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THE FUTURE OF OFFSHORE ENERGY & TECHNOLOGY

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Merger Mania

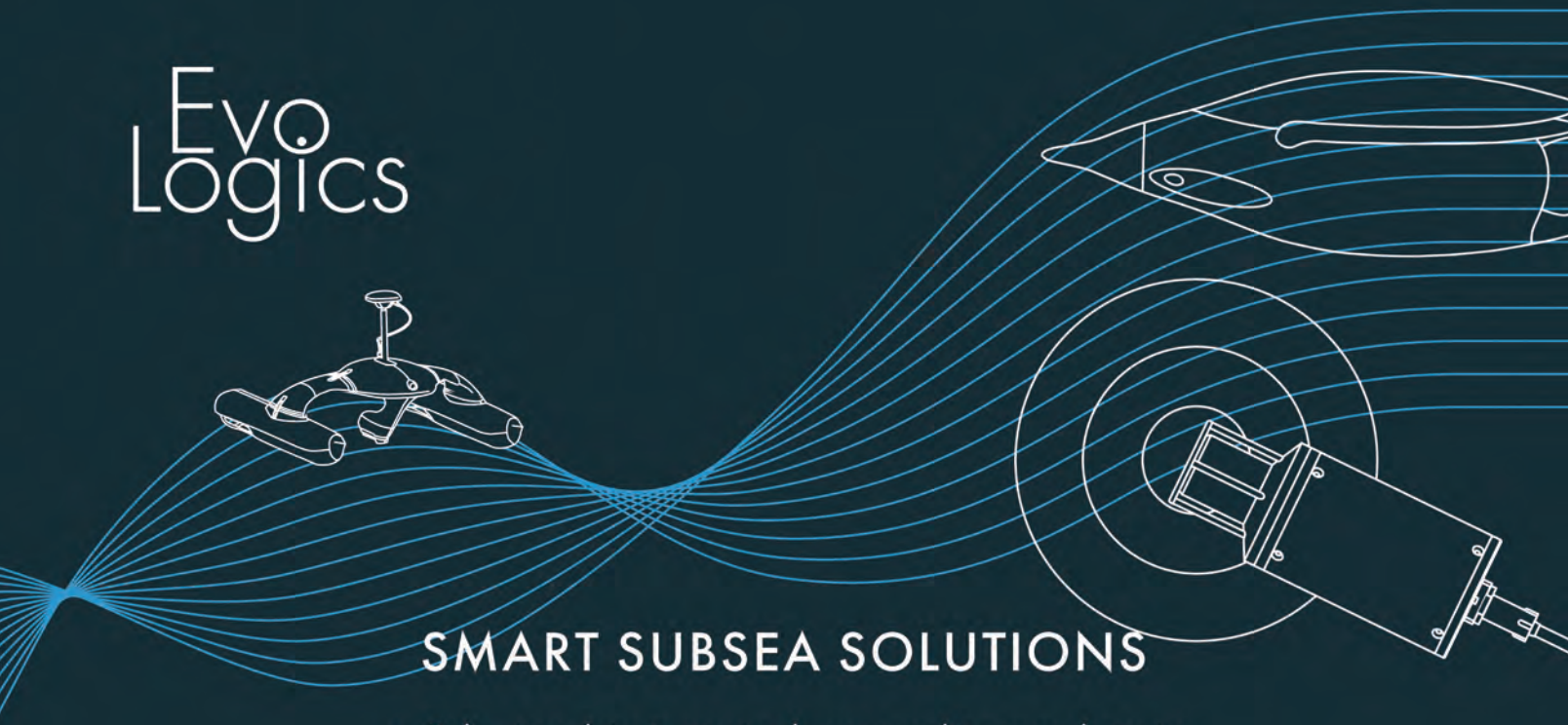
Early Innings of an Offshore Up-cycle

Seawater Electrolysis
Economic Folly?

Subsea Robotics
Driving IMR Efficiencies

Offshore Wind
East Asia & Pacific Markets

Evo Logics



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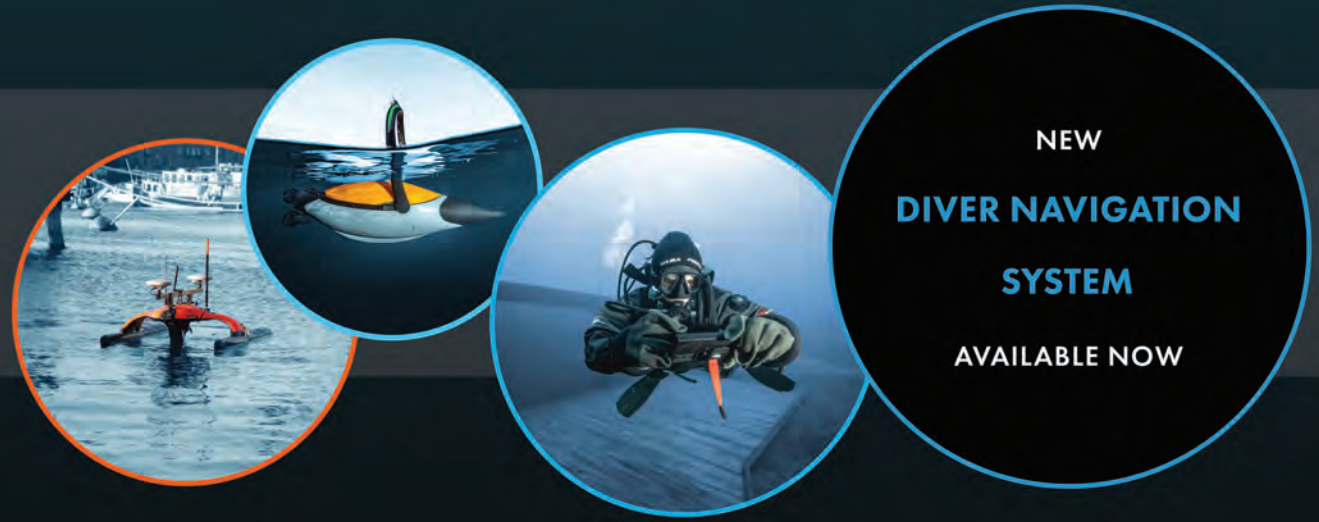

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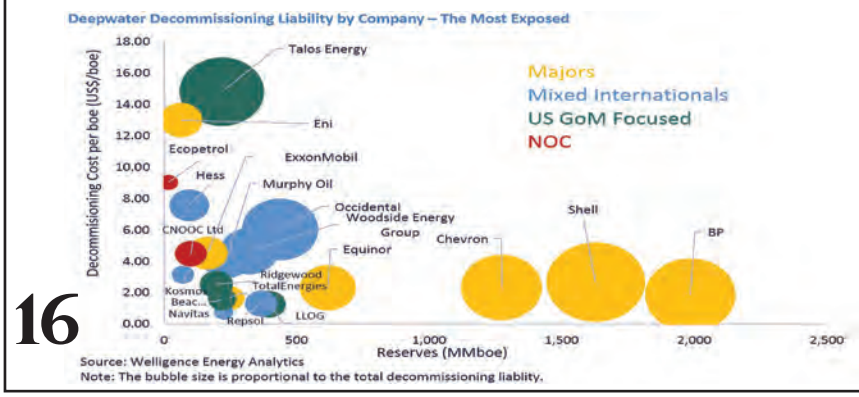
DEPARTMENTS



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In the short introduction to this edition, we coin a reference to the classic 1966 **Clint Eastwood** film *'The Good, The Bad and The Ugly'*, because looking at the offshore energy landscape now – and I guess always – the vision is the same as sectors ebb and flow.

Reporting on '**The Good**' this month is our New York City-based financial contributor Barry Parker, who takes a deep dive into floating production again to see how the recent and ongoing 'merger mania' is impacting the sector in the near term. But it wasn't long ago that floating production was 'the ugly', as the sector came to a dead standstill as oil and gas prices sank during Covid. But as Parker reports, consolidation across the sector and renewed prospects for a much longer bull run in the deepwater sector has opened the vault and money is flowing to the sector again.

'The Good' is not relegated only to floating production, as Teresa Wilkie – RigLogix, Director (Westwood Energy) reports Namibia is the "Newest Most Promising Deepwater Rig Demand Hotspot."

'**The Bad**' this month comes with a look inside the mounting costs of decommissioning, courtesy of Andrew Burr, North America Analyst, Wellligence Energy Analytics. Tightening global rules dictating how offshore structures are shutdown at the end of life comes with an increasingly high price tag … with current estimates indicating a liability at more than $300 billion. Key offshore producers Brazil, the US Gulf of Mexico (US GoM), the UK, and Norway face the largest bill at almost $150 billion combined.

Last but certainly not least, '**The Ugly**' is the ballooning cost for the first US-built WTIV, Charybdis, which according to the latest insights from Dominion via a recent investor presentation will be in the $715m range, reflecting new modifications to accommodate project specific turbine loads based on final certified weights and dimensions of the equipment and additional financing costs. While it is not unusual for any shipyard in any country to experience cost growth on a new vessel class, originally the ship was expected to cost about $500m, a figure which still stands in stark contrast to Cadeler recently taking the fifth and newest addition to its fleet – Wind Peak – the first of seven newbuilds for which Cadeler currently has signed contracts. This ship was built at COSCO Shipping Heavy Industry (COSCO) shipyard in Qidong, China, and according to Mikkel Gleerup, CEO of Cadeler, it was delivered "on time and within budget."

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Andrew Burr is a North America Analyst with Welligence Energy Analytics, based in Houston. He is responsible for covering offshore Americas primarily offshore Canada and the U.S. Gulf of Mexico. He holds a Masters in International Relations and Economics from Johns Hopkins SAIS.

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Herman Jorgensen became the Managing Director for GAC Malaysia in 2023. Previously, he held the same position for GAC UK, overseeing significant restructuring and expansion of services. With over 20 years of industry experience, Herman holds an MBA from Victoria University of Wellington and a BA in Business Administration from the Norwegian School of Economics. Outside of work, he enjoys playing guitar and bass, coaching and playing football, as well as other outdoor activities.

Wendy Laursen has 20 years of experience as a journalist. In that time, she has written news and features for a range of maritime, engineering and science publications. She has completed a Master of Science research degree in marine ecology as well as diplomas in journalism, communication and subediting.

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Jesper Skjong is a market analyst at shipbrokerage Fearnley Offshore Supply covering the offshore support vessel market, including O&G and offshore renewables.

Teresa Wilkie is the Director of RigLogix within Westwood Global Energy Group, leading a team of experienced offshore rig market analysts. She has over a decade of knowledge as an analyst in the oil and gas industry bringing expertise from her time at IHS-Markit (formerly ODS-Petrodata) and Esgian (formerly Bassoe Offshore).


Lewis


Parker


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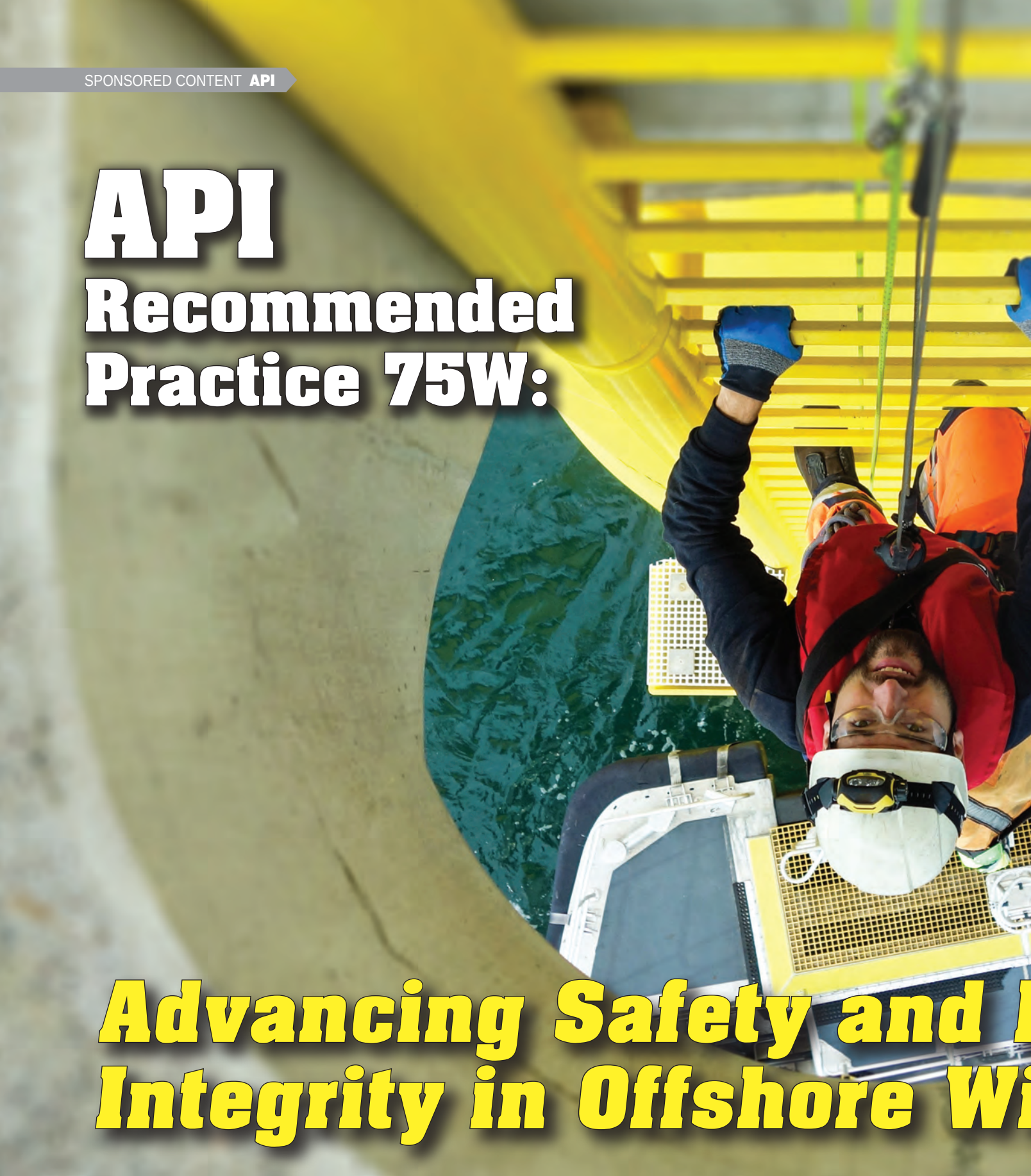
API Recommended Practice 75W:



Advancing Safety and I Integrity in Offshore Wi

All images courtesy Getty Images

Environmental ind Operations

Against the backdrop of a growing public demand for clean, renewable energy, offshore wind power has emerged as an attractive component of the global energy transition. While the promise of wind energy is compelling, careful and deliberate management is necessary to protect people and the environment. Addressing this critical challenge requires a robust framework to guide the safe development and operation of offshore wind projects.

In response to this need, the American Petroleum Institute (API) recently released the first edition of API Recommended Practice 75W, "Safety and Environmental Management System for Offshore Wind Operations and Assets" (API RP 75W). This landmark standard leverages API's extensive experience with offshore oil and natural gas development to provide a comprehensive framework for safety and environmental integrity in offshore wind operations.

From lease evaluation to decommissioning, API RP 75W's goal is to prevent incidents by establishing robust procedures and protocols, advancing the highest standards of safety and environmental integrity in offshore wind operations.

Expert Guidance

The development of API RP 75W was driven by the proliferation of offshore wind operations. According to a 2023 Department of Energy report, the U.S. offshore wind energy pipeline grew 15% from 2022, with 13 coastal states having announced plans to procure massive amounts of offshore wind over the coming decades. Given this rapid expansion, in 2022, the Bureau of Safety and Environmental Enforcement, which oversees and regulates offshore energy operations on the U.S. Outer Conti-

nental Shelf, identified the need for a safety framework specifically tailored to the offshore wind sector. And it reached out to API and the Offshore Operators Committee (OOC) for assistance.

API was consulted for its established expertise in standards development, and the work of the Center for Offshore Safety, who has established guidance for auditing, implementing and maintaining Safety and Environmental Management Systems (SEMS).

"BSEE has been working with offshore wind developers and standards development organizations for over a decade to develop offshore wind standards," said **Kevin Sligh, Director of the Bureau of Safety and Environmental Enforcement**, whose agency sought the support of API and the Offshore Operators Committee (OOC) in developing the standard. "BSEE shares API's dedication and commitment to fostering a clean energy future, one where safety is the No.1 priority for the offshore wind industry and workers on the Outer Continental Shelf."

In response to the BSEE, API and OOC agreed to collaborate on aligning their existing management systems with the needs of the emerging offshore wind industry. They formalized their collaboration through a Memorandum of Understanding (MOU) in September 2022, highlighting their intent to leverage the knowledge and practices in offshore oil and natural gas to establish a new standard for the offshore wind industry. Their cooperation led to the creation of a rigorous standard that lays a solid foundation for safety practices in an emerging energy industry.

"This is the first of hopefully many cross-industry collaborative efforts to capture lessons learned and share them across all forms of offshore energy development including carbon sequestration," said Evan Zimmerman, OOC Executive Director. "OOC greatly appreciates the collaboration on targeted standards like RP 75W with API. OOC also greatly appreciates the important participation from ACP and G+ that help ensure that these standards do not create conflicts or duplicate efforts that pull resources away from other standards development activities in the offshore energy sector."

