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Campos Basin: Reservoir Characterization and Management – Historical Overview and Future Challenges

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Abstract

The first oil discovery in the Campos Basin dates from 1974, when the ninth well drilled found Albian carbonate reservoirs (Garoupa Field) under a water depth of 120 m. Oil production started on August 13th, 1977, from the Enchova Field, which produced to a semi submersible platform moored at a water depth of 124 m. This was the beginning of a successful history that led Petrobras to become a world leader company in petroleum exploration and production in deep and ultra-deep waters. Forty-one oilfields were found between 50 and 140 km off the Brazilian coast (under water depths between 80 and 2,400 m), which produce from a variety of reservoirs, including Neocomian fractured basalts, Barremian coquinas, early Albian calcarenites, and (mostly) late Albian to early Miocene siliciclastic turbidites. These reservoirs were responsible for an average oil production of 1.2 million bpd in the year 2002 (83% of the total Brazilian production), and they are expected to be producing 1.6 million bpd by the end of 2005. The cumulative oil production from the Campos Basin comprises 3.9 billion bbl, and the current proven oil reserves are 8.5 billion bbl (89% of total Brazilian reserves).

Deep and ultra-deep water giant fields started to be discovered only in 1984. There was a succession of large discoveries, including Albacora, Marlim, Albacora Leste, Marlim Sul, Barracuda, Caratinga, Roncador and, more recently, Jubarte and Cachalote. The development of these fields has continuously provided new challenges for the reservoir characterization and management in the Campos Basin. These fields are developed with fewer, horizontal and high angle wells, drilled into poorly consolidated reservoirs. The extensive use of 3D seismic as a reservoir characterization tool has optimized well location and allowed the reduction of geological risks. Integration of high-resolution stratigraphic analysis with 3D seismic inversion, geostatistic (stochastic) simulation of reservoir properties constrained by seismic, well

log and core data, 3D visualization, and voxel-based automatic interpretation has guided the positioning of horizontal wells through thin (<10-15 m) reservoirs. Additionally, 3D visualization techniques have provided a new environment for teamwork, where seismic, well log, and core data are interpreted and added to detailed 3D geological models and, subsequently, to robust reservoir simulation models.

The deepwater subsea wells must be designed to allow high production rates (typically >10,000-15,000 bopd), with lifetime completions to avoid costly interventions. In order to assure high productivity, pressure maintenance must be efficient; if water injection is planned, the hydraulic connectivity between injector and producer wells must be guaranteed by high-quality 3D seismic, well log correlation, and observed pressure profiles. Detailed studies have been made in order to define the distribution and number of wells, since the number of wells strongly affects the net present value of deepwater projects. Wells with expected oil recovery of less than 10-15 million bbl are not drilled in the beginning of the projects, and remain as future opportunities to increase oil production and recovery.

Some of the new technologies devised for the characterization and development of the deepwater oilfields from the Campos Basin include reservoir imaging with pre-stack, depth-migrated seismic, 4D seismic, real-time well steering and updating of geological/reservoir models, extended reach wells, selective completion in gravel-packed wells, isolation inside horizontal, gravel-packed wells, intelligent completion, subsea oil-water separation, re-injection of produced water, scale prevention and treatment, and improved recovery techniques for heavy and/or viscous oil.

Introduction

Campos Basin is located in southeastern Brazil, mostly offshore of the states of Rio de Janeiro and Espírito Santo, occupying an area of 115,000 km² (Fig. 1). The basin has a small (500 km²) onshore portion, where the first exploratory well was drilled in 1959; this well records a 1,690 m-thick, very sand-rich Tertiary succession, Neocomian basalts, and the Precambrian metamorphic basement. Exploration in the offshore Campos Basin started in 1968, with the acquisition of 2D seismic data. The first offshore well was drilled in 1971. The first oil discovery dates from 1974, when the ninth well drilled found Albian carbonate reservoirs (Garoupa Field) at a water depth of 120 m. Oil production started on August 13th,

1977, from the Enchova Field, which produced to a semi submersible platform moored at a water depth of 124 m. This was the beginning of a successful history that led Petrobras to become a world leader company in petroleum exploration and production in deep and ultra-deep waters. Forty-one oilfields were found between 50 and 140 km off the Brazilian coast (under water depths from 80 to 2,400 m). The development of 37 fields is Petrobras' exclusive responsibility, with the remaining four being developed under partnership agreements (Albacora Leste, Bijupirá, Frade, and Salema; Fig. 1). Campos Basin reservoirs were responsible for an average oil production of 1.2 million bpd in the year 2002 (83% of the total Brazilian production) (Fig. 2), and they are expected to be producing 1.6 million bopd by the end of 2005. The cumulative oil production from the Campos Basin comprises 3.9 billion bbl, and the current proven oil reserves are 8.5 billion bbl (89% of total Brazilian reserves) (Fig. 3).

This paper presents an overview of the last 25 years of reservoir characterization and management activities in the Campos Basin; it also summarizes the technological challenges involved in the development of deep and ultra-deep water fields discovered after the mid 1980's, including the recently discovered Jubarte and Cachalote fields.

General Geological Setting

Campos Basin is one of the twelve eastern Brazilian marginal basins, which lie beneath the coastal plain, continental shelf and slope of the western portion of the South Atlantic Ocean. Their tectonic and sedimentary evolution is linked to the Neocomian breakup of Gondwana, and the subsequent opening of the South Atlantic Ocean. A large amount of geological information from the eastern Brazilian margin has been collected by Petrobras, particularly after 1968, when offshore exploration for hydrocarbons started. The general Late Jurassic to Recent stratigraphy of the eastern Brazilian marginal basins can be subdivided into six megasequences (Fig. 4): (1) Continental Pre-Rift Megasequence (Late Jurassic to Early Neocomian), (2) Continental Rift Megasequence (Early Neocomian to Early Aptian), (3) Transitional Evaporitic Megasequence (Middle to Late Aptian), (4) Shallow Carbonate Platform Megasequence (Early to Middle Albian), (5) Marine Transgressive Megasequence (Late Albian to Early Tertiary), and (6) Marine Regressive Megasequence (Early Tertiary to present).

Major Reservoir Types

Campos Basin oilfields produce from a variety of reservoirs, which include Neocomian fractured basalts and Barremian coquinas from the Continental Rift Megasequence, Early to Middle Albian calcarenites and calcirudites from the Shallow Carbonate Platform Megasequence, Late Albian to Middle Eocene siliciclastic turbidites from the Marine Regressive Megasequence, and siliciclastic turbidites from the Middle Eocene to Early Miocene Marine Regressive Megasequence (Figs. 1 and 4, Table 1). Fractured basalts, coquinas, and calcarenites/calcirudites comprise important reservoirs only in some of the oilfields that were the first to be discovered, during the 1970's, in shallow waters (< 200 m) of Campos Basin (Fig. 1). Siliciclastic turbidites also contain significant reserves in some of the shallow water oilfields, but their

importance has grown as Petrobras continuously has moved to aggressive exploration and production in deep and ultra-deep waters (up to 3,000 m). Organic geochemistry studies recognize that rift-phase, mudstones and marls accumulated in Barremian, shallow, saline lakes comprise the most important hydrocarbon source rocks in the Campos Basin (Mello and Maxwell, 1990).

Neocomian alkaline basalts (120-130 m.y.-old) interbedded with thin volcanoclastic and sedimentary rocks comprise the economic basement for the offshore Campos Basin. Fractured microcrystalline and vesicular basalts, and basaltic breccias comprise oil reservoirs in the shallow water (80-120 m) fields of Badejo and Linguado (Fig. 1; Table 1). The oil (28-32°API) is trapped in fractures, as also in vugs in some vesicular zones. Oil accumulation is controlled by rift-related extensional faults, which juxtapose reservoirs (fractured basalts) and source rocks. Initial flow rates can be as high as 6,200 bopd; however, the productivity tends to decrease rapidly, and to reach stable production around 2,000 bopd (Tigre et al., 1983).

Barremian coquinas (bioaccumulated calcarenites and calcirudites composed of pelecypods, ostracods, and gastropods) comprise oil reservoirs in the shallow water (80-120 m) fields of Badejo, Pampo, Linguado, and Trilha (Fig. 1; Table 1). Coquina-rich successions average 100 m (maximum thickness of 200 m); they include 10-50 m-thick coquina beds composed of stacked, coarsening-upward cycles of calcilutites grading up to calcarenites and calcirudites. These reservoir facies accumulated in lacustrine environments confined to rapidly subsiding, asymmetric half-grabens, which are defined by antithetic- and synthetic normal faults involving the Precambrian basement (Fig. 4). High-energy, matrix-free coquinas are found on syndepositional structural highs, while organic-rich marls and shales occupy adjacent lower areas (Dias et al., 1988; Fig. 4). Coquinas are very heterogeneous reservoirs, with average porosities typically in the range 10-20% (mostly intergranular and vugular), and average permeabilities ranging from < 1mD to >500 mD (matrix-free, poorly-cemented calcarenites and calcirudites). Oil trapping is defined by a combination of faulting, stratigraphic pinchout of coquina beds, and diagenesis (quartz and calcite cementation). Production zones can be correlated across the four oilfields, which are in pressure communication through the aquifer. The average well rates from Barremian coquinas typically range between 1,000 and 3,000 bopd (28-33°API), but maximum (initial) flow rates around 10,000 bopd have been recorded.

