstone and conglomerate
2) Red shale
3) Sandstone and conglomerate
4) Red shale and sandstone with limestone intercalations
5) Red and white sandstone and conglomerate
6) Shale, sandstone and conglomerate with some carbonate beds.
7) Limestone

Figure 192 Diagram of stratigraphic units in vicinity of Lake Titicaco, Altiplano basin (from Petroconsultants, 1989).

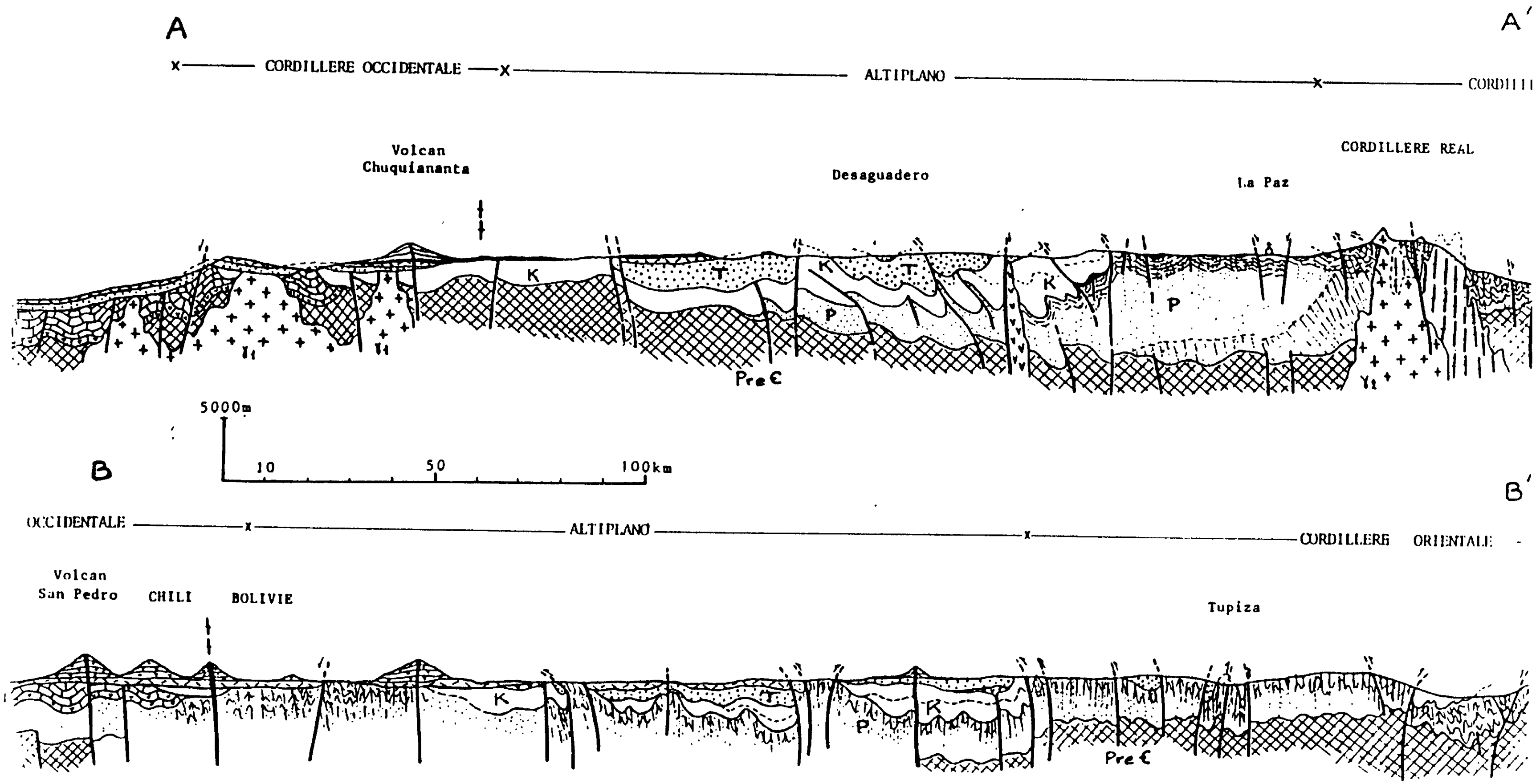


Figure 193 Geologic cross-sections of the Altiplano basin. P-Paleozoic, K-Cretaceous and T-Tertiary. Location of sections in figure 191 (modified from Martinez, 1988).

the poor sealing, only a minor amount of petroleum would be trapped. Cretaceous-sourced petroleum remains a possibility if some Cretaceous strata are sufficiently organic-rich.

Exploration History and Petroleum Occurrence. One small depleted field, Pirin, with a cumulative production of about 300,000 barrels of 40 degree API, 5 percent paraffin oil, is the only discovery (1875) in the basin. The field produces from a Cretaceous sandstone (Titicaca Group) at the north end of Lake Titicaca. Exploration has been minimal.

Estimate of Amount of Undiscovered Petroleum. There is some petroleum in the province as evidenced by one small field and some seeps. The stratigraphy is similar to that of the adjoining Subandean foreland basins and a straight areal analogy to the estimated ultimate resources of the combined foreland basins immediately opposite the Altiplano basin, i.e., the Santa Cruz-Tarija, the Beni, and the Madre de Dios basins, indicate undiscovered petroleum of some .115 BBO and 2.47 TCFG. However, the principal source rocks are poorer, presumably most of the Paleozoic rocks being overmature (or reached thermal generation too early) and the sealing and trapping less effective than those of the Subandean foreland basins. Consequently, the estimate is reduced to a tenth or .012 BBO and .25 TCFG.

D. Pacific Coastal Fore-arc and Intra-arc basins

Forearc and associated intra-arc basins extend the whole length of South America's Pacific coast. This study includes all these basins except those of Colombia.

Of all the South American Pacific coast basins, only the Talara basin at the Peru-Ecuador border and the adjoining Progreso basins have produced petroleum and, therefore, have been the most explored and better known. Consequently, these basins will be discussed first before proceeding northward to the other Ecuadorian coastal basins and then southward to the basins of Peru and Chile.

The significant forearc and intra-arc basins are in two groups, one along the Peruvian and Ecuadorian coast (extending marginally into northern Chile) and the other along the southern Chile coast. These basin groups of somewhat different geology are separated by the 900-mi (1,400 km) strip of Chile north of Valpariso. The continental shelf of this apparently barren strip is only 3 to 12 mi (5 to 20 km) wide and the continental slope is abrupt; some forearc basins may exist, but they would be of no appreciable size.

Peruvian and Ecuadrian Coastal Basins

In the following discussion the forearc basins, Talara, Progreso, Esmeraldas-Caraques, Trujillo, Lima, and Mellend-Tarapaca, will be discussed first, followed by the nearby and parallel intra-arc basins, Lacones, Manabi, Borbon, Sechuru, Salaverry, Pisco and Moqueqa.

Forearc Basins

Figure 194 shows the distribution of the coastal basins of Peru and parts of Ecuador and Chile, and figure 195 their tectonic setting in the northern part of the region. The only producing basins of the South American Pacific coast, the Talara and Progreso basins, have anomalous features compared to the usual forearc basin trend. For one thing, they lie seawards of the Coastal Range (which has been interpreted as a "trench-slope break" or "outer-arc ridge" by Lonsdale, 1978) and, therefore, these basins might be termed trench-slope basins rather than forearc basins. This unique basin position may result in substantially more exposure of the sediments to the effects of nutrient-rich upwelling prevalent along the Pacific coast.

Secondly, and perhaps more significantly, is the basin's position at the intersection of the main subduction trend and the Dolores-Guayaquil Megashear, a profound first order tectonic boundary. The Dolores-Guayaquil Megashear in the Talara-Progreso vicinity may be an extension and reactivation of the much older Tumbes-Guayana Megashear (fig. 195). The magnitude and significance of this megashear is attested by several observations which include: 1) the juxtaposition of oceanic crust on the north side with continental crust on the south side, 2) the contrasting dips of subduction; in Ecuador the dip is about 30° (Lonsdale, 1978), while south of the boundary in Peru it appears more nearly flat (Stauder, 1975), 3) a south-southwest trending, Quaternary volcanic arc in Ecuador terminates abruptly in the vicinity of the boundary (fig. 195), 4) the subduction edge of the continental crust is accreting in Ecuador, while in Peru and southwards the continental crust is being eroded by subduction (Lonsdale, 1978, Shepard and Moberly, 1981), and 5) the south-southwest structural trend of Ecuador becomes south-southeast south of the megashear in Peru.

The Dolores-Guayaquil megashear has a dextral movement so that Ecuador west of the megashear moved northwards, apparently opening a pull-apart basin, approximating the Gulf of Guayaquil at the megashear's abrupt westward swing (or Tumbes-Guayana Megashear extension) (Shepard and Moberly, 1981) (fig. 195). This pull-apart basin encompasses the Progreso basin and abuts against the Talara basin.

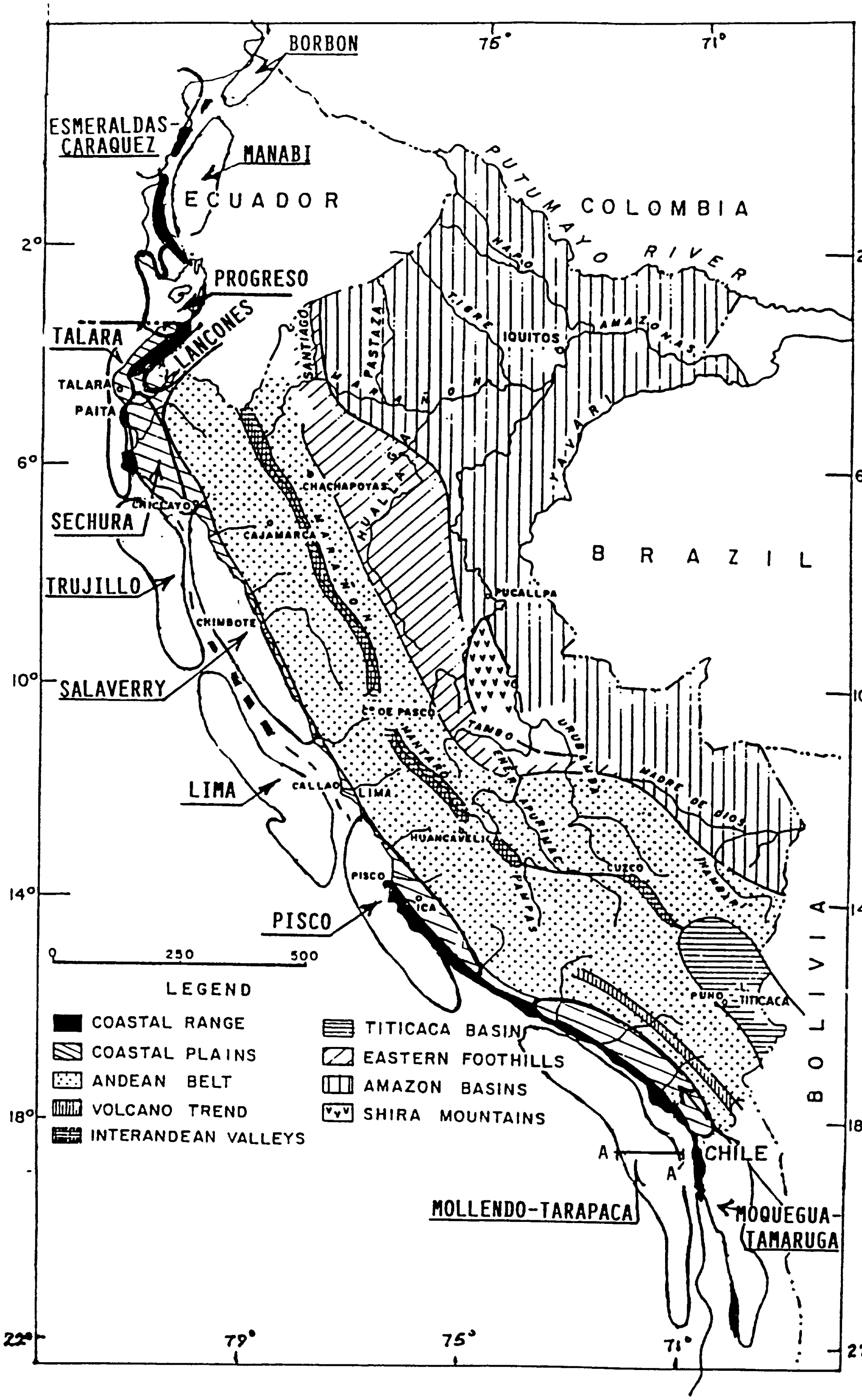


Figure 194 Map of Peru and adjoining Ecuador and Chile, showing coastal basins and their relation to the Coastal Range, an outer arc ridge or slope-break ridge (modified from Travis et al, 1974).

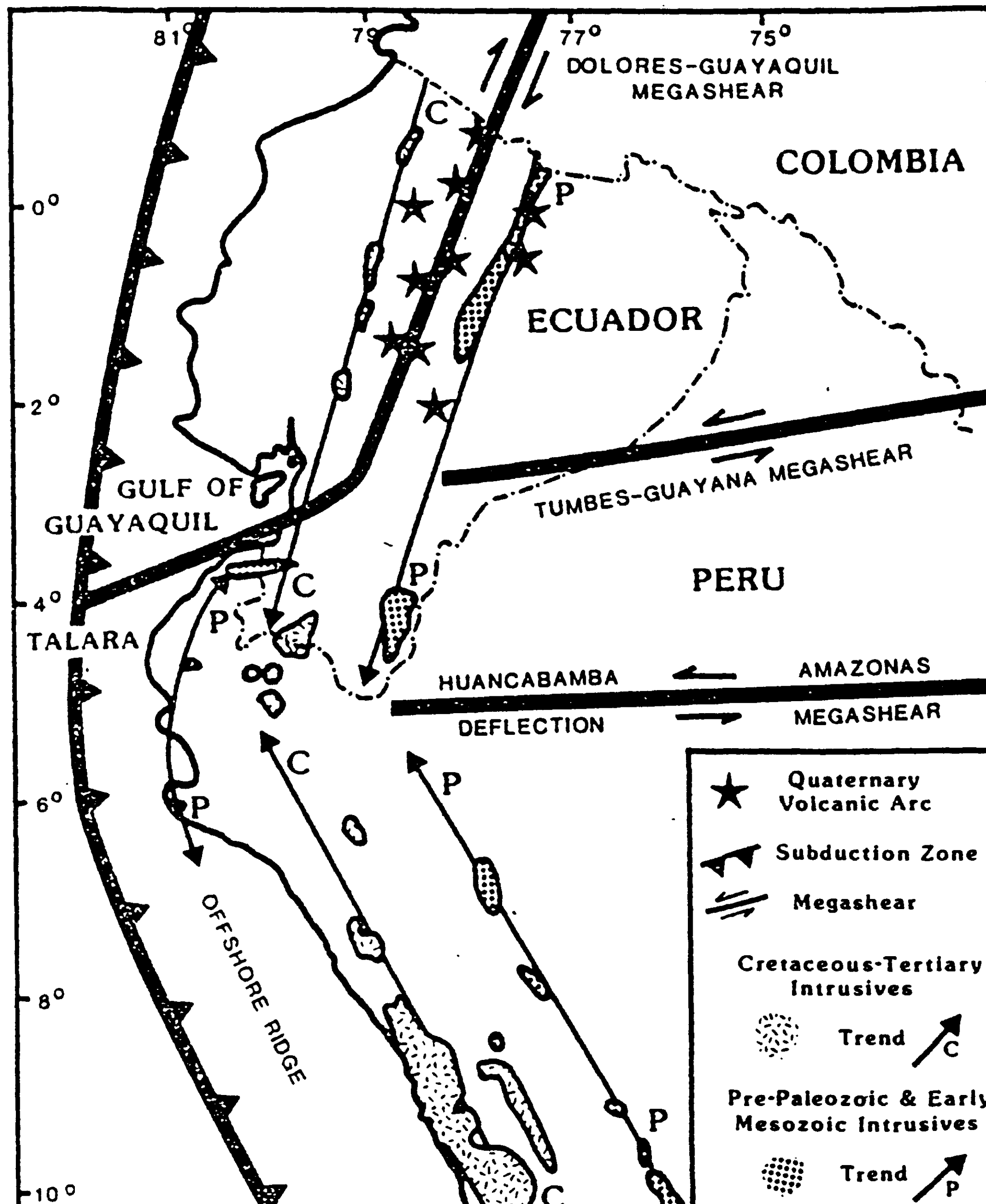


Figure 195 Structural map of coastal Peru and Ecuador showing subduction zone, megashears, volcanic arc, and Cretaceous-Tertiary and pre-Paleozoic and Early Mesozoic intrusives, after Zeil (1979) and Shepherd and Moberly (1981) (from Marsalaglia and Carozzi, 1990).

Talara basin

Area: 6,400 mi^2 (16,500 km^2) (to the 3,000 ft or 1,000 m isobath) More than half the area is offshore.

Original Reserves:	1.816 BBO	2.699 TCFG
Onshore	1.526	2.114
Offshore	.290	.585

(from Petroconsultants 1990)

Description of Area: The basin lies on the extreme north of the Peruvian coast (fig. 194). It is bounded on the east and southeast by the Coastal Range and on the west and south by the 3,000 ft (1,000 m) isobath. It is limited on the north by a transverse high near the Dolores-Guayaquil Megashear (or the extension of the Tumbes-Guayana Megashear) at about the Peru-Ecuador border (figs. 194 and 195).

Stratigraphy

General. The sedimentary rocks of the Talara basin consist of shale, sandstones and conglomerate which were deposited largely in a fan-delta complex. They range in age from late Cretaceous through Eocene. Carbonate facies occur only in the lowermost Cretaceous beds (Muerto and Pananga Formations) and in the Plio-Pleistocene sections (fig. 196). The maximum thickness of the sedimentary fill may reach 42,000 ft (12,750 m) (Feininger and Brestow, 1980) but measured thicknesses are locally affected by intensive and complicated normal faulting. The rocks represent deep marine to fluvial depositional environments, but appear to be largely marine. Since faulting was apparently continuous through the Tertiary, the Tertiary sedimentation was locally affected by block movements, causing irregular facies distribution. Over syndepositional high blocks, or groups of blocks, reservoirs may be winnowed and of better quality (Klemme, personal communication).

The basement as exposed in adjacent Coastal Range (Cerros de Amotape) consists of Paleozoic sediments and metasediments intruded by Jurassic granites.

The Cretaceous Pananga and Muerto Formations rest unconformably on the basement of metamorphosed rock and Jurassic plutons and consist of bituminous limestones (fig. 196). They are overlain by Cretaceous through Paleocene units of conglomerates, sandstones and shales. Overlying the Paleocene strata is the lower Eocene Basal Salina Formation, a transgressive sequence consisting of shales, siltstones and conglomeratic sandstones. Overlying deposits include Eocene shales, sandstones and conglomerates.

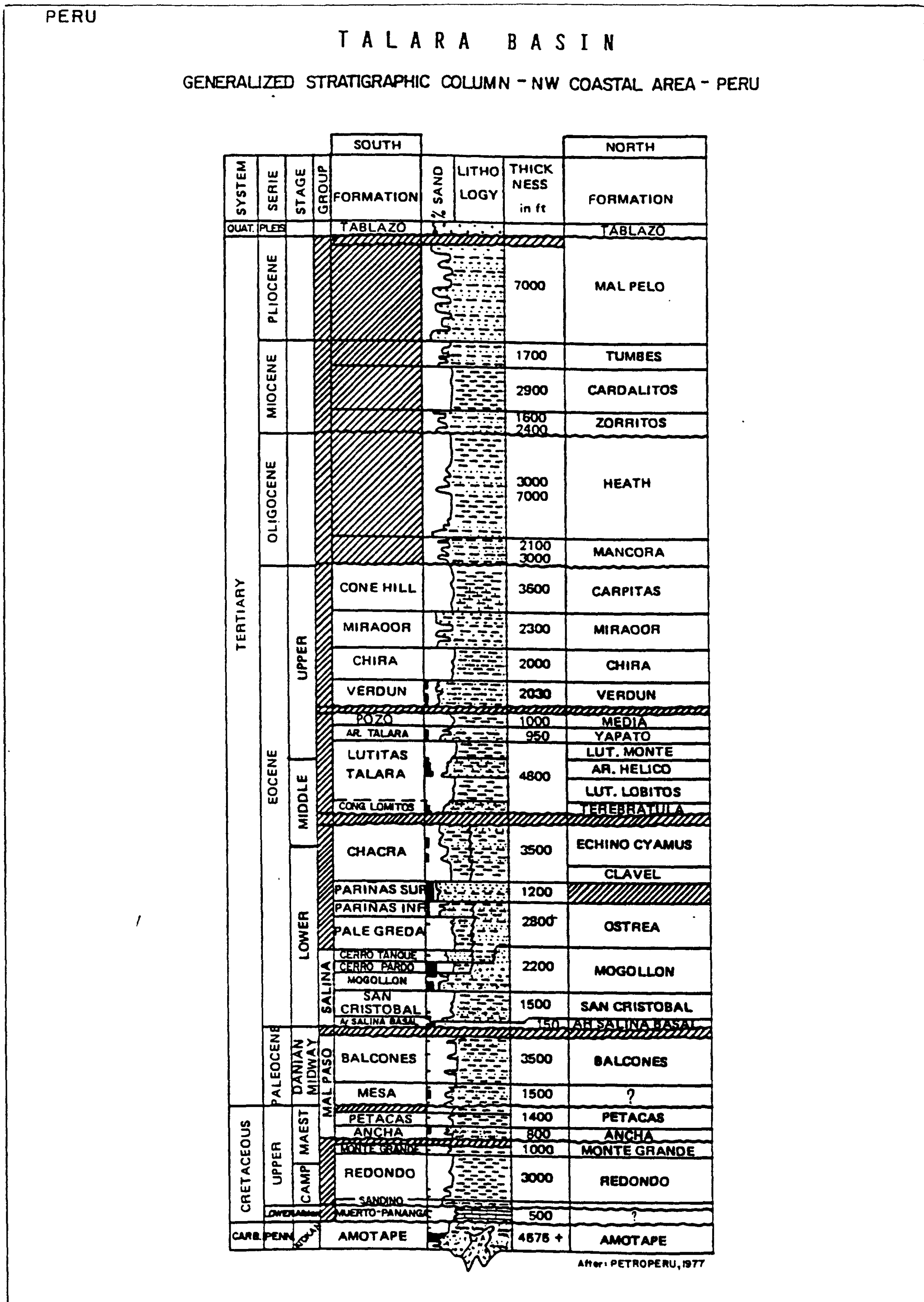


Figure 196 Generalized stratigraphic column of south and north Talara basin (after Petroperu, 1977, from Petroconsultants, 1989).

In the southern part of the basin all post-Eocene strata are missing, but to the north, more than 20,000 ft (6,000 m) of upper Tertiary shales and sandstones are present.

Source. Source rock data are not available. The Albian Muerto limestone is black and emits a strong petroleum odor when fractured. The Campanian Rodondo Formation shale is black in part, as is the Maastrichtian Petacas shale. Travis et al, 1974, state that the Cretaceous strata have good source potential. The black Paleocene Balcones shales and the Salina shales are similar to the Pelacas and Redondo shale (Travis, 1953) and so they may also be considered source rock. The overlying Eocene shales are also dark and may have source potential.

The position of the Talara and Progreso basin outside the outer arc ridge and exposed to upwelling nutrients may explain in part the richness of this forearc oil province.

Greater-than-normal heating of the source shale in a forearc setting, which normally has a low thermal gradient, may have occurred as a result of 1) unusually deep subsidence evidenced by the very thick (26,000 ft, 8,000 m) Eocene deposition, or by 2) the heat flow accompanying the attenuation of crust in the adjoining Gulf of Guayaquil pull-apart basin.

Reservoirs and seals. Marsaglia and Carozzi (1990) who studied the Basal Salina Formation, noted that the reservoirs have an unusually big quartz content in comparison to other forearc sandstones. The principal Eocene reservoir (Parinas Formation) is even more quartzose. This is another explanation, besides the higher thermal condition and arc position for the unique forearc petroleum abundance in the Talara basin. The provenance of the quartz is probably the granite-containing Coastal Range of northern Peru which extends southward at least as far as 8° south (fig. 195). Northwards, in Ecuador the Coastal Range is volcanic and ophiolitic, a poor quartz provenance.

The principal reservoirs of the basin are sandstones in the Parinas Formation. The sandstones range from fine-grained to conglomeratic with a few shale breaks. It is better sorted and more quartzose than most of the other Eocene sandstones (Marsaglia and Carozzi, 1991). The Parinas section is some 400 ft (120 m) thick in two distinct sandstones separated by 100 ft (33 m) of shale; the upper unit has high porosity and permeability but the lower unit is tight. In a typical field, the Monte Pool, for instance, the reservoir averages 102 ft (31 m) in thickness with a porosity of 25.5 percent and water saturation of 49 percent (Travis, 1953).

Other productive reservoirs are sandstones in the Basal Salina and Verdun Formations which together account for 23 percent of the production. There are no appreciable reservoirs in the Cretaceous or Paleocene section. Fracture porosity, and especially permeability, are important reservoir attributes of the Talara basin. The potential of a given prospect depends largely on the presence of sufficient reservoir.

Seals are provided by the shales, but the area is badly faulted and surface seeps abound.

Structure

There is no folding, but the basin is intricately normal-faulted (fig. 197). The structurally high areas of the oil fields are caused by relative uplift among intense block-faulting (fig. 198). Movement of large masses of rock on low angle (7°) surfaces, extending from more than 10 kilometers (Shepherd and Moberly, 1981), probably representing gravity slides, create chaotic zones (fig. 197). Submarine slumping and post-consolidation sliding is also recognized (Travis et al, 1975). The normal faulting of the region began in late Cretaceous and continued into the Cenozoic (Parodes, 1958). Although some of the faulting appears to be syndepositional, most of the faulting is post-Eocene, cutting all Eocene strata. It would appear that the Talara basin structure is dominated by the extension tectonics as would be expected of an area abutting a pull-apart basin such as supposed in the case of the Gulf of Guayaquil-Progreso basin.

A major conclusion of authors who have studied the Andes area is that there was a regional uplift of 10,000 to 13,000 ft (3,000 to 4,000 m) since Pliocene time which is still continuing (Quechua phase) (Shepherd and Moberly, 1981). This regional uplift probably affects the Talara area, and may account for the unknown amount of missing middle and upper Tertiary strata.

Exploration for and definition of traps is difficult since each of the many fault blocks has an individual structural position, a separate oil-water contact, and, therefore, a different oil pay. A field is not a single defined closure, but rather irregularly-shaped areas (or trends) of high blocks. These irregular shaped areas generally trend in an east-west direction, at nearly right angles to the regional structural trend (fig. 198).

Generation, Migration, and Accumulation. There are source rocks of unknown quality in the basin; they may be organically richer than most basins owing to their position outside the outer arc ridge, where they were exposed to the upwelling, rich nutrients prevalent on the South American Pacific coast.

The original thickness of the Eocene section is as much as 26,000 ft (8,000 m) and this is assumed to represent the cumulative Eocene basin subsidence. Since source beds are apparently present down to the base of the Eocene, sufficient subsidence for source shale maturation would have been reached at least by late Eocene, even given the low heat-gradient expected in a forearc setting. The Talara basin, the only appreciable forearc oil-producer of South

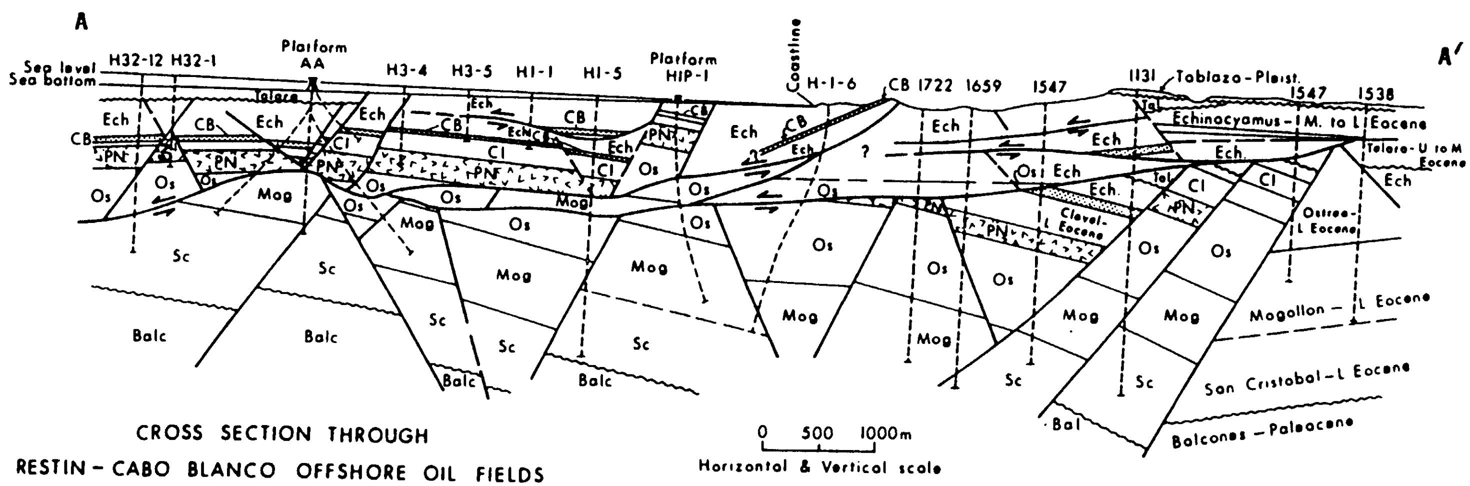


Figure 197 Simplified cross-section through the offshore Humboldt Norte and on-shore Los Organos-el Alto oil field complexes, Talara basin. Abbreviations indicate north Talara formations (fig. 196) Approximate location figure 198 (from Shepherd and Moberly, 1981).

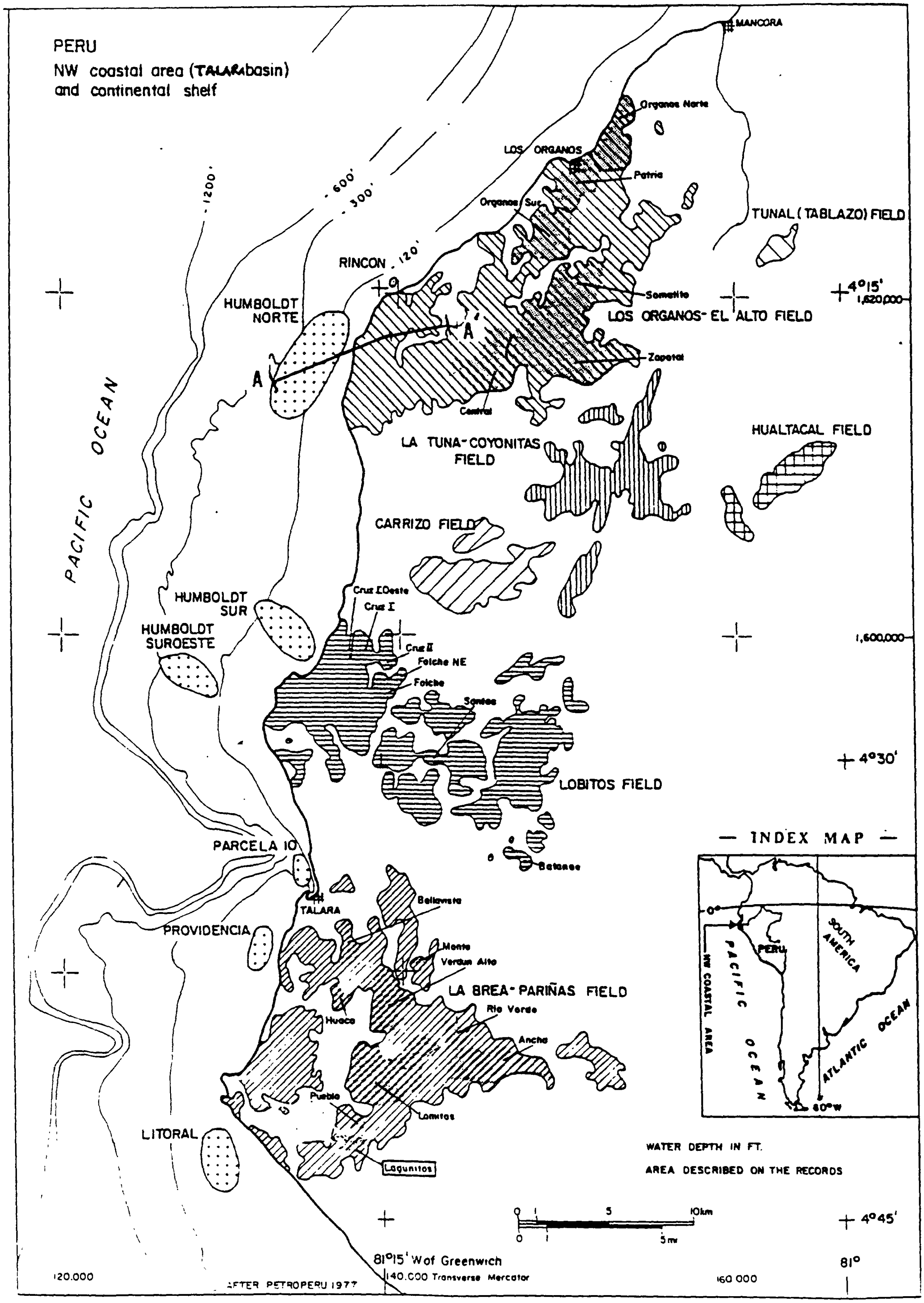


Figure 198 Index map of Talara basin showing location of oil fields. Approximate position of section A-A (fig. 197) (from Petroconsultants).

America, significantly appears to have the thickest sedimentary section, perhaps indicating the deepest subsidence and, thus, the most heat exposure. Another anomalous factor concerning the Talara basin is its position adjoining a major regional megashear which may have generated extra heat while causing the pull-apart basin or graben of the Gulf of Guayaquil.

Some migration and accumulation may have occurred prior to most of the faulting. In general, the faults appear to be seals rather than conduits, with little correlation of fluid levels from one adjoining block to another. However, oil and gas must have been leaking through most of the Tertiary as indicated by the abundant surface seeps. The main limit on petroleum volume appears to be related to uncertainties regarding reservoirs.

Plays. The principal play in the Talara basin is for petroleum in the Lower Eocene Parinas sandstone reservoirs within fault-blocks. Other plays would be for the basal Eocene Basal Salina, Upper Eocene Verdon and other Eocene sandstones.

