Technologies that have transformed the Exmouth into Australia's premier oil producing basin

Lead author
Richard Loro

R. Loro, R. Hill, M. Jackson and T. Slate
BHP Billiton Petroleum
125 St Georges Terrace
Perth, WA 6000
richard.loro@bhpbilliton.com

ABSTRACT

The oil and gas fields of the Exmouth Sub-basin, offshore WA, have presented a number of significant challenges to their exploitation since the first discoveries of heavy oil and lean gas were made in the late 1980s and early 1990s. Presently, some 20 oil and gas fields have been discovered in a variety of Late Jurassic to Cretaceous clastic reservoirs from slope turbidites to deltaic sands. Discovered oils are typically heavily biodegraded with densities ranging from 14–23° API and moderate viscosity. Seismic imaging is challenging across some areas due to pervasive multiples and gas escape features, while in other areas resolution is excellent. Most reservoirs are poorly cemented to unconsolidated and thus require sand control. Modest oil columns, most with gas caps, and variable permeability, present challenges for both maximising oil recovery and minimising the influx of water and gas. Oil-water emulsions also present difficulties for both maximising oil rate and metering production.

To date, more than 300 MMbbls have been produced from five developments (Enfield, Stybarrow, Vincent, Van Gogh and Pyrenees), and in 2013 the Macedon gasfield began production. This peer-reviewed paper focuses on the variety of technologies—geoscience, reservoir, drilling and production—that have underpinned the development of these challenging fields and in doing so, transformed the Exmouth into Australia's premier oil producing basin.

KEYWORDS

Exmouth Sub-basin, Stybarrow, Pyrenees, Enfield, Vincent, Van Gogh, petroleum technology, field development, 4D seismic, geosteering, completions, inflow control devices (ICDs), subsea multiphase metering, tracers, value of information.

INTRODUCTION

The oil and gas fields of the Exmouth Sub-basin, offshore WA, have presented a number of significant challenges to their exploitation since the first discoveries of heavy oil and lean gas were made in the late 1980s and early 1990s (Fig. 1). Presently, some 20 oil and gas fields have been discovered in a variety of Late Jurassic to Cretaceous clastic reservoirs from slope turbidites to deltaic sands (Fig. 2). To date, almost all oil discoveries have consisted of heavily biodegraded oil reflecting the relatively shallow depth of burial and consequent low reservoir temperature.

Seismic imaging is challenging across some areas due to pervasive multiples and gas escape features, while in other areas resolution is excellent. Most reservoirs are poorly cemented to unconsolidated and thus require sand control. Modest oil columns, most with gas caps, and variable permeability, present challenges for both maximising oil recovery and minimising the influx of water and gas. Oil-water emulsions also present difficulties throughout the production system.

To date, more than 300 MMbbls have been produced from five developments (Enfield, Stybarrow, Vincent, Van Gogh and Pyrenees), and in 2013 the Macedon gasfield began production to an onshore plant near Onslow.

This paper will start by outlining the 40-year exploration history of the Exmouth and its early development phases. It will then focus on the variety of subsurface technologies (geoscience, reservoir, drilling and production) that have enabled the development of these challenging fields, transforming the Exmouth into Australia's premier oil producing basin.

EXPLORATION HISTORY

Exploration in the offshore Exmouth Sub-basin got off to an inauspicious start in 1972 with the drilling of West Muiron–1. The well failed to get below 781 mMD despite three attempts, and after 55 days on location West Australian Petroleum (WAPET) abandoned the well. It transpired the well was located above the Macedon gasfield, the gas-water contact of which lay at only 1,003 mTVDSS. WAPET returned in 1975 to drill West Muiron–2, but despite reaching a depth in excess of 3,300 mMD the well failed to find hydrocarbons. This time the well lay just east of the still undiscovered Macedon gas pool. Other early wells such as Hilda–1 (1974), Resolution–1 (1979) and Jurabi–1 (1982) failed to find significant hydrocarbons within the targeted large Triassic horst blocks bordering the basin. The Hilda–1A well had in fact penetrated the Griffin oilfield on its way to the primary Triassic objective but the significance of the light oil recovered from the Barrow sands was not fully appreciated at the time.

The discovery of heavy oil at Novara (17° API) in 1982 by Esso and BHP did little to encourage further exploration, with a drill-stem test flowing at a mere 33 BOPD. As explained by Smith et al (2002), exploration efforts in the Exmouth Sub-basin were stymied for many years due to prejudices engendered by the original interpretation of Novara–1's highly flawed drill stem test (DST) and the heavily biodegraded crude it recovered.

A breakthrough appeared to come in 1992 with the discovery of the Macedon gasfield by BHP Petroleum. The third West Muiron well had finally been located within structural closure and encountered a 37 m net gas pay interval of early Cretaceous age Macedon Sandstone (Mitchelmore and Smith, 1994). Despite extensive appraisal, including the region's first 3D seismic survey in 1993, no market could be found for the Macedon gas and the field became a static resource until 2013, some two decades later.

Drilled as part of the Macedon appraisal campaign, the West Muiron–5 (1994) well encountered a 32 m gross biodegraded oil column underlying a 20 m gross gas cap within sands of the Pyrenees Member. A DST over the oil zone failed to establish stable flow, recording a maximum rate of 550 BOPD of 18°API oil. Despite being an improvement on the Novara result, the discovery was still viewed as non-commercial.

Pyrenees–1 (1994) was drilled to test the extent of the West Muiron–5 discovery; however, was plugged and abandoned as a dry hole after failing to penetrate reservoir-quality sands. The well was positioned using 2D seismic data. With time, it became apparent that it had been located less than 1 km from the Stickle oilfield. It would be another 10 years before the Pyrenees accumulations were discovered using 3D seismic direct hydrocarbon indicators (DHIs) (Scibiorski et al, 2005). Other small oil discoveries were made in the 1990s to the east of Macedon in the southern-most Barrow Sub-basin, but they too were deemed uneconomic; for example, Leatherback (by Lasmo in 1991), Outrrim (Esso in 1984) and Blencathra (BHP in 1995).

It was not until the acquisition of exploration scale 3D seismic surveys began in the late 1990s that the true potential of the basin began to reveal itself. Amplitude anomalies previously hinted on 2D could now be mapped and related to generally low relief structural closures at the top Barrow Group, and fault controlled traps within the Barrow Group. The Vincent–1 oil and gas discovery, drilled by Woodside in 1998, was the first well to successfully target such 3D amplitudes when it discovered a 19 m gross oil column overlain by some 8 m of gas. The well was tested and flowed at 4,300 BOPD (17° API) with 1.9 MMscfpd through a two-inch choke from high-quality Barrow Group sands. Commercial production rates had finally been established. A spate of oil discoveries then followed between 1999 and 2004, almost all reliant on amplitude anomalies being carefully interpreted to define fault and combined fault, and stratigraphic closures, within sandstones of the late Jurassic to early Cretaceous Barrow Group and its sub-divisions, namely Eskdale, Macedon and Pyrenees members (Table 1). By the end of this period more than one billion barrels of oil in place had been discovered, signaling the southern Exmouth Sub-basin as a major new hydrocarbon province.

