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BP GETS GO-AHEAD FOR *MAD DOG 2* SEMI

From Houston (BN): BP's new plan for the expansion of the *Mad Dog* (SEN, 31/19) development in the Gulf of Mexico features a 140,000b/d semi-submersible floating production platform.

Plans for *Mad Dog 2*, approved by the US Bureau of Ocean Energy Management, place the new facility in 1,353m in Green Canyon 780, two blocks west of the existing *Mad Dog* spar. Not yet named, the facility also will be capable of providing 280,000bw/d of low-salinity (LoSal) water flooding.

Back to the drawing board

In 2012, BP and its partners, BHP Billiton and Chevron, planned a second spar for *Mad Dog 2*, but hit the pause button in early 2013 citing high costs. Since then, the partners have reiterated their commitment to Mad Dog 2, but searched for a more economical approach.

The new plan calls for 29 subsea wells, including 17 producers and 12 water injectors. There will be five drill centers in GC825 and 870 with bottom-hole locations spread across six blocks - GC781, 824, 825, 826, 869 and 870.

Installation of the new platform is targeted for 2020, three years later than first oil in the earlier plan. Documents filed with BOEM indicate drilling could commence as early as next month and continue beyond 2025. Each well requires a separate permit prior to spudding and filing and approval of a development does not constitute a final investment decision.

The new plan, filed last August and approved 5 March, calls for 61km of infield flowlines, 84km of umbilicals as well as other related subsea infrastructure, with export through 37km of pipelines linked to the Mardi Gras system.

BP operates (60.5%) for BHP (23.9%) and Chevron (15.6%).

WHAT'S INSIDE

DEVELOPMENTS

BP PUSHES ON WITH DEEPWATER EGYPTIAN GAS

BP and partner RWE Dea have finalised agreements for the $12bn *West Nile Delta* (SEN, 31/19) project, offshore Egypt, which will cover development of 140bcm and 55mmbbls of condensate.

Production will be from two BP-operated offshore blocks, North Alexandria (NA) and West Mediterranean Deepwater (WMD).

The *Taurus* and *Libra* fields in the North Alexandria concession will be a subsea development tied back some 35km to the existing BG Group operated Burullus West *Delta Deep* facilities.

The *Giza*, *Fayoum* and *Raven* fields in WMD, meanwhile, will be two circa 70km deepwater subsea-to-shore tiebacks to the existing Rosetta plant, which will be modified for *Giza/Fayoum* and integrated with a new adjacent onshore plant for Raven. Field infrastructure will include new 24in gas lines, new 6in MEG lines as well as new umbilicals.

Production from *WND* is expected to reach up to 34mcm/d, equivalent to about 25% of Egypt's current gas production. The fields are in 400-700m and a total of 21 wells will be drilled in the initial phase.

BP believes that there is the potential through future exploration to add a further 140-200bcm which could boost WND production with additional investments.

At the same time, BP has also confirmed a new discovery in the North Damietta Offshore Concession in the East Nile Delta.

The *Atoll-1* well, which is being drilled with the semi *Maersk Discoverer*, reached 6,400m depth and hit approximately 50m of gas pay in high quality Oligocene sandstones.

Expected to be the deepest well ever drilled in Egypt, the Atoll well still has another 1km to drill to test the same reservoir section found to be gas bearing in BP's 2013 Salamat discovery, 15km to the south. It is located 45km to the north west of the Temsah offshore facilities.

Atoll-1 was drilled in 923m water depth and BP has 100% equity in the discovery.

GOM DEEPWATER IS HOLDING UP - FOR NOW

From Houston (BN): The deepwater Gulf of Mexico is resisting the sharp slowdown that the US onshore shale plays are experiencing due to lower world oil prices, according to a new Wood Mackenzie report.

Capital spending is increasing in 2015 for the fifth year in a row to $14.9bn with some of the world's most advanced drilling rigs working at near-record rates.

The reason, in a word, is momentum. A lot of projects were already under development when prices started slumping in June 2014. Much work was already done and significant cost already sunk. So capex is much lower than for projects not yet sanctioned.

For example, break-even of $10-$50/bbbl for Lucius (SEN, 31/23), *Jack-St Malo* (31/20) and *Tubular Bells* (31/20), which started up in the last six months. In the deepwater GoM, the size of the reservoirs (200mmbbls or more) and the longevity of fields (typically 30-40 years) can make even marginal costs tolerable if there is a long-term expectation of a higher oil price.

On the other hand, WoodMac analysts warned, some pre-FID projects have breakevens as high as $60-$80/bbbl and if the oil price slump persists, the deepwater Gulf could go into a deep freeze.

That is particularly true of the technically challenging Lower Tertiary. In that area, WoodMac sees breakevens as high as $70-$80/bbl for Kaskida (31/19), North Platte (30/21), Shenandoah (31/23) and Tiber (31/22).

Meanwhile, celebrate the six big projects plus several smaller ones that are coming onstream this year, raising deepwater output 23% to 1.6mmb/d.

ABB NABS FIRST PFS CONTRACT FOR *SVERDRUP*

From the North Sea (NT): Statoil has awarded ABB a NOK1.1bn ($140mn) contract to supply part of the power from shore (PFS) system for the first phase of the Johan Sverdrup (SEN, 31/22) development.

ABB, which earlier performed technical and conceptual studies for the system, will deliver electrical equipment for a converter station to be installed at the Kårstø gas terminal and a power module to be located on the riser platform. AC power from the national grid will be transformed to DC on land, transmitted to the field by a 200km HVDC cable and converted back to AC in the module.

Two further packages worth a combined NOK2bn are out to bid, industry sources tell SEN: for the subsea cable and installation, and for the onshore substation. The total cost of the phase one PFS system is estimated at some NOK6bn.

In the first stage, due onstream in late 2019, some 112-113MW will be drawn from the grid to ensure the delivery of 100MW to the field after transmission losses. ABB's contract also includes preparations for the second stage which is scheduled to come into operation in 2022. This will involve a substantial expansion of the system - to 250-300MW, to serve three other fields in the Utsira High area – Lundin's Edvard Grieg, Det norske oljeselskap's Ivar Aasen and Statoil's Gina Krog.

Meanwhile the failure of licensees to agree on unitisation of the four licences on which Sverdrup lies - Detnor has refused to accept the division proposed by its four partners - has caused a headache for Norway's Oil & Energy ministry.

