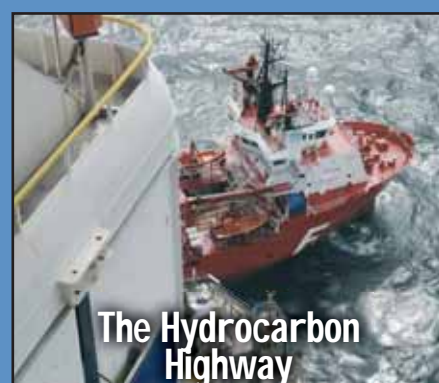
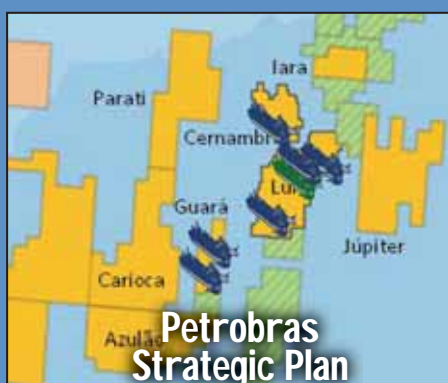


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By Mark van de Velden, SWE Technology Petroleum Development Oman; Greg Noel and Markus Kaschke, Enventure Global Technology, LLC.



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Editors

Wajid Rasheed
wajid.rasheed@eprasheed.com
Majid Rasheed
Mauro Martins

Design

Sue Smith
sue.smith@eprasheed.com

United Kingdom

➤ Head Office
Tel: (44) 207 193 1602
➤ Brian Passey
brian@bspmedia.com
➤ Sally Cole
sally@bspmedia.com

Houston

➤ William Bart Goforth
william.goforth@eprasheed.com
Tel: (1) 713 304 6119

Brazil

➤ Ana Felix
afelix@braziloilandgas.com
Tel: (55) 21 9714 8690
➤ Josefina Filardo
jfilardo@braziloilandgas.com
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New Oil Discovery in the Santos Basin Pre-Salt Cluster

Petrobras announces the discovery of a new good quality oil accumulation at well 1-RJS-689A (1-BRSA-925A RJS), to the north of Lula field, in the Santos Basin pre-salt cluster.

The new well, known as Dolomita Sul, is located at a water depth of 1,747 meters and is 177 km off the coast of Rio de Janeiro State (Block BM-S-42). Petrobras is the sole concession holder of this block.

This discovery pushes the potential of the pre-salt region

beyond the initial expectations.

The well, still in the drilling phase, also has more ambitious objectives.

After drilling is completed, Petrobras will evaluate the productivity of these reservoirs using formation tests.

The discovery was initially confirmed by cable test oil sampling, in pre-salt carbonate reservoirs, at around 5,660 meters deep. 🔦

The new well, known as Dolomita Sul, is located at a water depth of 1,747 meters and is 177 km off the coast of Rio de Janeiro State (Block BM-S-42).

BG Group to Sell Stake in Brazil's Comgas for \$1.8bn

UK gas producer BG Group has announced a deal to sell its stake in Brazil's Comgas to Sao Paulo-based Cosan for \$1.8bn (£1.1bn).


BG said it expected the deal to be completed by the end of the year.

The group also reported a surge in first quarter profits, which jumped to \$2.2bn from \$1.4bn a year earlier. Revenue rose 20% to \$5.8bn.

Profits were boosted by higher production and "robust" energy prices.

"BG Group has delivered significantly stronger financial results in the first quarter and with new production coming onstream, further progress on our major projects, and continued exploration success, we remain firmly on track to achieve our long-term objectives," said Sir Frank Chapman, BG Group's chief executive.

He said the company would be selling further assets in order to free up cash.

"We look forward to concluding [the Comgas] deal as part of our plans to release some \$5bn of capital in the next two years through strategic divestments." 

"BG Group has delivered significantly stronger financial results in the first quarter and with new production coming onstream, further progress on our major projects, and continued exploration success, we remain firmly on track to achieve our long-term objectives."

First Commercial Single-Diameter 8 x 9-5/8 in. Solid Expandable Openhole Clad Eliminates Tapering and Isolates Problem Section

By Mark van de Velden, SWE Technology Petroleum Development Oman; Greg Noel and Markus Kaschke, Enventure Global Technology, LLC.

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This paper was prepared for presentation at the 2011 AADE National Technical Conference and Exhibition held at the Hilton Houston North Hotel, Houston, Texas, April 12-14, 2011. This conference was sponsored by the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individual(s) listed as author(s) of this work.

Introduction

The solid expandable tubular system brought about a significant step change in downhole architecture by instituting a technology that reduces wellbore tapering and conserves precious hole size. The single-diameter solid expandable system takes that technology to another level by eliminating the tapering effect and preserving hole size. Although the idea of the single-diameter approach has been in development for years, the concept became a reality with the installation of an openhole cladding system in the Middle East.

An operator used an 8 x 9-5/8 in. single-diameter openhole clad to isolate a troublesome shale section between ~1,500 and 1,650 ft (~456 and 503m) in a large field in the north of Oman. Previous attempts to mitigate this area with cement reinforced slotted expandables proved unreliable. Setting regular casing in this section would compromise hole size, hinder well economics, and reduce production. The single diameter solid expandable system provided a post-expansion

inside diameter (ID) of 8.60 in. This pass-through retained an ID large enough to run the same 8-1/2 in. BHA as previously used for subsequent drilling. After placement and expansion of the single-diameter openhole clad, an 8-1/2 in. BHA was deployed to further well construction operations with adequate hole size.

This article will describe the first installation, including evaluation and operational considerations as well as the results affirming the technology's ability to isolate problem areas without sacrificing hole size. In addition, the article will describe the development of the technology and explain the potential to mitigate a variety of problems and conditions.

Drilling Objectives

Wells in this field face a consistently troubling formation. The operator of this project needed to isolate the problem section, but could not afford to lose the critical ID it needed to run the tools and technology

The rate and amount of corrosion caused by dissolved carbon dioxide is dependent on the oxygen content, the salts dissolved in the water, temperatures and fluid velocities.

that would move the drilling program forward. Initial attempts to use cement reinforced slotted expandables proved unreliable. The objectives as confronted required a two-fold solution – isolate the problem and maximize ID.

Geological Challenges

Reservoir facies in this field are in shallow-shelf carbonates of the Middle Cretaceous Mishrif and Maaddud formations. Interparticle porosity formed in the Mishrif as sand aprons of lithoclast and skeletal grainstones surrounding fault-block islands, and less commonly in the Maaddud as biostromes of rudist packstones. Moldic porosity after fine rudist debris is more common than interparticle porosity and occurs in thicker stratigraphic units, interpreted to have formed locally in meteoric-water lenses of islands, and regionally during subaerial exposure associated with sea level lows.¹ These types of conditions exemplify an exceptionally complex geology interspersed with multiple small oil deposits, each with unique geological structures and each requiring a new approach.²

Operational Considerations

The drilling environment consisted mainly of sandstone with multiple interbedded shale sections. One particular section, the deepest of the interbedded shale, tended to swell and was very reactive to water, which can lead to the drillstring becoming stuck when water

is passed by. To mitigate the potential for swelling, this section was drilled with inhibited water. The ideal solution to preventing swelling would consist of drilling with oil-based mud, but this approach ran the risk of contaminating shallow aquifers.

To compound the challenge, a carbonate formation below this section is prone to losses. If the troublesome shale section and the formation below were drilled together and a loss zone was encountered, the well could fill with water. This brackish water would cause a severe reaction in the shale section and could collapse the hole. The section needed to be isolated but setting conventional casing would reduce the hole size and jeopardize the well economics. In the past, curing losses in the carbonate formation was time consuming and encountering another fault would require abandoning the well and starting over.

The wells in this project are the soundest economically with an 8-1/2 in. hole followed by 6-1/4 in. hole into the reservoir. Scaling up the casing design to set a shoe below the troublesome shale would hinder economic viability. These factors led the operator to select Enventure's MonoSET® openhole clad (OHC) to isolate the shale without reducing the wellbore ID.

Installing a Solution

The drilling plan landed 9-5/8 in. casing at ~1,280 ft (390m) and cemented it in place back to surface. A

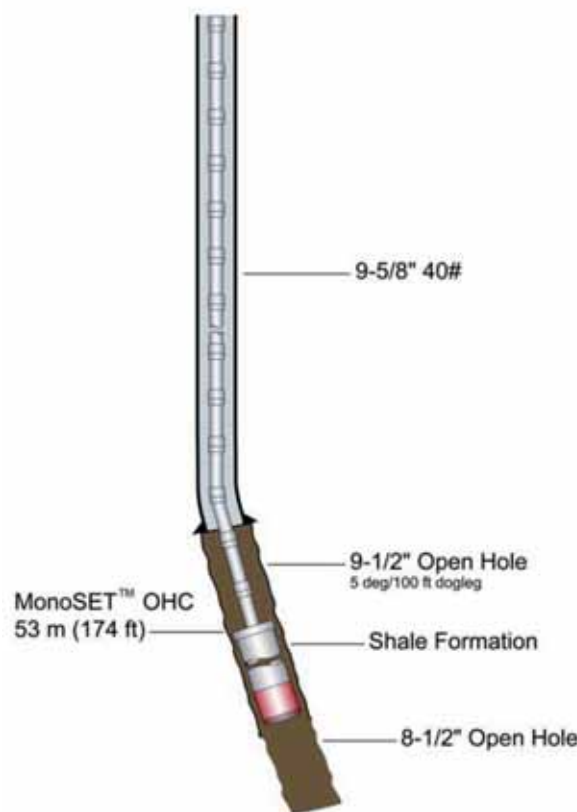


Figure 1 – Single-diameter openhole clad isolates troublesome shale section.

bottomhole assembly (BHA) with a 9-1/2 in. bi-center bit drilled to a TD of ~1,660 ft (~505m) and 43° angle. Four logging runs, using four- and six-arm caliper tools, identified two tight spots. Removal of the tight spots was accomplished with a 9-1/2 in. PDC reamer and a 12-1/4 in. roller-cone reamer. The operator took extra care to facilitate proper hole size and optimum wellbore conditions prior to running the single-diameter system. This systematic precaution helped ensure a smooth installation and an uncomplicated application.

The 8 x 9-5/8 in. OHC was run to a depth of ~1,650 ft (~503m) in three hours (Figure 1). This OHC is a single-diameter solid expandable tubular system designed to maintain the hole size of the previous casing string. In contrast to a conventional solid expandable system that reduces the tapering effect, the single-diameter system eliminates tapering.

Using a hydraulic-mechanical expansion assembly, expansion was initiated with 3,000 psi. The 150-foot (47m) OHC was expanded per plan with all parameters in the expected range. An 8-1/2 in. drilling BHA was picked up and run through the expanded liner, which confirmed the expanded ID and the placement of the

liner were both correct. After an 8-1/2 in. openhole section was drilled to 2,641 ft (805m), a 7 in. liner run through the OHC and cemented back to the surface. The OHC stabilized the trouble section, facilitating an efficient wellbore construction operation without compromising hole size. The operator remained on well design and drilled a 6-1/8 in. open hole to ~4,600 ft (~1,400m) as planned.