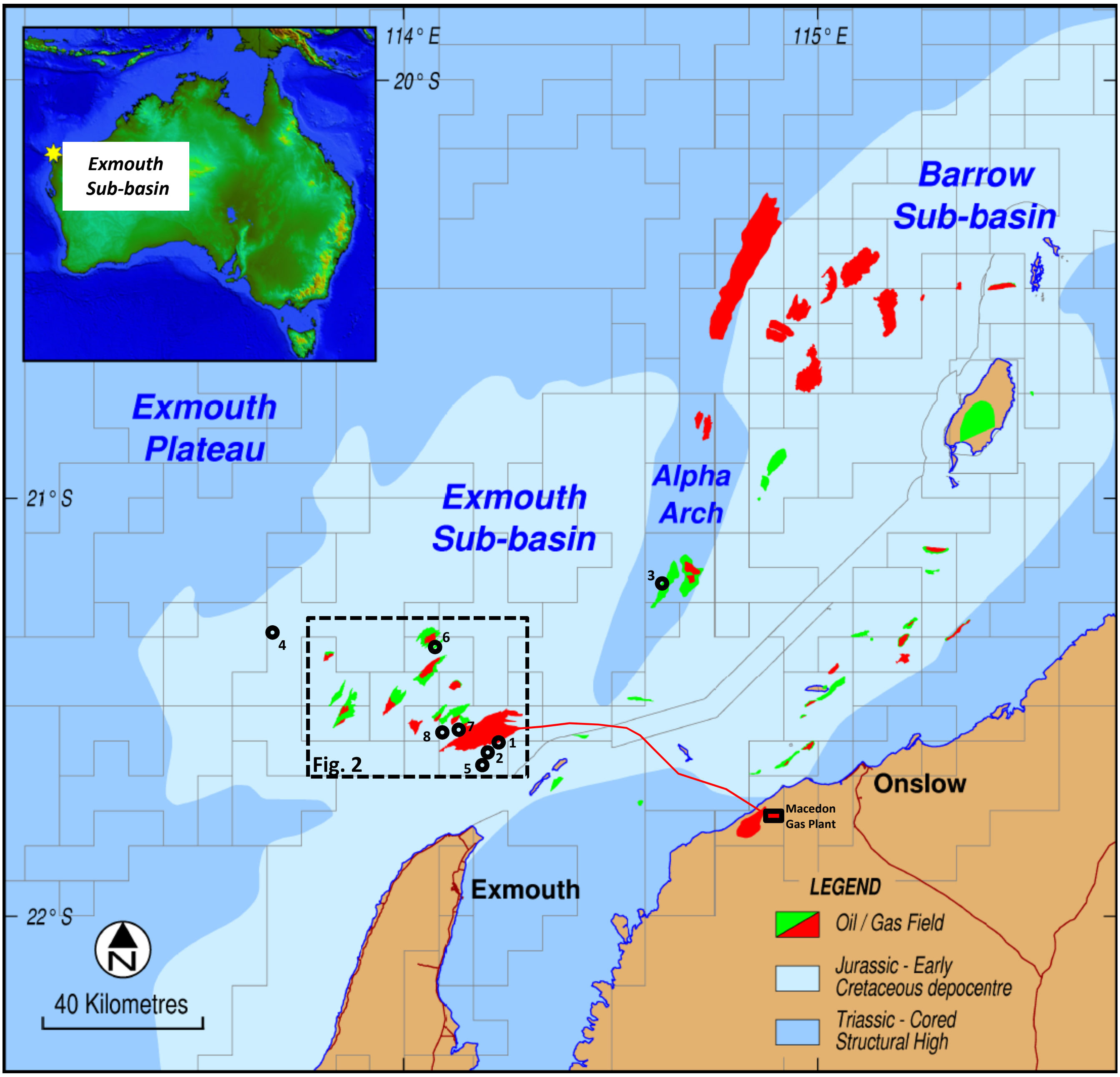


Figure 1. Location map: Exmouth Sub-basin fields and wells mentioned in paper (modified from Smith et al, 2002). Captioned wells: West Muiron–1 (1); West Muiron–2 (2); Hilda–1A (3); Resolution–1 (4); Jurabi–1 (5); Novara–1 (6); West Muiron–5 (7); and, Pyrenees–1 (8).

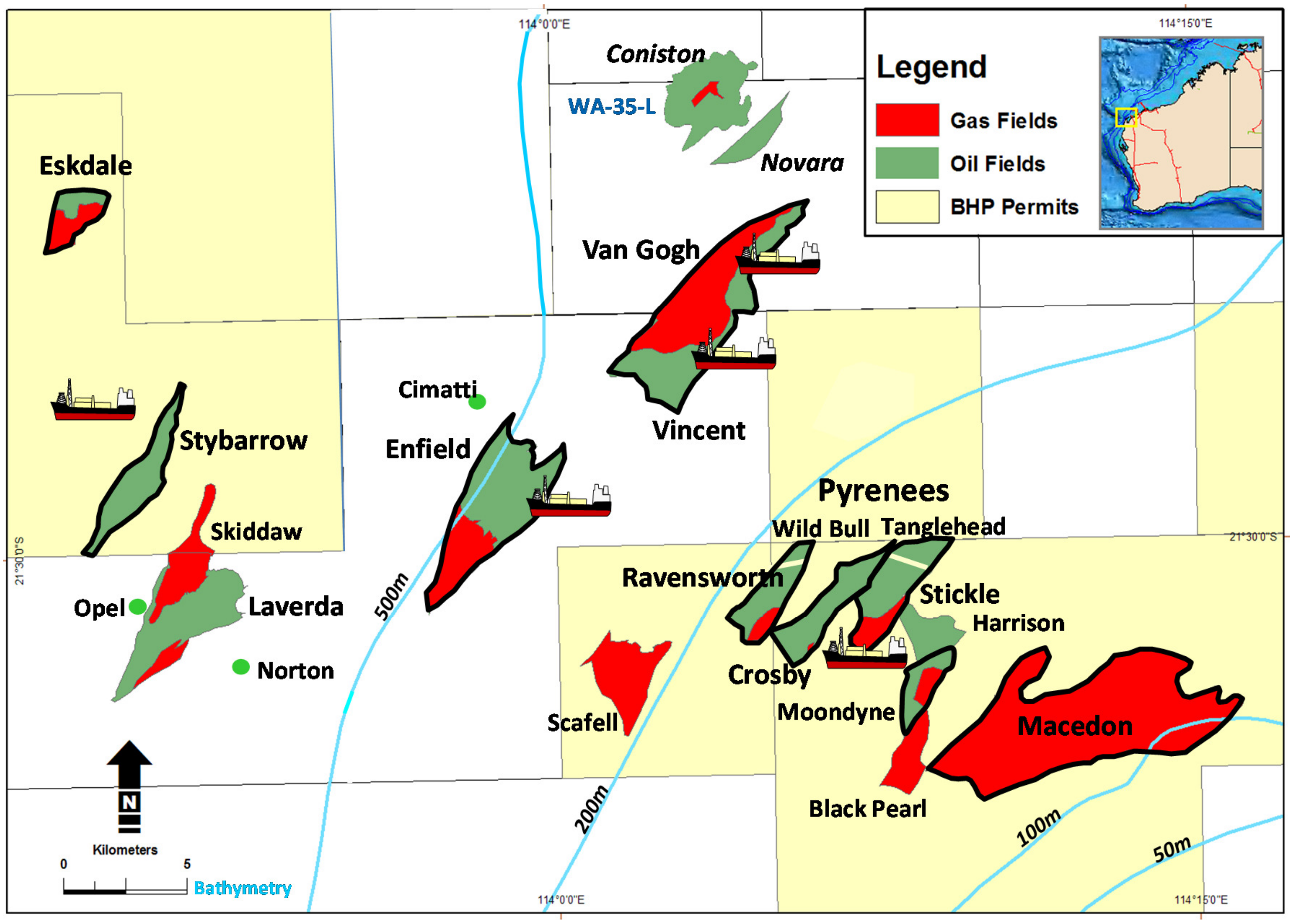


Figure 2. Location map: fields, discoveries and bathymetry in the Exmouth Sub-basin. Bold outlines denote fields presently in production.

Table 1. Exmouth Sub-basin oil discoveries.

Discoveries	Spud date	Operator	Reservoir	Oil API gravity
Novara	September 1982	Esso	Barrow Group	17
Moondyne	June 1993	BHP Billiton	Pyrenees Member	18
Vincent	December 1998	Woodside	Barrow Group	17
Enfield	March 1999	Woodside	Macedon Member	22
Coniston	January 2000	BHP Billiton	Barrow Group	15
Laverda	October 2000	Woodside	Macedon Member	20
Stybarrow	February 2003	BHP Billiton	Macedon Member	22
Eskdale	March 2003	BHP Billiton	Eskdale Member	46
Skiddaw	May 2003	BHP Billiton	Macedon Member	21
Ravensworth	July 2003	BHP Billiton	Pyrenees Member	19
Van Gogh	September 2003	BHP Billiton	Barrow Group	17
Crosby	October 2003	BHP Billiton	Pyrenees Member	19
Stickle	May 2004	BHP Billiton	Pyrenees Member	18
Harrison	May 2004	BHP Billiton	Pyrenees Member	19
Wild Bull[1]	July 2004	BHP Billiton	Pyrenees Member	19
Tanglehead[2]	August 2004	BHP Billiton	Pyrenees Member	18
Cimatti	November 2010	Woodside	Macedon Member	Not available
Opel[3]	October 2011	Woodside	Macedon Member	Not available
Norton	February 2012	Woodside	Barrow Group	19
Stybarrow East	December 2013	BHP Billiton	Macedon Member	Not available
Rydal	January 2014	BHP Billiton	Eskdale Member	Not available

Notes: Bold names denote fields in production. 1) Wild Bull discovered by Ravensworth–2. 2) Tanglehead discovered by Stickle–2. 3) Opel–1 re-entered after initial spud in 2010.

DEVELOPMENT HISTORY

Despite the wave of exploration success starting in the late 1990s and continuing into the early 2000s, the relatively modest size of discoveries, greenfield nature of the basin and proximity to the Ningaloo Class A marine reserve meant that the projects carried a perception of risk and remained marginal, especially given the prevailing oil price at the time.