Early to Middle Albian, calcarenites and calcirudites form oil reservoirs in the shallow water (100-200 m) fields of Garoupa (the first oilfield discovered in the Campos Basin), Pampo, Bonito, Bicudo, Enchova, and Linguado (Fig. 1; Table 1). The Albian carbonate reservoirs make part of NE-trending, elongated (up to 20 m-thick, <1 km-wide, up to 2.5 km-long) shoals, which are composed mostly of grainstones and packstones containing oncolites, peloids, oolites, and rare bioclasts. Shoaling-upward cycles, starting with peloidal wackestones, and followed by oncolitic/oolitic packstones and oncolitic/oolitic grainstones represent common facies associations (Spadini et al., 1988). In between the shoals, lower-energy, finer-grained carbonates, particularly peloidal calcisiltites, were deposited. Oncolite/oolite-rich, matrix-free calcarenites comprise the best reservoir facies; they typically present porosities ranging between 20 and 34%, and permeabilities exceeding 100 mD

(average > 2,000 mD). The oil accumulations have a strong structural control, provided by faulting and folding (the best reservoir facies occur preferentially on faulted anticlines and rollover crests). However, all of the six fields also have a stratigraphic control (particularly in the upper portion of the carbonate successions), given by the lateral transition of calcarenites and calcirudites to mud-rich calcarenites, calcisiltites and calcilutites. Faulting and folding related to halokinesis were able to define oil columns always exceeding 100 m (up to 275 m in the Bonito Field). The average well rates from Albian carbonate reservoirs typically ranges between 1,000 and 3,000 bopd (20-32°API), but maximum (initial) flow rates around 10,000 bopd have been recorded.

Turbidites are, by far, the most important petroleum reservoirs in the Campos Basin (Table 1). They comprise reservoirs in 37 oilfields, including the super giant fields of Marlim, Marlim Sul, and Roncador, with original total oil reserves of 2.7, 2.5, and 2.3 billion bbl, respectively. There are 12 major turbidite systems in the Campos Basin:

Marine Transgressive Megasequence:

- (1) Late Albian – Namorado Sandstone;
- (2) Late Cenomanian - Namorado Sandstone;
- (3) Turonian/Coniacian - Espadarte Sandstone;
- (4) Santonian - Carapeba Sandstone;
- (5) Campanian/Maastrichtian - Roncador Sandstone;
- (6) Late Paleocene - Barracuda Sandstone;
- (7) Early Middle Eocene - Enchova Sandstone;

Marine Regressive Megasequence:

- (8) Late Middle Eocene - Corvina Sandstone;
- (9) Early Oligocene - Caratinga Sandstone;
- (10) Late Oligocene – Marlim Sandstone;
- (11) Late Oligocene/Early Miocene – Marlim Sandstone;
- (12) Early Miocene – Albacora Sandstone.

Detailed studies of the Campos Basin turbidites have been developed in the last 30 years. These studies have shown that turbidite reservoirs comprise different types and can be very complex and heterogeneous; they can be discriminated mainly on the basis of grain size, net-to-gross ratio, external geometry, depositional processes, and depositional setting. The main types of turbidite reservoirs from the Campos Basin include (Fig. 4): (1) gravel/sand-rich, channel complexes, (2) trough-confined, gravel/sand-rich lobes, (3) unconfined, sand-rich lobes, and (4) sand/mud-rich lobes. The main characteristics of these turbidite types are listed in Table 2.

Most of the oil accumulations in turbidite reservoirs have a structural control by faults, which are soling out on underlying Aptian evaporites or are attached to the Precambrian basement; these faults may also have defined reservoir compartments, as well as provided conduits for oil migration from underlying rift-phase source rocks (Fig. 5). Most of the turbidite oilfields also have some degree of stratigraphic control, either by reservoir pinchout (Fig. 5) and/or partial reservoir erosion by younger, mud-filled channels (Fig. 6).

Turbidite oilfields (Fig. 1) show a great variation in water depth (80 m, Carapeba - 2,400 m, Marlim Sul), distance from the coast (50 km, Carapeba - 140 km, Marlim Sul), area (up to 650 km², Marlim Sul), overburden (< 500 m, Albacora Leste –

3,200 m, Carapeba), net pay (up to 270 m, Roncador), density of produced oil (13°API, Pampo - 31°API, Roncador), initial oil reserves (up to 2.7 billion bbl, Marlim), number of wells in production (1, Parati - 83, Marlim), well rate (up to 34,200 bopd, Marlim Sul), recovery factor (up to 62%, Marimbá), and production peak (up to 650,000 bopd, Marlim).

Evolution of Reservoir Characterization and Management

Since the beginning of oil production from the Campos Basin, Petrobras continuously moved to aggressive exploration and production in deep and ultra-deep waters. During the last 25 years the activities of reservoir characterization and management have also continuously evolved. Three major phases of reservoir characterization and management can be discriminated: (1) shallow water fields developed with a large number of vertical or deviated, relatively closely-spaced wells (400-500 m or less) (e.g. Marimbá, Namorado, Pampo, Cherne, and Carapeba); (2) deep water fields, still developed with a large number of wells, but this time combining vertical/deviated and horizontal wells, with well spacing typically in the range 600-800 m (e.g. Marlim and Albacora); and (3) deep to ultra-deep water fields developed with a relatively small number of mostly horizontal wells, with well spacing typically greater than 800-1,000 m (e.g. Marlim Sul, Barracuda, and Albacora Leste).

Deep and ultra-deep water giant fields started to be discovered only in 1984. There was a succession of large discoveries, including Albacora, Marlim, Albacora Leste, Marlim Sul, Barracuda, Caratinga, Roncador and, more recently, Jubarte and Cachalote (Fig. 1). These fields will be responsible for 70% of the total Brazilian oil production in the year 2005, which has been forecasted as 1.9 million bopd (Fig. 7). In order to achieve this goal, about US\$ 12.5 billion will be invested in production development (US\$ 8 billion only in the 10 major projects shown in Fig. 7).

The development of the deep and ultra-deep water fields from the Campos Basin has continuously provided new challenges for the reservoir characterization and management in the Campos Basin, particularly because these fields are developed with fewer, horizontal and high angle wells, drilled through poorly consolidated reservoirs.

Reservoir Characterization. Most of the shallow water oilfields from the Campos Basin were discovered with 2D seismic. The use of 3D seismic in field appraisal started only in 1986, and the use of 3D seismic in reservoir characterization became routine only after 1994. The higher quality of 3D in deepwater settings, particularly in the imaging of Tertiary reservoirs (Fig. 6), has stimulated the use of seismic data in reservoir characterization over the years. Additionally, Petrobras has made efforts to improve the quality of the acquired 3D seismic, particularly regarding information density per area (traces / km²). There was a remarkable increase in information density for the most recent seismic surveys oriented to reservoir geophysics (e.g. about 700 traces / 1,000 km² for the recent survey covering the Marlim Sul, Marlim Leste, Barracuda, Caratinga, and Espadarte fields; Johann, 1999). In recent years, Petrobras has applied new techniques for seismic processing, including 3D

AVO, pre-stack time/depth migration, and a workflow specially designed for reservoir characterization, which key steps comprise NMO / pos-stack migration, pre-stack time migration, and seismic inversion.

The extensive use of 3D seismic as a reservoir characterization tool has allowed risk reduction and optimization of well location. Integration of high-resolution stratigraphic analysis with 3D seismic inversion (both acoustic and elastic) (Fig. 8), accurate time-depth conversion (Fig. 9), geostatistic (stochastic) simulation of reservoir properties constrained by seismic, well log and core data (Fig. 10), 3D visualization, and voxel-based automatic interpretation has guided the positioning of horizontal wells through thin (<10-15 m) reservoirs (Fig. 9). Additionally, 3D visualization techniques have provided a new environment for teamwork, where seismic, well log, and core data are interpreted and added to detailed 3D geological models (Fig. 10), and, subsequently, to robust reservoir simulation models.

The first 4D seismic data acquired in the Campos Basin aimed the monitoring of the water injection path in the Marlim Field. In this case, the variations in the classical seismic attributes, such as amplitude, attributes derived from amplitude, and acoustic impedance did not reveal the drainage path. The subtle variation in the acoustic properties poses a new challenge for the use of 4D seismic in the monitoring of waterflooding in the heavy oil fields from the Campos Basin. It has become clear that, besides acoustic attributes, elastic attributes need to be investigated.

Historically, most of the faults found in the Campos Basin oilfields have been considered as extensional and non-sealing faults. In more recent times, some of these faults have been re-interpreted as strike-slip and (at least partially) sealing faults, capable of defining reservoir compartments. These reservoir compartments may have distinct oil-water contacts, pressure regimes, and/or oil with different composition, gravity and viscosity. The petrophysical properties (transmissibility) of sealing/non-sealing faults are now being incorporated into the 3D geological models and fluid flow simulation models.

Horizontal Wells. The shallow water fields from the Campos Basin were developed mainly with vertical or deviated wells. The first horizontal well drilled in the Campos Basin was the well BO-13H (464 m long, Bonito Field; Fig. 1), drilled at a water depth of 120 m. Oil production from this well started in March 1991 (1,600 bopd from Albian carbonates). Side-track horizontal drilling to reduce the formation of water cones, and to avoid the oil production with very high BSW, was first attempted in 1995, when it was drilled the 150-m long well VM-70H (Middle Eocene reservoirs, Vermelho Field; Fig. 1).