API RP 75W parallels the approach detailed in API RP 75, 4th edition, "Recommended Practice for a Safety and

Environmental Management System for Offshore Operations and Assets" (API RP 75), which has guided safety management in the offshore oil and natural gas industry for more than 30 years. The new standard was developed to address the unique challenges posed by offshore wind operations and incorporates examples specific to the industry.

The development of API RP 75W was a collaborative effort involving BSEE, the OOC, and industry stakeholders, including representatives from the wind energy sector. This diverse participation ensured that the standard would be inclusive for all stakeholders, fostering widespread adoption.

Key Features and Principles

API RP 75W provides a comprehensive framework for managing safety and environmental risks throughout the lifecycle of offshore wind projects. This includes risk assessment and procedures for safe work management as well as safe work practices, management of change, emergency preparedness and incident investigation.

The standard is performance-based, encouraging a proactive approach to safety and environmental management, and is organized around four core principles:

- **Commitment:** Demonstrate leadership and commitment to safety and environmental protection throughout an organization.
- **Risk Management:** Identify, assess and manage risks to prevent incidents and protect the environment.
- **Human Performance:** Recognize the importance of human factors in safety and environmental management and incorporate these considerations into all aspects of the SEMS.
- **Continual Improvement:** Regularly review and improve safety and environmental practices to adapt to new challenges and advancements in technology.

Significance of API RP 75W

Following a transparent, consensus-building approach to standards development, API published API RP 75W in July 2024. The standard is a first for the offshore wind industry and addresses its unique operational and environmental challenges. Its significance extends beyond current offshore wind projects, potentially shaping future renewable energy

standards across the industry. This highlights the value that a robust SEMS offers various energy operations.

Additionally, the standard can be used globally for offshore wind operations, a significant advantage as the offshore wind industry continues to expand across different regions, each with its own regulatory requirements and operational challenges.

Future Impact

API RP 75W represents a landmark standard for the offshore wind industry, providing a comprehensive framework to manage safety and environmental risks. Its collaborative and transparent development process enhances its credibility and ensures it meets the diverse needs of a wide range of industries involved.

By setting a high bar for safety and environmental integrity, API RP 75W strengthens safety and environmental performance for offshore wind operations, addressing industry's immediate needs while positioning it for future growth and sustainability.

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NAMIBIA: The Newest Most Promising Deepwater Rig Demand Hotspot

By Teresa Wilkie, Director of RigLogix, Westwood

Over the past few years the Namibian Orange Basin has emerged as an exciting new oil province and subsequently a provider of significant new demand and future demand potential for deepwater drilling rigs.

According to Westwood's Wildcat, "the Upper and Lower Cretaceous plays opened in the Namibian Orange Basin by the Venus and Graff wells in 2022, have delivered nearly 5bnbbl after the first nine wells, making it the second largest oil province to have emerged globally in the last decade".

Furthermore, the seven exploration wells that followed up the Graff and Venus play opening discoveries have resulted in four follow-on discoveries with an estimated recoverable oil resource of 2.8bnbbl. This includes Galp Energia's Mopane discoveries made in 2024 at an estimated 2.4bnbbl. If verified, this would make Mopane the largest ever discovery in sub-Saharan Africa and the third largest oil discovery globally in the last decade.

Growing Namibian Floating Rig Demand

Pre-2021, demand for rigs in Namibian waters was limited to say the least. Only eight semisubmersible (semi) or drillship contracts were awarded for drilling off the West African country between 2006 and 2018, resulting in the drilling of nine high-impact exploration wells and zero commercial discoveries. Chariot Energy, HRT, Repsol, Sintezneftgaz and Tullow Oil all took a stab at exploring the Namibe, Luderitz and Orange Basins off the country, with no material success during this period.

These rig deals were awarded to an array of different deepwater rig providers including Pride International, Diamond Offshore, Transocean, Rowan and Ocean Rig to name a few and during that 12-year period rig days off Namibia totalled approximately 820 days or 2.2 years of rig demand.

However, the market for deepwater rigs in this new province since 2022 has been increasing off the back of giant new discoveries. Despite no rigs currently working offshore, Westwood expects to see a few begin new pro-

Westwood Global Energy Group

	Rig Manager	Rig Type	Operator	Contract Start Date
Ocean Whittington	Diamond Offshore	Semisub	Shell	January 2002
Nanhai VII (Qi Hao)	Pride International	Semisub	Tullow Oil	April 2007
Deep Venture	Petrolia Drilling	Drillship	Sintezneftegaz	March 2008
Noble Deliverer	Maersk Drilling	Semisub	Chariot O&G	March 2012
Transocean Marianas	Transocean	Semisub	HRT	March 2013
Valaris DS-15	Rowan	Drillship	Repsol	April 2014
Deepwater Orion	Ocean Rig ASA	Drillship	Tullow Oil	September 2018
Deepwater Orion	Ocean Rig ASA	Drillship	Chariot O&G	September 2018
Valaris DS-10	Valaris	Drillship	Shell	November 2021
Noble Voyager	Maersk Drilling	Drillship	TotalEnergies	November 2021
Deepsea Bollsta	Odfjell Drilling	Semisub	Shell	December 2022
Tungsten Explorer	Vantage Drilling	Drillship	TotalEnergies	February 2023
Deepsea Mira	Odfjell Drilling	Semisub	TotalEnergies	June 2023
Hercules	Odfjell Drilling	Semisub	Galp Energia	November 2023
Deepsea Bollsta	Odfjell Drilling	Semisub	Chevron	October 2024
Noble Venturer	Noble Drilling	Drillship	Rhino Resources	December 2024

Source: Westwood RigLogix

Offshore drilling rigs contracted to work offshore Namibia 2002-2024 (contracts fixed as of 31 July 2024).

grammes in the coming months, while the long-term outlook is very promising.

Since August 2021, there have been 15 new contracts awarded or exercised contract options taken up, equating to approximately 1,700 days (or 4.4 years) of rig demand for operators to conduct work offshore Namibia. Supermajors, Shell and TotalEnergies, have been most active in contacting rigs, securing 80% of the firm rig time for Namibian operations since 3Q 2021. Galp Energia, with its successful campaign in PEL 83 using Odfjell Drilling-managed semi Hercules (10,000'), accounted for 10% of the total.

Meanwhile two upcoming exploration campaigns with new players – Chevron and Rhino Resources – makes up the remaining 10% of contracted rig time to date. In 4Q this year, Chevron will undertake a one-well exploration campaign in PEL 90 using Odfjell-managed harsh-environment UDW semi Deepsea Bollsta (10,000') a rig tried and tested by Shell for its Namibian campaign that ran from December 2022 through April 2024. Kapana and Maguni have been dubbed as potential drill targets.

Meanwhile, Rhino will also start a minimum two-well campaign in the final quarter of this year, using UDW drillship Noble Venturer (12,000'), with Sagittarius or Volans as likely prospects.

TotalEnergies is expected to return to exploration and appraisal drilling at its acreage in the coming months, with plans to drill the Kokerboom prospect in PEL 56, but which rig it plans to use is yet to be confirmed. The operator currently has UDW drillship Tungsten Explorer (10,000') booked in under a 10-year deal for which it can utilise it in different countries, while it still has UDW semi Deepsea Mira (10,000') on hire until at least mid-October this year with a 90-day option remaining on the deal. Both rigs are currently working off the Congo but had previously been drilling in Namibian waters.

In addition, TotalEnergies seems likely to be the first off the block to develop its new finds, with a Final Investment Decision (FID) expected for Venus in 2025, which will require further drilling of subsea wells to be tied back to

an FPSO.

Meanwhile, Shell has taken a hiatus from its drilling activities in PEL 39 and has not reported any further exploration or appraisal plans at this point.

Further Rig Deals on the Horizon

In addition to the firm backlog already in place, Galp Energia plans to drill four wells around its Mopane Complex, with the first well to spud before the close of 2024. Market sources indicate that the operator may have picked up the Deepsea Bollsta for at least the first well of its campaign, though this is yet to be confirmed by either party.

BW Energy also intends to drill two firm wells within PL003 next year; the first to be drilled since taking operatorship in 2017. The wells are expected to appraise Kudu and target a shallower Upper or Lower Cretaceous oil exploration target. A tender for a drillship or semi is expected to hit the market in August 2024. Kudu was the only significant hydrocarbon discovery made offshore Namibia prior to Venus and Graff.

Meanwhile, Woodside is yet to decide on its option to farm into PEL 87, containing the Saturn prospect, after carrying the cost of 3D seismic over the block in May 2023.

Alongside average global rig dayrates, Namibian rig contracts have been getting more expensive due to the ongoing market recovery. As an example, Tullow Oil and Chariot Oil & Gas paid $120,000 and $130,000 per day, respectively, for their short Namibian campaigns in 2018 with then Ocean Rig-owned drillship Ocean Rig Orion (10,000').

However, for those rigs fixed for work off the country since 2022, dayrates have averaged $365,000 for mutually agreed deals (i.e does not include fixed price options). Meanwhile, the most recent fixture, which was secured for a 7th generation drillship already in region, came with a price tag of $410,000 per day.

Challenges

Westwood's Wildcat reports that, "the Cretaceous turbidites plays in the Orange Basin have quickly emerged as the largest oil plays since the Upper Cretaceous play in Suriname-Guyana", which went from almost no rig activity prior to 2016 to having five drillships working in parallel for ExxonMobil by early 2020.

However, there are still many challenges facing the development of these Namibian resources including reservoir deliverability, gas management and extreme water depths.

The opportunities in Namibia are considerable to say the least for operators, rig managers and other service providers alike, but the next few years will be key in determining just how big the size of that prize will really be and if it can support current rig demand growth expectations.

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The Mounting Offshore Decommissioning Cost

By Andrew Burr, North America Analyst, Welligence Energy Analytics

The safe, timely and cost-efficient decommissioning of offshore infrastructure is one of the big challenges faced by the oil & gas sector. We estimate that the liability currently stands at over $300 billion (real terms), and this will only increase as companies continue to make and develop new discoveries. Key offshore producers Brazil, the US Gulf of Mexico (US GoM), the UK, and Norway face the largest bill at almost $150 billion combined.

A key concern for governments is ensuring the sector is able to cover these abandonment obligations, and the costs don't end up with the taxpayer. Several high-profile offshore bankruptcies in recent years have revealed regulatory weakness that left the taxpayer on the hook. Countries have been working to tighten their rules, most recently in the US where the regulator (BOEM) introduced new rules for the US Outer Continental Shelf (OCS) that have placed the topic front and center.

Diving into the US GoM Abandonment Landscape

The US GoM is one of the areas most impacted, accounting for almost US$40 billion of the global bill – around 80% of this is attributable to deepwater projects. The major cost item is subsea well abandonment. While most facilities can be floated off and sold for scrap, the wells must be dealt with in-situ and require the use of vessels to plug and abandon the wellbore. Per reporting to BOEM, this cost averages $28 million per well.

According to the regulator, there are almost 100 companies with some type of liability in the US GoM. The majority of the liability (around 70%) is associated with the top 15 E&Ps, all sizeable companies with large balance sheets and major participants in deepwater projects. The most exposed are the three big legacy producers (bp, Chevron, Shell), along with Talos Energy given the large infrastructure-based portfolio it has built through its M&A strategy over the last few years.

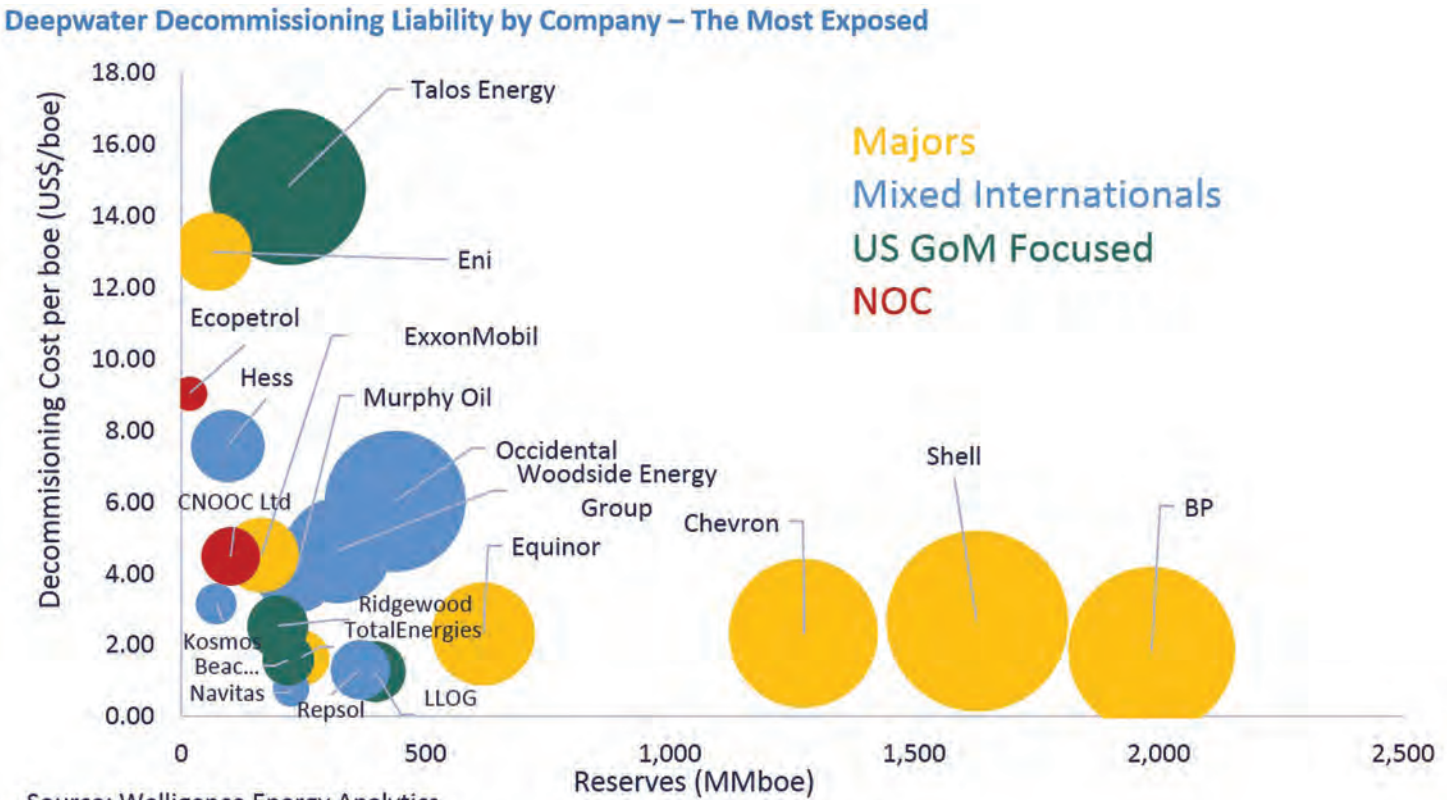
Global Offshore Decommissioning – Estimated Cost by Country

Source: Welligence Energy Analytics
Note: Decommissioning costs are in real terms and undiscounted.

Protecting the Taxpayer – Chain of Ownership and Sureties

Governments are putting in place regulations to ensure abandonment liabilities don't end up with the taxpayer. A couple of cases underline this concern. In Australia and New Zealand, fairly recent E&P bankruptcies resulted in $215 million and $192 million respectively in costs falling onto taxpayer shoulders. Indeed, the US Department of Interior states that the new rules covering the US OCS will "…protect taxpayers from covering costs that should be borne by the oil and gas industry when offshore platforms require decommissioning".