Gas

Modest resource size, lack of associated liquids, and the absence of gas infrastructure significantly challenged the commercialisation of the gas resources. Almost two decades after discovery, the start-up of Macedon in August 2013 signaled the first commercial gas sales from the Exmouth. The project faced additional challenges relating to the presence of low levels of inert components, which rendered the gas just outside of the original specification window for the Dampier to Bunbury Natural Gas Pipeline. Following a state gas shortage in 2008, the pipeline specification was broadened, paving the way for Macedon gas to enter the WA domestic market. As part of this revision, some 10,000 legacy gas appliances across the state were replaced or serviced by the Macedon joint venture (Zois, 2014).

Oil

Oil columns at the top Barrow closure (Vincent, Van Gogh, Pyrenees, Coniston and Novara) are generally less than 30–40 m, with large areal footprint, significant bottom water and overlying gas caps. This is in contrast to the discovered Macedon reservoirs (Stybarrow, Enfield and Laverda) where more significant oil columns are observed (50–300 m), though reservoir thickness tends to be thinner ranging between 5–20+ m. Reservoir quality can vary in both the top Barrow and Macedon reservoirs; however, it is generally excellent with net-to-gross (NTG) greater than 80% and average permeability exceeding 1 Darcy. A comprehensive review of the issues faced during development planning for the Stybarrow and Pyrenees fields can be found in Ementon et al (2004) and Slate et al (2010), respectively.

With the exception of the Eskdale and Rydal fields, oil discovered within the Exmouth Sub-basin to date has proven to be heavily biodegraded. As detailed by Tindale et al (1998), the temperature of the Barrow Group reservoirs is unlikely to have exceeded 80°C during the course of their histories, hence bacterial degradation has been essentially continuous, with evidence that it is ongoing even today (Murray et al, 2013). While biodegradation has been significant, the paraffinic nature of the original crude has meant the associated increase in viscosity is not severe by world standards, with in situ viscosities ranging between 3–30 cP, although dead oil viscosities can be a magnitude higher than this.

The predominate drive mechanism across developments to date has been water drive, by either natural aquifer influx or water injection. The key to development, therefore, has been the maximisation of sweep, attainable through accurate well placement, reservoir contact and zonal conformance.

By 2014, nine oilfields were in production along with the Macedon gasfield. In chronological order of start-up, a list of producing projects is shown in Table 2.

The ramp-up in Exmouth output has been significant, accounting for as much as 60% of Australia's crude production during 2011 (Fig. 3). Recently, natural field decline and floating production storage and offloading (FPSO) maintenance has impacted the Exmouth's share of Australian production; however, the return of the Nguijima-yin and Ningaloo Vision FPSOs, and additional planned development phases (Apache's Coniston and Novara Development, BHP Billiton's Pyrenees Phase 3, and additional phases at Woodside's Vincent Field) should see the Exmouth retain its premier position in the near term. Common among all these projects has been the application of technology to mitigate risk and increase value; in some cases it has only been the application of technology that has allowed the successful development of this significant resource.

The remaining portion of this paper summarises several of these key technologies, and ascribes the relative value derived from each. Given the allegiance of the authors, most examples will be from BHP Billiton projects; however, this in no way detracts from the work performed by other operators in the area, in particular Woodside and Apache. Indeed, cooperation among these parties and the transfer of best practices has been a key enabler in itself; a number of excellent publications document this work and are referred to in the following sections of the paper.

SEISMIC TECHNOLOGY

3D seismic

Seismic amplitude anomalies had been observed on regional 2D seismic surveys for a number of years, and appeared to be related to top Barrow closures and fault terraces within the Barrow Group. The anomalies, however, were often spatially aliased and ill defined. It was not until the acquisition of exploration 3D seismic surveys across large areas of the basin in the late 1990s that subtle elements of trap geometry, such as truncation edges and fault linkage, could be mapped and drillable prospects defined. Woodside's Vincent 3D shot in 1998 covered 800 km^2 and led directly to the discovery of the Vincent, Enfield, Laverda and Ravensworth oilfields. Similarly, the Stybarrow and Eskdale fields were defined on 3D seismic shot by BHP Billiton Petroleum in 2000 (HCA2000 Survey). The 3D seismic allowed not only detailed fault, reservoir truncation and pinch-out maps to be made, but also allowed for the recognition of a number of DHIs representing field oil-water and oil-gas fluid contacts (Scibiorski et al, 2005).

Seismic inversion

High-quality 3D seismic across some fields combined with extensive petrophysical data has enabled stochastic model-based seismic inversion to be undertaken to improve reservoir sand thickness prediction in a number of fields. Hill et al (2008a) outlined how this had been successfully applied to the Stybarrow Field during the development stage, and led to both reducing uncertainty in reservoir distribution and optimal placement of production and injection wells. The use of inversion techniques, particularly in relatively thin reservoirs, helped reduce the need for costly appraisal wells. The wealth of log and core data in the basin results in good calibration of rock physics models, which are essential for reliable reservoir net sand and fluid prediction.

4D seismic

4D seismic has been used for reservoir surveillance and targeting infill drilling in two of the producing Exmouth oilfields. Australia's first 4D—or time-lapse—seismic survey was acquired in the southern Exmouth over the Woodside-operated Enfield oil and gas field. The first Enfield monitor survey was acquired in 2007 after the field had been in production for less than a year. As part of the field development plan a dedicated baseline survey had been shot in 2004. Both the monitor and baseline surveys were processed in parallel to enhance the signal caused by production-related pressure and saturation

Table 2. Producing fields in the Exmouth Sub-basin.

Project	Operator	FPSO	Fields	Start-up	Discovery to production
Enfield	Woodside	Nganhurra	Enfield	Q3 2006	7 years
Stybarrow	BHP Billiton	Stybarrow Venture	Stybarrow & Eskdale	Q4 2007	4 years
Vincent	Woodside	Ngujima-yin	Vincent	Q3 2008	10 years
Van Gogh	Apache	Ningaloo Vision	Van Gogh	Q1 2010	7 years
Pyrenees	BHP Billiton	Pyrenees Venture	Phase 1: Ravensworth, Crosby and Stickle Phase 2: Tanglehead, Wild Bull and Moondyne	Q1 2010	7 years
Macedon	BHP Billiton	-	Macedon	Q3 2013	20 years

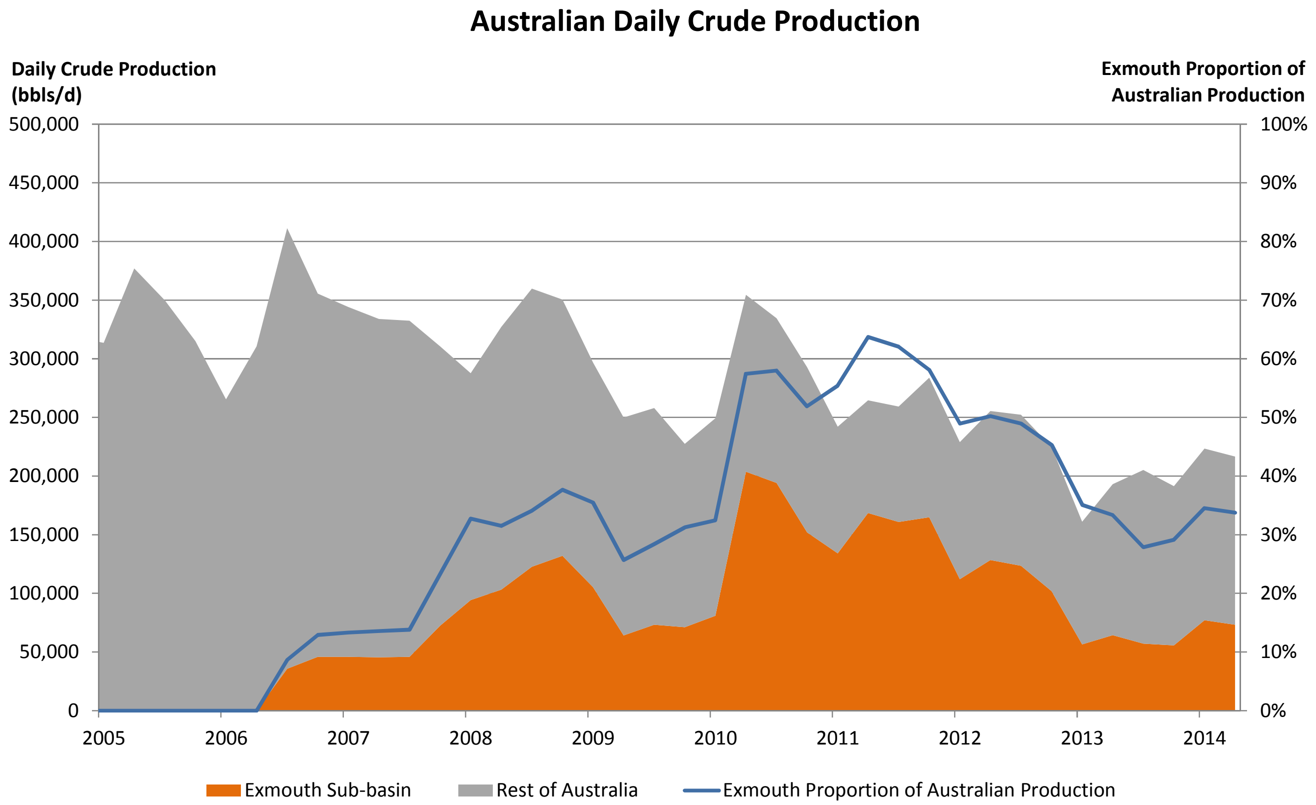


Figure 3. Exmouth oil production in relation to Australian production. Source: APPEA Biannual Production Statistics 2014—crude only (APPEA, 2014).