The development of the deep and ultra-deep water fields from the Campos Basin was very complex in the beginning, particularly because of the difficulties faced by Petrobras to obtain an efficient sand contention mechanism for wells drilled into poorly consolidated reservoirs. The first deepwater fields to be in production (Albacora, 1987, and Marlim, 1991) were still mostly developed with vertical and deviated wells; that was because only in 1998 the company was able to complete horizontal wells with open-hole gravel pack (OHGP). The OHGP technology allowed the next developments to be done preferentially with horizontal wells,

including the development of the Marlim Sul Field, which is characterized by thinner (< 50 m) reservoir successions, distributed over a very large area (about 650 km²).

The longest horizontal well (ESS-110HP; 1,076 m) was drilled in July 2002, in the Jubarte Field (Fig. 1), equipped with a 900 HP, 25,000 bopd-capacity ESP, installed above the X-mas tree (see detailed description in Pinto et al., 2003). Oil production from this well started in October 2002; it produced by natural flow for two months, with a stabilized rate of 16,500 bopd (17°API). In December 2002, the ESP was turned on, and the flow rate was increased to 18,200 bopd; the production has been limited because of constraints in the processing plant (FPSO Seillean).

Horizontal wells brought additional information to the characterization of the Campos Basin reservoirs, which are derived from well tests, wireline logs, core description, and probe permeametry of cores. Horizontal variograms of reservoir properties obtained from horizontal wells have supported the building of more detailed and sophisticated 3D geological models. The parameters used in these models were adjusted in order to reproduce the results from horizontal well tests; this procedure has enriched the knowledge of the internal reservoir architecture from the Campos Basin.

Well Design, Drilling and Completion Issues. Since the drilling of the first wells in deep water Campos Basin, many developments related to drilling techniques have been made (Bernardo et al., 2003). Improvements in well design, drill bits, drilling fluids and the use of new technologies helped to increase safety, cut costs and raise oil production (e.g. the introduction of slender wells in 1998 reduced the total drilling time per wells in three days).

The deepwater reservoirs from the Campos Basin are poorly consolidated, requiring the installation of sand contention systems. Gravel packing is one of the most difficult and complex completion operations that have been done on a routine basis in the wells completed in deep water Campos Basin. Different aspects must be considered, such as (1) the operations are made from floating rigs under harsh environmental conditions (high waves), (2) the high deviation angles in front of the pay zones, and (3) the need to prevent excessive pressure drop in order to maximize production rates. The use of high-rate water pack and frac-pack techniques was introduced in order to optimize the packing efficiency in deviated wells, and to minimize the pressure drop induced by the gravel pack. Petrobras has a great experience in applying the openhole gravel pack technique in horizontal wells, obtaining very high completion efficiency. New technologies in gravel packing operations have been used, such as alternate path technology and shale isolation using external casing packers in horizontal or high angle sections.

Reservoir Simulation. Campos Basin reservoirs have been simulated with commercial 3D black-oil simulators. Special features in the simulator are necessary, since forecasted production and injection requirements can be greatly under- or overstated if optimization techniques are not used. Some of the fundamental issues to be considered include (Corbishley et al., 2000): (1) maximization of oil production or discounted cumulative production from satellite and platform wells within

a framework of various fixed capacity platforms, (2) dynamic calculation of well production and injection potentials to allow maximized oil production, (3) pressure maintenance at specific pressure levels in different areas of the field, (4) individual management of multiple reservoirs with pressure maintenance by water injection over different platforms, (5) optimization of gas-lift with a limited gas supply, (6) scheduling drilling and completion within a realistic rig availability scenario, (7) consideration of platform operational factors for production and injection to reduce average rates without interfering with well potential calculations, and (8) multiphase flow calculations for multi-lateral wells or wells connected to subsea manifolds.

Reservoir Management. The surveillance and management of deepwater reservoirs tends to be quite different from this same activity for shallow water reservoirs. Data gathering in deep water fields is more difficult because of the high costs of subsea well interventions. In order to mitigate the relative lack of data from deepwater fields, all of the new wells are being completed with pressure and temperature gauges at the X-mas tree and downhole. Pressure downhole gauge (PDG) is the most cost-effective method to collect data from the reservoir, allowing the performance of a complete well test (including build up tests), directly from the production unit. The production of each well is deviated to the test separator about once a month, when the production parameters are calibrated, and the produced fluids are sampled and analysed. A similar procedure is applied to the water injection wells. Diagnostic plots of productivity, injectivity, GOR, and WOR are continuously updated. The integration of these data allows the diagnosis of the well performance, and multiphase flow efficiency. In the near future, reliable electronic (intelligent) completion systems should allow remote data acquiring and remote well recompletion. An intelligent completion system shall be installed in a deepwater subsea well from the Marlim Sul Field, probably in the first semester of 2003.

Pilot production projects and/or early production systems have been implemented in the Campos Basin oilfields in order to investigate the reservoir performance, before the permanent production systems be installed. These pilot projects have been designed in order to (1) verify the STOIP through material balance calculation, (2) obtain a better understanding of the reservoir compartments and/or internal heterogeneities, and (3) assure the oil flow in long pipelines, including the flow of oil as heavy as 16.5°API. The results from these pilot production projects have been used to optimize the design of the definitive production units.

Most of the deepwater wells are connected individually to the production units, because of their high productivity (typically > 10,000-15,000 bopd), and to make the reservoir management easier. Subsea manifolds were employed only where there was a restriction to the total number of risers. Despite the low oil gravity found in most deepwater fields, the gas lift method has been applied because of its simplicity and reliability in the subsea completion scenario, and the relatively high GOR (e.g. 80 m³/m³ in the Marlim Field). In most of the projects the gas lift is supplied through individual flowlines.

Decisions involving well interventions in deep water fields are always taken after an accurate economic analysis,

supported by reservoir simulation. To date, few well interventions have been made in the deepwater fields. The main reasons for these operations include (1) gravel-pack restoration, (2) damage removal in injection wells, and (3) hydrate removal in the X-mas trees or in the flowlines. Due to the high costs involved, the option of restoring a well is always compared with the options of drilling side-track wells and even drilling a new well.

Water Management. Many of the shallow water oilfields from the Campos Basin have a strong water influx, as for example, Marimbá (62% of oil recovery), Carapeba, and Vermelho fields (Fig. 1). However, water injection has been widely used both in shallow water (e.g. Namorado and Cherne) and deepwater (e.g. Marlim, Marlim Sul, and Espadarte) fields. The good lateral continuity of most reservoirs, the relative scarcity of gas, and the favorable characteristics of the relative permeability curves, make seawater injection as the most feasible method for pressure maintenance and increasing oil recovery in a large number of fields, particularly in the deep water portions of the basin. There are twelve fields under water injection in the Campos Basin, and there are other seven fields where water injection is planned to start in the next two years. The rate of water injection has already exceeded 880,000 bwpd, and the water production rate has reached 330,000 bwpd (Shecaira et al., 2002). The technology of 4D seismics is expected to help the mapping of water paths, supporting future operations of in-fill drilling.

In order to assure that the desired amount of water has been injected in the deepwater fields from the Campos Basin, it has been necessary to control the decline in water injectivity recorded in some injection wells. The injection water treatment systems have been continuously verified in the Campos Basin, and the quality of the injected water is evaluated by an index named Injected Water Quality Index (IQUAI). This index comprises parameters that describe the reservoir plugging (solids in suspension, oil and wax content, and number of particles with size above the cutoff), corrosion and scale potential (oxygen and CO₂ content, and soluble sulphide and bacteria). Laboratory analyses to determine the causes for water injectivity decline are continuously performed. In the Marlim Field, it was found that organic material was blocking the perforations, as a consequence of water injection without filtering; in this case, the water injectivity was restored by extending the perforation, and acidifying the formation.

Since seawater has been injected to maintain reservoir pressure and to displace oil, scaling has been recorded in some fields from the Campos Basin. Precipitation of barium and strontium sulphates has impacted oil production from the shallow water (110-250 m) Namorado Field (Bezerra et al., 1990), which was developed with deviated platform wells. In this case, interventions to squeeze scale inhibitors into the formation are feasible. However, as most of the deepwater fields are developed with horizontal subsea wells, workover problems are involved in scale treatment. Scale management requires the monitoring of producing wells, topside equipment and pipelines. Water analysis and scale composition have been considered to evaluate the risk of scale formation. Subsea

wells usually have individual and secondary flow lines that allow the dosage of chemicals, making the remote interventions (bullhead) in each well feasible. In order to prevent scaling, Petrobras is considering the following technologies: (1) squeeze treatment, (2) solid inhibitor (fracture proppant impregnated with inhibitor), and (3) inhibitor injection via capillary string and sulphate removal. Techniques such as compatibility of chemicals with different functions, and remote workover in subsea wells are currently being applied in some fields. The next step in scale treatment is the simultaneous application of correction and prevention remote treatment (bullhead) simultaneously.

