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Rebuild the Fleet

From Cable Layers to WTIVs, growth spurs investment

Digitalization
Designing with a Digital Twin

Subsea Processing
Emission Abatement Opportunity Knocks

A Seismic Shift
Seismic Surveyors Diversify

VOL. 46 / NO. 5

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FEATURES

Image Courtesy Image from Akselos.

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Designing with a Digital Twin

According to Oil & Gas UK's latest Tech Insights report, data and digital solutions are finally becoming an integral part of the asset lifecycle. One of the largest areas where they're applied is facilities management, but what about the design phase? OE takes a look at two approaches.

By Elaine Maslin

ON THE COVER: **Nexans Aurora is a cable laying ship central to the company's core electrification strategy. (See story page 44)**

Photo from Nexans

FEATURES

Image courtesy MAN Energy Solutions.

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Emissions abatement opportunity knocks?
A complete subsea factory may yet be a pipe dream. However, with its constituent parts now more or less ready, the industry has a much greater toolbox of technologies with which it can now apply to existing and new subsea developments.
By Elaine Maslin

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A Seismic Shift
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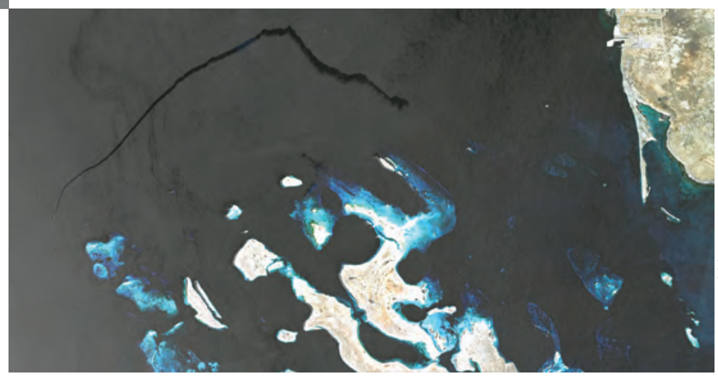
Image courtesy CGG

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BY THE NUMBERS

RIGS

Worldwide

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	10	58	68	85%
Jackup	144	295	439	67%
Semisub	26	54	80	68%

Africa

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	1	11	12	92%
Jackup	18	15	33	45%
Semisub		1	1	100%

Asia

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	5	4	9	44%
Jackup	60	86	146	59%
Semisub	10	14	24	58%

Europe

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	2	2	4	50%
Jackup	9	39	48	81%
Semisub	8	20	28	71%

Latin America & the Caribbean

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship		22	22	100%
Jackup	2	3	5	60%
Semisub	1	11	12	92%

Middle East

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Jackup	27	111	138	80%
Drillship	1	1	2	50%

North America

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	1	18	19	95%
Jackup	24	32	56	57%
Semisub	1	4	5	80%

Oceania

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	0	0	0	
Jackup	0	1	1	100%
Semisub	0	4	4	100%

Russia & Caspian

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Jackup	6	5	11	45%
Semisub	5		5	0%

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 October 2021.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*
Deepwater	12	16	16	20	13	11
Shallow water	66	74	53	85	39	27
Ultra-deepwater	15	12	18	18	8	4
Grand Total	**93**	**102**	**87**	**123**	**60**	**42**

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	567	44,602	22,892
Shallow water	3,221	423,270	142,116
Ultra-deepwater	325	40,699	23,853
Grand Total	**4,113**	**508,570**	**188,861**

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

	Water Depth of fields	*Remaining reserves gas mboe*	*Remaining reserves liquids mbl*
Africa	610	20,033	12,659
Asia	894	17,212	8,449
Europe	764	12,751	13,631
Latin America and the Caribbean	204	6,213	42,206
Middle East	130	78,595	145,345
North America	534	3,386	15,474
Oceania	91	10,926	1,368
Russia and the Caspian	60	17,601	14,571
Grand Total	**3,287**	**166,717**	**253,702**

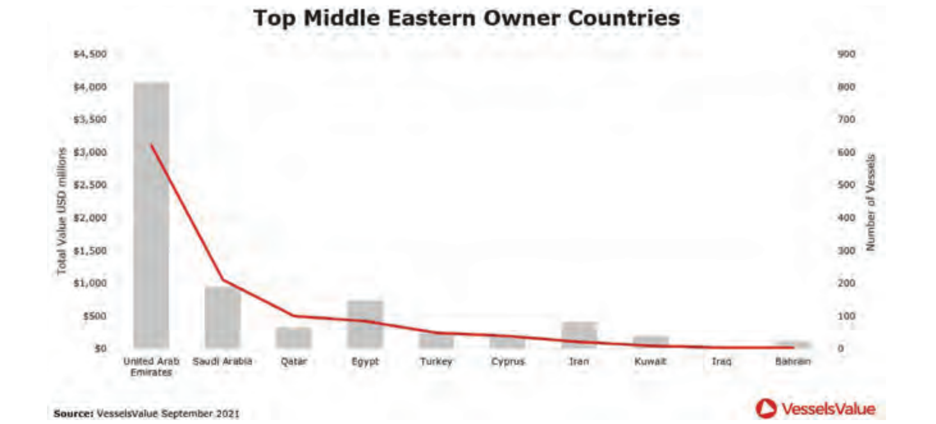
Onstream and under development.

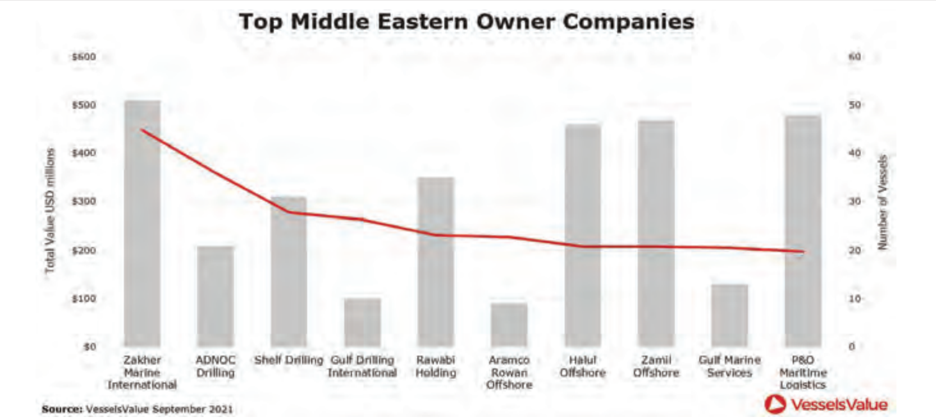
The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

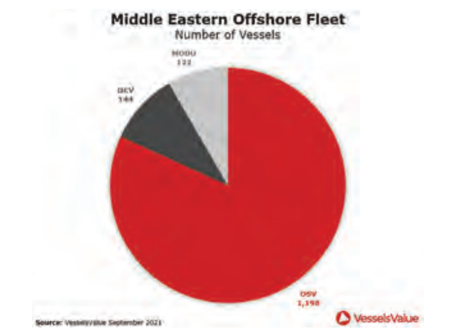
Source: Wood Mackenzie Lens Direct

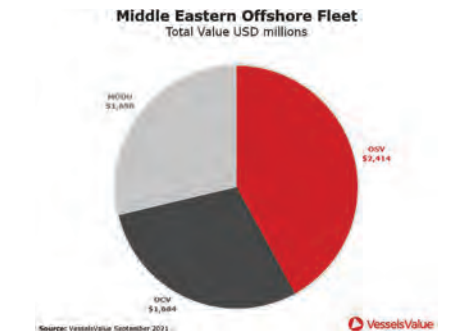
SECTOR IN FOCUS
MIDDLE EAST

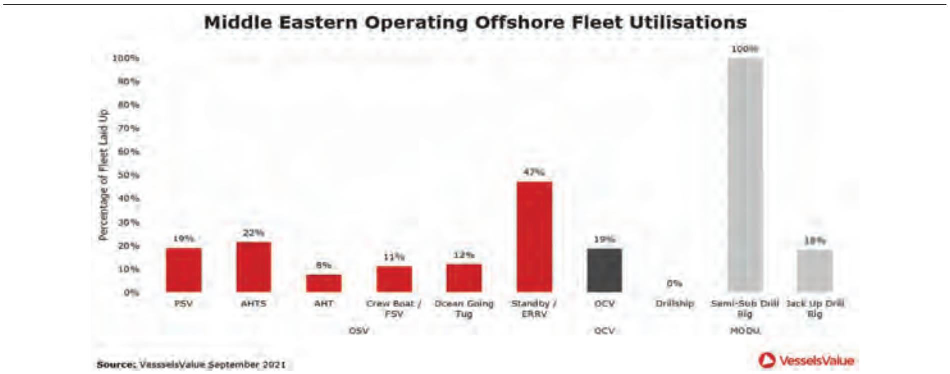
Data & Statistics powered by VesselsValue September 2021











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McCaul


Tomic


Tremblay


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THE DIGITAL PLUNGE

I ordered a shed last month from a *massive* corporate conglomerate, a project I opted to take on myself given the copious amounts of time I save daily not commuting into Manhattan, and equally important, the end of the boating season in the Northeast. When delivery of the shed slipped past the arrival date, I jumped online to find its whereabouts, only to end with zero actionable information. Next step, I called the company's customer service line to see if a live person might have better luck in helping me [a] track the rather large package, and [b] ascertain its new delivery date. Strike two, as the CSR was seemingly befuddled, unable to either find the package or give any intelligible guidance on its ETA. Strike three came the following week when the package arrived, only to see that it was battered and bent, the internal components damaged, ultimately returned for a refund. So much for global digital connectivity and clarity.

My point is not simply to regale you with tales of my domestic life, rather to point out that the promise and delivery of "Digitalization" and all that it entails still has a fairly long way to go in most industries. We talk about the digital trend throughout each of our media properties, from offshore energy to maritime to subsea to ports and logistics, and I contend that if you ask 100 people to define "Digitalization" you'll get 100 answers, as it tends to be highly specific to your niche and operations.

Specifically for this edition we are pleased to present a pair of articles, one that looks at Norwegian offshore constructor Aibel, authored by **Michael Hodgson** of Trimble and looking at how 3D models are at the heart of Aibel's work designing and manufacturing oil platforms. This article starts on page 22.

The second, authored by **Elaine Maslin** and starting on page 26, looks at two approaches to leveraging digital solutions, the first from FutureOn which says that digitalization can reduce up to 70% of the engineering hours in field development, and another from Dubai-based engineering and fabrication firm Lamprell and Swiss engineering simulation company Akselos which have shown that the amount of material needed for an offshore wind jacket foundation can be reduced by 30% using digital twin technology.

Finally, on page 33 we look at how Neptune Energy is applying a data visualization platform based on 3D gaming technology to get historical and live data from its subsea wells in Norway to enhance drilling and production efficiency and reduce time and costs.

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How to Decarbonize the Upstream Industry

AdobeStock/ Goodvibes Photo

By Jessica Brewer, Wood Mackenzie

As the energy transition accelerates, upstream companies are under pressure to decarbonize, and this is likely to intensify. Governments, investors, financial markets, society, along with other stakeholders are pushing for change. Companies need to define their strategy and act to future-proof their business and retain their social licence to operate.

There are strategic advantages to producing less carbon-intensive hydrocarbons. The market is shifting as some consumers look for a cleaner end product. We've started to see this with 'Green LNG,' but this will likely expand to cover other areas of the oil and gas industry.

The direction of travel is set. Early movers with 'cleaner' molecules will potentially be in a more advantaged position and rewarded by the market.

Future-proofing operations isn't only about gaining a strategic advantage. Governments will play a key role as they pursue their own environmental targets and goals, via tighter regulation and carbon pricing, for example.

The potential impact could be material. Wood Mackenzie's analysis suggests that for the top upstream emitters – leading NOCs and Majors – a global carbon tax of $110/

tonne, around the carbon price Wood Mackenzie estimates is required to limit the average global warming to two degrees above pre-industrial levels, puts up to a third of company upstream value at risk, with most of these portfolios in the 10% to 20% range.

The magnitude of the value at risk varies based on location, likelihood of carbon taxes, and intensity of the portfolio.

'Greener' operations not only offer environmental gains, but many of the steps are value accretive. Improving environmental impact can result in greater efficiency from production facilities, reduced leakage, and the capture – and monetization – of flare gas.

Many companies have already taken note, announcing bold commitments. Over 30 of the larger upstream players, including Majors, NOCs, and IOCs have set carbon reduction, net zero and/or scope 3 targets. Now, divesting out of 'dirtier' assets is one way to help meet these goals. But for many assets, especially those on production, this simply passes the problem down the line. What can operators do to reduce operating emissions if they want to retain their portfolio of assets?

Where do upstream emissions come from?