changes within the Macedon Member reservoir sands. The results revealed a strong 4D response to pressure and local water saturation changes after just seven months of production (Smith et al, 2007). Detailed understanding of rock physics based on log and laboratory core measurement was also critical in both modelling and interpreting the Enfield 4D reservoir response (Wulff et al, 2007). The first and subsequent monitor surveys were used extensively to both infill and re-drill oil production and water injection wells in the field to increase oil recovery (Medd et al, 2010).

4D seismic was shot in November 2008 over the Stybarrow oilfield some 12 months after production had begun. In this case, regional 3D data shot in 2000 was utilised as the pre-production survey, despite being acquired in a different orientation and with suboptimal cable depth to form an ideal baseline. These problems were overcome with innovative processing techniques including the treatment of strong azimuthal anisotropy in the overburden and reservoir (Duncan et al, 2013). Pre-acquisition seismic modelling had shown that the Stybarrow Macedon reservoir would be a good candidate for 4D seismic monitoring due to its homogeneous high porosity (~30%) and low acoustic impedance sands. Once the baseline and monitor data were co-processed, the effects of oil production and water injection on reservoir pressure and water saturation could be clearly observed (Hurren et al, 2013). The original HCA2000 3D survey indicated an area of elevated amplitude towards the northern end of the field; however, dim seismic amplitudes (indicative of poorer reservoir) separated this region from the main field. Consequently, this area was excluded from the original field development plan due to concerns regarding limited connection to planned water injectors. Technically, the oil volume in this northern area could be drained by a single development well, however economic assessment did not justify an additional water injector.

The first monitor survey shot in 2008 clearly indicated the area was becoming acoustically softer consistent with increasing reservoir pressure due to flank water injection. Furthermore, dynamic modelling, as part of an iterative (synthetic) seismic matching loop, was able to guide assessment of the degree of overpressuring. After a short field-wide production shut-in to allow reservoir pressure to decline to establish a safe drilling window, an additional horizontal production well was drilled and completed in the northern part of the field. This well entered production with an initial rate greater than 20,000 BOPD and evidenced communication with the field water injectors.

Further 4D seismic surveys have now been acquired across the Vincent, Van Gogh and Pyrenees (Duncan et al, 2015) oilfields. Such surveys continue to provide invaluable information about the dynamic behavior of reservoirs due to oil production and water injection and/or aquifer encroachment. The interpretation and integration of 4D data with accurate 3D seismic mapping, static and dynamic reservoir modelling has led to improved understanding of reservoir sweep. This enables areas of bypassed or attic oil to be identified, and leads to more effective design of infill development.

WELL CONSTRUCTION

Wellbore placement: geosteering

Wellbore placement encompasses three key facets, namely:

- ability to steer the bit;
- positioning of the bit relative to the reservoir window (usually roof or stand-off from contacts); and,
- accuracy of absolute well location or field depth reference.

The drilling and completion of horizontal wells has been common oilfield practice for many years; however, the use of steerable drilling assemblies coupled with boundary predictive resistivity tools is relatively new. The first application of deep-resistivity tools to geosteer wells in Australia occurred in 2006 in the Stybarrow Field (Hill et al, 2008b). Wells approximately 500 m in length were successfully steered within thin (5–20 m) Macedon sands maintaining high net-to-gross reservoir throughout using first-generation deep-reading resistivity tools such as Schlumberger's PeriScope and Baker Hughes Inteq's Azitrak.

Developing fields with relatively thin oil columns (Pyrenees, Vincent and Van Gogh flank areas) have required wells to be placed as close to the top of the oil column as possible. This minimises attic oil and creates maximum stand-off from the oil-water contact, thereby delaying water breakthrough. These objectives have to be tempered by the need to minimise the risk of exiting the reservoir roof if steered too close, and managing dog-leg severity to ensure completions can be run to TD (total depth). Woodall et al (2014) described how development wells in the Pyrenees fields were successfully geosteered to within 1–2 m of the top reservoir over distances of up to 2,000 m, with all wells being successfully completed to TD. Geosteering was performed real-time, with data from the formation evaluation logging while drilling (LWD) tools streaming directly into static reservoir models and constantly compared to pre-drill seismic and modelled stratigraphy and faults. This facilitated continuous adjustment to the planned well paths based on deep-reading resistivity tools detecting reservoir boundaries, faults, and occasionally fluid contacts. The first generation of tools permitted boundaries to be detected up to ~5 m above or below the wellbore but by 2012, a second generation of tools (e.g. Schlumberger's DDR/Geosphere) allowed the imaging of multiple bed boundaries up to ~30 m from the wellbore, including, on occasion, fluid contacts (Fig. 4).

The evolution in geosteering capabilities has resulted in improvements in downhole directional surveys enabling more accurate real-time measurement of wellbore position. The consequences of not using continuous survey data collected while drilling was dramatically demonstrated in one of the Vincent horizontal oil development wells (Lim et al, 2012). High definition survey (HDS) techniques, which use both continuous and static survey data, are now routinely used on all wells to reduce errors in wellbore positioning.

Reservoir exposure

Early production tests in vertical wells clearly demonstrated limited production rates. In particular, the thin oil columns of the top Barrow accumulations drove the need to drill long (1,500+ m reservoir sections) production wells to maximise both rate and recovery. Both point-the-bit and push-the-bit rotary steerable systems have been deployed, allowing both accurate well positioning and maintenance of azimuth and inclination in often very poorly cemented to unconsolidated sands. The most recent systems combine both point and push the bit technologies delivering wells in Vincent drilled to ~4,300 mMD and in Barrow reservoir sands that are located between 1,300 m to 1,310 mTVDSS; all while maintaining offset from the top reservoir to within 1–3 m (Smith and Gongara, 2012). Similar results were achieved in the Pyrenees development where more than 30 km of reservoir section has been drilled and completed, the longest well drilling to 4,597 mMD with a true vertical depth of 1,115 mTVDSS (Woodall et al, 2014). Aspect ratios (horizontal departure/vertical departure) of these wells approach 3.5, which, given the relatively shallow depth and subsea environment, are world-class examples of extended reach drilling.

The adoption of multi-lateral drilling with dual-, tri- and quad-lateral wells being completed in Vincent and Van Gogh, has improved project economics by reducing both the proportion of time spent drilling to the reservoir and subsea infrastructure costs. According to Lawrence et al (2010):

> 'A total of 97% more reservoir exposure was added to the wells requiring only 41% additional rig time. As a corollary, only 29% of the total project time was spent on creating and completing the upper lateral. The nine multilateral production wells replaced 18 single wells in the economic base case, resulting in a capital expenditure saving of approximately 24%.'

Geomechanics has also played an important role in not only the selection of mud type and weight, but in wellbore orientation to minimise invasion, definition of fracture pressure for injection and critical pore pressure to initiate fault slippage (White et al, 2006). Key to the successful construction of predictive geomechanical models is the calibration to adequate core material, not only within reservoir rocks, but also non-reservoir mudstones and the adjacent over-burden and under-burden. Adequate conventional core has the added benefit of providing material for optimal completion design (e.g. in defining grain-size distribution and clay characterisation).

Completion

The final key component in well construction is the adoption (and evolution) of the correct completion philosophy. This is crucial to ensuring long-term reliability and optimal drainage performance of wells. A number of facets require consideration.

An important starting point is the design of drill-in-fluids in conjunction with wellbore clean-up procedures. The ideal drill-in-fluid is low-invasion, non-damaging (or non-reactive) and subsequently back-producible through the completion. Chung et al (2010) describes the considerable effort that went into planning the well clean-up operations that were implemented during the Pyrenees development. Significant time was spent to develop high-performance drilling and completion fluids to preserve productivity along the entire producing interval (Napalowski et al, 2008).