History of Exploration and Petroleum Occurrence. Oil from seeps and shallow holes was recovered from the Talara area for centuries. The first oil well was drilled in 1874; by 1920 nearly 1,000 wells had been drilled, by 1952 4,000 wells, and by 1984 more than 9,000 wells. Offshore drilling began in 1960. The great number of wells was necessitated by the intricate normal-faulting with each fault block having different fluid levels. The onshore Talara basins appears to have reached exploration maturity and only a small amount undiscovered oil and gas remain. Offshore exploration has been successful, but probably limited by the economics of testing small individual pools.

Estimation of Undiscovered Oil and Gas.

There appears to be only a minimal amount of undiscovered oil and gas in the maturely-explored onshore portion of the basin. Consensus is that offshore and onshore geology of the Talara basin is essentially the same (fig. 197). Having approximately the same area, therefore, the offshore area should have about the same reserves as onshore, i.e., 1.5 BBO and 2.00 TCFG. Subtracting the already discovered (.3 BBO and .6 TCFG), the undiscovered oil and gas of the Talara basin, essentially all offshore, should be 1.2 BBO and 1.4 TCFG.

Progreso Basin

Area: (Gross estimates as boundaries ill-defined)

Total:	7,500 mi^2 (19,400 km^2)	
Santa Elena Subbasin:		1,400 mi^2 (3,600 km^2)
Progreso S.S. Subbasin:		1,800 mi^2 (4,700 km^2)
Gulf of Guayaquil subbasin		4,300 mi^2 (11,000 km^2)
	Ecuador:	3,000 mi^2 (7,700 km^2)
	Peru:	1,300 mi^2 (3,300 km^2)
Total Ecuador:	6,200 mi^2 (16,000 km^2)	
Total Peru	1,300 mi^2 (3,400 km^2)	

Original Reserves:			
	Peru:	4 MMBO	40 BCF
	Ecuador:	127 MMBO	211 BCF
		.131 BBO	.251 TCFG

Description of Area: The Progreso basin has been defined variously by different authors. Here the Progreso basin is taken to include all the area seaward of the Coastal Range and out to approximately the base of the continental slope or about the 3,000 ft (1,000 m). It extends from the Talara basin at the Zorritos ridge near the Peru-Ecuador border (at intersection of the south-bounding Dolores-Guayaquin Megashear with the Peru trench) northward to about 2°N latitude, (figs. 194, 195, 199). As so defined, it includes three separate tectonic provinces or subbasins: 1) Santa Elena shelf or subbasin, 2) the Gulf of Guayaquil rifted area or subbasin, and 3) the southeast-plunging graben or rifted area to the north (Progreso subbasin, sensu stricto) (fig. 199). The Progreso basin is 85 percent in Ecuador and 15 percent in Peru (where it is often referred to as the Tombes basin).

Stratigraphy

The basement of the Progreso basin is taken to be the Pinon Group, a complex of volcanic rock which is regarded as part of the oceanic crust and extends over western Ecuador northwest of the Dolores Guayaquil Megashear (figs. 195 and 200).

The lower part of the Progreso basin section, i.e. the upper Cretaceous, has only been encountered in the Santa Elena Peninsula area, overlying the Pinon Group by gradational contact. It is the

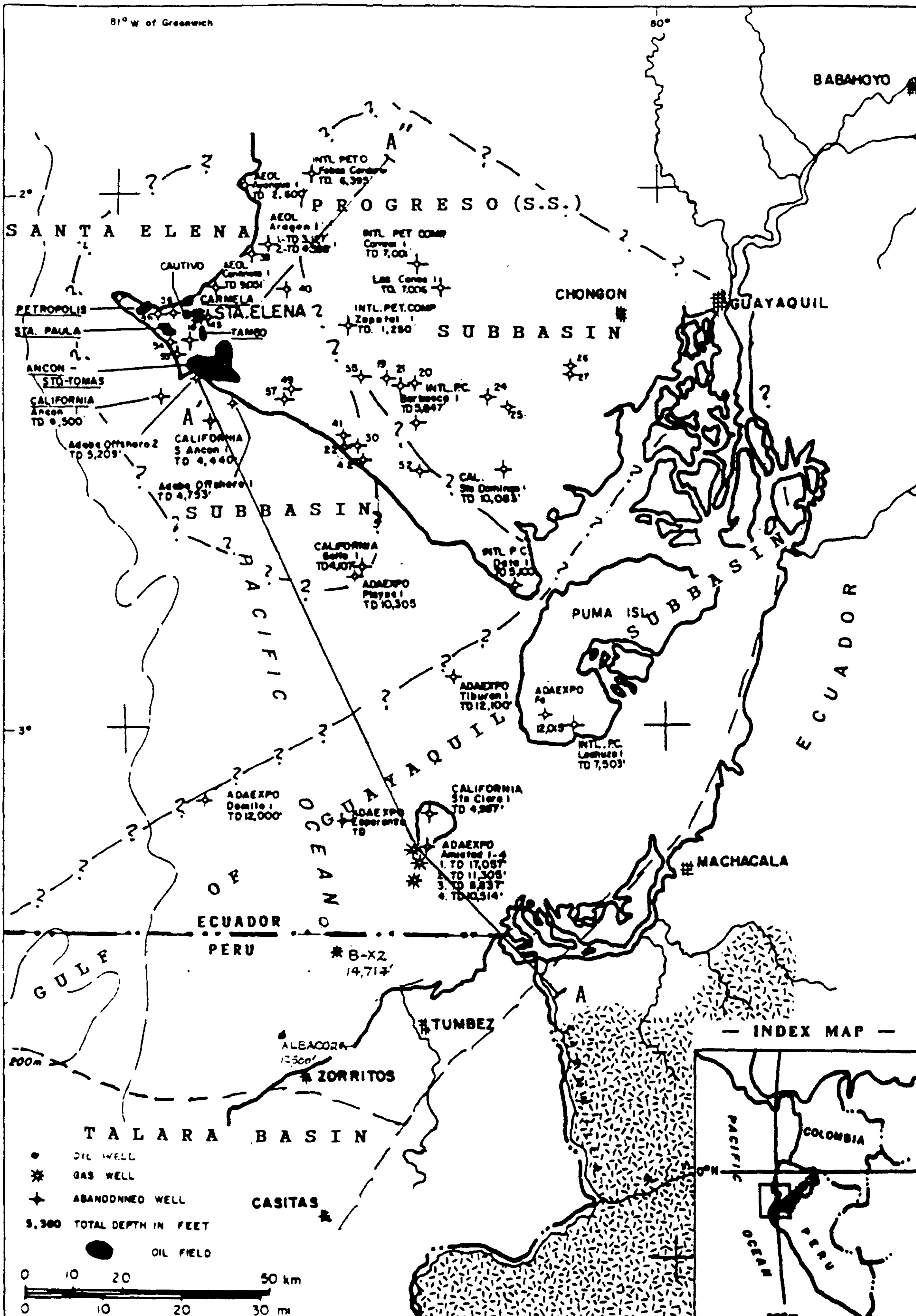


Figure 199 Index map of the Progreso basin showing fields, important wildcats and approximate areas of subbasins (modified from Petroconsultants).

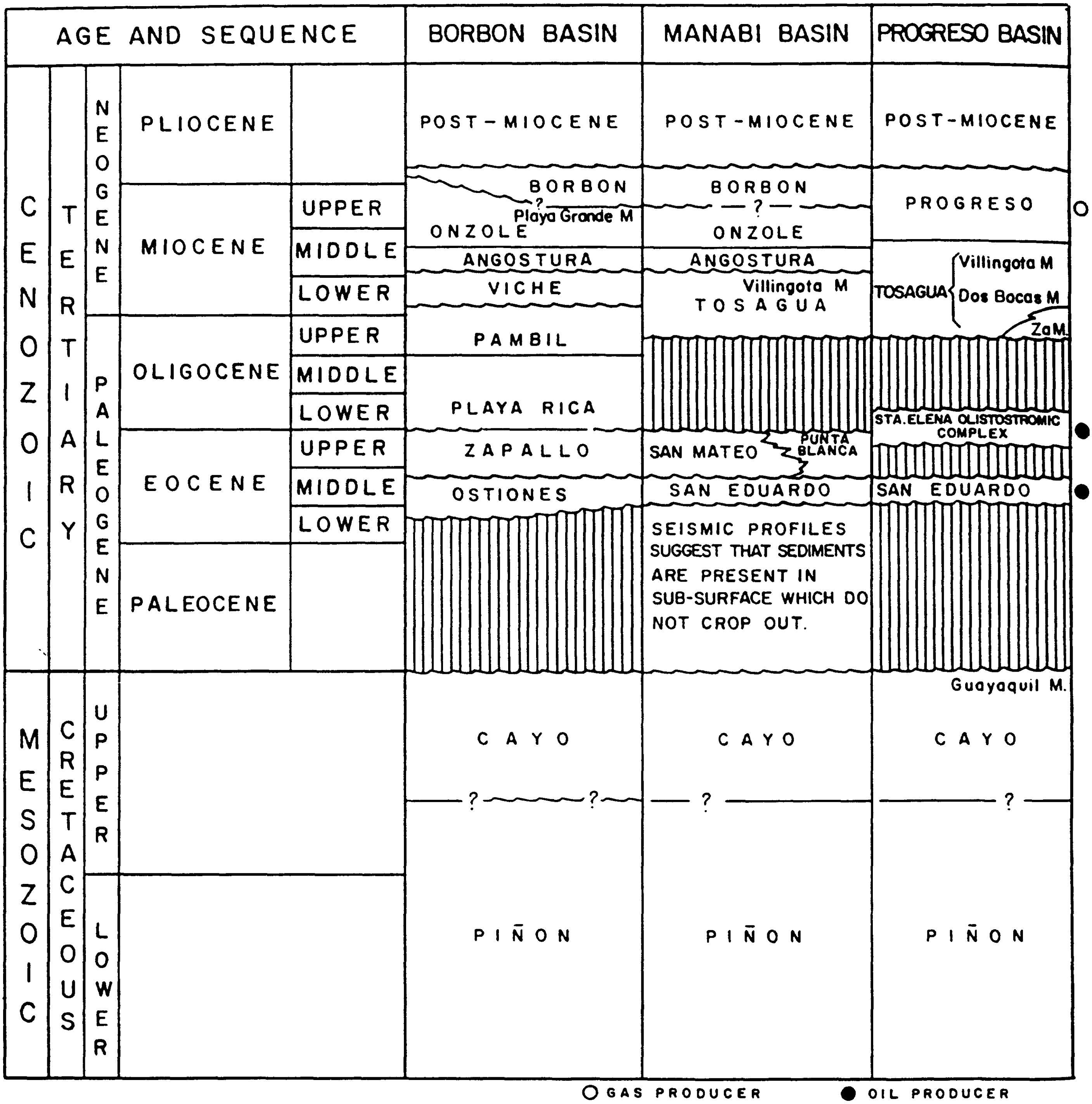


Figure 200 Stratigraphic sections of three principal coastal basins of Ecuador (from Rosania, 1989).

Cretaceous deep-water Cayo Formation of shales, argillites, cherts and tuffaceous sandstones with a thickness of 11,000 to 13,000 ft (3,500 to 4,000 m). (This formation is regarded as basement by some).

Disconformably overlying the Cretaceous in foothill outcrops is a relatively thin, argillaceous calcarinate unit (the middle Eocene San Eduardo Formation). In the Santa Elena Peninsula oil field area, the whole interval between the Cretaceous Cayo Formation and the Quaternary is represented by the Santa Elena Olistromic Complex; the complex is deemed to be largely upper Eocene in age (Rosania, 1989). The complex is very chaotic consisting of clay to pebbly clay to turbidite sandstone with olistoliths ranging from igneous and chert blocks in the lower part to sandstone, conglomerate and limestone blocks in the upper part. The principal reservoirs of the area are the very large fragmented sandstone blocks.

This chaotic interval has been separated into a number of groups and formation, with somewhat different age designations, but all in the Eocene and Paleogene (Jarren, 1975). The sedimentary structure, i.e., olistostromes, slides, and pebble beds are similar to features of affecting the Eocene rock of the Talara basin. Although these rocks have so far only been encountered in the Santa Elena Peninsula area, they are believed to lie at depth below most of the Progreso basin.

The Neogene part of the Progreso section largely occurs in the Guayaquil Gulf where it reaches a thickness of 18,000 ft (6,000 m), and in the Progreso sensu stricto area. The Upper Oligocene-Lower Miocene Tosagoa Formation of sandstones on the perimeter grades into shales basinwards and upwards in the section. Overlying by gradational contact is the middle to late Miocene Progreso formation of dark grey silty shales grading upward into grey siltstones and fine-grained sandstones.

<u>Source</u>. Dark grey to black, considerably fractured shales at the basal part of the Santa Elena Olistromic Complex (San Jose Formation, Jarrin 1975) are regarded as the principal source of the Santa Elena petroleum, but other dark shales of the complex may be source contributors. The source of the gas discoveries of the Gulf of Guayaquil is not known; Jarrin (1975) states that shales of the lower part of the Progreso Formation towards the center of the basin have characteristics of source rock. It appears, however, that the deeply-buried Eocene rocks would be a good possibility for gas source.

<u>Reservoirs and Seals</u>. The principal reservoirs of the Santa Elena Peninsula area are large, fragmented sandstone block olistoliths of Eocene age, which are not continuous, mappable reservoirs. The reservoirs of the Gulf of Guayaquil gas are sandstones in the lower part of Miocene Progreso Formation; the net pay reaches a thickness of 400 ft (122 m) in the Amistad gas field.

Seals are shales, but the dense faulting pattern allows for significant leakage, especially in the Santa Elena Peninsula area. In the Gulf of Guayaquil and Progreso (sensu stricto) subbasin, thick Tertiary shales and less faulting ensure better sealing.

Structure

The Progreso basin, as here defined, lies seaward of the Coastal Range which has been interpreted as a "trench-slope break" or "outer-arc ridge" making the Progreso basin, in part, a "trench-slope basin" (Lonsdale, 1978) (fig. 194). Superimposed on the east side of the basin is the Gulf of Guayaquil graben or pull-apart subbasin (fig. 201) conjectured to have been formed by the separation of western Ecuador from western Peru by dextral strike-slip movement on the Dolores-Guayaquil Megashear (Shepherd and Moberly, 1981). A subsidiary Neogene southeast-plunging subbasin, the Progreso (sensu stricto) subbasin along the north side of the basin, adjoins the Gulf of Guayaquil subbasin (figs. 199 and 202). The basin, therefore, is divided into three structural subbasins, the Santa Elena Peninsula, the Gulf of Guayaquil and the Progreso (sensu stricto) subbasins. It is assumed that the area was subjected to the same uplift postulated for the Talara basin, i.e., an uplift which began in the Pliocene and is continuing to date (Quechua Phase).

The Santa Elena Peninsula subbasin is structural similar to the Talara basin, having no folds but being complexly normal-faulted and having strong evidence of syndepositional faulting, gravity-sliding with olistostrome movement involving Paleocene and Eocene strata. It would appear that this petroliferous area was once a shallower continuation of the petroliferous Talara basin.

The intervening Gulf of Guayaquil subbasin, a deep embayment in the otherwise accurate coastline of northwestern South America is a Neogene graben or pull-apart feature adjoining the Dolores-Guayaquil Megashear which separates the oceanic-crust-floored western Ecuador from the continental-crust-floored eastern Ecuador and Peru. Not shown on the Gulf of Guayaquil geologic section (fig. 201) is that besides the graben-forming normal faults are young listric faults.

The Progreso (sensu stricto) subbasin is also a Neogene graben of similar structure and stratigraphy, plunging to the south and joining the Gulf of Guayaquil subbasin.

Potential petroleum accumulations would be in fault traps or drapes. In the Santa Elena Peninsula area, the normal faulting is dense and intricate and often the trap size and existence depends on the shape and distribution of the olistostrome reservoirs. The Gulf of Guayaquil fault blocks are presumed to be less complicated and larger. Rollovers associated with listric faulting also form potential traps in the Gulf of Guayaquil subbasin.

SCHEMATIC CROSS SECTION OF GULF OF GUAYAQUIL

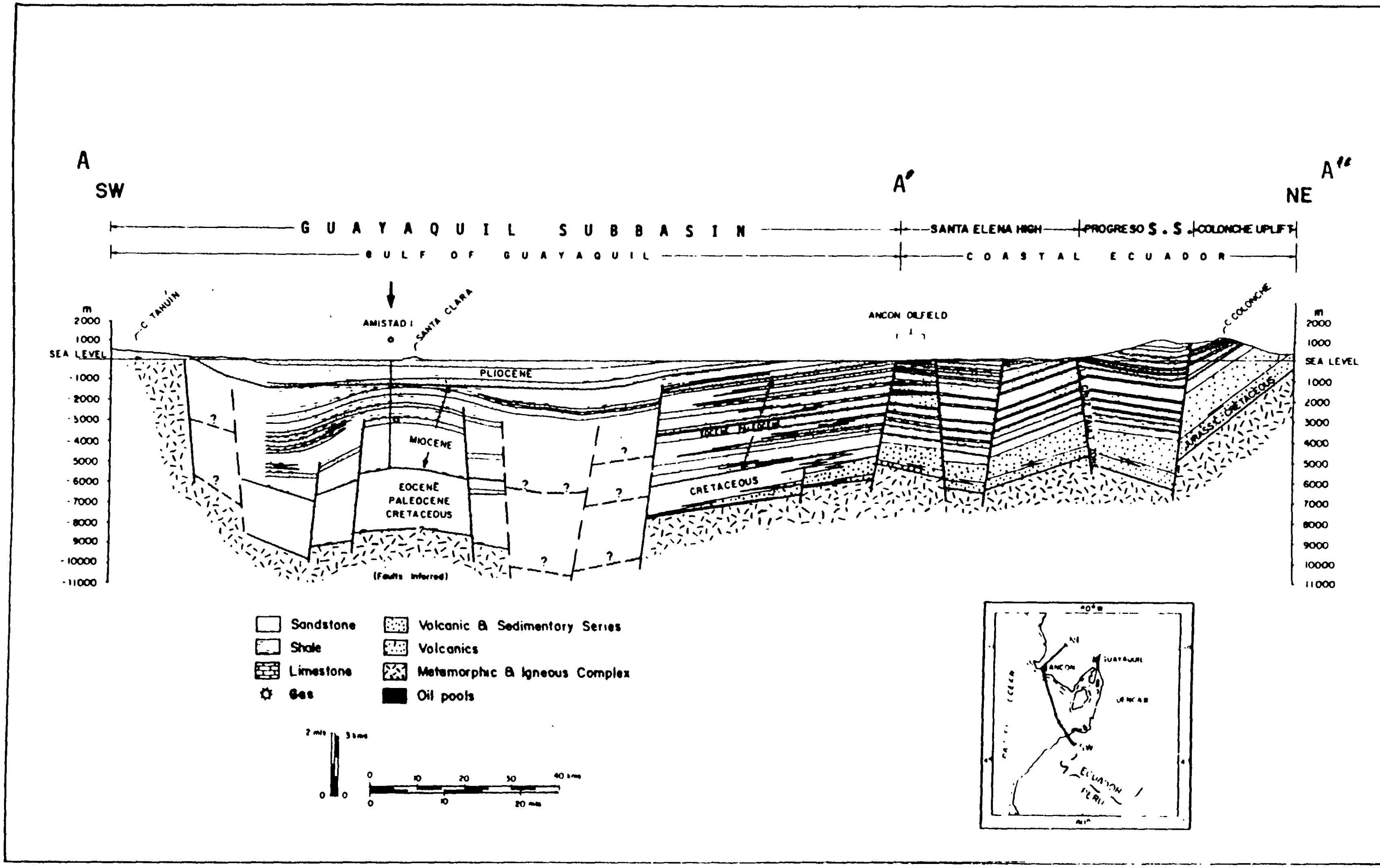


Figure 201 Schematic SW-NE cross section of the Gulf of Guayaquil. Location figures 199 and 202 (from Petroconsultants, 1989).

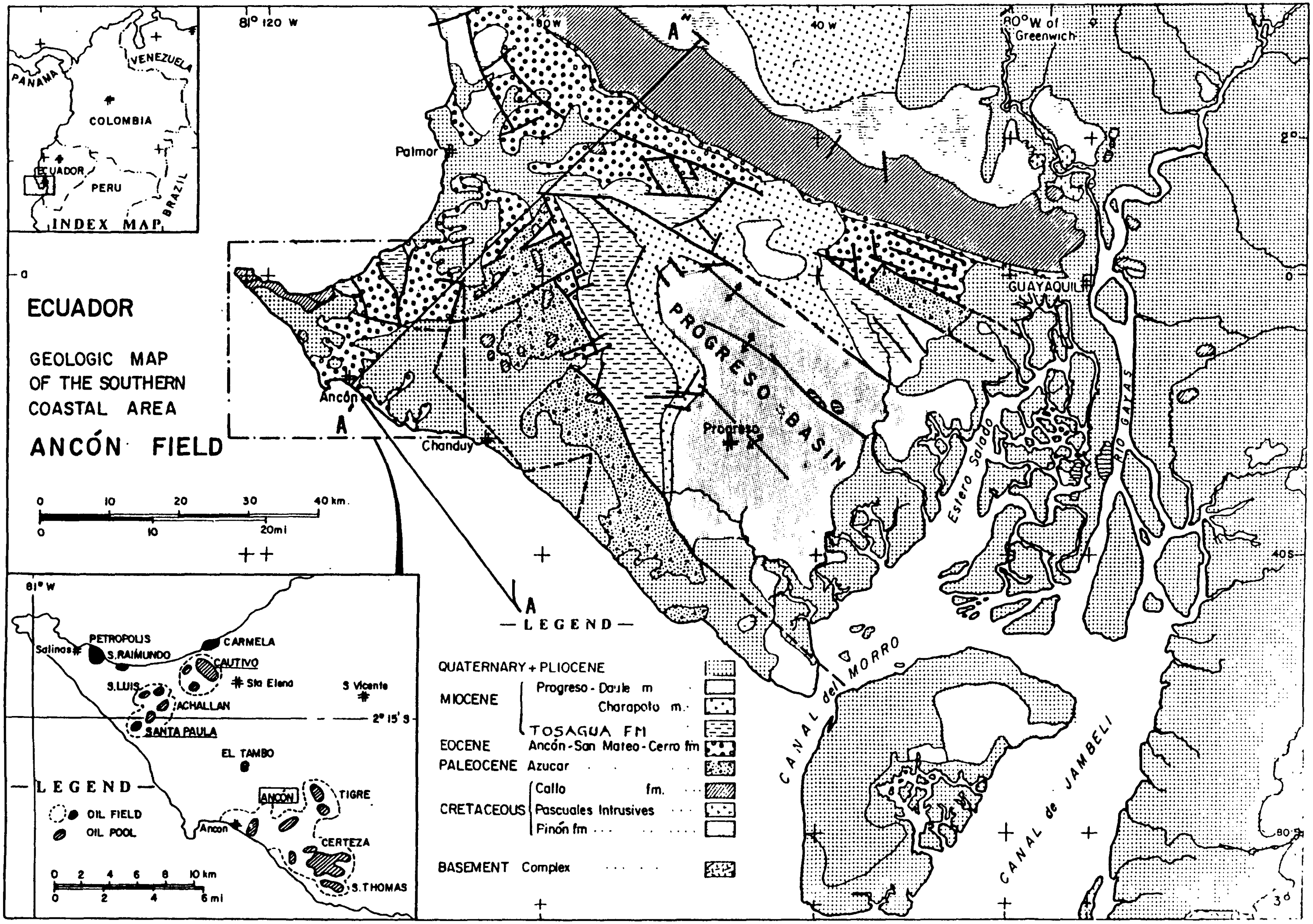


Figure 202 Geologic map of the Progreso (sensu stricto) and Santa Elena Peninsula subbasins and location map of fields of the Santa Elena Peninsula area (modified from Petroconsultants, 1989).

Generation, Migration and Accumulation. Early generation and migration of petroleum in this, usually unfavorable, forearc setting is believed to be similar and contemporaneous with that of the Talara basin. Petroleum generation from Paleocene and Eocene source shales began in the later part of the Eocene, the heat being supplied by an unusually deep Paleogene subsidence and/or by the effects of the heat flux accompanying the Gulf of Guayaquil pull-apart basin formation. As in the Talara basin, the limiting factor for petroleum accumulation is the presence of reservoirs. Trap formation appears to have been almost continuous, the normal-faulting affecting the Paleocene and Eocene sediments began in the Cretaceous and continued through the Eocene. The Gulf of Guayaquil and Progreso (sensu stricto) subbasin fault traps would receive hydrocarbon by primary migration from the deeply buried Eocene source shales or from deeply subsided Progreso shales.

Plays. There appear to be two principal plays in the basin: 1) Eocene olistostromes and small fault block closures in the Santa Elena Peninsula subbasin and perhaps at depth in the other subbasins, 2) drape, normal-fault or rollover closures involving Miocene Progreso and Tosagua sandstones in the Gulf of Guayaquil and Progreso (sensu stricto) subbasins.

Exploration History and Petroleum Occurrence. The first wildcat was completed in the Santa Elena Peninsula area in 1911 and drilling was continuous from 1919 to the late 1960s. The area is considered maturely explored (fig. 199) with modern exploration techniques. A few more fields may be discovered but they would be small of size. Some wildcats offshore of Santa Elena Peninsula have been drilled with no success (fig. 199).

The first discovery in the Gulf of Guayaquil subbasin was the onshore, now-abandoned, Zorritos oil field made in 1870 at the south end of the basin. Through the years the field produced 4 MMBO. Nearby Peruvian offshore wells found encouraging amounts of oil, but not enough for development (fig. 199). In early 1970 three gas wells were completed in the Armistad field in the axial part of the subbasin (fig. 199), which is reported to have reserves of 3 TCFG (Yrigoyen, 1991) but has not been developed. No discoveries have been made in the Progreso (sensu stricto) basin.

Estimation of Undiscovered Oil and Gas

The Santa Elena Peninsula subbasin has a similar geology to the Talara basin with which it probably was connected in Paleogene time. However, the Santa Elena stratigraphic section appears to be much thinner and more complicated and of probably of a lower thermal gradient, overlying oceanic crust. The area is maturely explored onshore, but the offshore area is not.

The amount of offshore prospective area adjoining the Santa Elena Peninsula appears, from the exploration drilling pattern to date, to be equal to at least the area of the onshore discovery area. Assuming the offshore is equally as prospective as the onshore area, some 127 MMBO would be present offshore. However, since all the offshore wildcats to date have been dry, this figure may be discounted to at least half and it is estimated that some 65 MMBO may be discovered. There is some associated gas in this highly faulted basin, but apparently is of small amounts, only utilized for reservoir injection in production maintenance.

The Gulf of Guayaquil appears to have a good probability for the discovery of more gas, as it seems to be, at least in part, underlain by the same Eocene source beds that underlie the Talara basin and Santa Elena Peninsula areas. In the Neogene, after generation had probably already begun in the Eocene, these Eocene source beds appear to have been down-faulted an additional 20,000 ft (6,000 m) (fig 201), subsiding the source shales and perhaps already generated oil into the gas window. In this rifting process, considerable petroleum would have escaped; probably half of the petroleum that would have accumulated without the Neogene rifting was lost. Areal analogy, on an oil-equivalent basis, to the ultimate resources of the 6,400-mi^2-Talara basin (of 3.7 BBOE), indicates 2.5 BBOE would be in the 4,300-mi^2 Gulf of Guayaquil subbasin. The half of the petroleum not lost in rifting would be 1.25 BBOE. If we assume the petroleum is 90 percent gas, as is surmised from the source-rock depth and discoveries to date, the ultimate resources amount to .13 BBO and 6.8 TCFG. Subtracting out the 3 TCFG Armistad discovery the undiscovered oil and gas amount to .13 BBO and 3.8 TCFG.

The smaller (1,700 mi^2, 4,400 km^2), shallower, and so far unproductive Progreso (sensu stricto) subbasin is deemed half as potentially productive and as gaseous as the Gulf of Guayaquil on an areal basis, indicating undiscovered resources of .03 BBO and 1.3 TCFG.

Altogether, the estimated undiscovered recoverable oil and gas in the Progreso basin amounts to .225 BBO and 5.1 TCFG.

Esmeraldas - Caraquez Basin

Area: 4,600+ mi^2 (12,000+ km^2)

Original Reserves: Nil

Description of Area: Figure 203 indicates the outline of the Esmeraldas-Caraquez basin as known from available data. It is part of a fore-arc basinal trend lying outside the Coastal Range (Jama and Mache Hills). It extends northward from the Talara and Progreso basins into Colombia (where it is represented by the Pacific Shelf basin, Bueno and Govea, 1975).

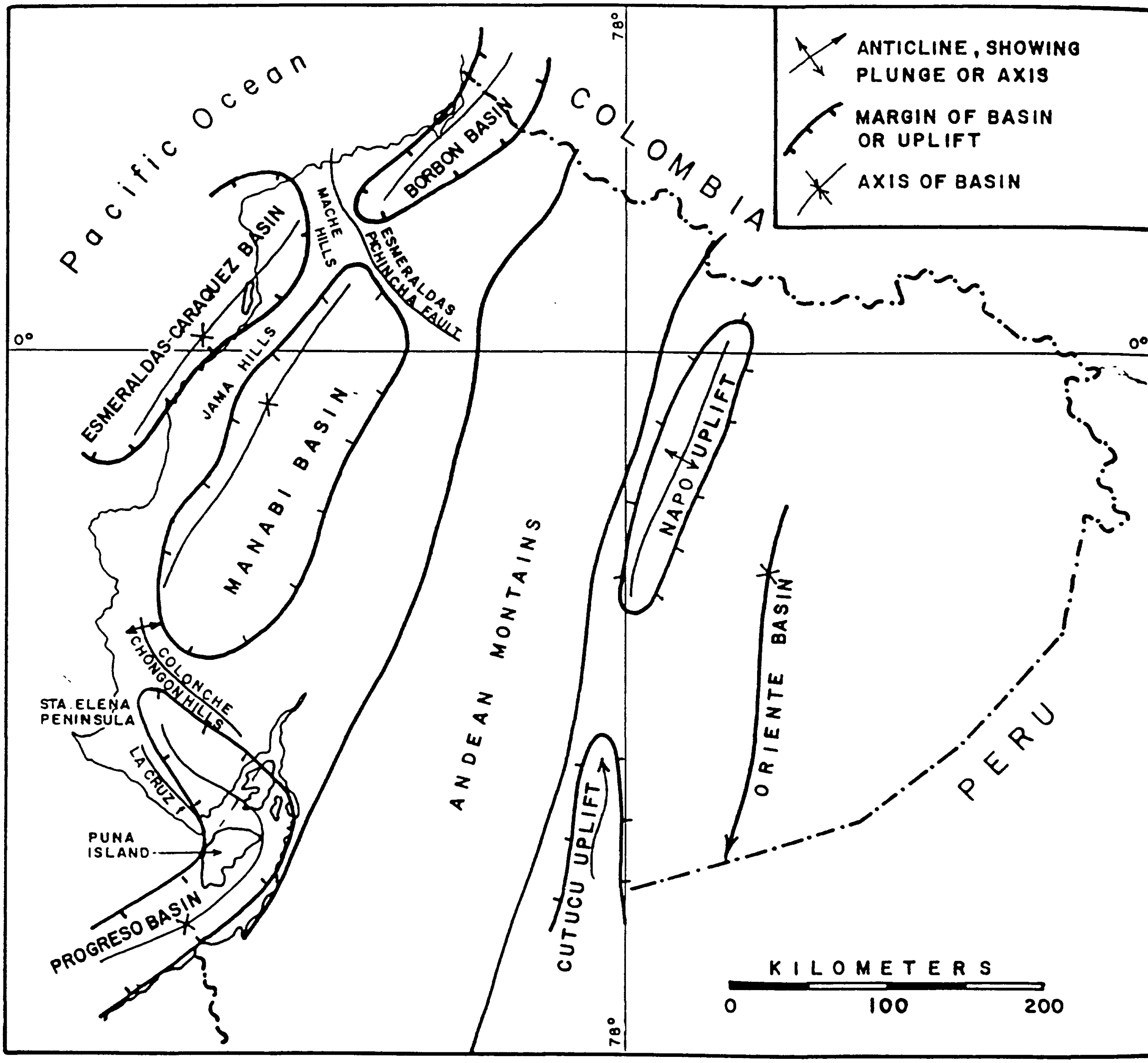


Figure 203 Index map of Ecuador showing the principal sedimentary basins (modified from Rosanio, 1989).

Stratigraphy

Little specific information on this or other offshore basins stratigraphy is published. Rosania (1989) states that the northern part (Esmeraldas) of the basin is geologically similar to the Borbon basin and southern part (Caraquez) is similar to the Manabi basin (figs. 203 and 200).

A wildcat, Camarones-1, drilled onshore at the north onshore end of the Esmeraldas-Caraquez basin, had a total depth of 4,613 ft (1,406 m) to basement and encountered 1,198 ft (365 m) of the Upper Cretaceous Cayo Formation of tuffaceous, silicified, hard clastics. Little is known of the overlying 3,415 ft (1041 m). Rosania (1989) indicates only that the Ostiones Formation of the Borbon basin is not present and that the Zapallo Formation is present which, as in the Borbon basin, has a lower sandy limestone member and an upper clastic member (fig. 200).

Source. Shales in the Middle Eocene Zapallo Formation are considered by Jarrin (1975) to be a possible hydrocarbon source. By analogy to the Progreso and Talara basin which are on-trend and lying outside the Coastal Range, these Middle Eocene shales could indeed be potential source rock.

Reservoirs and Seals. Rosania (1989) indicates that the reservoir characteristics found in the Camarones-1 hole are poor. However, a few sandstones in neighboring Borbon basin do have fair porosities, and that may apply to the Esmeraldas-Caraquez basin. Potential reservoirs that are equivalent to the sandstones of the San Mateo or younger sandstones of the Manabi basin may be present.

Tertiary shales provide reasonably good seals.

Structure. No information is available concerning the structure except the statement that the northern part of the Esmeraldas-Caraquez basin is geologically similar to the Borbon basin while the southern part is similar to the Manabi basin (Rosania, 1989). The structure of the Borbon basin is the result of considerable compression while the structure of the Manabi basin is largely normal- and strike-slip-fault controlled. The structural style of the on-trend Pacific Shelf basin of adjoining Colombia is said to be characterized by intensely folded strata and normal echelon faults stepping down westwards; domelike intrusion which are probably shale plugs are common (Bueno and Govea, 1975).