1. **Chain of ownership:** Countries are writing regulations to ensure companies can't 'sell off' their decommissioning obligations and forget about them – in bankruptcy cases, the liabilities passed on can come back to bite the original sellers via the historic chain of ownership. While establishing this chain can be very difficult onshore, it's a lot easier offshore where the participants tend to be established companies. When Fieldwood in the US GoM went under, it left $2.5 billion in decommissioning liabilities. This was passed back to the prior asset owners,

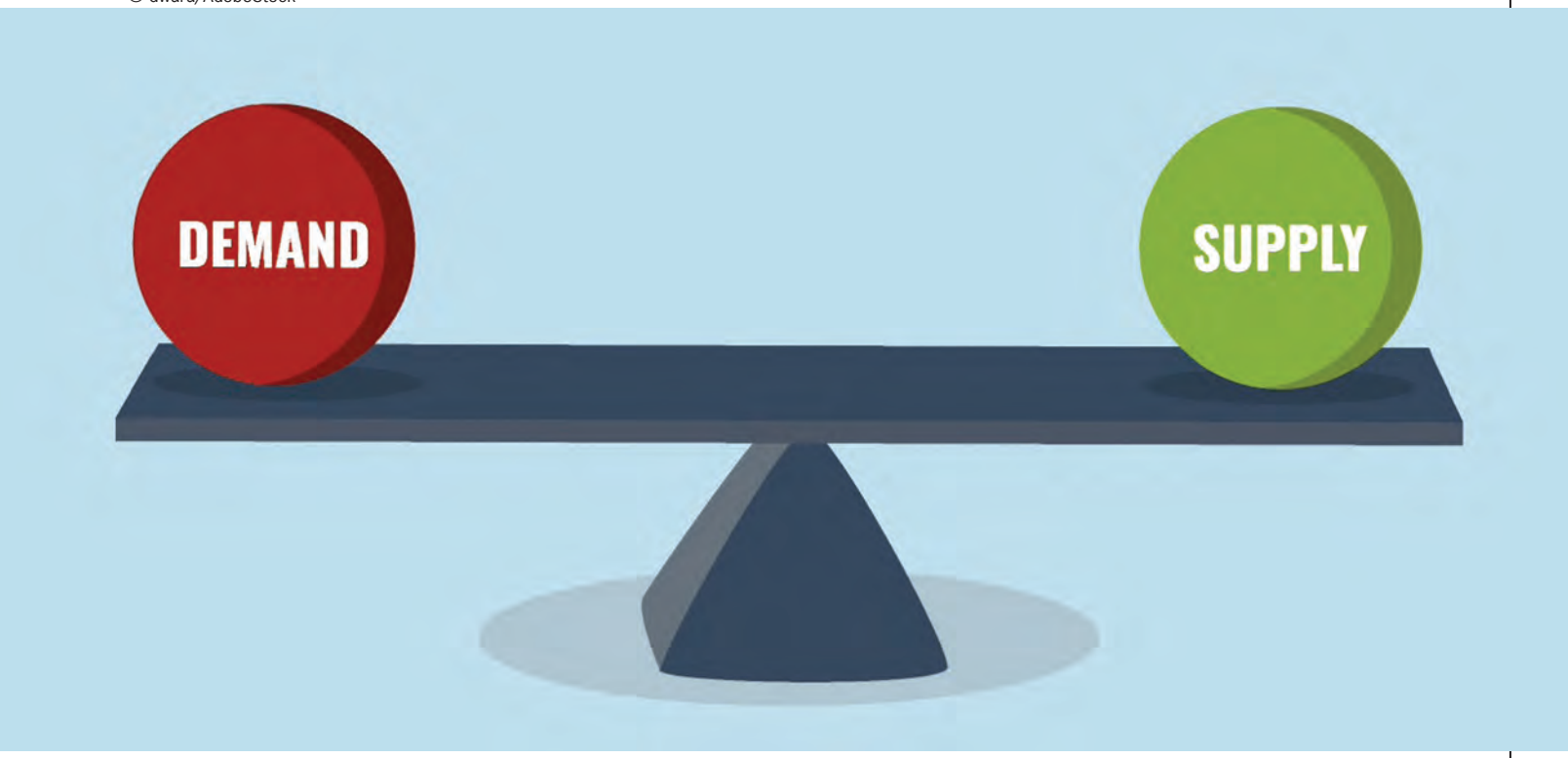


Source: Welligence Energy Analytics
Note: The bubble size is proportional to the total decommissioning liablity.

with Apache, bp, Marathon Oil, Shell, and Chevron taking the hardest hit. This wasn't just an unwelcome financial surprise, but a major operational challenge given most had not been involved in any of the projects for 10+ years.

2. **Financial sureties:** Despite these companies fulfilling their obligations, BOEM still felt the need to further tighten its regulations covering the US OCS. The new rules require additional financial sureties to cover decommissioning costs from companies that fail to meet new criteria regarding financial strength. The big players are largely unaffected, but there is a long tail of smaller companies that will struggle meet the new criteria and will therefore bear the brunt of the increased cost in financial assurances.

The new rules have faced significant pushback from the industry, which argues it will impact investment and deal-making. But such rules should not come as a surprise– the US is now in line with Brazil, the UK, and Norway, all of whom have implemented similar regulations in recent years.



North Sea Realism in a Busy Market

By Jesper Skjong, Market Analyst, Fearnley Offshore Supply AS

The offshore support vessel (OSV) market is very much a global industry where ships frequently mobilize between regional markets. This offers far more opportunities than markets more closely linked to their specific local geography and operational patterns. As a result of these additional opportunities, the supply- and demand balance in the respective regions are more dynamic than the offshore activity therein in isolation, which has allowed for a faster market recovery in the upcycle we are experiencing today.

A good example of this market dynamic in action can be observed between Southeast Asia and the Middle East where the respective market balances developed in vastly different fashions. In the former, we observed a tremendous oversupply of OSVs for the better part of the last decade on the back of the preceding newbuild boom. Especially towards the latter stages of the previous market cycle, newbuilds were predominantly delivered by Asian shipyards. In the absence of sufficient market demand, however, many, in fact the majority of which, quickly saw

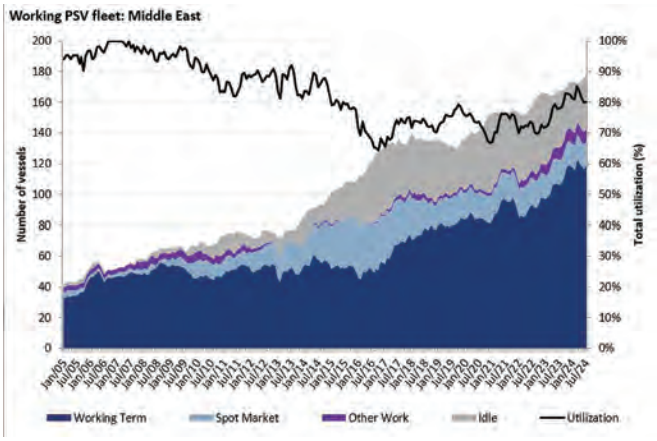
themselves idle or laid up.

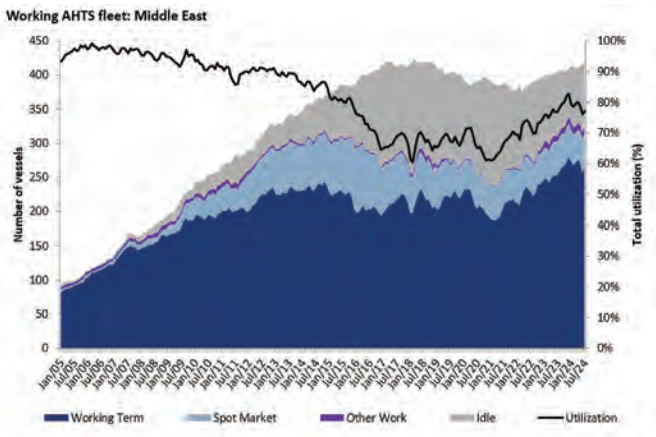
At the trough of the market, in 2016 and 2017, there were more than three and four times as many AHTS and PSVs in Southeast Asia as the market demanded respectively. This, of course, put significant downwards pressure on dayrates and utilization, and thus saw a whole host of vessels put into lay-up in order to reduce Owners' operational costs until the market recovered.

Meanwhile, the Middle East saw offshore exploration and production (E&P) activity growing steadily through this same period and as a result vessel demand even accelerated quite counter cyclically at times. Especially so for the number of working PSVs as well as the number of AHTS engaged on long term contracts, which both saw growth at times when most other regions were in decline or at their through.

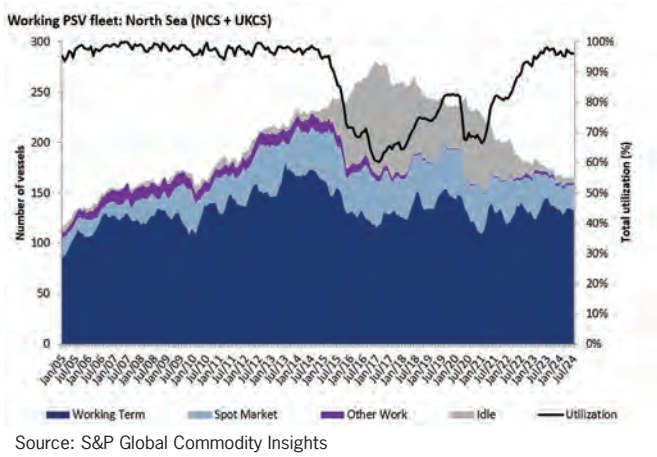
Granted, dayrates, and even utilization, grew only modestly during this time, but saw growth, nonetheless. Moreover, the additional demand in the Middle East allowed a large number of idle OSVs from other regions to migrate here and as such helped stabilize the market balances elsewhere that would otherwise been worse.

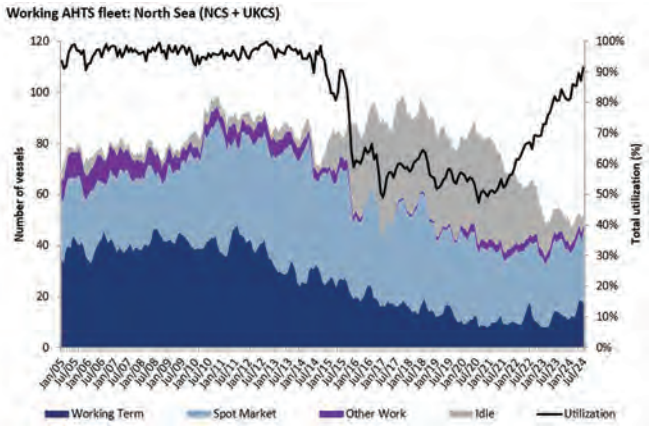
A large-scale migration of OSVs also occurred in other regions that were heavily impacted by the market crash, and in relative terms, few, if any, other regions saw a larger exodus of vessels than the North Sea. Granted, a large part of the vessels that found themselves laid up along the Norwegian costs especially, were ships that had returned home for this purpose after having traded internationally prior to the crash.





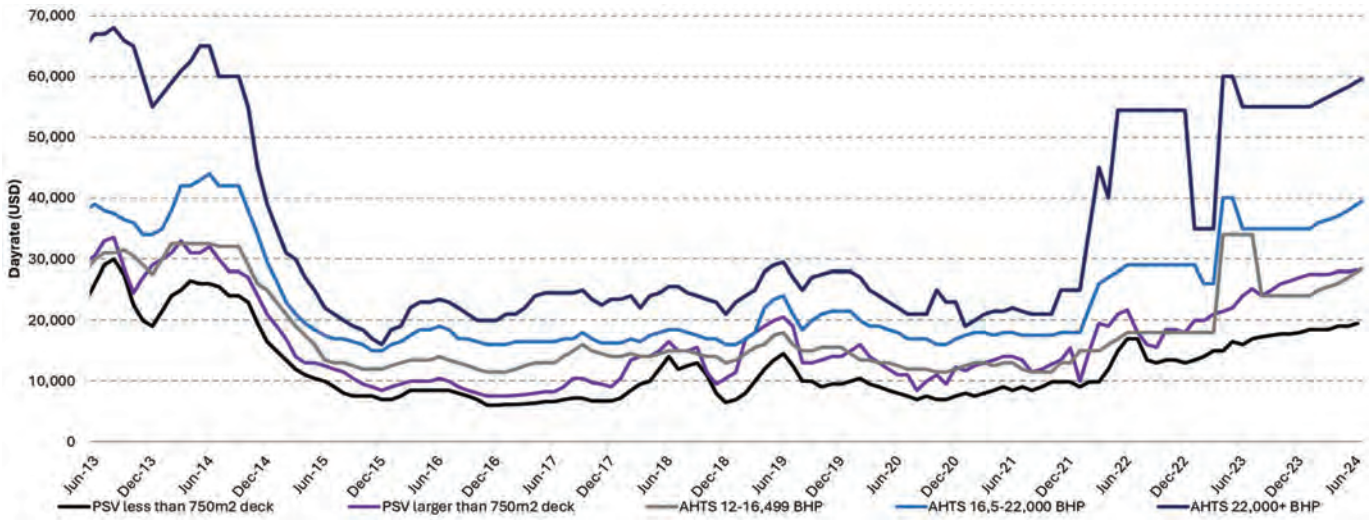
Source: S&P Global Commodity Insights





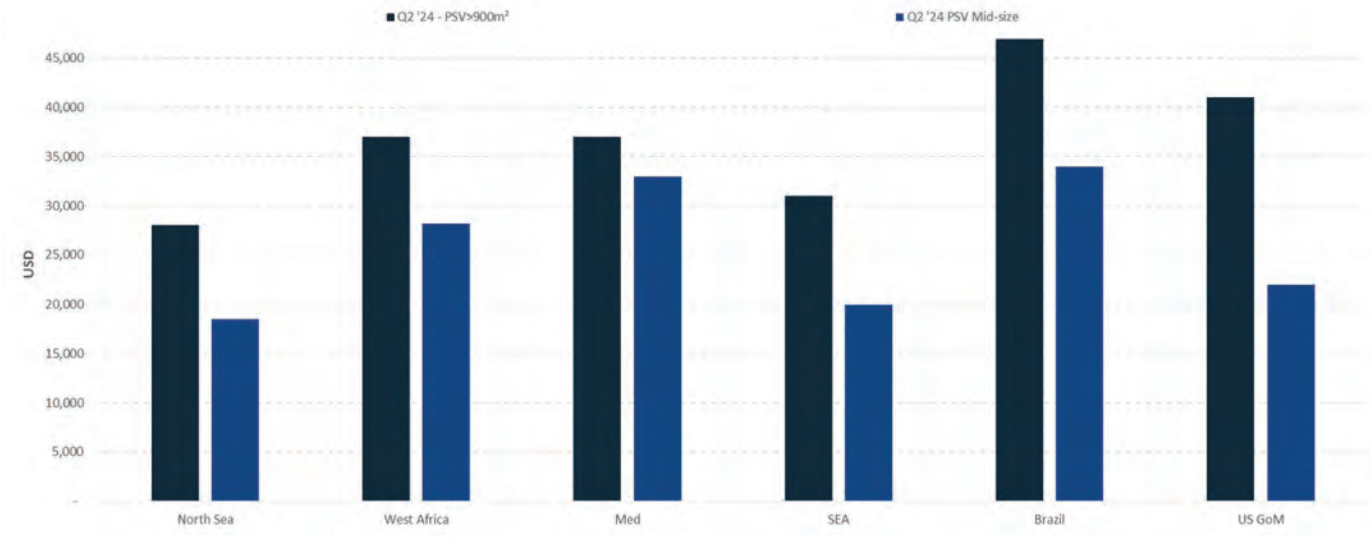
Source: S&P Global Commodity Insights

North Sea Term Dayrate



Source: Fearnley Offshore Supply

PSV Term Dayrates by Region 2Q 2024



Source: Fearnley Offshore Supply

When examining the market balance for PSVs and AHTS in this area, it becomes clear that the total number of vessels in the two fleets during the first quarter of 2017 outnumbered the previous peak demand by around 30%. While the market did see some momentum for vessel activity in this region, the total vessel demand is still significantly lower than before the crash. Additionally, it is worth noting that market demand today is even significantly lower than the momentum achieved prior to the activity halt brought on by Covid-19.

Despite this weak development on the demand side, both utilization- and overall dayrates have increased tremendously since the trough. This tells us that the strongest driver has not been demand, as one might expect, but in fact a reduced supply side as a result of a mass exodus of vessels. Even more so, when looking at the total number of OSVs in the North Sea region, we find that this figure is currently at its smallest in almost 20 years for PSVs and for even further back for AHTS.

This timeframe is unfortunately far from a coincidence and what it tells us further is less than encouraging. The UK, which together with Norway represent the vast majority of offshore activity in the North Sea, hit its peak production already back in 1999 at around 4.5 million barrels of oil equivalent per day (boepd). And while there was some renewed momentum after the oil price crash in 2014, it pales in comparison to historical levels and the country's current output stands at only around 1.3 million boepd.

Furthermore, the British government's recent deci-

sion to increase the windfall tax on oil and gas (O&G) producers does little to change this development. Late in July, the new Labour government announced that it will (yet again) increase the Energy Profits Levy by 3%, which brings the headline rate of tax up to 78%. Moreover, in an effort to shift investments into cleaner energies, it will also terminate the 29% tax offset allowance on capital re-invested.

Perhaps this column is not the best place to discuss the effects of carrots versus sticks, but we would argue that the only certain effect of these recent changes is that volume of investments will see another turn for the worse herein. And while there is something to be said for the politics of energy security, the impact on offshore activity, and as such, vessel demand, is thus likely to further decline.

The level of O&G investments in the other major offshore country in the North Sea region, Norway, has seen something of a renaissance in the last couple of years. The tax scheme incentive package that was initially offered in order to counter the negative impact Covid-19 had on the country's O&G industry saw 13 new greenfield development in addition to a several brownfield plans representing around NOK 300 billion in investment announced through 2022.

Moreover, the country's production development has also maintained a far greater momentum than that of its neighbour. At the start of 2024, Norway's O&G production was a little north of 4 million boepd, which is just around 12% lower than its peak production back in 2004. And although a large portion of the new field development are subsea focused, tie-backs or other types of developments based on existing infrastructure, it still maintains a significant level of vessel demand.

It should be mentioned, however, that the O&G industry as a whole has taken huge efficiency strides during the last decade, both in operations as well as technological aspects. More efficient drilling operations and an increased market share of the production infrastructure going on the seabed floor compared to topside means less vessel demand for PSVs and AHTS compared to more conventional developments.