Emissions occur throughout the whole hydrocarbon value chain – from the wellhead to end-use. Some upstream companies are taking the bold step to tackle scope 3 (end-use), but the focus here is on scopes 1 and 2 at upstream installations. These are the operational emissions that upstream producers can control. Note that transportation emissions are excluded from Wood Mackenzie's analysis, but oil and gas companies may include these in reported scope 1 and 2 figures if they are owners of the pipelines and/are tankers.

Wood Mackenzie split the sources into seven main categories – production, processing, drilling, liquefaction, flaring, venting, and methane losses.

Around 70% of emissions are produced to power operations – production, processing, liquefaction and drilling. Intensity is influenced by various factors.

- Well depth, lateral lengths and complexity are factors that influence **drilling** power requirements.
- The oil/gas recovery mechanism impacts **production**. Intensity increases when using artificial lift, secondary or tertiary recovery techniques
- Hydrocarbon quality/characteristics determine the type of **processing** required. Heavy oil, oil sands, acid/sour gas, and LNG are more intensive than their counterparts.
- Crucially, the type of **fuel** used to generate the power will determine the level of associated emissions, in all cases.

Flaring and fugitives (methane losses) are the second-largest contributor, with 26% of carbon emissions. Essential flaring is hard to avoid but, in some countries, large-scale flaring is a function of their dependence on petro-dollars from oil production. Associated gas is a by-product which requires disposal – flaring fits that need where there is no market for the gas. In others, transport infrastructure constraints can limit the outlet for product. Again, disposal may be a last resort.

Methane is the molecule that packs a punch – it is 28 times more potent than its carbon counterpart, according to the 5th IPCC Assessment Report. Release occurs from aging or 'leaky' kit – valves, compressors, pipelines etc, via incomplete combustion at the flare stack, and/or as part of a vented gas stream.

The final 4% is vented. These are the direct release of carbon emissions into the atmosphere. This can be due to separation, vaporization, or other routine operations. This includes those that have been stripped out of the hydrocarbon stream during processing to improve hydrocarbon quality or to meet specific requirements.

Each asset is different, so it will come as no surprise that there are regional variations when it comes to the intensity of oil/gas production. Oceania is heavily influenced by Australian LNG projects, high CO_2 projects in Asia drive up venting, and aging infrastructure in the Caspian impacts methane emissions.

Who are the biggest emitters?

Intensity allows a comparison on a like-to-like basis, but it will come as no surprise that it's mainly the large producers that contribute the most in terms of absolute emissions. The US, Russia, Saudi Arabia, Canada, and Iraq produce half of the global upstream emissions.

Canada is the slight exception in this group. Yes, its production is relatively high, but the main consideration here is the contribution made by oil sands where extraction and processing is such an energy-intensive process.

What are some of the solutions?

Solutions to reduce Scope 1 and 2 carbon emissions range in cost and complexity. There are the smaller-scale operational efficiency solutions and best practices, as discussed in the introduction. But the biggest gain will be from targeting power generation.

Low-carbon power

The majority of assets are powered by fossil fuels – using a portion of the produced hydrocarbons. Electrification allows operators to move to low-carbon power, either directly from renewables or by connecting to the grid where the grid mix is cleaner than the alternative fuel supply.

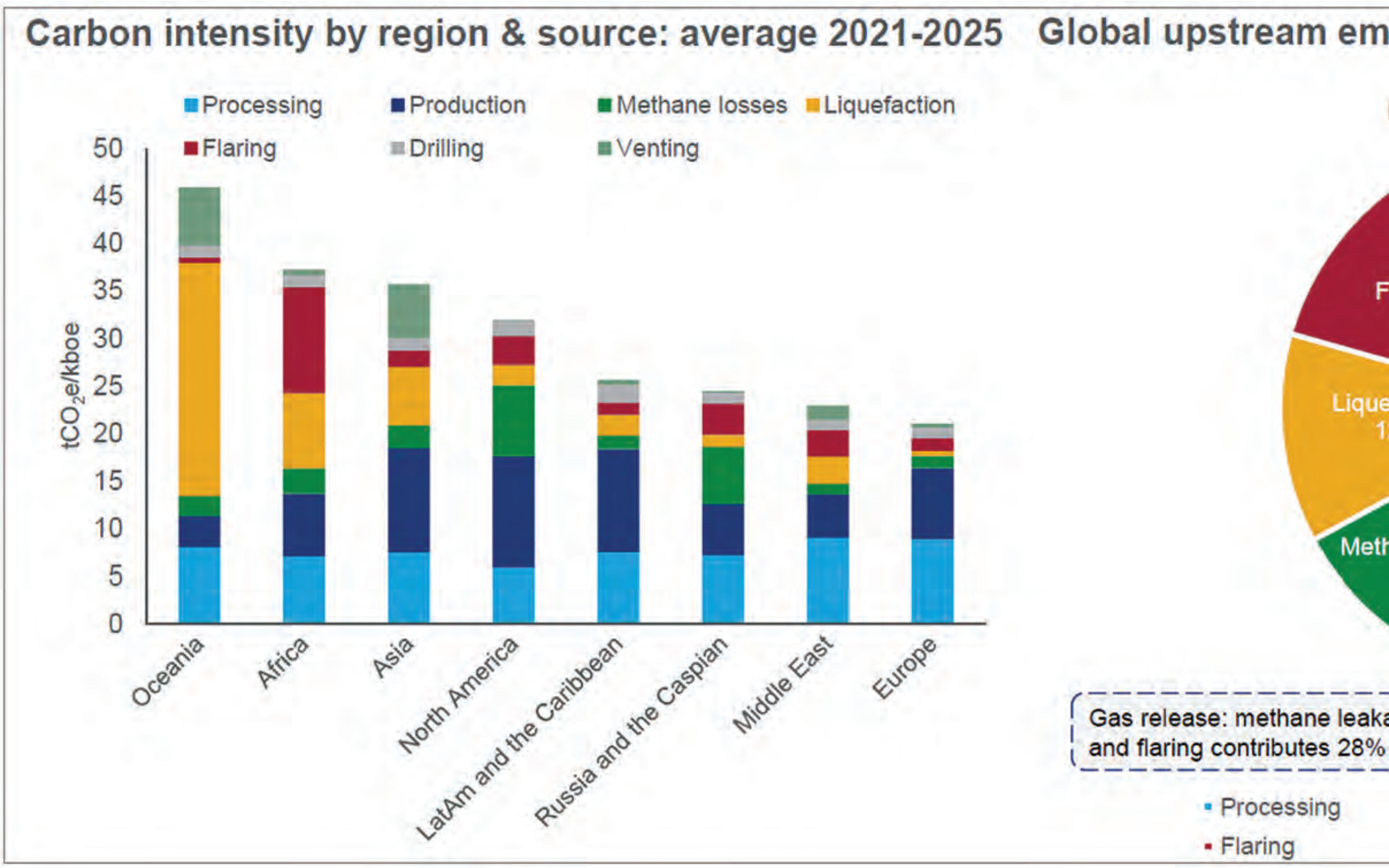
Norway is in an enviable position, with its power mix being predominantly hydroelectric power (90%+) – a renewable energy source without any corresponding intermittency issues. This, combined with the highest carbon taxes for E&Ps globally, has helped advance decarbonization efforts. By 2023, over half of Norway's production will be either fully or partially electrified. Wood Mackenzie estimates that once the Utsira High electrification project is brought online next year, Edvard Grieg offshore field's carbon intensity will be sub 2 tCO2e/kboe. This compares to a global average of 24 tCO2e/kboe for offshore projects.

Alongside lower emissions, electrification can offer reduced maintenance, lower fuel requirements, greater uptime, and ultimately, free up more molecules for sale. But challenges do remain:

- Dependent on the source of renewable power, intermittency issues may require backup generation, and if hooking up to the grid, the power mix will determine the scale of emissions reduction.
- Greenfield projects can be designed with electrification in mind. Retrofitting onstream projects is possible, but often more challenging. Not all installations can be electrified. Of those that can, some may only be able to handle partial electrification over full.
- Space and weight restrictions can limit options offshore. Electric motors can have a greater footprint and weight than the existing drive mechanisms.
- Field maturity can exclude many projects. The capital outlay required makes electrification of most late-life assets uneconomic.
- In some jurisdictions, the required regulation is not yet in place to support upstream electrification.

Flare reduction

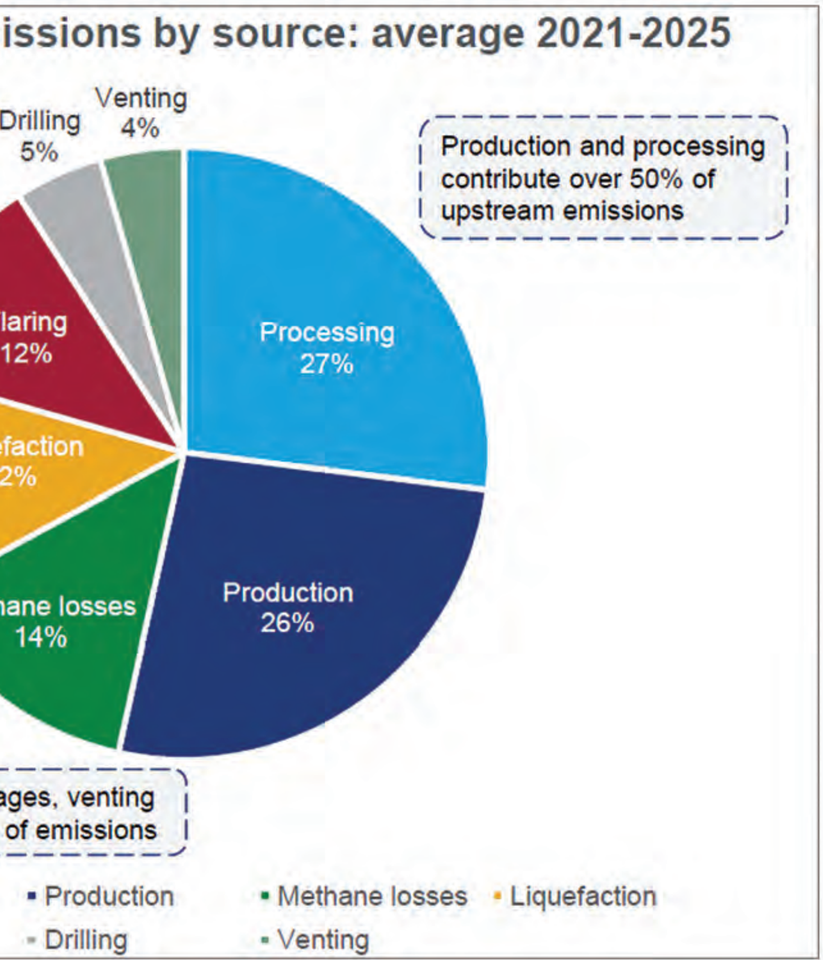
Gas capture projects offer an option for the large-scale flarers to limit emissions. Such projects can offer economic, as well as environmental, benefits. However, there are barriers to entry:



- A key consideration is whether there is a market for the gas, which could be sold either domestically or for export;
- Project economics need to stack up. The scale of the resource, capital outlay required and fiscal terms will determine viability;
- One deterrent for flare-gas collection, even when local markets exist, is the number and size of flaring sources;
- The location of point sources dictates how easy it is to capture the gas. Multiple small-scale emitting point sources with a large dispersion range are more challenging than a single large-scale point source;
- Mid-stream infrastructure needs to be in place to transport the gas;

The Basrah Gas Company's capture project in southern Iraq is a prime example of a development that is helping to reduce the volume of gas flared. At peak, over 1 bcfd will be captured from three of Iraq's super-giant oil fields – Rumaila, West Qurna One and Zubair. Associated gas that is otherwise flared as the country/government is highly dependent on its oil revenues.

Where projects are feasible, gas capture can provide an additional revenue stream for the companies involved, potentially greater income via taxes for governments and help satisfy unmet power demand.



Carbon capture and storage

Where carbon dioxide must be stripped from as streams to comply with infrastructure requirements, limited alternatives to venting exist.

Carbon capture and storage has become the frontrunner, with multiple operators across the Americas, Europe, Middle East, and Asia reviewing solutions. Although not widespread, there are existing projects online. The Sleipner project offshore Norway has been sequestering carbon for over two decades. But it is only in recent years that interest in CCS has taken off. However, CCS is still in its infancy, with many challenges to overcome.

- There is a lack of relevant legislation and regulation. Most countries lack a legal and fiscal **legislation** framework covering sequestration, licensing, and the ultimate liability for leakage risk.
- **Project economics** needs to stack up if CCS is to attract private capital/investment. In most jurisdictions, the commercial (and fiscal) frameworks are yet to be finalized.
- In addition, uncertainty around **costs** is a major factor. Costs will need to reduce if CCS is to scale-up capacity. To date, all the early adopters have received some form of government funding.