However it has found a handy solution - pass the problem to the Norwegian Petroleum Directorate. NPD has been asked to check licensees' work on in-place reserves and assess the geological conditions in the different licences which might affect recovery rates. This is presumably part of the reason for the disagreement.

NPD is due to report back by 9 June in order that the Storting (legislature) can still approve the NOK117bn development plan by the end of the spring session.

DEVELOPMENT BRIEFS

OneSubsea has delivered the industry's first ever subsea wet gas compressor (wgc) to Statoil for installation this summer on the **GULLFAKS SOUTH** (SEN, 31/21) field.

While this is actually the third subsea compressor ordered - *Ormen Lange* and *Åsgard* came first - it will be the first installed and should be ready for operations by the end of the year.

Like the *Tordis* subsea separation system before it, the *Gullfaks South* wgc has been trumpeted by Statoil as a 'commercial' enterprise, ie it will recover more reserves (22mmboe) than it cost.

Similar industry 'firsts' have often found themselves quickly superceded by even newer technology. Here OneSubsea believes it is out on its own with a technology that will take some time to be matched by its competitors.

Of course, Framo Engineering, subsumed into OneSubsea at the time of the latter's formation, first developed this technology more than a decade ago, but the prototype sat on a dock outside Bergen for years before someone was brave enough to order one. Who else but Statoil?

The current unit, very compact with a design that eliminates many process hardware add-ons (eg scrubbers and coalescers), has been extensively tested for over six months before being delivered to Statoil.

One would hope that this unit, unlike the *Tordis* and *Troll Pilot* seabed processing units, will not suffer some early equipment or operational failure. Fingers crossed!

From Australia (RW): The semi drilling unit *Atwood Osprey* has been assessed to have sustained minimal damage after it drifted from its spud location during Cyclone Olwyn off Western Australia last week.

The rig, contracted to Chevron Australia, was on working on the **IAGO-1B** well, when it broke free from its moorings and drifted about three nautical miles.

The well had previously been shut-in and secured, the rig ballasted down and all personnel evacuated in advance of the cyclone. No people were injured during the alert. It is expected that the semi will be out of service for a month for repairs.

From the North Sea (NT): Production on Lundin Norge's **BRYNHILD** (31/22) field was halted in mid-January, less than a month after it came onstream, due to operational issues on Bluewater's *Haewene Brim* fpso in the UK sector where it is tied back.

A leak was detected in a gas injection flexible flowline and a connection point between one of the mooring chains and the riser buoy was found to be damaged.

Lundin reported in early March that following repairs production had resumed. The jackup *Maersk Guardian* is currently drilling and completing the third and fourth wells.

Gas in the eastern Mediterranean continues to be problematic for suppliers and buyers alike.

The **TAMAR** (31/20) field partners in Israel have now concluded a sales agreement to supply 5bcm over three years to Egyptian buyer Dolphinus. On the other hand, almost the same grouping has had to cancel a deal to sell gas to the Palestine Power Generation Co from the upcoming **LEVIATHAN** (31/20) field as a result of a delay in sanctioning the project because of a negative competition ruling by the Antitrust Authorities in Israel.

Across the waters in Cyprus, Noble Energy, the big player in Israeli gas, looks set up declare the 125bcm **APHRODITE** (31/17) find commercial. Total is reportedly looking to extend its interests off the island as well.

From the North Sea (NT): Statoil's NOK4.6bn ($580mn) **RUTIL** (31/21) 'fast-track' subsea development has been approved by Norway's Oil & Energy Ministry.

Two subsea wells will be drilled through a four-slot template and tied back to the *Gullfaks* A platform via existing infrastructure. A 9.5km pipe-in-pipe system with a 13% chrome inner pipe is due to be laid by Technip next year. FMC will supply the subsea production hardware and Nexans the umbilical, while Agility Group will implement platform modifications.

Due onstream in early 2017, *Rutil's* 11.1bcm of gas and 5mmbbl of condensate will contribute to prolonging operations on *Gullfaks* A, the company says. Discovered in 2011, the field lies in Rimfaks Valley in the *Gullfaks* South area.

From Australia (RW): Sunbird Energy has signed a sales agreement to supply gas from its **IBHUBESI** (31/13)

EXPLORATION

STATOIL CONTINUES TO DRAW BLANKS IN THE GOM

From Houston (BN): Statoil faces another exploration disappointment in the deep waters of the Gulf of Mexico.

The *Perseus* well in Desoto Canyon 231 has been plugged and abandoned as a dry hole. It was drilled to a total depth of 7,036m in 1,401m. It targeted a Norphlet prospect.

Last year, Statoil's *Martin* well in 890m in Mississippi Canyon 718 found a small amount of Miocene hydrocarbons after hitting total depth of 9,570m, but was deemed non-commercial. The semi *Maersk Developer* which was used to drill the two duff wells has moved on to its next assignment, spudding the *Yeti* prospect in 1,800m in Walker Ridge 160.

Shell has won approval to explore its *Deep Sleep* prospect in Atwater Valley 18-19. BHP drilled a well, dubbed *Gnome*, in AT18 in 2001 without success. Shell plans to drill one well this year and, depending on the outcome, six other wells at the rate of one a year through 2021. The wells are expected to take 200 days each and involve water depths ranging from 1,280m to 1,350m.

Eni has received a green light to expand its *Allegheny* field by drilling, completing and producing a new well. The plan requires installation of a 3.8km 6in pipeline and a 5.2km umbilical. Work was expected to begin in February, but the plan was not approved until this month and no rig was yet reported on site last week in Green Canyon 298.

Anadarko has been given the okay to explore its *Warrior* prospect in Green Canyon 519 and 563. The plan calls for drilling 20 wells over the next 10 years, starting in May. Each well is expected to take 210 days. Water depths are from 1,250 to 1,283m.

Regulators also have cleared Anadarko's plan to drill three 190-day wells in Walker Ridge 51, next door to the *Shenandoah* discovery in WR52. The schedule hints at a deliberate development pace, one well to be drilled this year, a second in 2017 and a third in 2019.

GOM SALE CONFIRMS ONGOING FAITH IN DEEPER WATERS

From Houston (BN): Tracts around *Chevron's Anchor* (SEN, 31/22) discovery and Shell's *Vito* (31/22) and Anadarko's *Shenandoah* (31/22) developments attracted the biggest dollars in Central Gulf of Mexico Lease Sale 235.