The successful installation of this first single-diameter solution resulted in the application of a second OHC by the same operator in a different well. The subsequent application took place in similar conditions and parameters. An 8 x 9-5/8 in. MonoSET OHC a~141 ft (~43m) in length covered the trouble zones and enabled the 7-in. casing to be run to the planned depth and cemented in place. Both OHC systems kept the drilling program and the original well economics intact and on target.

Developing the Single-Diameter Technology

The path to actualizing the single-diameter system took a circuitous route that included amended theoretical approaches (ex. one-trip system vs. two-trip system),



Figure 2 – Running sequence for the single-diameter openhole clad system.

numerous design iterations of tool components and subsystems, and several field-appraisal tests. An intentional focus on developing the system spanned a decade that ran parallel with the maturation of conventional solid expandable tubulars. The evolving technology, the broadening application spectrum, and the commercial deployment of the OHC in the Middle East illustrate the results of a successful strategy to provide the enabling tools and processes to “lower lifting cost and maximize recovery”.

The single-diameter design concept itself was closely controlled and incorporated multi-disciplinary processes with a team that included drilling experts, engineers, designers, and end users. To develop a reliable tool for a myriad of conditions and applications, modular components proved to be the most practical plan for construction as it provided easier customization for specific applications, simplicity in overall design, and quick assembly of tools. The design team was able to leverage a sound foundation of solid expandable tubular knowledge that included an advanced understanding of pipe metallurgy, properties and the effects of stresses and strains endured during the expansion process.

Proving the Concept

The proof-of-concept, single-diameter well was completed in South Texas by Shell Exploration and

Production Company (SEPCO) in July 2002. Although this project provided a multitude of technical learnings and the well was commercially completed, the actual number of trips required to construct the single-diameter sections along with difficulties in zonal isolation, made this system configuration impractical for broad-based field use in that oilfield market. However, the basic principles to construct a single-diameter well were proven.³

From this proof-of-concept well a more refined perception and base operational overview emerged that identified design elements that needed refining. The result was a multifunctional tool that would integrate all sub-systems and assure self-contained contingencies. This direction represented a marked divergence from any conventional solid expandable tubular tool configurations or design. A tool string prototype was manufactured and tested in a live well in late 2004.

Continued refinements and enhancements led to a field appraisal test (FAT) in 2007. For the FAT, the string tested consisted of six different tools each subjected to a vigorous testing program. Each tool was placed in a right-hand torque test to 10K ft-lbs, the maximum torque loading for the casing connections. Testing to this torque capacity, which exceeds the allowable torque for the liner, ensured that the tools could be rotated to wash down in the hole while running. The tool string

In formations such as hard rock, the single-diameter system could be used in an openhole configuration to clad over problematic formations in an otherwise stable section.

was tested in the horizontal position with sand-laden fluid for flow testing and fluid cutting. In addition to horizontal, it was also run in the vertical position in oil- and water-based mud.

Following successful surface testing of the tools, the downhole portion of the FAT was initiated. As part of the construction of a dedicated test well, Enventure was able to drill deeper than the prescribed well requirements and install any number of liners as part of the test program. The test included the placement of three consecutive liners each with the same final ID of 10.4 inches. Each liner was installed using a slightly different tool configuration which emphasized the modularity of the system. The first liner was installed and included the expansion of a larger “bell” section at the bottom to act as a receptacle for the second liner. The second and third liners did not include the bell section. This required the overlap section in the second liner to be expanded along with the third liner. In all, a total of approximately 1,750 ft of single-diameter liners were installed in a hole that built to a final angle of ~55°.

The FAT provided the environment to affirm system performance and establish real results. The objective to simulate field parameters, such as high-angle bending forces, an oil-based mud environment, while confirming the functionality of the tools and the ability to cement through the single-diameter tools were exceeded by the test.⁴

The FAT also indicated that although it was possible to install single-diameter liners in a single trip, the complexity of the operation would need to be reduced for it to become a common practice. The natural progression is to break the process down into more simple pieces like the single-diameter OHC and shoe extension. Eventually, through experience and refinement, the smaller pieces will come back together in the construction of a true single diameter well

State of the Technology

The current operating parameters of the single-diameter openhole clad system provide an 8-1/2 in. pass through below the 9-5/8 in. casing. This system can be expanded against the formation, eliminating the need for cementing and the need to tie-back into base casing. The preservation of hole size can be the length of a single joint to or over 1,000 ft. The running sequence of the single-diameter openhole clad system is similar to conventional solid expandable tubular systems (Figure 2).

1. Drill through problem zone
2. Run liner and inner-string
3. Expand liner across problem zone
 - Activate anchor
 - Expand lower seals
 - Initiate mechanical expansion
4. Recover tools and operational pipe
5. Drill ahead

The successful installation of the previously discussed single-diameter systems strategically mitigated trouble zones in the formation by isolating targeted sections of the wellbore without anchoring back into the previous casing.

Identifying the Potential

The use of single-diameter expandable casing technology has the field-proven potential of significantly reducing a project's drilling and completion cost structure. These savings are realized by reducing drilling risk and resultant trouble time by successively isolating problem lithology and/or underpressured zones while preserving a single-diameter wellbore.

Reductions, in turn, result in zero compromise of the completion objectives and afford much greater completion flexibility and potentially lower the life of well costs with improved completion design and required interventions. Gulf of Mexico operators, which often encounter severe lost circulation zones at shallow depths, are watching the technology development in hopes of expanding long drilling liners to isolate these under-pressured zones and then later case off the expanded liner and problem zones. Other operators see the great potential of installing several uphole single-diameter drilling liners to allow a fullbore completion at total depth (TD).

The technology also has the proven, simulated and engineered potential of significantly increasing the lateral reach of many extended reach wellbores.⁵

Successive installation of expandable, single-diameter wellbores is possible, which primarily reduces the friction/drag forces that can limit lateral reach, again, while preserving a single-diameter wellbore as deep as required. In addition, this application affords higher weight-on-bit at comparable depths versus conventional drilling technology. This extended lateral reach results in increased reservoir contact that can often result in increased production per well.

Extended-reach laterals can be cased with successive liners that preserve ID. Using shorter lengths of casing that maintain a constant ID prevents friction and drag increases. A study done for a major North Sea operator showed that single diameter systems could extend the current ERD envelope up to 50%.⁶ The study concluded that added reach achieved by reduced friction could lower well count, raise well production, increase reservoir contact, increase reserve access, improve capital efficiency and lower field development costs. Proven drilling performance and additional cost studies indicate that expenditures reflected in the same North Sea study area could be reduced 30 to 50% of the current drilling cost with the application of solid expandable tubulars and constant-diameter technology.

More production from fewer wells can ultimately lower

required field well counts with an improved drilling cost structure profile. In select offshore applications, this technology can in turn result in lower platform installation requirements without reserve reductions or potentially increased reserves by tapping flank or step-out reserves. In many subsea applications, the technology can result in lower subsea templates, flowlines, pipelines and production center requirements. The technology also offers enhanced development flexibility with minimum economics by allowing the deferral of high capital cost outlays with improved development phasing. In subsea applications that include seabed geohazards, such as escarpments or Arctic iceberg risks, the reduced subsea infrastructure requirements further mitigates project risk and improves field economic returns.

In modeled worldwide offshore and subsea developments, the system greatly reduced observed and/or forecast drilling risks and trouble time. The modeling indicated that the prudent application of successive single-diameter expanded liners has proven to increase lateral reach potential by 25 to 50% and in select applications, these results exceed the current industry lateral reach record by over 35%. In formations such as hard rock, the single-diameter system could be used in an openhole configuration to clad over problematic formations in an otherwise stable section.

Wellbore diameter is maintained and the operator forgoes the need and cost to cover an entire zone. Another obvious benefit of this technology suite is its ability to facilitate a shoe extension. Multiple casing points can be made up or initially attained without losing hole size.

Conclusion


The successful installation of the previously described single-diameter systems strategically mitigated trouble zones in the formation by isolating targeted sections of the wellbore without anchoring back into the previous casing. Proving the validity of the equipment, the process, and the potential opens the possibility of diverse applications with far-reaching benefits. As with conventional solid expandable tubulars, the more the technology is utilized the greater the benefits realized. These benefits include decreasing drilling cost structure and/or reducing drilling risk and trouble time, improving field development economics, accessing greater reserves, increasing production per wellbore, and potentially

creating a smaller field development footprint. These systems no doubt will play a significant role in the current climate of accessing reserves that not only affect the bottom line but save time and resources as well.