Generation, Migration and Accumulation. Depth of the basin is uncertain. The Camarones-1 wildcat indicates that the Tertiary source shales are far too shallow, 3,400 ft (1,000 m), to have reached thermal maturation for petroleum. Although the hole is very probably not in the deepest part, it would appear that any potential source beds have not subsided to a sufficient depth for maturation in this presumably cool forearc basin. If, however, the basin is sufficiently deep, generation and migration would most probably have begun during the time of maximum burial in late Neogene, contemporaneously with the late Neogene Andes orogeny and the formation of structural traps.

Plays. There appears to be only one play, that is, petroleum in Tertiary sandstones involved in Neogene fault-associated closures and compressional folds.

Exploration History and Petroleum Occurrence. Two wildcats have been drilled, Camarones-1, in 1944, onshore at the north end of the basin and Caraquez-1 in 1971 offshore at the south end of the basin. Both wells were dry.

Estimation of Undiscovered Oil and Gas

The nearest tectonically similar basins are the petroliferous Progreso and Talara basins which, like the Esmeraldas-Caraquez basin, are outside of the Coastal Range. However, the Esmeraldas-Caraquez basin lacks the very thick Tertiary section of those basins, i.e., up to 42,000 ft (12,750 m) in the Talara basin. It also lacks the anomalous transverse shearing and pull-apart tectonics associated with the opening of the Gulf of Guayaquil. Both of these features are suggestive of higher subsurface temperatures. From the little evidence at hand, it appears unlikely that source rocks have reached thermal maturity for petroleum generation in the Esmeralas-Caraquez basin, assuming the usual low thermal gradient of forearc basins. Accordingly, it is probable that there are only negligible amounts of oil and gas in the Esmeraldas-Caraquez basin.

Trujillo Basin

Area: 6,700 mi^2 (17,400 km^2)

Original Reserves: Nil

Description of Area: The basin lies seaward of the southward submarine extension of the Coastal Range and of the Sechura and Salaverry basins, extending from about latitude 6° to 10° south. It occupies the outer continental shelf and the continental slope (fig. 194).

Stratigraphy

Figure 204 shows a stratigraphic thickness of more than 13,000 ft (4,000 m), thickening westward toward the Trujillo basin depocenter. The thickening is confined to the base-Tertiary-base-Miocene interval and is made by the addition of progressively older, underlying strata towards the basin center. It would appear likely that these older strata may be equivalent to the petroliferous Talara Lower and Middle Eocene.

Petroperu's (1984) Trujillo-basin column (fig. 205) gives details of an up to 11,713 ft (3,570 m) stratigraphic section extending to basement. This section apparently does not represent the section of the basin center. It shows an Upper Eocene to Miocene section, similar and correlatable to that of the adjoining Sechura basin, but with no Lower or Middle Eocene strata (the most petroliferous part of the Talara section). However, the position of the forearc Trujillo basin on-trend and in close proximity to the forearc Talara basin and the additional, progressively older, underlying strata towards the basin depocenter as shown by figure 207 indicates the Talara petroliferous lower Eocene strata may be present in the deeper parts of the Trujillo basin.

Source. There is no source rock data available concerning this basin. The most compelling evidence that source rocks exist is an offshore oil seep at its north boundary with its Sechura basin, 43 mi (70 km) offshore, which has been known for 400 years (Petroperu, 1984). The source rock is probably in the lower part of the section where there has been sufficient burial depth and most likely an extension of the Eocene source shales of the Talara basin.

Reservoirs and Seals. As indicated in figure 205, there are apparently sufficient sandstones for reservoirs and shales for seals in the Upper Eocene and Neogene part of the section.

Structure

The basin is a forearc basin separated from the intra-arc Sechura and Salaverry basins by the southern offshore extension of the Coastal Range. The basin lies largely on the continental slope. It is probably complexly normal faulted as are the Talara and other adjoining basins. Seismic sections indicate normal faulting was most active in pre-Miocene times, but as has been observed in the Talara basin, much of the faulting does not show up in the usual seismic sections. Miocene listric faulting is prevalent (fig. 204).

Traps would be fault- and drape-closures and possibly listric fault-associated rollovers. Petroperu (1984) report "marine reconnaissance seismic work indicates structures of possible interest." By analogy to the Talara basin, dense block-faulting should cause small, complex traps, which in continental slope water depths, i.e., 500 to 10,000 ft (200 to 3,000 m), may cause severe exploration problems.

Generation, Migration and Accumulation. Seeps indicate that generation has occurred and it seems likely that it involved Eocene shales correlative to the source of the Talara oil. Generation and migration probably began in late Neogene near maximum subsidence. At that time Tertiary reservoirs and fault associated traps would be available for accumulation.

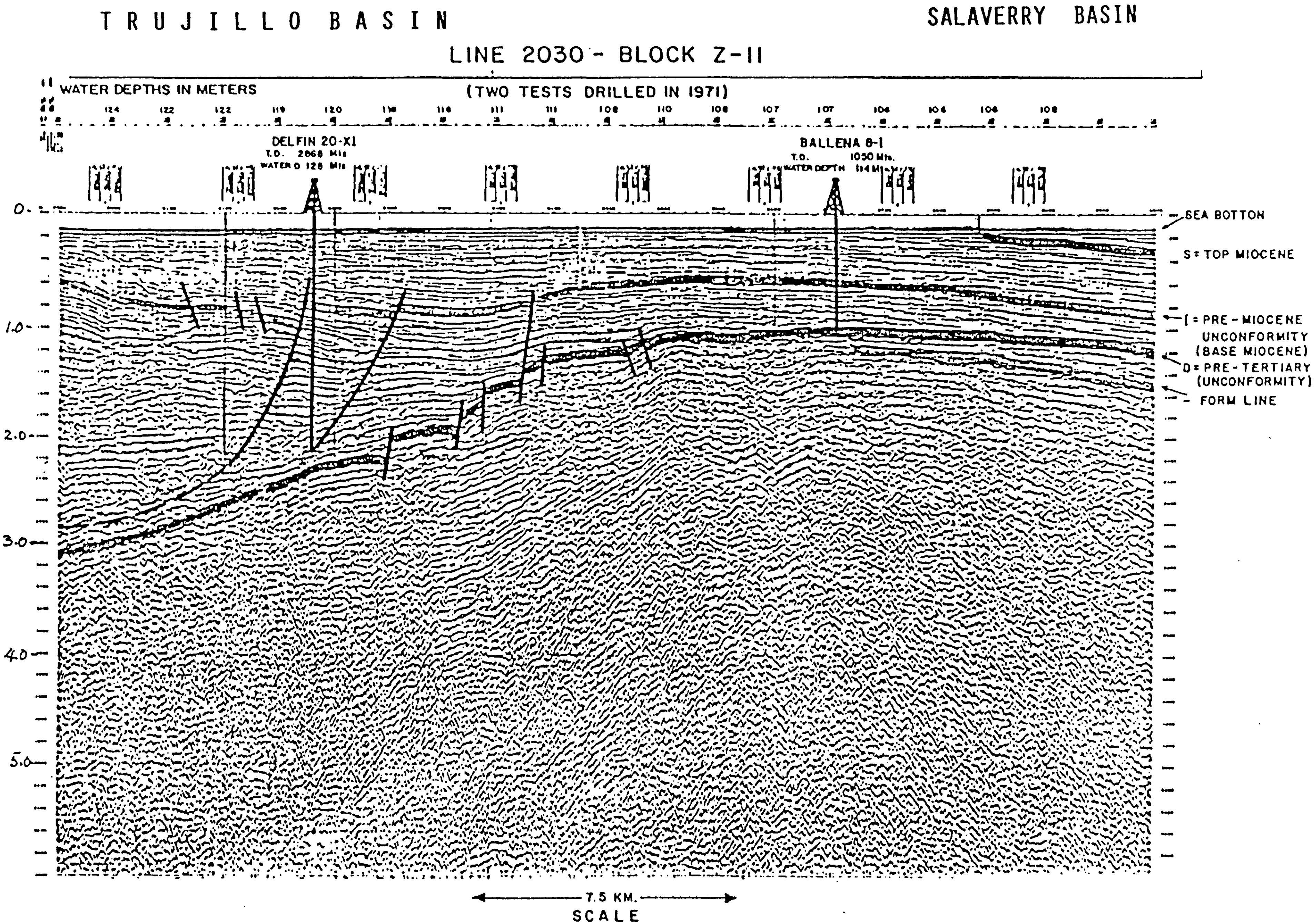


Figure 204 Interpreted seismic section SW-NE through wildcats Delfin 20-X1 and Ballena 8-1 from the east flank of the Trujillo basin over the Coastal Ranges southward subsurface project (outer arc ridge) into the west flank of the Salaverry basin, showing the intepreted top of the pre-Tertiary, the top of the pre-Miocene and the top of the Miocene. Location in Figure 194 (modified from Petroperu, 1984).

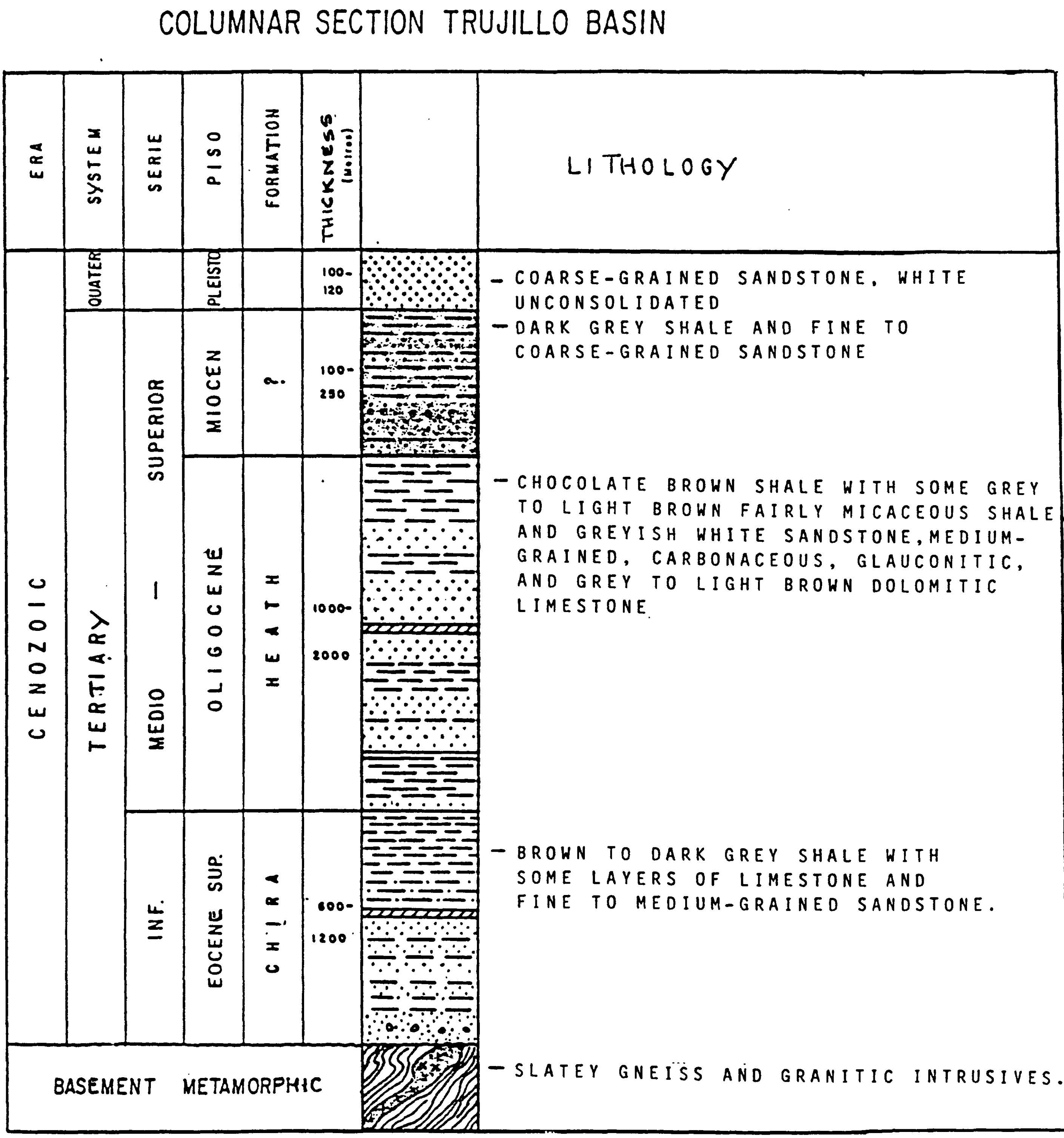


Figure 205 Columnar section, Trujillo basin (from Petroperu, 1984).

However, the amount of petroleum generated in this forearc setting, where thermal-gradients are assumed to be low, depends on greater burial depth of potential source beds. In the Talara basin the sedimentary fill amounts to some 42,000 ft (12,750 m) and Progreso, some 19,000 ft (5,800 m), while in Trujillo basin, the fill is about 13,000 (4,000 m). Another unfavorable factor in comparison to the Talara-Progreso area, is the absence of the Dolores-Guayaquil Megashear and accompanying pull-apart of the Gulf of Guayaquil, which may have raised the thermal gradient of the Talara-Progreso vicinity.

Plays. The principal play is accumulations in Tertiary sandstones in normal-fault and drape closures.

Exploration History and Petroleum Occurrence. As of 1984 some 1,344 mi (2,167 km) marine seismic lines were accomplished. Two wildcats were drilled in 1971 which had no shows. An offshore oil seep, which has been known for 400 years,occurs at the north end of the basin .

Estimation of Undiscovered Oil and Gas

It appears that outside the productive Talara and Progreso basins, the Trujillo basin has the highest petroleum potential of any of the Pacific coast basins of South America. It has generated oil, holds a good possibility of having at least some of the Eocene petroliferous section of the adjoining on-trend Talara basin, has the same tectonic setting as the Talara and Progreso basin, i.e., outboard of the Coastal Range, and has a fairly thick sedimentary fill, i.e., 13,000 ft (4,000 m). However, it differs from the Talara basin in several respects: 1) it apparently has a thinner pre-Miocene Tertiary sedimentary interval, 12,000 ft (3,700 m) versus 26,000 ft (8,000 m), 2) the over-all section is thinner indicating less subsidence and, therefore, lower subsurface temperatures in this zone of low thermal gradients, and 3) it has nothing comparable to the transverse Dolores-Guayaquil Megashear and the opening of the pull-apart Gulf of Guayaquil presumably accompanied by a higher heat gradient. Nevertheless, the basin does have positive indications of some petroleum, and it appears that, on an areal basis, the Trujillo basin may have perhaps 5 percent of the petroleum of the Talara basin or .157 BBO and .215 TCFG. The presumably small trap-size along with continental slope depths may inhibit recovery of these estimated resources.

Lima Basin

Area: 9,500 mi^2 (24,700 km^2)

Original Reserves: Nil

Description of Area. The Lima basin lies on the continental slope opposite Lima, Perus and extends southward from approximately latitude 10° to 14° south. It is seaward of the submarine extension of the Coastal Range or outer arc ridge separating it from the Salaverry and Pisco basins (fig. 194).

Geology

No wildcats have been drilled. The geology may be analogous to that of the on trend Trujillo basin. Petroperu (1984), however, indicates that the thickness of the sedimentary fill is only 6,500 ft (2,000 m). This being the case, there is no opportunity for thermal generation of oil and gas and this basin is considered to have negligible quantities of oil and gas.

Mollenda (Arequipa)-Tarapaca Basin

Area: Peru: 5,000 mi^2) (12,000 km^2)

Chile: 3,000 mi^2 (8,000 km^2)

Original Reserves: Nil

Description of Area: The basin is located 20 to 60 mi (30 - 90 km) offshore and is largely confined to the continental slope (water depths 3,000 ft to 4,000 ft, 900 to 1,200 m). It extends southwards from opposite Arequipa (latitude 16° south) to Chile where it continues southwards as the Tarapaca basin to latitude 21° south. The Mollenda-Tarapaca basin is about 60 percent in Peru and 40 percent in Chile (fig. 194).

Stratigraphy

No wells have been drilled, and only seismic data are available. Figure 206, a seismic section across the basin as has been interpreted by (1989), shows prograding sedimentation. Gonzalez infers an Eocene (?) section of some 6,000 ft (2,000 m) lapping shoreward onto an acoustic basement, but being uplifted by post- or syn-Eocene structure seaward. Miocene (?) strata thin on both flanks of the basin as do the younger strata.

The stratigraphic fill reaches a thickness of about 10,000 ft (4,000 m) in both Peru and Chile.

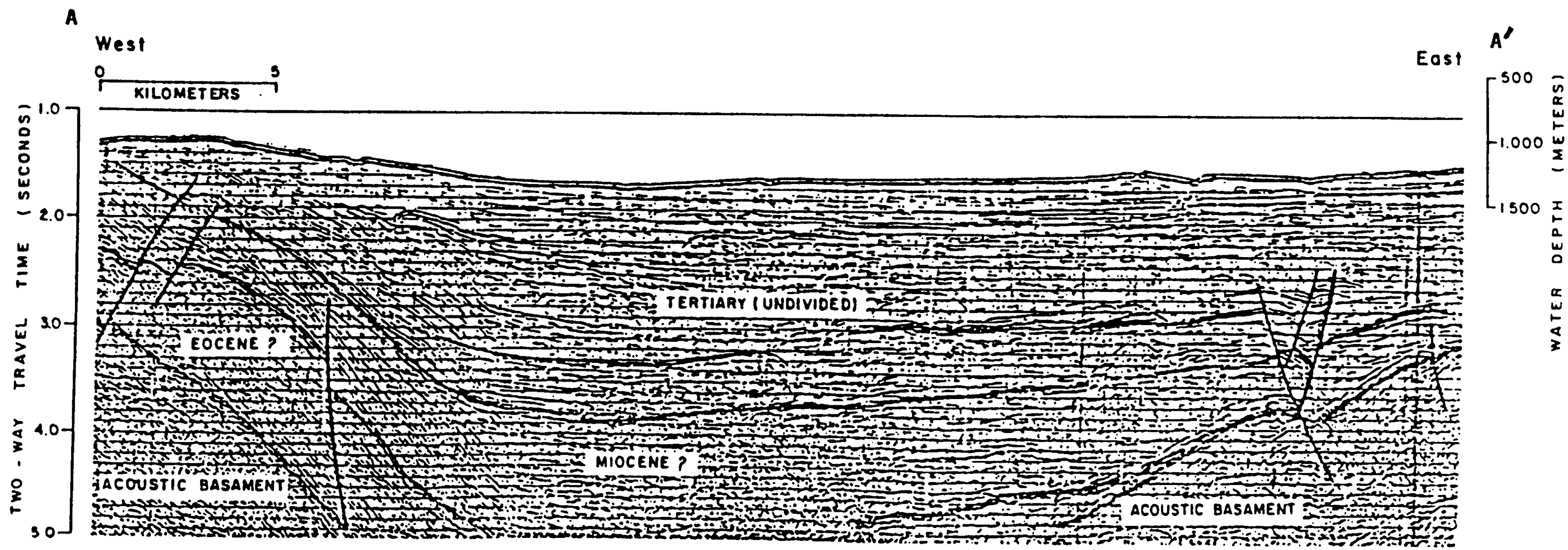


Figure 206 Interpreted seismic dip section across the Mollenda-Tarapaca basin showing stratigraphy and structural style. Approximate location - figure 194 (from Gonzalez, 1989).

Source. The source potential is unknown. By analogy to the on-trend Talara trench-slope basin, any source rock would most likely be in the Eocene (?) part of the section. The thickness of the fill is marginally sufficient for the lowermost beds to become thermally mature in this zone of presumed low heat gradients.

Reservoirs and Seals. Heterogeneous reflections indicate the presence of mixed lithologies which probably include potential reservoir sandstones and sealing shales such as found in the forearc basins of Talara and Progreso.

Structure

The Mollenda-Tarapaca basin is a forearc basin The basin fill appears to be only slightly deformed. Several synthetic and antithetic faults, parallel to the coast, cut the acoustic basement. Some of these faults are wrench faults showing flower structures. Indicated regional tension suggests that there may be abundant normal faulting of limited throw, not visible in the seismic section.

Sparse geophysical coverage shows the presence of one structure as large as 110 mi^2 (283 km^2), as well as block faulted basement highs with drapes (Petroperu, 1984). By analogy to the Talara and Progreso basins, small complex closures may occur which may not be economic targets in this deep water basin.

Generation, Migration and Accumulation. The basin appears to have continually subsided through the Tertiary, resulting in some 13,000 ft (4,000 m) of sedimentary fill. Assuming a low thermal gradient, as is usual for forearc basins, this depth may be barely sufficient for the early stages of generation for the lowest beds. Generation and migration would have been initiated during maximum burial in the late Neogene. At that time the fault-associated traps were in place as well as the Tertiary sandstone reservoirs.

Plays. The principal play is Tertiary sandstones in fault-traps and drape closures.

History of Exploration and Petroleum Occurrence. Reconnaissance geophysical work was carried out in both the Peru and Chile sectors, but, as far as known, no detailed work or wildcat drilling was accomplished. No oil or gas shows have been reported.

Estimation of Undiscovered Oil and Gas

The tectonic position of the basin is similar to the Trujillo and Lima basins. However, the Mollenda-Tarapaca basin is further from the Talara basin and the analogy is not so clear; it has no known oil seeps. Although the Mollenda-Tarapaca basin reportedly may have a thicker section than the on-trend Lima basin, it is believed to be of equally low potential and only have negligible amounts of petroleum.

Intra Arc Basins

Lacones Basin

Although the Lacones basin is essentially a Cretaceous basin, it is included here with the largely Tertiary coastal intra-arc basins for convenience of description.

Area: 2,000 mi^2 (5,250 km^2)

Original Reserves: Nil

Description of area: Lacones Basin lies between the Coastal Range and the Andes where the north-northwest trending Andes turns to a northeastern trend, parallel to the Gulf of Guayaquil (fig. 194).

Geology

The Lacones basin is older than the Tertiary (and upper Cretaceous) subduction related basins of the Pacific coast. The sedimentary fill from published maps and cross sections (fig. 207) show the fill to be Cretaceous interbedded with volcanics (although Petroperu's [1984] columnar section indicates some 4,000 ft [1,200 m] of Eocene section may be present.) The Cretaceous appears to be intruded by Tertiary coastal batholiths and, judging by the seismic opacity of Cretaceous strata in adjoining basins, these strata are probably too well indurated and over-mature to generate hydrocarbon.

The structure appears generally extensional with much faulting. The basin's trend parallel to the Mesozoic(?) Dolores-Guayaquil Megashear indicates it may contain faults with strong strike-slip components. Six surface structures have been mapped (Petroperu, 1984).

Exploration to date has been only surface geologic studies. No oil or gas seeps are reported.

Because of uncertainty as to the amount of reported Eocene strata (the source and reservoir rock of the adjoining Talara and Progreso basins), some difficulty is introduced into the basin's assessment. It is assumed, however, that any Eocene strata would be shallow and limited in area and not an important factor since they are not shown in published sections or maps and have induced no serious exploration investigation. Probably no appreciable amounts of hydrocarbon are to be discovered in the Lacones basin.

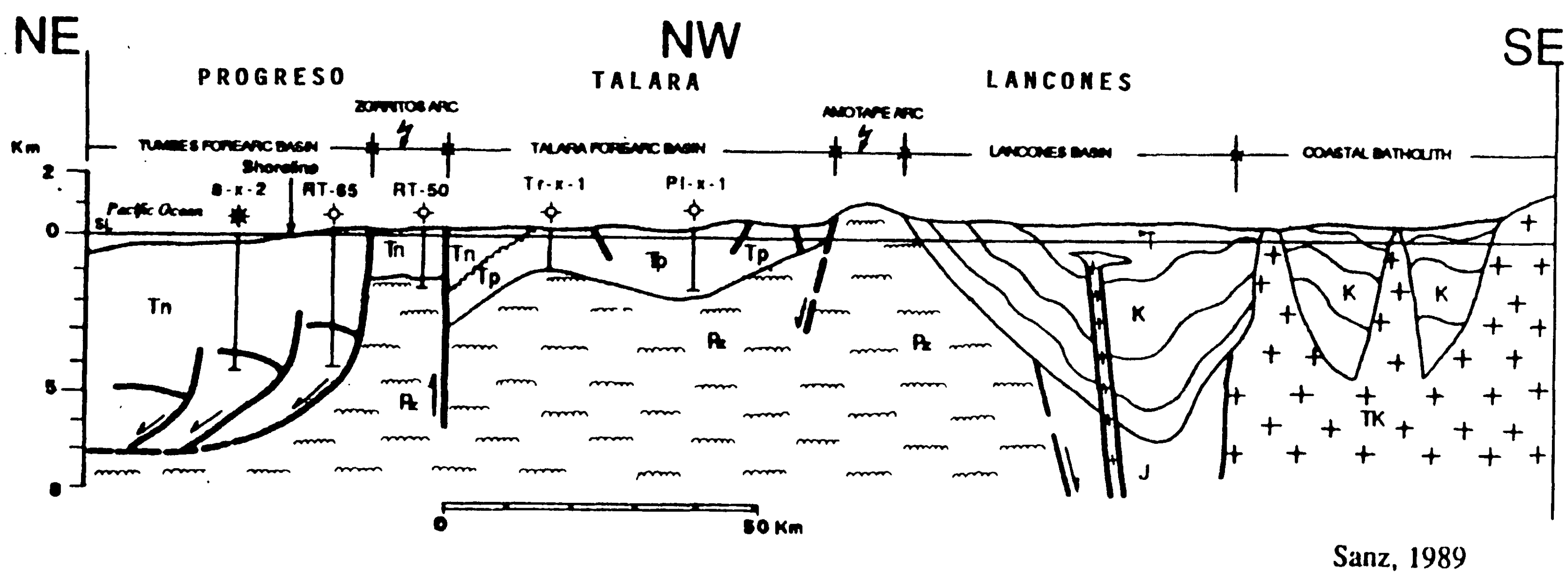


Figure 207 Northeast-southwest geologic section through the Lancones, Talara, and Progreso (Tumbes) basins (modified from Yrigoyan, 1991).

Manabi Basin

Area: 6,000 mi^2 (16,000 km^2)

Original Reserves: Nil

Description of Area: The Manabi basin lies inland and east of the Jama Hills segment and north of the Colonche-Chongon Hills segment of the curving Coastal Range. It is bounded on the north by Esmeraldas-Pichincha fault zone. The Tertiary and Cretaceous beds thin eastwards, so that the eastern border is some 40 mi (65 k) east of the Jama Hills (figs. 194 and 203).

Stratigraphy

The Manabi basin, like all the basins of Ecuador northwest of the Dolores-Guayaquil Megashear (fig. 195), is underlain by the Cretaceous Pinon Formation of volcanics (fig. 200), which is thought to be part of the oceanic crust (Shepherd and Moberly, 1981). Overlying the Pinon Formation by gradational contact is the Upper Cretaceous Cayo Formation of well-indurated, thick, (10,000 ft, 3,000 m) section of marine tuffaceous, siliceous sediments containing chert and some limestone.

Unconformably, above the Cayo Formation at the outcrops, is the middle Eocene San Eduardo Formation of chiefly limestone. In the more central basin areas, however, seismic data indicate that the Cretaceous-Middle Eocene unconformity interval contains an appreciable thickness of sediment. Overlying the Eduardo Formation is an upper Eocene, 3,000 ft (1,000 m) sequence of tuffaceous clastics, generally sandy in the south (San Mateo Formation) and shaly in the north (Punta Blanca Formation).

Unconformably overlying these Eocene formations is a Neogene section of a tuffaceous clastics which are generally correlatable with the Neogene sections of the other coastal basins of Ecuador.

Source. Several holes drilled in the Manabi basin encountered slight to good oil and gas shows, so some source rock is present. No likely source rock descriptions have been seen in the literature although Jarrin (1975) mentions that a black shale facies present in the deeper basin part of the San Mateo Formation may be a source. Geochemical studies of Tertiary surface samples indicate they are immature. There are thought to be 20,000 ft (6,000 m) of Tertiary in the northern part of the basin (Rosania, 1989). Even though the heat gradient is assumably low on this forearc basin, the very lowest Tertiary bed may have reached thermal maturity.

Reservoirs and Seals. Potential reservoirs are present in the Upper Eocene San Mateo Formation sandstones and locally in the sandstones of some of the Miocene formations. These sandstones are generally tuffaceous. Reefal facies of the San Eduardo Formation are mentioned as a reservoir possibility (Rosania, 1989).

The only seals would be Neogene tuffaceous shales.

Structure

The Manabi basin is a intra-arc basin behind the Coastal Range; it is bounded in the south by an eastward deflection of the Coastal Range (Colonche-Chongon Hills and in the north by the Esmeraldas-Pichinha Fault. Most of the major faults of the Manabi area strike northeasterly parallel to the Jama Hills. Seismic studies indicate the northern part of the basin is deeper, probably because of faulting, and more than 20,000 ft (6,000 m) of Tertiary sediments may be present.

Traps would be fault-block or drape closures since no folding is evident.

Generation, Migration and Accumulation. In this intra-arc basin, overlying presumably oceanic crust, the heat gradient is assumed to be low. The 20,000 ft (6,000 m) of Tertiary sediment indicates just barely enough subsidence so that the basal part of the Tertiary rock would reach thermal maturity. Generation, if any, would only have begun in late Neogene when the maximum subsidence was probably reached. The faulting, which would have formed any traps, probably was active until late Neogene, so that migration timing would be favorable.

Plays. There appears to be only one appreciable play in the basin and that is fault block or drape closures involving Eocene and Miocene sandstones.

History of Exploration and Petroleum Occurrence. Three wildcats were drilled in the mid-1940s of which one (Solano-1) had slight shows of oil and gas. In the late 1980's three more wildcats were drilled which may have had shows, but were all dry and the exploration concessions were relinquished.

Estimation of Undiscovered Oil and Gas

The thermal gradient is assumed low since such a gradient is usual for basins which overlie oceanic crust. Therefore, even though 20,000 ft (6,000 m) of Tertiary section appears present, only the basal part of these sediments would possibly reach maturity. No source section has been identified and reservoirs, although present, are largely tuffaceous.

Given these negatives and considering the failure of the three recent (late 1980s) wildcats (of a consortium of Corporacion Estatal Petrolera Ecuatoriana (CEPE) and Texaco), who must have applied state-of-the-art to the pre-drilling exploration, the prospects of the basin appear low. I believe the amount of undiscovered oil or gas in the Manabi basin to be negligible.

Borbon (Tumaco) Basin

Area: 1,500 mi^2 (4,000 km^2) (Ecuador portion)

Original Reserves: Nil

Description of Area. The Borbon basin averages about 25 mi (40 km) in width and lies east of the offshore extension of the Coastal Range (Jama Hills). It is bordered on the south by the Esmeraldos-Pichincha Fault and on the north extends into Colombia (fig. 203).

Stratigraphy

As in the other Ecuadorian coastal basins, the Borbon basin is floored by the Cretaceous volcanic Pinon Formation which is presumed to be part of the oceanic crust (fig. 200). Overlying the Pinon Formation by a gradational contact is the Upper Cretaceous Cayo Formation, consisting of well-indurated, tuffaceous deep-water marine clastics, which is thin or absent in the northern part of the basin.

Figure 200 shows the Tertiary succession. Paleocene and Lower Eocene rocks are missing in the Borbon basin, the Cretaceous Cayo being directly overlain by the discontinuous, patchy Middle Eocene carbonate Ostiones Formation which correlates with the San Eduardo Formation of the Progreso basin. Unconformably overlying this formation is the Upper Eocene Zapallo Formation which can be separated into two members. The lower member is made up largely of carbonates and the upper member of hard, dark brown to grey shales. Thickness of the Zapallo Formation varies from 1,000 ft (300 m) to 5,000 ft (1,500 m). These Eocene beds are overlain by the Oligocene Playa Rica and Pambil Formations which consist of largely dark colored, hard, tuffaceous shales and some sandstones and are of apparent limited extent. The overlying Neogene formations are tuffaceous sandstones and shales.

Source. Oil or gas was not encountered in the two holes drilled in the northern coastal area; however, one well, Chagui-1, drilled in the Colombian extension of the basin, found shows of light oil and gas (Bueno and Govea, 1975) indicating the presence of some source rock. Jarrin (1975) considers the Zapallo shales as the hydrocarbon source of the Borbon and Emeraldas-Caraquez basins. More than 13,000 ft (4,000 m) of Tertiary sediment are probably present at the north end of the Borbon basin (Rosania, 1989), but even this indicated depth of burial, in conjunction with the low thermal gradient, is probably insufficient to allow the Upper Eocene source rock to have reached the required thermal maturation for oil or gas generation.

Reservoirs and Seals. A few of the sandstone units penetrated in the Borbon basin wildcats appear to have fair porosities (Rosania, 1989), but no specific data has been published. Some of the outcropping sandstones of the Zapallo and Neogene Viche Formations have fair porosities (Rosania, 1989). The tuffaceous nature of the section probably precludes good reservoir characteristics. Shales provide adequate seals for any oil accumulation.

Structure

The Borbon basin is a intra-arc basin located shoreward or north eastward of the Coastal Range's offshore projection. It plunges northeastwards into Colombia. Unlike the coastal basins to the south, the Borbon basin has been subjected to considerable compression, or transpression. It is likely that wrench faults play an important role in the structure of the basin. In the Colombia extension of the basin two large anticlines have been mapped (Bueno and Govea, 1975).

Generation, Migration and Accumulation. If generation occurred in any significant amount, it would be at the time of maximum burial which was probably late Neogene. Faulting occurred at various times during the basin's history, but most faulting must have occurred in late Neogene when this area of subduction and mountain building was most active. It appears, therefore, that Late Neogene generated and migrated petroleum would have available, contemporaneous traps.

Plays. There appears to be only one play in the Borbon basin, Tertiary sandstone reservoirs in late Neogene fault and fold traps.

Exploration History and Petroleum Occurrence. Two wildcats, Borden-1 and Telembi-1, were drilled in the Borbon basin in the mid 1940's (Rosania, 1975), and very little exploration has been conducted since. In the Colombian continuation of the basin to the north, where the basin is designated the Tumaco basin, one well, Chagui-1, drilled in 1955, found light oil and gas shows, but apparently no further work was done (Bueno and Govea, 1975).