The auction was otherwise lacklustre, pulling in just $539mn in total bids compared to the billions exposed in other recent CGOM sales, a demonstration of the current uncertainty.

Chevron led the way near *Anchor*, its Lower Tertiary find announced in January in Green Canyon 807. A Chevron-Venari partnership (75%-25%) offered top bids totaling $100mn for GC673, 717-718, 726, 759-761, and 804. Chevron subsidiary Union also partnered with Venari to offer apparent winners for GC720 ($26.3mn) and GC719 ($2.2mn).

Ten blocks north of *Anchor*, ExxonMobil tendered a high bid of $33mn for GC364, but lost out to Marathon ($5.6mn to $3mn) for GC320 just to the north.

Shell's subsalt Miocene discoveries at *Vito* (Mississippi Canyon 983) and *Power Nap* (MC942) stirred interest along the MC-Atwater Valley border. Shell which plans to drill *Deep Sleep* in AT18-19 just south of *Vito* bid $9.7mn for MC896.

A few blocks to the southeast, PXP Offshore bid $38.9mn for AT153, which also is near Freeport McMoRan's *Sun* prospect in AT198. Other investors in the area were Hess, which bid $3.3mn for AT152 and $1.5mn for AT108, and a grouping of Ridgewood, Red Willow and LLOG, which bid $16.7mn for MC769. To the west of Vito, Ecopetrol and Murphy put up $16mn for MC977.

There was an eyebrow-raising development involving tracts near the big *Shenandoah* find. Anadarko and Venari teamed to submit $8.3mn in high bids for Walker Ridge 98, 99 and 143 that, just a few months ago, they retunred to the government,.

The tracts are the site of Chevron's 2013 *Coronado* discovery, which the company bragged about as continuing Lower Tertiary success, then abruptly sold last year. Then remaining partners ConocoPhillips, Anadarko and Venari terminated the leases last November.

None of the companies commented publicly except COP, which said in an earnings call that the first appraisal well was disappointing. Obviously there is something interesting there that brought Anadarko and Venari back.

Not far from *Shenandoah*, Statoil and Samson teamed to win WR227 ($28.2mn) and WR315 ($12mn). Statoil said the leases would complete ownership of the *Monument* prospect, for which no exploration plan has been filed yet. The two acquired the lease in between, WR271, in 2013. To the east, Red Willow and Houston Energy laid out $52mn – the highest bid in the sale - for WR107. That tract is in Miocene-Lower Tertiary overlap country, halfway between *Shenandoah* and *Chevron's Big* Foot in WR29.

Overall, one has to go back a decade to find fewer total bids at a CGoM sale. Comparison with the last Central Gulf auction (Sale 231 in March 2014): 42 participating companies (50); 195 bids (380); 169 tracts bid on (326). And yet, 64 of the bids in Sale 235 were in waters 1,600m or deeper (compared with 108 in Sale 231), a sign of long-term interest in deep water.

Other notes: Shell had the most high bids, 17; Chevron exposed the most money, $78.6mn; and Statoil had 14 high bids for $51.4mn.

EXPLORATION NOTES

From Houston (BN): Petrobras set a Brazilian record for **WATER DEPTH**, drilling an exploration well in 2,990m in the Moita Bonita area of the Sergipe-Alagoas Basin, 92km offshore of Aracaju. The area appears promising. A 2012 drillstem test confirmed light, high quality crude and good productivity. Petrobras has drilled eight wells in the region in waters of more than 2,700m.

Analysis of seismic data from the **SILVERBACK** prospect in the South Celtic Sea off the south coast of Ireland has Providence Resources all excited.

Seismic interpretation confirms the prospect to be a large Lower Triassic structural closure, similar to major hydrocarbon accumulations proven at the *Wytch Farm, Morecambe Bay* and *Corrib* (31/15) fields.

Providence says it is encouraged about the quality of the oil prone source rocks within the Lower Jurassic interval and has applied for a 12-month extension to its licence to allow for further assessment.

John O'Sullivan, technical director, said, 'Once we have completed this study, we plan to commence farm-out discussions with potential co-venture partners to progress the *Silverback* prospect to drilling.'

Meanwhile, Searcher Seismic has begun the acquisition of the Echidna Regional Broadband 2D seismic survey.

Comprising of approximately 9,000 km of high quality, long-offset broadband 2D seismic data, the survey will be the first comprehensive well-tie survey covering the Atlantic Margin off western Ireland.

The survey includes well-ties to over 30 exploration wells and recent drilling results have indicated oil potential in the area.

From Houston (BN): Schlumberger has completed acquiring 2,750km2 of full-azimuth seismic over the Garden Banks and Green Canyon areas of the **GULF OF MEXICO.**

After processing, the surveys will provide high-density broadband data for multiple clients to use in operational decision-making. The work combines WesternGeco Dual Coil Shooting multi-vessel full-azimuth acquisition with ObliQ broadband acquisition and imaging technology to enhance views of subsalt prospects. The campaign is part of Revolution X and Revolution XI, which will provide 3,800km2 of data for suprasalt targets as well as 2,940km2 of data for subsalt prospects, including the deeper subsalt Miocene and Wilcox (Lower Tertiary) prospects.

GDF Suez has made a new discovery in the UK Central North Sea with the **DALZIEL** (31/5) find. The 22/16-6 well flowed at rates in excess of 8,000boe/d. The well, drilled by the jackup *Transocean Galaxy II*, is now being sidetracked to appraise this discovery.

Eni has completed post drilling studies on the **MERAKES-1** gas discovery in the deepwater East Sepinggan Block, off Indonesia, which have boosted the potential of *Merakes* by 50% to 57bcm.

The well was drilled in October 2014 in 1,372m, encountering a 60m section of high quality sandstones. The East Sepinggan block is located offshore East Kalimantan, 170km south of the Bontang LNG plant.

Eni will bring forward the appraisal programme to evaluate the possible 'fast track' development of the find with its nearby (35km) *Jangkrik* (31/6) field.

Eni has also made what it calls a 'significant' gas and condensate discovery in the **BAHR ESSALAM SOUTH** exploration prospect in Area D offshore Libya.

The find was made 22km from the producing *Bahr Essalam* field and will be tied back to the infrastructure there.

The discovery was made through the B1-16/4 well, drilled at a water depth of 150m, which encountered gas and condensates in the Metlaoui Formation of Eocene age.