Acknowledgments

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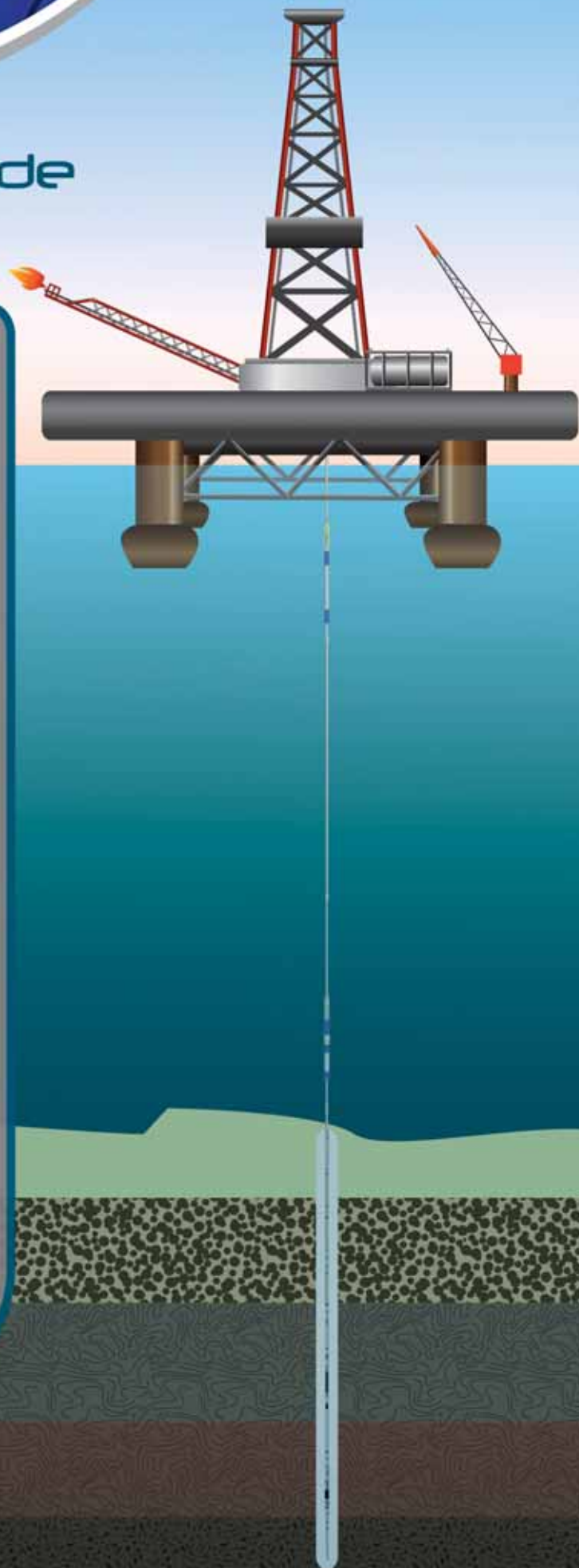
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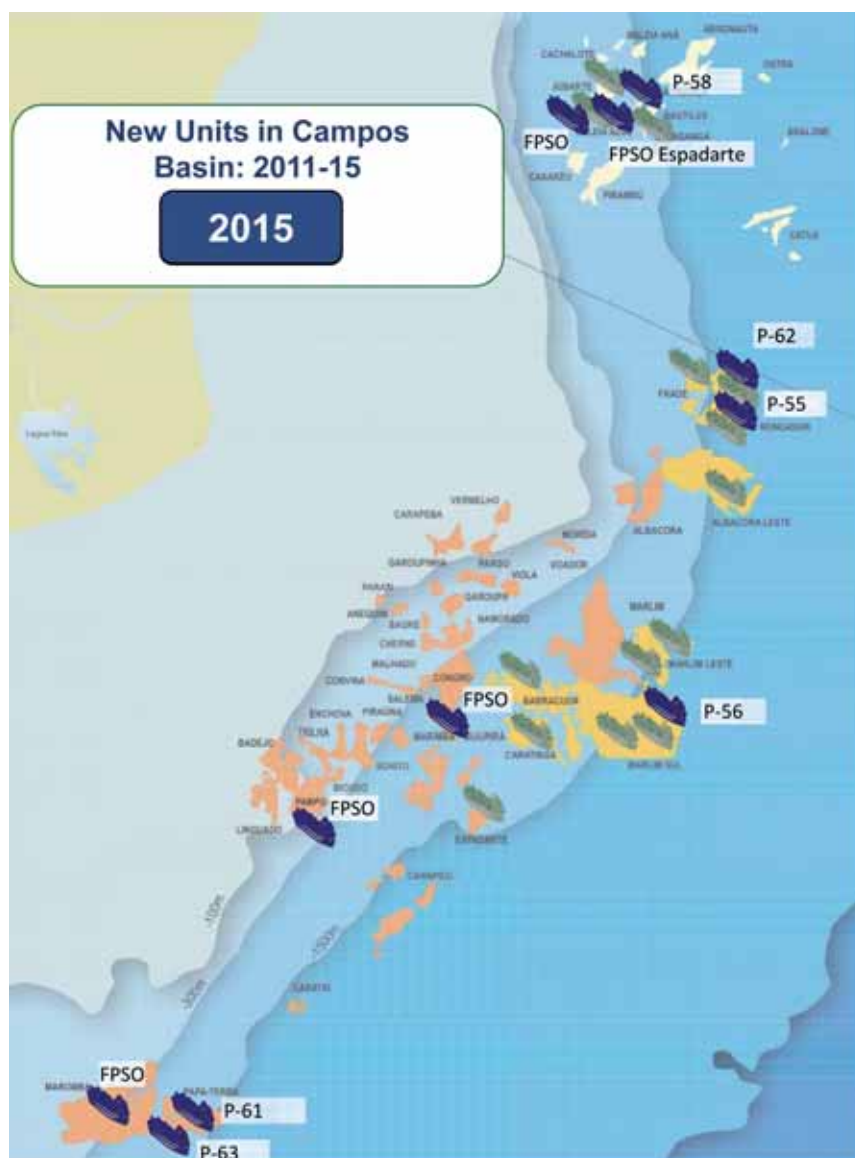
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Petrobras Strategic Plan

“New units in Campos Basin 2011–15.”



New Units

2011

P-56 – 100.000 bpd

2012

P-55 – 180.000 bpd

FPSO Espadarte – 100.000 bpd

2013

P-58 – 150.000 bpd

P-61 – 150.000 bpd

P-62 – 180.000 bpd

P-63 – 150.000 bpd

FPSO (Marimbá) – 40.000 bpd

FPSO (Aruana) – 100.000 bpd

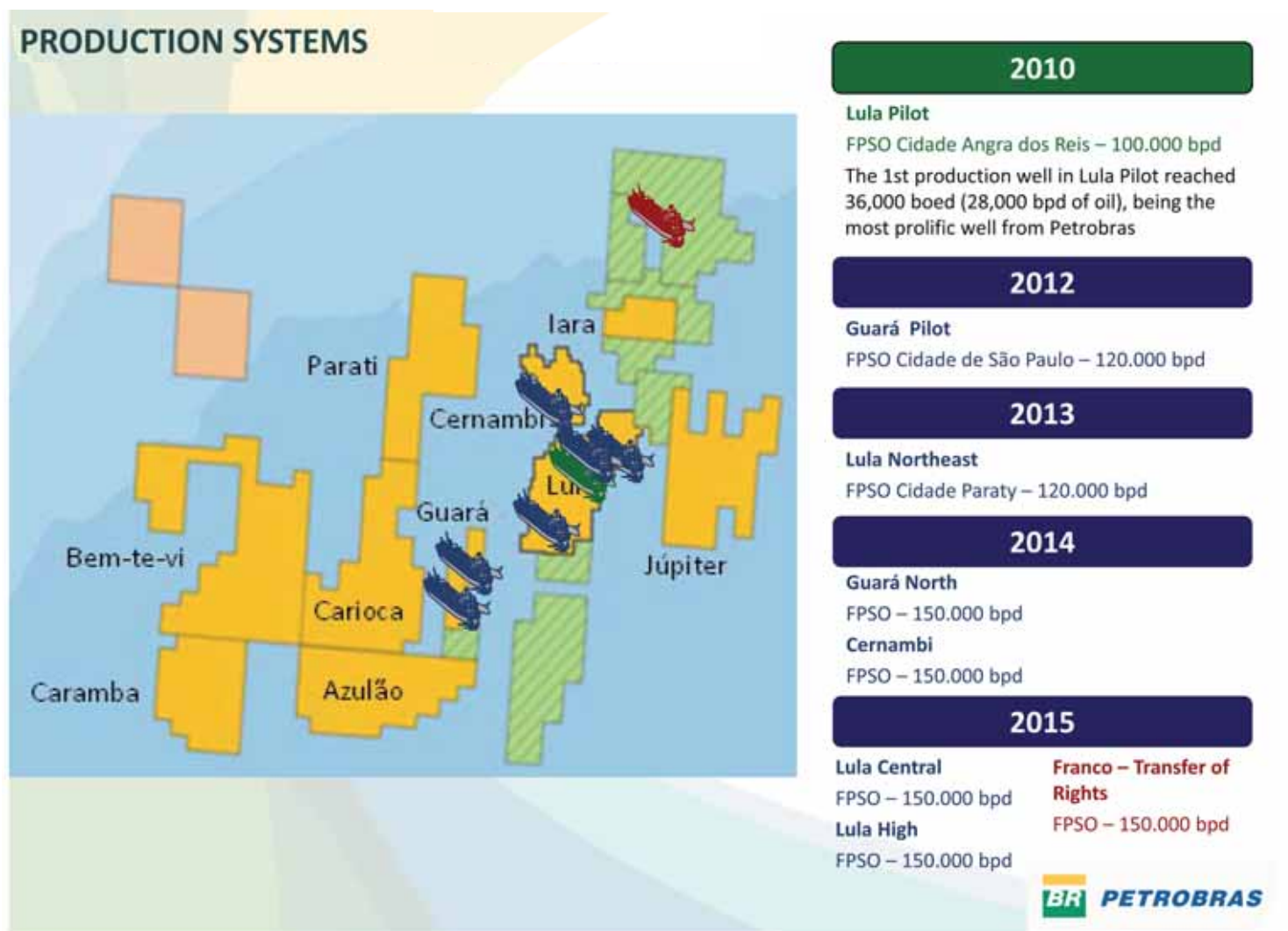
2014

FPSO (Baleia Azul) – 60.000 bpd

2015

FPSO (Maromba) – 100.000 bpd

“Seven new systems to 2012, having already hired six.”



“Technological development and exploratory optimization in existing concessions.”

VARREDURA PROJECT



Varredura Project

- Additional recoverable volume from discoveries:

- Post-salt: Marimbá, Marlim Sul and Pampo: 1,105 MM boe;

- Pre-salt: Barracuda, Caratinga, Marlim, Marlim Leste, Albacora and Albacora Leste: 1,130 MM boe*.

- Well productivity exceeds 20,000 bpd

67 exploratory wells will be drilled between 2011 and 2015 in production areas in Campos basin

*No volumes have been announced regarding the Marlim Leste and Albacora Leste discoveries.

“E&P results confirming the potential of the area.”

PRE-SALT ACTIVITY



CAMPOS BASIN

- Jubarte: 14,000 bpd (ESS-103)
- Baleia Franca: 25,000 bpd (BRF-1 + BRF-6)
- Brava: 7,000 bpd (MRL-199D)
- Carimbé: 21,000 bpd (CRT-43)
- Tracajá: 20,000 bpd (MLL-70)
- TOTAL (Nov/11): 87,000 bpd**

PRE-SALT CLUSTER IN SANTOS BASIN

- EWT Carioca NE: 24,000 bpd (SPS-74)
- EWT Lula NE: 14,000 bpd (RJS-662A)
- Lula Pilot: 53,000 bpd (RJS-660 + RJS-646)
- TOTAL (Nov/11): 91,000 bpd**

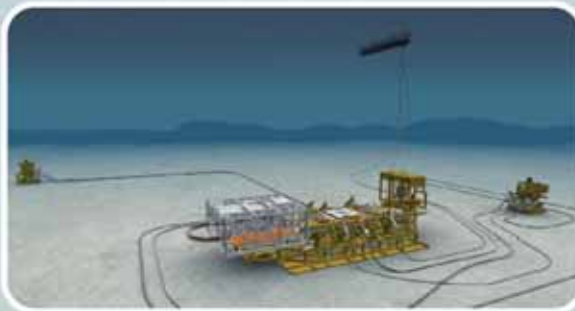
INTENSIFYING DEVELOPMENT CAMPAIGN IN THE PRE- SALT SANTOS BASIN

- 34 wells drilled through Oct 11 (27 Exploratory), with an additional 5 new wells by year end 2011
- Lula Pilot: 1st well - 28 thous. bpd, 2nd well - 25 thous. bpd and 3rd well to start producing at the end of Nov.
- The number of rigs in the area will double by the end of 2012 (currently 10 rigs operating)

Average production in all Pre-salt wells approximately 20,000 bpd , with no evidence of decline

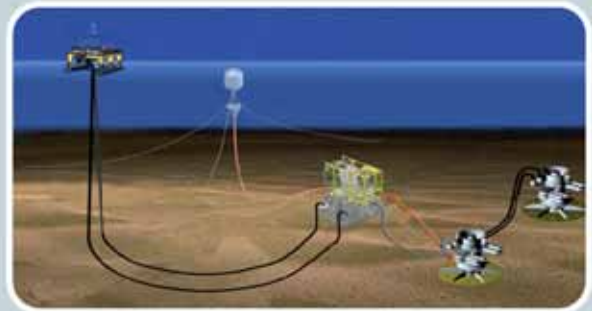
“Petrobras is implementing cutting-edge technologies.”