What's next?

To date, the pace of decarbonization has varied from region to region. One of the key differentiators is the level of government support. Those with government-supported initiatives are achieving more than the regions that have a solely corporate-led strategy. As more governments set environmental and climate goals, we expect more of a push for upstream decarbonization efforts. Things can move relatively quickly, and companies don't want to be left behind.

However, nations that rely on hydrocarbon revenues may be slower to react. Wood Mackenzie's analysis indicates that the risk of policy change is greatest for producers operating in the developed economies. Will we see a divergence between the developed economies and those that are reliant on petro-dollars? Are all the big producers onboard, or will a 'carbon chasm' form between the OECD and petro dependent nations?

Emerging Opportunities and Challenges of the US Offshore Wind Market

By Philip Lewis IMA/WER

Much has changed in the US wind market in 2021.

Despite being the second largest market for onshore wind, accounting for over 16% of the global market, the United States is today a minor player in offshore wind in comparison to the European and Asian offshore wind markets. The US market accounted for less than 1% of the global offshore capacity figure at the end of 2020.

Global offshore wind capacity reached 32GW of installed capacity by the end of 2020 – produced from over 7,300 predominantly bottom-fixed wind turbines. Two operational projects of seven offshore wind turbines with a nameplate capacity of 42MW has been the contribution of US wind to the global offshore wind total.

After several false starts, the US offshore wind market development continues to pick up speed in 2021. A major federal OCS project has reached FID, nine federal OCS projects are under final review, 14.3GW of project capacity has secured offtake commitments from East Coast states, 16.6GW of new federal leasing activity in the northeast, South Atlantic and California is underway, turbine component, foundation, and cable factories are being built in the US, and offshore wind port development is accelerating.

The project development pipeline now stands at close to 47GW.

Ports, fabricators, component manufacturers, vessel operators, engineering firms and lenders will benefit from the $142bn CAPEX, $4.8bn annual OPEX, and $21bn DECEX opportunity.

These are the findings shared in a recent report on the US offshore wind by World Energy Reports (WER).

The 100+ page report examines the business conditions likely to drive offshore wind project development in the US within this decade, forecasts the number, CAPEX, OPEX and timing of projects, and provides a roadmap to accessing these market opportunities.

Summary Forecast for US Offshore Wind Projects by Final Investment Decision Timing

Forecast ($ billion)	GW	CAPEX	OPEX/yr	DECEX
0-6 months	0.8	3.0	0.1	0.4
6-18 months	0.2	0.7	0.0	0.1
18-36 months	12.7	43.8	1.3	5.7
36-60 months	16.3	50.2	1.7	7.4
Over 60 months	16.7	44.2	1.7	7.5
Total	**46.7**	**142.0**	**4.8**	**21.0**

Source: WER Database

Setting the Scene

Dozens of countries including the US have announced ambitions to transition to “net zero” by 2050 – meaning achieving Paris Agreement goals to limit global temperature rise to 1.5°c and bring CO2 emissions to net zero – or in simple terms decarbonizing the economy. To decarbonise the economy not only means how we produce electricity but all aspects of transport, heating, industrial processes, and consumer behaviour.

Focusing on electricity generation, last year slightly over 60% of the US’s electricity was produced from oil, gas, and coal – where the use of natural gas is growing as coal demand falls. Nuclear accounted for an additional 19%. Nuclear is relevant as this is also another baseload technology that is currently being challenged. This means an energy transition towards net zero is effectively a transition away from 60-80% of US baseload electricity generation capacity at the same time as they plan to increase our baseload electricity supply as the economy is electrified.

Onshore wind currently accounts for around 9% of US generation capacity – with a capacity of around 120GW.

According to forecasts by the US Energy Information Administration (EIA), fossil fuel in the electricity generation mix will fall to 53% and nuclear to 15% by 2030 as the share of renewables increases to 32%. Natural gas is forecast to account for around 35% of all electrical generation capacity by 2030 – a reflection on the need to secure baseload electricity generation power.

A key challenge of the main renewable energy source, wind and solar, is that the wind does not always blow and the sun does not always shine. As a result, renewable energy supplies are variable technologies – which pose a challenge to securing baseload energy supply.

As a result, the industry is working on solutions to address variability. For wind, this means moving wind turbines offshore where wind speeds are more constant and coupled with the deployment of the largest wind turbines, achieve higher capacity factors than onshore turbines. It also means adding the ability to store power – either through the deployment of battery systems or through the conversion of wind to an energy carrier, such as hydrogen, which can be stored and used when needed. Much of this technology is at the early stage of development – but these technologies will play a key role in supporting the growth of offshore wind as a variable baseload technology.

The Drivers for Offshore Wind Growth in the US

The US has a quantified offshore wind net commercially feasible resource at 2,060GW in 29 states along the Atlantic, Pacific, Gulf of Mexico, and Great Lakes coasts. This is almost two times today’s total electricity generation capacity.

The US federal government is one of many who have established offshore wind targets amounting to over 270GW of global offshore wind capacity by 2030 -- 30GW in development by 2030 in the case of the US and 110GW by 2050. These targets aim to increase confidence in the supply chain to develop the capacity and competency to deliver on these targets.

In the US, it is the states that drive procurement of offshore wind, through renewable energy goals and specific offshore wind procurements. Till now 4GW of state offshore wind targets have been set – with 14.3GW of capacity already procured.

State Activities

State	Renewable Goals	Offshore Wind Goals (GW)	Committed offtakes (GW)
Massachusetts	35% by 2030	5.6	1.6
Rhode Island	100% by 2030	Unspecified	0.4
Connecticut	43% by 2030	2.3	1.1
New York	70% by 2030	9.0	4.3
New Jersey	50% by 2030	7.5	3.8
Maryland	50% by 2030	1.6	0.4
Virginia	30% by 2030	5.2	2.7
North Carolina	Unspecified	2.8	0
Total		**34.0**	**14.3**

It is the federal government's role to award and administer offshore wind leases and to permit developer construction and operations plans (COPs) – which establish the design envelope for a project. Only once a project is permitted can a developer construct a project to deliver power secured through state procurements.

BOEM, the central federal administration agency for US offshore wind, has permitted one project for 804MW and is progressing the review or planning to commence review on COPs for developments amounting to over 15GW. Over the last eight months, the pipeline of projects under federal permitting review has increased and the timelines for project approvals have become clearer – which provides an indication for developers to plan a final investment decision (FID) and offshore construction.

A 46.7MW Project Forecast

As of end September 2021, there are 19 projects for close to 14GW which are post-FID or where a final investment decision is expected within the next 36 months. This is made up of large projects in the federal administered waters (OCS) as well as floating wind technology demonstrators in the Great Lakes, the Atlantic and the Pacific.

Over 31GW of federal Atlantic and Pacific offshore wind potential has been identified – but has yet to progress to the COP stage. This capacity will provide the supply chain demand through the next decade.

Site assessment work continues for another eight east coast projects with around 9GW of project potential. Around 5GW of additional potential is in leases already awarded, where site assessment work has yet to commence. BOEM is advancing plans to lease up to 9.8GW in New York Bight offshore wind leases through 2022, as well as 4.6GW of floating wind leases in California and 2.2GW in the Carolinas.

Most of the planned activity in the Atlantic is bottom-fixed wind. However, plans are well underway to develop a demonstration floating wind turbine each in Maine and Massachusetts and pilot arrays consisting of several turbines in Maine and California. These projects will be essential to address the unique challenges posed by floating wind projects – which require a different construction process to bottom-fixed wind.

A $142B CAPEX and Annual $4.8B OPEX Opportunity; But Supply Chain Challenges

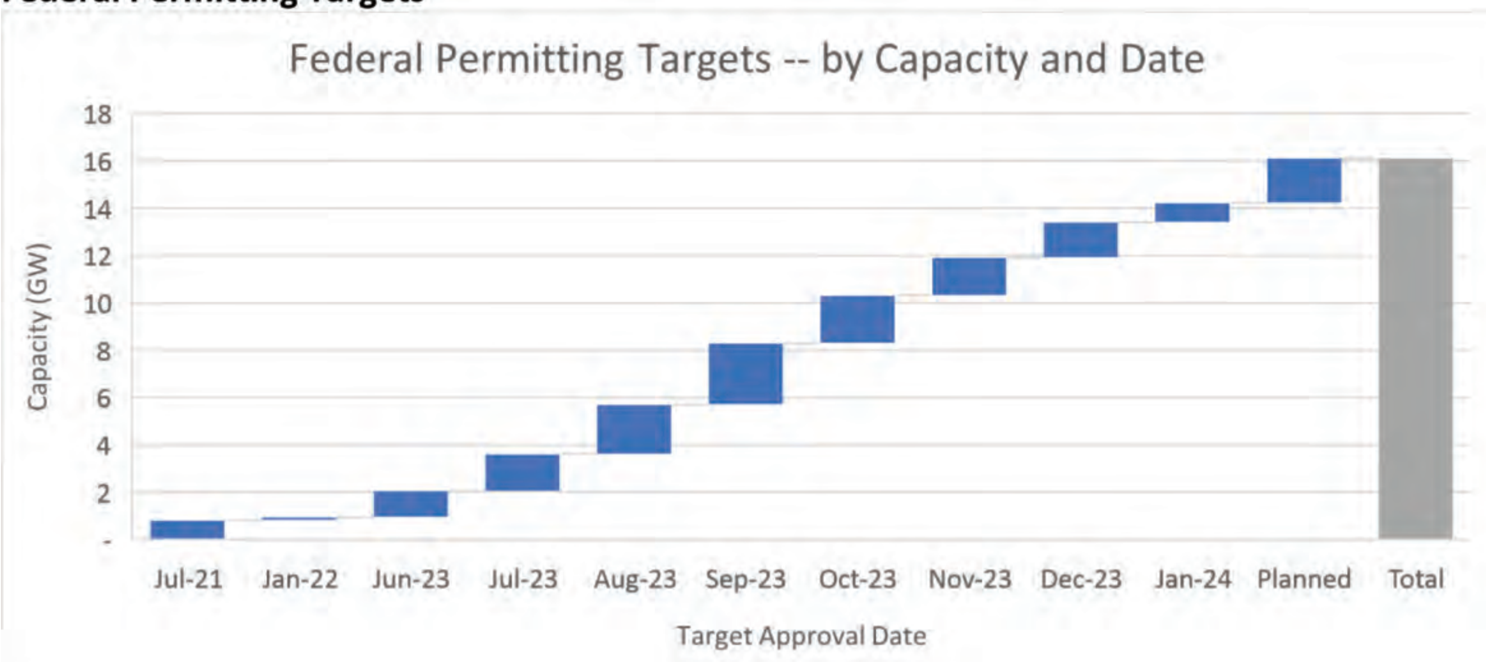
Our bottom-up forecast model breaks the $142B of CAPEX into component spend.

We are forecasting close to $113B to be spent on material supply, manufacturing and/or fabrication of turbines, cables, foundation structures and other equipment.

We anticipate around $25B will be spent on installation and commissioning activities.

Based on COP details and developer announcements, US project activity will be at a peak from 2023 to 2026. This will coincide with a spike in bottom-fixed project activity in

Federal Permitting Targets



Europe and East Asia – and increase competition for limited supply chain resources. 2025 and 2026 is a peak year for international project commercial operations (COD) – based on projects already permitted or in the permitting process.

To manage this, certain US developers are clustering projects to better plan resources. Our report analyzes the various project clusters.

An additional constraint that the developers of US wind projects must consider is the Jones Act.

In Europe, the practice has moved to large purpose-built turbine (WTIV) and foundation (WFIV) installation vessels – that shuttle to and from a turbine or foundation factory or marshalling port to the work site. Only one US Jones Act is currently being built. Demand is the US will exceed five vessel years for WTIVs and WFIVs in each year from 2025-2026.

The global fleet of high-spec vessels WTIVs sufficient to install the large turbine and foundations planned for US projects will stand at 16 by 2025. Six to seven of these WTIVs are already committed to projects in Asia and Europe over the middle of the decade. In terms of the specialist WFIV fleet of six vessels, five already have commitment in Europe and Asia. In summary, turbine and foundation capable installation capacity becomes a potential bottleneck over the middle of the decade for US and international projects – and can lead to increased costs and/or project delays.

In the same way that high-end supply of turbine and foundation installation capacity will be at a premium when US project developers will be building their projects, the cable lay vessels and barges required for inter-array cabling and connecting the wind farms to shore will also be in short supply. Again, the lack of Jones Act vessels is an issue – a foreign flag vessel needs to be able to sail to the US with enough cable onboard to avoid having to return to a factory or supply point to restock with cable. Due to the size of US projects, the size of cable lay vessel will need to be large. There will only be around 25 of these large cable layers globally in 2024 – the point where international demand will exceed supply. This will drive the deployment of less efficient cable laying barges and small cable lay vessels– and can lead to increased costs and/or project delays.