The Exmouth reservoirs (Macedon, Pyrenees and Barrow sands) are generally unconsolidated to poorly cemented, and thus provision of sand control is a requisite of any completion design. The early Macedon sand developments (Enfield and

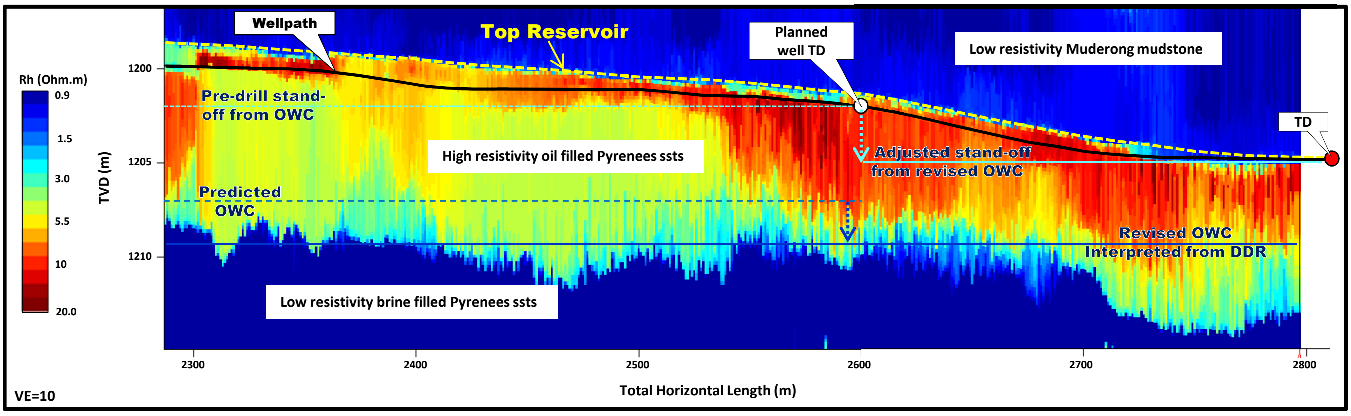


Figure 4. Example of a Pyrenees geosteered well. Note in this well the pre-drill stand-off from predicted oil water contact (OWC) and actual OWC are seen with the DDR tool. The well was lengthened by more than 200 m as a result of imaging the deeper contact, adding significant productivity (modified from Woodall et al, 2014).

Stybarrow) employed open-hole gravel packs (OHGPs) to deliver this control. In Enfield, McCarthy and Mickelburgh (2010) described how OHGPs were installed with gravel placed using a conventional brine-based alpha-beta wave technique (circulating gravel packs). Installation in the vertical wells proved effective with pack efficiencies estimated between 95–100%; however, the Phase 1 horizontal wells proved problematic with incomplete gravel placement (pack efficiencies 45–55%). These wells were subsequently sidetracked in a later development phase and following adaptation of the placement technique to alternate path, were successfully recompleted with pack efficiencies between 95–102%.

In Stybarrow, four horizontal wells with reservoir sections up to 480 m each were installed with circulating gravel packs using a water-based carrier fluid. The operation went as planned with pack factors between 108 and 118% achieved. The Stybarrow gravel packs were the first successful implementation of horizontal OHGP completions in Australia.

The extended horizontal reservoir sections necessary to develop the top Barrow fields challenged the selection of gravel packing as the primary sand control technology from both CAPEX and execution feasibility standpoints. Premium standalone screens have instead been implemented as the system of choice. The combination with swell packers and ICDs (inflow control devices) to discretise the annulus and encourage uniform inflow along the well length has brought significant benefits both for production efficiency and sand control through minimisation of hot spotting. This downhole configuration has proven popular in the later Exmouth developments with extensive application in the Vincent, Van Gogh and Pyrenees fields. The authors are unaware of any screen failures across these projects to date. Based upon the success experienced at Pyrenees, BHP Billiton applied this design to a later infill well in Stybarrow with excellent results.

The virtues of swell packer and ICD completions are well-extolled in literature (Gavioli and Vicario, 2010). They are an effective means of encouraging flow contribution along the entire length of a horizontal well, particularly in high-productivity wells where pressure loss along the lateral exceeds or is of a similar magnitude to sandface drawdown. Application to the Exmouth reservoirs has been successful both for production optimisation and recovery enhancement (Fig. 5). When effectively sized and placed, ICDs can slow water-cut development and limit gas production. In long horizontal wells, the benefits of improved water cut and/or gas oil ratio (GOR) outweigh the reduction of well productivity resulting from the pressure drop through the ICD elements. The introduction of autonomous ICDs that selectively retard gas or water may further improve results.

PRODUCTION OPERATIONS

The goal of any development is to minimise risk to environment and safety while maximising up time and ultimately production. A combination of metocean conditions, cyclones, water depth, modest resource size, and proximity to the World Heritage listed Ningaloo Reef and Marine Park has dictated that oilfields in the area have been developed through subsea wells tied back to disconnectable FPSOs. To deliver a successful project, the FPSO design is required to address several key characteristics of the Exmouth area. These include:

- Environmental:
  - a) cyclone avoidance; and,
  - b) waste stream disposal:
    - (i) produced water reinjection/polishing before discharge; and,
    - (ii) gas reinjection for storage/disposal.
- Operational:
  - a) oil-water emulsion processing;
  - b) provision of well artificial lift;
  - c) gas compression reliability; and,
  - d) metocean condition impact on process and offtake operations.

The above list is not meant to be exhaustive; however, it provides some insight into the required design basis. It is beyond the scope of this paper to discuss these in detail, but it is sufficient to state that no matter how well the subsea component of the project is designed, the project will be at best mediocre if the topside availability is poor. BHP Billiton's aggregate uptime for the history of the Stybarrow and Pyrenees projects is greater than 90% inclusive of weather interruption. This performance sets a world-class standard for FPSOs operating in cyclone-prone areas.

Multiphase metering

The practice of installing permanent tubing head (PTHP) and downhole pressure gauges (PDHG) within production and injection wells is well-accepted and now industry standard. The data provided by such instruments are invaluable, allowing insights into reservoir behaviour and the means with which to optimise recovery efficiency and production performance. As equally important as pressure (some may argue more so), yet often accepted with far less rigour, is production rate measurement. In traditional systems, individual well production is measured by a test separator on an intermittent basis, usually monthly. The testing process itself often incurs production deferral amounting to several percent due to a movement away from the optimal well lineup. Changes to the well flowing conditions due to the alteration of well lineup can impact the quality of the measurement taken. Based on these intermittent readings, production is back allocated to wells over a set period (again, often monthly).

The advent of subsea multiphase flowmeter (MPFM) technology has allowed the production rates of wells to be monitored in real time, without the need to alter line up or incur deferral. Both the Vincent and Van Gogh projects have made use of MPFM technology with a meter mounted on each subsea manifold allowing production wells to be tested sequentially with minimal deferral. BHP Billiton expanded on the implementation of this technology in the Pyrenees development, where every well was installed with a dedicated subsea MPFM. Though a significant investment, the project was justified based on the following arguments:

- production allocation—the development straddled two production licence areas with varying interests;
- complex subsea architecture—high number of wells leading to significant deferral under a traditional well testing methodology;
- production optimisation—managing well cycling and well lineups in the subsea network; and,
- facilitation of improved well and integrated production modelling efforts through improved well allocation.

Jackson et al (2012) details a number of excellent examples where the value of the MPFMs has been clearly demonstrated.

Tracers

Tracers fall broadly into two categories: inter-well and inflow. Both applications have been used in the Exmouth. Hurren et al (2012) described how inter-well tracers were used in the Stybarrow Field to characterise producer-injector pair connectivity and transit times. A similar application is described by Hamp et al (2008) in Enfield. Napalowski et al (2012) demonstrated the use of inflow tracers in several key wells in Pyrenees for surety in wellbore cleanup completion (oil soluble tracer) and timing and location of water breakthrough (water soluble tracer) in horizontal production wells. The water breakthrough data proved to be an effective history match constraint, aiding calibration of the reservoir model.

A key feature of tracers is that they are a comparatively cheap option for wellbore surveillance, which is otherwise prohibitively expensive for subsea developments. Advancements in distributed temperature sensing (DTS) and distributed pressure sensing (DPS) are expected to make these technologies practical for subsea applications.