A large amount of produced water is expected as the fields get more mature. To deal with this problem, technologies such as oil-water separation and re-injection at the sea floor should be considered. The higher salinities of mixture (sea) water, greater volumes, higher permeabilities, and greater produced volumes, when compared to onshore fields, are challenges to be overcome. If large amounts of produced water cannot be avoided, destination of this water is another challenge. The disposal in the sea after a rigorous treatment to remove oil particles will require more space and load on the production units. Furthermore, the environmental laws have become more restricted, with the tendency of disposal in the sea become more restricted or even prohibited. Water re-injection in the reservoir or disposal in non-productive formations may be considered as viable options.

Development of Heavy Oil Fields. Large volumes of heavy (13-17°API) and high viscosity (20-400 cp at the reservoir conditions) oil have been found in the deep and ultra-deep water Campos Basin. The economic oil production from these accumulations relies on a group of new production technologies including mainly (Pinto et al., 2003): (1) long horizontal or multilateral wells (producing with high power ESPs, hydraulic pumps or submarine multiphase pumps) to compensate the decrease in productivity caused by the high oil viscosity), (2) efficient heat management systems, and (3) compact oil-water separation systems. Pinto et al. (2003) describe some successful extended well tests performed in the Marlim Sul (well MLS-3B; 16.5°API), and Jubarte (well ESS-110HP; 17°API) fields. In October 2002 was created the Petrobras Offshore Heavy Oil Program (PROPES), who is responsible for the development of new technologies to optimize the development of the large volumes of heavy oil discovered in the Campos Basin.

Development Projects for Deep Water Reservoirs - Lessons Learned Over the Last 25 Years

Value of Information. Develop or not? The conditions to develop an oilfield change from company to company. Decisions have been taken by Petrobras over the last 25 years on the basis of a minimum amount of information, which may include well logs, well tests, fluid data, 3D seismic data, 3D geological models, data from analog fields, and reserves estimates. New information obtained from pilot production systems or early production systems, appraisal wells, new seismic acquisition and reprocessing, and detailed reservoir characterization studies have provided important input to the conception of definitive production systems. The Value of

Information technique has been applied on a routine basis to approve investments to gather reservoir information.

Processing Capacity of Production Units. The decision about the processing capacity of the production units has been influenced by factors such as the company's opportunity cost, and the technological limits for offshore processing units. A simple rule of thumb (Pinto et al., 2001) used in most of the deepwater fields is that the capacity of processing of the production units should be higher than 3% of the STOIP per year.

Number of wells. The NPV of deepwater production projects is strongly affected by the number of wells, since their cost usually represents more than 50% of the CAPEX. Detailed studies has been done must be done in order to define the distribution and number of wells; these studies consider not only the economic results, but also the oil recovery factor and the risk reduction (Guedes et al., 2000). Wells with expected oil recovery less than 10-15 million bbl are not drilled in the beginning of the projects, and remain as future opportunities to increase oil production and recovery.

Risk Analysis. If a development project is considered robust, i.e. it is economic in the "lower case" (even considering the uncertainties in oil price, CAPEX and OPEX), then it is time to start the investments. However, as uncertainties exist, the development plan cannot be deterministic. A "base case", usually a P50 scenario, is considered in the technical-economic feasibility studies. However, although the definition of the project is made on the basis of the "base case", some leeway is provided (whenever possible), in the main systems of the processing unit, and well slots in the manifolds or at the platform. The "lower case" and "upper case" are also evaluated, with the expected NPV being calculated by averaging the NPV of each scenario with its probability of occurrence (Guedes et al., 2000).

Pressure Maintenance. In deepwater projects, due to the intensive investments, oil production must be high and remain constant during the first years of production. The wells must be designed to allow high production rates (typically >10,000-15,000 bopd), with lifetime completions to avoid costly interventions (Pinto et al., 2001). In order to assure high productivity, pressure maintenance must be efficient; if water injection is planned, the hydraulic connectivity between injector and producer wells must be guaranteed by high-quality 3D seismic, well log correlation, and observed pressure profiles. Most of the deepwater reservoirs from the Campos Basin are characterized by solution gas drive (the Late Oligocene/Early Miocene reservoir from the Albacora Field is one of the few exceptions). Water injection has been selected as the pressure maintenance method, for its simplicity and also due to the relative permeabilities, favorable to waterflood. The use of polymer flooding and WAG has been studied, but so far these methods have not been implemented.

Conclusions

The discovery of the Garoupa Field (1974), and the first oil produced from the Enchova Field (1977), represent the

beginning of a successful history that led Petrobras to become a world leader company in petroleum exploration and production in deep and ultra-deep waters. Since the beginning of oil production from the Campos Basin, Petrobras continuously moved to aggressive exploration and production in deep and ultra-deep waters. During the last 25 years the activities of reservoir characterization and management have also continuously evolved. Three major phases of reservoir characterization and management can be discriminated: (1) shallow water fields developed with a large number of vertical or deviated, relatively closely-spaced wells (400-500 m or less), (2) deep water fields, still developed with a large number of wells, but this time combining vertical/deviated and horizontal wells, with well spacing typically in the range 600-800 m, and (3) deep to ultra-deep water fields developed with relatively small number of mostly horizontal wells, with well spacing typically greater than 800-1,000 m.

The development of fields discovered in gradually deepening water depths has continuously provided new challenges for the reservoir characterization and management in the Campos Basin, particularly because these fields are developed with fewer, high-productivity (>10,000-15,000 bopd) horizontal and high angle wells, drilled through poorly consolidated reservoirs. Some of the new technologies devised for the characterization and development of the deepwater oilfields from the Campos Basin include reservoir imaging with pre-stack, depth-migrated seismic, 4D seismic, real-time well steering and updating of geological/reservoir models, extended reach wells, selective completion in gravel-packed wells, isolation inside horizontal, gravel-packed wells, intelligent completion, subsea oil-water separation, re-injection of produced water, scale prevention and treatment, and improved recovery technologies for heavy and/or viscous oil.

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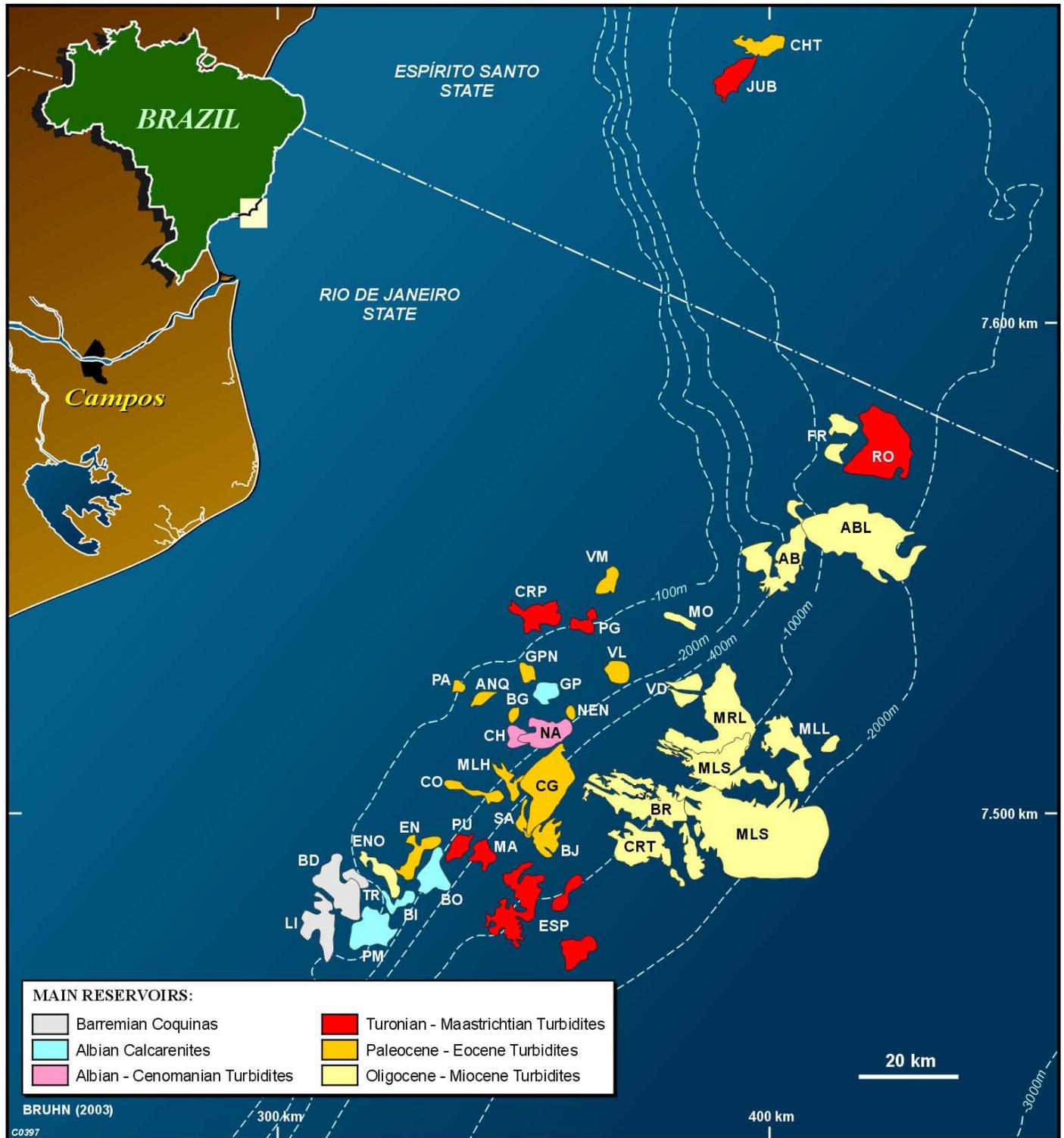