As with offshore oil and gas projects, a significant amount of lifetime project cost in an offshore wind farm is represented by routine planned operations and maintenance. For an offshore wind farm this is typically 40-45% of the lifetime cost. Our forecast identifies around $4.8B of annual recuring OPEX once the identified projects are commissioned.

Wind farm operators will set routine inspection and maintenance schedules, chartering in long-term vessel support for the activities. The tonnage will be mostly Jones Act vessels. Certain vessel categories can be modified/redeployed for the existing Jones Act fleet. Other requirements call for new buildings. We forecast a long-term demand of around 30 service operations vessels (SOVs) and crew transfer vessels (CTVs) – the demand for which is analyzed in our report.

Offshore Wind Going Forward

States are continuing to discuss with federal agencies the development of future offshore wind activity.

In the coming years, we expect to see new federal leasing activity in the Atlantic, Pacific, and possibly the Gulf of Mexico. We also anticipate further investigation by states of the potential in the Great Lakes.

Competitive floating wind solutions will be required to open the potential off the continental and Hawaiian Pacific coasts.

But significant challenges remain to be addressed for both bottom-fixed and floating wind technologies if the US is to deliver on its ambitions.

Details off all the projects in the forecast are provided in our report.

For more information: ***www.worldenergyreports.com*** or contact Rob Howard at +1 561 732 4368 / howard@marinelink.com or Philip Lewis at +44 203-966-2492

East Asian, European and US Project Activity by COD

Region	2023	2024	2025	2026	2027
East Asia (excl. China)	835	1,040	3,850	504	704
Europe	5,973	4,491	5,620	7,665	2,700
US	132	804	3,488	2,940	2,815
Installed Capacity (MW)	**6,940**	**6,335**	**12,958**	**11,109**	**6,219**

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FLOATING IDEAS

The world's FPSO fleet is getting older, with 55 FPSO units in the global fleet reaching the end of their design life in the next five years, with an additional five having life extension in place. With 19 more FPSOs currently being evaluated for life extension, safety issues and structural integrity concerns come to the fore? Matt Tremblay, ABS Vice President, Global Offshore, explains the challenges for FPSO operators, and discusses why a new working group comprised of major players in the FPSO marketplace has been created.

ABS is no stranger to the Floating Production Storage and Offloading (FPSO) market, as it classed the first FPSO vessel in U.S. waters in 1978 and continues to lead safety and innovation with new technology that supports larger, more complex FPSOs operating in ultra-deep water and in the pre-salt region of Brazil.

With more than 60% of all FPSOs in service classed by ABS, and more than 70% of FPSOs in Brazil operating under ABS class, including 30 vessels with capacity to handle more than 100,000 barrels per day, ABS is committed to setting standards for safety and excellence in design and construction.

Focused on the safe and practical applications of advanced technologies and digital solutions, ABS recently brought together leading companies in the FPSO sector to form a consortium to help address the safety challenges produced by a fleet where more than half of the FPSO vessels are over 30-years-old and a quarter are over 40-years-old.

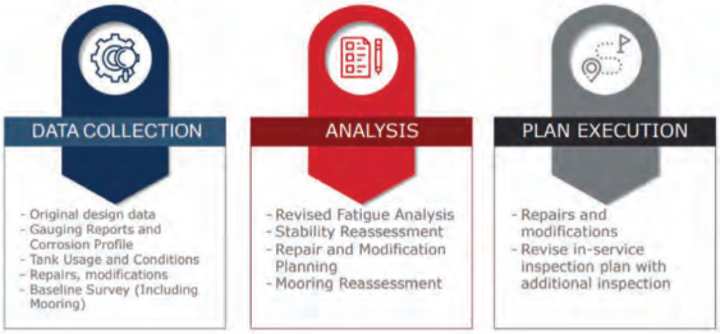
The aim is to advance industry best-practice to protect people and the environment bringing together industry leaders to address risks within the current and anticipated FPSO fleet. Two over-riding goals of this consortium include:

1. Identifying critical risks posed to the offshore industry by an ageing global FPSO fleet.
2. Determining the steps to mitigate safety and environmental risks posed by aging FPSOs.

Ageing units require more maintenance effort to maintain in Class, and maintenance needs to increase with age to reduce downtime. Across industry, it is widely accepted that increases in life extensions puts an increased burden on ageing asset maintenance issues.

The new consortium which includes Chevron, Shell, Petrobras, MODEC, and SBM Offshore, as well as the Bahamas Maritime Authority, the Republic of the Marshall Islands Registry, and the U.S. Coast Guard 8th District, has created five joint industry projects (JIPs) aimed at using technology to

ABS Life Extension Process



tackle a range of FPSO safety issues.

The JIPs, which make up much of the work activity of the consortium, are essential to help share experience, knowledge, ideas and ways in which critical risks can be better managed from a safety, efficiency and cost perspective. Members of the consortium are already discussing how new learning can be factored in to future FPSO design, including how Class Rules can be enhanced to further provide support for tomorrow's FPSO designers, newbuilds and operators.

This type of approach provides the opportunity for all the stakeholders in the FPSO value chain to pool their knowledge, technical expertise and their resources to deliver better safety outcomes – and deliver on a shared commitment to quality, compliance and continuous improvement.

Deep Diving into Issues

Efforts of the working group will produce outcomes that will assist with the evaluation of whether equipment is still suitable for continued service and potential acceptance of life extension. For example, working groups will tackle composite material repairs for offshore structures and include aspects such as life extension of wire rope mooring systems which have been in existence for 20 years and are approaching the end of their design life.

As the FPSO fleet ages, the timely launch of the consortium is providing a forum for manufacturers and operators to come together to talk about the risks they identify that are specific to aging FPSOs, especially those risks that were not being adequately addressed, such as:

- Hot working during standard operation is challenging
- Marine and Operating groups are not aligned
- Best practices are not presently shared
- Design of FPSO units doesn't align with actual use
- Competency of personnel

Collectively, members will all work together to determine how best to mitigate these risks and to find tangible actions that will help reduce risk posed by aging FPSOs. Discussions have started which include the prospect of a five-year engineering check, which includes a review of the overall structural integrity of an FPSO, survey and UTM reports to support decisions of surveyors and identify any areas that need to be changed. This includes loading conditions, produced water management, metocean conditions, calculated corrosion rates, residual structural and equipment strength, and cumulative fatigue damage.

Technology Supporting a Better Analysis

It has been determined by Marine Insurance Companies and the International Maritime Organization (IMO) that 60 to 80 percent of Marine losses of life, property or damage to the environment are due to human error or a human factor.

To take equipment out of service and to examine both its external as well as internal condition is a challenging exercise. One of the JIPs has a mandate to assess the use of management software; applications of photogrammetry and 3D Lidar laser scanning; and the role of artificial intelligence in corrosion detection and analysis, particularly in terms of hull and structural integrity. FPSO Digital Twin Lifecycle approaches are critical in this area to help test and validate equipment or structures on a digital asset with that of the in-field asset to help expediate decision making and reduce non-service productive time. It can be safer, faster, and more cost effective using a digital platform and safeguards human intervention for inspection in often challenging or dangerous environments. It offers a move away from the traditional inspection methods and eliminates human-entry, as well as reduces reactive repairs by corrective action to preventive and predictive maintenance.

Last year, ABS created an AI tool that has the capability to look at images of equipment and structures and helps to evaluate the actual percentage of corrosion in that item. It is a clever innovation that can also estimate corrosion rates based on image analysis to a high degree of accuracy.

AI can be 'trained' and enhanced in its operation with more direct assessments on equipment and structures. In doing so it can quickly educate itself with the breadth and scope of different image assessment and corrosion rates on various items.

Making improvements to Class

ABS has developed its Rules, with a significant number of changes applicable to FPSOs, both for existing units and for new facilities. These Rule changes are intended to address many of the risks related to aging FPSOs from both a design and a maintenance perspective.

The working group are overseeing the efforts of this JIP which has resulted in more than 40 changes to the ABS Class Rules regarding FPSOs. These changes are already being assessed for implementation during this year to help reduce risks related to aging FPSOs. These changes and improvements will be shared with the launch of new publications and best practice guides regarding FPSO maintenance and inspection.

How to Reduce Risk Across the Lifecycle of Floating Production Assets

Using digital transformation to mitigate risks and increase performance of offshore rigs.

By Greg Trostel and Roger Burnison

Floating production storage and offload vessels (FPSOs) are among the largest investment trade-offs an oil and gas producer will make. On the one hand, these immense vessels offer the promise of exponentially increased production and storage flexibility over onshore counterparts. On the other, they come with a colossal price tag in terms of equipment, operations and maintenance.

According to a survey by McKinsey, projects in heavy industry sectors overrun their budgets and schedules by 30% to 45% on average. The average engineering, procurement and construction (EPC) project fares even worse throughout the industry. Production is yet another challenge. Due to suboptimal operations, unplanned downtime and operational incidents, according to Rystad Energy, the upstream part of the industry experiences approximately $500 billion per year in deferred revenue globally. However, despite these industry statistics, the more successful FPSO operators are achieving better than 99% uptime and, in some cases, very close to 100%. But how can companies operating at these high levels of productivity, embrace digital technologies to maintain and even optimize their existing operations?

For those producers embarking on new floating production facility journeys or looking to upgrade existing ones, it's time to shift gears and redirect the trajectory. A floating production vessel might be disconnected physically from land, but it can still take full advantage of the latest developments in digital technologies and work processes. This article shares insight on a new end-to-end connected strategy that enables producers to proactively mitigate risks and extract more value at every stage of their floating vessel's lifecycle.

FLOATING PRODUCTION-FACILITY CHALLENGES

Before we drill into how to digitalize, let's take a closer look at the major challenges weighing down the operational effectiveness of FPSOs.

Reliability and management of key production assets continue to be an area of critical focus – unplanned maintenance on a floating production facility costs an estimated 100 times the amount of the onshore equivalent. Assets are operated to production limits. Maintenance equipment and expertise are often lacking onboard, which necessitates the high costs and inconvenience of transporting equipment and personnel to remote locations. Plus, the turnover rate for operations staff is higher than average. New personnel must be trained specialists with qualified experience to be effective and follow crucial safety measures. All these issues negatively impact equipment life and increase operations and maintenance costs.

Meanwhile, Health, Safety, Security and Environment (HSSE) is another major challenge. An overriding and undeniable goal of the industry is to decrease and eliminate incidents, whether they're related to safety, spills (hydrocarbon containment), cyber security or something else.

For example, the number of ransomware incidents involving the manufacturing sector increased 156% between the first quarters of 2019 and 2020. In addition, recently several manufacturing organizations were targeted with cybersecurity threats, including one of the largest U.S. pipeline operators, Colonial Pipeline. In May, the operator shut down 5,500 miles of pipeline, which carries 45% of the East Coast's fuel supplies, to contain a ransomware breach.

To help with these challenges, oil and gas companies need to implement industry-proven standards such as NIST and ISO/IEC 27032 across their enterprise to manage their assets through continuous monitoring and lifecycle management. Oil and gas producers are also pushing to minimize the number of staff in the production environment and improve overall physical safety conditions. And finally, all operating oil and gas companies are committed to achieving full regulatory and environmental compliance as part of their social responsibility goals, including drastically reducing hydrocarbon releases.

ENABLING DIGITAL TRANSFORMATION

Together, these major challenges have dramatically affected the effectiveness of major offshore projects. However, by creating a "connected vessel," especially with a third party that can help design and deploy the entire strategy, producers can mitigate these and other risks, and set a course to reduce total cost of ownership through effective initial project execution to First Oil Date and achieve long-term operational efficiency.

Based on a fully digitized approach, the connected vessel benefits each phase of the project and operations. Unifying the digital strategies and content leveraged across the organization is key. This "digital thread" starts during design and flows through the full production lifecycle of the facility. The cohesive digital plan takes total advantage of digital enablement in system design, while setting the stage for proper commissioning and smooth start up, optimized ongoing operations and maximized performance.

Through digital transformation, producers can save in total cost of ownership through effective initial project execution and long-term operational efficiency, because:

- A streamlined scope reduces capital costs
- Project schedule improvements reduce project costs
- Improved operations via availability, reliability, and maintainability increase production and overall operational equipment effectiveness

The result? The use of the connected vessel execution methodologies and technologies lead to a potential savings of $150 million per floating production project. Not to mention the life-time benefits.

So, why not take measures to control what you can? By making the investment to build and operate a connected vessel, producers can effectively reduce risks, drive efficiency, optimize performance and realize the true potential of their assets.