Eni has three drilling rigs operating in Area D to explore and delineate discoveries there.

Eni started production in 2004 from the area D fields of *Wafa* and *Bahr Essalam*, which supply gas to domestic markets and Italy via the *Greenstream* pipeline. The fields also yield high percentages of associated liquids.

From the North Sea (NT): Statoil's discovery of gas at **SNEFRID NORTH** is a valuable contribution to the *Aasta Hansteen* (31/19) development, increasing the resource base by some 15%.

The well, 6706/12-2, drilled by the semi *Transocean Spitsbergen* in a water depth of 1,312m, found reserves provisionally estimated at 5-9bcm. The company has described Hansteen's 46.5bcm as marginal. The field will be the northernmost development in the Norwegian Sea when it comes onstream in 2017 through the world's largest spar platform.

Snefrid North lies 6km west of *Hansteen* and is expected to be developed as a subsea tieback. This week the semi *Transocean Spitsbergen* spudded the Roald Rygg wildcat 6706/12-3, 16km west of Hansteen.

FLOATERS

FIRE SHUTS DOWN *KNARR* FPSO

From the North Sea (NT): Production from BG Group's *Knarr* (SEN, 31/18) field in Norway only started last week, but in the early hours of Tuesday morning it was halted when a fire broke out in a technical room.

The field came onstream 10 months behind the original schedule and four months after the *Petrojarl Knarr* fpso was installed on the field.

The newbuild Teekay vessel, which has 63,000b/d processing capacity and 800,000bbl storage, is on a firm six-year lease with options. With reserves of some 80mmboe, the field in Norwegian North Sea block 34/3 is expected to continue producing for at least 10 years.

The production ship was built by Samsung; infield pipelay and subsea construction, including provision of a pipeline bundle, was performed by Subsea 7; subsea production equipment for six wells was supplied by FMC and the semi *Transocean Searcher* drilled the wells.

Teekay is responsible for oil lifting and gas is exported to the *FLAGS* system in the UK via a 100km line laid by Allseas layship *Audacia*.

According to government figures released last October, capex for the project, at NOK 16.2bn ($2bn), was running 36% over the PDO budget, mainly due to fpso design changes and increased equipment prices, including the subsea facilities.

The search for additional reserves has proved disappointing so far. The 2010 Blåbær discovery in 34/5 is considered unlikely to be developed and a recent well on *Jordbær Southeast* in the *Knarr* block found only shows. An exploration well is ongoing on *Jordbær South*.

QUESTIONS TO FOLLOW AFTER *P-58* SHUTDOWN

From Houston (BN): The smell of desperation emanates from Petrobras' recent shutdown of its *P-58* fpso, which started up in the *Parque das Baleias* complex early last year.

Despite already being in operation, Petrobras says it is still 'in commissioning', another way of saying 'unfinished.' At the request of workers unions, Brazil's energy regulator ANP sent inspectors aboard. Shutdown of production, reportedly 106,000b/d at the time, followed on 19 March. The vessel's design capacity is 180,000b/d.

In public statements, the workers unions - FUP and Sindipetro-ES - cited unstable cranes, multiple equipment leaks and poor lighting as major hazards.

A Petrobras spokeswoman said the 'temporary' shutdown was 'necessary to carry out preventive maintenance and improve the operational efficiency of some systems, in compliance with the prevailing safety standards and guidelines.'

She pointed out that P-58 has operated since March 17, 2014, with 'no process accidents leading to stoppages... and no events resulting in environmental impacts.'

But regulators' sensitivity to risk has risen since an 11 February explosion aboard fpso *Cidade de Mateus* (31/23) killed nine workers and injured a number of others.

...now the good news

The P*etrobras 61*, Brazil's first tension leg platform started operation on the Papa Terra (31/8) field in the southern Campos Basin.

P-61 joins the *P-63* fpso, which has been in operation on the field since late 2013. Thirteen dry-tree production wells will be connected to *P-61* in addition to the five subsea producers already linked to *P-63*.

The heavy oil field (APIo14-to-17) requires water injection, heated flowlines and subsea centrifugal pumps making this one of the most complex so far developed by Petrobras.

P-61 is linked to a tender assist drilling platform equipped with a drilling and completion rig. With a processing capacity of 140,000b/d, 1mcm/d and 340,000bw/d for injection, this is also Brazil's first deepwater dry-tree facility. Shuttle tankers transport oil from the field. Excess gas is reinjected into a nearby reservoir. *Papa Terra* is operated by Petrobras (62.5%) for Chevron (37.5%).

Early production began from the *Buzios* field in the Santos pre-salt Transfer of Rights area using the fpso Dynamic Producer.

Output will be limited to 15,000b/d for six months as Petrobras prepares to use the *P-74* fpso currently in conversion at a Rio de Janeiro shipyard. Petrobras did not say what the ultimate production target is.

Petrobras also announced a new pre-salt production record in February, 737,000 b/d, from its own and partnered projects in the Santos and Campos basin pre-salt plays.

STATOIL HITS THE BRAKES HARDER ON FLOATER PROJECTS

From the North Sea (NT): Statoil and its partners in the *Johan Castberg* (SEN, 31/23) and *Snorre* (31/23) licences have decided to give themselves a further year to prepare field development plans.

The collapse in the oil price since mid 2014 has added to existing pressures to find sound and robust solutions for both fields.

In the case of *Castberg* in the Barents Sea, the decision to continue with a project – DG2 – has been postponed from mid 2015 to the second half of 2106, with an investment decision expected to follow in 2017.

The search for a viable plan has already undergone two 12-month delays. Significant cost reductions have been achieved, but the licensees see the potential for more, Statoil says. It confirms that the option of an onshore oil terminal serving multiple fields remains under study by a group of operators which also includes Eni, Lundin and ÖMV.

In the case of the further development of *Snorre* to maintain production through 2040, the decision to continue, which had already been pushed back from March to next October, is now scheduled for late 2016 with a final investment decision following in late 2017 and start-up pushed back by a year to late 2022.

While *Snorre* is one of Norway's biggest fields with the largest remaining reserves, the subsurface is complex, and more time is needed to reduce costs and improve reservoir understanding, Statoil says.

Reserves currently stand at 1.63bbbl, up from 760mmbbl in 1989 when the original development permission was initially sought, while recovery has improved from 25% to an expected 47%. By installing a large wellhead tlp, the licensees aim to lift this recovery rate even higher.