NEW TECHNOLOGIES



OIL/WATER SUBSEA SEPARATION

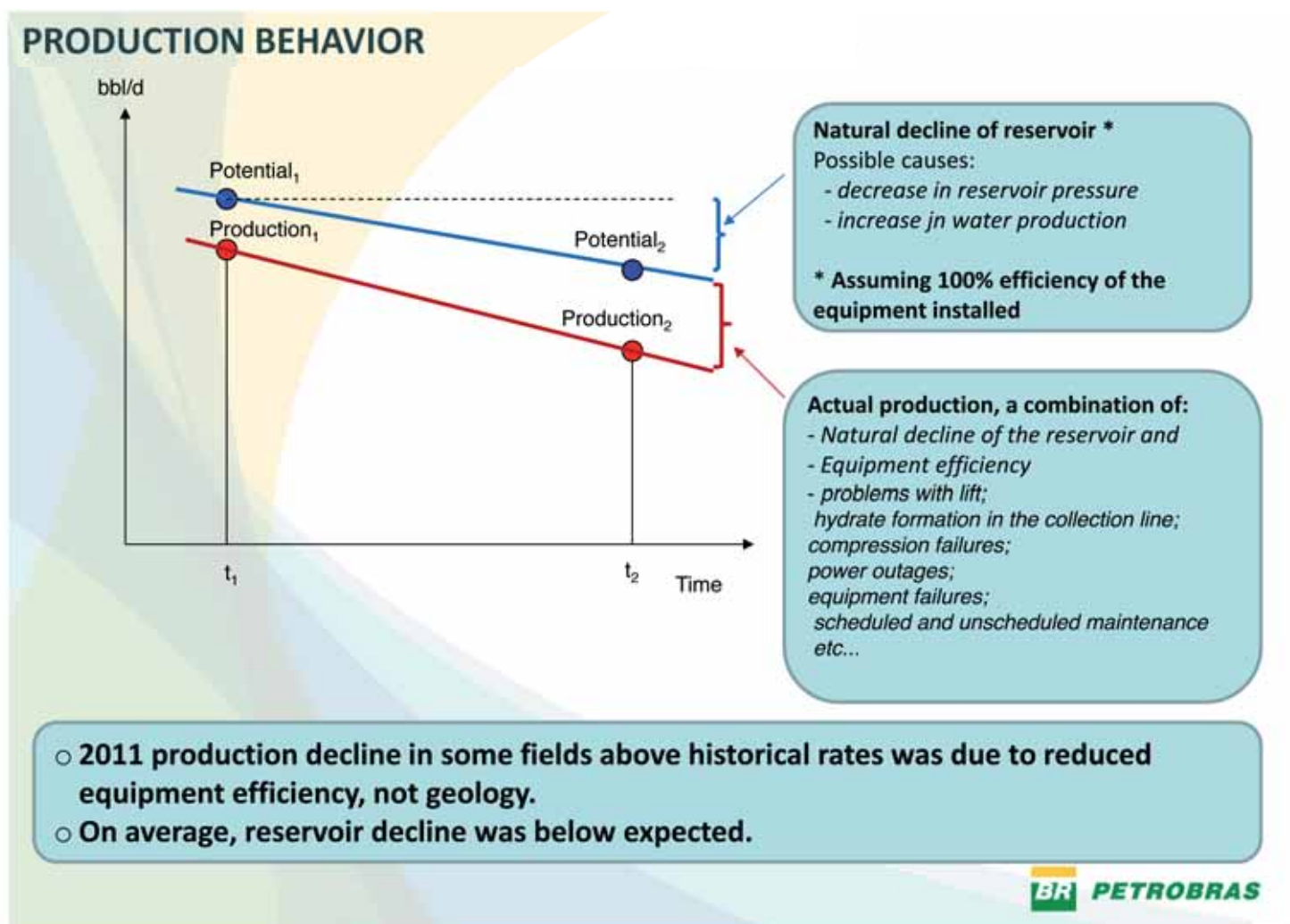
- Resolves limitations from growing water production
- Separates water and oil under the sea, reinjecting water and relieving the size of the surface equipment on the platform
- Field: Marlim (Nov/2011)



RAW WATER INJECTION

- Increases production in existing systems
- 3 subsea systems for pumping raw water (with little treatment) to pressurize the reservoir, increasing recovery factor without increasing surface systems. Pioneer in the world in such water depth
- Field: Albacora (Dec/2011)

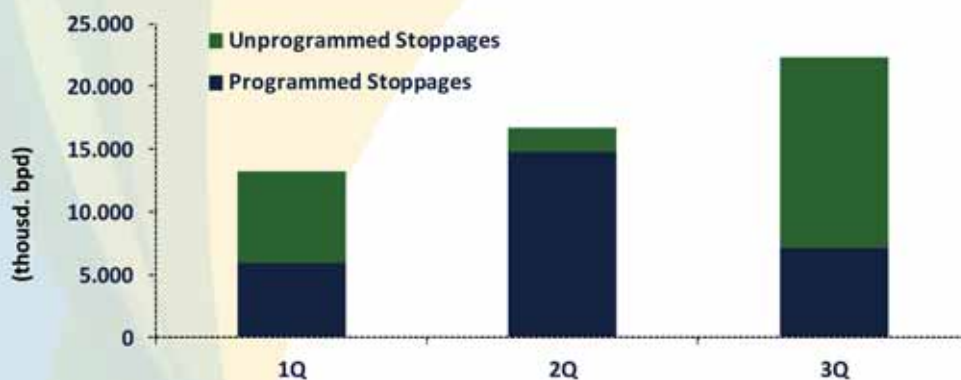
“Reservoirs and equipment set production over time.”



“Production below target mostly explained by unplanned maintenance.”

PRODUCTION - 2011

Production loss due to operational causes – effect on annual production

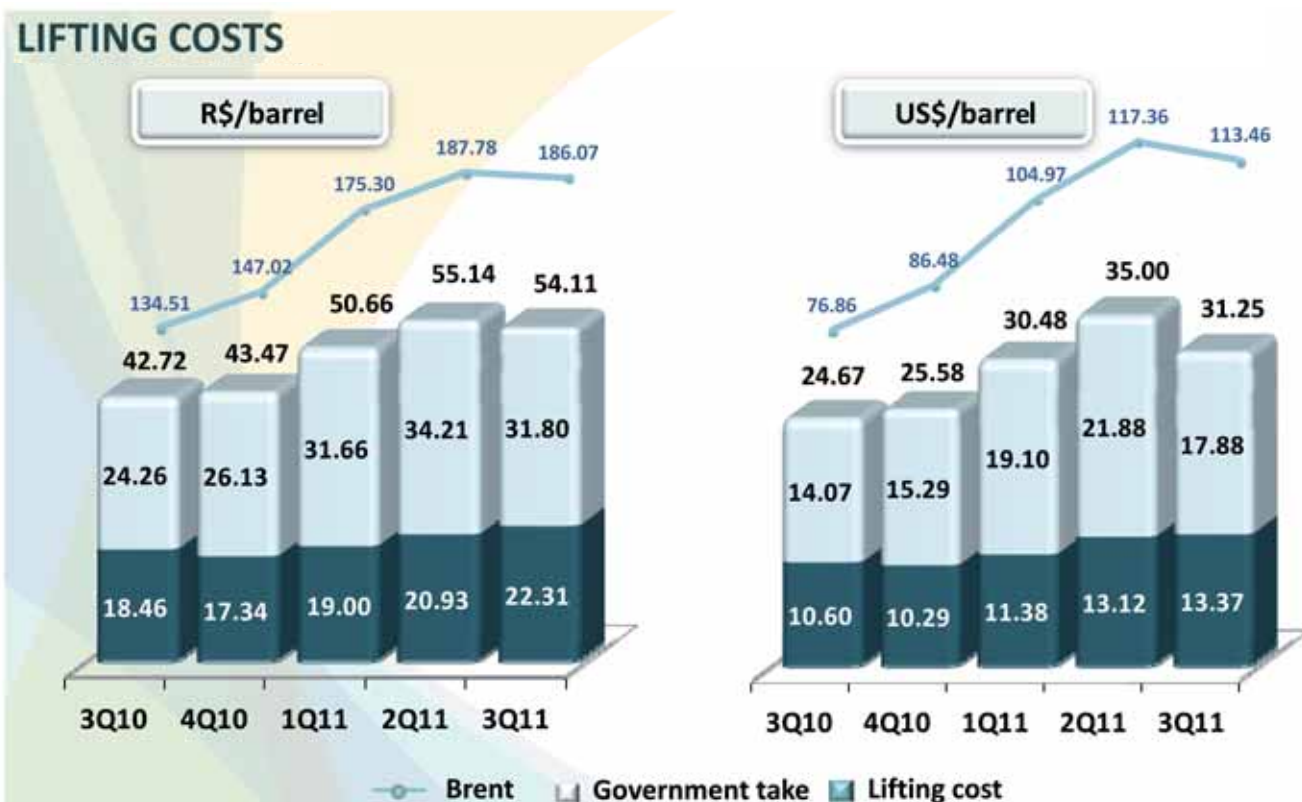


Unplanned maintenance and additional time for planned maintenance in the 9M11 lowered production by an average of 44 thousand bpd in the year

Other factors that reduced production relative to targets

- o Delays in the completion and connection of wells, due to the late arrival of new rigs from international shipyards.
- o Logistical and market restrictions reduced production of natural gas, in turn reducing oil production by 20 thousand. Bpd during 9M11 (Uruguá: 10 thousand. bpd; Lula: 10 thousand. bpd)

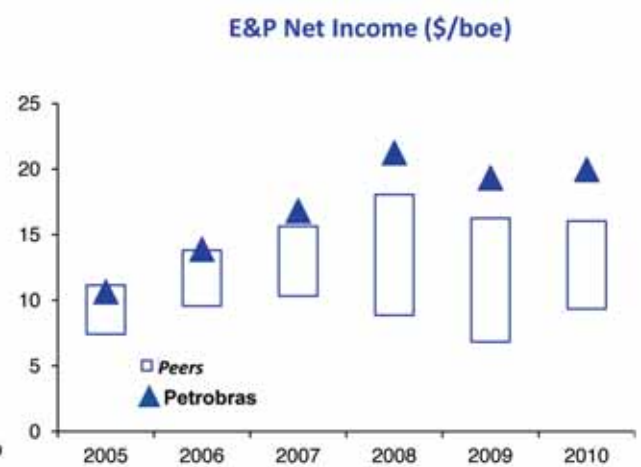
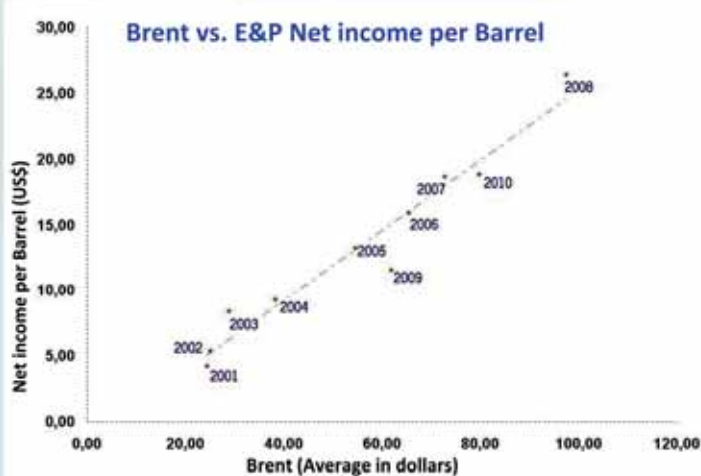
“Costs pressured by a combination of factors during first nine months of 2011.”