CONNECTING THE VESSEL

This end-to-end strategy takes an innovative design and implementation approach to building and managing floating production facilities to address the automation, electrical and measurement project scope. It also addresses the entire process – from the reservoir through topsides production, and beyond – including:

- Reservoir production, sea floor operations management and well flow
- Power management systems, including switchgear and motor controls
- Hull and marine applications that include bridge management
- Process and safety production systems
- Management of the topsides production modules as well as the subsea modules
- Networking and connectivity to on-board and remote operations center(s)

Bringing a connected vessel to fruition centers around the following main areas of development:

PROJECT EXECUTION

In any project, major automation and electrical systems become the critical path to project completion and long-term operational performance. Without proper design and implementation, ensuing changes cause delays and add expense in the near and long terms. Poor execution also results in costly changes at the shipyard, causing delays in commissioning and start up. While automation and control systems are a fraction of the overall project budget, the coordination of master and module systems is critical to the success of the project and success in operations. Producers need efficient, integrated systems they can rely on that are digitally enabled, all of which a connected vessel provides.

PRODUCTION AND OPERATIONS

A lack of visibility into and understanding of the reservoir and well-flow conditions often cause poor performance. Ener-

gy producers need confidence in the accuracy of fiscal metering. Measurement of flow is a mission-critical component of the operations; knowing exactly what is flowing into and out of the vessel can be the difference in a project's commercial success and compliance with national regulations. As such, in a connected vessel, production modules are designed and supplied to the shipyard with consistency and standardization. They can be operated using advanced technologies to implement asset management and remote support, along with obsolescence and spare-parts management. Furthermore, a connected vessel enables data-driven reliability, availability targets and critical asset-maintenance strategies to bolster operational equipment effectiveness.

To address production and the operational life of the vessel, the latest technologies are deployed to ensure maximum production, visibility and flow assurance from the reservoir through the production units. Plus, reservoir analysis and management maximize production over the life of the facility. Such benefits are well documented and result in improvements in project and operating costs, production rates and recovery rates. Meanwhile, with this approach, the offshore facility is virtually connected to an onshore operations center to deliver the objectives of a fully digitalized project. This provides a central location for coordinated operations for the life of the vessel and enhances access to subject matter experts – within the operating company and externally – to supply asset and process experts.

HSSE

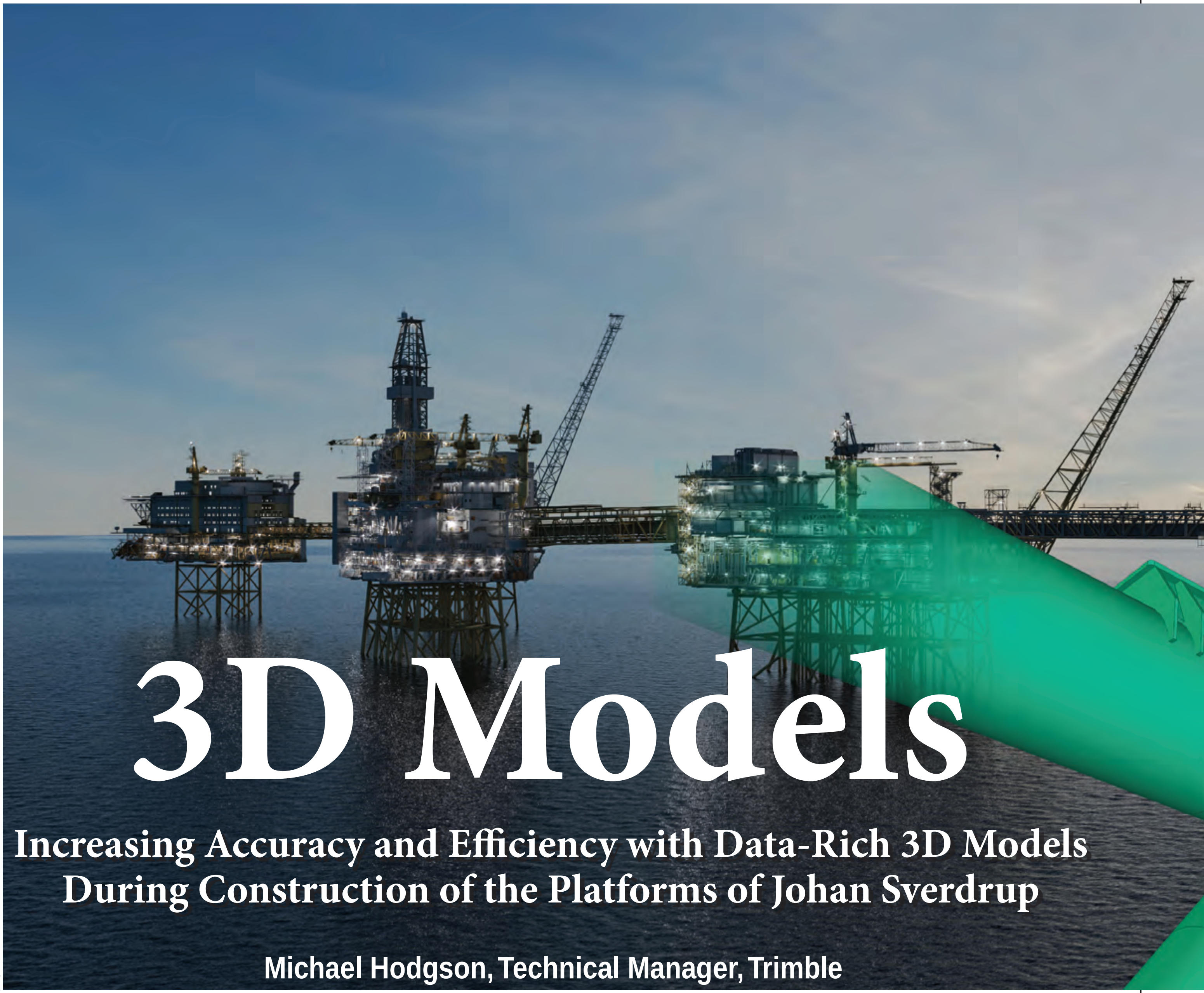
The nature of floating production projects in extremely isolated locations requires that all efforts are made, and all viable technologies are deployed, to minimize the number of people required onboard and their transportation to and from the production vessel. Although rigorous safety protocols are put in place, actively monitored, and effectively followed, there is always inherent risk that can impact personnel, equipment and the environment.

To address both operations and HSSE issues directly, the latest technologies and workflows are used to remotely connect operations personnel to information and expertise in real time. This also allows the training and implementation of a fully connected operator via multiple tools and technologies to other team members onboard or onshore, to knowledge bases on the production vessel and to remote subject matter experts anywhere and anytime, as needed.

Furthermore, the implementation of a fully connected remote operations center makes it possible to minimize the need for staff onboard the vessel, while giving them greater access to information and expertise. So, operations team competency and performance increases, and allows for renewed analysis of optimal team size. This ultimately helps reduce manpower on the vessel, which reduces risk and lowers the cost of transportation and other operating expenses.

LOOKING AHEAD

Already 20% to 30% of oil and gas production comes from offshore facilities, with more producers looking to procure new FPSOs worth billions of dollars just to build and even more to operate. By embarking on a connected digital strategy that anticipates and addresses the many significant and costly challenges of project execution, production, operations and HSSE, producers can be far more confident and better equipped for long-term success. To get there, working with a trusted third-party partner that can provide end-to-end strategic support streamlines project management and execution, design, and implementation, and provides continuity from construction or conversion through the entire lifecycle of the vessel.



Equinor

3D Models

Increasing Accuracy and Efficiency with Data-Rich 3D Models During Construction of the Platforms of Johan Sverdrup

Michael Hodgson, Technical Manager, Trimble

The design and construction of offshore oil and gas platforms are both complex and unique, requiring incredible precision and close collaboration between all parties. For this reason, 3D models play an important role in the lifecycle of offshore oil platforms.

Norwegian offshore constructor Aibel has put 3D models at the heart of its work designing and manufacturing oil platforms.

Founded more than 130 years ago, Aibel serves the global energy industry with engineering, construction, and maintenance services. The company employs 4,000 people at engineering offices and yards in Norway, Singapore, and Thailand, and to date, has built or modified more than 50 platforms.

In 2013, Aibel set a goal to reduce overall engineering time by up to 30 percent. To meet its target, the company began looking closely at how construction documentation is produced and the ways in which teams working in different locations collaborate and share information.

Through this process, Aibel discovered constructible BIM and its ability to help the company create 3D models with data so accurate it translates directly to the physical world. As it embarked on several projects for the Johan Sverdrup offshore oil field, finding the right solution that would allow Aibel to create constructible models and efficiently extract

fabrication information from them, as well as collaborate across teams in multiple locations would allow the company to design and construct offshore platforms with greater efficiency and accuracy.

"Our colleagues in Singapore and Thailand were already using Trimble's BIM software Tekla Structures for the high-value engineering work we do in Southeast Asia," said Charles Halaas, IT manager of field development and offshore wind for Aibel. "When we saw how efficient their output is and the tremendous volume of documentation they are able to produce, we set up a team to see how we could use it in other projects too."

Uncovering Efficient Design and Automating Production

The project was not without its challenges due to standardization requirements within the oil and gas industry and the need to integrate Aibel's BIM software with existing solutions.

"The design model and the fabrication model should always be the same, but as our industry requires the use of E3D as a design tool, it is challenging to extract a 3D fabrication model into the BIM software," said Halaas. "Thanks to some great cooperation with experts, we were able to produce interface methodology to overcome this challenge and semi-automate our drawing production."

Introducing constructible BIM into the fabrication process is instrumental in helping Aibel with robotics, another of the company's focus areas for development. Aibel uses state-of-the-art computer-controlled cutting machines in its yards and, through integration with its BIM software, has achieved a higher degree of automation across the design and manufacturing process.

"We see the greatest benefit of this integration in our profile-cutting machines," said Halaas. "For example, when we have two metal beams meeting at a given point, there is usually a crossover joint that is quite complicated to cut. Previously, we used manually operated mechanical saws to cut these. Now we use the Tekla model to guide the robot and cut with incredible accuracy."

Building Some of the Industry's Largest Oil Platforms

The efficiencies achieved with constructible 3D models are critical for Aibel as the company builds some of the industry's largest oil platforms in the Johan Sverdrup oilfield.

The Johan Sverdrup oilfield's location made its discovery in 2010 somewhat of a surprise. In the area of the North Sea where the field is situated, oil exploration began in the late 1960s.

It was long thought that the area was exhausted of oil, which couldn't have been farther from the truth.

As one of the largest oil fields in Norway's history, production in Johan Sverdrup will continue until at least 2050 and yield an estimated 2.7 billion barrels.

In 2018, Aibel was awarded a contract for the engineering, procurement, and construction of the Johan Sverdrup Process Platform II, the company's largest project to date, weighing approximately 25,000 tons and requiring more than 17,000 structural drawings.

"We are very much into digital fabrication at our operations in Norway and Thailand," said Halaas. "At Aibel, we want to go all the way and develop 3D models that are ready for machinery and fabrication. This is our vision of a digital yard. If we do not go in the digital direction, then we risk losing future projects by not being competitive enough. Fabrication-ready 3D models are a very efficient way of working. In addition to efficiency gains, the improved robotics have made our yards safer, as there is less need for employees to lift and cut heavy materials."

Getting Buy-In Across the Company

To ensure employees at all levels of the organization were behind its adoption of 3D modeling and new collaboration process, Aibel used a pilot-project approach and enlisted the help of key internal influencers.

"This has been a giant leap for us that demanded trust, commitment, and hard work from people across Aibel's operations," said Halaas. "The result is that we are now more seamless in distributing and sharing work around the world, as Tekla Model Sharing makes collaboration much easier. We can now appoint anyone anywhere in the world to create drawings for us."

Aibel typically does design work in Norway and then extracts the drawings for fabrication in Thailand and Singapore. "This global way-of-working has been much more challenging in previous projects, when we were not able to share 3D models in the cloud," said Halaas. "In the past, we had to freeze the work more often. Now we can work much more flexibly."