TIMOR LESTE OFFERS TO BUY OUT *SUNRISE* PARTNERS

From Australia (RW): The government of Timor Lesté wants gas from the *Greater Sunrise* (SEN, 31/23) fields in the Timor Gap processed onshore and is willing to buy out operator Woodside Petroleum and any other partner who wants to sell.

Speaking at a conference in Perth, Petroleum Minister Alfredo Pires suggested that if one or more of the partners wanted to vacate the project, Timore Lesté's $17bn petroleum fund would buy into the project if it would help to get the development up and running.

He said Timor Gap E&P – the national petroleum company – or a third party could then develop the resources 'if Woodside finds it too hard to handle'. Pires did admit, however, that to his knowledge Woodside is not thinking of selling.

The minister said his country was keen to become more involved with *Sunrise* directly, or fund infrastructure such as the proposed pipeline to a location at Bea on the country's south coast rather than seeing it built with 'unproven' floating LNG technology being advocated by the partners.

He said Timor Gap E&P has completed its own FEED and marine facility studies with the help of Norwegian firms and believes Timor Lesté could make a good return on its investment.

Pires said that there was some indication that the preliminary figures given by Woodside – $19bn for a pipeline to Timor Lesté, $15bn for a pipeline to Darwin and $12bn for an FLNG facility – are over-estimated. Consequently, the government sought to verify the figures.

He added that no serious consideration was taken on the Timor Lesté option to test the pipeline crossing of the 3,000m deep Timor Trench. His government has spent $20mn double-checking the *Sunrise* JV's figures including $6mn to map the seafloor for the first time. He said the claims of an impassable trench making the pipeline option to Timor unviable were overstated.

Pires said the Timor pipeline would cost $800mn, whereas the Darwin option would cost $1.8bn. German company Europipe has said the Timor line was not outside the technological envelope.

It was also suggested that FLNG vessels were targets for terrorists, hinting that the pipeline option to Timor is a much safer option.

FLOATER BRIEFS

From Houston (BN): A fleet of nine tugs moved Chevron's **BIG FOOT** (SEN, 31/20) tension leg platform out of Kiewit's Ingleside TX yard on Corpus Christi Bay and into the Gulf of Mexico early on 14 March.

The pre-dawn sail-out took 11 hours to cover the 21km to open water and, announced on local maritime radio by the Coast Guard, it attracted a photo-snapping crowd along the Port Aransas jetties.

The platform – 30 stories tall, 90m square and alive with red and white lights twinkling against the darkness – loomed over Port Aransas like an alien space ship.

Chevron said *Big Foot* would take eight or 10 days to reach its already prepared mooring location in 1,600m in Walker Ridge 29, about 360km south of New Orleans.

First oil from the $5bn project is expected by the end of the year. The dry-tree extended tlp has a drilling rig and capacity to handle up to 75,000b/d and 0.7mcm/d.

Chevron operates (60%) for Statoil (27.5%) and Marubeni (12.5%).

From the North Sea (NT): Nexen has extended the lease on Bluewater's *Aoka Mizu* fpso, which produces the **ETTRICK** (30/19) field and its **BLACKBIRD** (30/19) satellite in the UK Central North Sea, beyond March 2016, partner Atlantic Petroleum reports.

At that time, the dayrate will be reduced, which together with other cost-saving initiatives will extend the economic life of the two fields, Atlantic comments. Over the last three years, *Aoka Mizu*u has been one of the best performing fpso's in the North Sea in production efficiency and HSE metrics, it adds.

When it came onstream in 2009, *Ettrick* was expected to remain in production for seven years, although the firm period of the lease was initially just five years.

EnQuest is making progress on its UK North Sea **KRAKEN** (31/14) fpso development with the

workscope this year including installation of the manifolds for the first drill centre which connect to the templates already installed.

Two templates for the second drill centre and the mooring system for the fpso will also be installed. Development drilling will also begin in the second half of the year.

Work on the fpso also continues, with installation of the turret infrastructure by the end of this month. First oil is anticipated in 2017.

Meanwhile, **ALMA/GALIA** (31/20) is on course for first oil by mid-year, with five wells now available to come onstream. Drilling on the *Galia* production well is to be completed and tied in in the latter part of the year.

EnQ also plans submission of an FDP is anticipated this year for the development of **SCOLTY/CRATHES** (31/17).

In 2015, capex on current projects is due to be about $600mn, including around $350mn for *Kraken* and about $100mn for *Alma/Galia*.

Average production guidance for 2015 is between 33,000-36,000boe/d.

GE Oil & Gas and Oceaneering have scooped contracts from Eni for its deepwater **OFFSHORE CAPE THREE POINTS** (31/23) fpso project off Ghana.

The subsea production system will be delivered by a GE/Oceaneering consortium and includes the subsea production and control system (SPS) and umbilicals' engineering, as well as project management, fabrication, transport and testing.

Oceaneering's $100mn scope is for supply of 51km of electro-hydraulic, steel tube umbilicals which will be manufactured in Panama City, Florida. Work is expected to begin in the second quarter of 2015 and be completed in the fourth quarter of 2017.

GEOG's $850mn contract includes supplying turbomachinery for the production ship.

The OCTP block is located in offshore Ghana at a water depth of 500-1,100m, 60km from the coast.

The Chinese National Offshore Oil Corp is working on the design of a 2mt/a **FLOATING LNG** vessel with initial work on liquefaction technology complete...**SBM OFFSHORE** has signed a memorandum of understanding with authorities in Brazil setting out a framework for a settlement of possible illegal activities in the country...Lankhorst Mouldings is supplying VIV suppression strakes as well as moorning ropes for Statoil's **AASTA HANSTEEN** (31/19) spar...SOFEC is providing an external turret for the fso for Hess' **NORTH MALAY** BASIN development, offshore Malaysia...FES has delivered diverless bend stiffener connectors to Oceaneering for umbilicals supplied to ExxonMobil for **KIZOMBA SATELLITES PHASE 2**, offshore Angola...Balmoral Offshore Engineering has supplied the buoyancy modules and mounting system for Dana's **WESTERN ISLES** (31/18) development in UK waters...Triyards in Singapore is fabricating the external turret for the Brazilian LIBRA (31/x) field extended well test fpso under a sub-contract from London Marine Consultants...BW Offshore has sold the vlcc **BW OPAL** to its parent group for $85.5mn.