Overall, the market in the North Sea certainly has recovered from the doldrums of past years and, as seen in the graph above, dayrates for term work is currently at levels last seen in 2014 measured in USD. Yet this is without adjusting for inflation, and while we report higher utilization rates as of late these figures admittedly concerns a smaller number of vessels than prior to the downturn.

Even more so, it is also important to consider just how persistently fragile the market balance in the North Sea region is. The UK and Norway now have roughly the same amount of AHTS and PSVs. The total demand for supply vessels on the Norwegian side has developed relatively flat and is not likely to accelerate within the near future. With an absence of activity in the UK side, the historically busy summer season we just went through was a let-down for a lot of the shipowners in the region.

In the spot market, average dayrates for PSVs in July were just GBP 12,500 for large vessels with fixtures reported as low as GBP 5,000 – this in one of the most important months of the year. AHTSs fared quite a bit better, averaging around GBP 56,000 per day, yet herein the utilization during the month as a whole could certainly improve.

Meanwhile demand for OSVs continues to rise firmly almost across the board with calls for international tonnage to participate more often than not. As for the rationale behind mobilizing further vessel out of the North Sea it becomes abundantly clear when comparing term dayrates across key offshore regions. The graph below, which shows regional distribution of term dayrates in USD at the end of the second quarter, tells us that the North Sea is lagging behind other comparable regions, so why would you not seize opportunities that arise elsewhere?

In conclusion, we remain positive about improving market conditions in the OSV industry as a whole and in the North Sea region overall. Yet we need to maintain a certain degree of realism to what has been the main driver behind positive development and what we can reasonably expect going forward. We find it difficult to see local market demand impact dayrates herein, but rather expect continued vessel demand globally to likely see more vessels mobilize out of the North Sea.

A Look Inside the East Asia & Pacific Offshore Wind Markets

By Philip Lewis, Research Director, Intelatus Global Partners

Images of all flags: The World Factbook 2021. Washington, DC: Central Intelligence Agency, 2021.

Whereas the foundations of commercial offshore wind development are found in Europe (and Europe will remain the largest overall regional market for offshore wind activity in the coming decade), the rapid development of the large East Asia and Pacific region provides both opportunities and some challenges to the supply chain.

According to World Bank data, the technical potential for the East Asia and Pacific region amounts to over 15,000 GW, of which ~27% is suited to bottom-fixed foundations and the balance floating technologies. 90% of the potential is found in seven countries, which are (in descending order) Australia, China, New Zealand, Japan, South Korea, and Taiwan. Of these countries, only New Zealand does not currently have offshore wind activity.

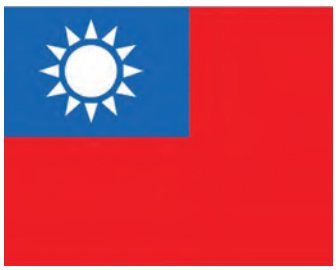
CHINA

The dominant East Asia and Pacific market, where domestic Tier 1 suppliers are increasingly looking to international markets

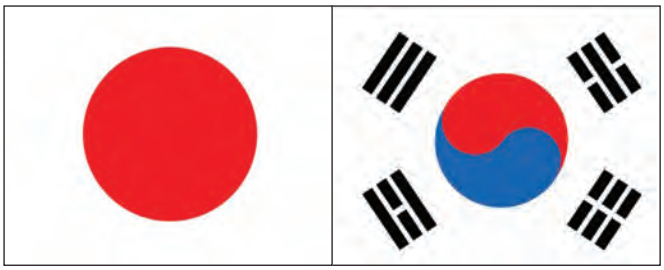
At end of 2023, operational offshore wind capacity in the region amounted to just over 32 GW, of which the majority was grid connected in the regions offshore wind powerhouse and world's largest offshore wind market, China. Growth in the Chinese installed capacity and the domestic supply chain has been rapid, mainly in the bottom-fixed segment. Whereas the Chinese supply chain generally meets the majority of domestic requirements, leading Chinese manufacturers are playing an increasingly important role in the international market. Increasingly large Chinese made turbines and foundations are being supplied to projects in the major European market and the emerging East Asian markets. Cable manufacturers Hengtong, Ningbo Orient Cable and ZTT have also supplied European projects. Of particular note, where the three dominant western turbine OEMS (Vestas, Siemens and GE) are focusing efforts on commercializing ±15 MW turbines, Chinese OEMS are developing a range of models from 16-20+ MW. There has been some resistance to the Chinese players supplying European projects, but where performance, price and delivery times all count, we anticipate an increasing role of the Chinese supply chain in the European and East Asian markets.

Vessel demand in China relies mainly on domestic supply. Chinese yards also maintain a strong position in the international vessel new building segment, both for construction and logistics/support vessels.

TAIWAN, JAPAN, SOUTH KOREA



Taiwan, Japan and South Korea – much promise but measured development and high local content barriers have taken some of the shine of the opportunity



After much initial excitement, underpinned by a clear development plan to support the deployment of ~1.5 GW per year to achieve ~20.5 GW by 2035, Taiwan's offshore wind market has begun to face increased challenges, with only half of the 2035 capacity aspiration currently awarded. ~5.1 GW of capacity is either operational or under construction. Local weather and ground conditions, high local content requirements, a one-year delay in the Allocation Round 3.1 commissioning and grid connection deadline, and a challenging auction process have resulted in development being behind the aspiration. The gap between reality and aspiration is impacting the supply chain which is looking to other East Asian market to fill order books. In the short- to mid-term, this means Japan and South Korea. Both markets are planning auctions before the end of 2024 to support their respective 10 GW and 14.3 GW aspirations by 2030. Despite the longer-term potential in these two markets, both for bottom-fixed and floating wind technologies, annual auction allocations remain comparatively small (below 1.5 GW), and we anticipate that local supply chains will continue to demand more project activity to justify capacity investments. As with Taiwan, we anticipate that projects in Japan and South Korea will require

high levels of local content.

Japan, South Korea and Taiwan all feature floating wind development plans. Whereas as Japan and Taiwan's efforts can be classed as technology and pre-commercial scale, South Korea is moving to auction commercial scale floating capacity in the east of the country by the end of 2024, and South Korean EPCI contractors and shipyards are gearing up to meet the challenge.

All three counties are home to domestically built, owned and operated bottom-fixed construction vessels. South Korea is also a major builder of international construction vessels. Given the comparative weakness in the oil & gas vessel segment of these three countries, it is still to be seen if floating wind auction activity will trigger domestic newbuilding programs of targeted wind vessels.

VIETNAM

Much promise but slow development

Till now, Vietnam has only featured intertidal projects that do not rely on traditional offshore wind supply chains. Central planning aspires to deploy 6 GW of bottom-fixed offshore wind by 2030 from north to south of the country. However, there have been delays in adopting the necessary legal and regulatory frameworks to support the aspiration.

Vietnamese yards are already active in building offshore wind support vessels for the European market. We anticipate that bottom-fixed projects will rely on the support of regional construction vessels supported by the domestic offshore support vessel segment.

AUSTRALIA

Emerging as a potential major regional market

Australia is fast becoming a market with major potential to develop offshore wind capacity. The government has designated a total of six priority offshore wind zones in the country. The government has developed a robust process for identifying and awarding offshore wind licenses. 12 projects have recently received 7-year feasibility licenses to progress the construction and operations planning for projects in the State of Victoria, the first state to set offshore deployment targets – at least 2 GW by 2032, 4 GW by 2035 and 9 GW by 2035. Whilst the initial Victoria wind farms feature bottom-fixed technology, the anticipated feasibility licenses for New South Wales will require floating wind solutions.

As with oil & gas projects in the country, we anticipate that construction vessel supply will be largely provided from the international fleet, but logistics and operations & maintenance support will be met by domestic owners.

THE PHILIPPINES

One to watch

The Philippines is emerging as a potential market for the end of this decade and into the next. The country aspires to deploy the country's first offshore wind farm by 2030 and to install around 20 GW by 2040 and is working with developers to create conditions to advance projects.

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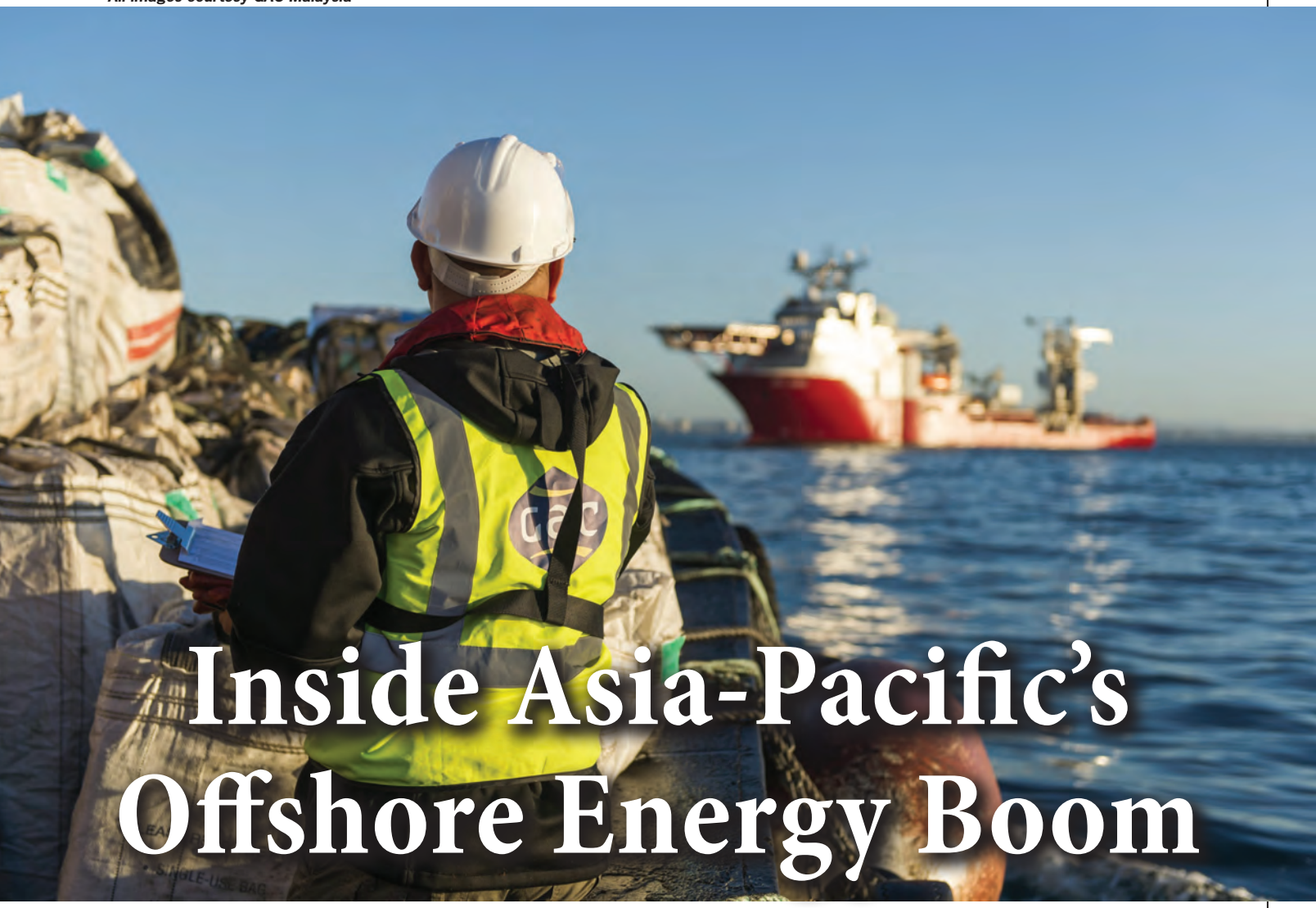


Inside Asia-Pacific's Offshore Energy Boom

Asia Pacific is seeing a renaissance in offshore energy activity, especially upstream. Malaysia, in particular, is focusing on substantial development with a renewed emphasis on traditional offshore oil & gas (O&G) projects

By Herman Jorgensen, Managing Director of GAC Malaysia

Strategic initiatives are attracting investors and petroleum contractors to Asia Pacific's offshore energy market, propelling the region towards enhanced security and economic growth. As countries tap into their local resources to meet rising demand, the region is being presented with exciting opportunities for investors, energy players and the interconnected maritime and logistics sectors.

While countries like South Korea, Taiwan and Vietnam transition to cleaner energy sources and embrace environmental sustainability, the oil and gas (O&G) sector is experiencing a resurgence across the region.

Malaysia is prioritizing traditional O&G projects, particularly offshore drilling, following the discovery last year of significant offshore reserves totalling more than 1 billion barrels. Not surprisingly, analysts at BMI say Malaysia's O&G sector is acting as a magnet for investors and Petroleum Arrangement Contractors (PACs), evidenced by their active participation in recent petroleum bidding rounds.

Offshore O&G discoveries in both Malaysia and Indonesia have reignited investment, reflecting renewed confidence following the 2015 oil price downturn.

The Energy Council's Regional Spotlight report highlights the expansion of Southeast Asia's O&G industry as the markets shift strategically from coal to natural gas, as well as rising domestic energy demand and increased industrialisation.

Increased Demand

Global fuel demand is projected to increase by 1.7 million barrels per day (mb/d) in the first quarter of 2024, driven partly by emerging markets. The tanker business has also seen significant growth post-pandemic, particularly from companies like Shell and Chevron, which hold substantial global contracts.

A recent report from the International Energy Agency (IEA) states that the current oil demand in Asia Pacific is approximately 30.8 mb/d, a figure likely to increase to 38.5 mb/d by 2030. Countries in the region are turning to their local offshore resources to meet rising demand and enhance energy security.

Recent discoveries and strategic initiatives are enhancing the attractiveness of the O&G sector in Indonesia. Plans are underway to offer new exploration blocks in the North Sumatra basin by mid-2024, focusing on unconventional resources. These efforts are complemented by substantial revisions to the Oil and Gas Law and the implementation of investor-friendly fiscal policies to streamline the investment process.

In January, Malaysia's state energy firm Petronas was awarded production-sharing contracts for six exploration blocks in the 2023 bidding round. A fresh bidding round was launched to explore 10 blocks and clusters, targeting potential investors. In July, Petronas signed contracts for three Discovered Resource Opportunities (DRO) clusters located offshore Peninsular Malaysia.

Malaysia is set to drill approximately 30 exploration wells this year and 35 wells in 2025, a sharp rise from just eight in 2021. Meanwhile, Indonesia is expected drill around 40 wells this year, doubling the number drilled during the pandemic. And while exploration in Indonesia is expected to decrease slightly in the latter half of the decade, it is expected to remain consistent in Malaysia through 2028 due to successful bidding rounds in recent years.

Fossil fuels currently account for three-quarters of the increase in energy demand by 2030 in the Asia-Pacific region, leading to a notable rise in related carbon emissions. To accelerate the transition to clean energy while meeting rising demand, the region must attract significantly higher levels of investment in the energy sector.

Strengthening local support

Countries in the region are increasingly localizing energy projects, collaborating with local partners and suppliers to gain more control over production. Such critical energy projects require substantial local support if they are to reach their potential. Unlike projects in Europe

and the North Sea, where foreign investors that come with their own support networks are welcomed, Malaysia mandates the extensive use of local support for offshore energy projects.

The surge in activity demands a comprehensive range of maritime services to support expanding demand. With its integrated shipping, logistics, and marine services portfolio, GAC is well-equipped to meet the diverse needs of the energy sector and supports projects across multiple locations and international borders.

GAC Malaysia has expanded its operations nationwide, with 17 offices covering 23 ports. The Labuan office specifically supports the offshore O&G sector as a supply base for offshore projects, as does the Kota Kinabalu office opened in August 2023.

Increased activity drives steady demand for supply vessels, drilling ships, floating production storage and offloading units (FPSOs), as well as port facilities and yard space to support energy projects. Competition is fierce, particularly around effective mobilization and demobilization projects, but experience and expertise to sufficiently support offshore O&G and renewable energy projects.