Estimation of Undiscovered Oil and Gas

Because this forearc basin presumably overlies oceanic crust, the heat gradient was probably always low. The maximum burial that any source rock may have experienced is about 13,000 ft (4,000 m); thus, it is likely that very little of the sedimentary rock reached sufficient thermal maturity for oil generation. There are other negative factors, such as the apparent failure to find encouraging results in the wells drilled to date and the high content of tuffaceous material in the reservoirs. It would appear, therefore, that there probably is not a significant amount of undiscovered oil or gas in the Borbon basin.

Sechura Basin

Area: 11,600 mi^2 ((30,000 km^2) out to the 3,000 ft (1,000 m) isobath, 60 percent onshore.

Original Reserves: Nil

Description of Area: The Sechura basin is bounded on the west and north by the Coastal Range (Amotape Mountains), on the east by the Andes, on the south by a east-west trend of subsurface basement highs, separating it from the Salaverry basin, and on the southwest by the 3,000 ft (1,000 m) isobath (fig. 194).

Stratigraphy

Paleozoic and other pre-Tertiary rocks, including Cretaceous shales and carbonates fill the lower part of the Sechura basin (fig. 208), but are largely indurated and seismically opaque in some areas, and are generally regarded as economic basement. However, they should not be entirely ruled out as a gas source. Upper Cretaceous and Lower Eocene sediments may exist in locally restricted areas, but the basins sedimentary fill is largely Upper Eocene, Oligocene and younger Tertiary clastics and minor amounts of carbonates. This fill is some 8,200 ft (2,500 m) thick onshore and 11,500 ft (3,500 m) offshore (Petroperu, 1984). The rocks are of shallow marine and brackish-water origin and are made up of silty shale and argillaceous sandstones. The section is characterized by tuffaceous material, diatomite and phosphate beds. It is believed correlative to the Monterey shale of California (Petroperu, 1984).

Source. Oil and gas shows occur, so some source rocks are present. However, even allowing for Plio-Pleistocene uplift, the basin's sedimentary rock appears to be generally shallow for large-scale petroleum generation in this presumably low-thermal-gradient forearc basin. Possibly, the now well-indurated Cretaceous dark shales generated hydrocarbon which migrated prior to their further maturation.

Reservoirs and Seals. Friable quartzitic sandstones exist in the Oligocene and Miocene parts of the section. Thick shales and some evaporites in the Oligocene and Miocene should provide potential seals.

Structure

The Sechura basin appears to be an intra-arc basin (although it has also been classified as a forearc basin) lying inboard of an outer ridge of continental crust material. This basin, like the Talara and other neighboring basins, has been in an extensional tectonic phase throughout the Tertiary and is extensively normal faulted with some wrenching. Figure 209 gives some indication of this faulting.

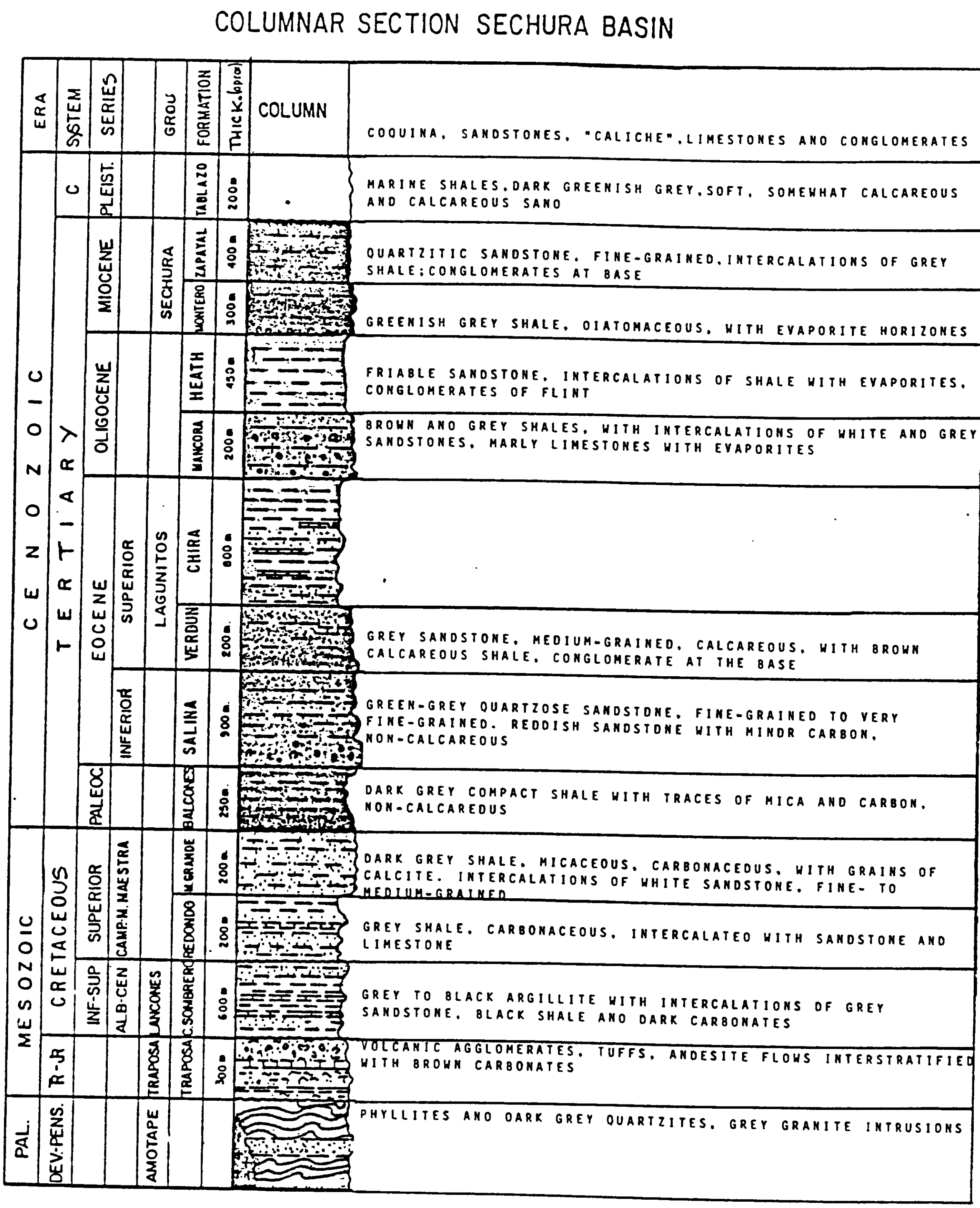


Figure 208 Columnar section of Sechura basin (modified from Petroperu, 1984).

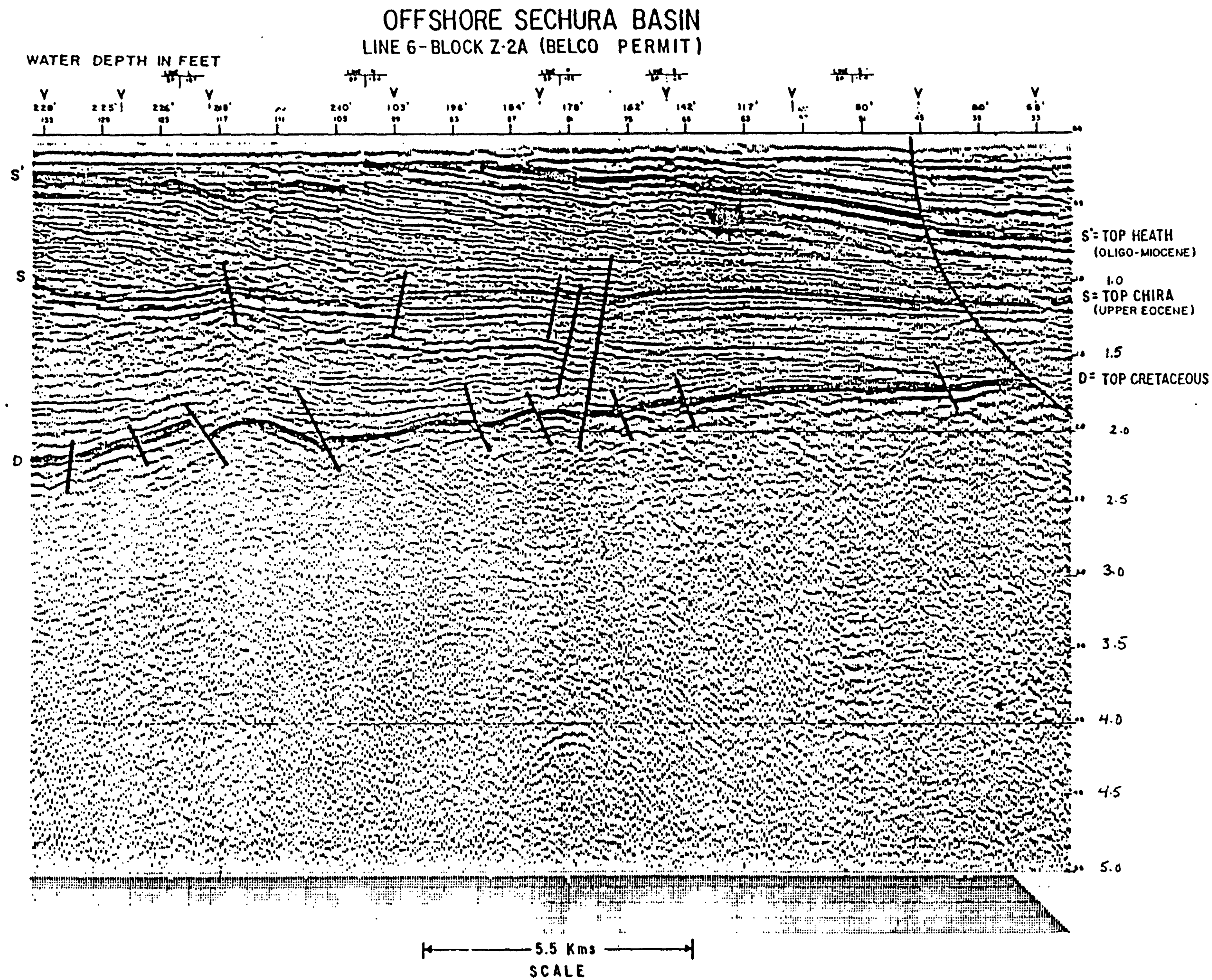


Figure 209 Interpreted seismic section through the offshore area of the Sechura basin showing the top of the seismically opaque Cretaceous, the top of the Eocene, and the top of the Oligo-Miocene or Miocene section. Location and orientation not precisely known (modified from Petroperu, 1984).

Potential traps would be fault-traps and drape closures, and possibly associated syndepositional and turbidite stratigraphic traps.

Generation, Migration, and Accumulation. The average depth of the Sechura basin depocenter considering only the seismically transparent Tertiary sediments is estimated to be some 8,000 to 11,000 ft (2,400 to 3,500 m). This indicates that the sediments are very largely immature for hydrocarbon generation; however, local depocenters may contain mature Lower Eocene or unindurated Cretaceous source sediments, or Cretaceous shales may have yielded hydrocarbon prior to further maturation and induration developed. Assuming some generation and migration occurred, Neogene reservoirs and closures would be in place only for any late-Neogene-generated petroleum.

Plays. There appears to be mainly one play in the basin, that is, Tertiary reservoirs in fault traps and drapes.

Exploration History and Petroleum Occurrence. In the 1950s, 28 onshore wells found 14 Tertiary and 2 pre-Tertiary gas shows and 1 Tertiary, 3 Upper Cretaceous and 1 Paleozoic oil shows. One offshore well had Tertiary gas shows and an Upper Cretaceous oil and gas show. Oil seeps occur along the southwest edge of the basin.

Estimation of Undiscovered Oil and Gas

Principally because of the shallowness of the basin precluding the thermal maturation of a significant amount of potential source shale, the amount of undiscovered gas, and particularly oil, are regarded as too small to be significant.

Salaverry Basin

Area: 12,340 mi^2 (32,000 km^2)

Original Reserves: Nil

Description of Area: The Salaverry basin is entirely offshore, occupying the continental shelf approximately between latitude 7° and 11° south (fig. 194).

Stratigraphy

The lowest unit of the basin fill is an Eocene, largely sandstone sequence of some 800 ft (240 m) (fig. 210). The overlying Oligocene sequence is some 5,300 ft (1,620 m) of largely shale beds intercalated with mudstones and claystones and thin carbonates; some argillaceous sandstones are in the lower part. The section is

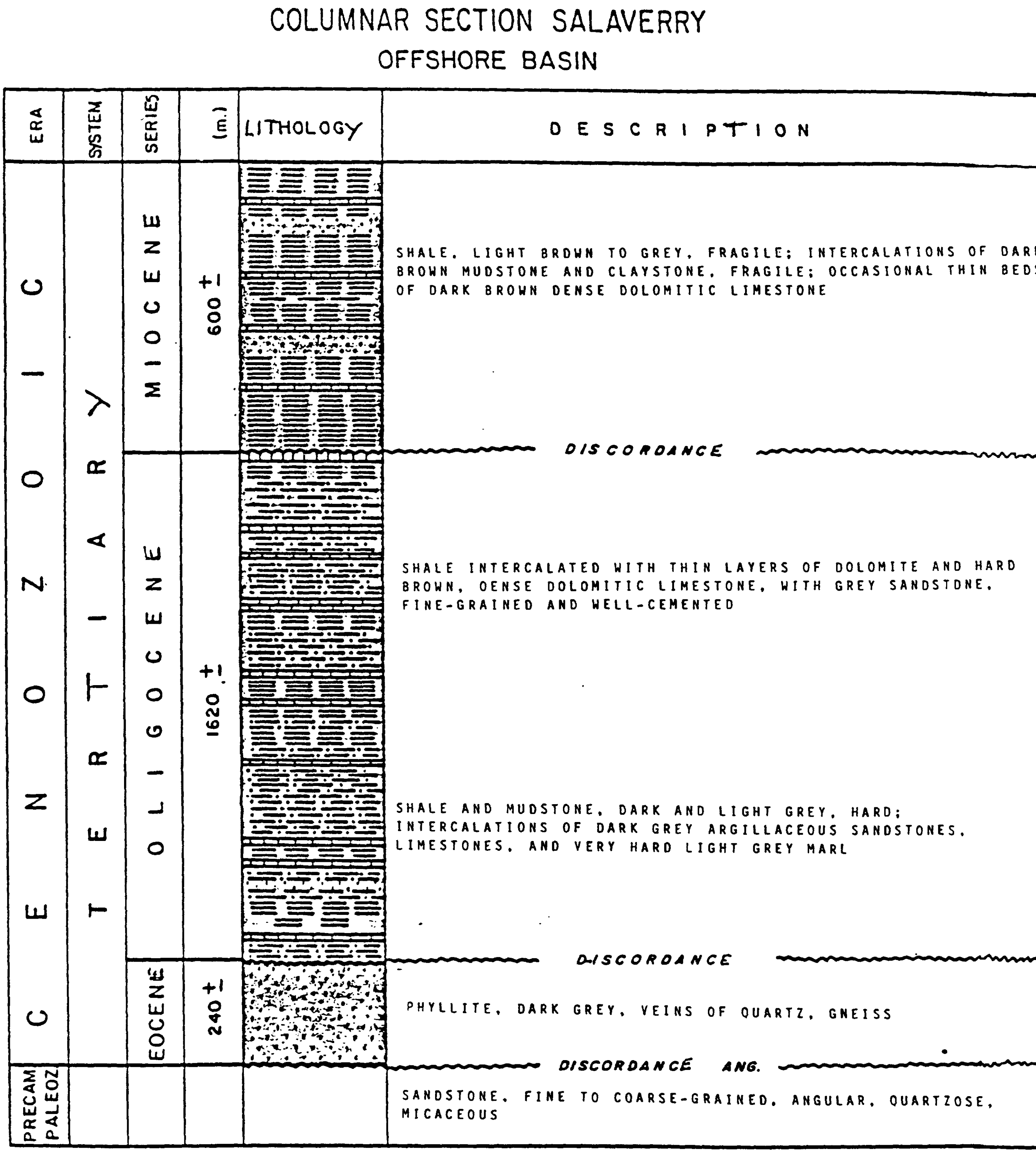
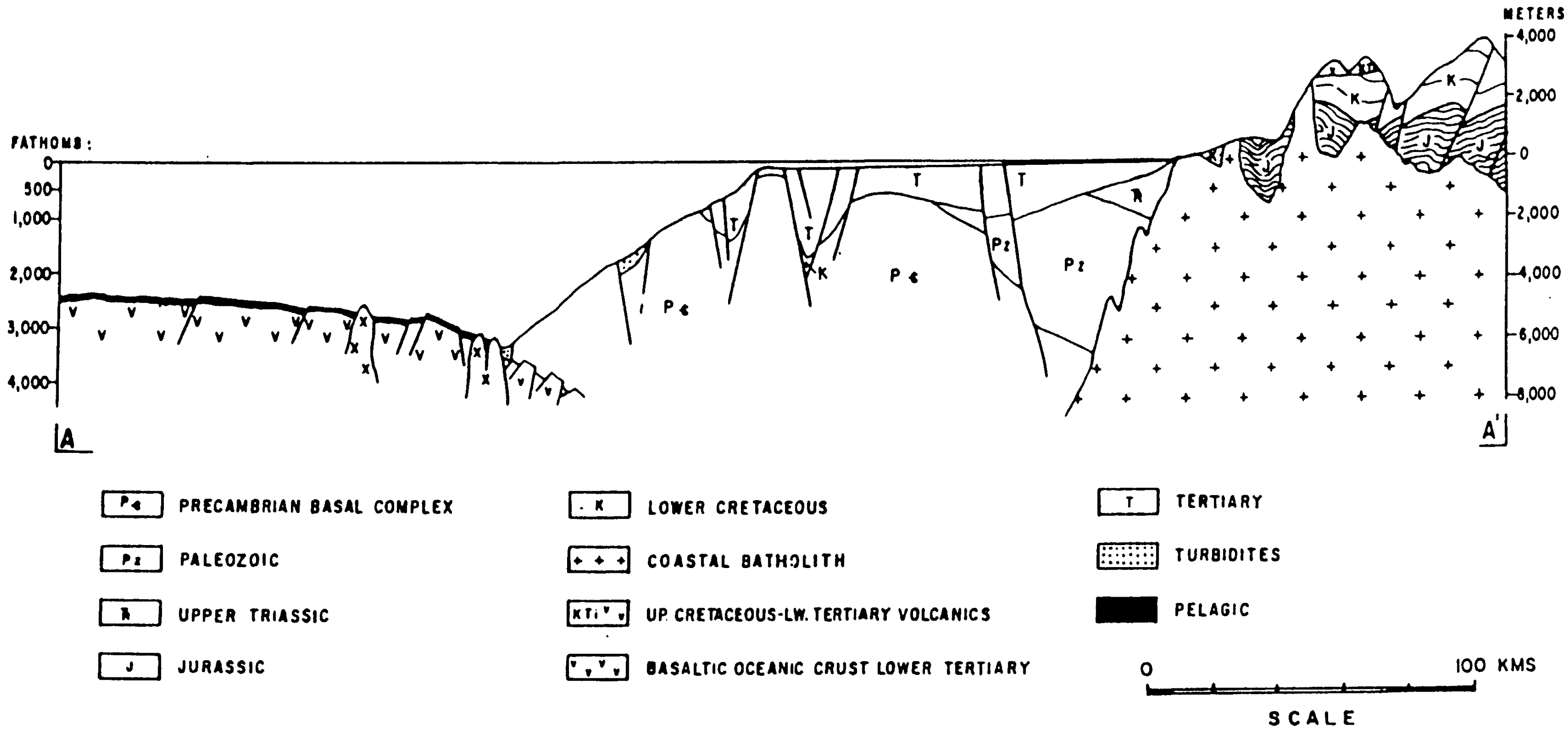


Figure 210 Columnar section of the Salaverry basin (modified from Petroperu, 1984).



PETROLEOS DEL PERU
EXPLORATION - PRODUCTION

Figure 211 Diagrammatic sketch section showing the relation of the Salaverry basin to a subduction process involving tectonic erosion (from Travis et al, 1975).

topped by a 200 ft (600 m) Miocene sequence of dominantly shale with interbedded minor limestone and sandstone beds.

Source. No source information available. The Oligocene dark grey shales may be of source potential if buried sufficiently deep. The Lower and Middle Eocene shales which source the Talara oil are missing.

Reservoirs and Seals. Sandstones of any thickness appear confined to the Eocene and less so to the Miocene. No parameters are available. The basin section appears to be dominantly shales so ample seals exist.

Structure

The Salaverry basin is an offshore intra-arc basin behind a ridge of pre-Cambrian rock which separates it from the Trujillo basin to the west (fig. 204). The basin is under extension and profusely block-faulted; it appears to be generally shallow, probably less than 6,000 ft (2,000 m). Figure 211 shows diagrammatically the relation of the basin to the subduction erosional or stopping process.

Traps have been mapped; they are fault traps and drapes.

Generation, migration and accumulation. The basin appears to be too shallow for appreciable amounts of thermally mature source rock. Any migration would be in the late Neogene when fault traps and drapes closure would be available as well as any Tertiary reservoirs.

Plays. The principal play of the basin would be Tertiary sandstones in fault traps or in drape structures.

Exploration History and Petroleum Occurrence. Seismic surveys have been made, and, as of 1984, sixteen structures mapped. Two offshore wildcats were drilled in the vicinity of which one (Ballena-8-1) was on the west edge of the basin and penetrated some 3,445 ft (1,050 m) of Tertiary sediment (fig. 204). No shows were found in either wildcat.

Estimation of Undiscovered Oil and Gas

Owing to the shallowness of any potential source shale and the absence of the Talara source section, the amount of undiscovered oil and gas is believed negligible.

Pisco Basin

Area: 13,000 mi^2 (50,000 km^2)

Original Reserves: Nil

Description of Area: The Pisco basin is located along the Peru coast south of Lima, Peru extending from about latitude 13°30′ to 16° south. It is 70 percent offshore and 30 percent on land. As presently defined, the subsea extension of the Coastal Range divides the basin into two sectors, an eastern intra-arc and a western forearc basin (fig. 194).

Stratigraphy

The stratigraphy as shown in figure 212 is from onshore wells and applies largely to the eastern part of the basin. The oldest prospective Tertiary sedimentary unit is Upper Eocene and is lithologically correlatable to those of the Salaverry basin being largely a shale. The overlying Miocene strata characteristically containing large amounts of diatomite and phosphate nodules. The eastern sector of the basin has a total fill of about 8,000 ft (2,500 m) (Petroperu, 1984).

Source. Cretaceous rocks contain shale and bituminous limestones which could be generative, but are indurated to the extent that they are seismically opaque. Tertiary shales of the eastern basin which may be of source quality appear to be too shallow and, therefore, immature. Middle and Lower Eocene source rock analogous to those of the on-trend Talara basin may occur in the western part of the basin.

Reservoirs and Seals. The Tertiary section appears to be dominantly shale although there are some sandstones in the Upper Eocene and Pliocene. Fractured shale might reservoir oil and gas.

In this generally shale sequence, seals should be adequate.

Structure

The basin, as has been designated, is part intra-arc and part forearc separated in the middle by the Coastal Range. Like the other Peruvian coastal basins, the Pisco basin has been under tension through the Tertiary but most of the faulting occurred in the Paleogene (fig. 213). The basin appears to be extensively normal-faulted. Wrench faulting is probably also prevalent, given the oblique subduction motion.

Potential traps are in fault and drape closures, and possibly drag folds.

Generation, Migration, and Accumulation. It appears that at least the eastern part of the basin is too shallow to have generated appreciable amounts of petroleum as indicated by a dip seismic section opposite Pisco City (fig. 213) indicates a generally shallow basin. Any migration would be late Neogene and Tertiary fault associated closures and Tertiary reservoirs would be available.

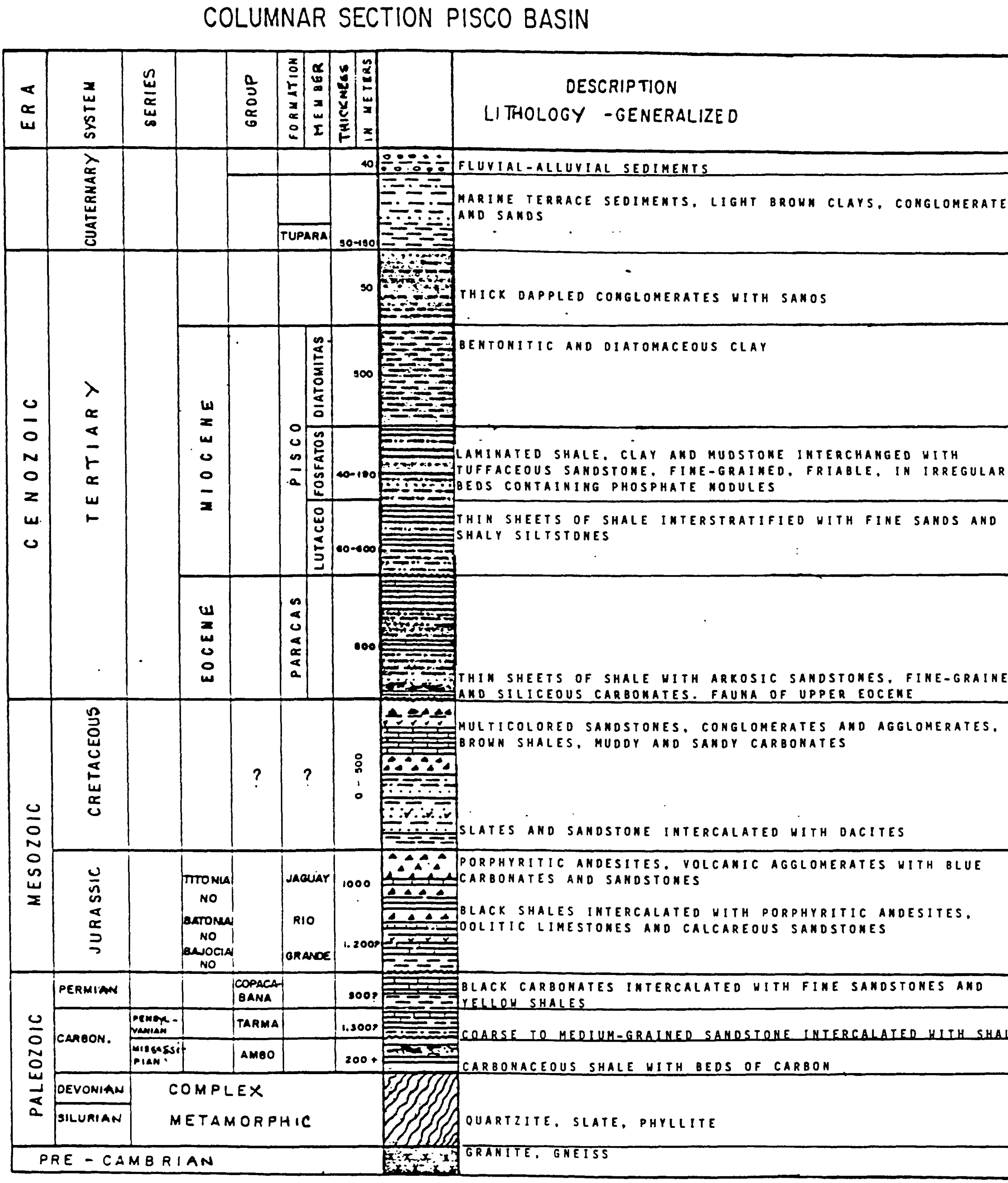


Figure 212 Columnar section of the eastern Pisco basin (from Petroperu, 1984).

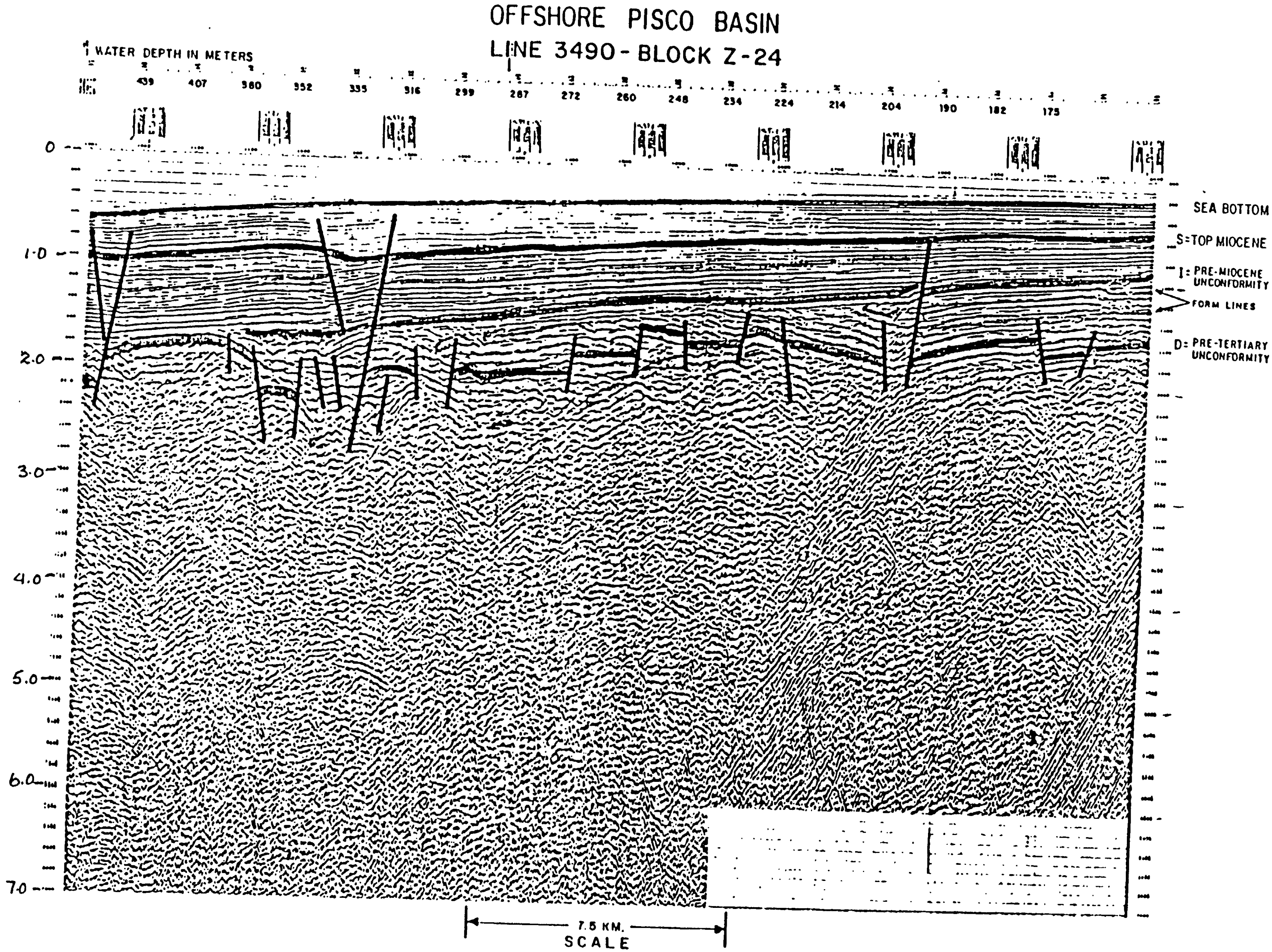


Figure 213 Interpreted seismic dip section in the offshore Pisco basin. Precise location unknown (from Petroperu, 1984).

Plays. The only significant play appears to be Tertiary sands involved in fault-associated closures.

Exploration History and Petroleum Occurrence. Offshore seismic aeromagnetic and surface geologic surveys have been conducted and one onshore wildcat drilled. There are no surface seeps and the wildcat had no shows.

Estimation of Undiscovered Oil and Gas

The eastern part of the basin appears too shallow for petroleum generation. The western part is barely deep enough and may contain a small amount of undiscovered oil and gas.

Moquegua-Tamaruga Basin

Area: 17,850 mi^2 (46,000 km^2)

Peru: 6,250 mi^2 (16,000 km^2)

Chile: 11,600 mi^2 (30,000 km^2)

Original Reserves: Nil

Description of area: The Moquegua-Tamaruga intra-arc basin lies between Coastal Range and the Andes and extends southward from about lat. 14°S in Peru to 22°S in Chile (fig. 194).

Stratigraphy

The stratigraphic section as shown in figure 214 is seen to be very largely volcanic throughout the Mesozoic and Tertiary, indicating a rather close affinity to the Altiplano basin. The section is described from Peruvian outcrops since no holes have been drilled in either Peru or Chile. Petroperu mention Triassic-Jurassic limestones, in part reefal, but they are not shown on the accompanying columnar section (fig. 214). In fact, the section appears predominantly continental. Petroperu (1984) state the basin fill to be "10,000 ft"(?) (3,280 m).

Source. There are no oil or gas seeps and no source determinations of rocks are reported. From the lithology of the section, no possible dark shale or other likely source rock appears present.

Reservoirs. Considering the amount of indicated tuff in the section, good reservoirs seem improbable.