Fig. 1 – Location map for the forty-one oilfields from the Campos Basin. Most of the fields contain reserves in more than one reservoir type; it is indicated only the most important reservoir (according to the original recoverable reserves) for each field. Discovery year and year of first oil are indicated between parentheses. Oilfields: GP (Garoupa, 1974/1979), PG (Pargo, 1975/1988), GPN (Garoupinha, 1975/1980), BG (Bagre, 1975/1984), NA (Namorado, 1975/1979), BD (Badejo, 1975/1981), CH (Cherne, 1976/1983), EN (Enchova, 1976/1977), BI (Bicudo, 1976/1982), PM (Pampo, 1977/1980), BO (Bonito, 1977/1982), LI (Linguado, 1978/1981), CO (Corvina, 1978/1983), VL (Viola, 1979/1985), PA (Parati, 1980/1982), CG (Congro, 1980/1982), PU (Piraúna, 1981/1983), ENO (Enchova Oeste, 1981/1984), ANQ (Anequim, 1991/1985), CRP (Carapeba, 1982/1989), TR (Trilha, 1982/1984), VM (Vermelho, 1982/1989), MO (Moréia, 1983/1986), MA (Marimbá, 1984/1985), AB (Albacora, 1984/1987), MRL (Marlim, 1985/1991), MLH (Malhado, 1986/1990), ABL (Albacora Leste, 1986/1998), FR (Frade, 1986/No Oil Production), MLL (Marlim Leste, 1987/2000), VD (Voador, 1987/1992), NEN (Nordeste de Namorado, 1987/1987), MLS (Marlim Sul, 1987/1994), ESP (Espadarte, 1988/2000), BR (Barracuda, 1989/1997), BIJ (Bijupirá, 1990/1993), SA (Salema, 1990/1993), CRT (Caratinga, 1994/1997), RO (Roncador, 1996/1999), JUB (Jubarte, 2001/2002), and CHT (Cachalote, 2002/No Oil Production).

CAMPOS BASIN OIL PRODUCTION

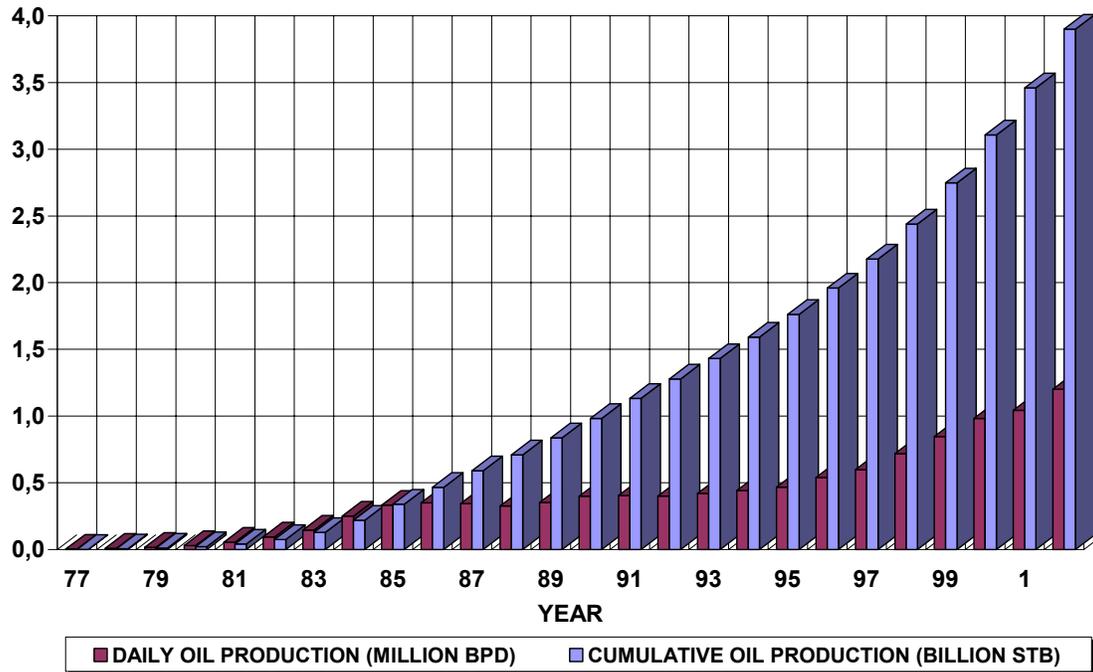


Fig. 2 – Evolution of the oil production from the Campos Basin (1977-2002). In 2002, the average daily oil production from the Campos Basin (1.2 million bopd) corresponded to 83% of the total Brazilian oil production.

CAMPOS BASIN OIL RESERVES

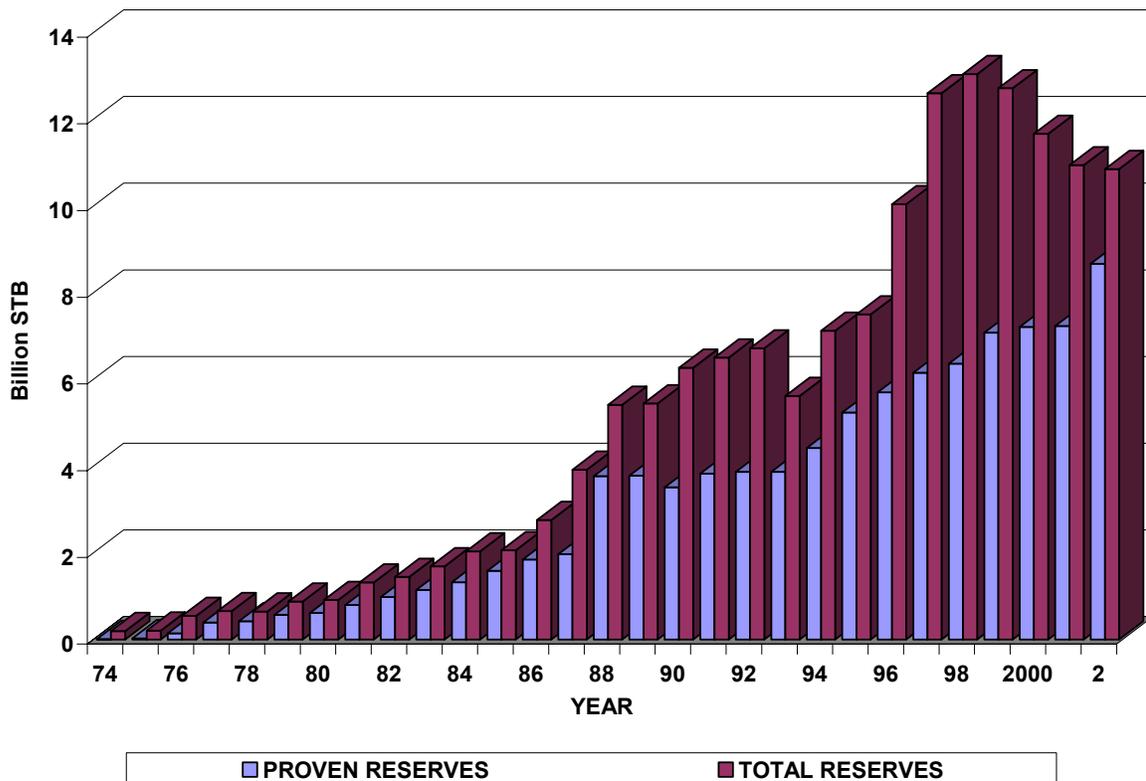


Fig. 3 – Evolution of the oil reserves from the Campos Basin (1974-2002). In 2002, the proven oil reserves from the Campos Basin (8.5 billion bbl) reached the equivalent to 89% of the total Brazilian oil reserves.