- o In 3Q11 lifting costs increased by provisioning for 2011 Collective Bargaining Agreement, under negotiation.
- o Increasing lifting cost trend in 2011 as a result of start-up of new production systems, increase in planned and unplanned stoppages and higher oil prices affecting service and energy costs.

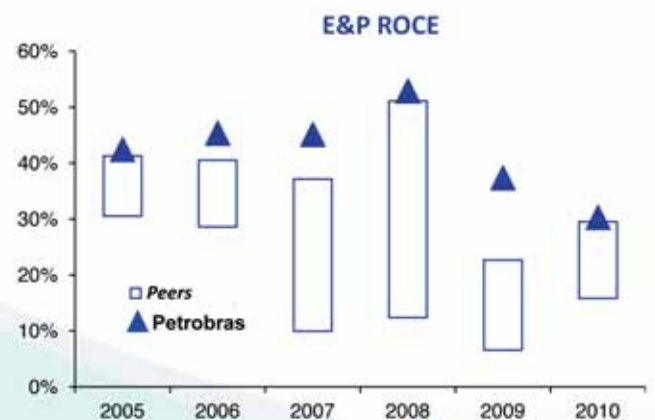
“Profitability of oil production in Brazil fully exposed to oil prices.”

E&P PROFITABILITY IN BRAZIL



- E&P profitability strongly correlated to oil price
 - Production in Brazil: 86% oil and 14% gas
 - Higher net profit per barrel yields better return than its peers
 - Stable regulatory environment allows for capturing the benefits of the increase in oil prices

Source: PFC Energy

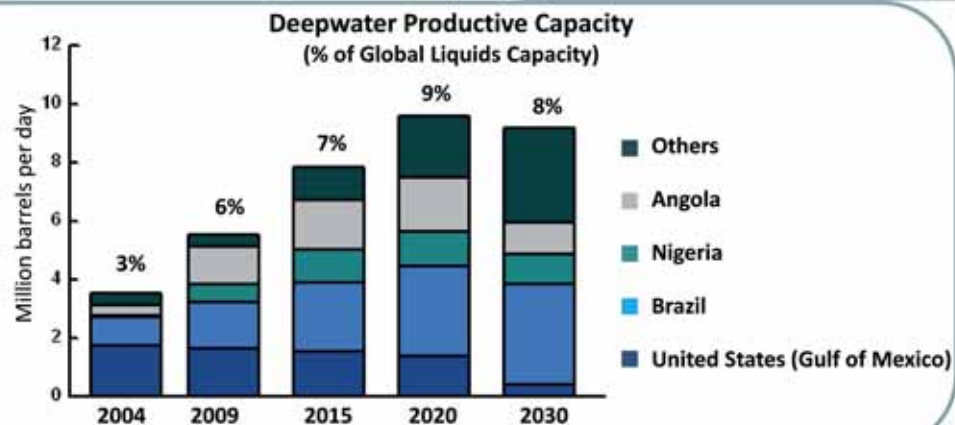
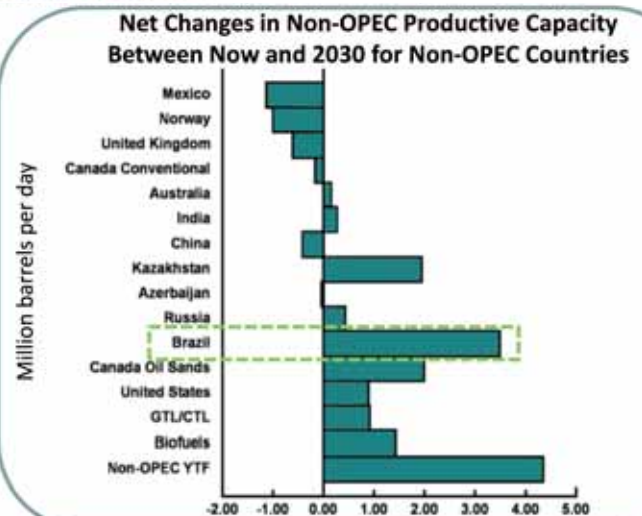
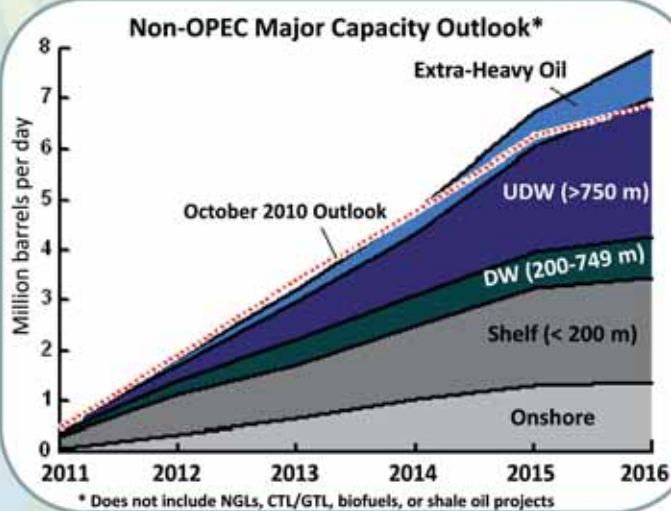


Peers: BP, CVX, XOM, RDS, TOT



“Brazil is the main country to contribute to the increase in DW and UDW.”

OFFSHORE CAPACITY GROWTH WILL STAY STRONG



Source: IHS CERA

“Integration with suppliers, research centers and other oil companies.”



“Resources required for production growth.”

NEW VESSELS AND EQUIPMENT

| Critical Resources | Current Situation (Dec/10) | Delivery Plan (to be contracted) Accumulated Value | | |
|---|-------------------------------|---|-------------------|-------------------|
| | | By 2013 | By 2015 | By 2020 |
| Drilling Rigs Water Depth Above 2,000 m | 15 | 39 | 37 ⁽¹⁾ | 65 ⁽²⁾ |
| Supply and Special Vessel | 287 | 423 | 479 | 568 |
| Production Platforms SS e FPSO | 44 | 54 | 61 | 94 |
| Others (Jacket and TLWP) | 78 | 80 | 81 | 83 |



Supply Vessel



Drilling Rigs



Production
Platform (FPSO)

DRILLING RIGS UNDER CONTRACT

| Water Depth | 2006 | 2008 | 2010 | 2011 | 2012 | 2013 |
|-----------------------|------|------|------|------|------|------|
| Up to 1,000 meters | 6 | 11 | 11 | | | |
| 1,000 to 2,000 meters | 19 | 19 | 21 | +2 | +1 | +1 |
| Over 2,000 meters | 2 | 3 | 15 | +10 | +13 | +1 |

(1) Two rigs reallocated from international operations, expire in 2015, so it is not considered in the 2020 accumulated value

(2) The demand for long-term will be adjusted as new demand assessments are made.

“Flexibility in concession agreements.”

LOCAL CONTENT

| | | | |
|----------------|---|-------------------------------|--|
| Round 0 | No local content required | Rounds 7, 9 and 10 | Minimum and maximum limits by block: In deep water, between 37% and 55% in the exploration phase, and between 55% and 65% in the production development phase. |
| Rounds 1 to 4 | Maximum limit 50% in the exploratory phase 70% in the production development phase | Transfer of Rights Concession | Minimum exploration limit: 37% Minimum production development limit: <ul style="list-style-type: none"> • Up to 2016: 55% • 2017-2018: 58% • After 2019: 65% |
| Rounds 5 and 6 | Minimum limit by block Between 30% and 70% in the exploration and production development phases | | |

| 2011-2015 Projects | | | | |
|-----------------------|-------------------------------------|---------------------------------|--|---------------------------|
| 2011 | 2012 | 2013 | 2014 | 2015 |
| Marlim Sul SS P-56 | Guará Piloto FPSO Cid. São Paulo | Lula NE FPSO Cid. de Paraty | Guará Norte FPSO Cid. de Ilhabela | Lula Central FPSO P-67 |
| | Baleia Azul FPSO | Parque das Baleias FPSO P-58 | Cernambi Sul FPSO Cid. de Mangaratiba | Lula Alto FPSO P-66 |
| | Roncador SS P-55 | Papa-Terra P-61 & FPSO P-63 | BALEIA AZUL FPSO | ESP/MARIMBÁ FPSO |
| | Tiro/Sidon FPSO Cid. de Itajai | Roncador FPSO P-62 | SIRI 2 jacket and FPSO | Maromba FPSO |
| | | Aruana FPSO P-62 | | Franco 1 FPSO P-74 |

- Lower local content requirements in the ANP's initial concession rounds give local industry time to adapt.
- Concession and Transfer of Rights agreements permit waivers from local content requirements when terms are uncompetitive relative to international metrics (e.g. price, deadline, technologies).

“Detailing of needs into critical categories permits long-term strategy.”