COLUMNAR SECTION MOQUEGUA-TAMARUGA BASIN

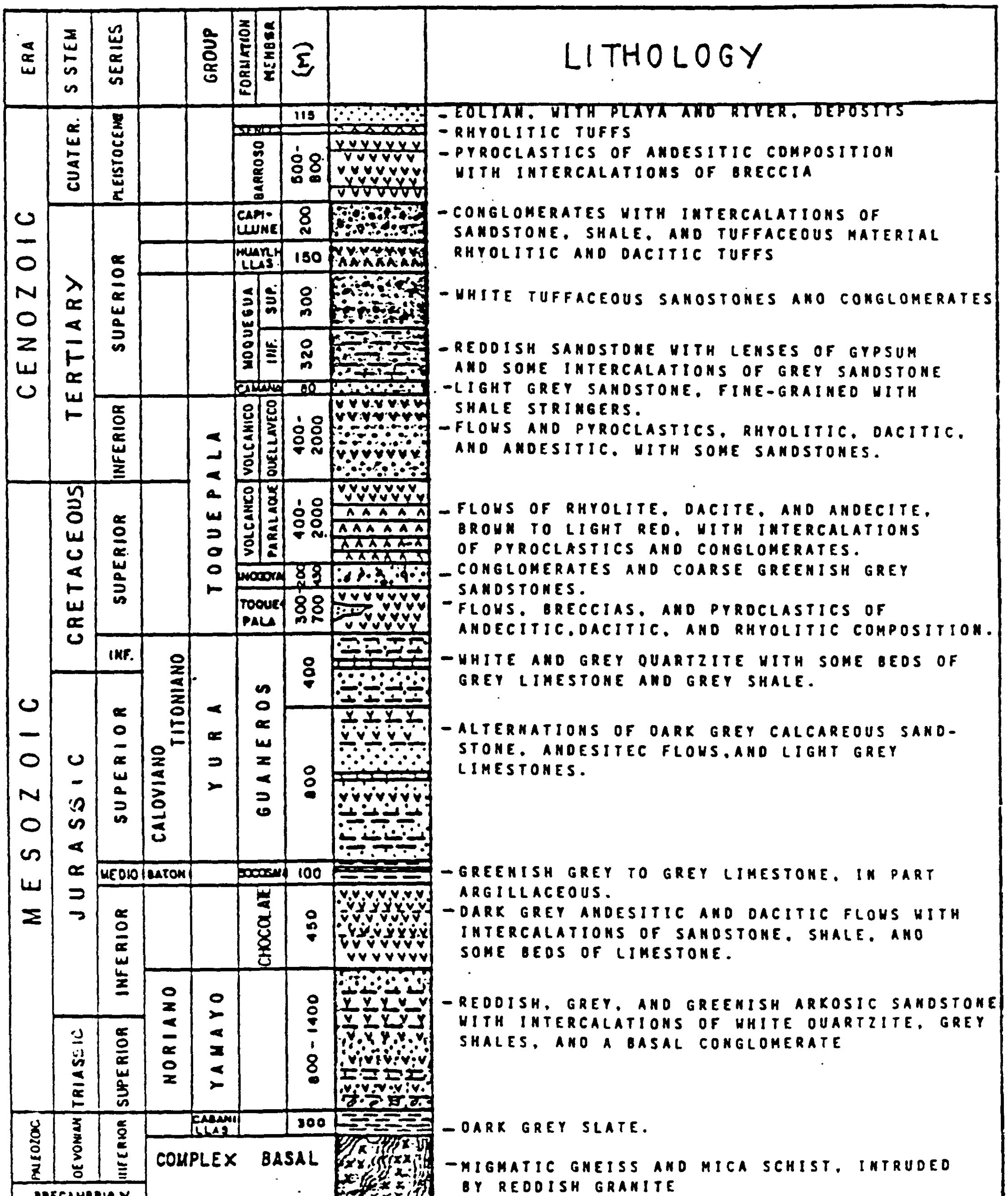


Figure 214 Columnar section Moquegua (Tamaruga) basin (from Petroperu, 1984).

Structure

No data are available but the area is tectonic under tension and undoubtedly Tertiary fault associated closures exist.

Generation, Migration and Accumulation. If the basin fill is about 10,000 ft (3,280 m), only source shales at the base of the section would barely reach thermal maturity in this area of presumably low heat gradients. Since there appears to be no lithological likely source rock near the base (or elsewhere in the section), the probability of sourcing and generating appears low. The timing of any generation and migration would be in late Neogene when the basin neared its maximum subsidence which would be favorable for accumulation in Tertiary created closures.

Plays. Probably the main play would be Tertiary clastic reservoirs involved in fault-associated closures.

Exploration History and Petroleum Occurrence. The exploration appears to have consisted of outcrop surveys. No seeps are reported.

Estimation of Undiscovered Oil and Gas

In view of the 1) largely coarse clastic, volcanic section with little evidence of possible source or reservoir rock, and 2) the probably thinness of the basin fill which would allow only the basal part of the section to be marginally mature, the amount of undiscovered oil and gas are judged negligible.

Salar de Atacama (Antofagasto Intra-arc Basin

Area: 17,400 mi^2 (45,000 km^2)

Original Reserves: Nil

Description of Area: The Salar de Atacama basin is located at the western foot of the Andes, extending southwards from latitude 22°15'S to 26°30'S (fig. 191).

Geology

Little is known of the geology but it is deemed similar to the on-trend Moquegua-Tamaruga basin whose Mesozoic and Tertiary section is largely volcanics. The adjacent Altiplano section is also largely volcanics (fig. 214).

At least two exploratory wells have been drilled which encountered high pressures but were apparently dry. No seeps are reported.

Reportedly, the depth of the Salar de Atacama basin may be 18,000 ft (5,500 m), considerably deeper than the supposed depth of the Moquegua-Tamaruga basin. Otherwise, however, it appears analogous to the Moquegua-Tamaruga and, accordingly, no appreciable amounts of oil and gas will be discovered in the Salar de Antacama intra-arc basin.

2. South Chilean Coastal Basins

Forearc Basins

The southern coastal basins extend from Valpariso, Chile to the southern tip of South America. There are three elongate, largely offshore forearc basins, the Central Chilean, Madre de Dios, and the Diego Ramirez forearc basins (figs. 215 and 219), the northernmost of which is divided into a string of eight subbasins (usually referred to as separate basins) (A-H, fig. 215). Paralleling the forearc basins inland between an intermittent Coastal Range and the Andes Mountains is a string of four intra-arc basins, the Curico, Temuco, Osorno-Llanquihue, and Penas basins (figs. 215 and 219).

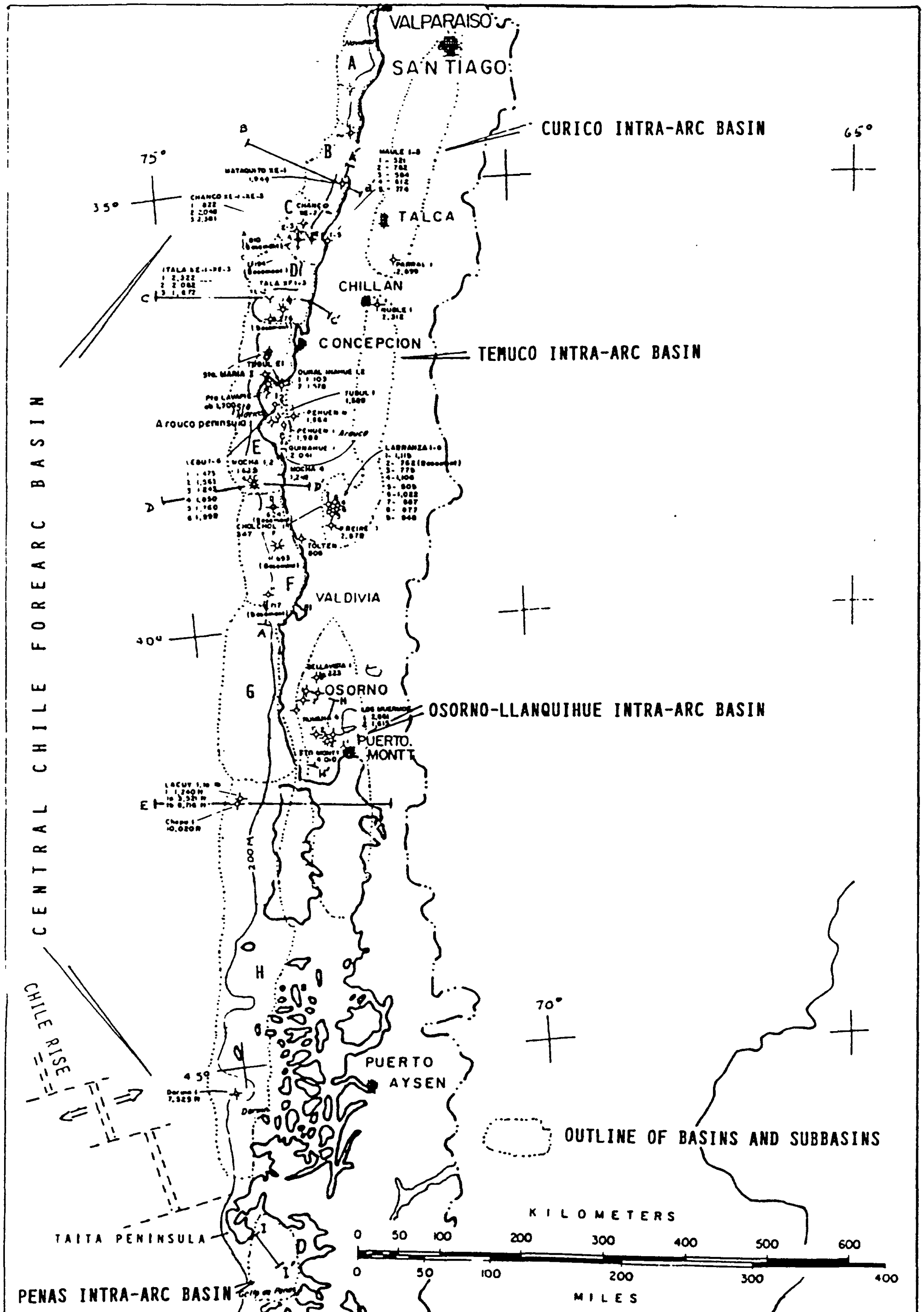


Figure 215 Index map of Chilean central coast showing the Central Chile Forearc basin and four adjoining intra-arc basins, Curico, Temuco, Osorno-Llanquihue, and Penas. Forearc subbasins are: A-Navidad, B-Mataquito, C-Chanco, D-Itata, E-Arouco, F-Valdiva, G-Pucatrihue, H-Chiloe (modified from Petroconsultants).

Central Chilean Basin

Total Area: 25,100 m^2 (66,200 km^2)

Subbasins:	Navidad	1,500 mi^2 (4,000 km^2)
	Mataquito	1,000 mi^2 (2,600 km^2)
	Chanco	1,500 mi^2 (4,000 km^2)
	Itata	2,000 mi^2 (5,600 km^2)
	Aranco	3,000 mi^2 (8,000 km^2)
	Valdivia	3,000 mi^2 (8,000 km^2)
	Pucatrihue	1,500 mi^2 (4,000 km^2)
	Chiloe	11,600 mi^2 (30,000 km^2)

Original Reserves: Nil

Description of Area. In the literature these subbasins are usually treated as individual basins, but because they are structurally and stratigraphically joined and are, except for the Chiloe subbasin, of relatively small size, they are treated here as a single forearc basin termed the Central Chilean basin. In most cases, there appears to be a zone of acoustic basement (or outer arc ridge) between the basin and the trench. Unlike the Ecuadorian and Peruvian coastal basins, the Central Chilean forearc basin is largely on the continental shelf, only extending somewhat onto the upper slope. The basin extends southward from Valparaiso to the Taituo Peninsula at the Gulf of Penas (about latitude 47° south) where the Chile Rise spreading ridge intersects the Chile Trench (fig. 215).

Stratigraphy

The amount of sedimentary fill varies rapidly from one subbasin to another but, in general, the maximum thicknesses appear to range from 10,000 ft (3,000 m) to more than 13,000 ft (4,000 m). The stratigraphy is based on findings of some 18 or so wildcats together with reflection seismic data as reported by Gonzalez (1989).

The stratigraphy as displayed on figure 216 is much affected by the rather complex structure, the basin being affected by transverse tectonics possibly related to Pacific Oceanic transform movements, as well as strong coast-paralleling wrench fault movement evidently related to the oblique subduction. Nevertheless, the indicated stratigraphic units do have distinguishing characteristics throughout the basin. Figure 216 shows the correlation of stratigraphic units along the strike of the basin. Since, in general, the units

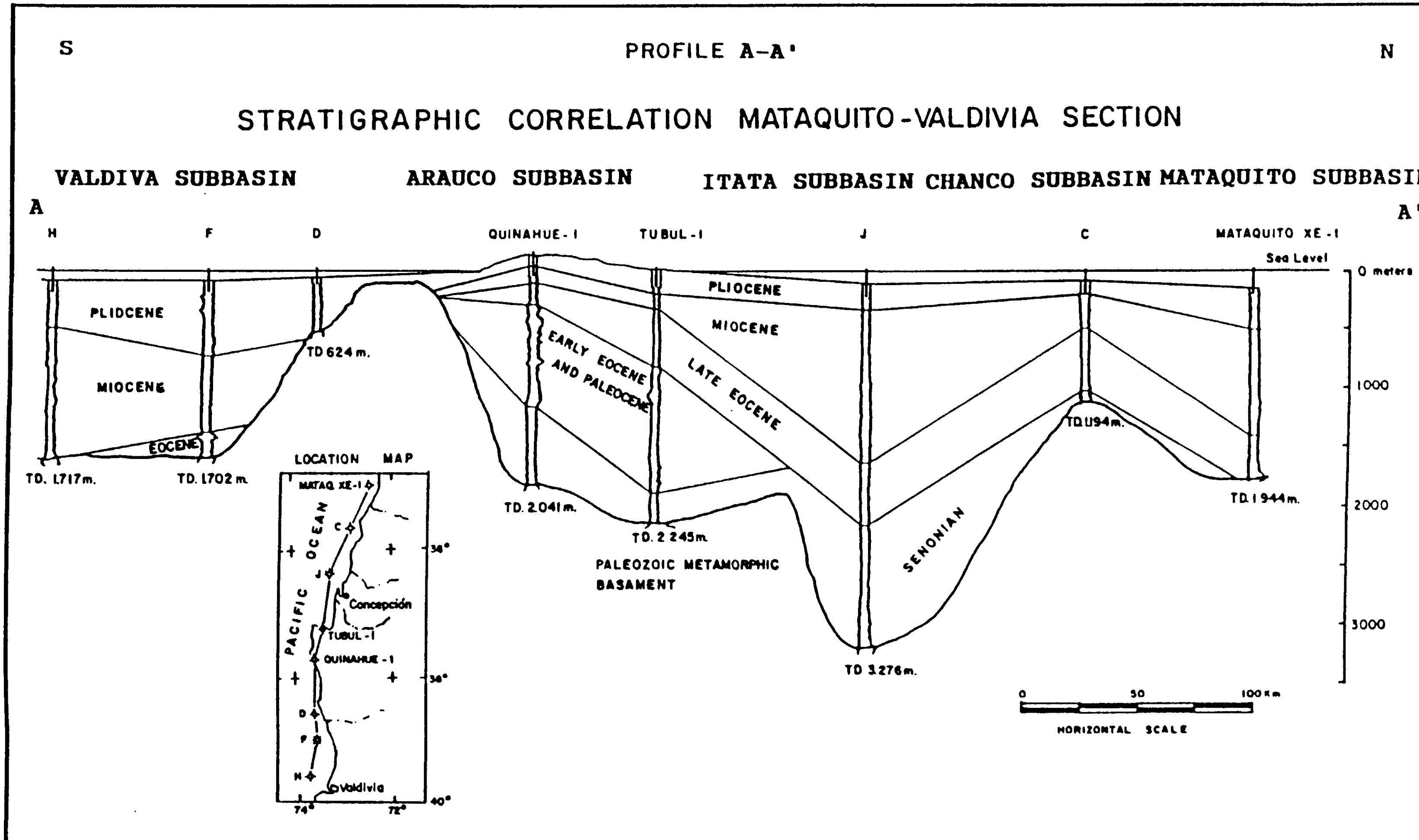


Figure 216 South to north stratigraphic correlation of exploration boreholes along strike of Central Chilean Forearc basin. Stratigraphy simplified, e.g., Miocene includes some Oligocene and early Eocene is included with Senonian in Chanco subbasin (modified from Gonzalez, 1989). Location of basin and subbasins figure 215.

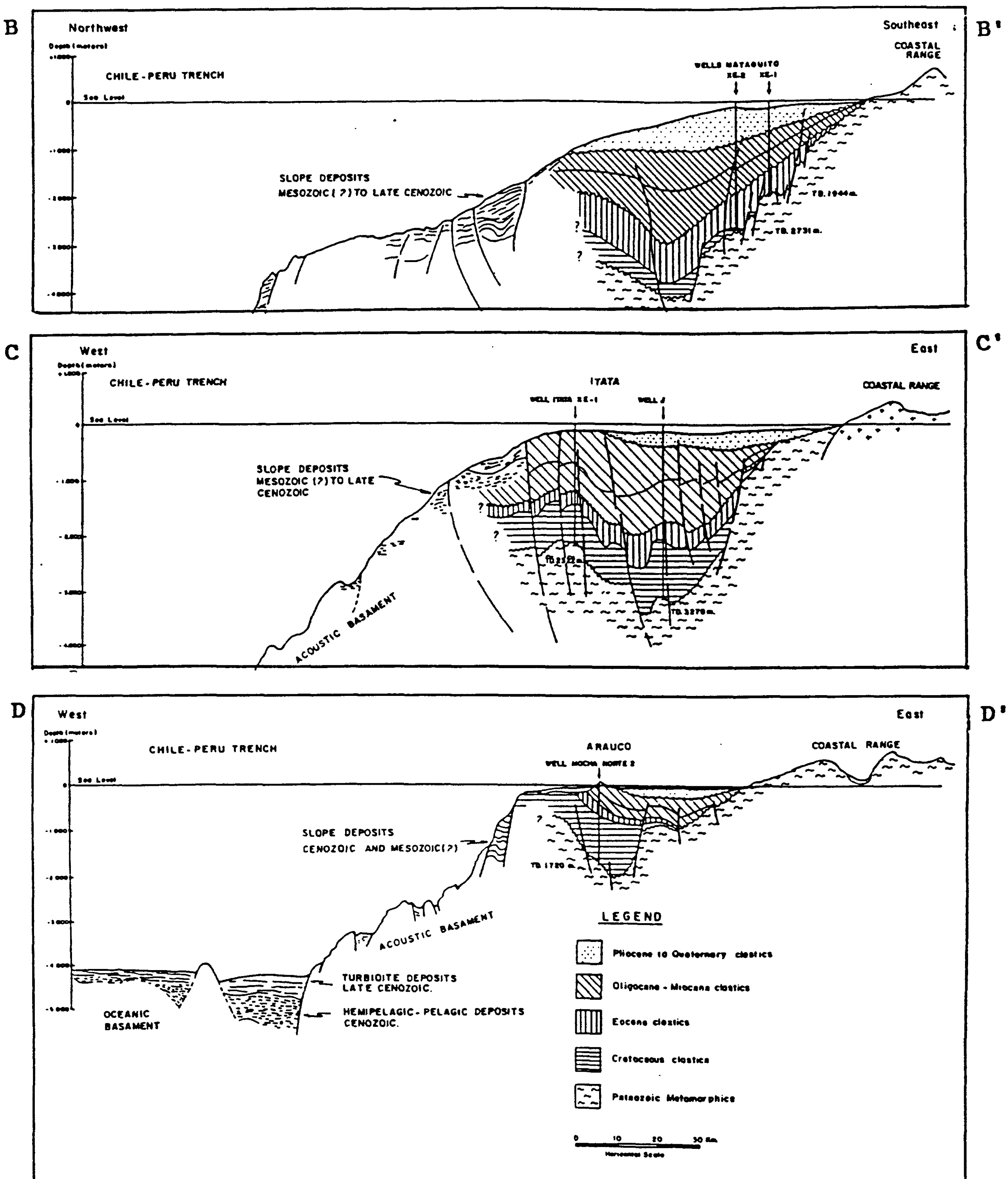


Figure 217 West-east geologic cross-sections of Central Chilean Forearc basin, stratigraphy simplified; e.g., in section B-B′ Early Eocene is included with Cretaceous and in D-D′ Eocene includes some Paleocene. Locations figure 215 (after Gonzalez, 1989).

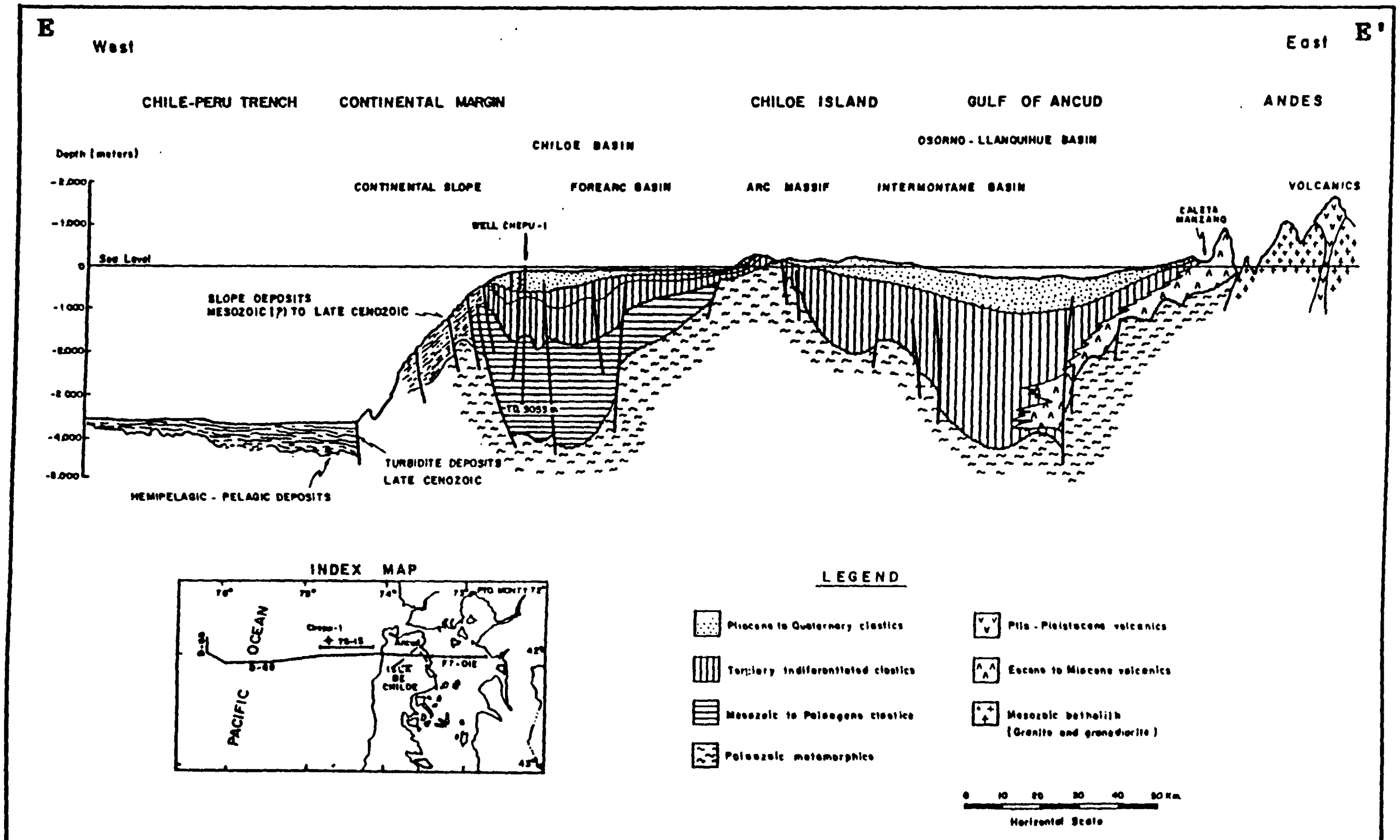


Figure 218 West-east geologic cross-section across the Chiloe subbasin of the Central Chilean Forearc basin and the Osborno-Llanquihue intra-arc or intermontane basin. Location figure 215 (after Gonzalez, 1989).

are thinning and shaling-out seawards perpendicular to the strike, the position of the control boreholes relative to the depositional strike somewhat distorts the stratigraphic representation. Sections B-B′, C-C′, D-D′ and E-E′ (fig. 217 and 218) show the dip depositional relationships.

The Central Chilean forearc basin appears to have been recently uplifted in the vicinity of the Arauco Peninsula (Arauco subbasin) (E, fig. 215, fig. 216, and D-D, fig. 217) so that forearc sediments are more observable on land at a shallower depth in many bore holes and coal mines. Consequently, the stratigraphic units are described here first and then their lateral extensions in the subbasins to the north and then to the south.

The Senonian or Late Cretaceous is found, or interpreted to exist from seismic data, in the basin within and north of the Arauco subbasin, but further south the presence of Late Cretaceous strata remains conjectural. In the Arauco subbasin the Senonian or Late Cretaceous section consists of basal sandstone, claystone with intercalations of siltstone, and fine-grained sandstone, having a maximum thickness of 3,770 ft (1,150 m) (fig. 216, D-D, fig. 217).

The thickest Late Cretaceous section was penetrated in the Itata subbasin (D, fig. 215) immediately to the north where 4,777 ft (1,456 m) of quartz sandstone, siltstone and shale were encountered (fig. 216 and C-C, fig. 217). Onshore of the Iata subbasin are some 1,000 ft (300 m) of Late Cretaceous marine and deltaic conglomerates, sandstones, siltstones, and shales.

Further north in the Chanco subbasin (C, fig. 215), the Late Cretaceous is not always separated from early Eocene strata. Together they consist of 330 to 500 ft (100 to 150 m) of basal quartz sandstones (fig. 216). Here the Late Cretaceous appears to wedge out down-dip on the western flank of the basin. At the north end of the basin, the Mataquito (B, fig. 215) and Navidad (A, fig. 215) subbasin, a relatively thin Cretaceous-Eocene section is interpreted from seismic data (fig. 216 and B-B fig. 217). In summary it would appear that the Upper Cretaceous is a largely sandstone unit with some shale and is best developed in the north-central part of the basin. The source is from the east.

The Paleocene and early Eocene in the Arauco subbasin is made up of sandstone with interbedded coal beds, claystone, and silt-stone, having a maximum thickness of 5,250 ft (1,600 m) which consists of a deltaic facies in the east and marine facies in the west over part of the basin (Gonzalez, 1989) (fig. 216 and D-D′ fig. 217). The early Eocene and Paleocene part of this section, however, appears to be limited largely to the Arauco subbasin itself, and in the Itata subbasin, immediately to the north, there is only a maximum of 1,100 ft (330 m) of Late Eocene claystone, fine sandstone and siltstone (fig. 216 and C-C′, fig. 217). Further north in the Chanco subbasin the early Eocene is grouped with a Cretaceous largely sandstone unit which appears to thin out seawards. Still further north in the Mataquito subbasin early Eocene strata are grouped with Cretaceous sandstone while later Eocene consists of 1,000 to 1,500 ft (300 to 450 m) of claystone with silty and sandy intercalations. At the northernmost end of the basin the Eocene is grouped with a thin seismically indicated Cretaceous unit.

Immediately to the south of the Arauco subbasin in the Valdivia subbasin (F, fig. 215) the Eocene is represented by siltstone and fine grained, argillaceous sandstone with intercalations of claystone, having a maximum thickness of 500 ft (150 m). Eocene strata thin on the flanks of high-relief features (fig. 216). Further south the Eocene is grouped with older or younger strata in seismic interpretations. In the Chiloe subbasin (H, fig. 215 and fig. 218), the Eocene is part of sequence grouped together as Paleogene or older. The sequence has a maximum thickness of 3,600 ft (1,100 m) and is predominantly marginally marine, quartzose greywacke sandstone which contains intercalations of hard, fractured shale and siltstone. The entire sedimentary section thins abruptly towards the basement high at the shelf border between the basin and the trench.

In summary, it appears that the early Eocene and Paleocene strata are largely in a sandy facies, though perhaps less sandy than the underlying Cretaceous. They are thickest in the Arauco vicinity and sourced from the east. They apparently thin and shale-out westwards, and thin around older high-relief features. They are of a continental environment becoming more marine westward. The middle and late Eocene appears to be more shaly.

The Miocene and Oligocene are usually grouped together. In the Arauco subbasin the Miocene-Oligocene is represented by a maximum of 3,000 ft (930 m) of quartz sandstone and claystones prograding to the west (fig. 216 and D, fig. 217). Further north, and probably in more down-dip positions, the boreholes of the subbasins to the north of the Arauco Peninsula found the Miocene-Oligocene section represented largely by claystone, ranging to somewhat over 4,000 ft (1,200 m). To the south of the Arauco Peninsula, the Miocene-Oligocene section is not so well observed but it appears to be largely claystone. In summary, it appears that, except for the up-dip Arauco area, the Miocene-Oligocene period is represented by finer-grained sedimentation, claystone predominating.

The Pliocene-Pliestocene varies along strike but, in general, is fine-grained.

<u>Source</u>. There is some petroleum being thermally generated in the basin as attested by noncommercial gas which contains some ethane, propane and isobutane in the Arauco subbasin.

The organic matter in the Tertiary continental and marine claystones ranges from 0.26 to 1.23 percent and the predominant kerogen is of types II and III. The organic matter in the Cretaceous marine claystone is 0.74 to 2.6 percent and the predominant kerogen is rich in lipids (Gonzalez, 1989).

The thermal gradients average 1.10 to 1.65°F/100′ (20° to 30°C/km) (Gonzalez, 1989) which, for Cretaceous source rocks, assuming continuous subsidence, indicated petroleum generation depths of 8,000 ft (2,500 m) to 13,000 ft (4,000 m). Thermal maturation sufficient for petroleum generation as indicated by vitrinite reflectance in Upper Cretaceous strata was found in the Borehole "I" of the Itata subbasin, where values ranged from 0.90 to 1.02 percent average R_0 at depths over 8,000 ft (2,500 m). In the adjoining Arauco subbasin the Upper Cretaceous sequence, thermally mature rock is found at a depth of 6,000 ft (1,400 m) (shallowness probably reflecting the presumed Pliocene uplift of Arauco area). In the Chiloe subbasin to the south, the Paleogene is barely mature (0.45 to 0.75 R_0) at 6,600 ft (2,000 m). It appears that with depths ranging down to somewhat over 13,000 ft (4,000 m), but averaging less than 6,600 ft (2,000 m), there may be a limited amount of mature source rock in the basin, confined to the Upper Cretaceous interval and, most probably, in the deeper, or once deeper, Arauco, Itata, and Chanco subbasins. It should be noted that the Upper Cretaceous sequence is largely sandstone so that the volume of source shale may be quite small.

Reservoirs and Seals. Porosity and permeability value of sandstones range from 2 to 31 percent and 2 to 1,727 md. The best sandstone reservoirs are the basal sandstones of the Late Cretaceous and sandstones within the Miocene-Pligocene sequence. Late Cretaceous basal sandstones in the Chanco subbasin, for example, are 75 to 500 ft (23 to 150 m) thick and have porosites of 23 to 28 percent and permeabilities of 19 to 1,727 md. Good Late Cretaceous sandstones also exist in the adjoining Iata and Arauco subbasins. Miocene-Oligocene sandstone reservoirs in the Arauco (and adjoining intra-arc Osorno-Llaqquehue basin) are 16 to 330 ft (5 to 100 m) thick with porosities of 10 to 34 percent and permeabilities of 23 to 713 (Gonzalez, 1989); Miocene-Oligocene sandstone exist in the other subbasins.

Tertiary and Cretaceous claystone and shale units interbedded with potential reservoir sandstones provide widespread thick seals.

Structure. This basin is termed a forearc basin from its position between the Andean magmatic arc and the subduction trench. There appears to be a ridge or at least a zone of acoustic basement between this Central Chilean forearc basin and the trough (figs. 217 and 218). The basin appears to have been under tension from Late Cretaceous through Oligocene time and is cut by much normal faulting. Transverse highs between the subbasins may be related to oceanic fracture zones. There is reported evidence of coast-paralleling wrench faults which would be expected to accompany the oblique eastward subduction with a northern component.

Traps would be uplifted blocks of fractured basement, fault closures, drapes, and possible drag folds accompanying the wrenching. Stratigraphic traps may exist on the flanks of fault blocks.

Generation, Migration and Accumulation. The apparent depth of the basin, with a maximum of somewhat over 13,000 ft (4,000 m), is enough for generation, but limited to the lowest part of the fill involving Upper Cretaceous strata in the deeper, or once deeper, subbasins, e.g. Aruaco, Iata, and Chanco subbasins. Assuming continual subsidence, necessary maturation depths would only have been reached in the late Neogene. By that time traps and reservoirs would be in place.

Plays. The primary play is for Lower Cretaceous sandstones in fault-associated traps. A secondary play would involve Miocene-Oligocene sandstones in the same type of traps.

Exploration History and Petroleum Occurrence. The existence of the Central Chilean forearc basin was first established by geophysical studies of surveys conducted by the USNS Charles Davis in 1967. Between 1970 and 1986, 20,213 mi (32,530 km) of seismic survey has been accomplished and 18 exploratory wells have been drilled. Two accumulations of non-commercial gas were found in the Arauco subbasin, and biogenic gas was found in the F well of the Valdivia subbasin (fig. 216).

Estimation of Undiscovered Oil and Gas

It appears that only those deeper parts of the basin and where there is Lower Cretaceous source shale are likely to have oil and gas potential. This, from the data at hand, apparently limits any appreciable amounts of oil and gas potential to the Arauco, Itata, and Chanco subbasins, an area of some 6,500 mi^2 (17,600 km^2). By areal analogy to the ultimate resources (reserves plus estimated undiscovered petroleum) of the Talara basin an estimate of 3.7 BBOE is obtained. However, the Central Chilean Forearc basin for a number of reasons is much less prospective than the Talara basin: 1) the depth of the basin subsidence, as indicated by the stratigraphic thickness, is, at most, only half that of Talara; only the lowest potential source shales are apt to be thermally mature for petroleum generation; 2) the stratigraphic section, particularly the lower part, i.e., Upper Cretaceous and Paleogene is largely sandstone with apparently only a small volume of potential source shale; 3) regional geology suggests that the thermal gradient may be lower than the Talara area, and 4) there is a general lack of oil shows in the 18 boreholes, although gas shows occur. Accordingly, it would appear that in the Central Chilean forearc basin there is only about one-tenth the potential for petroleum as in the Talara basin, or .37 BBOE. Furthermore, because the seeps and shows are all gas, the basin is probably gas prone. Assuming the petroleum is 90 percent gas, the estimate for Central Chilean forearc basin is .04 BBO and 2.0 TCFG.

Madre de Dios Basin

Area: 5,600 mi^2 (15,000 km^2)

Original Reserves: Nil

Description of Area: The Madre de Dios basin is offshore, occupying the continental shelf and part of the upper slope and extending southward from the Gulf of Penas vicinity (47°45′S) to Desolacion Island (53°S) (fig. 219).

Stratigraphy

General. Gonzalez (1989) states that this basin contains more than 13,000 ft (4,000 m) of sedimentary rock in its depocenter; however, judging from a seismic line through the center of the basin (fig. 220), the average depth would be around 10,000 ft (3,000 m). Wildcat A-IX did not penetrate to basement, but reached total depth in Oligocene-Miocene rock. Its results suggest that there is not space between the total depth of wildcat A-IX (8,337 ft, 2541 m) and the opaque basement to accommodate an appreciable thickness of Eocene and, particularly, Upper Cretaceous sedimentary rock. The sedimentary sequence wedges gradually towards basement highs in the west and towards the shelf in the east. The Oligocene-Miocene shows prograding, is fine-grained, and is missing from the northern third of the basin.

Source. The Oligocene-Miocene rocks, as observed in wildcat A-IX, are low in organic carbon, which is largely type III kerogen, and are thermally immature.