Prospects

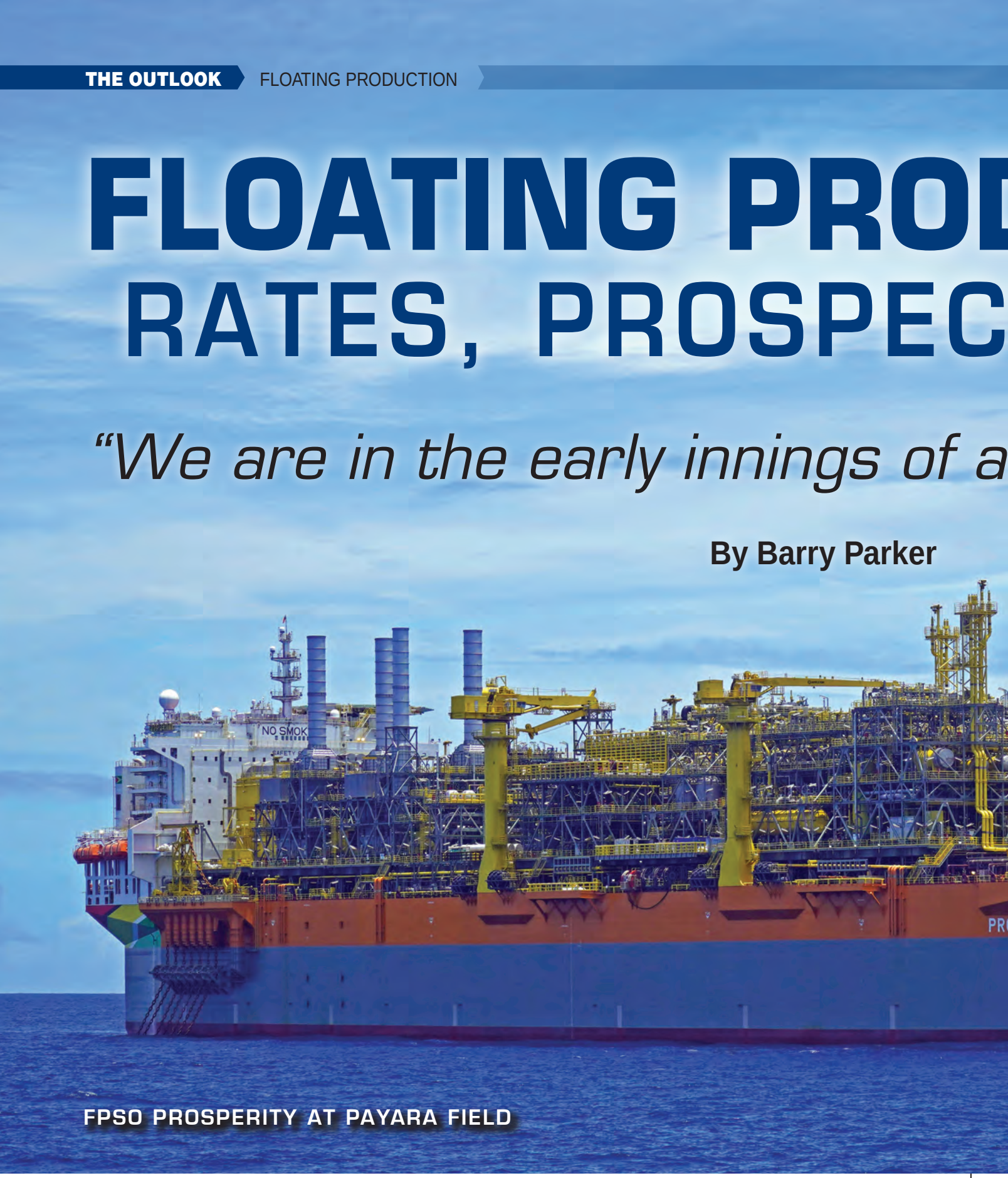
Malaysia's prospects for the coming years look promising, with the development of new technologies offering more opportunities for new players to enter this market. The region as a whole is brimming with offshore energy opportunities. Right now, it's an exciting place to be.

Strategic investments and regulatory reforms are driving growth in the offshore energy sectors, transforming the regional market landscape and enhancing its potential role in addressing global energy demands. Ensuring the maritime and logistics sector can support these offshore projects effectively, be they O&G drilling platforms or wind farms, is vital if Asia Pacific is to realize its energy potential.

FLOATING PROD
RATES, PROSPEC

"We are in the early innings of a

By Barry Parker



FPSO PROSPERITY AT PAYARA FIELD

Exxon Mobil

DUCTION:
TS SURGE

n offshore up-cycle"

The energy sector's robust Merger and Acquisition (M&A) activity of 2023 has continued in 2024, with a number of high-profile deals impacting the offshore oil and gas sector. But many of the reported transactions have seen oil companies bolstering their stakes onshore, notably in the Permian Basin (a trend labeled as "Shale 4.0" by analysts at Rystad Energy) following the announcement earlier this year that ConocoPhillips would acquire Marathon Oil for roughly $22.5 billion.

But offshore oil and gas still looms large.

In a late 2023 deal that was labelled as a "blockbuster", Chevron (NYSE: CVX) announced an agreement to acquire Hess (NYSE: HES) in shares-for-shares deal valued at $53 billion. In late May, Hess shareholders approved the deal. But an imbroglio regarding Hess's assets in the Stabroek Block offshore Guyana has delayed the transaction's closing, which was originally set for first half 2024. In the dispute, which is currently being arbitrated, Exxon Corporation (NYSE: XOM), with a 45% stake in Stabroek, has claimed a right of first refusal ("preemptive rights") to purchase Hess's Guyana holdings under an operating agreement that also includes China National Oil Company (CNOOC, with a 25% holding, filed separately for arbitration).

After the end May vote, Hess said: "Completion of the merger remains subject to other closing conditions… and the satisfactory resolution of ongoing arbitration proceedings regarding preemptive rights in the Stabroek Block joint operating agreement. Chevron and Hess are working to complete the merger as soon as practicable." Exxon, however, suggested that the arbitration, filed with the International Chamber of Commerce (in Paris), might continue into 2025.

Geopolitics further complicates things, as Guyana is engaged in a dispute regarding Venezuela's possible rights to ownership, stemming from a treaty signed in the late 1800s. Though the International Court of Justice (a United Nations agency) asked Venezuela to refrain

Petrobras

from asserting sovereignty over a large swath of Guyana (intersecting with Stabroek), the issue remains unresolved.

Economics of Exploration

Amidst these uncertainties, which followed on surges in exploration and discoveries in 2022-2023, chartering activity for exploratory drilling in the region had been muted. As exploration continues; March, 2024 saw the year's first discovery, at the Bluefin well (XOM's sixth sanctioned project in Staboek). First half 2024 saw XOM taking two ultra-deepwater drillships, Stena Carron (Gen 6 DP3, already stationed in Guyana) and Stena DrillMAX (completing a brief stint off Newfoundland & Labrador for ExxonMobil, following earlier work in Guyana, including the successful Bluefin discovery), for work starting in late 2024 at undisclosed day-rates. Activity is again picking up. Analysts Evercore ISI noted in its May edition of "Offshore Oracle" that: "Dayrates for Ultra DeepWater <drillships and semi-submersibles> are looking robust, averaging in the high 400s YTD. Four rigs announced this year so far exceeded $500 kpd, including the Deepwater Asgard (Transocean $505 kpd), the Deepwater Atlas (Transocean $505 kpd), the West Capella (Seadrill $545 kpd), and the Deepsea Aberdeen (Odfjell Drilling $504 kpd)"

How might these escalating day rates impact the economics of exploration; could projects be cancelled? At the 2024 Marine Money event held in late June in New York, Rystad Energy consultant Mike McCormick's wide-ranging presentation addressed this question, saying: "We are in the early innings of an offshore up-cycle," noting that global offshore capital expenditures in 2023 had reached $205 billion (with 13% tied to exploration). For 2028, Rystad forecast growth up to $242 billion of offshore capex. In his remarks, McCormick opined that the advent of $500k day rates would have minimal impact on decisions to move ahead; indeed, he said "Upcoming deepwater Final Investment Decisions (FIDs) are highly profitable at current price and cost levels." In explaining the economics at play, he noted that oil majors would look for a 15% - 20% return threshold for moving ahead on projects. The Rystad analysis suggested that, with $500k/day hires on rigs, a proportion of around 15% of deepwater projects awaiting FID would see internal rates of return below 20%. Reminding the Marine Money audience that the previous upcycle saw day rates nearing $800K/day, he suggested that around 50% of contemplated projects could still go ahead if hires on drilling assets approached such levels again.

Fleet Developments

The exploration sector's onshore merger mania (which saw XOM complete its $60 billion purchase of Pioneer Resources in Spring, 2024) has been complemented with an offshore component. In June, 2024, Noble Drilling announced terms of its acquisition of Diamond Offshore, in

FPSO CARIOCA MV30 PRODUCING AT SEPIA

MODEC

a transaction expected to close in early 2025. Noble wrote that: "Noble will own and operate a fleet of 41 rigs including 28 floaters and 13 jackups. Additionally, backlog for the combined company would be approximately $6.5 billion as of today." After the deal, with a closing anticipated in Q1 2025, Diamond shareholders will own approximately 14.5% of Noble's shares. According to Evercore ISI, the merger would create the fourth largest rig owner (following COSL, ADES and Valaris).

Enhanced technologies, tied to optimizing operations, are playing a role throughout maritime sectors, including in offshore. The drillship Stena Drillmax, bound for Guyana following its deployment offshore Newfoundland & Labrador, also achieved a first, receiving the ABATE (P) notation from Class society DNV. As explained by DNV, "Stena Drilling has implemented several technical and operational measures to enable Stena Drillmax to substantially reduce Greenhouse Gas Emissions." DNV adds that "this notation (reflecting best practices for emissions reduction, and monitoring) follows on to Stena Drilling gaining the ISO 50001 certification for energy management."

Offshore production, typically accomplished through consortia of large oil companies, is seeing continued technical advances, buttressed by the project finance structures behind the deployment of FPSOs. Liza Unity, one of two FPSO's working for XOM at its Liza field (the oil giant's first sanctioned project at Guyana) recently attained the first REMOTE-CON

Stena Drilling

DRILLSHIP STENA DRILLMAX


FPSO LIZA UNITY


OIVIND TANGEN,
CEO, SBM OFFSHORE

Images this page courtesy SBM Offshore

notation for an FPSO from American Bureau of Shipping (ABS). According to ABS's President and Chief Operating Officer, John McDonald, "Safety and quality are at the heart of our mission, and we join SBM Offshore and ExxonMobil Guyana in the commitment to exploring new innovations for the betterment of offshore energy production."

In early 2024, XOM paid more than $1.25 billion to SBM Offshore, which had built the FPSO Liza Unity in Singapore at the Keppel yard (now Seatrium), to attain ownership of the FPSO. Under a "project finance" structure, initial financing (of $1.14 million at Libor plus 1.50%) agreed in 2019 was sourced by SBM Offshore from a consortium of nine international banks. The payment from XOM was then used to pay off the original project finance facility (following a standard two year post "post completion" period in the initial loan, when the ownership of the unit is transferred to the new owner).

Liza Unity, along with a second unit, Liza Destiny (deployed in 2019), were the first to be constructed using SBM's innovative Fast4Ward program which combines the multi-purpose hull and several standardized topsides modules. SBM has plans in place for construction of eight hulls with the uniform designs. In late 2023, SBM announced that it had booked a $210 million "revolver" with an 18-month tenor (option of an additional six month) for hull financing. When the hulls are sold, or project finance loans are drawn down, then a portion of that revolving credit will be repaid (along with senior loans that might also be in place). The FPSO Prosperity is also working for XOM in the region. XOM explains that these units use

Petrobras

produced gas to help power the FPSOs- reducing emissions compared to flaring of the gas.

In Spring, 2024, XOM announced that it was forging ahead on "Whiptail", a new project offshore Guyana which is slated to come online in late 2027. In advance of the FID, the oil giant had previously set in motion a contract for engineering/design of the fifth FPSO, to be named Jaguar, in the Fast4Ward program. According to SBM Offshore, the new Fast4Ward FPSO, which will be moored in waters with a depth of 1,630 meters, will be able to produce around 250,000 bbl/day of oil; storage capacity is 2 million bbl/day. In June 2024, the hull (designated as MPF5 and now set for topside work in Singapore) was launched from a drydock of the Shanghai Waigaoqiao Shipbuilding (SWS), a subsidiary of China State Shipbuilding Corporation Limited (CSSC). In a new business model for SBM Offshore, it will operate the FPSO for the oil company owner. Øivind Tangen, the CEO of SBM Offshore (assuming the role in April, 2024), commented in a Q1 financial report, "…It will be our first based on a sale and operate model, adding an accelerated cashflow profile for the project to our backlog. Following transfer of ownership to the client at the end of the construction period, we expect to operate the FPSO under our 10-year Operations and Maintenance Enabling Agreement." SBM Offshore also announced that it had sourced $250 million in a 12-month bridge loan (optional six month extension), to be repaid when a construction finance package kicks in.

To the east of Guyana, Suriname is also seeing oil exploration, and production. Total Energies, the operator of "Block 58" in waters approximately 150 miles offshore Suriname, is expected to make a FID in late 2024 regarding an FPSO project, following successful exploration using the drillship Noble Valiant. If plans move ahead, production would start sometime in 2028. In preparation, SBM Offshore, partnering with Technip Energies, and in line with the Front End Engineering and Design (FEED) studies, has reserved another a Fast4Ward hull.

Still father to the east, Petrobras has been ramping up its activity in the Santos Basin offshore Brazil. Late April saw the arrival of the newly constructed FPSO Marechal Duque de Caxias, owned by MISC Berhad, at the Mero field, following a voyage from Yantai, China. This FPSO had been converted from a VLCC at the CIMC Raffles yard, which also handled construction and integration of topside modules.

In May 2024, after FID was taken on new projects, Petrobras announced that it had awarded Seatrium with construction contracts for two FPSOs (to be named P-84 and P-85), with an aggregate pricing in excess of the equivalent of $8 billion. According to Seatrium, each FPSO will each have a production capacity of 225,000 barrels of oil/day and gas processing capacity of 10 million m3/day. Delivery of the two FPSO's is slated for 2029; they will operate in the Atapu and Sépia fields (also in the Santos Basin); where Petrobras has majority stakes (but consortia members also include Total and Petrogas). Petrobras's Strategic Plan for 2024 – 2028+, unveiled in late 2023, pointed to deployment of 14 new FPSOs, of which 10 had already been contracted. According to the company, "A new generation of more modern, more technological, more efficient platforms, with lower emissions, is being built."

Shell (with a 16.7% holding in the Atapu consortium), elaborated on the advanced technologies, saying: "The new unit <P-84> will feature all-electric capability, aimed at lowering carbon intensity for production processes." Seatrium goes into additional detail, saying that: "Both FPSOs will incorporate advanced technologies such as zero routine flaring and venting, variable speed drives and measures to control emissions and capture CO2, including an all-electric concept, which focuses on efficient power generation and increased energy efficiency to achieve a 30% reduction in greenhouse gas emissions intensity."

Shenzhen University

SEAWATER ELECTROLYSIS: ECONOMIC FOLLY?

While scientists hail their advances in producing green hydrogen directly from seawater, others see it as pointless.

By Wendy Laursen

"The energy savings available are a mere rounding error in terms of system efficiency, and the cost of reverse osmosis equipment is a tiny fraction of the cost of a hydrogen plant."

– Paul Martin,
Process Engineering Consultant, Spitfire Research

The idea of getting rid of the pre-treatment of seawater that is required to provide pure water to electrolyzers seems to make sense – it reduces costs, footprint and energy consumption, ultimately reducing the cost of producing green hydrogen.

However, the challenges are considerable. The NaCl in seawater would lead to the production of chlorine gas. "If we were to meet the world's hydrogen needs without solving this issue first, we'd produce 240 million tons per year of chlorine each year – which is three to four times what the world needs in chlorine," said RMIT University's Dr Nasir Mahmood on announcing his team's development of new catalyst technology that could overcome the problem.

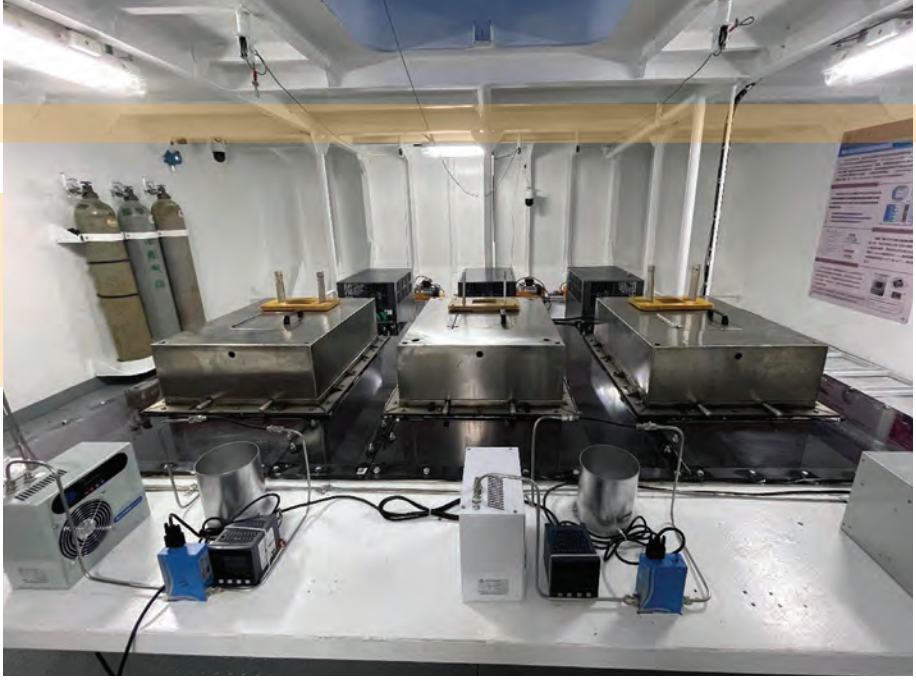
"Seawater electrolysis is a solution that is looking for a problem," says Bart Kolodziejczyk Associate Director at Boston Consulting Group. In a blog explaining his stance, he says the complexity of performing electrochemistry in seawater is high due to the large number of organic and inorganic species it contains. The cost and energy benefits, meanwhile, are negligible.