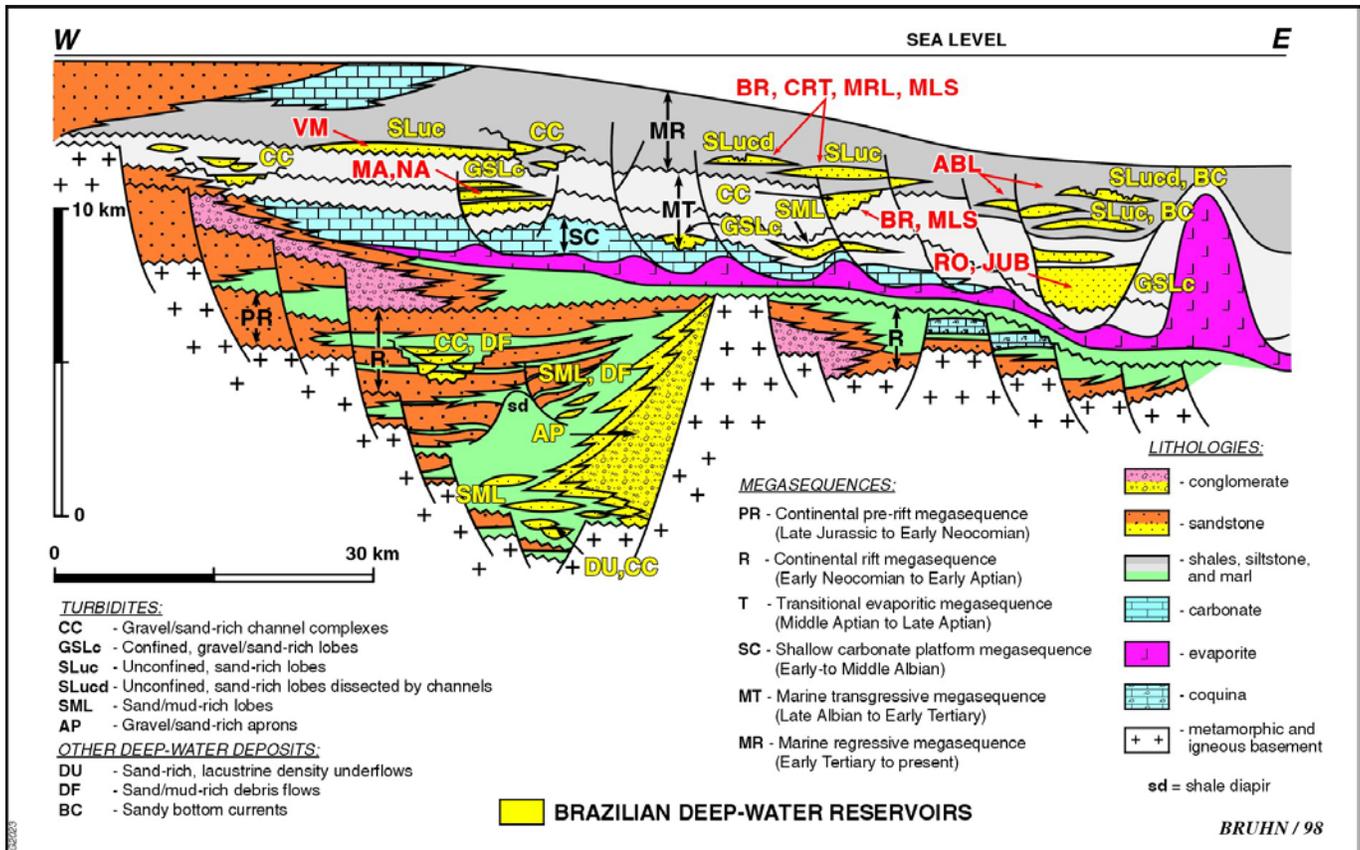


Fig. 4 – Generalized geological section for the eastern Brazilian marginal basins (Bruhn, 1998). Major types of deep-water reservoirs are highlighted in yellow. Turbidite reservoirs from the Campos Basin include mostly (1) gravel/sand-rich channel complexes (CC), (2) confined, gravel/sand-rich lobes (GSLc), (3) unconfined, sand-rich lobes (SLuc), and (4) sand/mud-rich lobes (SML). The approximate stratigraphic position of some important oilfields is indicated in red: Albacora Leste (ABL), Barracuda (BR), Caratinga (CRT), Jubarte (JUB), Marimbá (MA), Marlim (MRL), Marlim Sul (MLS), Namorado (NA), Roncador (RO), and Vermelho (VM).

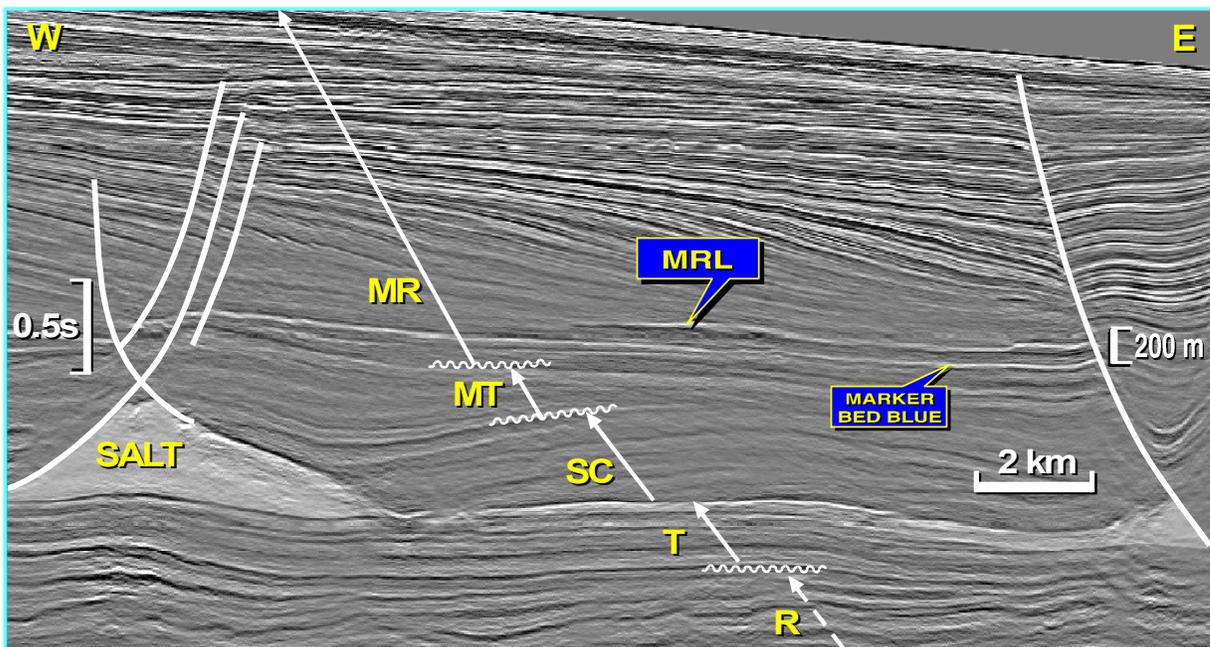


Fig. 5 – Typical seismic profile for the eastern Brazilian margin (Bruhn, 1998): (R) Continental Rift Megasequence, (T) Transitional Evaporitic Megasequence, (SC) Shallow Carbonate Megasequence, (MT) Marine Transgressive Megasequence, and (MR) Marine Regressive Megasequence. The top of the Marlim Field reservoir is indicated by MRL. The oil accumulation is defined by reservoir pinchout to the west, and by a large extensional fault to the east, which acted as a conduit for oil migration from the underlying rift megasequence.

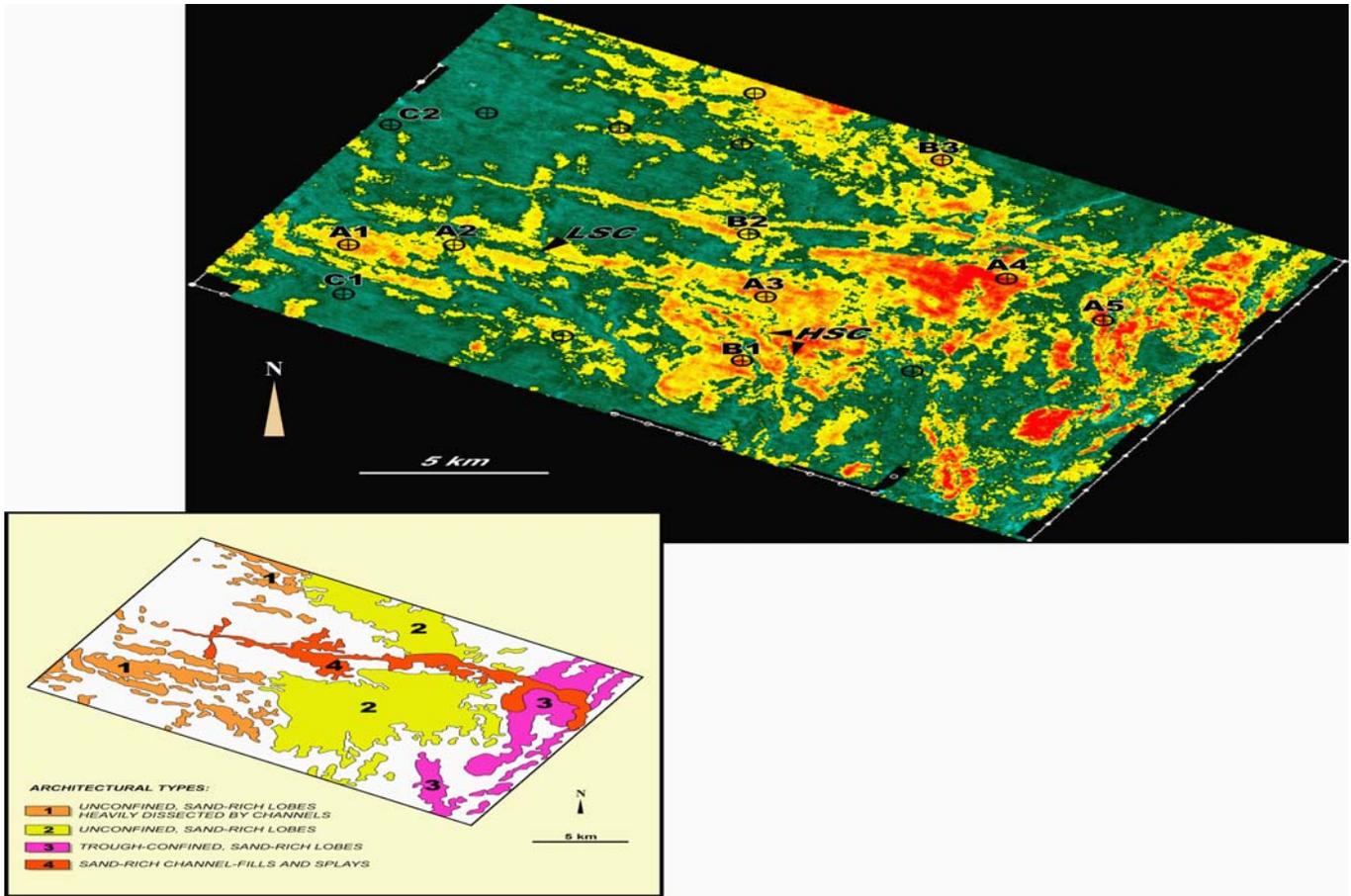


Fig. 6 – Seismic amplitude map for turbidite reservoirs from the Marlim Sul and Barracuda fields (Lopes et al., 1999). Red and orange indicate thicker sandstone successions. Four major types of reservoir types are illustrated. LSC = low-sinuosity channels; HSC = high-sinuosity channels.