Reservoirs and Seals. Wildcat A-IX found no adequate reservoirs. There is a chance, however, for basal sandstones below the wildcats total depth. Seals would apparently be adequate in the generally fine-grained Oligocene-Miocene interval.

Structure

The Madre de Dios basin appears to be a forearc basin, most of the sedimentary fill being in a depression between the shelf on the east and uplifted blocks of basement rock on the west. Strike-slip faults are the dominant structural feature, particularly in the south. Towards the north the shelf becomes narrow and shallow and the fill is principally along the upper slope. As indicated in figure 220, most of the faulting appears to be about Oligocene age. The shelf and slope of the southern part of the basin are furrowed by deep canyons which are western extensions of the main Patagonian Archipelago canals (Mordojovich, 1981). Traps are fault and drape closures in the pattern shown in figure 220. Drag folds may be associated with the strike-slip faults.

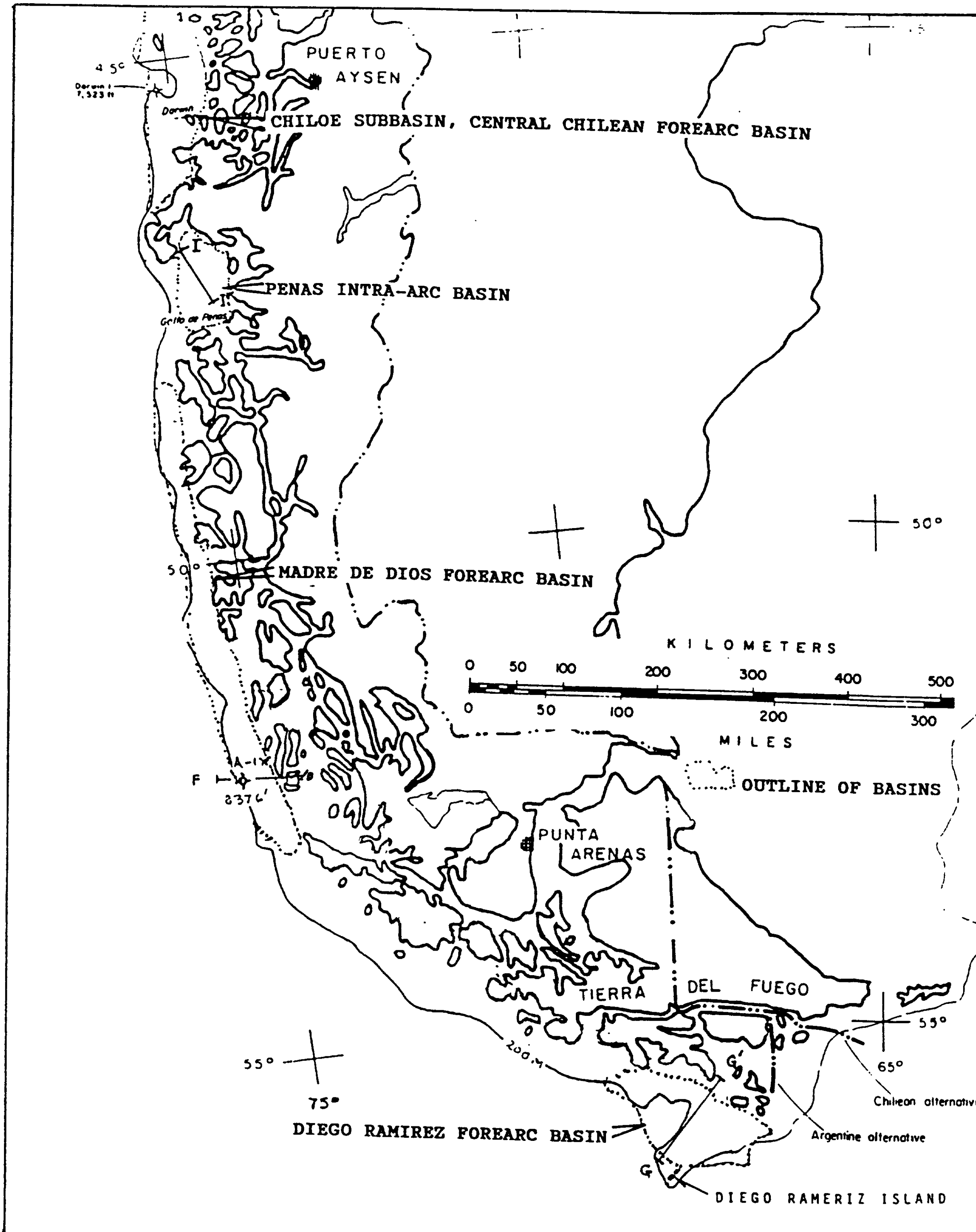


Figure 219 Index map of southern Chile showing the forearc and intra-arc basins (modified from Petroconsultants, 1989 and Gonzalez, 1989).

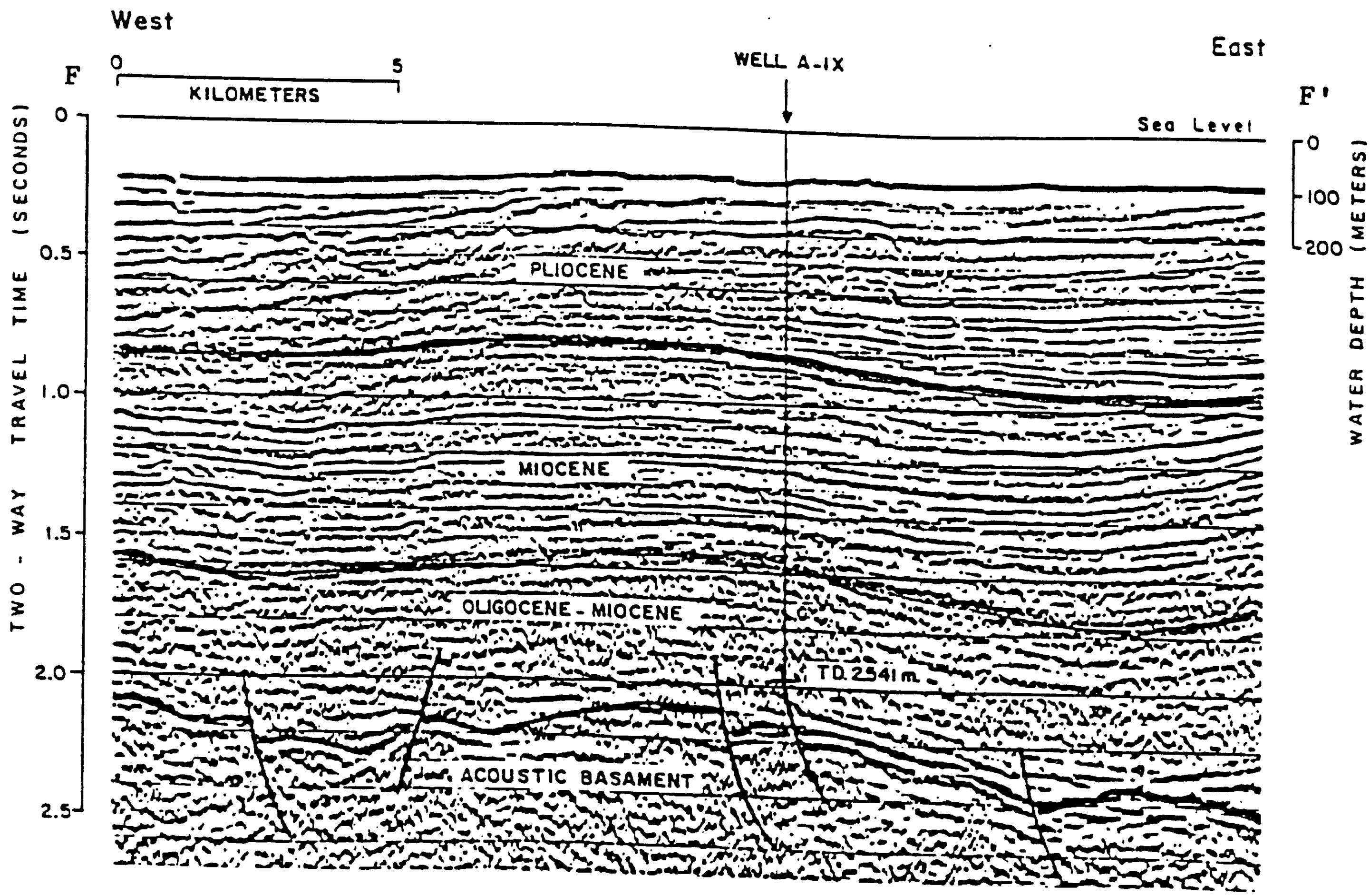


Figure 220 West-east seismic cross-section through exploratory well, A-1X of the Madre de Dios (location figure 219) (after Gonzalez, 1989).

Generation, Migration, and Accumulation. The general shallowness of the basin, 13,000 ft (4,000 m) in the depocenter, but probably averaging around 10,000 ft (3,000 m) in this presumably low-heat-gradient basin, along with the low organic carbon content in an interval near the base of the section (Oligocene-Miocene interval) suggests the sufficiently rich source rock, if it exists, would necessarily be of small volume. Any migration would begin in the late Neogene as the basin reached maximum subsidence depth. At that time traps would have recently formed and Tertiary reservoirs, if any, would be available.

Plays. The only play would appear to be Tertiary sandstones in fault or drape closures.

History of Exploration and Petroleum Occurrence. Seismic survey have located a number of structural trap of which one was drilled. The wildcat, A-X1, found no adequate reservoirs and was dry.

Estimation of Undiscovered Oil and Gas. The closest analog to the Madre de Dios basin is the Central Chilean forearc basin which is estimated to have .04 BBO and 2.0 TCFG. By straight areal analogy the Madre de Dios basin should have .008 BBO and 0.44 TCFG. In view of the possible lack of Upper Cretaceous source and reservoir rock which are the principal factors in favor of the petroleum potential of the Central Chilean forearc basin, however, the resources of this basin are probably negligible.

Diego Ramiriz Basin

Area: 7,700 mi^2 (20,000 km^2)

Original Reserves: Nil

Description of Area: The Diego Ramiriz basin is at the extreme southern tip of the South American continental shelf lying between the Diego Ramiriz Islands (lat. 56°30′S., long. 68°45′W) and the Patagonian Archipelago Islands (fig. 219).

Stratigraphy

No exploratory wells have been drilled in the basin so the stratigraphy can only be interpreted from seismic data tied to outcrops. These data indicate a sedimentary fill of some 16,500 ft (5,000 m) in the depocenter which falls into two sequences. The upper sequence is a slightly deformed, relatively thin unit attributed to the Late Tertiary and Quaternary overlying disconformably a lower, more deformed sequence of higher seismic velocity, 10,000 to 11,500 ft/sec (3,000 to 3,500 m/sec). The lower sequence is divided into two units; the upper unit is interpreted to be Cretaceous and Paleogene flysch deposits and the lower unit Late

Jurassic to Early Cretaceous turbidites and volcano clastic rock (fig. 221) (Gonzalez 1989).

Source. No source information has been obtained. However, bitumen impregnations were found in a sea-bottom sample from the upper slope at the southeasternmost part of the basin (Gonzalez, 1989) indicating some petroleum generation may have occurred. The shallowness of the basin suggests any source rock would have to be in the Jurassic-Early Cretaceous interval (fig. 221).

Reservoirs and Seals. No reservoir and seal information is obtained, but the nearby presence of the Jurassic-Neogene Patagonian batholith indicate that erosion products of quartz sands are likely to provide adequate reservoirs.

Structure

The Diego Ramiriz basin is in a complicated juncture of several megatrends, but can be classified as a forearc basin. The northeast margin is upfaulted granitoid complex and southeast margin is a regional basement high at the shelf margin which may represent accreted terrane. Northeast-trending horst and graben structure predominate, but northwest-trending strike-slip faults are prevalent.

The indicated relative thinness of the Neogene and the unindurated Jurassic sediments suggest that the Diego Ramiriz basin was not so much effected by Andean orogeny and subduction as the more northern basins. It appears from figure 221 that the principal faulting and trap formation was in the mid-Tertiary, largely ceasing by the end of the Tertiary. Tertiary uplift of unknown amplitude occurred.

Generation, Migration and Accumulation. In the absence of source and reservoir data, generation, migration and accumulation timing can only be conjectured. This basin appears to be older than the other forearc basins to the north, but nevertheless, they provide the best available analogy. In these northern basins the timing is controlled by the Neogene subduction which caused more or less contemporaneous generation, migration and trap formation in the Neogene. Figure 221 indicates that in the Diego Ramiriz basin maximum subsidence and trap formation occurred sometime in mid-Tertiary, somewhat earlier than the basins further north, but with favorable, relatively contemporaneous timing between generation-migration and trap formation. Any mature source rock would have to be in the Lower Cretaceous-Jurassic interval.

Plays. The principal play in the Diego Ramiriz would appear to be Mesozoic or Tertiary sandstone reservoirs involved in fault traps and drape closures.

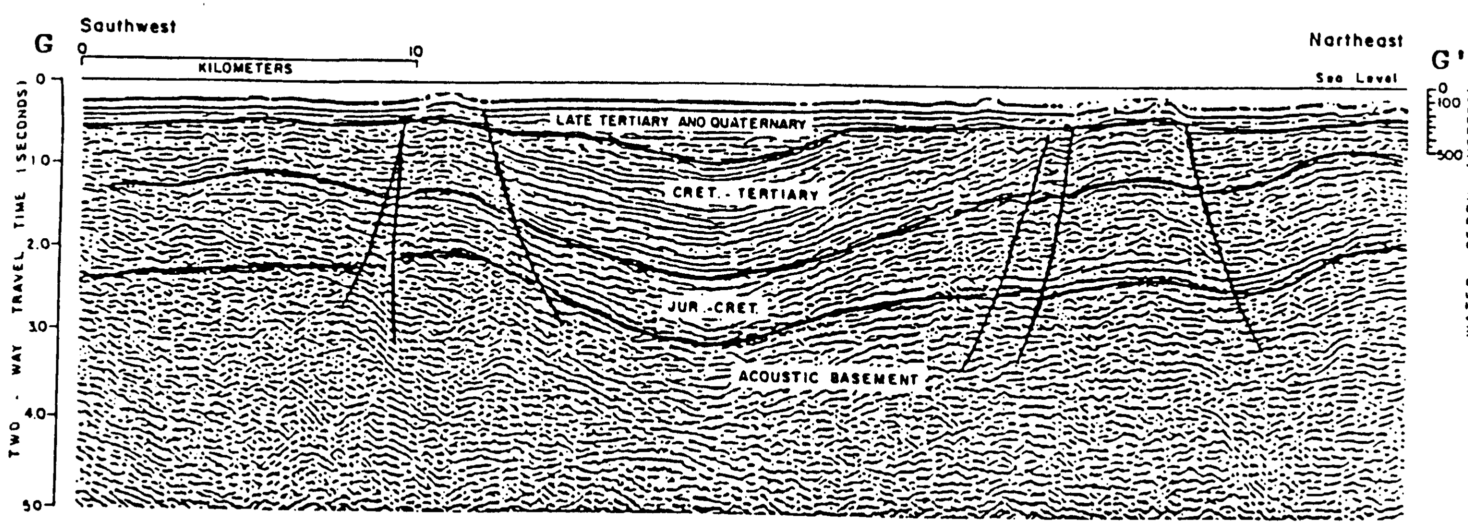


Figure 221 Southwest-northeast geologic cross-section across the Diego Ramirez basin of southernmost Chile (location figure 215) (after Gonzalez, 1989).

Exploration History and Petroleum Occurrence. Exploration to date has been surface geologic and marine seismic surveys; no wildcats have been drilled. One oil show, bitumen impregnations of a sea-bottom sample from the upper continental slope at the southeasternmost part of the basin, was observed.

Estimation of Undiscovered Oil and Gas. In the absence of much data the only available basis for an estimation of undiscovered oil and gas is an analogy to the petroleum resources of the forearc basins to the north even though the geology appears to be somewhat different. By a straight areal analogy to nearest forearc basin, Madre de Dios, the most likely resources of the Diego Ramiriz basin would be .011 BBO and .770 TCFG. In this large basin with extremely inclimate weather, these amounts may be considered negligible. In view of the largely unknown nature of this basin, it should be mentioned that, although the most likely estimate is low, Mesozoic and Paleogene accumulations of substantial size are possible if there had been substantial subsidence prior to the pre-Late Tertiary uplift and presumed erosion, allowing thermal maturation of the Mesozoic possible potential source shales.

Coastal Intra-arc Basins

Onshore along the coast of southern Peru and Chile, there are a number of intra-arc, or intermontane, basins between the Coastal Range and the Andes. The geology of these intra-arc basins is quite similar to that of the parallel, offshore forearc basins and, in some cases, were continuous with them prior to Miocene time.

These intra-arc basins from north to south are the Curico, Temuco, Osorno-Llanquihue, and Pena basins (fig. 215). The most explored and from which the most data are available is the Osorno-Llanquihue basin. It will be assessed first, then the Curico and Temuco, and finally the Pena basins.

Osorno-Llanquihue Basin

Area: 10,400 mi^2 (27,000 km^2)

Original Reserves: Nil

Description of Area: This intra-arc basin lies between the Coastal Range and the Andes and includes the southern Central Valley and most of the Gulf of Ancus, i.e., from 40°S south to 43°30'S (fig. 215).

Stratigraphy

The basin is divided into a western and an eastern subbasin. The western subbasin has somewhat more than 7,500 ft (2,300 m) of marine Oligo-Miocene strata and continental Eocene strata containing sub-bituminous coal beds (fig. 222, 218). The eastern subbasin is covered by a 3,300 ft (1,000 m) of interbedded glacial deposits and volcanics overlying 13,000 ft (3,000 m) of Tertiary continental and marine clastics interbedded with volcanics.

The Upper Cretaceous which has the favorable source and reservoir rock in the Central Chilean forearc basin is missing.

The Eocene part of the Tertiary sequence of the Osorno-Llanquihue basin is made up of coal-bearing continental claystones and sandstones which are similar, and correlatable to, Eocene rocks of the Valdivia and Arauco forearc subbasins and the Temuco intra-arc basin immediately to the north with which it formed a continuous basin in the Eocene.

The overlying Oligo-Miocene section is marine tuffaceous clastics which is found extending from the continental shelf to the Nirihuau basin of Argentina (Gonzalez, 1989).

Source. The Miocene rocks are low in organic content and immature. The Eocene rocks have more organic matter (types II and III kerogen) and maturity only placing them at the beginning stage of petroleum generation. The thermal gradient is low, .98° to 1.37°F/100 ft (18° to 25°C/km) (Gonzalez, 1989). Gas containing heavier hydrocarbon molecules up through n-butane indicates some mature source rock.

Reservoirs and Seals. Good reservoirs exist in the Oligocene-Miocene sequences which have thickness of 300 to 360 ft (95 to 110 m) porosities of 5 to 32 percent, and permeabilities of 11 to 168 md. The Eocene sequence continental sandstones have thickness of 60 to 660 ft (18 to 200 m) and porosities of 6 to 17%.

Tertiary claystones overlying the sandstones provide adequate seals.

Structure

The basin is termed an intra-arc basin separated from the Central Chilean Forearc basin by the Coastal Range. A complex system of north- to northeast-trending normal and strike-slip faults is present. An eastern subbasin is a north-trending graben bounded by faults of great vertical displacement. An upfaulted block of crystalline basement divides the eastern subbasin from a western subbasin which is bounded on the west by a normal fault system. The basin is bounded in the north and south by Paleozoic basement highs. Apparently, the basin was continuous with the intra-arc basin to the

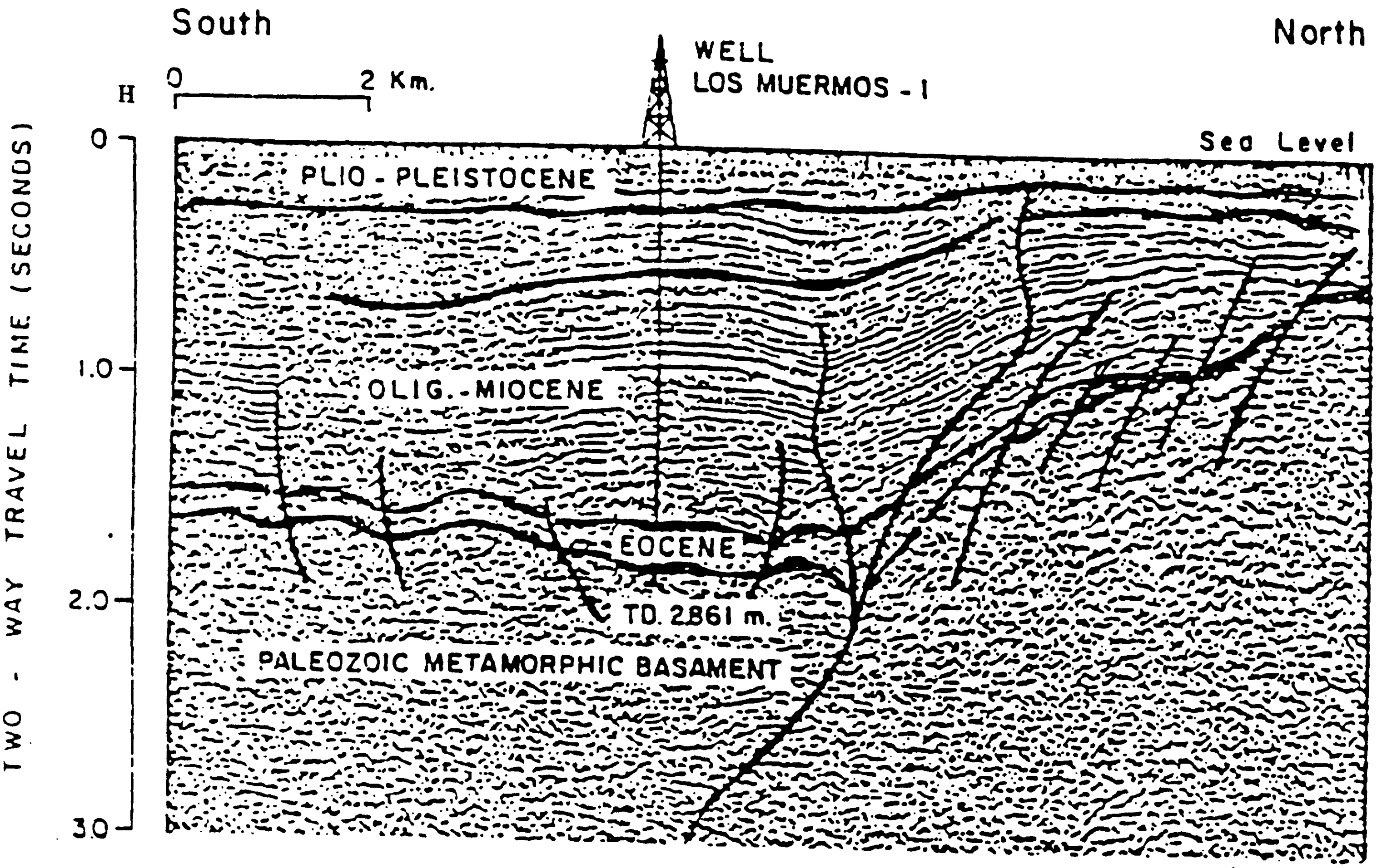


Figure 222 South-north seismic section through the Los Muermos-1 exploratory well of the Osorno-Llanquihue basin (well location fig. 219) (from Gonzalez, 1989).

north, Temuca, and the forearc subbasins, Itata and Arauco during the Eocene, but was later separated by Miocene block-faulting.

Potential traps are fault traps, drape closures over fault blocks and basement paleohighs, rollover anticline associated with listric faulting, and drag folds associated with wrench faulting.

Generation, Migration and Accumulation. Gonzalez (1989) states the fill of the western subbasin is more than 7,500 ft (2,300 m) which, with the present thermal gradient of .98° to 1.37°F/100 ft (18° to 25°C/km), would only thermally generate marginal amounts of petroleum assuming source shale were near the base of the section. The eastern subbasin is indicated to be deeper, some 13,000 ft (4,000 m) of fill including 3,300 ft (1,000 m) of glacial and volcanic beds, which would allow marginal generation, but this subbasin has not been tested; given the apparent lack of good source and volcanic nature of the fill, generation would be minor. Generation and migration would begin in late Neogene when maximum subsidence was reached. At that time, Tertiary traps would be formed and available.

Plays. The principal play is Tertiary sandstones in fault-associated closures, i.e., fault traps, drapes, rollovers and drag folds. Drapes over basement highs would be a secondary play.

Exploration History and Petroleum Occurrence. Some ten or so wildcats were drilled in the northern, onshore position of the basin in the 1960's, and, apparently, there has been no drilling activity since. Significant thermally-generated gas containing heavier hydrocarbon molecules up through n-butane was found in two of the wildcats.

Estimation of Undiscovered Oil and Gas

The Osorno-Llanquihue intra-arc basin is geologically similar, and was probably continuous with at least part of the nearby Central Chilean forearc basin, particularly the Valdivia and Arauco subbasins, prior to the Miocene. It apparently differs, however, from the forearc basin in that: 1) it apparently contains no Upper Cretaceous strata which contain the potential source rock and better potential reservoirs of the forearc basins, and 2) it appears to have appreciably more tuffs and other volcanics in the section. It would therefore appear that the basin is less prospective than the forearc basin. Assuming that it has half the potential on an areal basis of the Central Chilean forearc basin, the Osorno-Llanquihue Intra-arc basin has .008 BBO and .414 TCFG.

Temuco Basin

Area: 8,000 mi^2 (21,000 m)

Original Reserves: Nil

Description of Area:. The Temuco intra-arc basin lies between the Coastal Range and the Andes and extends southwards from Lat. 36°30'S to 39°15'S, i.e., approximately between the cities of Chillan and Valdivia (fig. 215).

Geology

Little information is available concerning the geology of Temuco intra-arc basin other that is similar to that of the Osorno-Llanquihue basin with which it may have been connected prior to some Miocene uplift. Some eleven exploratory holes were drilled with no success; however, a cluster of nine holes in a small area (Labranza) indicates some encouraging shows may have been encountered.

Estimation of Undiscovered Oil and Gas. On the basis of the similar geology it is assumed that the petroleum potential of the Temuco and Osorno-Llanquihue intra-arc basins are areal analogous. This would indicate the undiscovered resources of the Temuco intra-arc basin to be .006 BBO and .318 TCFG.

Carico (Los Angeles) Basin

Area: 7,500 mi^2 (19,500 km^2)

Original Reserves: Nil

Description of Area: The Curico intra-arc basin lies between the Chilean Coastal Range and the Andes. It extends southward from near Santiago for some 225 mi (365 km) to Chillan, i.e., Lat. 33°30'S to 36°15'S (fig. 215).

Geology

No data are available concerning the geology, but it is assumed to be similar to the Temucu intra-arc basin which is in the same tectonic position. One exploratory well has been drilled in the extreme south of the basin. Judging by the relative lack of exploration effort, this basin may be less prospective than the intra-arc basins to the south.

Estimation of the Undiscovered Oil and Gas

The Curico intra-arc basin is assumed to have the same petroleum potential as the Temuco intra-arc basin, even though exploration activity is less. By areal analogy undiscovered resources of .006 BBO and .306 TCFG are indicated.

Penas Basin

Area: 2,300 mi^2 (6,000 km^2)

Original Reserve: Nil

Description of Area. The Penas intra-arc basin covers the Gulf of Penas. It lies east of an extension of the Coastal Range indicated by Mesozoic plutons on the Taita Peninsula at northwest edge of the Gulf (fig. 215).

Stratigraphy

A northwest-southeast seismic section shows a sedimentary fill of some 12,000 ft (3,600 m) (fig. 223), although it reportedly reaches about 13,000 ft (4,000 m) at its deepest. According to Gonzalez (1989) the basin apparently originated during the Tertiary. Subsequent subsidence and accumulation of sediments was rapid. No details of the stratigraphy are available; the sediments are undoubtedly all clastic and probably Tertiary. The Upper Cretaceous sequence which contained the potential source rock and better quality reservoirs of the Central Chilean forearc basin appear to be missing.

Source. Gonzalez (1989) states there are quartz sandstones in the basin believed to be satisfactory reservoir rocks and that Tertiary shales over the sandstones are sealing rocks.

Structure

The basin apparently originated during the Tertiary through rupture and separation of blocks along wrench faults. The southeastern boundary of the basin is northeast-trending, right-lateral wrench fault and the northern boundary is marked by a northwest-trending fault. A complex system of associated fractures and faults greatly affect the basin configuration. As may be seen from fig. 223, the faulting is concentrated in the Paleogene and wrench-faulting (flower structure) is present.

Possible traps are associated with fault blocks, drapes and possible drag folds accompanying the wrench faults.

Generation, Migration and Accumulation. Generation probably began in the late Neogene when the basin reached near its present maximum depth and when an elevated thermal gradient may have been caused by the near approach of the intersection of the Chile Rise with the trench (fig. 215). In that time the Tertiary reservoir sandstones and the fault-associated traps were available to any migration.

Plays. The principal play would be Tertiary sandstone reservoirs involved in fault-associated traps.

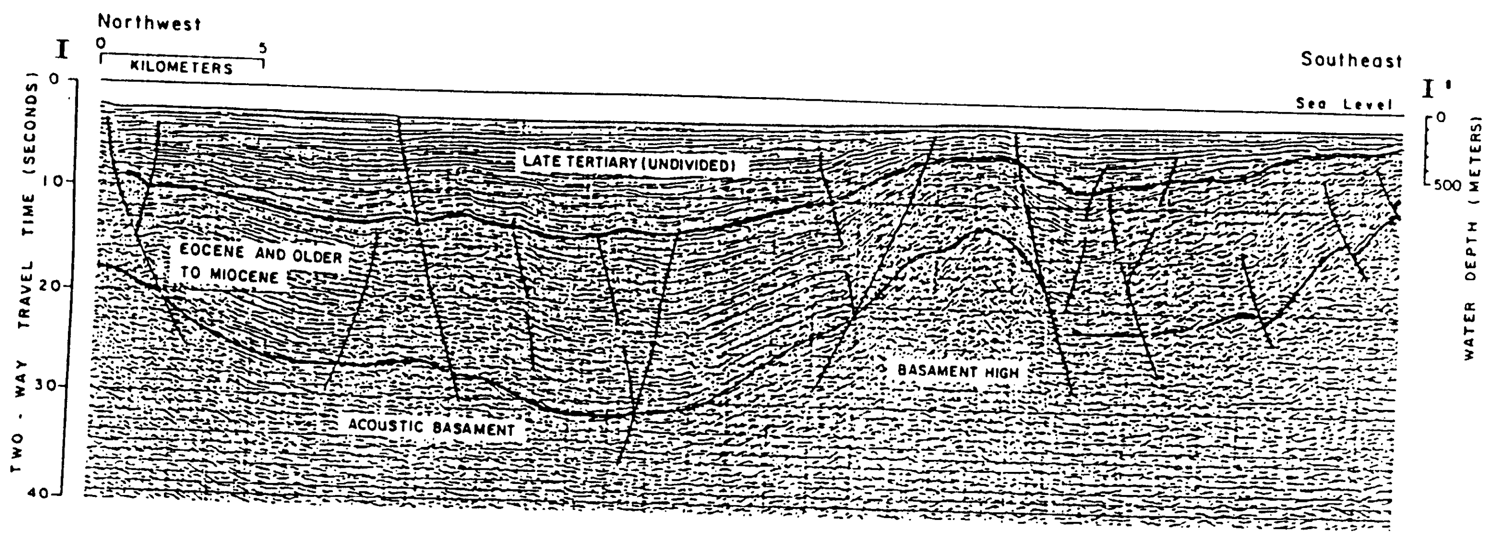


Figure 223 Northwest-southeast seismic section across the Penas basin (location figures 215 and 219) (from Gonzalez, 1989).

Exploration History and Petroleum Occurrence. Exploration has been some marine seismic survey and outcrop studies. No wells have been drilled. No gas or oil seeps reported.

Estimation of Undiscovered Oil and gas

The geology of the Penas intra-arc basin appears similar to the other Chilean intra-arc basins. The basin fill appears to be only Tertiary. The adequately rich Upper Cretaceous shales of the Central Chile Forearc basin appear to be missing. The good Upper Cretaceous reservoirs are missing but Tertiary sandstones are probably sufficient. The Tertiary clastic fill is relatively thin, but a postulated higher thermal gradient may have enhanced generation.

By its probable analogy to the Osorno-Llanquhue basin, on an areal basis, the resources would be .0017 BBO and .092 TCFG. However, the postulated increased thermal gradient may double the resources to .003 BBO and .184 TCFG.

V SUMMARY AND CONCLUSIONS

A. SUMMARY

1. The area of study includes the South American portion of the old Gondwana continent, exclusive of the northern perimeter affected by continental collisions and incursions of the Tethyan seas, i.e. Venezuela and Colombia.

2. The area constitutes 88 percent of the South American area but has only half the proved oil reserves, i.e. 25 BBO versus 53 BBO. Table VI shows the estimated proved reserves of the producing countries exclusive of Venezuela and Colombia.

3. Preliminary estimates of undiscovered oil and gas in each of the 61 major basins considered, along with the corresponding estimated reserves, are summarized in Table VII.

4. On the basis of this preliminary study,.consensus estimates of the undiscovered oil and gas on a more regional basis were made by the World Energy Program group of the U.S. Geological Survey. These estimates are given in a range of probabilities, a 95 percent, a modal or "more likely," a 5 percent, and a mean probability. This range of probabilities of undiscovered oil and gas for each of the geologic provinces is shown in (unadjusted) Table VIII. In general, the consensus estimates were more optimistic than the preliminary study, increasing the estimates by an average of 25 percent for oil and 20 percent for gas; this increase is especially great for the interior sag basins.

5. Sometime after the consensus as to the regional amounts of undiscovered oil and gas was reached, a review of the 1983-1993 history of the oil and gas reserves indicated that our initial consensus estimates were too low. The estimates were too low largely because they were based on comparisons to geologically analogous fields, the published reserves of which, though not often stated, are Original Proved Reserves rather than the total or Original Identified Reserves (see Appendix A for explanation). Consequently, estimations of the Original Identified Reserves of the analogous accumulations were calculated (Table IX) and the ratio between the Original Indicated Reserves and the Original Proved Reserves found. This ratio times the initial undiscovered oil and gas estimates (which were largely based on Original Proved Reserve analogies) gave estimates that were closer to the true amounts of undiscovered oil and gas (Table X). The final adjusted range of probabilities of undiscovered petroleum were derived from Table X, as explained in Appendix A, and shown in Tables XI and XII on a basin by basin and on a country by country basis.