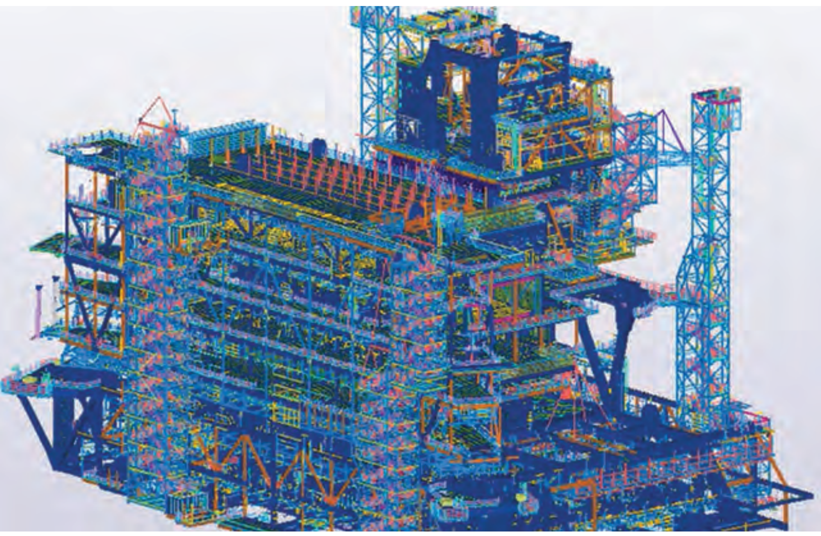
Breaking Barriers with Data-Rich Models and Global Collaboration

Constructible 3D models and collaboration will continue to play a very important role in Aibel's future.

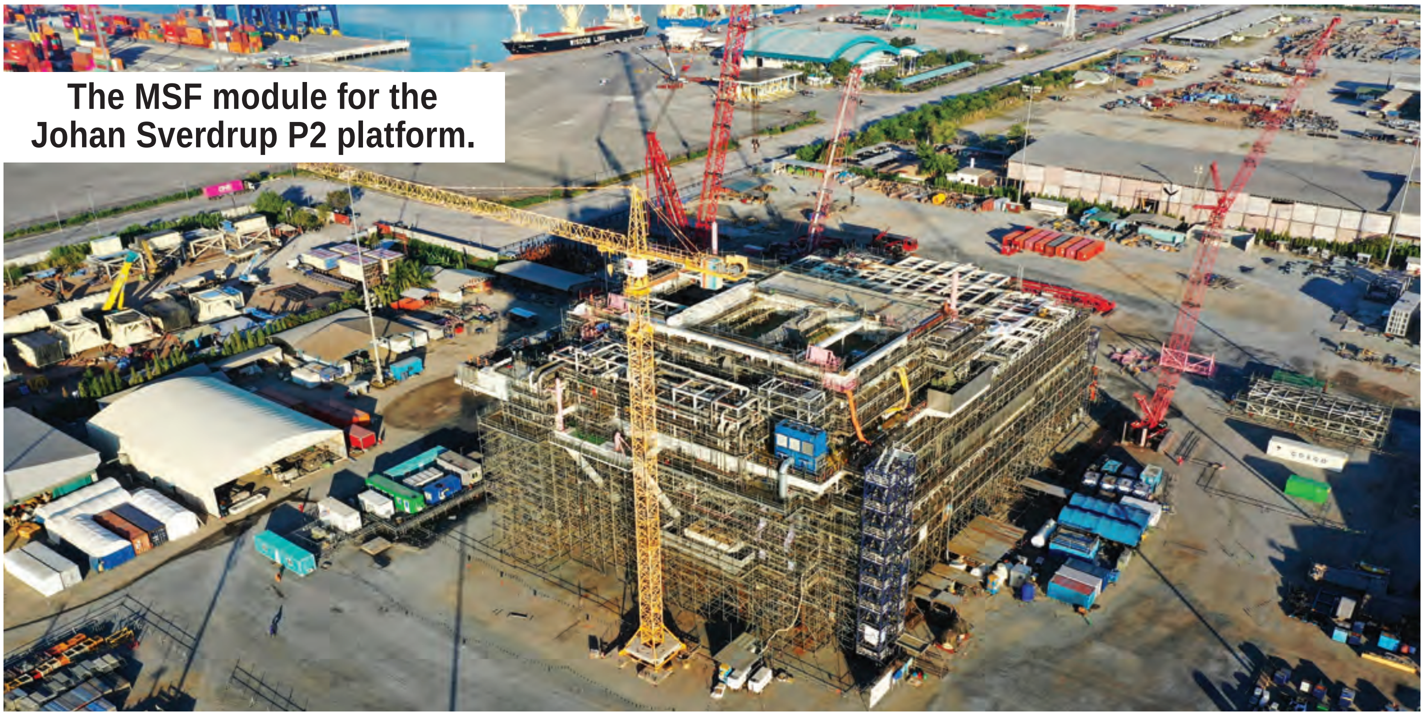
The P2 project exceeded its digitalization ambitions to reduce interfaces, automate drawing production and increase efficiency and robustness for the project execution," said Ståle Nordal, project director, Johan Sverdrup P2 Topside, Equinor. "Tekla is one of the initiatives that increased quality and reduced drawing production time for P2 and will provide a positive impact for future projects."

Less than a year after the Platform II contract was awarded, the first construction activities began at Aibel's yard in Laem Chabang and also at its subcontractor Deeline in Rayong, Thailand. Two years later, the module was completed and comprised four decks with a perimeter equivalent to a football field and a total weight of approximately 14,500 tons. Overall, this makes it the largest platform module ever built on Thai soil – beating the previous record held by the Johan Sverdrup Drilling Platform Main Support Frame, which was also built by Aibel Thailand.

This giant module will be transported to Aibel's yard in Haugesund, Norway, by the vessel GPO Sapphire. Arriving in Norway, it will be connected with the two remaining modules, UPM and HVDC, creating one platform for the Johan Sverdrup oil field. This spectacular lifting operation will be performed by the world's largest crane vessel, Sleipnir. The complete platform is scheduled for final delivery to client Equinor in early 2022.



Eivind Berg/BuildingPoint Scandinavia



The MSF module for the Johan Sverdrup P2 platform.

Aibel

DESIGNING

AKSELOS LAMPRELL –
Turbine foundation weight has been reduced through using Akselos' Reduced Basis Finite Element Analysis digital twin.

Akselos

WITH A *DIGITAL TWIN*

According to Oil & Gas UK's latest Tech Insights report, data and digital solutions are finally becoming an integral part of the asset lifecycle. One of the largest areas where they're applied is facilities management, but what about the design phase? **Elaine Maslin takes a look at two approaches.**

It's an area ripe for innovation. According to Norwegian digital company FutureOn's Customer Success Manager Gregor Deans, digitalization can reduce up to 70% of the engineering hours in field development. Much of that is in lead time reduction in the planning and design phases, with a potential for 30-80% reduction, Deans told the Underwater Technology Conference (UTC), held in Bergen and online earlier this year.

But it's not just about time to first oil. Dubai-based engineering and fabrication firm Lamprell and Swiss engineering simulation company Akselos have shown that the amount of material needed for an offshore wind jacket foundation can be reduced by 30%, using digital twin technology. Lamprell has been using the same technology to reduce weight in oil and gas foundations by 10%.

FutureOn was spun out of visualization technology firm Xvision in 2014. Its FieldTwin Design product, offered as software as a service (SAAS), is a platform that brings together a wide range of data sets, from bathymetry to reservoir data and well trajectories to pipeline data, into an environment that engineering teams can use.

Lundin Energy has been using the service on early phase subsea engineering work to "quadruple efficiency" and improve the quality of engineering outcomes, says Tom Widerøe, Lundin's chief engineer subsea, who was also a speaker at UTC.

He says that efficiency has largely been gained by separating data from applications, so that there's a "single source of truth" for data, and then applying web-based APIs within the FieldTwin environment to run any workflows required.

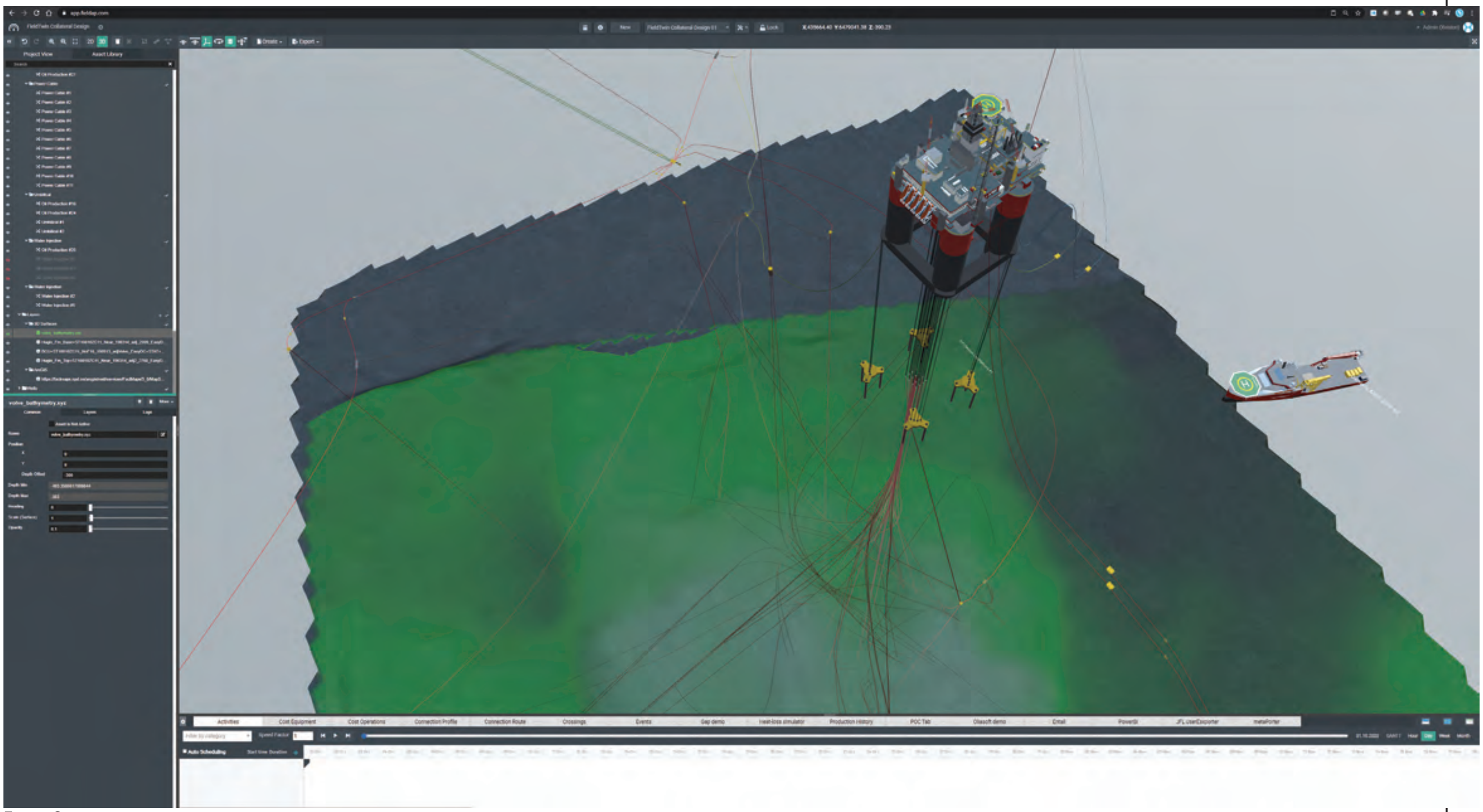
For early-phase design, where Lundin has a case book to look at different design cases, which can be anywhere from 10-20 to several hundred, this has helped ensure they're all kept up to date when any inputs change, such as oil price and production profiles.

"Until recently, this has been a very manual process, with little time for iterations," he told UTC. "Similar data is residing within different applications and different companies. Time and costs associated with maintaining and updating this data are significant. However, new tools and new working methodologies are now disruptively changing the way we work with field developments."

Looking back to 2018, a case would be developed based on data from the reservoir and drilling departments, a whiteboard drawing of a field layout would be created, then there would be a process to see if there's anything that could be done to

FutureOn's FieldTwin Design

creates a visualization environment from which simulations and workflows can be run.



FutureOn

optimize it, Widerøe says. Suppliers would also be brought in to support this work. Sketchup (3D design software) would then be used to create a field layout, where the wells are, how long the pipelines are, etc. Then a manual process, in Excel, would begin, to cost the project, as well as work on flow assurance, freespan calculations, rocking dumping requirements, etc., that would be done internally and externally in specific simulations, e.g. Olga, etc.