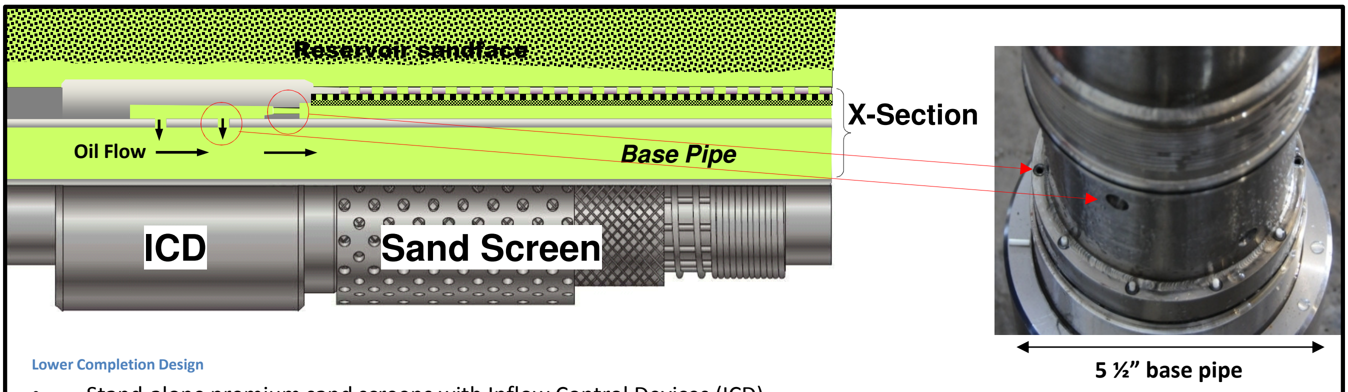
Subsea multiphase booster pumps

Multiphase boosting has been used in the Vincent development as a means to increase production rates. Subsea multiphase pumps (MPPs) also enable a reduction in subsea flowline diameter and increase the allowable tieback distance. Nallipogu et al (2012) describe the selection criteria and design process used in the Vincent application. Dual pump units were specified to provide availability, and different delta pressure impeller designs, thus increasing operational flexibility over an extended range of water cuts and gas volume fractions.

Production uplifts of the order of 30% were observed on high water-cut flank wells. Additional benefits attributed to MPPs include the ability to segregate production into high and low pressure flowlines to manage well backpressure and a reduction in well startup time in comparison to traditional gas lift systems.

VALUE OF TECHNOLOGY: PYRENEES CASE STUDY

The preceding discussion highlights a number of examples where the application of technology has been key to developing the Exmouth reservoirs. While the cost of each technology is (generally) well-understood ahead of its implementation, the deliverables are often far less determinate against a background of project uncertainty. In addition, recognition of the less tangible elements is often not possible until after implementation. Yet in the value equation, particularly in a capitally constrained world, characterisation of all benefits (both tangible and intangible) is of equal importance to the implementation cost. Rarely is the value of the technology examined retrospectively in the context of the overall project outcome to determine what impact, if any, the technologies have brought to the bottom line. The following



Lower Completion Design

- Stand-alone premium sand screens with Inflow Control Devices (ICD)

ICD Purpose

- Reduce risk of screen failure due to annular flow causing hot spotting and erosion
- Even out fluid contribution along the entire horizontal wellbore
- Improve well clean-up and maximise inflow along horizontal well

ICD Design

- Combination of 2.4 mm and 2.6 mm nozzles
- Approx. 10 swell packers per well to eliminate annular flow
- Optimum nominal pressure drop across ICD is ~20 psi

Figure 5. Pyrenees field generic lower completion design, ICDs and sand screens.

section attempts to step through a (necessarily) high-level analysis using BHP Billiton's Pyrenees development as a case study.

It is important to note at the outset that each value analysis will be specific to its reference case. Thus the relative value of technologies can and will change depending on the project, and is the reason why assessment needs to be performed on a case-by-case basis. In the Pyrenees example, it is simply the intent of the authors to leave the reader with an impression of the criticality of each of the technologies applied.

Numerous descriptions of the Pyrenees development are available in the literature and have been previously cited in the paper. Key development challenges include:

- heavily biodegraded, moderately viscous (8–15 cP) oil, with strong emulsion-forming tendencies;
- relatively thin oil columns (15–40 m), overlain by gas and underlain by strong aquifer;
- unconsolidated sands;
- high NTG reservoir, yet variable in quality; and,
- multiple field development through complex subsea infrastructure.

The development screening phase identified a number of strategies aimed at mitigating these challenges. Each strategy was underpinned by one or more key enabling technologies. These included:

- maximum reservoir exposure—extended horizontal well step out versus shallow TVD;
- optimal well placement—geosteering;
- multipurpose lower completion—standalone screens, swell packers and and ICDs; and,
- real-time production measurement—multiphase metering.

The incremental value delivered by each of the technologies has been analysed using the history-matched reservoir simulator. Development scenarios, whereby each technology is progressively removed from the project, have been constructed and the outputs compared. As a proxy for value, cumulative recovery for each of the cases has been discounted at 10% per annum, and normalised to the project's discounted recovery (Fig. 6). In total, the application of technology is estimated to have added ~20% of incremental value to the project. A discussion on the derivation of each of the items follows.

Extended reach drilling

Though considered relatively modest by today's standards, the initial development phase delivered wells with horizontal departures (HD) approaching 3 km in an overburden section of approximately 900–1,000 m, giving aspect ratios (HD/TVD) between 2.5 and 3. This was a significant achievement in Australia at the time, given the subsea nature of the development.

A number of challenges existed, including:

- effective circulating density control and hole cleaning management;
- fluid losses in a highly permeable reservoir;
- unconsolidated and abrasive reservoir sand; and,
- sand screen placement (i.e. completion to bottom).

The final challenge is of particular importance and not trivial. In fact, the limiting factor in the horizontal length was observed to not be drilling related; rather, the ability to successfully run screens to bottom. To put this in context, in a typical well with a 1,800 m horizontal section, by the time the first screen enters the open-hole section, there is still another 500 m or so of screen remaining to be run through the rig floor. This puts great onus on the minimisation of dogleg severity in the wellbore trajectory, and confirmation that the wellbore is clear of drilling debris prior to the commencement of completion activities. That all 13 horizontal wells were drilled to TD with more than 20 km of screen successful placed, is testament that these challenges were successfully met.

Recovery at Pyrenees is seen to be a strong function of well length. On average, each loss of 100 m of completed wellbore corresponds to a loss of 500,000 BBLs recovery. A loss of contributing well length could arise either through failure to reach TD or an inability to run screens to depth. For the purposes of the value exercise it was assumed that 30% of the original well stock (four wells) was drilled 500 m short of the target TD. Four wells of average performance were chosen across the three fields and simulated with a reduction in well length. The loss represents an approximate 6% drop in normalised project recovery.

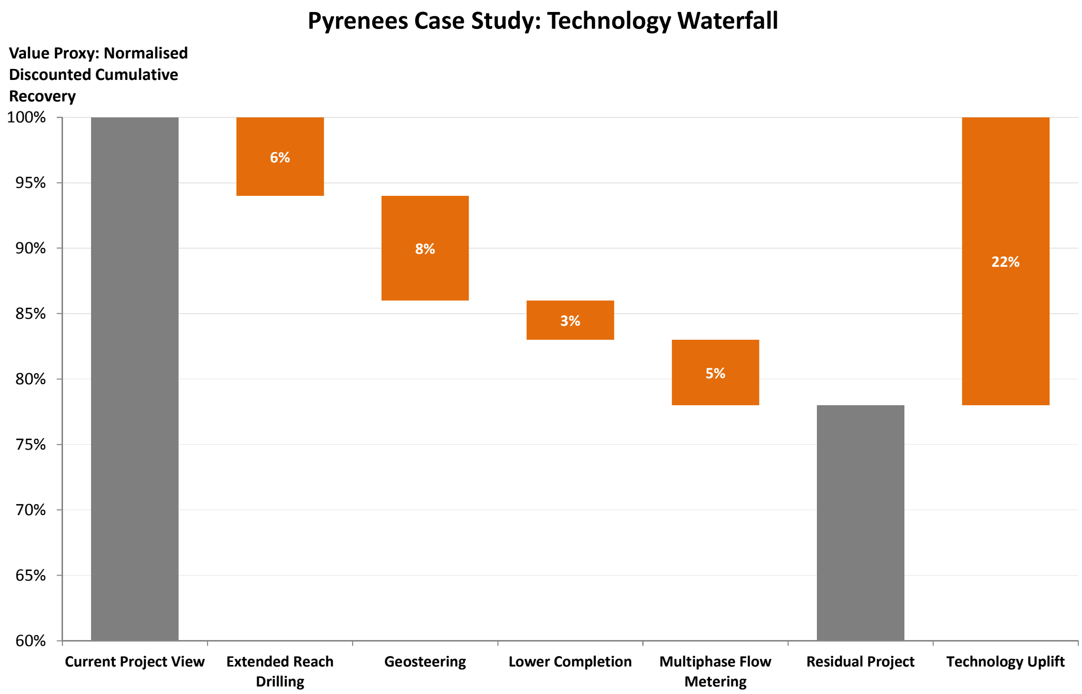


Figure 6. Pyrenees technology waterfall.