6. The sum of the mean probabilities of undiscovered oil and gas of the countries (Table XII) indicate that the undiscovered petroleum of South America (exclusive of Venezuela and Colombia)

TABLE VI

ESTIMATED ORIGINAL RESERVES OF PETROLEUM PRODUCING COUNTRIES OF SOUTH AMERICA (EXCLUSIVE OF VENEZUELA AND COLOMBIA)

(APPROXIMATELY 1990 DATA)

	OIL(BBO)	GAS(TCFG)
ARGENTINA	7.122	36.481
BOLIVIA	0.480	7.200
BRAZIL	9.904	12.614
CHILE	0.323	8.513
ECUADOR	3.402	0.883
PERU	3.362	14.572
SURINAM	0.045	----
TOTAL	24.975	80.402

TABLE VII (Page 1)

PRELIMINARY INDIVIDUAL BASIN SUMMARY OF PETROLEUM RESOURCES OF SOUTHERN SOUTH AMERICA (1)
(Modal or "most likely" of estimates)

BASINS	ESTIMATED ORIGINAL PROVED RESERVES(2)		ESTIMATED UNDISCOVERED PETROLEUM	
BRAZILIAN CRATON AREA(3)	BBO(4)	TCFG	BBO(4)	TCFG
RIFTED MARGIN				
PELITOS	----	----	0.086	0.518
SANTOS	0.048	0.725	0.028	3.967
CAMPOS	7.440(5)	4.522(5)	4.154(5)	2.521(5)
ESPIRITO SANTOS	0.108	0.528	0.202	0.544
BAHIA SUL	0.021	0.001	0.031	0.162
SERGIPE-ALAGOAS	0.499	0.790	0.798	1.263
POTIGUAR	0.220	----	0.274	0.337
CAERA	0.084	0.065	0.389	0.288
BARREIRINHAS	0.004	----	0.146	0.116
PARA-MARANHOA	0.007	----	0.068	0.062
FOZ DO AMAZONAS	----	0.880	0.423	10.900
GUYANA (SURINAM,GUYANA)	0.045	----	0.305	0.250
	(8.476)	(7.511)	(7.184)	(20.913)
INTERIOR RIFT				
RECONCAVO	1.436	3.043	0.186	0.393
TUCANO-JATOBA	----	0.060	0.061	0.803
TACUTU	----	----	0.026	0.034
	(1.436)	(3.103)	(0.273)	(1.234)
INTERIOR SAG				
SOLIMOES	0.037	2.000	0.040	2.000
AMAZONAS	----	----	0.035	2.070
PARNAIBA	----	----	0.037	1.900
PARANA	----	----	0.100	5.080
CHACO(ARGENTINA)	----	----	0.025	1.350
	(0.037)	(2.000)	(0.237)	(12.400)
TOTAL BRAZILIAN CRATON	9.949	12.614	7.694	34.547
BRAZILIAN FORELAND				
ACRE	----	----	0.190	2.920

(1) Preliminary to regional consensus estimates of Tables VIII and XI and not adjusted for growth.
(2) Estimated to be approximately proved reserves.
(3) All basins through Acre are Brazilian except Guyana and Chaco.
(4) Includes condensate.
(5) Estimates were made on 1990-1991 data. Establishment of the giant Barracuda field in 1991 (reported in 1992) with reserves of 1.1 BBO (and presumably a corresponding 0.632 TCFG) is assumed to have increased the 1990 Campos reserves and decreased the 1992 undiscovered petroleum estimates accordingly.

TABLE VII (Page 2)

PRELIMINARY INDIVIDUAL BASIN SUMMARY OF PETROLEUM RESOURCES OF SOUTHERN SOUTH AMERICA (1)

BASINS	ESTIMATED ORIGINAL PROVED RESERVES)2)		ESTIMATED UNDISCOVERED PETROLEUM	
PATAGONIAN ACCRETED AREA	BBO(4)	TCFG	BBO(4)	TCFG
FORELAND/INTERIOR RIFT				
MAGALLANES	0.763	14.228	0.224	0.627
MALVINAS	----	----	0.215	3.235
MALVINAS PLATEAU	----	----	0.070	1.000
MALVINAS TROUGH	----	----	0.007	0.103
SAN JORGE	3.450	2,670	0.365	0.671
COLORADO	----	----	0.060	0.060
SALADO	----	----	0.030	0.030
NIRIHUAN	----	----	Ng(6)	Ng
NEUQUEN	1.997	24.610	0.171	1.173
CUYO	1.115	0.216	0.044	0.011
RIFTED MARGIN				
EAST PATAGONIA	----	----	0.175	1.066
TOTAL PATAGONIAN BASINS	7.325	41.274	1.362	7.976
SUBANDEAN REGION				
FORELAND BASINS				
PAMPEANAS AREA	----	----	0.070	0.014
ORAN	0.108	0.360	0.119	0.397
SANTA CRUZ-TARIJA	0.492	10.560	0.042	1.690
BENI	----	----	0.073	1.660
MADRE DE DIOS	----	----	0.420	6.000
UCAYALI	0.786	11.740	0.619	6.770
MARANON-ORIENTE-PUTUMAYO	4.300(7)	0.080(7)	3.700(7)	0.600(7)
OVERTHRUST BELT				
HUALLAGA	----	----	0.250	3.700
SANTIAGO	----	----	0.140	2.000
ANDEAN INTRA-ARC				
ALTOPLANO	0.0003	----	0.012	0.250
TOTAL SUBANDEAN BASINS	5.686	23.460	5.445	23.081

(6) Ng = Negligible resources.
(7) Includes Colombian portion of basin (reserves= .267 BBO, undiscovere petroleum= .36 BBO and .06 TCFG).

TABLE VII (Page 3)

PRELIMINARY INDIVIDUAL BASIN SUMMARY OF PETROLEUM RESOURCES OF SOUTHERN SOUTH AMERICA (1)

BASINS	ESTIMATED ORIGINAL PROVED RESERVES(2)		ESTIMATED UNDISCOVERED PETROLEUM	
PACIFIC COASTAL BASINS	BBO(4)	TCFG	BBO(4)	TCFG
PERUVIAN-ECUADORIAN BASINS				
FOREARC BASINS				
TALARA	1.816	2.699	1.200	1.400
PROGRESO	0.131	0.251	0.225	5.100
ESMERALDAS-CARAQUEZ	----	----	Ng	Ng
TRUJILLO	----	----	0.157	0.215
LIMA	----	----	Ng	Ng
MELLENDA-TARAPARA	----	----	Ng	Ng
INTRA-ARC BASINS				
LANCONES	----	----	Ng	Ng
MANIBI	----	----	Ng	Ng
BORBON	----	----	Ng	Ng
SECHURA	----	----	Ng	Ng
SALAVERRY	----	----	Ng	Ng
PISCO	----	----	Ng	Ng
MOQUEGUA-TAMARUGA	----	----	Ng	Ng
SALAR DE ALTACAMA	----	----	Ng	Ng
TOTAL PERUVIAN-ECUADORIAN	1.947	2.950	1.582	6.715
SOUTH CHILEAN BASINS				
FOREARC BASINS				
CENTRAL CHILEAN	----	----	0.040	2.000
MADRE DE DIOS	----	----	0.008	0.440
DIEGO RAMIREZ	----	----	0.011	0.770
INTRA-ARC BASINS				
OSORNO-LLANQUIHUE	----	----	0.008	0.414
TUMUCO	----	----	0.006	0.318
CURICO	----	----	0.006	0.306
PENAS	----	----	0.003	0.184
TOTAL SOUTH CHILE BASINS	----	----	0.082	4.432
TOTAL PACIFIC BASINS	1.947	2.950	1.664	11.147
TOTAL SOUTH AMERICA (Exclusive Venezuela and Columbia)	24.975	80.402	16.351(8)	79.671(8)

(8) The total of these modal or "most likely" estimates are less than the total of the mean of a range of estimates (Tables VII and IX) which include the low probability of very large discoveries.

TABLE VIII

UNADJUSTED (1)

UNDISCOVERED OIL AND GAS BY GEOLOGIC PROVINCE (BASED ON 1990 DATA)

SOUTH AMERICA (EXCLUSIVE OF VENEZUELA AND COLOMBIA)

OIL (BBO)	95%	MODE	5%	MEAN (2)
BRAZILIAN CRATON REGION				
RIFTED MARGIN				
S.E. COAST	2.50	7.00	12.50	8.00(3)
N.E. COAST	0.30	0.80	1.20	0.86
INTERIOR RIFTS	0.03	0.20	0.50	0.27
INTERIOR SAGS	0.20	1.30	6.50	2.65
(FORELAND BASIN)	0.005	0.10	0.20	0.12
PATAGONIAN ACCRETED REGION				
ARGENTINA	0.97	2.90	10.75	4.86
CHILE	0.20	0.40	1.00	0.53
SUBANDEAN REGION				
FORELAND BASINS				
ARGENTINA	0.02	0.11	0.32	0.16
BOLIVIA	0.09	0.30	0.80	0.41
PERU	1.08	3.44	9.10	4.74
ECUADOR	0.08	2.42	6.37	3.32
INTERMONTANE	0.01	0.05	0.20	0.09
PACIFIC COASTAL BASINS				
PERU	0.50	1.10	3.10	1.18
ECUADOR	0.10	0.20	0.80	0.35
CHILE	0.05	0.18	0.42	0.23
TOTAL OIL (BBO)				27.79

GAS (TCFG)	95%	MODE	5%	MEAN (2)
BRAZILIAN CRATON REGION				
RIFTED MARGIN				
S.E. COAST	4.50	11.30	27.00	14.75 (3)
N.E. COAST	5.00	11.00	40.00	18.23
INTERIOR RIFTS	1.00	3.00	8.00	4.15
INTERIOR SAGS	2.50	8.90	53.00	20.52
(FORELAND BASIN)	0.20	0.50	1.00	0.60
PATAGONIAN ACCRETED REGION				
ARGENTINA	3.90	16.60	38.00	21.21
CHILE	0.10	0.40	1.00	0.53
SUBANDEAN REGION				
FORELAND BASINS				
ARGENTINA	0.90	1.31	6.03	2.53
BOLIVIA	2.20	7.40	18.20	9.80
PERU	6.90	21.89	55.14	29.37
ECUADOR	0.80	2.50	7.80	3.78
INTERMONTANE	0.07	0.42	1.65	0.73
PACIFIC COASTAL BASINS				
PERU	0.87	2.19	6.35	3.17
ECUADOR	1.13	4.10	12.00	5.97
CHILE	2.00	4.43	10.00	5.62
TOTAL GAS (TCFG)				140.95

(1) Based on Original Proved (Measured) Reserves of analogous oil and gas accumulations rather than Original Identified Reserves.

(2) In fitting individual basins into group-estimates, or vice versa, mean values are arithmetically, and range values judgmentally, integrated.

(3) This estimate, based on 1990 data, should theoretically be reduced by the amount of the giant Barracuda discovery of 1991 (1.1 BBO and presumably .632 TCFG). Reduced in Tables XI and XII

TABLE IX

ESTIMATED ORIGINAL IDENTIFIED RESERVES (in BBO) OF SOUTH AMERICAN KEY BASINS WHICH ARE REPRESENTATIVE OF THEIR GEOLOGIC PROVINCE

As derived from Petroconsultants data up to 1989, using field-growth calculation methods and model of Root and Mast (1993)

	1 TOTAL OIL DISCOVERIES (As of discovery date)	2 UNPROVED RESERVES (Up to 1989)	3 IDENTIFIED RESERVES (1989)
BRAZIL CRATON REGION			
RIFTED MARGIN			
S.E.COAST(1)			
CAMPOS	7.278	9.192	16.478
SERGIPE-ALAGOAS	0.714	0.438	1.151
N.E COAST			
CAERA(2)	0.088	0.055	0.143
INTERIOR RIFTS			
RECONCAVO(3)	1.193	0.372	1.565
INTERIOR SAGS			
SOLIMOES(4)	0.037(0.070)(4)	0.104(0.198)(4)	0.142(0.268)(4)
PATAGONIAN REGION(5)			
MAGALLANES (Chile)	0.347	0.180	0.504
MAGALLANES (Arg.)	0.324	0.233	0.580
SAN JORGE	3.450(0.881)(6)	0.345(0.270)(6)	3.795(1.151)(6)
NEUQUEN	1.474	0.779	2,562
CUYO	1.136	0.311	1.447
SUBANDEAN REGION(7)			
SANTA CRUZ-TARIJA (Arg.)	0.011	0.008	0.019
SANTA CRUZ-TARIJA (Bol.)	0.480(0.206)(8)	-----(0.124)(8)	0.570(0.330)(8)
UCAYALI (9)	0.786	2.100	2.866
MARANON-ORIENTE-PUTUMAYO	4.104	2.237	6.341(10)
PACIFIC COAST BASINS			
TALARA(11)	1.186	Incomplete growth data Assumed 1.1 growth-factor(12)	1.305

(1) Campos and Sergipe-Alagoas basins contain 98 percent of S.E.Coast reserves.
(2) Although Caera basin contains only 23.3% of N.E.Coast reserves, available data give best basis for estimation of growth factor and Original Identified Reserves of the N.E.Coast region.
(3) Reconcavo basin contains virtually all of Interior Rift reserves.
(4) Solimoes basin contains all of the Interior Sags reserves. Petroconsultants list discoveries of 0.070 BBO, but Petbras show reserves of only 0.037 BBO; therefore, calculated Original Identified Reserves are lowered proportionately from 0.268 to 0.142 BBO .
(5) Four listed basins contain virtually all the Patagonian Region reserves
(6) Petroconsultants data for this basin are incomplete (in parenthesis) and indicate a too high growth factor (1.306) for such a maturely explored basin. Assuming a low growth factor of 1.1 and using published Original Proved Reserves of 3.45 BBO, Original Identified Reserves of 3.795 BBO is estimated.
(7) Three listed basins contain virtually all reserves of the Subandean Region
(8) Petroconsultants growth data appear incomplete and low (in parentheses), compared to a YPF Bolivia reported 1990 Proved Reserves of 0.480 BBO, but do indicate a growth factor (Discoveries to Identified Reserves) of 1.60. This growth factor, though seemingly high, is applied to the .480 BBO Proved Reserve figure to obtain an Identified Reserve estimate.
(10)Not used as analog for basins undiscovered oil estimate. See Table X.
(11)Talara basin contains all the oil of the Pacific Coast basins.
(12)Incomplete growth data, so assumed a low growth of 1.1 consistent with the maturely explored Talara basin.

amounts to some 43 BBO and 140 TCFG. This is twice the 1990 published oil reserves and one and three-fourths the gas reserves.

B. CONCLUSIONS

1. General.

a. Of the countries studied, Brazil has the greatest petroleum potential, having a 52 percent of southern South America's undiscovered oil and gas (on an oil-equivalent basis). Peru is second with an 18 percent share; Argentina third with a 15 percent share; Ecuador has an 8 percent share, and all the other southern South American countries together have a 7 percent share.

b. Of the various plays of southern South America, the play with the highest potential is that of the turbidites of the Atlantic rifted margin with estimated undiscovered petroleum amounting to 11 BBOE. The next highest may be the overthrust and fold belt play of the eastern Andes, recently high-lighted by the Cashiari gas and condensate discovery of southern Peru; its estimated potential amounts to 6 BBOE. A third high-potential play may be the still unexplored, the supposed Cretaceous stratigraphic trap play of the Maranon-Oriente-Putumayo basin which may amount to 3 BBOE.

c. The maturity of southern South America exploration varies from area to area, ranging from exhaustively explored to virtually unexplored, but, generally, exploration is still immature. The onshore basins of Argentina, the Santa Cruz-Tarija basin of Bolivia, the Reconcavo basin of Brazil, and the onshore Talara basin of Peru have been maturely explored. The remaining basins are immaturely explored largely because of operational difficulties, e.g. deep waters of continental slopes, inaccessible, remote jungle areas of interior basins, and inclimate weather and political situation in the Falkland areas. Political instability and lack of capital are problems in some regions. The areas which appear to have the highest potential, i.e. turbidite slopes, overthrust belt and foreland stratigraphic traps, may all be considered frontier areas. Totally unexplored areas are the Malvinas plateau and trough and some of the smaller forearc and intra-arc basins of the Pacific region.

d. Over a third of the undiscovered oil and gas of South America, on an oil equivalent basis (exclusive of Venezuela and Colombia) is estimated to be in offshore areas and at least three-fourths of that is on the slope.

e. A relatively high estimate is made for the interior sag basins, largely of Brazil, but these basins have severe operational problems, e.g., thick volcanic cover, pervasive diabase intrusives, remoteness and thick jungle in the Amazon drainage area, so that economic feasibility requires large accumulations. So far, there is little indication of such accumulations.

TABLE X - **UNDISCOVERED OIL ESTIMATES BASED ON COMPARISONS TO ORIGINAL IDENTIFIED RESERVES OF GEOLOGICALLY ANALOGOUS ACCUMULATIONS (IN BBO).**
As converted from initial estimates based on comparisons to Original Proved Reserves of same analogous accumulations.

	1	2	3	4	5
	ANALOGOUS OIL RESERVES			UNDISCOVERED OIL (MODE OF ESTIMATE	
	ORIGINAL PROVED(1) (Col.1,TableVII)	ORIGINAL IDENTIFIED(2) (Extrapolated from Col.3,TableIX)	IDENTIFIED OVER PROVED RATIO (3) (Col.2/Col.1)	BASED ON ORIGINAL PROVED RESERVE ANALOG(4) (Mode,TableVIII)	BASED ON ORIGINAL IDENTIFI RESERVE ANALOG(5) (Col.3 X Col.4)
BRAZIL CRATON REGION					
RIFTED MARGIN					
S.E.COAST	8.116	18.00	2.22	7.00	15.54
N.E.COAST(6)	0.360	0.60	1.67(6)	0.80	1.34
INTERIOR RIFTS(7)	1.436	1.56	1.09(7)	0.20	0.22
INTERIOR SAGS(8)	0.037	0.14	3.84(8)	1.30	4.99
PATAGONIAN REGION					
ARGENTINA	7.001	8.38	1.20	2.90	3.48
CHILE	0.324	0.50	1.56	0.40	0.62
SUBANDEAN REGION					
FORELAND BASINS					
ARGENTINA	0.012	0.02	1.58	0.11	0.17
BOLIVIA	0.480	0.57	1.20(9)	0.30	0.36
PERU					
UCAYALI	0.786	2.86	3.64	0.12	0.44
M-O-P (10)	-----	----	1.00(11)	3.32	3.32
ECUADOR					
M-O-P (10)	-----	----	1.00(11)	2.60	2.60
INTERMONTANE	Ng	Ng	----	0.05	0.05
PACIFIC COAST BASINS					
PERU (Talara)	1.816	----	1.10(12)	1.10	1.21
ECUADOR	0.131	----	1.10(12)	0.20	0.22
CHILE	Ng	Ng	1.10(12)	0.18	0.20

(1) Proved Reserve estimates from various sources, estimate dates ranging from 1989 to 1991.
(2) Calculated exclusively from Petroconsultants annual discovery and reserve data up to 1989, employing the Root and Mast (1993) method and model. As noted, Petroconsultants data not always in conformity with other reserve information.
(3) Ratio of calculated Original Identified Reserves to Original Proved Reserves of accumulations upon which initial undiscovered oil estimates were directly or indirectly based.
(4) Mode (most likely) of the range of estimates of the World Energy Resource Program consensus, Table VIII (after review of initial author's presentation summarized in Table VII).
(5) Estimates increased proportionately to the degree Original Identified exceeds Original Proved Reserves of analogous oil accumulations
(6) Ratio of group province assumed to be proportional to its best-documented basin, Caera.
(7) Ratio of group-province assumed to be proportional to its principle basin, Recancavo.
(8) Ratio of group-province assumed to be proportional to its only producing basin, Solimoes.
(9) In the absence of tenable data, an estimated ratio of 1.2 for a maturely expored basin (first discovery 1924) has been assumed.
(10)The M-O-P basin, apparently having at least one substantial unrealized play, appears to hav insufficient intra-basinal established oil accumulations to serve as analogies, and the undiscovered oil estimates (Mast et al,1989) of the geologically similar Powder River basin of the USA was adopted as an analogy on an areal basis for the M-O-P basin undiscovered oil estimate.
(11)Assumes the ratio, 1.00, as the Powder River undiscovered oil estimates were made with with the Original Identified Reserves in mind (Mast et al, 1989)
(12)A low ratio, 1.1, consistent with the mature exploitation of the Talara basin, is assumed.

TABLE XI

UNDISCOVERED OIL AND GAS BY GEOLOGIC PROVINCE (BASED ON 1990 DATA)

SOUTH AMERICA (EXCLUSIVE OF VENEZUELA AND COLOMBIA)

(Adjusted for growth from Table VIII; See Appendix A)

OIL (BBO)	95%	MODE (1)	5%	MEAN
BRAZILIAN CRATON REGION				
RIFTED MARGIN				
S.E. COAST	5.55	15.54	27.75	17.76(2)
N.E. COAST	0.50	1.34	2.00	1.44
INTERIOR RIFTS	0.03	0.22	0.55	0.29
INTERIOR SAGS	0.77	4.99	25.00	10.18
(FORELAND BASIN)	0.01	0.12	0.23	0.14
PATAGONIA ACCRETED REGION				
ARGENTINA	1.16	3.48	12.19	5.83
CHILE	0.31	0.62	1.56	0.83
SUBANDEAN REGION				
FORELAND BASINS				
ARGENTINA	0.02	0.17	0.51	0.25
BOLIVIA	0.11	0.36	0.96	0.49
PERU	1.17	3.76	9.94	5.13
ECUADOR	0.08	2.60	6.84	3.56
INTERMONTANE	0.01	0.05	0.20	0.09
PACIFIC COASTAL BASINS				
PERU	0.55	1.21	3.41	1.23
ECUADOR	0.11	0.22	0.88	0.39
CHILE	0.06	0.20	0.46	0.25
TOTAL OIL (BBO)				47.86

GAS (TCFG)	95%	MODE (1)	5%	MEAN
BRAZILIAN CRATON REGION				
RIFTED MARGIN				
S.E. COAST	4.25	10.67	25.25	13.93 (2)
N.E. COAST	5.00	11.00	40.00	18.23
INTERIOR RIFTS	1.00	3.00	8.00	4.15
INTERIOR SAGS	2.50	8.90	53.00	20.52
(FORELAND BASIN)	0.20	0.50	1.00	0.60
PATAGONIA ACCRETED REGION				
ARGENTINA	3.90	16.60	38.00	21.21
CHILE	0.10	0.40	1.00	0.53
SUBANDEAN REGION				
FORELAND BASINS				
ARGENTINA	0.90	1.31	6.03	2.53
BOLIVIA	2.20	7.40	18.20	9.80
PERU	6.90	21.89	55.14	29.37
ECUADOR	0.80	2.50	7.80	3.78
INTERMONTANE	0.07	0.42	1.65	0.73
PACIFIC COASTAL BASINS				
PERU	0.87	2.19	6.35	3.17
ECUADOR	1.13	4.10	12.00	5.97
CHILE	2.00	4.43	10.00	5.62
TOTAL GAS (TCFG)				140.14

(1) Mode values from column 5, Table X.
(2) The original estimate, based on 1990 data, is reduced by the amount of the giant Barracuda discovery of 1991 (1.1 BBO and .632 TCFG).

TABLE XII

UNDISCOVERED OIL AND GAS BY COUNTRY

SOUTH AMERICA (EXCLUSIVE OF VENEZUELA AND COLOMBIA)

OIL (BBO)	95%	MODE	5%	MEAN(1)
ARGENTINA	1.18	3.66	13.43	6.07
BOLIVIA	0.11	0.36	0.96	0.49
BRAZIL	6.82	22.09	53.30	29.41(2)
CHILE	0.37	0.82	2.01	1.08
ECUADOR	0.20	2.62	7.72	3.95
FRENCH GUIANA	0.00	0.01	0.02	0.01
GUYANA	0.02	0.06	1.20	0.36
PARAGUAY	0.00	0.01	0.02	0.01
PERU	1.75	4.93	13.48	6.45
SURINAM	0.01	0.05	1.00	0.03
URUGUAY				
Total oil				47.86

GAS (TCFG)	95%	MODE	5%	MEAN
ARGENTINA	4.80	17.19	43.00	22.85
BOLIVIA	2.20	7.40	18.20	9.80
BRAZIL	12.95	34.07	127.25	57.43 (2)
CHILE	2.10	4.83	11.00	6.16
ECUADOR	1.93	6.60	19.80	9.75
FRENCH GUIANA				
GUYANA				
PARAGUAY				
PERU	7.84	24.50	63.14	33.27
SURINAM				
URUGUAY				
TOTAL GAS				140.14

(1) In fitting individual basins into group-estimates, or vice versa, mean values are arithmetically, and range values judgmentally, integrated.

(2) The original estimate, based on 1990 data, is reduced by the amount of the giant Barracuda discovery of 1991 (1.1BBO and .632 TCFG).

f. Some 21 forearc and associated intra-arc basins occur along the Pacific coastal drainage area of South America. Of these, only the Talara and adjoining Progreso basins have petroleum production. These two forearc basins appear to have two particular features indicating a higher than normal thermal history: 1) an unusually thick Eocene stratigraphic section signifying deep Eocene subsidence, and 2) a unique pull-apart graben, at the intersection of the subduction zone with a regional megashear in the region of the Gulf of Guayaquil. Lacking these heat-supplying circumstances, the remaining, presumably cool, forearc and associated intra-arc basins appear to have a low petroleum potential.

2. Country-by-County

a. Brazil.

Brazil is the richest country in original oil reserves as well as estimated undiscovered oil and gas. Most of Brazil's undiscovered oil and gas is in the shelf and slope of the continental margin. Nonassociated gas potential is in the Paleozoic interior sag basins and in the Amazon delta, but of minor quantity compared to the associated gas potential of the continental margin. Most of the exploration has been done by Brazil's national oil company and appears to have been a massive and persistent effort through the years at the leading edge of current technology. On an oil-equivalent basis, the estimated amount of undiscovered oil and gas is about three times the 1990 proved reserves.

b. Argentina.

Argentina presently has the most gas production, having almost half the original gas reserves of southern South America. However, the potential gas resources, including undiscovered gas, are surpassed by Brazil. Since the Argentine basins are largely onshore, relatively jungle-free, and easily accessible, exploration is more mature and, therefore, estimated remaining undiscovered oil and gas is not such a significant quantity as in other South American countries, only amounting to three-fourths of 1990 reserves.

c. Peru.

Peru's undiscovered oil and gas is estimated to be largely in the immaturely explored foreland basins east of the Andes in two plays; Andean overthrust and fold belt closures and Cretaceous foreland stratigraphic traps. In this remote, inaccessible and hostile area large accumulations would be required for economic production. Peru also has estimated undiscovered oil and gas in the offshore portion of the maturely explored onshore Talara basin and perhaps in the adjoining offshore Trujillo forearc basin. The economics for offshore operations, however, may not be favorable since the petroleum apparently occurs in many small complicated fault-block traps. The estimated undiscovered oil and gas of Peru is two and a half times the 1990 reserves.

d. Ecuador

Ecuador's undiscovered oil and gas is very largely in the Oriente sector of the Maranon-Oriente-Putumayo basin. It probably will be found there in further structures and in Cretaceous stratigraphic traps. The stratigraphic traps apparently present the best possibility for future discoveries, but large accumulations will be economically required in this remote area. Offshore areas of the Progreso basin have undiscovered oil and particularly gas. The estimated undiscovered oil and gas of Ecuador is about one and a half of the present reserves on an oil equivalent basis.

e. Bolivia

Bolivia is maturely explored in the southern one-third of the Subandean zone (the Santa Cruz-Tarija basin), but the northern two-thirds is not, probably owing in part to the northward diminishing of the Tertiary-covered fold-belt foothills (Pied de Monte) and to a northward thinning of the Siluro-Devonian and Carboniferous sections which contain most of the source and reservoir rock of the basin. Most of the additional oil and gas will continue to be found in the south. Estimated undiscovered petroleum is one and a fourth times present reserves.

f. Chile

It is estimated that only minor amounts of oil and gas will be found in the forearc and intra-arc basins along the Pacific coastal areas. Also, only minor amounts of oil and gas will be found in Chile's portion of the maturely-explored Atlantic-facing Magallanes basin. The estimated undiscovered oil and gas are 120 percent of present reserves, largely in small accumulations in the Pacific area.

g. Remaining countries

The remaining small countries of South America (exclusive of Venezuela and Colombia), Surinam, Guyana, French Guiana, Paraguay and Uruguay, have no appreciable petroleum production and are estimated to have minor to negligible amounts of undiscovered oil and gas.

Bibliography

Alves, R.J., 1988, Bacias sedimentares: potencial petrolifero da America do Sul, Boletim Geociencias das Petrobras, v. 3, no. 4, p. 321-336.

Aquino, G.S., and Lana, M.C., 1990, Exploracao na Bacia de Sergipe-Alazoas: O "Estado da Arte", Boletim Geociencias da Petrobras, v. 4, no. 1, p. 75-84.

Arai, M., 1988, Geochemical reconnaissance of the mid-Cretaceous anoxic event in the Santos basin, Brazil, Revista Brasileira de Geociencias, v. 18, no. 2, p. 273-282.

Aramayo, F., 1988, El cinturon plegado y sobrecorrido, subandino del norte Argentino, Proceedings III, Simposio Bolivariano, Exploracion de las cuencas subandines, Caracas, p. 254-280.

Asmus, H.E. and Ponte, C.F., 1973, The Brazilian marginal basins, The Ocean Basins and Margins, v. 1, The South Atlantic, Plenum Press, New York, p. 87-133.

Asmus, H.E., 1981, Geologia das bacios marginais Atlanticas Mesozoicas-Cenozoicas da Barasil, in Cuencas sedimentarias del Jurasico y Cretacico de America del Sur, v. 1, p. 127-155, Buenos Aires.

Bacoccoli, G. and Toffoli, L.C., 1988, The role of turbidites in Brazil's offshore exploration--a review, 10th Annual Offshore Technology Conference 1988 Proceedings, v. 1, p. 5618-5677.

Baumgarten, C.S., Dultra, A.J.C., Scuta, M.S., Figuieredo, M.V.L., and Sequeira, M.F.P.B., 1988, Coquina da Formacao Lagoa Feia, Bacia de Campos: Evolucao da geologia de desenvolvimento, Boletim Geociencias da Petrobras, v. 2, no. 1, p. 27-36.

Bertani, R.T., Neto, A.F.A. and Matos, R.M.D., 1987, O habitat do petroleo e as prospectivas exploratorias da Potiguar emersa, Boletim Geosciencias da Petrobras, v. 1(1), p. 4-49.

Beurlen, G. and Regali, M.S.P., 1987, O Cretaceo da plataforma continental do Maranhoa e Para, Brasil: Biostratigrafia e evolucao paleombiental, Boletim geociencias da Petrobras, v. 1, no. 2, p. 135-155.

Bhattacharjee, S.K., 1989, A review of South America's Chaco basin, Oil and Gas Journal, Jan. 23, 1989, p. 90-91.

Biddle, K.T., Uliana, M.A., Mitchum, R.M., Fitzgerald, M.G., and Wright, R. C., 1986, The stratigraphic and structural evolution of the central and eastern Magallanes basin, southern South

America in Allen, PA, and Homewood, P., editors, Foreland Basins, Special Publication no. 8, International Assoc. of Sedimentologists, Blackwell Scientific Publications.

Bigarella, J.J., 1973, The geology of the Amazon and Parnaiba basins, The Ocean Basins and Margins, v. 1, The South Atlantic, Plenum Press, New York, p. 24-86.

Blassusi, A.S., Maciel, A.A. and Carvalho, R.S., 1990, Bacia do Espirito Santo: O "Estado da Arte" da exploracao, Boletim Geociencias da Petrobras, v. 4, no. 2, p. 13-19.

Brazil, I.R., 1990, O potencial petrolifero e as perspectivas exploratorias da bacia do Solimoes - norte do Brasil, Boletim Geociencia da Petrobras, v. 4, no. 1, p. 85-93.

Bruhn, C.H.L., Cainelli, C. and Darros de Matos, R.M., 1988, Boletim Geociencias da Petrobras, v. 2, no. 2/4, p. 217-253.

Bueno, R. and Govea, C., 1975, Potential for exploration and development of hydrocarbons in Atrato Valley and Pacific Coastal and Shelf Basins of Colombia, American Association of Petroleum Geologists Memoir 25, p. 318-327.

Calderon, H.C. and Margfoy, P.T., 1985, Cuenca del Putumayo Provincia petrolera meridional de Colombia in Proceedings II Simposio Bolivariano, Exploracion petrolera en las cuenca subandinas, Bogota.

Campos, C.W.M., Ponte, F.C., and Miura, K., 1975, Geology of the Brazilian Continental Margin in Ed Burk, C.A. and Drake, C.L., The Geology of Continental Margins, p. 447-461, Springer-Verlag, New York.

Canfield, R.W., Bonilla, G. and Robbins, R.K., 1982, Sacha oil field of Ecuadorian Oriente, American Association of Petroleum Geologists Bulltin, v. 66, no. 8, p. 1076-1090.

Caputo, M.V., 1985, Genese do alinhamento estrutural do Jurua e do arco de Iquitos, Proceedings III Simposio Bolivariano, v. 2, B. Proyectos en progresso - areas en desarrollo, p. 1-38.

Carozzi, A.V., 1981, Porosity models and oil exploration of Amapa carbonates, Paleogene, Foz do Amazonas basin, offshore NW Brazil, Journal of Petroleum Geology, v. 4, no. 1, p. 3-34.

Castro, J.C., Miura, K., and Braga, J.A.E., 1978, Stratigraphic and Structural Framework of the Foz do Amazonas Basin, OTC 3265, Proceedings 10th Annual Offshore Technical Conference, v. 3, p. 1843-1847.

Castro, L.O.C. and Silva, O.B., 1990, Occurrencia de gas sulfidrico na bacia do Solimoes modelo geologico e implicacoes, Boletim Geociencias da Petrobas, v. 4, no. 3, p. 285-298.

Cerqueira, J.R. and Marques, L.F.S.P., 1985, Avaliacao Geoquimica da Bacia de Sao Luis, Buletim tec. Petrobras, v. 28 (3), p. 151-158.

Crawford, F.D., Szelewski, C.E., and Avery, G.D. 1985, Geology and exploration in the Takutu graben of Guyana and Brazil, Oil and Gas Journal, March 5, 1984, p. 122-129.