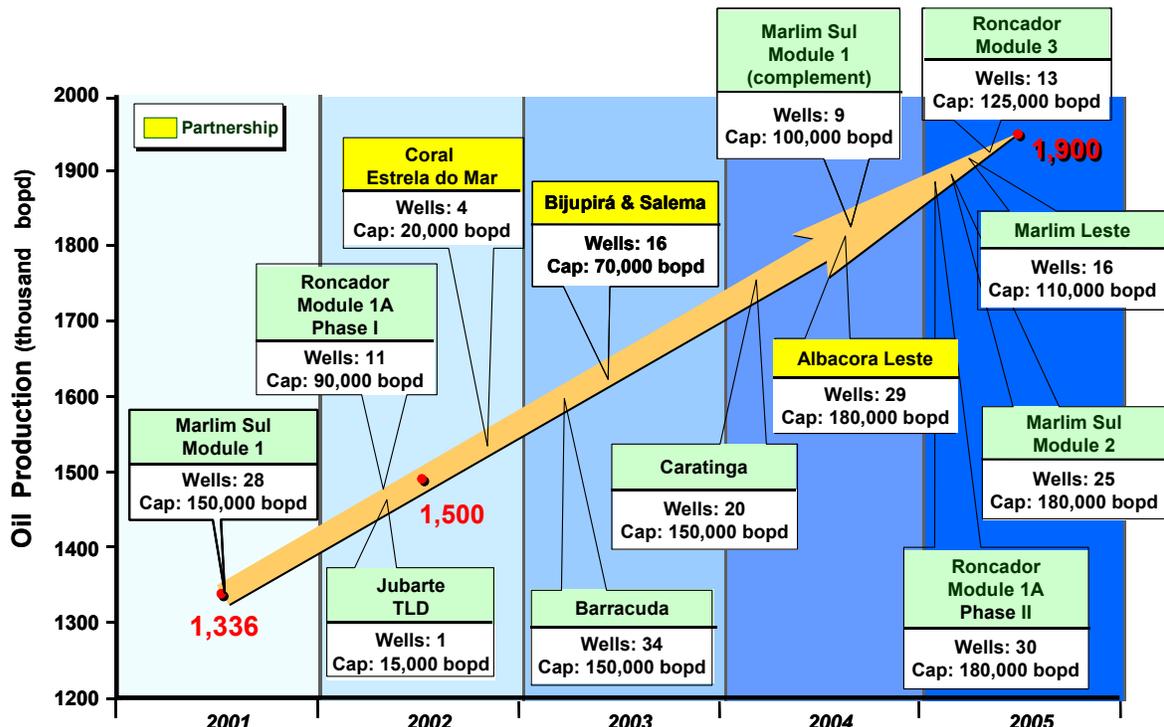


Fig. 7 – Petrobras major projects for development of oil production. These projects fully support an oil production target of 1.9 million bopd for the year 2005; they will demand investments of US\$ 8 billion, to drill wells and build production units with processing capacity of up to 180,000 bopd. Considering only those projects in operation after 2003, a processing capacity of 1.2 million bopd will be installed within a time period of only three years.

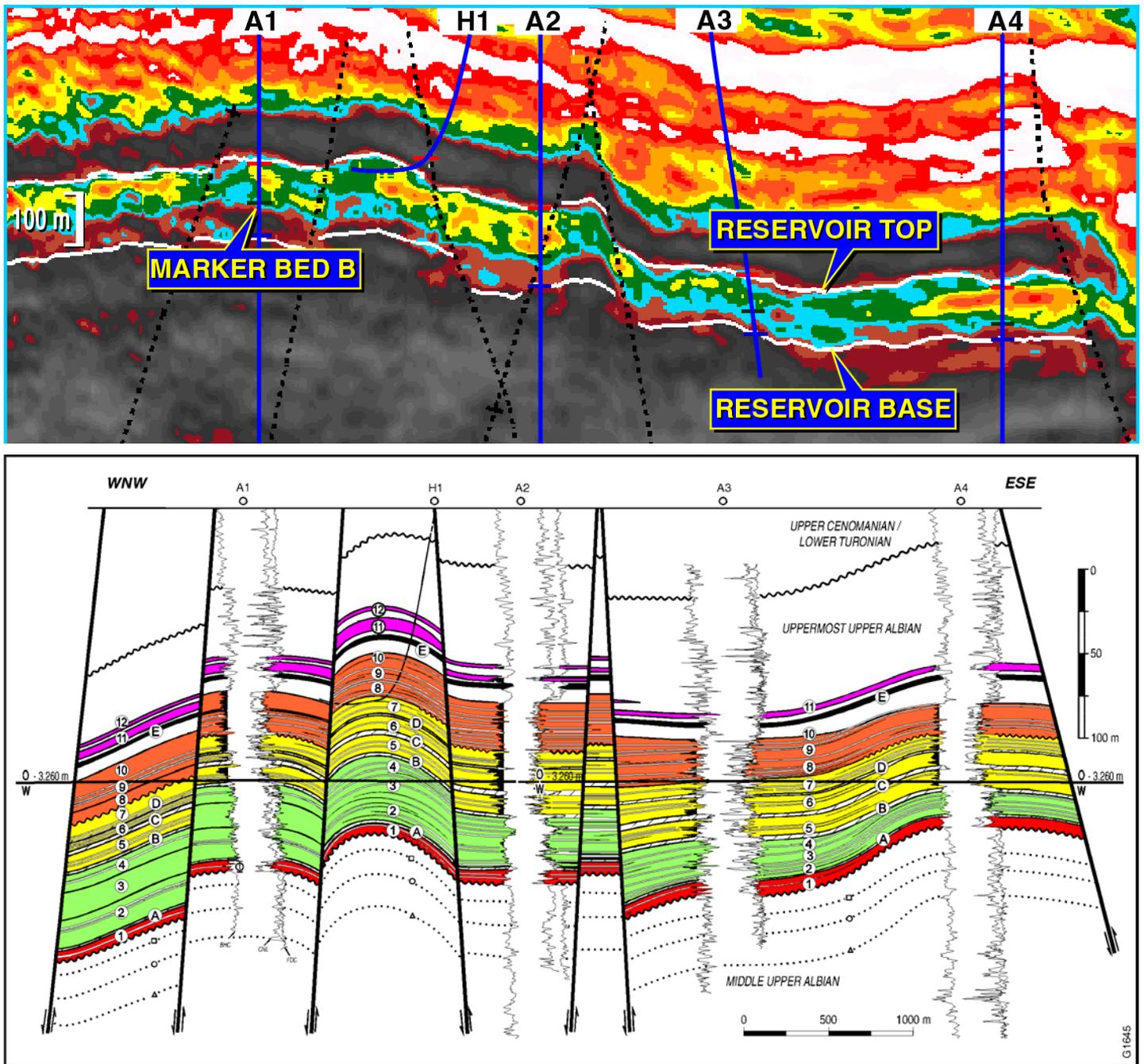


Fig. 8 – Seismic impedance section, and geological section for the Late Albian reservoirs from the Albacora Field (Bruhn et al., 1998). Twelve production zones were discriminated on the basis of seismic data, well log patterns, and core data. Zones 5-12 (above marker bed B) have higher porosities and permeabilities (indicated in yellow and orange in the seismic impedance section).