Geosteering

Given the relatively thin columns in the Pyrenees fields, the ability to accurately map and steer relative to the roof of the oil column was considered a key challenge. Application of Schlumberger's PeriScope tool, which had successfully been used in BHP Billiton's earlier Stybarrow development, was the main enabler in delivering wells 2–3 m from the top of the sand. Without the application of this technology, wellbore placement would likely have been much more conservative, with wells guided using seismic calibrated to the exploration and appraisal wells alone. Predrill, the top structure uncertainty was estimated between 6–10 m, which is significant where wells are targeting oil columns less than 30 m. Wells within the simulator were thus shifted down 5 m (7–8 m from top) to investigate the impact of suboptimal well placement. A drop in normalised project recovery of 8% was observed.

It should be noted that this is only one approach to gauging the benefits delivered by geosteering. An alternative would be to consider a more aggressive standoff from the roof, say 4–5 m, and be prepared to sidetrack as necessary if the overlying Muderong mudstone is encountered. The downside to this approach is that the sidetracking operation costs rig time, results in increased drilling risk, and introduces doglegs into the horizontal section, which limits the ability to run screens to bottom, thereby reducing effective wellbore length.

Lower completion

The lower completion design has played a key role in the development of the Pyrenees reservoirs, delivering the primary requirement of sandface stabilisation (sand exclusion). Additionally, the integration of ICDs allows for normalisation of inflow across the entire length of horizontal wellbore.

For the purposes of the exercise, the application of standalone screens for sand exclusion will be ignored, as it is considered the only viable methodology to deliver sand exclusion in horizontal wells of this length; without their implementation, the entire subsurface development concept would need to be revisited—hence a breakdown in this analysis.

The incorporation of ICDs into the lower completion has played an important role in the normalisation of inflow, leading to a more efficient recovery through the retardation of water and gas influx. While investigations by reservoir simulation show only minor incremental reserves between the with and without cases (~2%), benefit is seen during the early-time blowdown of the Ravensworth and Stickle gas caps (lower producing GOR), and the delay to water production—both for breakthrough timing and early rate of increase. These benefits correspond to an impact to a normalised project recovery of 3%.

Multiphase metering

Accurate production measurement is a fundamental requirement of effective reservoir management. The addition of a multiphase meter (MPFM) to each Pyrenees development well has delivered this requirement, both in terms of improved accuracy compared to traditional methods and through real-time monitoring. This technology was initially justified upon elimination of well test deferral due to suboptimal well lineups during testing (~5%), and real-time feedback on production network optimisation efforts including:

- optimisation of well cleanup duration;
- well gaslift optimisation; and,
- reduced engineering time for production allocation.

Experience post implementation has clearly validated this expectation (see Jackson et al, 2012), although in fairness significant engineering time has been spent during the commissioning phase and ongoing monitoring and management of meters. This time is considered well-justified given the quality of the information obtained. A number of additional benefits not originally recognised have also been subsequently identified, including:

- additional facets of production optimisation:
  a) identification of producing GOR dependence on drawdown during early gas constrained periods; and,
  b) a change in optimisation mode towards a well cycling strategy during recent gas lift constrained periods;
- justification of infill development; and,
- measurement and optimisation of downhole chemical injection to alleviate the effects of emulsion formation.

Early reservoir modelling was able to be calibrated through the application of high-confidence production data and used to identify and assess an infill opportunity. Offset well watercut behavior demonstrating clear flush production following a period of rest was also observable using the meters and significantly derisked the opportunity. The infill project was successfully executed and resulted in the addition of a well whose performance is equal to the initial development wells.

The formation of oil-water emulsions was anticipated given the biodegraded nature of the crude with allowances for this made in the separation train. The loss in productivity through the subsea system due to the accompanying increase in fluid viscosity, however, was much greater than expected. Detailed nodal analysis clearly demonstrated the increase in pressure drop as a function of water cut, and facilitated a relatively straightforward diagnosis. Key to this analysis was the high-confidence in the production rate allocation to the wells. Without the data provided by the MPFMs, it is less certain whether such a clear finding would have been possible.

The observation initiated a set of field trials of emulsion breaker chemicals that were successfully applied at subsea manifolds and reduced subsea flowline pressure drops by 1–2 bar, resulting in a production uplift of ~4%. Following the development of a careful test program, which included chemical qualification and reassessment of downhole scale inhibitor injection needs, downhole chemical injection lines were re-qualified for injection of the demulsifying agent. A reduction in tubing pressure drops of 15–20% were seen in target wells with accompanying increases in liquid production of 20–50%, and corresponding increases in oil production.

Ascribing value to the multiphase meters in terms of the normalised recovery metric is difficult. The meters themselves have not directly increased recovery, yet the data they have provided has been fundamental to the analyses that have. Additionally, much of the gain has been in terms of production optimisation and acceleration, the value of which is strongly impacted by the discount factor used and the time window considered. Based on the integration of the previous examples into the simulator, and drawing upon the authors' experiences to assign a dependency factor, an impact of 5% to normalised recovery has been determined.

SUMMARY AND CONCLUSIONS

The Exmouth Sub-basin has had an interesting and colourful exploration and development history thus far. Several unique surface and subsurface challenges, in combination with the depressed oil price environment, presented significant hurdles to resource development.

The tailored application of exploration and development technologies and cooperation between the regional operators have been key to unlocking the hydrocarbon potential of the Exmouth reservoirs. As remaining undeveloped potential continues to diminish in size, the smart application of technology becomes increasingly vital, both to maximise extraction and enhance project value. The Pyrenees example cited in this paper demonstrates the relative magnitude of increases in project value such applications can bring.

Over 300 MMbbls of oil has been recovered, with the basin delivering more than a third of Australia's crude oil production during the past several years. From humble beginnings where exploration potential was written off in the 1970s, the application of technology has transformed the Exmouth Sub-basin into Australia's premier crude oil province.

ACKNOWLEDGMENTS

The authors wish to thank BHP Billiton management and the APPEA Technical Program Committee for the opportunity to publish this paper. The authors would also like to thank co-workers within BHP Billiton, Joint Venture partners, and other operators in the basin for their valuable discussions and contributions during the past two decades, all of which have helped develop this challenging offshore region of Australia. The authors also thank the APPEA peer-reviewers for their comments.

REFERENCES

APPEA, 2014—Biannual production statistics, first half 2014. Published 28 October 2014. Accessed 27 January 2015. <http://www.appea.com.au/?attachment_id=5904>.

CHUNG, C., MARIAN, D., NAPALOWSKI, R. AND THOMSON, J., 2010—Dynamic well clean-up flow simulation for field start-up planning in the Pyrenees development, offshore Western Australia. SPE Asia Pacific Oil and Gas Conference and Exhibition, Brisbane, Queensland, 18–20 October, SPE 133838.

DUNCAN, G., HURREN, C., HILL, R., STANLEY, M., WOODWARD, J. AND LUMLEY, D., 2013—The Stybarrow Field – a 4D case study. ASEG/PESA, 23rd International Geophysical Conference and Exhibition, Melbourne, Victoria, 11–14 August.

DUNCAN, G., KOSTAS, K., FLOREZ, M., CAI, J., PERRETT, T., STEWART, J. AND KUZMIN, S., 2015—4D Seismic over the Pyrenees Fields. ASEG/PESA, 24th International Geophysical Conference and Exhibition, Perth, Western Australia, 15–18 February.

EMENTON, N., HILL, R., FLYNN, M., MOTTA, B. AND SINCLAIR, S., 2004—Stybarrow oil field – from seismic to production, the integrated story so far. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Western Australia, 18–20 October, SPE 88574.

GAVIOLI, P. AND VICARIO, R., 2010—The evolution of the role of openhole packers in advanced horizontal completions: from optional accessory to critical key of success. SPE Asia Pacific Oil and Gas Conference and Exhibition, Brisbane, Queensland, 18–20 October, SPE 132846.

HAMP, R., MEE, B., DUGGAN, T.J. AND BADA, I.A., 2008—Early reservoir management insights from the Enfield oil development, offshore Western Australia. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Western Australia, 20–22 October, SPE 116915.

HILL, R., O'HALLORAN, G., NAPALOWSKI, R., WANIGARATNE, B., ELLIOTT, A. AND JACKSON, M., 2008a—Development of the Stybarrow oilfield, Western Australia. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Western Australia, 20–22 October, SPE 115373.