DEVELOPMENT OF NATIONAL INDUSTRY



| | CATEGORY | NATIONAL MARKET AVAILABILITY | FPSO cost |
|----|----------------------------|------------------------------|-----------|
| 1 | Process equipment | | ▲▲ |
| 2 | Turbomachinery | | ▲▲▲ |
| 3 | Mechanical equipment | | ▲ |
| 4 | Electrical equipment | | ▲▲ |
| 5 | Instrumentation/automation | | ▲ |
| 6 | Ship structure and systems | | ▲▲▲ |
| 7 | Pipeline and valves | | ▲ |
| 8 | Security | | |
| 9 | Telecommunications | | |
| 10 | Ventilation and AC (VAC) | | ▲ |
| 11 | Engineering services | | |
| 12 | Architecture | | |
| 13 | Commissioning services | | |

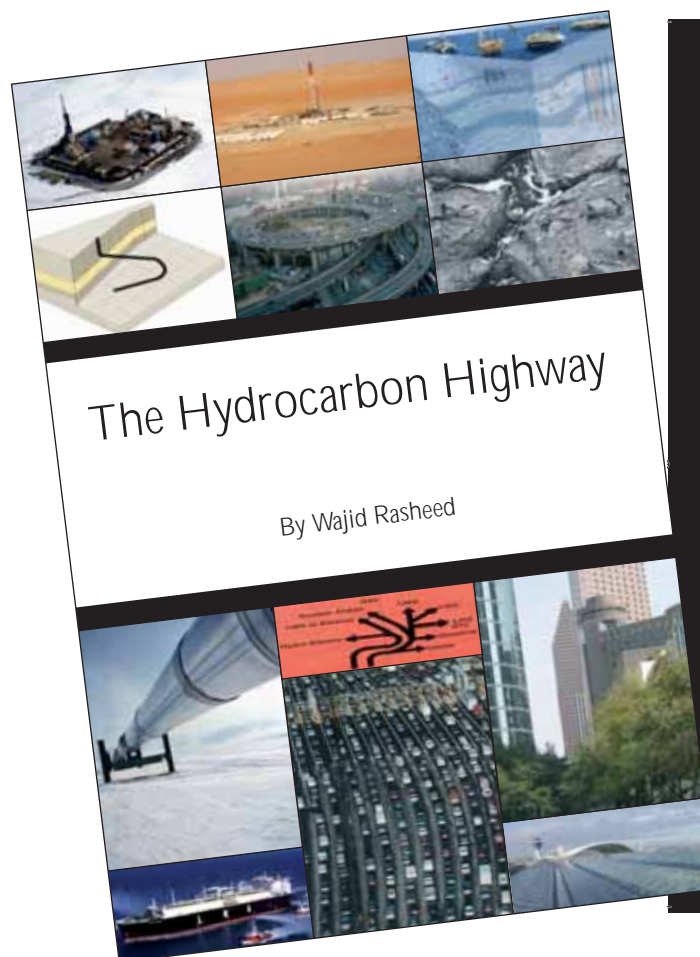
▲ Proportional share of FPSO cost
 ≤30%
 30% ≤ F ≤ 60%
 ≥60%



Extensive experience of contracting FPSOs combined with operational scale and equipment standardization will help create an internationally competitive offshore industry.

Mature Fields

*A Chapter from The Hydrocarbon Highway,
by Wajid Rasheed*



"There have been many books concerning the oil industry. Most are technical, some historical (e.g. the Prize) and some about the money side. There are few, if any, about the oil industry that the non-technical person will appreciate and gain real insight from. Wajid Rasheed in this book, *The Hydrocarbon Highway*, has made a lovely pen sketch of the oil industry in its entirety. The book begins with the geology of oil and gas formation and continues with the technical aspects of E & P, distribution, refining and marketing which are written in clear language. In particular, the process of oil recovery is outlined simply and with useful examples. There is a short history of how the oil companies have got to where they are, and finally a discussion concerning the exits—alternative energy. This is all neatly bundled into 14 chapters with many beautiful photographs and a helpful glossary. The book is intended to give an overview to the industry without bogging the reader down. I enjoyed the journey along the highway."

Professor Richard Dawe of the University of West Indies, Trinidad and Tobago

"A crash course in Oil and Energy, *The Hydrocarbon Highway* is a much-needed resource, outlining the real energy challenges we face and potential solutions."

Steven A. Holditch, SPE, Department Head of Petroleum Engineering, Texas A&M University

"I found the book excellent because it provides a balanced and realistic view of the oil industry and oil as an important source of energy for the world. It also provides accurate information which is required by the industry and the wider public. Recently, I read several books about oil which portrayed it as a quickly vanishing energy source. It seems that many existing books predict a doomsday scenario for the world as a result of the misperceived energy shortage, which I believe is greatly exaggerated and somewhat sensational. Therefore the book bridges the existing gap of accurate information about oil as a necessary source of energy for the foreseeable future. The *Hydrocarbon Highway* should also help inform public opinion about the oil industry and our energy future. It looks at the oil industry in an up-to-date and integrated view and considers the most important factors affecting it."

Dr AbdulAziz Al Majed, the Director of the Centre for Petroleum and Minerals at the Research Institute at King Fahd University of Petroleum and Minerals

www.hydrocarbonhighway.com
www.eprasheed.com

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Inevitably, all producing fields reach maturity one day, so the importance of mature field technology is set to grow as greater numbers of assets enter maturity. This chapter provides an overview of Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR), as well as several practical field applications.

Pumps, polymers and permanent seismic are just a few of the technologies used to enhance and improve production in mature assets. Mature fields are challenging as they exhibit a decline in hydrocarbon rates, increased water production as well as the

responsibility of decommissioning platforms, wellheads or pipelines¹.

For our purposes, a field is defined as mature once its natural reservoir drive mechanisms—gas drive, water-



Figure 1 - Nodding Donkey Or Rod Pump (EPRasheed)

drive or gravity drainage—are incapable of sustaining production. Consequently, hydrocarbons must be artificially swept from the reservoir and be able to travel through production tubing, the wellbore and to surface installations².

Reservoir Drive

Reservoir pressure curves correlate directly with reservoir production rate curves. As long as reservoir pressure is greater than bottom-hole pressure, the differential pressure will result in production. Pressure differentials can be created by reducing bottomhole pressure or by increasing reservoir pressure, either of which will increase hydrocarbon production³.

Following the development of low-hanging fruit, most mature assets have traditionally been distributed onshore; however, the trend now shows extensive

numbers of shelf and deepwater assets entering maturity. Already, several notable offshore fields are classified as mature assets; for example, Brent and Troll in the North Sea, and Marlim in offshore Brazil.

Pump Up Production

Primary or artificial lift methods to increase production include the nodding donkey or rod pump, Electrical Submersible Pump (ESP) or a gas-lift system. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically around 10% for oil reservoirs and 15% for gas reservoirs⁴.

Secondary production (IOR) of hydrocarbons is achieved when a fluid such as water or gas is injected into the reservoir through injection wells. Injectors are carefully drilled into formations so that fluid communication or flow pathways can be made to

To ensure smooth transition from lab technology to field application, oil companies run pilot programmes; for example, a pilot water re-injection programme would handle say 5% of actual water volumes produced from the reservoir and re-inject this to maintain reservoir pressures.

production wells. The purpose of secondary recovery is to increase reservoir pressure and to displace hydrocarbons toward the production wellbore⁵. As a consequence of prudent reservoir management, wells may be converted from producers to injectors or new injector wells may be drilled. The trick is to consider the entire field as a 'production unit' and manage all wells with the objective of increasing overall production. This can be a very complex and contentious issue when several landowners are involved. Imagine an oil company telling a farmer that the prolific oil well on his property that is returning him a handsome revenue in royalties is about to be converted into a water injection well.

Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. The mechanics of gas and water injection are complex and include consideration given to directional injectors and multi-phase flow. A pressure maintenance programme can begin during the primary recovery stage, but it is still considered a form of enhanced recovery. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and

the production is no longer economical. For some fields this could be 50%, while for others it could be as high 80%. In Oman, wells are currently producing economic volumes of oil with over 90% water cut. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15% to 40% of the original oil in place⁶

Tertiary recovery (EOR) not only restores formation pressure, but also seeks to improve reservoir flow characteristics. With greater numbers of mature assets, oil companies target mature onshore and offshore oil fields worldwide in order to extract maximum value from sunk costs. Tertiary oil recovery applications are internationally recognised and this area of production engineering covers most categories of crude oil with American Petroleum Institute (API) grades varying from 13° to 41°. The industry adopted a broad ranging methodology, which enabled pilot testing to commercial/field applications using steam injection, carbon dioxide (CO₂) injection and polymer flood. EOR methods range from chemical flooding (alkaline or micellar-polymer based), biological flooding (microbial or bacterial based), miscible displacement (CO₂ injection

In all thermal recovery processes, the cost of steam generation and the availability of water will play a major part in determining whether the cost of oil production is commercially viable.

or hydrocarbon injection), and thermal recovery (steam flood or in-situ combustion)⁷.

Sometimes these methods are accompanied by additional stimulation services, such as hydraulic fracturing, or by drilling sidetrack lateral wells from the main wellbore to access stranded oil.

A thorough characterisation of reservoir heterogeneity and the nature of reservoir fluids is required for a mature field production strategy and only after extensive analysis of the application can a particular method be chosen. The application process can be split into three basic stages: modelling future behaviour, field data analysis and corrective correlation of the model⁸.

Typically, data maybe collected from permanent seismic (time-lapse or 4D) or downhole equipment that monitors production. The objective is to draw up a reservoir management strategy that will address:

- The effect of recovery methods on reservoir fluids
- Migration and production of oil and gas
- Communication with adjacent reservoirs
- Sealing faults

- Fracturing
- Induced pathways due to modified permeability
- Scale formation
- Hydrogen Sulphide (H₂S) mitigation, and
- Water disposal.

Analysis will include:

- Reservoir temperature
- Pressure
- Depth
- Net pay
- Permeability and porosity
- Residual oil and water saturations, and
- Fluid properties such as oil, API gravity and viscosity^{9,10}.

Seismic

A major goal for oil companies is to improve recovery factor for mature fields. A key method is to use imaging as a way of identifying stranded hydrocarbons and improving the efficiency of water injection. This helps mitigate the problems associated with water production, such as souring and scaling, and thus decreases the lifting costs of old fields. By using 4D seismic, and examining the differences between subsequently acquired seismic images, production geophysicists can: map reservoir

Besides handling increasing volumes of water at surface, the challenge is to increase recovery by improving the sweep or production of hydrocarbons through water injection.

drainage patterns; identify flow barriers such as faults or unconformities that are below the resolution of direct seismic imaging; and, plan the location of future injector wells.

Mature Field Applications

Water Injection

Water management is a major challenge associated with mature fields. Besides handling increasing volumes of water at surface, the challenge is to increase recovery by improving the sweep or production of hydrocarbons through water injection. This requires the correct evaluation of reservoir drainage patterns. In order to meet water management and environmental needs, oil companies are shifting from water injection to water re-injection. To ensure smooth transition from lab technology to field application, oil companies run pilot programmes; for example, a pilot water re-injection programme would handle say 5% of actual water volumes produced from the reservoir and re-inject this to maintain reservoir pressures. Water injection is easily applicable offshore where the entire ocean is available, but recently land operators have had problems finding water to inject. Farmers object to the use of aquifers for obvious reasons.

Accordingly, operators have figured ways to re-inject

unwanted water produced in conjunction with the oil. This recycling solves two problems at once: it is an elegant way to dispose of the unwanted saline water that is not suitable for irrigation or drinking, and it augments oil production. Now, even offshore operators are recycling produced water because it is unlawful to dump it into the sea because of its high saline content and because it contains traces of residual oil.

To get an idea of the volumes manipulated, Petrobras handles an average water injection volume of two million barrels of oil per day (MMbbl/d) half of which come from produced water. This accounts for approximately 1.87 million barrels (MMbbl) of oil which is an average water cut of 50%. Petrobras plans to construct a system for 'raw' water injection which would be placed over the seabed and used to capture and filter water prior to injection. This has a good application on mature fields or fields whose small platforms are often space-limited¹¹.