This is partly because desalination technology is already efficient. Prof. Mohamed Mamlouk of Newcastle University says its cost depends on parameters such as feed water salinity, plant capacity and labor costs. Reverse osmosis has the lowest investment, total water cost and footprint and is better suited to offshore wind farms than other technologies. While fouling can occur, redundancy or a store of fresh water could account for shutdowns.

The benefits of seawater electrolysis are speculative at best, says Paul Martin, process engineering consultant at Spitfire Research. The energy benefit of eliminating reverse osmosis water purification is 0.035kWh versus 50-65kWh to make a kilogram of hydrogen from water. "The energy savings available are a mere rounding error in terms of system efficiency, and the cost of reverse osmosis equipment is a tiny fraction of the cost of a hydrogen plant.

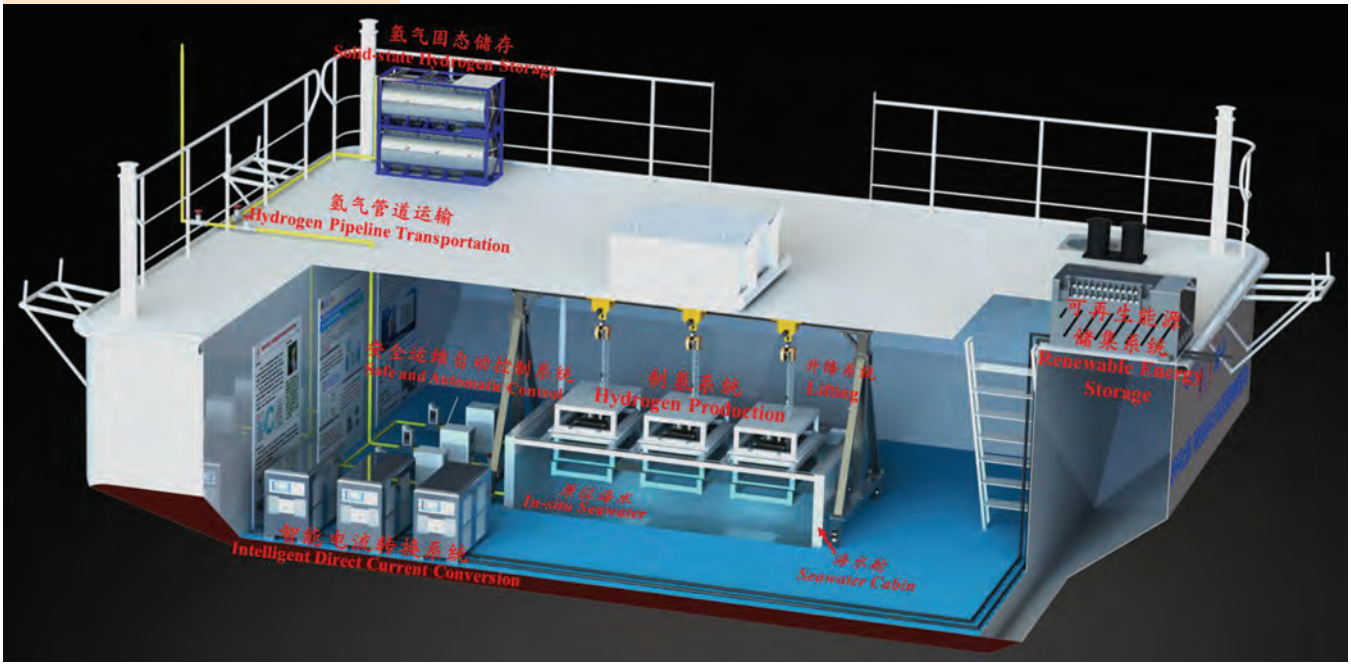
"Yes, people in deserts worry that foolish hydrogen companies will steal what little fresh water they have available, but the best hydrogen production projects will be on the sea where hybrids of wind and sun will raise capacity factor and make the projects more economical," says Martin.

That's not to say that transporting hydrogen to shore to replace the coal and natural gas used by industry will be more economically viable than using locally available electricity ashore. To think otherwise is what Martin calls single fuel substitution thinking, and it could stem from the desire to have a gas that might eventually and gradually replace natural gas.



In-situ direct electrolysis of seawater without desalination for hydrogen production live test.

Shenzhen University



Floating platform for renewable energy utilization and seawater hydrogen production.

Shenzhen University

"If you're Japan or South Korea or somewhere that doesn't have any other options, and you want to import molecules for energy, what you're admitting is that your major industries are going to be completely bankrupt. There are economic competitors in the world that will be using electricity directly and paying about a tenth as much per joule for energy as you are."

Still, On December 16, 2022, a mere 16 days after the publication of a seawater desalination research paper by Shenzhen University researchers, Dongfang Electric Corporation made a dedicated investment of 30 million RMB ($4.2 million) to help develop the technology. This resulted in the world's first successful test of direct seawater electrolysis for hydrogen production offshore from wind power in June 2023. The demonstration achieved stable, continuous operation for over 240 hours.

The researchers claim that the elimination of seawater transportation, desalination and the treatment of the brine produced reduces the costs of hydrogen production to slightly higher than the cost of grey hydrogen from coal and significantly lower than the cost of blue hydrogen derived from natural gas.

The plan now is to make the technology more efficient, more stable, more scalable and more intelligent. This, they say, will lead to a comprehensive zero-carbon hydrogen energy development pathway in China and distinctive electrolysis hydrogen production industrial models.

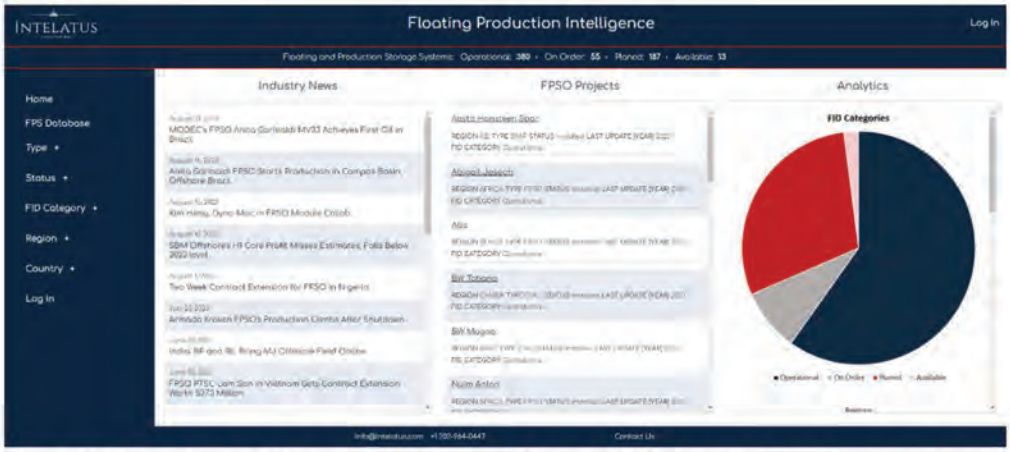
Economic folly? Time will tell.

INTELATUS

GLOBAL PARTNERS

The all-new way to track FPS production in real time

Floating Production Systems Intelligence



Introducing the **ultimate online resources for offshore energy professionals** - the Floating Production Systems Intelligence and the Floating Wind . This comprehensive database provides key technical and commercial details on all floating production systems worldwide.

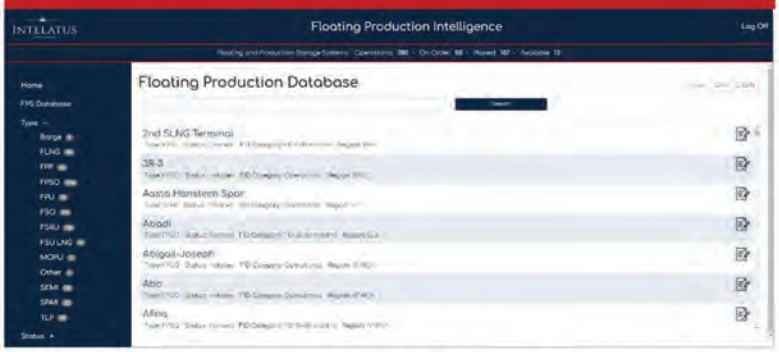
Track Progress and Production on:

Operational: 380

On Order: 55

Planed: 187

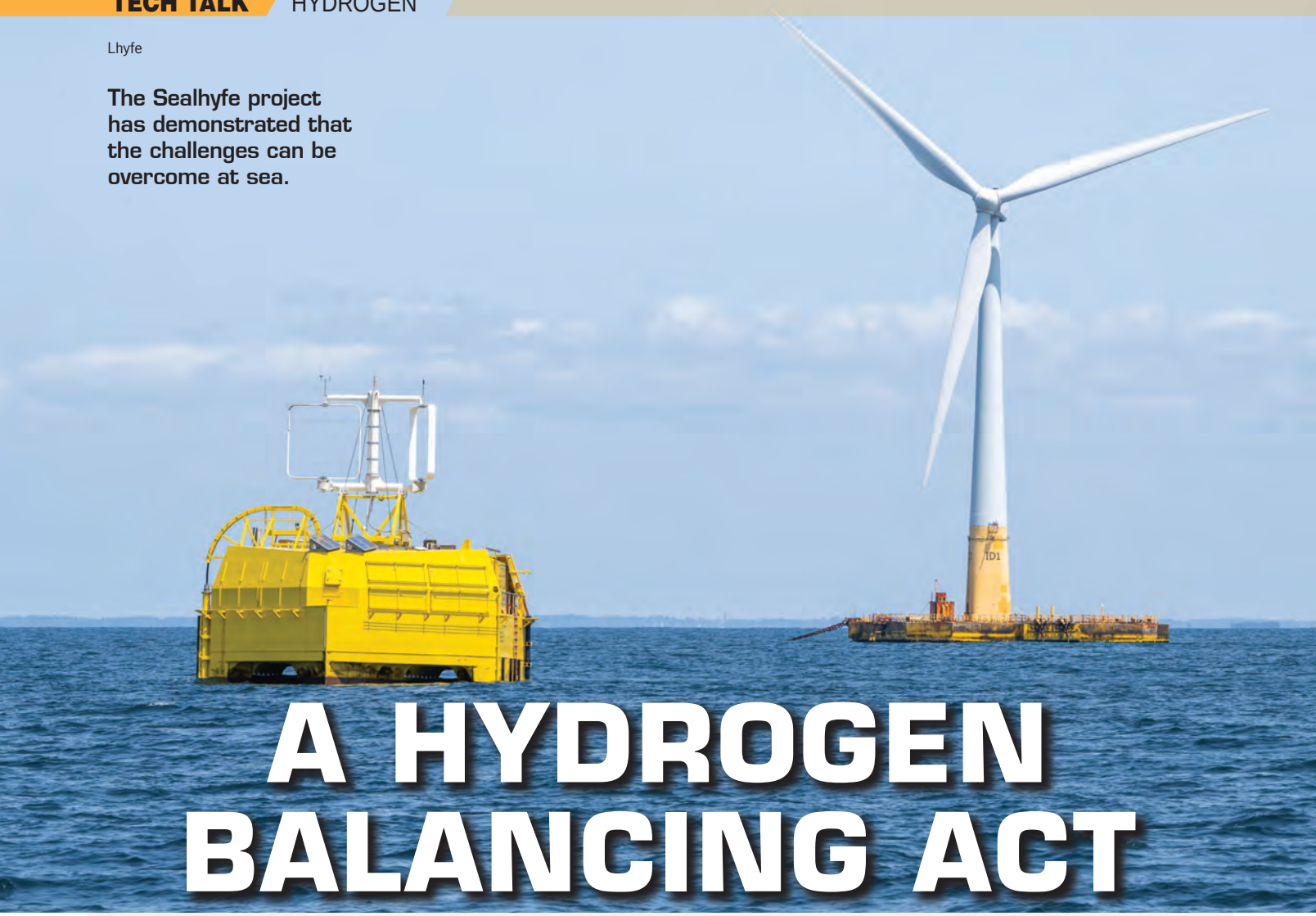
Available: 13



With over 700 floating production unit listings, the database is the most extensive compilation of FPSO, FPU, FPS and other floating production system information available.

The user-friendly interface allows for easy browsing and searching of the database by easy to filter parameters. Each system profile includes all key facts and capabilities, storage capacity, mooring type and more.

Visit https://fpso.intelatus.com for pricing and more information.



Lhyfe

The Sealhyfe project has demonstrated that the challenges can be overcome at sea.

A HYDROGEN BALANCING ACT

The intermittency of offshore wind power is both a challenge and an opportunity for green hydrogen production.

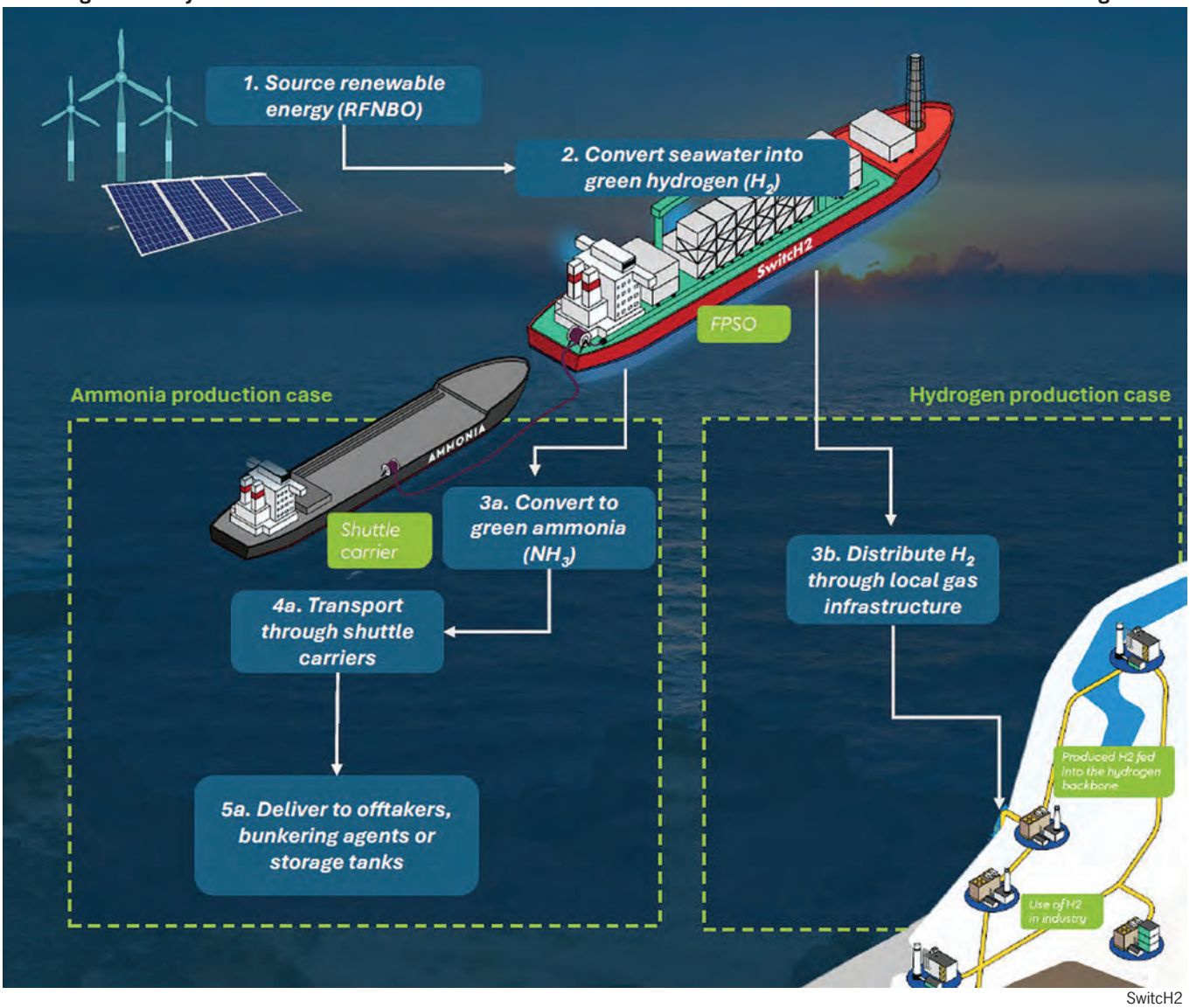
By Wendy Laursen

There will be a new generation of platforms taking up space in offshore wind farms as hydrogen production is used to help balance power supply and demand. Green hydrogen could be produced at off-grid windfarms but, if grid-connected, it can also be produced at peak times by running electrolyzers and then stored for later.

"Here, there's an important role to play for green hydrogen which can operate at a different scale to batteries to balance out fluctuations in the supply of, and demand for, renewable energy production," says Synne Myhre Jensen, Public Affairs Advisor at Norwegian hydrogen company Hystar. As part of the HyPilot project, collaborator Equinor is planning to demonstrate Hystar's high-efficiency PEM electrolyzer for hydrogen production tailored to the variable output typically found in offshore wind applications.

PEM electrolyzers can ramp up and down quickly to deal with the fluctuations in power, although frequent starting and stopping could lead to component degradation, but the Sealhyfe project has already demonstrated that the challenges can be overcome - at sea. Lhyfe conducted a 14-month trial of a 1MW PEM electrolyzer from Plug that confirmed the system's ability to manage the variability of power experienced, including at maximum production capacity. The

Green hydrogen could be produced at off-grid windfarms, but it can also be produced at peak times by running electrolyzers and then stored for later in cases where the windfarm is connected to the grid.