HILL, R., O'HALLORAN, G., ELLIOTT, A., LOCKE, M., NAPALOWSKI, R. AND CROFT, M., 2008b—Development of a slope turbidite reservoir: a case history from the Stybarrow Field, Western Australia. GCSSEPM Foundation 28th Annual Bob F. Perkins Research Conference: Answering the Challenges of Production from Deepwater Reservoirs, vol. 28, 345–382.

HURREN, C., BROAD, C., DUNCAN, G., HILL, R. AND LUMLEY, D., 2012—Successful application of 4D seismic in the Stybarrow Field, Western Australia. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Western Australia, 22–24 October, SPE 158753.

HURREN, C., O'HALLORAN, G., DUNCAN, G. AND HILL, R., 2013—Detailed stratigraphic architecture of the Macedon Member turbidite reservoirs of the Stybarrow Field, NW Australia: an integration of well, production and 3D/4D seismic data. In: The Sedimentary Basins of Western Australia 4. Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, Western Australia, 18–21 August.

JACKSON, M., NAPALOWSKI, R., PARIS, N. AND MOKSNES, P.O., 2012—Operational experience with subsea multiphase flow meters in the Pyrenees development, offshore Western Australia. SPE Asia Pacific Oil & Gas Conference and Exhibition, Perth, Western Australia, 22–14 October, SPE 158518.

LAWRENCE, B., ZIMMERMAN, M., CUTHBERT, A. AND FIPKE, S., 2010—Multilateral wells reduce CAPEX of offshore, subsea development in Australia's Northwest Shelf. IADC/SPE Drilling Conference and Exhibition, New Orleans, Louisiana, 2–4 February, IADC/SPE 128314.

LIM, V., KEMP, H. AND SKINNER, G., 2012—New technological developments and methods for improving well placement in the Vincent Field, Australia. SPWLA 53rd Annual Logging Symposium, Cartagena, Columbia, 16–20 June, SPWLA 2012-132.

MCCARTHY, T.A. AND MICKELBURGH, I.J., 2010—The evolution of sand control practices for the Enfield deep water development. SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 10–12 February, SPE 12794.

MEDD, D., THOMAS, P., SIBBONS, C. AND SMITH, M., 2010—Integration of 4D seismic to add value: the Enfield ENC01 sidetrack story. SPE Asia Pacific Oil and Gas Conference and Exhibition, Brisbane, Queensland, 18–20 October, SPE 136538.

MITCHELMORE, L. AND SMITH, N.H., 1994—West Muiron discovery, WA155P, new life for an oil prospect. In: Purcell, P.G. and Purcell, R.R. (eds) The Sedimentary Basins of Western Australia, Proceedings of the Petroleum Exploration Society of Australia, 584–96.

MURRAY, A.P., DAWSON, D.A., CARRUTHERS, D. AND LARTER, S., 2013—Reservoir fluid property variation at the metre-scale: origin, impact and mapping in the Vincent oilfield, Exmouth Sub-basin. In: The Sedimentary Basins of Western Australia 4, Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, Western Australia, 18–21 August.

NALLIPOGU, T., OPPEDAL, J.H., MCKAY, L. AND GLUCINA, A., 2012—An operator's experience of the successful deployment of a subsea multiphase boosting system offshore Western Australia. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Western Australia, 22–24 October, SPE 160292.

NAPALOWSKI, R., HILL, R., STOMP, R., FAGERVIK, E., DERKACH, E. AND MANNING, D., 2008—Successful implementation of horizontal open-hole gravel packing in the Stybarrow Field development, offshore Western Australia. Paper revised in 2010 and published in March 2010. SPE Drilling & Completion, 25 (1), 123–36. SPE 116434.

NAPALOWSKI, R., LORO, R., ANDERSON, C., ANDRESEN, C., DALAGER, A. AND NYHAVN, F., 2012—Successful application of well inflow tracers for water breakthrough surveillance in the Pyrenees development, Offshore Western Australia. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Western Australia, 22–24 October, SPE 158423.

SCIBIORSKI, J.P., MICENKO, M. AND LOCKHART, D., 2005—Recent discoveries in the Pyrenees Member, Exmouth Sub-basin: a new oil play fairway. The APPEA Journal, 45 (1), 233–52.

SLATE, T., NAPALOWSKI, R., PASTOR, S., BLACK, K. AND, STOMP, R., 2010—The Pyrenees development: a new oil development for Western Australia. The APPEA Journal, 50, 241–52.

SMITH, G. AND GONGORA, A., 2012—The Vincent oilfield: development of a thin oil column by geosteering long horizontal wells. 74th EAGE Conference and Exhibition, Copenhagen, Denmark, 4–7 June.

SMITH, M., GERHARDT, A., BOURDON, L. AND MEE, B., 2007—Using 4D seismic data to understand production-related changes in Enfield, NWS Australia. ASEG Extended abstracts 2007: 19th Geophysical Conference. Crows Nest, New South Wales: Australian Society of Exploration Geophysicists.

SMITH, N., DEMPSEY, C., JACKSON, M. AND PRESTON, J., 2002—Overcoming historical biases – an integrated geological and engineering assessment of the Coniston prospect, Exmouth Sub-basin. In: Keep, M. and Moss, S.J. (eds) The Sedimentary Basins of Western Australia 3: Proceedings of the Petroleum Exploration Society of Australia, 687–706.

TINDALE, K., NEWELL, N., KEALL, J. AND SMITH, N., 1998—Structural evolution and charge history of the Exmouth Sub-basin, Northern Carnarvon Basin, Western Australia. In: Purcell, P.G. and Purcell, R.R. (eds) The Sedimentary Basins of Western Australia 2, Proceedings of the Petroleum Exploration Society of Australia, 447–72.

WHITE, A., STREIT, J., NAPALOWSKI, R. AND Hill, R., 2006—Fault seal stability risk assessments during field development planning. GeoAsia Conference, Kuala Lumpur, Malaysia, 12–14 June.

WOODALL, M., KOSTAS, K., HAYNES, E., SKINNER, G., VIANDANTE, M. AND PONTARELLI, L., 2014—The role of geosteering in the development of the Pyrenees Fields. The APPEA Conference and Exhibition, Perth, Western Australia, 7–9 April. Extended abstract.

WULFF, A.M., GERHARDT, A., RIDSDILL-SMITH, T. AND SMITH, M., 2007—The role of rock physics modelling for the Enfield 4D seismic. ASEG, Perth, Australia.

ZOIS, N., 2014—Macedon Project. The APPEA Conference and Exhibition, Perth, Western Australia, 7–9 April. Plenary Session: Project Updates.

Authors' biographies next page.

THE AUTHORS

Richard Loro graduated from The University of Queensland in 2000 with a BEng (Hons) in chemical engineering before joining Santos as a graduate engineer.

During his 15 years of experience, Richard has enjoyed various assignments across the production and reservoir engineering spaces, contributing to projects in Australia and West Africa.

He joined BHP Billiton in 2010 and is presently the Reservoir Engineering Supervisor for BHP Billiton's Australian Production Unit in Perth. Member: Society of Petroleum Engineers (SPE).

richard.loro@bhpbilliton.com

Mark Jackson received a BEng (Hons) in electrical engineering from the University of New South Wales in 1980 before joining Schlumberger wireline with assignments in the UK North Sea, Spain and Australia. He later received a MEng (Dist) in petroleum engineering from Heriot-Watt University in 1993.

Mark has more than 30 years of petroleum engineering experience encompassing exploration, development and production phases. He is a Chartered Engineer with Engineers Australia, and is presently Production Engineering Supervisor for BHP Billiton's Australian Production Unit in Perth. Member: SPE.

mark.jackson@bhpbilliton.com

Robin Hill received a BSc (Hons) in geology from Kingston Polytechnic in 1980. During the past 34 years he has worked for a variety of companies on new ventures, exploration, development and production projects in numerous basins across Europe, North Africa, the Middle East, North America and Australasia.

He is a Chartered Geologist with The Geological Society, and is presently Geoscience Manager at BHP Billiton Petroleum in Perth. Member: American Association of Petroleum Geologists (AAPG), SPE, Petroleum Exploration Society of Australia (PESA), and Petroleum Exploration Society of Great Britain (PESGB).

robin.hill@bhpbilliton.com

Tony Slate graduated from RMIT University Melbourne in 1981 with a BSc in applied geology before joining SADMP in 1981. He joined BHP in 1984 and worked as an exploration geologist and later as a development geologist on BHP Billiton's operated developments in offshore Carnarvon, Timor Sea and Bonaparte basins, in addition to operated onshore developments in Victoria, Vietnam and Pakistan. He is Subsurface Manager for the Australian Production Unit in Perth. Member: PESA and SPE.

tony.v.slate@bhpbilliton.com

THIS PAGE LEFT BLANK INTENTIONALLY.