H₂S in Mature Fields

The term 'souring' describes various sour gas and H₂S management strategies. The Health, Safety and Environmental (HSE) implications of water injection are well understood as injection has been ongoing in certain areas since 1978. In Brazil's Offshore Campos Basin in the Marlim field, water injection begun in 1994 and a H₂S breakthrough occurred in 2003. Injecting

The injection decline curve for injector wells must be precisely drawn in order to evaluate the economics of two options: to perform effective water treatment that requires fewer workovers or to inject lower quality 'water' that requires more frequent workovers.

nitrate to mitigate the problem and to simulate the reservoir behaviour of H₂S generation processes helps to define, for the fields under development, which strategy to adopt. This approach is dependent on the forecast of how much H₂S is involved and when it will be produced¹².

If only trace H₂S volumes are expected, there is no need to act; if there are medium levels, metallurgical improvements may be selected. In addition, sulphate removal for scaling treatment may help to mitigate some of the souring problems. If levels are high, nitrates must be injected. Field pilots usually test the effectiveness of nitrate injection by having one pilot re-inject reservoir water and another pilot inject seawater. It should be noted that both would be using nitrate. These technologies are developed in conjunction with service and research companies, which are performing lab tests to help determine the simulation parameters of H₂S generation in the reservoir¹³.

Salt and Scale

Offshore operations also create salt and scale problems. This can occur anywhere between surface and sub-surface equipment. Remote operations have been used successfully to perform interventions such as well cleaning and squeezing of scale inhibitors into the formation. Satellite wells using subsea Christmas trees are employed in all Brazilian deepwater fields, and remote handling avoids incurring high rig costs for intervention. The problems of corrosion and its effects on subsea installations need to be carefully considered¹⁴.

Steam Onshore Fields

Onshore fields have seen good results from EOR using cyclic or continuous steam injection, as is demonstrated by the production of a total of 20,000 barrels per day (bbl/d). Applications in the Fazenda Alegre, onshore Espírito Santo Basin, have seen production rates improve

Onshore fields have seen good results from EOR using cyclic or continuous steam injection, as is demonstrated by the production of a total of 20,000 barrels per day (bbl/d).

in horizontal wells due to the introduction of thermal recovery methods. Several research projects are testing theories and feasibility of in-situ combustion. Petrobras is also considering variations of in-situ combustion and steam injection. The old vertical injector – vertical producer scheme – is being substituted by innovative geometries; for example, a vertical well to inject and a horizontal well to produce. Another alternative is to associate steam with solvents. This technology was recently applied in a field in the Espírito Santo Basin to mobilise oil which had not responded to steam injection alone.

Steam Assisted Gravity Drainage (SAGD) is an enhanced oil recovery technology for producing heavy oil. It involves the parallel drilling of a pair of horizontal wells spaced apart a few metres. Pressurised steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out.

In all thermal recovery processes, the cost of steam generation and the availability of water will play a major part in determining whether the cost of oil production is commercially viable.

Microbial Applications

Another EOR front uses microbial applications based on water and bacterial interaction to increase production.

The water and bacteria are pumped down and this is followed by nutrients. The bacteria develop a biomass that clogs the porous medium and subsequently increases the viscosity of water and diverts flow along new pathways to increase production. Biopolymers, generated by the metabolic process of the bacteria, clog the water pathways of higher permeabilities. Continuously injected water displaces the remaining oil from the lowest permeability zones. This process has been tested by Petrobras' Carmópolis field in the Sergipe Basin¹⁵. Alternatively, microbes are used to 'eat' clay particles that clog pore throats, thus improving permeability. A limitation to the use of microbes is their relative temperature limit. Ongoing research seeks to breed colonies of microbes that are more temperature resistant.

Modifying Relative Permeability

A neat application is the use of chemicals to control water. Water shut-off control in more than 200 wells has been achieved with the injection of a patented polymer called Selepol, which is a relative permeability modifier. Several formulations were attempted with the more recent based on tiny pieces of hydrophilic gel¹⁶.

Drilling in carbonates or tight sands is another area of interest where stimulation technology plays a central role. There have been five fractures in a well drilled in the Enchova field, a shallow water, low permeability, light oil-bearing carbonate.



Figure 2 - Offshore Vessel in the Troll Field

Steam is responsible for virtually all tertiary recovery production, estimated to be presently 3% of Brazil's total oil production.

A new exploratory approach may bring into focus a new family of reservoirs of this kind, previously thought to be marginal in Brazil¹⁷.

A novel gas management programme was designed to characterise gas reservoirs, principally for the tight sandstone Mexilhao field in the Santos Offshore Basin. The development of a gas-producing province at the Santos Basin, south of Campos, is a major goal for Petrobras and the company is focusing on stimulating flow in low permeability porous media^{18,19}.

Steam Injection

In the late '70s, following the discoveries of heavy oil reservoirs in the onshore part of the Sergipe-Alagoas and Ceará-Potiguar Basins, cyclical steam injection was introduced into Brazil. These first successful projects were later expanded and commercialised²⁰. Subsequently, continuous steam injection was applied to a total of 15 cyclical and continuous steam injection projects covering a broad range of oil viscosities. Steam is responsible for virtually all tertiary recovery production, estimated to be presently 3% of Brazil's total oil production. In the Fazenda Alegre field, located in the onshore Espírito Santo Basin, extremely low API grade oil is being cold-produced using steam injection and horizontal wells completed with slotted liners and stem rod pumps²¹.

In-Situ Combustion

Two in-situ combustion pilots were performed in the '80s in the Buracica and Carmópolis fields, and in the Recôncavo and Sergipe-Alagoas Basins respectively. The best results were obtained in the Buracica pilot, which was characterised by a low temperature oxidation process; however, sand production and well surface facility corrosion were major operational problems. Additionally, oxygen breakthrough interrupted the project due to the risk of well explosion. The Carmópolis pilot showed poorer results, despite the fact that it generated the best combustion efficiency. Poor reservoir characterisation was the main reason for losing control of the combustion. Electrical heating was tried in two heavy oil reservoirs in the Potiguar Basin as an alternative to steam injection. Results showed that the electrical heating process cannot replace steam, but can be useful in areas where steam is not applicable. Further electrical heating and water injection techniques have been applied in a pilot project conducted in the Canto do Amaro field²².

Polymers

The first polymer injection project was implemented in 1969 in the Carmópolis field. After operating for some years, the project was interrupted but evaluations showed that an additional oil recovery of 5% could be

Oil companies commonly apply dual geoscience programmes of seismic for reservoir characterisation and also 3D geological modelling.

credited to polymer injection. Besides the technical success of this project, the drop in the costs of polymers and the increasing ease with which polymer could be handled and prepared offered new opportunities to apply this technique. Currently, there are three polymer projects in course, one in the Carmópolis field and the other two being carried out in the Buracica field, Recôncavo Basin and in the Canto do Amaro field in the Potiguar Basin²³.

Water Management in Petrobras Fields and Treatment of Subsea Xmas Tree Wells

Water Flooding

Flooding is the main recovery method used in Brazil in both onshore and offshore fields. Offshore operations in the Campos Basin are responsible for a daily output of roughly 75% of the total country's output. The volumes of water injected exceed 800,000 bbl/d and the water production reaches values of over 350,000 bbl/d²⁴.

Due to the importance of water injection for the Petrobras fields, water management has become a major priority. Problems associated with water injection and production has been the focus of several important projects developed in the past few years.

It is worth emphasising that 'simple' problems in onshore fields, such as the stimulation of injector wells that have lost injectivity, become more complex offshore. Many wells located in deepwater areas are completed as satellites; therefore, workovers are extremely expensive due to the need for a floating rig. For such scenarios, remote operations are performed as a way of decreasing intervention costs.

A major factor in managing water is the rate of water injection that is required. The injection decline curve for injector wells must be precisely drawn in order to evaluate the economics of two options: to perform effective water treatment that requires fewer workovers or to inject lower quality 'water' that requires more frequent workovers.

Petrobras has been injecting seawater in offshore fields for twenty years. Water quality has been monitored using an index which covers parameters involved in water treatment such as injection and disposal volumes, corrosion risk, bacteria, solids and oxygen content. Irrespective of the quality of the injection programme, there is an ultimate loss of effectiveness over time. Some remote treatments using acid to remove damage in injection wells have been performed and have yielded very good results²⁵.

Many wells located in deepwater areas are completed as satellites; therefore, workovers are extremely expensive due to the need for a floating rig.

Remote Acidisation

This technique has been performed in the Marlim field which is a giant complex of oil fields located in water depths that vary from 1968 ft (600 m) to 3,445 ft (1050 m). It produces 600,000 bbl/d from high permeability turbidites. To maintain reservoir pressure, an equivalent amount of water is injected daily. Despite excellent reservoir properties, injector wells lose effectiveness after a few months of water injection. Conventional acid treatments cannot be performed due to high rig costs. The solution, therefore, is to pump acid from the production platform which is often several kilometres away from the subsea Xmas tree wells. Careful laboratory tests are needed before field operations can begin to ensure that the treatment does not damage subsea equipment such as injection lines, well heads and injection columns²⁶.

To date, only vertical or slant cased wells have been treated. The challenge is to perform remote pumping in horizontal wells completed with slotted liners.

An alternative that may help guarantee effective water injection is to inject low quality water at pressures high enough to keep fractures open. Safe water injection

requires extensive modelling of reservoir sweeps, geometry and fracture propagation²⁷.

Flow Assurance

Flow can be interrupted or halted altogether due to inorganic scale formation caused by seawater and reservoir water mixing together; therefore, the prediction, prevention and corrective treatment of scale is fundamental to ensure the flow of oil. The Namorado field was the largest Brazilian offshore field in the '80s and suffered from scale formation. Interventions to squeeze scale inhibitors into the rock formation were performed and oil production was maintained without interruption.

As some deepwater fields contain horizontal, uncased satellite wells, scale treatments are more difficult to perform. Nevertheless, some excellent results were achieved in the Marlim field using a special chemical process developed by Petrobras. Oil production increased by more than 13,000 bbl/d after the treatment. Again, the challenge for the next few years is the application of these treatments in horizontal uncased wells²⁸. Sea floor water separation and re-injection are techniques under development²⁹.

Due to the increasing number of brown fields worldwide, 4D seismic applications have increased substantially; however, as seismic is a recent technology, there are relatively few processes available to evaluate it.

Polymers

The use of polymers to control water is another potential solution and Petrobras has performed more than 170 well treatments in onshore fields. The rate of success for such treatments is in excess of 65%. The process modifies the relative permeabilities of the oil-water-sandstone system, retaining water in the wellbore vicinity. Higher seawater salinities, higher temperatures, higher permeabilities and higher produced volumes, as compared to onshore conditions, are the main challenges to be overcome offshore³⁰.

Water Disposal

Once large amounts of produced water cannot be avoided, disposal becomes the priority. The focus is on treating water to remove oil (this can be difficult due to space restrictions on platforms) in an environmentally acceptable manner so that re-injection into the reservoir or disposal in non-productive formations can be achieved³¹.