SwitcH2


SwitcH2

SwitcH2 believes it's logical and more economical to have a centralized platform for the electrolyzers.

performance achieved was as high as on land. Lhyfe aims to have a 10MW system in operation from 2026.

In another project, SwitcH2 and BW Offshore, along with partners Strohm, MARIN and TU Delft, are developing an offshore green ammonia FPSO able to produce 790 tons of green ammonia per day at its peak using a 300MW electrolyzer plant.

The FPSO will use wind and wave energy, converted to DC onboard, to power PEM electrolyzers. "The ship's power generation and distribution system is able to produce the power needed to keep the electrolyzers running at all times, because we can add power from the ship's power generation system in addition to the renewable energy," says Bob Rietveldt, International Director at SwitcH2. "This way we avoid any shutdown of the plant and are always able to generate the essential loads needed to keep operating, even in the days when there is no wind."

He says it's logical and more economical to have a centralized platform for the electrolyzers. "In the case of decentralized deployment on individual wind turbines, it would mean there are times it cannot produce at all if you cannot store the power, and it would be difficult to start-up again and most likely require hydrogen storage or battery power at the turbine to overcome the situation, thereby making it very costly. Centralized electrolyzers will always remain operational as we can supply additional power from the ship's system when needed."

Solar in addition to offshore wind makes a lot of sense, he says. "Combining wind, wave and solar is more stable but still there can be days where back-up power is required. Energy storage in the form of produced liquid ammonia in our FPSO is the easiest and most economical way to do this, and it is easy to store inside the FPSO. Hydrogen storage or battery storage are more difficult and not the most optimal solution."

Anion exchange membrane (AEM) electrolyzer technology, a development of PEM that uses non-critical raw materials, could also offer a scalable and economic solution, according to participants in the EU-funded HYScale initiative. The specific technology, developed by CENmat, can operate stably at higher current densities, says CEO Dr Schwan Hosseiny, and this means the plant can be more compact. "Low space requirements are important because the projected electrolysis installation to 4-5 terawatts by 2050 would require enormous space if electrolyzers operated at low current densities."

Oceaneering International

ROBOTICS DRIVE OFFSHORE EFFICIENCIES

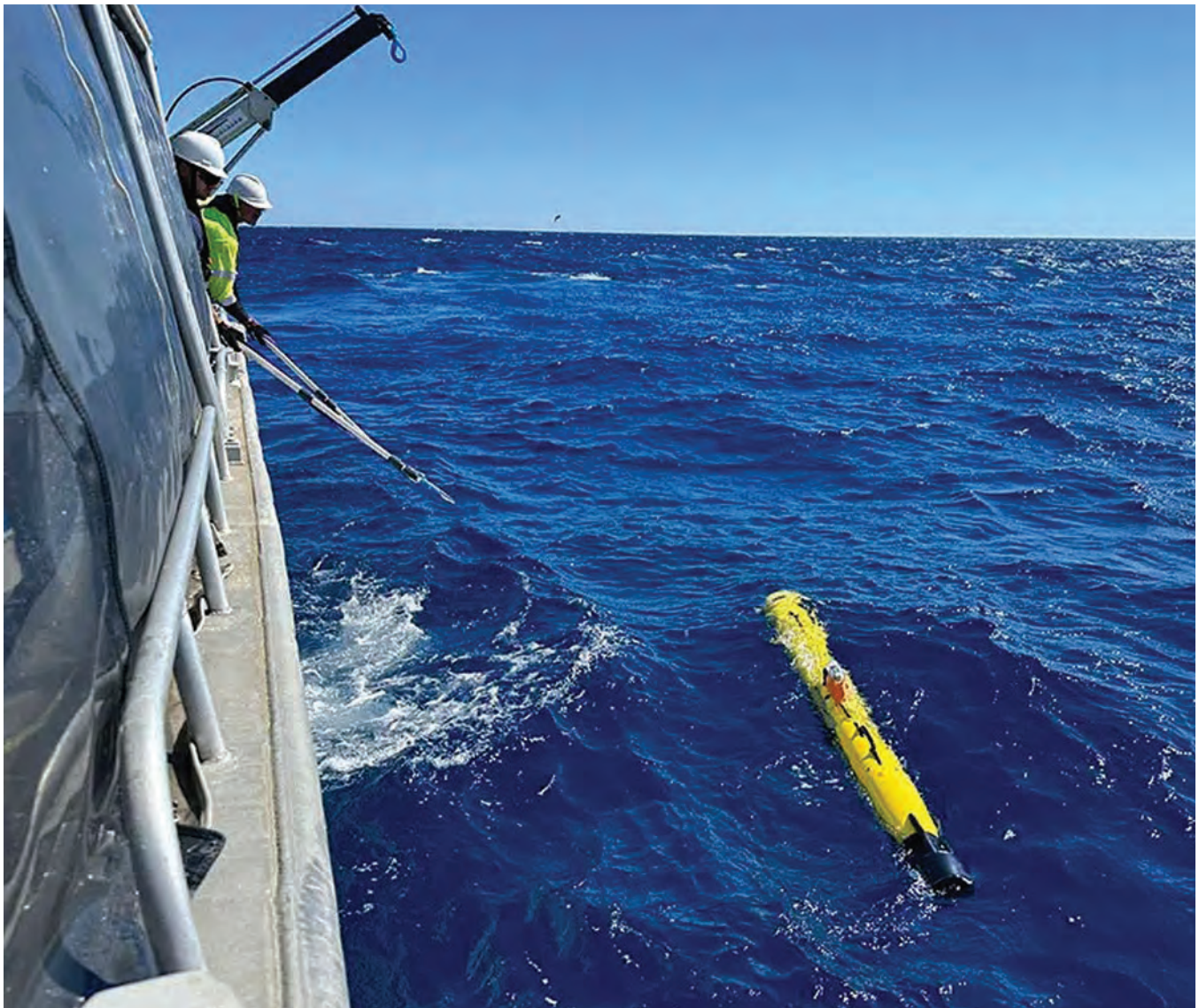
For subsea inspection, maintenance and intervention, robotics solutions are increasingly brought to the fore in the name of efficiency and safety.

By Amir Garanović, Managing Editor at Offshore Engineer

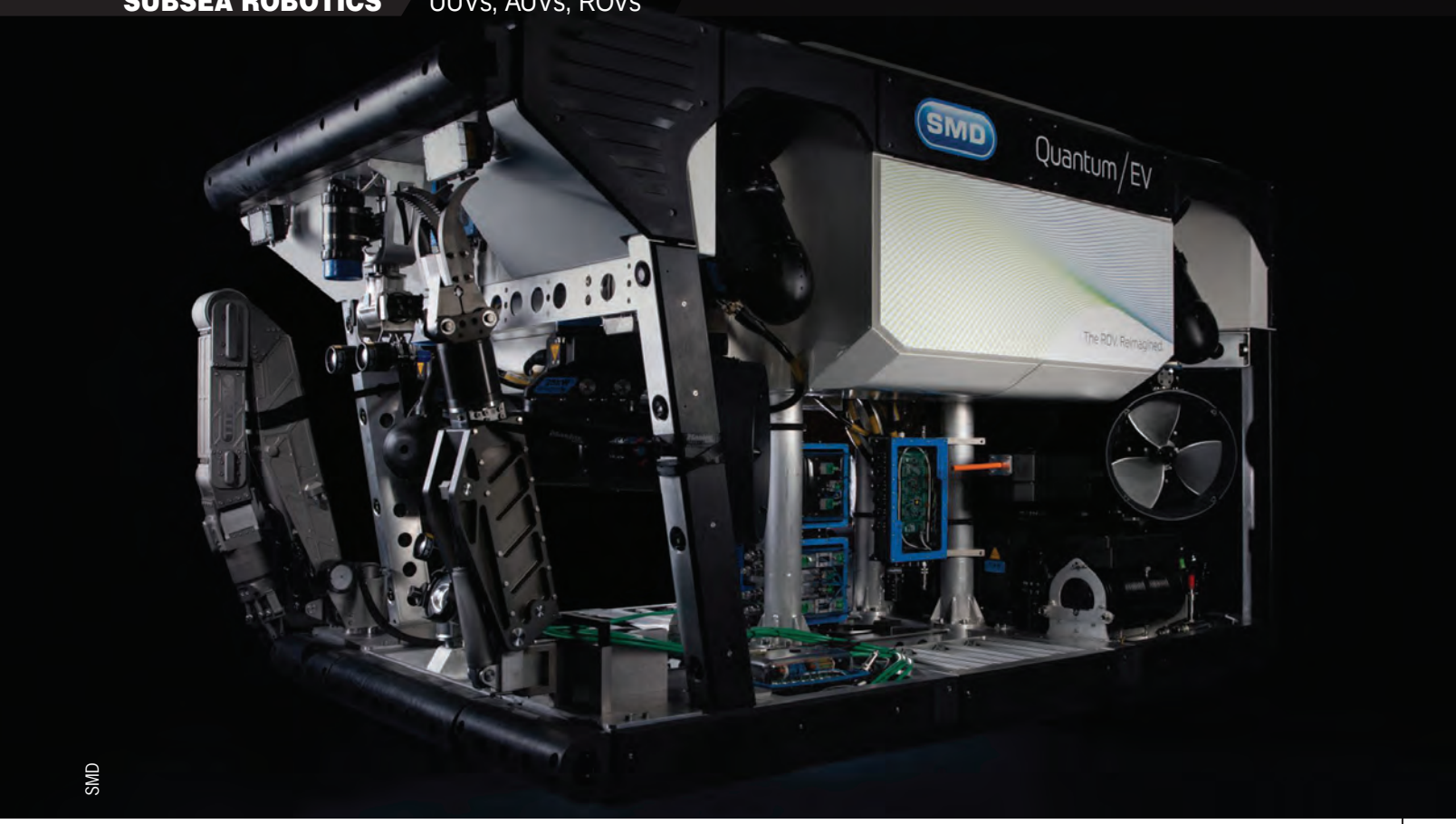
Oceaneering solidified its position as one of the leaders in AUV tech with significant projects in 2024. One of the key highlights includes its collaboration with TotalEnergies, where Oceaneering's advanced hybrid AUV/ROV system was deployed for subsea inspection and monitoring tasks. Late in May 2024, Oceaneering's Freedom AUV concluded the pipeline inspection industrial pilot project in the North Sea, which covered an inspection of over 120 km of subsea pipelines, resulting in a reduction in time, and emissions, of an estimated 50% compared to existing methods with equivalent quality of the inspection, according to the companies.

The Freedom AUV design incorporates a multi-thruster design which provides six degrees of freedom in vehicle maneuverability. It features onboard adaptive behaviors, developed to provide additional insights into subsea features. The onboard autonomous capabilities, together with high specification instruments – including a laser scanning system and multibeam sonar technology – resulted in a detailed external inspection of subsea pipeline features. In addition to commercial applications, Oceaneering has been engaged in projects with the U.S. Navy, where the Freedom AUV has been used to evaluate capabilities of the platform for potential future development of a large displacement unmanned undersea vehicle (LDUUV) prototype.

UTEC tested its upgraded Teledyne Gavia AUV offshore Australia earlier in 2024, achieving several milestones – including the deepest dive and the first-time positioning with the new subsea ultra-short baseline (USBL) system, which aids the vehicle inertial navigation system positions. The Gavia AUV is suited for use for reconnaissance surveys, route surveys for cable and pipeline pre-engineering, site surveys, as well as pipeline and platform inspections. The upgrades to the Gavia AUV conducted by UTEC included the addition of INS/Doppler velocity log (DVL) modules (PHINS C3 and Pathfinder DVL); battery modules increasing mission endurance from six hours to 12; cNode USBL modules and nose cone enabling USBL tracking, aiding acoustic communications to the AUV and incor-



Acteon



SMD

porating a new eight-megapixel camera in the nosecone.

The most significant upgrade, however, is the addition of the module that enables subsea USBL aiding of the vehicle INS positioning. This means the vehicle does not need to surface periodically to update the internal position and account for INS/DVL drift, creating efficiencies by allowing the vehicle to remain subsea and on task for the full 12-hour mission endurance as well as allowing use of the full 1000 m depth rating.

Previously, the requirement for the vehicle to return to the surface to update real-world position using Global Positioning System (GPS), meant that the deepest that the AUV had worked was 100 m, as anything deeper was too inefficient with the time spent diving and surfacing to update the position in deeper waters.

EXAIL, RTSYS AND ABYSSAL TEAM

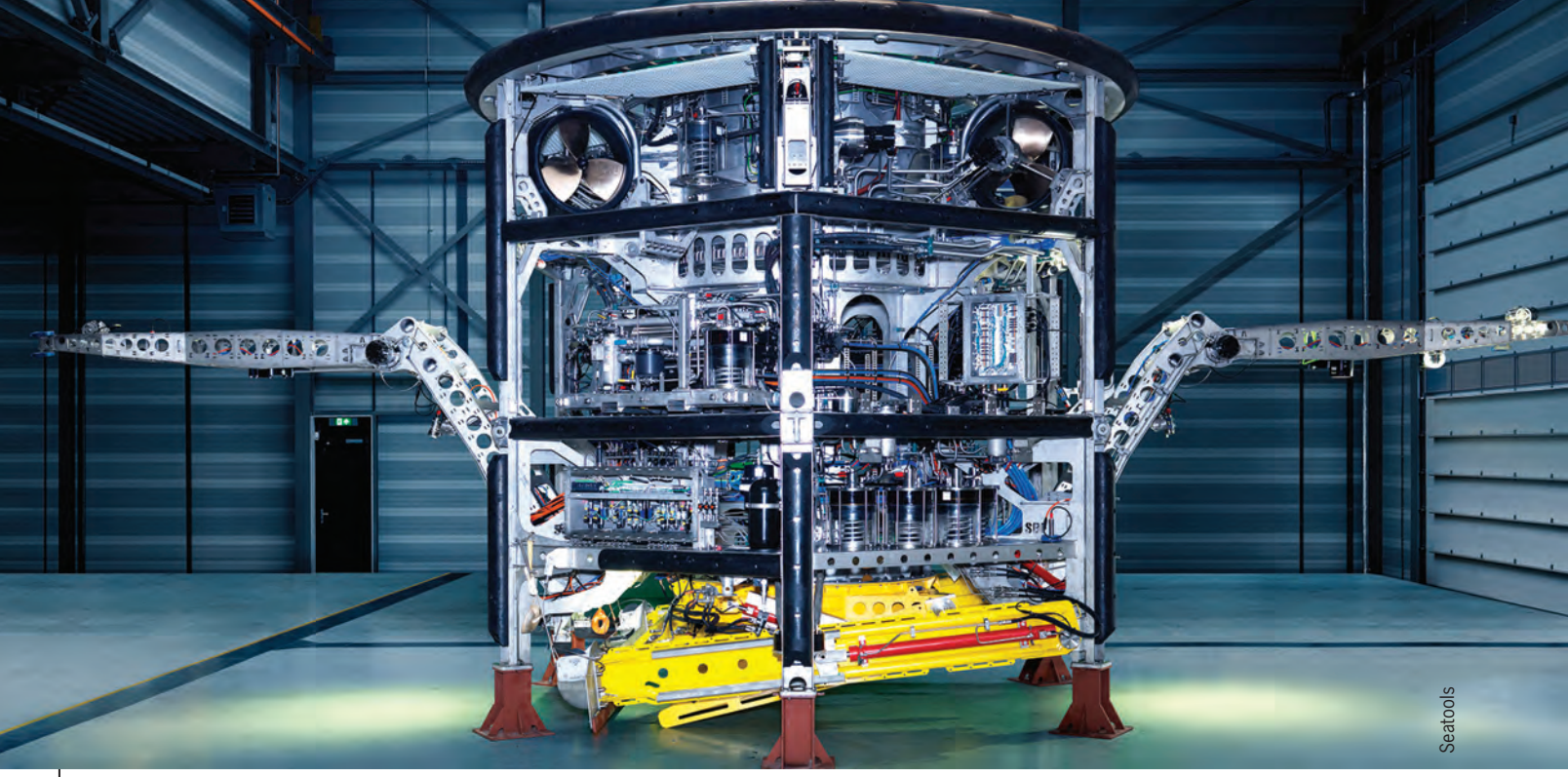
In a significant development for seafloor mapping, Exail has joined forces with RTsys and Abyssal to advance the capabilities of AUVs in complex subsea operations as part of the French government-backed project CARMA, that aims to develop swarms of AUVs for efficient ocean floor mapping.

The companies will work together to create a solution in which a multi-sensor underwater drone, capable of diving to 3,000 meters, will coordinate multiple AUVs to increase the surface of the exploration area, with the deployment of operational demonstrator expected in 2026.

As part of this project, for which the companies entered into strategic partnership in July 2024, Exail will improve the capabilities of its deepwater AUV A18-D to serve as the leading AUV to guide the swarm and enable navigation down to 3,000 meters.

RTsys will extend the capabilities of its newly developed AUV COMET-3000 to dive up to 3,000 meters. Multiple units will be provided to act as followers, along with the development of an innovative launch and recovery system for the AUV swarm.