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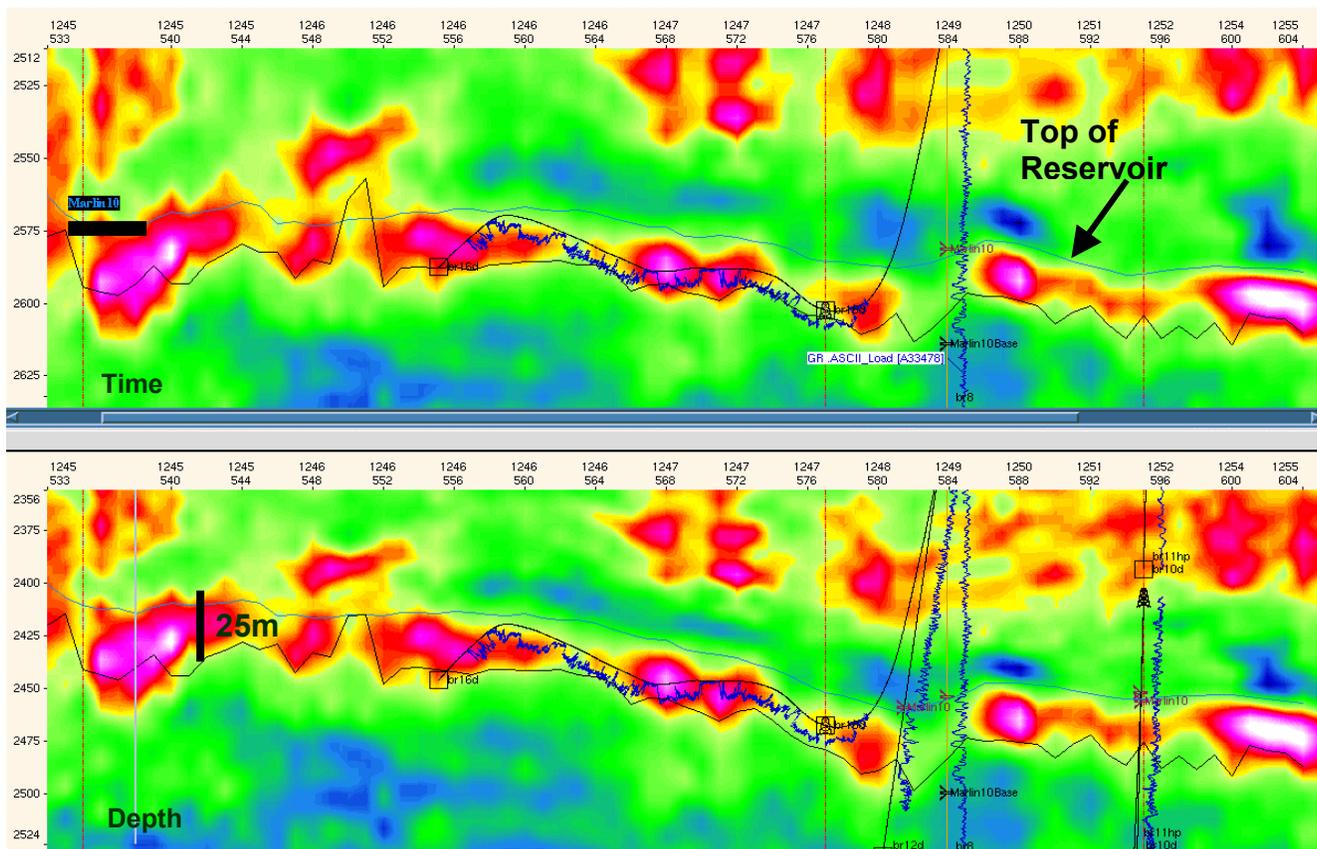


Fig. 9 – Seismic impedance section for the Late Oligocene/Early Miocene reservoirs from the Barracuda Field (Johann et al., 1999). Purple and red indicate higher NTG ratio. The accurate time-depth conversion is essential to guide the drilling of horizontal wells through thin reservoirs (mostly 10-15 m-thick).

Table 1 – Distribution of Campos Basin Oil Volumes by Major Reservoir Types.

Major Reservoir Types	Number of Fields *	Most Important Fields	STOIPP		Original Recoverable Oil Reserves		Proven Oil Reserves (Dec	
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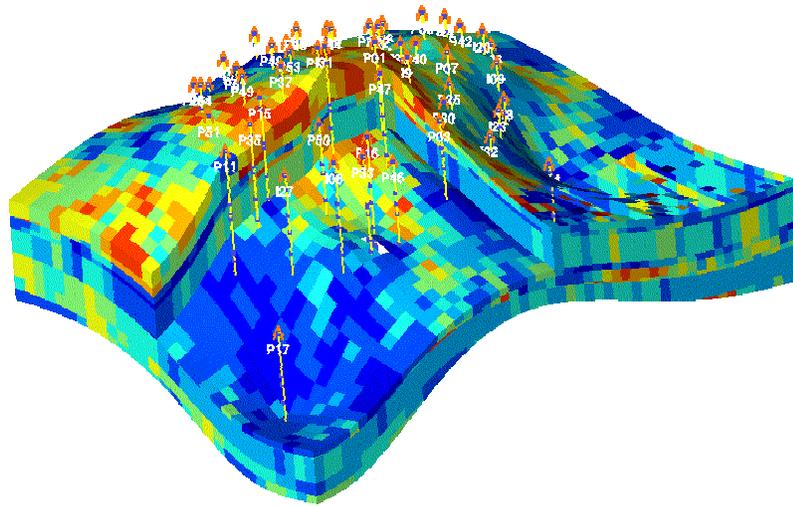


Fig. 10 – 3D geological model for the Namorado Field (Johann, 1997). The distribution of reservoir porosity was simulated on the basis of the integration of seismic, well log, and core data (Johann, 1997).

Table 2 - Characteristics of the major types of turbidite reservoirs from the Campos Basin (Bruhn, 1998).

TYPES	GEOLOGICAL SETTING	RESERVOIR GEOMETRY	RESERVOIR QUALITY
1. Gravel/sand-rich, channel complexes (CC): bouldery conglomerates to very fine-grained sandstones.	Intra-slope troughs in areas with slope oversteepening due to intense faulting and upward movement of underlying Aptian evaporites (Late Paleocene and Middle Eocene - Marine Transgressive Megasequence; Middle Eocene, Early Oligocene, Late Oligocene, transition Late Oligocene/Early Miocene, Early Miocene - Marine Regressive Megasequence).	Channel-fills: 10-50 m-thick, 200-2,000 m-wide (>90% are 200-800 m-wide), and 0.5->10 km-long (>90% are <2 km-long). Channel complexes: 20-100 m-thick, 1-6 km-wide, and 1->10 km-long. Complex, multi-storied geometry resulting from the amalgamation of many channel-fills and preservation of overbank/levee and/or background deposits between channel-fills.	Porosity (Phi) and permeability (K) mostly controlled by grain size and sorting. Typical average values: Phi = 21% / K = 400 mD (bouldery to granular, intraformational conglomerates, intraclastic sandstones, and very coarse- to coarse-grained sandstones); Phi = 27% / K = 900 (coarse- to fine-grained sandstones); Phi = 32% / K = 500 mD (very fine-grained sandstones).
2. Trough-confined, gravel/sand-rich lobes (GSLc): pebbly conglomerates to fine-grained sandstones.	Intra-slope troughs defined by subsidence along listric faults soling out on underlying Aptian evaporites, and erosion by high-density turbidity currents (Albian/Cenomanian, Turonian/Coniacian, Santonian, Campanian/Maastrichtian - Marine Transgressive Megasequence).	Lobes and tabular sandstone bodies: 10-140 m-thick, 1-12 km-wide, and 3->20 km-long. NTG >70%. Lobe complexes up to 350 m-thick.	Porosity (Phi) and permeability (K) mostly controlled by grain size and sorting: Phi = 15-20% / K = 100-800 mD (conglomerates and granular sandstones); Phi = 18-22% / K = 300-1,000 mD (very coarse-grained sandstones); Phi = 20-24% / K = 100-900 mD (coarse-grained sandstones); Phi = 24-32% / K = 100-900 mD (medium- to fine-grained sandstones).
3. Sand-rich lobes (SLuc): coarse- to very fine-grained sandstones.	Intra-slope, wide depressions with low (<1°) bottom gradients, developed by withdrawal of underlying Aptian evaporites (Middle Eocene, Early Oligocene, Late Oligocene, transition Late Oligocene/Early Miocene, Early Miocene - Marine Regressive Megasequence).	Lobes: 5-60 m-thick, 1-8 km-wide, and 2-12 km-long. NTG > 70%. Lobe complexes: up to 500 m-thick (Middle Eocene), up to 150 m-thick (transition Late Oligocene/Early Miocene), up to 60 m (Early Oligocene, Late Oligocene, Early Miocene); spreading over areas up to 500 km ² .	Porosity (Phi) and permeability (K) relatively homogeneous, with small variation mostly controlled by grain size and sorting: Phi = 27-32% / K = 1,000-2,500 mD.
4. Sand/mud-rich lobes (SML): fine- to very fine-grained sandstones.	Intra-slope, wide depressions with low (<1°) bottom gradients, developed by withdrawal of underlying Aptian evaporites (Late Albian - Marine Transgressive Megasequence; Early Oligocene, Late Oligocene, transition Late Oligocene/Early Miocene - Marine Regressive Megasequence).	Lobes: 2-20 m-thick, 1-20 km-wide, 2->20 km-long. NTG <70%. Lobe complexes up to 120 m-thick.	Late Albian: great variation in porosity (Phi) and permeability (K) because of contrasting mud matrix content and diagenesis (burial history and cementation); Phi = 2-32%, K = <1-1,600 mD. Early Oligocene, Late Oligocene, and transition Late Oligocene/Early Miocene: porosity (Phi) and permeability (K) relatively homogeneous, with small variation mostly controlled by grain size and sorting: Phi = 27-32% / K = 1,000-2,500 mD.