Trends in Reservoir Geophysics

The challenge for seismic contractors is to increase the quality and resolution of seismic data, not only in exploration, but also in mature applications. New acquisition and seismic processing parameters oriented

to reservoir characterisation and monitoring are helping improve seismic quality and resolution. With this new data set, reservoir geophysicists can potentially better understand external reservoir geometry, the internal heterogeneity of turbidite reservoirs and monitor the fluid flows. Historically, reservoir geophysicists have been using the same sequential process normally used in exploration. Nowadays, oil companies are applying new techniques such as 4D seismic adapted to reservoir needs³².

Mature Field Seismic

In the following applications, we look at the benefits of seismic in brown fields owned by BP, Petrobras and StatoilHydro. These oil companies have successfully used the latest 4D and time-lapse seismic to maximise the life of the reservoir, characterise stacked and thin-bed reservoirs as well as monitor water injection in deepwater reservoirs. This has helped these companies reach bypassed payzones, extend production and even change the definition of what was once considered economic.

Reservoir Studies of BP's Mature Fields in the Columbus Basin, Trinidad

4D seismic accompanies the lifecycle of an oil and gas asset and can provide valuable production monitoring

In Southern Greater Cassia, several trillion cubic feet (tcf) of gas reserves are located under shallow gas reservoirs, which often blur seismic visualisation.

information. This is because, as with all technology, seismic is subject to constant improvement. Seismic shot 20 or 10 years ago would have had limited 'vision' and likely only located 'shallow' reservoirs. Today, opportunities exist to find deeper reservoirs in mature fields, which were once characterised by 2D (early less sophisticated seismic). This can be seen in the new frontiers or deep gas plays, which are being explored in the Gulf of Mexico (GOM) and in the Columbus Basin³³.

This has tremendous value in shaping decisions as to the peaking of production rates and decline curves. Usually, a cost-benefit analysis is conducted which measures costs and attributes the value gained. This exercise can be difficult as the value gained may often be indirect. 4D seismic is used mainly to better manage reservoir production across the lifecycle of a field. Due to the increasing number of brown fields worldwide, 4D seismic applications have increased substantially; however, as seismic is a recent technology, there are relatively few processes available to evaluate it³⁴.

In 2004, BP in Trinidad and Tobago faced the challenge of valuing a number of seismic survey options over the Greater Cassia Complex in the Columbus Basin, Trinidad. In Southern Greater Cassia, several trillion cubic feet (tcf) of gas reserves are located under shallow gas reservoirs, which often blur seismic visualisation.

Development of these reserves is complicated by the presence of 27 stacked reservoirs with reserves trapped in over 100 separate segments³⁵.

BP had to identify and value the style of survey required to improve seismic visualisation over the southern half of the complex, which was affected by shallow gas imaging problems, and value the benefits that 4D seismic could offer for reservoir management and future well placement. This required consideration of expensive 4D Ocean Bottom Cable (OBC) seismic acquisition options. Additional benefits from 4D seismic for monitoring dynamic reservoir performance could be foreseen with a permanent installation. Here BP developed several research programmes to ascertain which 4D acquisition option was the best solution. The integration of these results, along with other elements, helped support decisions for a seismic strategy for the 'Life of the Cassia Complex'³⁶.

Mature Field Seismic Application in Petrobras' Deepwater Campos Basin, Brazil

Petrobras acquired its first 4D seismic in the Marlim field in 1997. In 1999, Petrobras started several 3D, reservoir-oriented seismic acquisition programmes covering former 3D surveys. These occurred in the South Marlim, Barracuda and Caratinga, Espadarte, Marimbá, and Pampo-Linguado fields in the Campos Basin.

Regarding the specific challenges that reservoirs create, modelling reveals such things as key depositional features and reservoir geometry which can help explain the gross size, volumes and channels of the reservoir.

Common seismic processing techniques were used to map reservoir turbidite systems and to reduce appraisal and production risk. Visualisation techniques were applied in 3D views of exploration and development projects³⁷. From its initial evaluation of the 4D interpretation, Petrobras was able to re-locate the trajectories of 11 development wells planned for the Marlim Complex. In addition, the company was able to identify the need for nine additional wells to improve reservoir drainage efficiency. In short, the company realised a Return on Investment (ROI) of more than 40 times by saving US \$1.6 billion by not drilling wells in the wrong place. It remains to be seen how much additional revenue the company will gain from drilling its development wells in the right place.

Geosciences

Oil companies commonly apply dual geoscience programmes of seismic for reservoir characterisation and also 3D geological modelling. Seismic for reservoir characterisation is a main issue. An acquisition project was started in 2005 with the objective of acquiring base 4D timelapse data of the whole Marlim Complex

(Marlim, Marlim Sul and Marlim Leste fields). Petrobras has a '4D-room' where geologists and engineers can visualise geological phenomena^{38,39}. At the time, Marlim was the largest seismic acquisition ever acquired both in terms of area and the amount of data acquired. The data amounted to 157 terabytes and required the continuous application of 12,000 processing units (9000 of which were located in Houston and 3,000 in Gatwick, UK).

Regarding the specific challenges that reservoirs create, modelling reveals such things as key depositional features and reservoir geometry which can help explain the gross size, volumes and channels of the reservoir⁴⁰.

Mature Field Application of 3D Seismic and Multilaterals in Norway's Troll Field

The Troll field is located approximately 50 miles (80 km) off the west coast of Norway in shallow seawaters. Troll's reserves are mainly gas (at one time it was considered to be a gas play only), but it also contains sizeable oil reserves and has produced more than one billion barrels of oil.

This oil, however, was distributed in hard-to-reach thin oil-bearing layers that were just 13 ft to 85 ft (4 to 26 m) thick and spread out over an area of approximately 173 square miles (450 sq km)^{41,42}.

A combination of multi-laterals and state-of-the-art geosteering drilling technology was required to drain the thinly dispersed pockets of oil. This included the latest rotary steerable systems in conjunction with reservoir imaging tools, which allowed the oil company to place the well in the best parts of the reservoir. This, however, was only half the story as state-of-the-art completion and production technology was required due to challenges such as Subsea sand and water separation.

In the late 1980s, it was the belief that the development of Troll oil would 'never' be economically feasible because its oil reserves were so thinly layered and the price of oil was US \$10 per barrel; however, with the creative use of technology, Troll became one of the largest oil producing fields in the North Sea. The success of this drilling and production approach led to its application in even thinner oil layers measuring just 23 ft to 46 ft (7 to 14 m) thick⁴³.

The Troll story is one of realising the potential of the field by: applying modern drilling technology; placing well trajectories within a very difficult and challenging reservoir; and keeping sand and water production to a minimum to achieve maximum production.

These successful field applications illustrate the immense financial and technical risks faced by the oil companies in reaching their prize, and show how challenges can be overcome to realise added profit and extended reservoir life.

We have seen how technology in Extreme E & P and mature field applications has extended Hubbert's peak into a plateau. With the powerful combination of technology and knowledge we are producing from reservoirs once thought to be unproduceable and improving overall recovery rates.

But how does the oil and gas from wells reach consumers?

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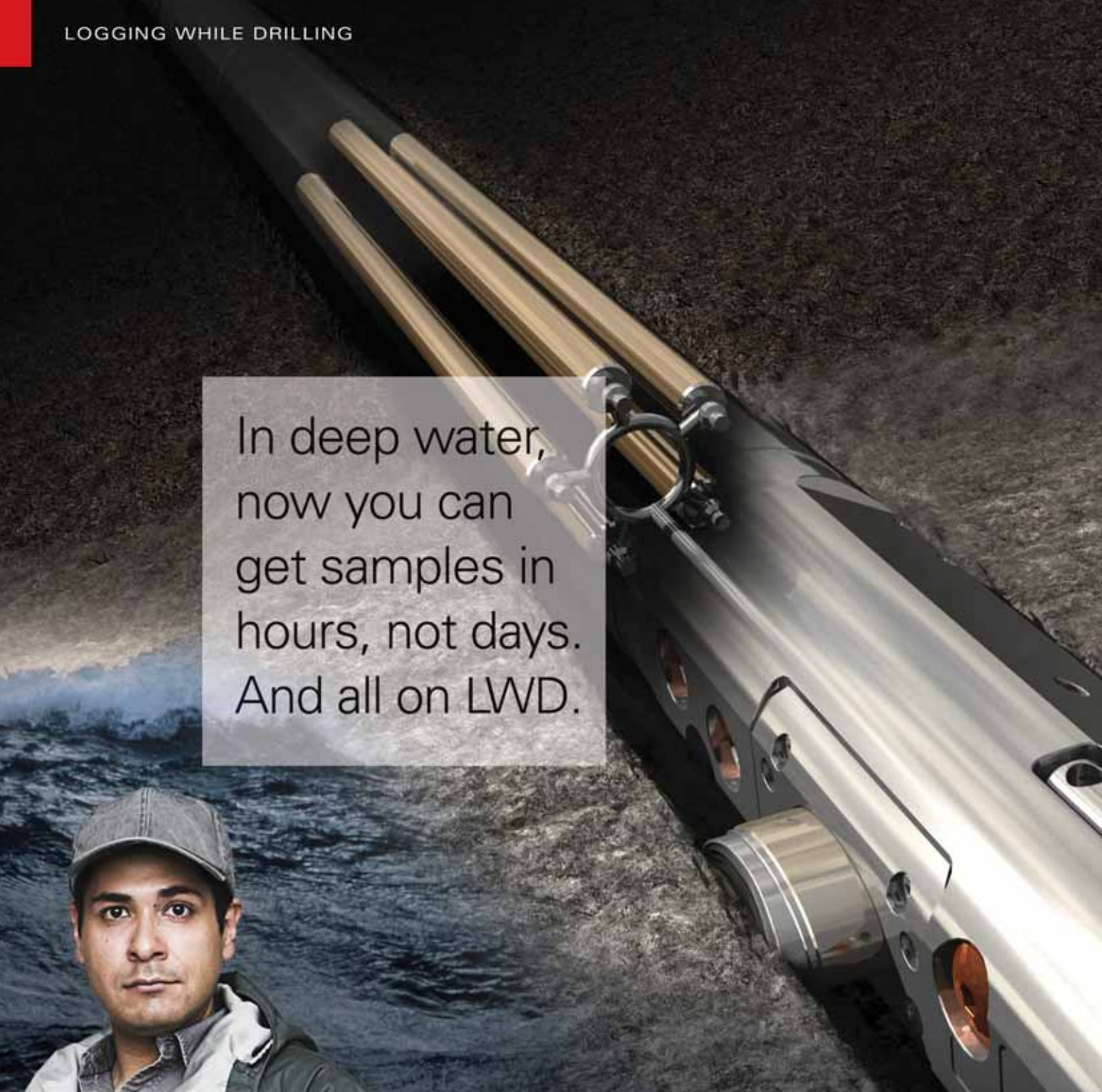
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