ABYSSA will focus on developing exploration strategies for deep-water swarms of AUVS, and will also process the magnetic data collected to map the magnetic anomalies on the seabed. At the same time, the project will carry out a preliminary study on extending exploration capacity to 6,000 meters depth.


Seatools

ROVS

In the ROV segment, companies like Reach Subsea, Seatools and DeepOcean are pushing the boundaries of what ROVs can achieve, offering more precise, autonomous, and efficient subsea operations, while some, like Soil Machine Dynamics (SMD), signal a shift to fully-electric ROV, having recorded its first sale of such unit in 2024.

SMD has developed a modular robotic range ROV, available in work-class and survey class forms. The Quantum EV platform is suitable for heavy-duty construction, IRM, salvage and science work. The lighter-duty Atom EV is well placed for renewables, drill support and IRM applications.

SMD claims that its new robotics range is twice as efficient as an older generation hydraulic ROV. For a given input surface power, a hydraulic ROV will only convert around 34% into usable thrust performance.

However, SMD said its EV range is capable of converting 63% of the input power into useable thrust performance.

According to the company, its robotics range does not just offer better performance and reliability but they also consume less energy and dramatically reduce potential oil contamination risk, making operations more cost-effective and environmentally friendly.

In March 2024, SMD sold its first electric ROV to Luxembourg-based marine contractor, Jan De Nul Group.

SMD's Quantum EV will be integrated into Jan De Nul Group's new cable laying vessel, Fleeming Jenkin, and deployed to offshore energy projects globally.

The new fully-electric ROV offers superior levels of stability, position-keeping, efficiency and reliability, for increased performance across a wide range of subsea applications, at a lower operational cost, noted SMD.

Seatools, a specialist in subsea technology, has partnered with Belgium-based offshore installation services firm DEME to develop and deploy a state-of-the-art fall pipe ROV. This ROV is specifically designed for subsea rock installation projects, where precise placement of materials is required to protect pipelines and other subsea infrastructure. The newly developed Fall Pipe ROV introduces several innovative features, including the integrated rotator, which enables the offsetting of the ROV's heading relative to the vessel heading. This innovation ensures an optimal vessel heading, enhancing the workability level of rock installation operations while saving significant power compared to conventional Fall Pipe ROVs, according to Seatools. Another feature of the ROV lies in its expansive on-board survey equipment suite, employed for precise ROV positioning, monitoring operations and the environment, as well as conducting comprehensive pre- and post-surveys. The Fall Pipe ROV passed Factory Acceptance Tests (FAT), conducted by Seadrill, ahead of deployment on DEME's rock installation vessel Yellowstone, which secured a job in the U.S. to work on the Coastal Virginia Offshore Wind project, where DEME is installing 176 monopile foundations, three offshore substations and subsea cables.

Dominion Energy

The United States' first domestically built WTIV, Dominion Energy's Charybdis, is currently under construction at Seatrium AmFELS in Brownsville, Texas, and is slated for delivery in 2025.

COST OF US-BUILT WTIV CHARYBDIS BALLOONS TO $715 MILLION

By Eric Haun

The cost to construct the United States' first domestically built wind turbine installation vessel (WTIV), Charybdis, has risen to $715 million, Dominion Energy revealed in its latest quarterly results, marking another snag for the fledgling U.S. offshore wind industry.

The first-of-its-kind vessel — the only WTIV being built in the U.S. to comply with the Jones Act — was originally slated to cost about $500 million when U.S. power company Dominion ordered it from Brownsville, Texas shipbuilder Seatrium AmFELS (then Keppel AmFELS) in 2020. Dominion will own the 472-foot Charybdis through its subsidiary Blue Ocean Energy Marine.

The updated $715 million price tag is up from Dominion's $625 million projected cost given last quarter, reflecting new modifications to accommodate project specific turbine loads based on final certified weights and dimensions of the equipment and additional financing costs, Dominion said in its most recent investors presentation. The modifications will enable Charybdis to handle the "latest technology turbine design", according to Dominion, which did not reply to a request for comment.

Charybdis will have a maximum lifting capacity of 2,200 tonnes and be able to lift to heights of approximately 175 meters above sea level, while the largest international WTIVs currently under construction will be able to lift upwards of 3,000 tonnes and 220 meters.

The Cost of US Shipbuilding

The elevated cost of U.S.-built vessels is seen as a weight on America's offshore wind industry, which is already grappling with a number of cost-related issues.

"In the context of the international WTIV segment, where South Korean and Chinese yards dominate the new building landscape, the Charybdis can be seen as expensive, costing approximately 50% more at time of new building contract than a similar specification vessel contracted in South Korea in the same period," said Philip Lewis, director of research at Intelatus Global Partners.

For comparison, Danish company Cadeler recently announce a contract to build a WTIV in South Korea for $400 million.

"Charybdis is a Jones Act compliant vessel, requiring construction in yards that are not used to recent industrialized production of WTIVs, despite vast experience in jack-up rig and lift boat building," Lewis said. "On a like for like basis, Jones Act wind vessels cost more than their European- and Asian-built counterparts," Lewis added, noting that U.S.-built service operations vessels (SOV) and crew transfer vessels (CTV) are also significantly more expensive than those being built overseas for operations in Europe.

In addition to cost overruns, the Charybdis build program is also facing significant delays, having blown past its original 2023 delivery target. The project, which was originally planned to run 36-48 months, will now be closer to 60-72 months once sea trials are completed, Lewis said.

The vessel is now 89% complete and on track for delivery in late 2024 or early 2025, Dominion said in its most recent presentation to investors, noting that the main crane structures and helideck structure have recently been installed while engine load testing has recently commenced and upper leg construction is continuing on track.

Charybdis was previously under contract to enter service out of New London, Conn. to support construction at the 704-megawatt (MW) Revolution Wind project off the coast of Rhode Island and 924-MW Sunrise Wind farm off the coast of New York, but developer Ørsted announced in May that it canceled the charter agreement.

Instead, Charybdis' first job will be to install the turbines on Dominion's 2.6-gigawatt (GW) Coastal Virginia Offshore Wind (CVOW) project in federal waters off Virginia Beach, Va. Lewis noted that Siemens Gamesa has indicated that turbine installation will commence in May 2025, which appears to be in line with the current reported project status by Dominion, which envisages project commissioning by the end of 2026.

Advantages of a Jones-Act-qualified WTIV

To date, all offshore wind foundation and turbine installs in the United States have been performed using foreign installation vessels supported by U.S. tugs and barges for feedering. Notably, because Charybdis is Jones-Act-qualified, it will be able to install these components without tug and barge feeder spreads, potentially leading to productivity gains.

"Feeder vessels are more prone to weather disruptions and increase the handling (and exposure to damage) of delicate components," Lewis said.

U.S.-flag WTIVs also free developers in the U.S. from having to rely on European and Asian installation vessels, which are already in high demand and relatively short supply globally—a problem that is only expected to intensify in the years ahead.

Shell, NOV Help Equip Stena Evolution

Stena Drilling's Stena drillship is set to undergo a significant equipment upgrade with the systems supplied by Shell and NOV, which will make it capable of drilling and completing wells requiring 20,000 psi (20K) pressure control.

The upgrade includes the installation of cutting-edge drilling equipment and technology aboard Stena Evolution, starting from 2026.

Stena Drilling, together with equipment supplier NOV, and Shell, will install the 20K Subsea blow-out preventer (BOP) and other key equipment aboard its state-of-the-art 7th generation drillship, which was delivered to the offshore drilling contractor by Samsung Heavy Industries after a decade in the making,

A BOP is a large, high-pressure safety valve used to prevent the uncontrolled flow of liquids and gases during well drilling operations. Pressure control is a critical part of the drilling process, and, as a fail-safe component, a blowout preventer is essential to the safety of the rig.

When the new 20K equipment package is installed, the Stena Evolution will be able to perform completion operations in the Sparta field on behalf of Shell in the U.S. Gulf of Mexico, enabling the drilling in previously inaccessible reservoirs for Stena Drilling's clients.

AI Boosts Offshore Oil Field Production

The implementation of Artificial Intelligence (AI)-enabled digital operations at offshore oil fields can significantly increase their production and at the same lower their carbon footprint, with the most recent achievement made by Abu Dhabi National Oil Company (ADNOC) which boosted the production at one of its Middle Eastern fields by 25%.

The technologies that deployed at ADNOC's SARB field, which marked the significant rise in its production to a total of 140,000 barrels per day (bpd), include tools developed by AIQ, the Abu Dhabi-based AI champion delivering transformative solutions to the energy sector.

AIQ solutions DrillRep and OptiDrill process data from rigs and wells at the field, enhancing drilling efficiency and optimization.

By utilizing daily drilling data reports and rig sensor data, AIQ's technology supports drilling operations with the necessary insights and actions to optimize the drilling process.

DrillRep is a web-based application that automatically analyzes the written description of drilling activities, and suggests code and sub-code allocations, based on analysis of accurate historical DDR data, which drives greater operational efficiencies.

OptiDrill on the other hand is designed to validate key data against proven quality-control processes, using powerful data integration and management tools to analyze the data from an entire drilling operation.

Requiring just one-time configuration to stream data from surface sensors to monitor drilling processes, OptiDrill reduces the gap between how actual procedures occur as compared to best practices in the given activity using

Ricardo Santos - Equinor ASA

micro-KPIs and real-time alerts.

Located 120 kilometers northwest of Abu Dhabi, the digital solutions implemented onsite at SARB allow the field to be operated remotely from Zirku island, 20 km away.

Remote monitoring, smart well operations and production management technologies are integrated at the remote control center for optimized real-time decision-making.

This has enabled the accelerated growth in field capacity with reduced costs and emissions. The field's digitalization will enable the deployment of additional AI solutions to further enhance and optimize operations, according to ADNOC.

Equinor, SLB: Autonomous Drilling Reaches New Depths

A major step towards fully autonomous drilling operations has been achieved as Equinor and SLB set the record for the most autonomous well section drilled to-date offshore Brazil, leveraging SLB's digital technologies for surface automation, autonomous on-bottom drilling, and directional drilling.

The combination of SLB's technologies enabled 99% of a 2.6-kilometer section to be drilled in autonomous control mode. Over a five-well program, a 60% increase in rate of penetration was achieved, resulting in faster well delivery while reducing cost and carbon emissions.

Multidisciplinary experts collaborated to design and implement interconnected autonomous workflows, enabling the system to seamlessly drill the section.

On the rig floor, manual pipe handling and equipment sequencing tasks were automated with DrillPilot software.

On-bottom drilling performance was maximized using AI-driven technology in the DrillOps automation solution.

Neuro autonomous solutions determined the optimum trajectory and delivered the well plan, adjusting steering sequences and drilling parameters to reach the target as designed by the DrillPlan coherent well construction planning solution.

The DrillOps and DrillPlan solutions are SLB's cloud-based applications on the Delfi digital platform. The platform combines apps, artificial intelligence (AI), physics-based science and free-flowing data to accelerate and improve exploration, development, drilling, production, and new energy operations.

With more than 30 engineering algorithms working simultaneously in the cloud and enabling a collaborative environment, the DrillPlan well construction planning produced drilling program, automatically calculating hydraulics, casing design, torque and drag, well integrity and more.

The autonomous drilling milestone was achieved at Equinor's Peregrino C platform, which produced its first oil on October 10, 2022 as part of Peregrino phase 2.

Peregrino phase 2 will extend the life of the Peregrino field to 2040, adding 250–300 million barrels of oil, while at the same time halving expected CO2 emissions per barrel over the field remaining lifetime.

Managed Pressure Drilling Systems

The integration of Managed Pressure Drilling (MPD) systems into drillships represents a significant advancement in offshore drilling technology, improving safety and efficiency of drilling operations, as confirmed Diamond Offshore which is installing the system on its Blackships fleet of drillships.

Over the course of the last year and a half, Diamond Offshore has been increasingly implementing MPD systems across its fleet of drillship, and has already achieved significant improvements when it comes to the efficiency of its operations.

Namely, four of its drillships have successfully drilled wells with a remarkably narrow 0.2ppg drilling window - a staggering 86% reduction compared to conventional methods, according to the company.

MPD systems on drillships are advanced technologies designed to precisely control the annular pressure profile throughout the wellbore during drilling operations. MPD is especially important in offshore environments, where wellbore stability and control over formation pressures are critical to avoid issues like well kicks, blowouts, and non-productive time. By enabling better control over drilling conditions, these systems improve safety, reduce operational risks, and allow drillships to operate in deeper and more complex reservoirs. According to Diamond Offshore, the MPD system allows it to compete for the highest day rates in the 7th-generation drillship market.

The company plans to complete the MPD upgrades on its drillships by the end of 2024.

Petrobras, GA Drilling: Next-Gen Downhole Drilling System

Slovakian drilling specialist GA Drilling has teamed up with Brazil's state-owned oil and gas giant Petrobras to deliver more efficient deep drilling system, in an effort to reduce well construction costs and risks in challenging drilling applications.

The partnership pairs Petrobras with GA Drilling's technology, a downhole anchoring and drive system that will form the cornerstone of an advanced autonomous reeled drilling system.

The collaboration aims to enable deep and complex offshore wells to be drilled from a light well intervention vessel rather than a more costly semi-sub or drillship, saving 30% of well construction cost.

GA Drilling's novel system significantly improves drilling efficiency and enables the replacement of conventional drill pipe with reeled continuous tubing, thus minimizing pipe handling hazards, tripping times, and well control risk, the company claims.

The new technology includes sophisticated drilling automation and control systems and real-time wireline communications to the surface that optimizes and drives the drilling process downhole at the rock face rather than many thousands of feet above.

Wellube Debuts Double Isolation Pipeline Stopper Tech

Wellube launched the Double Isolation Pipeline Stopper (DIPS). This solution, developed in-house by the Wellube Research and Development team, marks a significant advancement in pipeline intervention and safety management.

The Double Isolation Pipeline Stopper (DIPS) provides a fail-safe isolation using a single size-on-size hot tap intervention, eliminating the need for additional tapping for bleed and vent ports. This approach reduces risks and enhances safety, making it ideal for use in critical and harsh environments.

Wellube's DIPS technology is third-party approved and is designed to reduce the risk to both asset and operator in highly volatile operational situations, ensuring it meets the highest performance standards trusted by clients globally.

BY THE NUMBERS

RIGS

Worldwide

Rig Type	Available	Contracted	Total	Utilization
Drillship	7	70	77	91%
Jackup	179	293	472	62%
Semisub	30	42	72	58%

Africa

Rig Type	Available	Contracted	Total	Utilization
Drillship		15	15	100%
Jackup	14	14	28	50%
Semisub		2	2	100%

Asia

Rig Type	Available	Contracted	Total	Utilization
Drillship	3	5	8	63%
Jackup	81	76	157	48%
Semisub	18	4	22	18%

Europe

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	1	3	33%
Jackup	10	30	40	75%
Semisub	7	17	24	71%

Latin America & the Caribbean

Rig Type	Available	Contracted	Total	Utilization
Drillship		26	26	100%
Jackup	3	5	8	63%
Semisub	3	8	11	73%

Middle East

Rig Type	Available	Contracted	Total	Utilization
Jackup	37	136	173	79%
Drillship				

North America

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	22	24	92%
Jackup	25	26	51	51%
Semisub	1	3	4	75%

Oceania

Rig Type	Available	Contracted	Total	Utilization
Drillship				
Jackup		1	1	100%
Semisub		6	6	100%

Russia & Caspian

Rig Type	Available	Contracted	Total	Utilization
Jackup	8	2	10	20%
Semisub	1	2	3	67%

Global Average Dayrates

Floaters		*Jackups*	
Ultradeep water	470.0	High-spec	167.5
Deepwater	361.5	Premium	139.6
Midwater	403.9	Standard	98.1

This data focuses on the marketed rig fleet and excludes assets that are under construction, retired, destroyed, deemed noncompetitive or cold stacked.

Data as of June 2024
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*
Deepwater	20	13	14	22	15	9
Shallow water	88	48	59	38	60	11
Ultra-deepwater	18	12	7	22	12	3
Grand Total	**126**	**73**	**80**	**82**	**87**	**23**

Shallow water (1-399m) Deepwater (400-1,499m) Ultra-deepwater (1,500m+)

Offshore Undeveloped Recoverable Reserves

Water Depth	*Number of fields*	*Recoverable reserves gas mboe*	*Recoverable reserves liquids mbl*
Deepwater	593	50,827	23,217
Shallow water	3,269	460,474	154,206
Ultra-deepwater	349	43,861	26,889
Grand Total	**4,211**	**555,161**	**204,311**

Contingent, good technical, probable development.

The total proven and probably (2P) reserves which are deemed recoverable from the reservoir.

Offshore Onstream & Under Development Remaining Reserves

Region	*Number of fields*	*Remaining reserves gas mboe*	*Remaining reserves liquids mbl*
Africa	578	19,145	11,641
Asia	841	16,630	7,453
Europe	762	12,359	11,576
Latin America and the Caribbean	193	6,992	40,777
Middle East	138	89,351	150,671
North America	468	2,565	12,885
Oceania	85	10,829	1,092
Russia and the Caspian	59	16,960	12,647
Grand Total	**3,124**	**174,832**	**248,743**

Onstream and under development.

The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

Source: Wood Mackenzie Lens Direct

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