Cruz, C.E.S., Barrocas, S.L.S. and Appi, C.J., 1987, Modelo deposicional dos reservatorios turbiditos Oligocenicos/ Eomiocenicos do Campos de Albacora Campos, bacin de Campos, Brasil, Boletim Geociencias da Petrobras, v. 1, no. 2, p. 215-223.

Cupertino, J.A., 1990, Estagio exploratorio das bacias do Tucano central, norte e Jatoba, Boletim Geociencios da Petrobras, v. 4, no. 1, p. 45-53.

Damuth, E.D. and Kumar, N. 1975, Late Quaternery depositional processes on continental rise of western equatorial Atlantic: Comparison with western North Atlantic and implications for reservoir rock distribution, American Association of Petroleum Geologists Bulletin, v. 59, no. 11, p. 2172-2181.

Daniel, L.M.F., Souza, E.M. and Mato, L.F., 1989, Geoquimica e modelos de migracao de hidrocarbonetos no Campo de Rio do Bu-Integracao com o compartimento nordeste da bacia do Recancavo, Bahia, Boletim Geociencias da Petrobras, v. 3, no. 3, p. 129-269.

de Almeida, F.F.M., 1978, Tectonic Map of South America, Ministry of Mines and Energy National Department of Mineral Productions, with UNESCO, Brazilia.

Dietzman, W.D. and Rafidi, N.R., 1983, The petroleum resources of South America, Energy Information Administration, U. S. Department of Energy, Washington, D.C.

Evias, J.F. and Kinoshita, E.M., 1988, Evidencias de movimentos transcorrentes na bacia do Tacutu, Boletim Geociencias da Petrobras, v. 2, no. 2/4 p. 193-208.

Feininger, T. and Bristow, C.R., 1980, Cretaceous and Paleogene geologic history of coastal Ecuador, Geologische Rundschau, v. 69, p. 849-874.

Figueiredo, A.M.F. and Martins, C.C., 1990, 20 Anos de exploracao da bacia de Campos e o sucesso nas agua profundas, Boletim de Geociencias da Petrobras, v. 4, no. 1, p. 105-123.

Figueiredo, A.M.F. and Mohriak, W.V., 1984, A Tectonica salifera e as acumulacoes de petroleo da bacia de Campos, Anais do XXXIII Congresso, Rio de Janeiro, v. 3, p. 1.380-1.394.

Fitzgerald, M.G., Mitchum, R.M., Uliana, M.A., and Biddle, K.T., 1990, Evolution of the San Jorge Basin, Argentina, American Association of Petroleum Geologists Bulletin, v. 74, no. 6.

Francolin, J.B.L. and Szatmari, P., 1987, Mechanismo de rifteamento da porcao oriental da margem norte Brasileira, Revista Brasileira de Geociencias, v. 17, no. 2, p. 196-207.

Freire, W., 1988, An overview on Campos basin, 20th Annual Offshore Technology Conference 1988 Proceedings, v. 4, p. 5807-5882.

Friere, W., 1989, Campos Basin deepwater giant fields, Offshore Technology Conference, 1989 Proceedings OTC 5970, p. 117-125.

Goes, A.M.O., Souza, J.M.P. and Teixeira, L.B., 1990, Estagio exploratorio e perspectivas petroliferas da bacia do Parnaiba, Boletim Geociencios da Petrobras, v. 4, no. 1, p. 55-64.

Gonzalez, E., 1989, Hydrocarbon Resources in the Coastal Zone of Chile, in Geology of the Andes and its relation to hydrocarbon and mineral resources, Circum-Pacific Council for Energy and Mineral Resources, Earth Science Series, v. 11, p. 383-403.

Guardado, L.R., Gamboa, L.A.P., and Lucchei, C.F., 1990, Geology of the Campos Basin, in Eds. Edwards, J.D. and Santogrossi, P.A., Divergent/Passive Margin Basins, American Association of Petroleum Geologists Memoir 48, p. 3-79.

Helwig, J., 1972, Stratigraphy, sedimentation, paleogeography, paleoclimates of Carboniferous ("Gondwana") and Permian of Bolivia, Association of Petroleum Geologists Bulletin, v. 56, no. 6, p. 1008-1033.

Jahnert, R.J., 1987, Gradiente geothermico da Bacia de Campos, Boletim Geociencias da Petrobras, Rio de Janeiro, v. 11, no. 2, p. 183-189.

Jarrin, A., 1975, Exploration and development of the hydrocarbon resources in the Pacific basins of Ecuador-Summary, American Association of Petroleum Geologists Memoir 25, p. 328-330.

Jordan, T.E. and Allmendinger, R.W., 1986, The Sierras Pampeanas of Argentina: A modern analogue of Rocky Mountain Foreland Deformation, American Journal of Science, v. 286, December, 1986, p. 737-764.

Jordan, T.E., Bryan, L.I., Allmendinger, R.W., Brewer, J.A., Ramos, V.A., and Ando, C.J., 1983, Andean tectonics related to geometry of subducted Nazca plate, G.S.A., Geologic Study of America Bulletin, v. 94, p. 341-361.

Kingston, J., 1988, The undiscovered recoverable petroleum resources of Southern Africa: U.S. Geological Survey Open-File Report 88-223, 166 p.

Lamb, W. C. and Truitt, P., 1963, The petroleum geology of the Santa Cruz Area, Bolivia, in Proceedings, Sixth World Petroleum Congress, Frankfort an Main, Section 1, p. 573-594.

Lawrence, S. and Coster, P. 1985, Petroleum potential of offshore Guyana, Oil and Gas Journal, Dec. 9, 1985 p. 67-74.

Lesta, J.P., Digregoria, J., Mozetic, M.E., 1985, Presente y futuro de la exploracion de petroleo en las cuencas subandinas, Argentina, in Simposio Boliviriano, Exploracion Petrolera en las Cuencas Subandinas, 2, Bogota, Colombia, v. 3, p. 1-34.

Lonsdale, P., 1978, Ecuadorian subduction system, American Association of Petroleum Geologists, v. 62, no. 12, p. 2454-2477.

Ludwig, W.J., Windisch, C.C., Houtz, R.E. and Ewing, J.I., 1978, Structure of the Falkland Plateau and offshore Tierra del Fuego, Argentina, in Geological and geophysical investigations of continental margins, Mem. American Association of Petroleum Geologists, v. 29, p. 125-137.

Magnavita, L.P. and Cupertino, J.A., 1987, Concepcao atual sobre as bacias do Tucano e Jatoba, nordeste do Brazil, Boletim Geociencias da Petrobras, v. 1, no. 2, p. 119-134.

Mancini, C.D., and Serna, M.J., 1981, Evaluacion petrolera de la cuenca de Nirihuau, sudoeste Argentina, Proceedings III Simposio Bolivariano, Exploracion petrolera de las cuencas subardinas, Caracas, p. 118-141.

Marchase, H.G., 1985, Cuenca Neuquina, sus principales characteristicas geologas de produccion y exploracion, in: Simposio Bolivariano, Exploracion Petrolera en las Cuencas Subandinas, 2, Bogota, Colombia, v. 1, p. 1-4.

Marroquim, M., Tigre, C.A., and Lucchesi, C.F., 1984, Bacia de Campos: resultados e perspectivas, Annais do XXXIII Congresso Brasileiro de Geologia, Rio de Janeiro, v. 3, p. 1.366-1.379.

Marsaglia, K.M. and Carozzi, A.V., 1990, Depositional environment of the Basal Salina Formation (lower Eocene), northwestern Peru, Journal of South America Earth Sciences, v. 3, no. 4, p. 253-267.

Martinez, C., 1980, Structure and evolution de la chains hercynienne et de la chains Andine dans le nord de la Cordillera des Andes de Bolivia: Paris, Memoire ORSTRUM 119, 352 p.

Mast, R. F., Dolton, G.L., Crovelli, R.A., Root, D.H., Attanasi, E.D., Martin, P.E., Cooke, L.W., Carpenter, G.B., Pecora, W.C., and Rose, M.B., 1989, Estimates of Undiscovered Conventional Oil and Gas Resources in the United States--A Part of the Nation's Energy Endowment, U.S. Geological Survey, Minerals Management Service, Department of Interior.

Masters, C.D., Root, D.H., and Attanasi, E. D., 1991, Resource Constraints in Petroleum Production Potential, Science, Vol. 253, p. 146-152.

Mato, L.F. and Souza, E.M., 1988, Petrografia e diagenese dos arenitos do Membro Gomo/Formacao Candeias (Cretaceo Inferior) no Campo de Rio do Bu, bacio do Recancavo, Boletim Geociencias da Petrobras, v. 2, no. 2/4, p. 277-289.

Mello, M.R., Solan, A.L., and Cerqueira, J.R., 1984, Geoqimica sub-bacia de Mundau-bacia do Ceara, Boletim tec. Petrobras, Rio de Janeiro, v. 27, no. 2, p. 97-108.

Milani, E.J.M., Kinoshita, E.M., Araujo, L.M., and Cunha, P.R.C., 1990, Bacia do Parana: Possibilidades petroliferas da calha central, Boletim Geociencias da Petrobras, vo. 4, no. 1, p. 21-34.

Mingramm, A., Russo, A., Pozzo, A. and Cazan, L. 1976, Sierra Subandinas, in Proceedings, Segundo Simposo de Geologia Regional Argentina, Cordoba, p. 95-137.

Mohler, H.P., 1989, Hydrocarbon habitat of San Martin and Cashiriari gas/condensates discoveries, Southern Ucayali Basin of Peru, American Association of Petroleum Geologists Bulletin, v. 73, no. 3, p. 393 (abstract).

Moraes, M.A.S., 1989, Diagenetic evolution of Cretaceous-Tertiary Reservoirs, Campos basin, Brazil, American Association of Petroleum Geologists Bulletin, v. 73, no. 5, p. 598-612.

Mordojovich, C., 1981, Sedimentary basins of Chilean Pacific offshore, in Energy resources of the Pacific region: American Association of Petroleum Geologists Studies in Geology, v. 12, p. 63-68.

Neto, A.F.A. and Tsubone, K., 1988, Structural models of the Upper Amazonas basin, northern Brazil, Proceedings III Simposio Bolivariano, Exploracion Petrolera de las cuencas subandinas, Caracas.

Netto, A.S.T., 1985, Estrategias de Explotacao na bacia do Recancano, Boletim Tec. Petrobras, v. 28, no. 2, p. 85-89.

Neves, C.A.O., 1990, Prospectos potenciais e areas prioritarias para exploracao na bacia do Amazonas, Boletim Geociencias da Petrobras, v. 4, no. 1, p. 95-103.

Oil and Gas Journal, 1990, Petrobras draws bead on Amazon region for more oil and gas, Feb. 12, 1990, p. 17-20.

Ojeda, H.A.O., 1982, Structural framework, stratigraphy, and evolution of Brazilian marginal basins, AAPG Bulletin, v. 66, no. 6, p. 732-749.

Oliveira, C.A.P., and Coelho, R.P., 1989, Marlim Field Development, Offshore Technology 1989 Proceedings, OTC 5971, p. 127-134.

Paredes, M.P., 1958, Terciario de la Brea y Parines y Area de Lobitos (M.S. thesis): Universided Nacional de San Augustin, Arequipa, 36 p.

Pereira, M.J. and Macedo, J.M., 1990, A Bacia de Santos: perspectivas de uma nova provincia petrolifera na plataforma continental sudeste Brasileira, Boletim Geociencias da Petrobras, v. 4, no. 1, p. 3-11.

Pereira, M.J., Trindade, L.A.F., Gaglianone, P.C., 1984, Origem e evolucao das acumulacoes de hidrocarbonetos na bacia de Campos, Anais do XXXIII Congresso Brasileiro de Geologia, Rio de Janeiro, v. 10, p. 4.763-4.777.

Petrobras, 1992, Barracuda: another super field, Petrobras News, no. 138, p. 1-8.

Petroperu, 1984, Peruvian petroleum, a renewed exploration opportunity, Petroperu S.A., November 1984, p. 1-75.

Ponte, F.C. and Asmus, H.E., 1976, The Brazilian marginal basins: current state of knowledge, Anais da Acadamia Brasileira de Ciencias, v. 48 (Supplemento), p. 215-239. Proceedings of the International Symposium on continental margins of Atlantic type, Sao Paulo.

Ponte, F.C. and Asmus, H.E., 1978, The geologic framework of the Brazilian continental margin: Geol. Rundshau, v. 7, p. 201-235.

Porto, R. and Szatmari, P., 1983, Classification of onshore sedimentary basins in Brazil, Oil and Gas Journal, Aug. 1, p. 109-117.

Ramos, V.A., Jordan, T.E., Allmendinger, R.W., Mpodozois, C., Key, S.M., Cortes, J.M., and Palma, M., 1986, Paleozoic terranes of the Central Argentine-Chilean Andes, Tectonics v. 5, no. 6, p. 855-880.

Rezende, W.M., and Arajo, E., 1970, Integracao geologica regional da areas continental e oceanica da bacia Barreirinhas, Anais do XXIV Cong. Bras. Geol. Soc. Geol. Brasilia, 1970, p. 141-155.

Roeder, D., 1988, Andean-age structure of Eastern Cordillera (Province of La Paz, Bolivia), Tectonics, v. 7, p. 23-39.

Root, D. H. and Mast, R. F., 1993, Future Growth of Known Oil and Gas Fields, American Association of Petroleum Geologists Bulletin, v. 77, no. 3, p. 479-484.

Rosania, R.S., 1989, Petroleum prospects of the sedimentary basins of Ecuador, in Geology of the Andes and its relation to hydrocarbon and mineral resources, Circum-Pacific Council for Energy and Mineral Resources Earth Science Series, v. 11, p. 415-430.

Russo, A., Ferello, R. and Chebli, G., 1980, Llanura Chaco Pampeana, in Geologia Regional Argentina, Cordoba, v. II, p. 150-182.

Santos, C.F. and Braga, J.A.E., 1990, O "estado arte" da Bacia Recancavo, Boletim Geociencias da Petrobras, v. 4, no. 1, p. 35-43.

Scientific Staff, 1974, Southern Atlantic, leg 36: Geotimes, v. 19, p. 16-18.

Shepherd, G.L. and Moberly, R., 1981, Coastal structure of the continental margin, northwest Peru and southwest Ecuador, Geological Society of America Memoir 154, p. 351-391.

Souza, J.M., Scarton, J.C., and Candido, A., 1989, The Marlim and Abacora Fields: geophysical, geological, and reservoir aspects, 21st Annual Offshore Technology Conference, 1988 Proceedings OTC 5894, p. 109-114.

Stander, W., 1975, Subduction of the Nazca plate under Peru as evidenced by focal mechanisms and by seismicity: Journal of Geophysical Research, v. 80, p. 1053-1064.

Tissot, B., Demaison, G., Masson, G., Delteil, J.R. and Combaz, A., 1980, Paleoenvironment and petroleum potential of Middle Cretaceous black shale in Atlantic basins, American Association of Petroleum Geologists Bulletin, v. 64, no. 12, p. 2051-2063.

Touzett, P.J. and Sanz, V.R., 1985, Presente y futuro exploration de petroleo en las cuencas subandinos, Peru in Simposio Bolivariano, Exploracion petrolera en las cuencas subandinos, 2, Bogota, Colombia, v. 3, p. 1-85.

Travis, R.B., 1953, La Brea - Parinas Oil Field, Northwestern Peru, American Association of Petroleum Geologists Bulletin v. 37, no. 9, p. 2093-2118.

Travis, R.B., Gonzales, G. and Pardo, A., 1975, Hydrocarbon potential of coastal basins of Peru, American Association of Petroleum Geologists Memoir 25, p 331-338.

Tschapp, H.J., 1953, Oil explorations in the Oriente of Ecuador, 1938-1950, American Association of Petroleum Geologists Bulletin, v. 73, no. 10, p. 2303-2347.

Urien, C.M. and Zambrano, J.J., 1973, The geology of the basins of the Argentine continental margin and Malvinas plateau, The Ocean Basins and Margins, v. 1, The South Atlantic, Plenum Press, New York, p. 135-169.

Urien, C.M., 1981, The basins of southeastern South America (Southern Brazil, Uruguay and Eastern Argentina) including the Malvinas Plateau and southern South Atlantic paleogeographic evolution _in_ Comite Sudamericano del Jurasico y Cretacico: Cuencas sedimentarias del Jurasico y Cretacico de America de Sur, v. 1, p. 45-125, Buenos Aires.

Urien, C.M., Zambrano, J.J. and Agosto, 1985, Las cuencas subandinas desda Venezuela hasta el plateau de Malvinas, _in_ Proceedings II Simposio Bolivariano, Exploracion petrolera en las cuencas subandinas, p. 1-32.

Van der Van, P.H., Cainelli, C. and Fernandes, G.J.F., 1989, Bacia de Sergipe-Alagoas: Geologia e exploracao, Boletim Geociencias da Petrobras, v. 4, no. 2, p. 13-19.

Vargas, J.M., 1988, Potencial petrolifero de lu cuenca Huallaga, Oriente Peruano _in_ III Simposio Bolivariano, Exploracion petrolero de las cuencas subandinas, Caracas.

Winslow, M.A., 1982, The structural evolution of the Magallanes basin and neotectonics in the southernmost Andes, _in_ Antarctic: Geoscience (Ed. by C. Craddock), p. 153-154, Univ. Wisconsin, Madison.

Yrigoyen, M.R., 1991, Explanatory notes for the energy-resources map of the Circum-Pacific region, southeast quadrant. Circum-Pacific Council for Energy and Numeral Resources, U.S. Department of Interior, U.S. Geological Survey.

Zanotto, O. and Szatmari, P., 1987, Mecanismo de rifteomento da porcao ocidental da margem norte Brazileria, Para-Maranhao basin, Revista Brasileria de geociencias, v. 17, no. 2, p. 189-195.

Zembruscki, S.G. and Campos, J.N.P., 1988, Comportamento geotermico regional e provavel movimentacao de fluidos no bacia do Parnaiba, Maranhao, Boletim Geociencias da Petrobras, v. 2, no. 2/4, p. 133-145.

Zembruscki, S.G., and Kiang, C.H., 1989, Gradiente Geotermico das Bracias Sedimentares Brasileiras, Boletim de Geociencias da Petrobras, v. 3, no. 3, p. 129-269.

Zuniga, F. and Rivero, F., Pardo, Valdivia, H., and Velarde, P., 1976, Hydrocarbon potential of Amazon basins of Colombia, Ecuador, and Peru, in eds. Halbouty, M.T., Maher, J.C., and Lian, H.M., Circum-Pacific Energy and Mineral Resources (1976) American Association of Petroleum Geologists Memoir 25, p. 339-348.

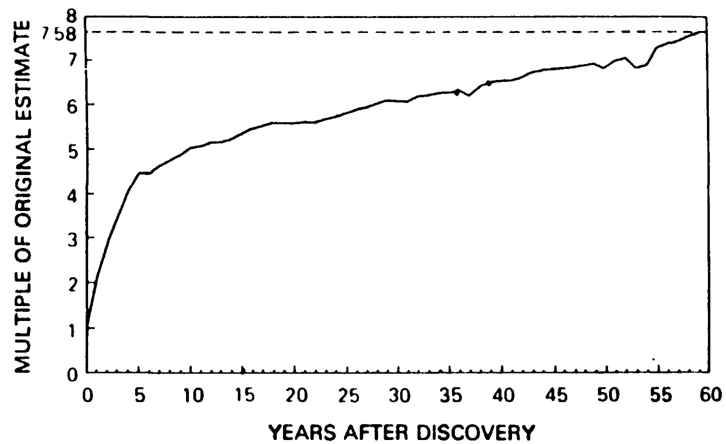
APPENDIX A

In the final stages of this study, after observing some rather incomplete, but nevertheless convincing, Petroconsultant's historical 1983-1993 reserve data of southern South American basins, it seems that our preliminary and consensus-derived undiscovered oil and gas estimates of (unadjusted) Table VIII are too low. The Petroconsultant's 1983-1993 reserve data indicate: 1) an amount and rate of discovery for the ten-year period disproportionately high to our estimate of undiscovered oil and gas, and 2) a very substantial amount of field-growth for the ten-year period that should translate into higher estimates of Undiscovered Resources.

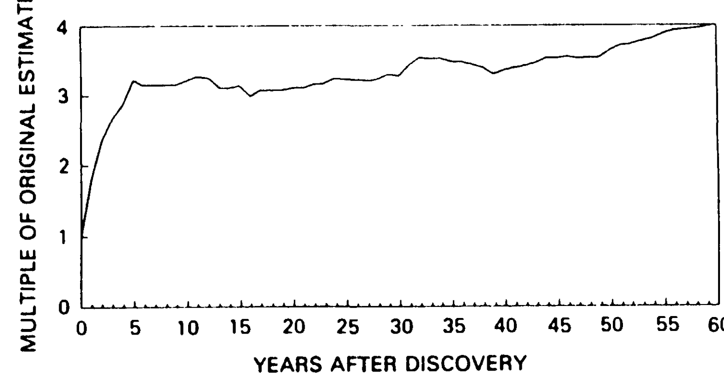
Our estimates of undiscovered oil, although arrived at by various means, inherently depend, directly or indirectly, on comparisons to, or extrapolations from, the Original Reserves thought to be in geologically analogous producing fields, plays, or basins. The available estimates of Original Reserves, in the area of this study, although not distinguished as such, appear to be primarily only Original Proved Reserves (see Table A). Original Proved Reserves, however, are only a fraction of the ultimately recoverable reserves (i.e. the Original Identified Reserves) of a given field, play, or basin. Consequently, any analogy-derived undiscovered oil estimates based on Original Proved Reserves would indicate only the fractional amount of Undiscovered Resources equal to Original Proved Reserves/Original Identified Reserves. A truer Undiscovered Resource estimate of oil requires that the analogy be made to the total Original Identified Reserves of the geologically similar accumulation. Original Identified Reserves include Cumulative Production, Proved Reserves, and Unproved Reserves of the field, play or basin from which the analogy is drawn. Unproved Reserves include both Probable (Indicated) and Possible (Inferred) Reserves (Table A, Appendix A) which are not commonly included in Reserves notations but constitute the growth increment in question.

To make truer assessments of the Undiscovered Resources of petroleum, it is necessary to make estimates of the Original Identified Reserves of the petroleum accumulations, to which the estimates of undiscovered petroleum resources strongly relate. For estimates of these required Original Identified Reserves, the United States model of field growth, demonstrated by Root and Mast (1993), was applied to the Reserves values in those principal fields and basins of South America which provide the analogies for the assessment of the undiscovered petroleum resources

Although there is some uncertainty as to the validity of this approach and model, particularly since in the United States it is customary for fiscal, and other reasons, to early-report initial reserve estimates thereby resulting in subsequent increased field growth, I believe the application of the United States model to this study is generally valid and will yield more appropriate Reserves estimates for the following reasons:



The growth of estimates of the amount of recoverable oil discovered in a given year in the conterminous United States versus the number of years after the year of discovery. Data from the American Petroleum Institute and others (1972-1979, v. 26 through 33).



The growth of estimates of the amount of recoverable natural gas discoverd in a given year in the conterminous United States versus the number of years after the year of discovery. Data from the American Petroleum Institute and others (1971-1979, v. 25 through 33).

Figure 1 Graphs showing the growth of estimates of amounts of oil and gas discovered in a given year in the conterminous United States versus the number of years after the year of discovery (from Dolton et al, 1981).

TABLE A

RELATION AND DEFINITION OF PETROLEUM RESERVE NOMENCLATURE
(From C.D.Masters, personal communication)

<table>
<tr><td colspan="5">Ultimate Resources</td></tr>
<tr><td></td><td colspan="4">Futures Resources</td></tr>
<tr><td colspan="4">Original Identified Rsvs.</td><td></td></tr>
<tr><td colspan="3">Original Demonstrated Rsvs.</td><td></td><td></td></tr>
<tr><td colspan="2">Original Proved Rsvs.</td><td></td><td></td><td></td></tr>
<tr><td></td><td colspan="3">Identified Rsvs.</td><td></td></tr>
<tr><td></td><td colspan="2">Demonstrated Rsvs.</td><td></td><td></td></tr>
<tr><td></td><td></td><td colspan="2">Unproved Reserves[2]</td><td></td></tr>
<tr><td>Cum. Prod.</td><td>Proved Rsvs.
(Measured)</td><td>Probable Rsvs.[1]
(Indicated)</td><td>Possible Rsvs.[1,3]
(Inferred)</td><td>Undiscovered Resources
Hypothetical-Speculative
|< 95% Mode Mean 5% >|</td></tr>
</table>

1. Probable (Indicated) and Possible (Inferred) Reserves are variably assigned a probability of occurrence of greater than 50% or less than 50% respectively. Or they are used to differentiate the source of the additional reserves as coming from recovery improvements (Prob.) or physical reservoir extensions or new pools (Poss.); the probability of occurrence concept remains qualitatively the same as in the first method of distinction.

2. Unproved Reserves constitute potential field growth.

3. Possible Reserves also include regulatorily restricted reserves and Potential Additional Reserves assigned to "single-well" (insufficient data) discoveries. Footnote descriptions are appropriate.

The word Original relates to reserves and includes the quantity of cum. production.

The word Ultimate includes both reserves and Undiscovered Resources as well as the quantity of cum. prod.

Futures Resources includes reserve and undiscovered resources but excludes cum. prod.

1) The Identified Reserve to production ratio (R/P) for Argentina is 14; for Brazil it is 13; and for the other South American countries (outside of the OPEC country, Venezuela, Trinidad) it is 13. These ratios are low in comparison to 16 for the United States (Masters, et al, 1991). In these South American countries, where fairly aggressive, state-of-the-art recovery methods are practiced (and in the case of Brazil, exploration is relatively immature), these low ratios denote conservative reserve estimates comparable to the United States and suggest, therefore, similar field-growth potential. By contrast the Former Soviet Union's (FSU) Identified Reserve to production ratio is about 38, and the Middle East ratio is 93.

2) Field development in the United States and elsewhere eventually force more complete reserve figures to emerge, such that the growth of middle-aged fields in North America becomes comparable to growth in most other areas. As shown in Figure 1, Appendix A, the rapid growth of Proved Reserves in the United States, in the first five years, is a function of normal field development that commonly occurs in many countries before the first reserve values are reported. Afterwards, the growth diminishes reflecting the reduced opportunities for field expansion.

3) The substantial degree of field growth in South America, as indicated by Petroconsultant's rather incomplete data over a ten-year period, suggests that ratios of Original Identified Reserves to Original Proved Reserves, may be similar to the ratios in the United States, especially in the later years.

Following the Root and Mast (1993) methods and model to obtain an Ultimate Reserve value, the amount of oil accredited to a field in a given year is multiplied by that year's historically-derived growth factor. This growth factor is obtained from the pattern of field growth of United States fields prior to 1980. The factor declines over time reflecting maturity in the growth process. The product of the estimated reserve value and the growth factor, for each year, is added to the products of the other years to give the total discovery amount (including growth) for the basin, or country (Table B, Appendix A); this final value is the Original Identified Reserves. In this study, the Original Identified Reserves in the key basins (basins of over 0.5 BBO reserves or representing important trends of similar basins) have been calculated using the Root and Mast (1993) model (Table IX, p. 421). These basins contain over 90 percent of the oil reserves of southern South America.

The ratio of the calculated Original Identified Reserves to the reported Original Proved Reserves varies inversely with the exploration maturity. For example, in the least maturely explored basin, Solimoes (first discovery 1986), the ratio is 3.83; in the Campos basin (first discovery 1974), it is 2.26; in the Sergipe-

TABLE B
ANNUAL PETROLEUM DISCOVERIES IN THE LOWER 48 STATES
December 31,1979 (from Root and Mast, 1993)

Annual Petroleum Discoveries in the Lower 48 States, December 31, 1979*

Year	Oil Lower 48 Discoveries (million bbl)	Oil Growth Factors	Oil Discoveries with Growth** (million bbl)	Gas Lower 48 Discoveries (bcf)	Gas Growth Factors	Gas Discoveries with Growth** (bcf)
1979	75	8.862	661	2735	4.142	11328
1978	116	4.049	469	3045	2.309	7030
1977	365	2.782	1015	4609	1.793	8264
1976	239	2.336	559	4726	1.573	7434
1975	384	2.028	779	6876	1.469	10101
1974	391	1.842	721	6394	1.303	8331
1973	579	1.812	1049	9444	1.311	12381
1972	322	1.755	565	7967	1.302	10374
1971	606	1.707	1034	8289	1.302	10793
1970	735	1.672	1228	4646	1.291	5998
1969	599	1.617	969	6671	1.267	8452
1968	982	1.603	1574	6311	1.238	7813
1967	707	1.575	1114	5159	1.249	6444
1966	513	1.558	800	8239	1.284	10579
1965	772	1.531	1182	8609	1.289	11096
1964	857	1.502	1287	9545	1.265	12075
1963	497	1.470	731	12825	1.325	16993
1962	974	1.454	1416	11075	1.294	14331
1961	506	1.431	724	9788	1.288	12607
1960	1023	1.436	1468	12871	1.288	16578
1959	754	1.434	1081	7661	1.276	9775
1958	1181	1.428	1687	19980	1.268	25335
1957	2077	1.422	2954	15818	1.251	19788
1956	1941	1.400	2718	19979	1.247	24914
1955	1545	1.390	2148	10299	1.220	12564
1954	2163	1.372	2967	16169	1.228	19856
1953	2179	1.352	2945	12589	1.226	15434
1952	1317	1.339	1763	16818	1.232	20720
1951	1746	1.321	2307	11319	1.218	13787
1950	2814	1.302	3664	14194	1.198	17004
1949	3453	1.299	4486	25626	1.200	30751
1948	3429	1.301	4461	8417	1.143	9620
1947	1610	1.275	2053	14338	1.100	15771
1946	1497	1.273	1906	6845	1.118	7653
1945	2196	1.257	2760	13987	1.112	15553
1944	2725	1.256	3423	11757	1.129	13273
1943	1366	1.244	1699	8526	1.131	9642
1942	1463	1.261	1845	9248	1.138	10524
1941	2246	1.227	2756	15419	1.163	17933
1940	3670	1.217	4467	13313	1.189	15829
1939	1977	1.209	2390	12100	1.176	14230
1938	4055	1.201	4871	14859	1.163	17281
1937	3421	1.193	4081	21544	1.154	24861
1936	7109	1.162	8260	24482	1.144	28007
1935	2495	1.154	2879	13665	1.120	15304
1934	3877	1.133	4393	13561	1.134	15378
1933	1577	1.129	1780	4081	1.124	4587
1932	587	1.126	661	4007	1.123	4500
1931	2475	1.121	2774	5406	1.122	6065
1930	7656	1.114	8529	10563	1.132	11957
1929	3754	1.125	4223	15129	1.106	16733
1928	2948	1.105	3257	10132	1.080	10942
1927	1779	1.094	1946	13645	1.077	14696
1926	4771	1.126	5372	4929	1.062	5234
1925	1063	1.116	1186	1012	1.050	1063
1924	905	1.056	955	2351	1.033	2429
1923	1212	1.038	1258	1843	1.026	1891
1922	1374	1.031	1417	39121	1.019	39864
1921	1947	1.017	1980	5135	1.011	5192
1920	2260	1.010	2282	2230	1.004	2239
PRE-1920	27131	1.000	27131	92351	1.000	92351
Totals	136986		165061	734270		869534

*Source for oil and gas discoveries: American Petroleum Institute, American Gas Association, and Canadian Petroleum Association (1979)
**Discoveries with growth are the product of discoveries and growth factor. Discrepancies are due to rounding.

Alagoas basin (first discovery 1957), it is 1.61, and in the most mature basin, Reconcavo (first discovery 1939), it is 1.31.

In one important area, the turbidite fields of the Campos continental slope, the above growth determinations which possibly apply for most basins, probably allow for too much growth in Campos since several factors tend to produce an initial Original Proved Reserve estimate of more than usual dimension and precision. These factors are: 1) the perimeter and areal extent of the turbidite fields are fixed at the outset by three-dimensional high-amplitude reflection seismic surveys (fig. 22), 2) relatively well-defined tabular sandstones of lateral uniformity, presumably, provide initial, fairly reliable, areal reserve parameters, and 3) the extremely high cost of continental slope field development mandates early, accurate reserve estimation. We believe, therefore, that the field growth will be much less than that calculated from the U.S. model and arbitrarily deem it to be about one half, indicating only 4.6 BBO of growth in the Campos basin (Table IX).

In several basins, the Root and Mast (1993) procedure was not entirely followed because sufficient historical data are lacking for the calculation of Original Identified Reserves. In the Talara basin of the Peruvian Pacific coast, it is assumed, however, that since the Talara on-shore area, from which the undiscovered oil analogy is drawn, is so maturely explored (first discovery 1874) that the ratio of Original Identified Reserves to Original Proved Reserves (the growth factor) is low--about 1.1. Accordingly, this ratio is applied to the initial undiscovered oil estimate (column four, Table X) to obtain a more realistic undiscovered oil estimate of the Talara basin.

Another maturely explored basin (first discovery 1924), where tenable growth data are lacking, is the Bolivia portion of the Tarija-Santa Cruz basin. Because of its advanced degree of exploration, a growth factor of 1.2 is assumed and applied to the initial undiscovered oil estimate (Table X).

In the case of the extensive and immaturely explored Maranon-Oriente-Putumayo basin of Peru, Ecuador, and Colombia, where apparently at least one considerable play is as yet unexploited, no viable local analog exists. However, the basin is geologically similar to the maturely explored Powder River basin of the United States where assessments have been made of the undiscovered oil and gas (Mast, et al, 1989).

Based primarily on an areal analogy to these undiscovered oil and gas estimates of the Powder River basin, the initial consensus estimate of the undiscovered oil and gas of the Peru and Ecuador portions of the Maranon-Oriente-Putumayo basin was made. Mast, et al (1989) had made estimates of the Original Identified Reserves of the oil and gas accumulations of the Powder River region which undoubtedly provided analogies to their undiscovered oil and gas estimates which, in turn, were the analogies for the initial estimate of Maranon-Oriente-Putumayo undiscovered oil.

Accordingly, no adjustment is deemed necessary to our initial assessment and the ratio of Identified to Proved Reserves of column three, Table X, is shown as 1.00.

In accordance with the upward adjusted modes of undiscovered oil estimates (column five, Table X), the initial values of the ranges of estimates (Table VIII) also are adjusted upwards, that is, the 95 percentile, the 5 percentile, and the mean values of the ranges are raised proportionally (Table XI).

Table XI shows the finally adjusted range of estimates for undiscovered oil, along with unadjusted gas estimates, geologic province by geologic province. Table XII shows the same estimates on a country-by-country basis.