CONFERENCE REPORT

BIG PROJECTS AND BUZZ WORDS HEARD AT DEEPWATER EVENT

From London (MT): The usual crop of buzz words and catchphrases came to the fore at the MCE Deepwater Development event in London this week, but there was substance to back up the rhetoric.

Sitting through sessions where 'collaboration', 'standardisation' and 'driving value' made frequent appearances, as at the recent Subsea Expo in Aberdeen, what was apparent was that those using these words were experienced hands who have been through these oil industry cycles and come out the wiser. So their words carry weight.

Paul Hillegeist of organiser Quest Offshore Resources gave a quick overview of the current subsea and offshore market. The key challenge for the industry, he said, is to 'maximise the value of every barrel of oil equivalent'. He flagged up the economics of deepwater projects as an area of major concern. This includes the cost of fps topsides, which have been driving up floater costs and adding to increased project delays.

Hillegeist also pointed out the current drop-off in exploration which means a reduced backlog of discoveries to develop post-2021. Exploration will need to pick up over the next five years, he said, to drive developments.

An interesting delegate vote saw the audience highlight West Africa as the number one hotspot for long term project activity, with nearly 60% voting for it. This is quite a change from last year's vote when Brazil was the favoured hotspot.

Karl Wetherell of BP's eastern region of its Global Subsea Hardware organisation outlined efforts to multi-task its subsea engineers.

GSH, formed in 2011, covers everything from wellheads, trees and manifolds to controls, umbilicals and services. This cross-system approach tackles subsea concept development engineering for pre-defined projects with fewer than 25% of GSH employees dedicated to any one site. This, said Wetherell, provides approximately 30% efficiency over a 'project dedicated' model, and also issued a 'single voice to the subsea suppliers'.

This model is backed up with hard cash. GSH stewarded $1.2bn in capital in 2014 and that figure will be higher in 2015, Wetherell said.

He also noted standardisation initiatives, such as post-FEED efforts on subsea xmas trees on one Egyptian project which used the same tree components, materials, engineering and quality requirements as on its Trinidad trees.

One mega-project currently underway, Inpex's 340bcm *Ichthys* (SEN, 31/x) floater-to-LNG development off Western Australia, was the subject of a talk about collaboration by the project manager Louis Bon.

Bon knows about high-profile projects. On secondment from partner Total, he was responsible for managing several deepwater projects, including *Pazflor*, offshore Angola.

According to Bon, it's all about having an integrated team in order to overcome the major HSE and logistical challenges of a global project like *Ichthys*. He highlighted that the project has equipment being built in South Korea, Thailand, China, the Philippines, Indonesia, Singapore and Malaysia.

'We have a meeting in Perth every year ... to foster that team approach,' he said.

Ichthys is more than 64% complete with the 7,000t turret for the fpso being inserted at present and the seabed riser support structure recently installed. Deepwater pipelay is expected to be complete by the end of this year. Two semis are drilling development wells – Ensco 5006 and Jack Bates.

Bon described *Ichthys* as 'a very significant subsea installation,' with more than 30,000t of equipment to be installed on the seabed.

The semi central processing facility (CPF) is not small either. With topsides weighing in at around 70,000t, it is actually due to be about 70% heavier than the next heaviest topsides facility – BP's *Thunder Horse* which came in at a 'mere' 40,000t.

Bon justified this leap in weight, compared to other facilities, outlining how partners had decided on a robust design life for the CPF that would last for the full 40-year life of field while able to withstand cyclones while on-station.

Another option not chosen was going for a 25-year design life followed by brownfield upgrades, revamps, heavy maintenance programmes, et al, which was seen as not desirable due to the lack of clarity over future expense.

DEEPWATER MUSINGS: BP floater specialist Guy Drori pointed out that there have been 107 mooring incidents related to 73 facilities across the offshore industry between 1997 and 2012. These were incidents of either a total failure or replacement required.

The culprit in most cases was damage in the splash

zone close to the floating facility or on the seabed at the touchdown point. Drori pointed out damage was often caused by poor handling of equipment during transportation or installation, leading to early failure.

Ronald Doherty of INTECSEA - another experienced hand - said cutting costs in the engineering phase causes more expense later or a lower net present value than would otherwise have been achieved. In one generic example he estimated the loss in NPV of around $2bn over a project's total life.

From an operator's perspective, Martijn Dekker of Shell said that a 'big opportunity being missed is efficiency in fabrication'. There is a big gain to be had there, Dekker said, before he turned on the installation contractors saying there could be a 'huge gain in efficiency in these areas'.

Dekker did go on to stress the importance for operators and contractors to better understand each other in the current climate. This includes better understanding by operators of what contractors can provide. 'This means having a dialogue. What are we paying for, and what are we getting?'

Another 'old' hand, David Bloom of Subsea 7, was in agreement on this as well. 'Operators genuinely want to listen to contractors from what we hear. If we do not do it now...we never will.'

POLICY AND POLITICS

THE SHAPE OF THINGS NOW: WORKFORCE GETS BIGGER

From Aberdeen (IF): The changing shape of North Sea workers has been highlighted in a new study just concluded in Aberdeen.

Males employed offshore in UK waters are now on average almost 19% heavier and 2% taller than in the mid-1980s. The typical weight is now 90.5kg in minimal clothing and the average height is now 178.7cm.

The circumferences of different parts of the body have also risen substantially since 1985 when a previous study of North Sea workers was undertaken.

The latest work was carried out by researchers at Robert Gordon University in collaboration with Oil & Gas UK.

A total of 588 male offshore workers were selected for the research. Each underwent seven body scans using the latest portable 3D scanning technology.

One leader of the project was Arthur Stewart, knowledge exchange co-ordinator at RGU's Institute for Health & Wellbeing Research.

'We now have a unique insight as to how the shape of offshore workers has altered profoundly since the 1980s,' Stewart said. 'Compared with that of a generation ago when many...installations were constructed, the size of today's workforce, together with the size increase imposed by different types of clothing, will enable space-related risk to be managed and future design for space provision optimised.'

Robert Paterson, HSE issues director at OGUK, said the data will inform all aspects of offshore ergonomics and health and safety, from seat design in helicopters and lifeboats, survival suit design and space availability in corridors and work environments offshore.