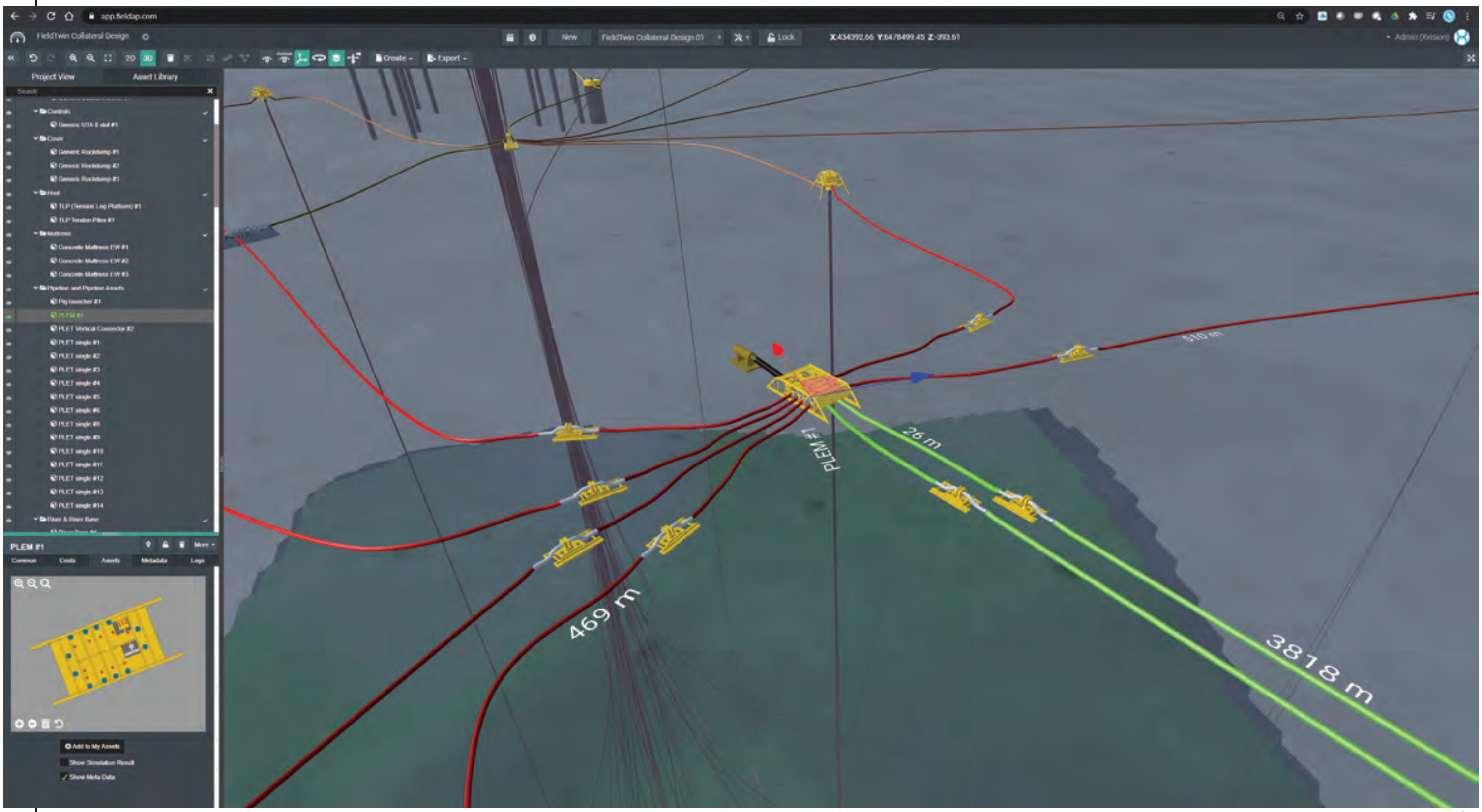
"It's a manual process that takes a lot of time and when there are more than 200 case books to look into. It takes a lot of time, so there's little time for iterations. There's similar data residing within different applications, data residing at contractors, quality is questionable, it's difficult to keep track of changes, and you're reliant on individuals. The data residing within applications at different companies has to be manually updated in each place," he says.

Using a platform like FieldTwin (which Lundin has supported the development of), the data is separated from the applications to create a single set of data, stored in the cloud, that all the involved platforms and digital tools can access through an API, with automated dataflow across applications and companies, and automated generation of a standardized case book with a full track of history, says Widerøe.

FutureOn

"We see we're able to do double the number of cases, using half the time. And due to better transparency and standardization and increased communications, the quality of the work will increase significantly."

– Gregor Deans, FutureOn



FutureOn

"A significant advantage of that data being stored in the cloud and accessible in the cloud via the API is allowing integration of other programs, so I can easily do flow assurance, or my OrcaFlex calculations through FieldAp (FieldTwin) applications." It's all also visualized and contextualized with imported GIS, bathy, or license maps from the Norwegian Petroleum Directorate, which gives the operator an overview of licenses, pipelines in the area, or any other nearby structures.

"If I change a wellhead location in FieldAP, then the pipeline geometry gets updated," says Widerøe. Integrated applications, run in FieldAP, are also typically updated on the fly, while external applications, maybe free-span calculations, will download the latest pipeline geometry from the cloud data to perform calculations, and then a new case book is automatically generated, he says. "We see we're able to do double the number of cases, using half the time. And due to better transparency and standardization and increased communications, the quality of the work will increase significantly."

Deans says some challenges are being worked on through industry joint industry projects and workgroups. The Data Liberation front, coined by Aker BP/Cognite in 2018, to encourage easier access to data, is one step, he says, but data socialism is also needed, to make collaboration easier.

And to do that, he says, everyone needs to speak a common language, which currently isn't the case. Each contractor has its own metadata, and that increases the time and effort needed to integrate the different solutions, he says.

An initiative, called Capital Facilities Information Handover Specification (CFIHOS), under the International Association of Oil & Gas Producers (IOGP) JIP 36, is working to develop specifications to facilitate transfer of information between operators and suppliers, to make this easier.

Also, there's development of a reference data library to support standard equipment naming.

Another IOGP project, JIP 33, is developing standard equipment specifications and another, DISC, is focused on the adoption of information standards. The OSDU forum is also developing open-source data standard models and platforms, mostly around well and reservoir data to date, says Deans.

This year Equinor and Total (now TotalEnergies) have been working together to align their internal metadata sets with external tools and contractors, he adds. The final agreed subsea metadata library will be added to the FieldTwin platform and it's expected that other operators' metadata libraries will be similar and the goal is an industry standard meta data library to submit to CFIHOS. That's work in progress…

The TetraSpar floating offshore wind turbine design that Akselos is now working on.

Akselos

Akselos – Offshore Wind

Another approach to the digital twin is Akselos' physics-based simulation technology. The technology, licensed from MIT, is a reduced basis finite element analysis (RB-FEA) software based on algorithms that the firm says are 1000 times faster than those typically used in conventional FEA analysis. Unlike FEA, RB-FEA can also provide detailed structural integrity simulations of entire assets, the firm says.

Akselos was founded about nine years ago and initially focused on integrity management through a software-as-a-service (SAAS) model, with venture capital funding and support from Shell. But it's also been looking at design engineering, helping to make fatigue calculations, across entire assets, faster and better. John Bell, SVP at Akselos says that FEA, the primary tool for testing strength in an asset, hasn't changed for about 40 years and that it is always a compromise; if you want high fidelity it can only be done at small scale, as it's generally not able to compute detailed models of full systems, and that if you want a full system analyzed, it has to be done via lots of smaller models, leading to layers of design conservatism in the model. It's also slow, which is especially an issue for supporting operational decision-making.

Akselos' RB-FEA is based on reduced order models; numerical methods to reduce the computation required for evaluating high-fidelity models, such as FEA. This is complex stuff – Akselos' RB-FEA algorithms, based on a component-based version of reduced basis methods, took MIT about 12 years to build, under funding from the US Department of Defence, which wanted better – faster – ways to understand the structural integrity of its ships in a live battle situation.

The parameterized components which are connected to form a model make the computation much faster than traditional FEA because fewer numbers have to be crunched.

"Pre-analysis, and a component-based approach, allows us to significantly reduce the amount of data we need to calculate," says Michiel van Haersma Buma, VP for Customer Success at Akselos, "accelerating each solve by orders of magnitude."

That makes it faster and also scalable to well over a 100 million degrees of freedom, he says, adding that "there is really no other technology capable of handling those levels of complexity, so we genuinely believe this will change the game in both Design and Operations."

Any changes to the components – material properties, loads, geometries – can be quickly resolved in the model, making design iterations faster and across an entire asset, such as a turbine, not just the blade.

UAE-based Lamprell has seen this as an opportunity. The company has been working in offshore wind for some time and currently has a contract for 30 offshore wind turbine jackets with suction bucket foundations on SSE's Seagreen 1 project off Scotland, each of which will host 10MW MHI Vestas turbines.

Lamprell COO Hani El Kurd says the company started on its digitalization journey by digitalizing existing processes, automating things like welding in its yards and using robotics.

It's then started looking at design optimization, as part of efforts to help reduce inspection requirements. The time it took to run simulations was a limiting factor, he told a webinar run by Akselos, limiting how many iterations to change and influence concept designs could be done. RB-FEA has overcome that challenge and they can also look more at constructability. Traditionally, a design for an offshore wind jacket will take nine-18 months, but that could be radically reduced, by half or less, even, says Van Haersma Buma, with RB-FEA.

Sabih Laham, VP of engineering, also says the previous methodology was siloed with different analyses being run at different levels of the design and with full model revalidation requirements resulting in a "laborious" process and uncertainty. In comparison, RB-FEA is allowing them unrestricted degrees of freedom to be simulated in a single model at speed without needing high amounts of computing power. So far, Lamprell has been reducing the weight of an oil and gas foundation by 10% and the steel input for offshore wind turbine jackets by up to 30%, the firm says.

Akselos itself is also now working with Shell and RWE to model the Stiesdal design TetraSpar floating offshore wind demonstrator, which was recently installed offshore Norway. In this case, the structure model will include live data from the installed structure, so it can be analyzed in near real-time to support future design improvements and optimization. This work follows a project on Principle Power's Windfloat Atlantic project.

There is more that could be done from an industry perspective, if the data was available. However, it can be hard getting, for example, the required turbine data, which means a design has to ping back and forth between the foundation designer and turbine manufacturer, lengthening the process, says Van Haersma Buma, who joined Akselos in 2021 after supporting the company through Shell Ventures.

"If we had access to detailed turbine data earlier in the offshore wind design cycle, we could start the foundation optimization process early and reduce project uncertainty for an offshore wind developer by order of magnitude," he says.

Downhole Gamification

Still, much of the focus for the digital twin is in the production and maintenance phase, from helping make the most out of subsea wells through to better pipeline monitoring.

Neptune Energy, for example, recently said it is applying a data visualization platform based on 3D gaming technology to historical and live data from its subsea wells in Norway to enhance drilling and production efficiency and reduce time and costs.

These "digital twins" were developed in collaboration with InformatiQ, an oil and gas data visualization firm that combines infrastructure, wells and geology data to create detailed cloud-based 3D models.

Neptune Energy's Director of Drilling & Wells for Norway, Thor Andre Løvoll, says: "By digitalizing all subsea wells within our Norwegian portfolio we have greatly improved our ability to plan interventions, monitor drilling and production operations in real-time and gain better understanding of the wells' history."

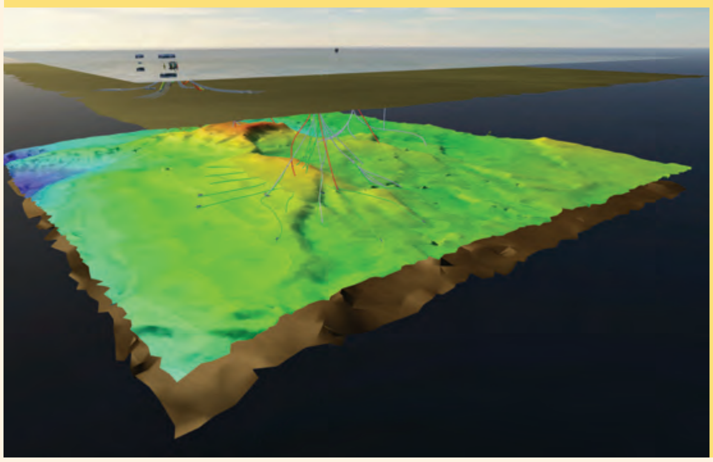
He says that the gaming approach differentiates the system from other heavy data visualization tools because the data is only visualized with x.y.z surfaces and locations, so it does not need supercomputers and heavy mathematical calculations running to handle the task. "Where the user needs to dive into the details, he can simply zoom in or move into applications which contain the detailed dataset," says Løvoll. "Also, locating data tagged in the 3D model will allow the user to navigate through data landscape, rather than selecting files and folders systems with the same data."

"We have already linked up real-time data sets from the rig site and streamed real-time and true updates of ongoing well paths and compared with planned well paths in the digital twin. The future version of the GeologiQ digital twin can be very similar to gaming, where the user can navigate through different levels and solve tasks in the digital twin to enrich the well delivery database leading up to a final well program, design and execution plan. Well Engineering can become addictive!"