'Our research partnership has also been very timely because it has also helped inform the work being done in response to Civil Aviation Authority concerns about passenger size and helicopter emergency push-out window size,' Paterson added.

UK GETS BUDGET BOOST, BUT WILL IT BE ENOUGH?

From Aberdeen (IF): The UK government has finally unveiled a package of measures to help the country's ailing offshore industry which it says will encourage more than £4bn of additional investment over the next five years.

The move has been widely welcomed, although industry watchers feel it could be too little too late for a mature sector which has given a massive boost to the British economy over several decades, paying to date over £330bn to the country in production taxes alone.

Thousands of jobs are currently being cut by the North Sea industry as firms desperately look to cut costs due to the double whammy of a plunging oil price and soaring costs. There are major doubts if these changes will be enough to turn things around.

One industry figure said the changes may only benefit a handful of tax-paying North Sea producers and will not address much larger, structural issues facing the industry.

The long-awaited announcements in last week's Budget include a new, simpler investment allowance. In addition, supplementary corporation tax is being cut from 30% to 20%, although this simply returns it to the level prior to the hike by this government two years ago. Petroleum Revenue Tax (PRT) on older fields is being reduced from 50% to 35%.

Meanwhile, exploration will get a boost from £20mn of funding for seismic surveys in under-explored areas of British waters.

Also last week, the government said the new Oil & Gas Authority (OGA) will be given a range of powers. It will have the ability to issue fines of up to £1mn; to revoke licences where necessary; as well as having the right to attend meetings; and have access to data to enable it to spot and resolve issues at an early stage.

Energy Secretary Ed Davey said, 'We have worked hard along with industry to establish this new regulator as part of the government's commitment to the North Sea and the hundreds of thousands of jobs it supports. We've moved quickly to get the OGA up and running to help the industry with the challenges it is facing, but it's also vital that we give it the powers it needs to be an effective regulator.

'It was important for us to work with industry to get that right,' Davey said, 'and I think what we have developed together will enable the OGA to be very effective.'

Malcolm Webb, CEO of Oil & Gas UK, said the budget announcement laid the foundations for the regeneration of the UK North Sea.

'The industry itself must now build on this by delivering the cost and efficiency improvements required to secure its competitiveness,' Webb said.

But Robert Collier, chief executive of Aberdeen & Grampian Chamber of Commerce, said only time will tell whether the measures will provide a sufficient incentive.

Jon Fitzpatrick, president of the Scottish Oil Club, said the concessions will likely only benefit the handful of tax-paying North Sea producers and will not address the much larger, structural issues facing the industry here.

Fitzpatrick said it was impossible to predict when the oil price will recover and added: 'There are a vast number of projects that are unfunded and unsustainable at current oil prices and many companies may not stay in the basin or business long enough to see the dawn of the oil price rising again.

He added that 'critical North Sea infrastructure' will likely be decommissioned leaving existing discovered resources at risk of never being developed.

'To address the underlying issues and attract substantive third-party investment, the industry and UK Government need to work more closely to encourage a more aggressive drilling and production programme and protect employment and economic opportunities over the longer term,' he said.

BUSINESS

TOP DOWN DECISION-MAKING TO DRIVE FORSYS SUBSEA VENTURE

The announcement this week of the formation of Forsys Subsea, a new field development venture which brings together market leaders FMC and Technip, might appear to some to fall into the category of 'desperate times require desperate measures'.

This view would fail to take into account that such a venture is always some time in gestation. And so it has been. Management of the two companies first started talking about coming together to find a way to cut project costs last summer, long before the precipitous oil price fall which has sent shivers through the offshore industry.

In fact, the fallling oil price only highlighted the need to find a way to reduce project capex. If field economics were struggling at $100/bbl, what would they look like at the current $50-60/bbl or even at a recovered rate of $70-80/bbl?

There have, in the past, been various ventures and alliances between subsea hardware suppliers and offshore contractors aimed at providing 'integrated solutions'. Mostly they came to nought. So why is this one different?

According to one FMC executive, it is where the impetus has come from. It seems that rather than a 'lowly' engineer from an operator suggesting a new way of doing projects to his boss which then has to climb the ladder to find a champion, the current drive to reduce costs is coming from the top - worried ceo's who think they might be replaced if they can not find a way to revive earnings to previous levels.

That is, no projects, no new production, no 'buzz' at results meetings means that finding a way to create excitement is essential.

At the formal announcement earlier this week, substantive numbers were tossed about. The idea that 25-30% could be cut from project capex by letting Forsys undertake your project has to be enticing. Especially as the partners here are the big guns in the subsea sector. While there may have been similar ventures in the past, they have never included companies like the market leader in subsea hardware (FMC) and one of the big players in SURF (Technip).

As is often the aim of such ventures, Forsys wants to get into the picture as early as possible in the project process. Technip will be putting up some of the resources of its front-end specialist Genesis with FMC throwing its FEED team in as well. There will be over 300 secondees to this venture backed up by the full support of their parents.

Not only will Forsys be aiming at the front-end, but the back-end, ie life cycle, of well life plus R&D aimed at cost reduction.

The management team is one with formidable experience. From FMC come Rasmus Sunde (ceo) and Arild Selvig (FEED leader) with Alain Marion (chief technology officer) and Gerald Bouhoud (life of field) from Technip.

As the British like to say, the proof of the pudding is in the eating. Who will be the first operator to take a bite of this cherry and turn over its EPCI development to Forsys? It may be someone with an 'uneconomic' project willing to take a shot at revived NPV.

As always, further developments are awaited.

SURVEY POINTS TO COMPANY GROWTH

From Aberdeen (IF): Companies in the UK's oil and gas service sector are still preparing to expand, despite the current gloom surrounding the industry.

A survey for Bank of Scotland's fourth annual oil and gas report reveals 92% of firms are planning to grow over the next two years.

Of the 101 companies questioned, 73 expect head-count to increase with only nine expecting a reduction.

Nearly 40% acknowledged that the fall in the oil price had delayed proposed investment in growth, but thousands of new jobs are still expected to be created over the next two years. The oil price was identified by survey participants as the single biggest issue, though the increased cost of production was named as the top challenge.

Other findings included more firms planning international expansion - up from 64% in last year's survey to more than 91% this year. North America (35%), the Middle East (26%) and South America (25%) are the most popular regions.

Stuart White, BoS area director of commercial banking, said, 'Firms continue to be concerned by an ageing work-force and a lack of skills, which explains why the industry is determined to get through the current storm without major workforce reductions.'

Mike Tholen, Oil & Gas UK's economics director, said many of the more positive aspects of the report relate to 'the desire of many companies to diversify and grow their export business given the current challenges facing their home market.'

Tholen said this reflects well on 'the quality of technology and expertise...here', there has to be 'a critical mass of domestic activity' to retain the supply chain.

Meanwhile, the possibility of industrial action by thousands of UK North Sea workers looms ever closer as another union is to ballot members on potential strikes as firms move to cut costs.

RMT is unhappy about changes to sick pay, pensions, travel allowances and the controversial move towards a 'three-on, three-off' shift pattern. The GMB and Unite unions are also balloting members.

In addition, it has emerged that offshore catering workers are to be balloted by their unions over potential industrial action.

They have been told by the Caterers Offshore Trade Association, which represents six catering companies, that a 2% pay rise planned for 2015-16 will not go ahead.

BUSINESS BRIEFS

Never believe the intentions of big companies when they start stalking smaller ones. Dredging and transport specialist Royal Boskalis Westminster swears that it has no intention of making an offer for **FUGRO** (31/22), but it has now increased its holding in the seismic data-survey contractor to 25.1%.

RBW is using all the correct words about 'common' ground, 'fits' and 'global coverage' which simply suggests it is trying not to create a surge of activity in Fugro shares before it makes a firm offer.

In the meantime, Fugro has beaten off an attempt by RBW to force a vote at its shareholder meeting on 30 April on various 'protective measures' in the Fugro constitution. It is getting interesting.

From the North Sea (NT): Norwegian independent **NORECO** is in danger of losing its 30% interest in Denmark's Nini field, having not paid its share of costs since January.

By breaching its licence obligations, it has opened the way to the other licensees claiming its holding without any consideration. Noreco's 61% stake in *Cecilie* and 16% in the *Xana* wildcat which is currently drilling are also at risk, although its interests in *Lulita* and the Huntington (31/21) field, which are held through a Danish subsidiary, are unaffected.

Noreco was instructed to withhold payments to the Nini licence by its bondholders, whom the company has also been unable to pay since December (31/19). However, there is now light at the end of the tunnel, following bondholder approval for a financial restructuring proposal earlier this month, which has also enabled Noreco's shares to resume trading on the Oslo stock exchange.

The restructuring has now been effected with the conversion of bonds into new shares, and a new board with bondholder representation is due to be elected this week. But a good period of uninterrupted production from its fields, particularly *Huntington*, is needed to get Noreco fully back on its financial feet. In February it reported paltry production of 2,752boe/d, down by more than a third on January. However, the total excludes output from *Nini*, as this information has been withheld from Noreco because of its breach of the licence obligations.

On the recent item about the acquisition of **UMBILICALS INTERNATIONAL** (31/24), it was incorrectly stated that Seanamics Group was set up by Simmons & Co. It was actually established by Simmons Private Equity. Sorry for any confusion.

WINTERSHALL has set itself the target of raising production to 190mboe by 2018. The German operator reported profits of 1.46bn last year.

The increase will come from the ongoing development of the Edvard Grieg, Maria and Aasta Hansteen projects in Norway, as well as Achimgaz in Siberia and the Vega Pleyade gas project off the Argentinean coast in Tierra del Fuego.

Despite months of production interruptions in Libya, Wintershall managed to increase oputput by 3% to 136mmboe in 2014.

Chairman Rainer Seele said the company will invest at least £4bn to expand production in the next five years. 'The strategy remains the same: we want to achieve more profitable growth at the source and continue our focused diversification,' he said.

Norway, where it has a strong relationship with Statoil, is a core growth region. It has expanded activity there significantly in recent years and holds stakes in over 50 licences, more than half as operator.

During the last few years it has boosted output twenty-fold to 60,000boe/d and it expects to continue this strong growth trend.

From Australia (RW): **TAP OIL** (31/24) has begun a strategic divestment review in the shadow of a boardroom challenge from Thai millionaire Chatchai Yenbamroong.

The divestments could include its flagship Manora oil development in the Gulf of Thailand along with non-core Australian assets.

Tap says the review will consider any potential 'whole-of-company' proposals that may emerge if they provide compelling value for Tap shareholders.

This follows recent valuations achieved by shareholders in other ASX-listed companies with Australian and Asian portfolios such as Fosun's acquisition of Roc Oil and Bangchak's purchase of Nido Petroleum.

Tap has attacked Yenbamroong's move as an opportunistic attempt to take control of the company without making a formal offer and paying a premium to shareholders. Yenbamroong owns Manora partner Northern Gulf Petroleum which recently increased its holding in Tap from 6% to 19.98%.

Yenbamroong has proposed to oust three directors and appoint 80% of the board despite having voting control of just 19.98% of the shares. A shareholders meeting matter is likely to be held in late April or early May.

From Australia (RW): Australian vessel provider **BHAGWAN** MARINE has launched a new subsea division along with opening a new base and laydown facility near Perth.

The new division will offer solutions on subsea projects using a new range of state-of-the-art equipment. The company has a fleet of more than 150 vessels along with regional bases across Australia. Initial subsea services will include diving, ROV, survey and engineering.

From Australia (RW): **GE OIL & GAS** has opened a dedicated facility in Broome, northwest Western Australia to support subsea projects off WA with upcoming Browse Basin LNG developments in mind.

The new facility will support the offshore installation stage of the Inpex group's *Ichthys* (31/23) LNG project. This will involve local support for the preparation, storage and routine maintenance of subsea equipment supplied by GE Oil & Gas.

GE is also eying the proposed Woodside group's Browse LNG project where an investment decision is expected by mid-2016.

Browse is likely to require up to three floating LNG vessels and the subsea side could be supported by the new Broome facilities.

With the WA government wanting to scrap plans for James Price Point supply base, a new supply base in Broome along with a possible domestic gas plant attached to the Browse project would complement the GE base.

JDR is expanding its activities in Nigeria with a new service and maintenance facility in Port Harcourt in partnership with Royal Niger Emerging Technologies...**BEL VALVES** is setting up a new £10mn subsea engineering facility on Tyneside... *Scotty Sparks* has been named exec veep, operation, at Helix Energy Solutions as of 11 May matching the retirement of *Cliff Chamblee* who was COOL and exec veep.

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