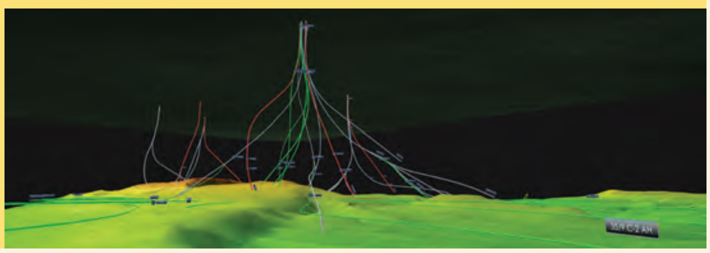
Like most digital/data tasks, a key challenge was defining the unique data identifiers that could be linked to the rest of the dataset, as well as checking the quality of the data, which is aided by the loading and visualisation process, as misplaced x.y.z. or time data can easily be spotted if they appear in the wrong place, says Løvoll.

However, having started with just its subsea wells, "a limited and controllable dataset," they can now relatively easily import global well data into the model, from its own wells to any official well data set, such as Norwegian Petroleum Directorate data, that's freely available.

Data visualization in GeologiQ helps Neptune Energy to enhance drilling and production efficiency.



Thor Andre Løvoll, Neptune Director of Drilling & Wells in Norway



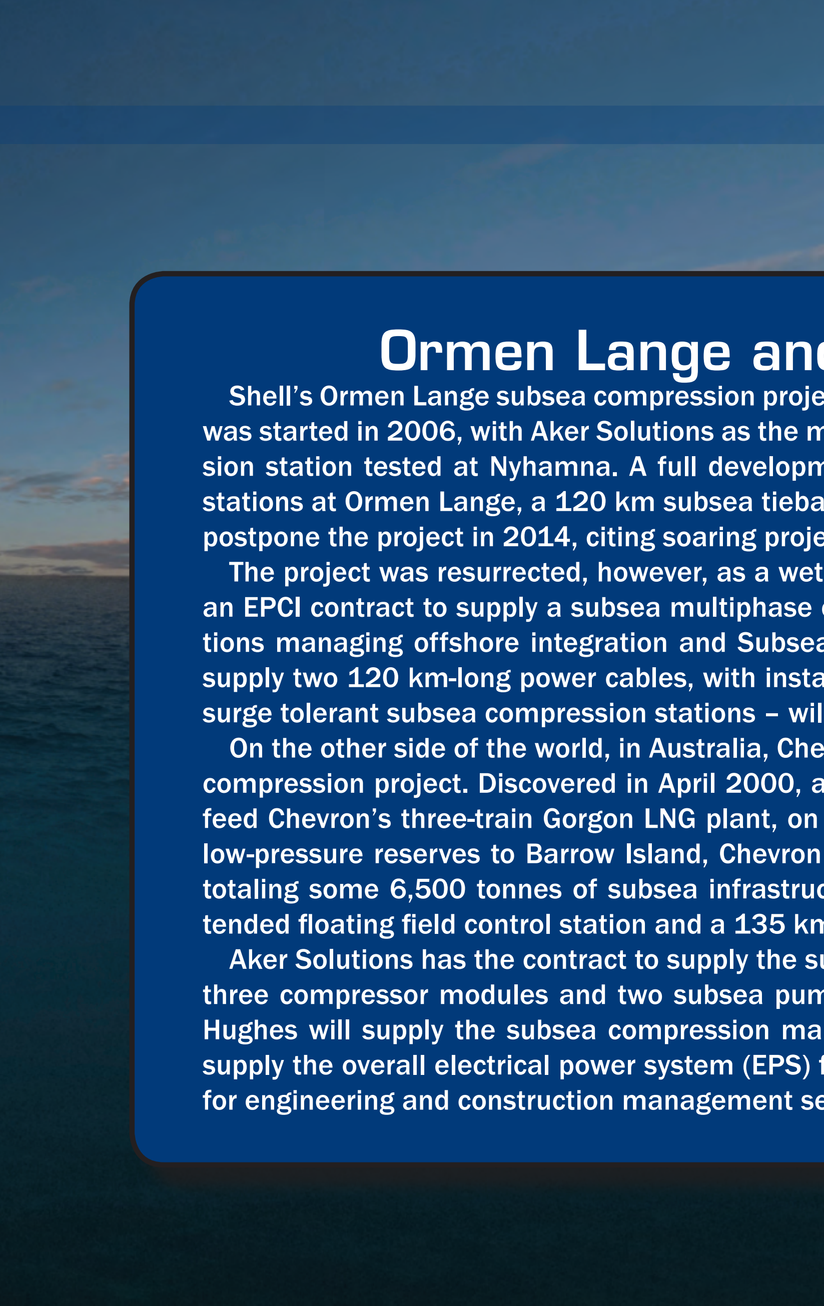
Images from Neptune Energy

SUBSEA PROCESSING - EMISSIONS ABATEMENT OPPORTUNITY KNOCKS?

A COMPLETE SUBSEA FACTORY MAY YET BE A PIPE DREAM. HOWEVER, WITH ITS CONSTITUENT PARTS NOW MORE OR LESS READY, THE INDUSTRY HAS A MUCH GREATER TOOLBOX OF TECHNOLOGIES WITH WHICH IT CAN NOW APPLY TO EXISTING AND NEW SUBSEA DEVELOPMENTS. BUT IS THERE WILLINGNESS, EVEN WITH THE TEMPTATION OF BEING ABLE TO REDUCE THEIR CO_2 FOOTPRINTS?

BY ELAINE MASLIN

Image above: Aker Solutions



Ormen Lange and Jansz-Io in focus

Shell's Ormen Lange subsea compression project is well over a decade old. Originally, a pilot project was started in 2006, with Aker Solutions as the main contractor for a 12.5 MW pilot subsea compression station tested at Nyhamna. A full development base case was for two 12.5 MW compression stations at Ormen Lange, a 120 km subsea tieback to shore development. However, Shell decided to postpone the project in 2014, citing soaring project costs.

The project was resurrected, however, as a wet gas compression project. In 2019, OneSubsea won an EPCI contract to supply a subsea multiphase compression system for the project, with Aker Solutions managing offshore integration and Subsea 7 supporting on the installation side. Nexans will supply two 120 km-long power cables, with installation expected in 2023. The system – two 16-MW surge tolerant subsea compression stations – will be installed in 850 m of water depth.

On the other side of the world, in Australia, Chevron is moving forward with its US$4 billion Jansz-Io compression project. Discovered in April 2000, about 200 km off Australia's mainland, Jansz-Io will feed Chevron's three-train Gorgon LNG plant, on Barrow Island, which is 70 km offshore. To get the low-pressure reserves to Barrow Island, Chevron is due to install two subsea compression stations, totaling some 6,500 tonnes of subsea infrastructure, supported via a 27,000-tonne normally unattended floating field control station and a 135 km power cable from Barrow Island.

Aker Solutions has the contract to supply the subsea compression system for the project, including three compressor modules and two subsea pump modules, with delivery expected in 2025. Baker Hughes will supply the subsea compression manifold structure, connectors, and controls. ABB will supply the overall electrical power system (EPS) for the project. Worley has been awarded a contract for engineering and construction management services on the project.

When Equinor's Åsgard subsea compression project in the Norwegian Sea came on stream in 2015, closely followed by the Gullfaks wet gas compression project, a new era of subsea processing seemed to be opening up.

After years – decades even – of engineering effort, the 2020 subsea factory vision, promoted by Statoil in 2012, looked possible. Yet, it's now 2021, and they are still the two only projects of their type in operation and, when the next projects start up, there will have been a gap of almost 10 years (Ormen Lange in Norway, expected in about 2024, followed by Jansz-Io project, offshore Australia, in 2025).

Slow take-up is not new in the subsea processing world. Despite being the most mature subsea processing technology, subsea boosting (first installed at Draugen in 1993) remains relatively untapped. According to Norwegian analyst Rystad, there are currently only 52 subsea boosting projects worldwide, with about 142 pumps installed.

It's not for lack of opportunities. According to Rystad's research, there are some 200 projects globally, 50% of which are brownfield and where the subsea boosting could make an immediate impact by increasing production profitably.

The top 100 of those projects could offer, on average, a 61 million barrel increase in recoverable reserves, per project, with a profit of $11.30/barrel, it says. Half of the projects identified were in the US, with Brazil and Angola following as the countries with the most opportunities. Norway, the UK, Guyana, and then Nigeria follow, in that order.

Erik Vinje, an analyst with Rystad Energy's energy service team, says that one reason for the low take-up in subsea boosting was system reliability, which was an issue in the early days of subsea boosting. However, reliability has increased in recent years. "It's mostly (now) about convincing the operators that the technology is mature enough and the reliability is good," he says.

"Conservative operators are stuck in the past when it comes to this technology."

In some cases, suppliers have taken on more risks to get projects over the line. Going forward, it might be that more of the smaller operators take up boosting technology, Vinje adds, like deepwater-focused Kosmos Energy and Gulf of Mexico-focused Fieldwood Energy, as they look to tap subsea tiebacks, deepwater projects, and faster payback.

While subsea boosting is a hard sell for some, subsea compression is an even harder one.

"The technology offers numerous benefits, but it requires a substantial amount of [gas] resources to justify the very high investment cost," says Vinje. "In the current price environment, there are 13 potential candidates with a start-up before 2030."

But Vinje doesn't expect 6-7 of these to materialize. Even with increasing incentives around emissions reduction, which could make subsea compression more attractive, the technology itself will need to be smaller and more compact, so that it can also be applied to small to medium-sized gas fields, not just the larger fields, he says.

Emissions reduction high on vendor's agendas

Hans Fredrik Lindøen-Kjellnes, Principal Process Engineer at OneSubsea, the subsea technologies, production, and processing systems division of Schlumberger, says: "Kg/co2 per barrel of oil equivalent turns out to be one of the most important parameters to measure today," he says.

"In 2019, almost a third of emissions from Norway came

Load-out of the recently installed Vigdis pump station at OneSubsea, Horsøy near Bergen.

Photo by Jan Arne Wold & Audun Skadberg, from Equinor from the oil and gas industry. More than 80% of the emissions from our industry are related to power generation with gas turbines and we know our largest consumers are pumps and compressors. So, to reduce the CO_2 footprint, it makes sense to look at how we're doing pumping and compression and if we're doing it in the right way with the right systems for the job."

Using subsea compression reduces power consumption, Nicolas Barras, Senior Manager, Aker Solutions told UTC.

When comparing topside versus subsea compression for a 100-150 km tieback to shore with a 30-year field life, 35MW would be needed topside compared with 26MW subsea – a 3.6Twh difference of life of field. The energy used could also be provided by offshore wind, he says, which would help limit CO_2 emissions.

This would need to be in areas with reliable winds, and the compressor speed could be controlled and adjusted according to the power available, says Barras, and, with energy storage, there could be further optimization.

The company is also addressing Vinje's view that smaller, more compact compression systems are needed for smaller reservoirs, not just the large projects. Aker Solutions is doing this by directly coupling the compressor motor to the compressor in a common housing and using active magnetic bearings, reducing the weight of such a system by 30-40%, says Barras.

Dealing with CO_2 - at the seabed

Subsea compression could also be used in areas where fields contain high CO_2 content, says Barras. The CO_2

could be captured "at source" and then reinjected locally, he says, reducing the power needed for reinjection but also reducing the size of the production flowline and the amount of topside equipment needed to condition the gas.

This is something Aker Solutions is working on, says Barras, with qualification of gas separation membranes for subsea carbon capture from natural gas ongoing.

In Brazil, Petrobras, together with Libra Consortium partners, is also looking at high CO_2 concentration gas removal and injection at the seabed at ultra-deepwater high pressure, high gas oil ratio (GOR) oilfields with high (e.g. over 20-30%) CO_2 content, Herbert Prince Koelln, Subsea Engineer at Petrobras told UTC in his presentation made with co-authors Ana Margarida de Oliveira, Fabio Menezes Passarelli and Marcello Augustus Ramos Roberto.

This would be possible through HISEP, Petrobras' patented high-pressure separation technology, currently in the qualification stage.

The wellstream would first pass through, initially, gravity-based separators, with dense gas being split off to two 6MW pumps in series to be reinjected into the reservoir in a water-alternating-gas loop, and the oil transported topside with a much reduced GOR.

The idea is to help dealing with gas containing high CO_2 content at the seabed and debottleneck surface facilities, which otherwise need significant ancillary equipment to handle huge volumes of gas.

By transferring part of the process (and in the future possibly removing the entire process) from the topside to subsea, with only single-phase pumps required subsea for the reinjection, instead of topside compressors, power consumption is reduced by up to 20% compared with topside compressors, he says.

Overall, a 12% reduction in CO_2 per barrel could be reached, he said.

As part of this work, Petrobras is also testing in a real field application a subsea variable speed drive (SVSD) for a 6MW subsea motor, for applications where subsea power might come from a different platform to the one the oil is being produced to or longer tiebacks, says Koelln.

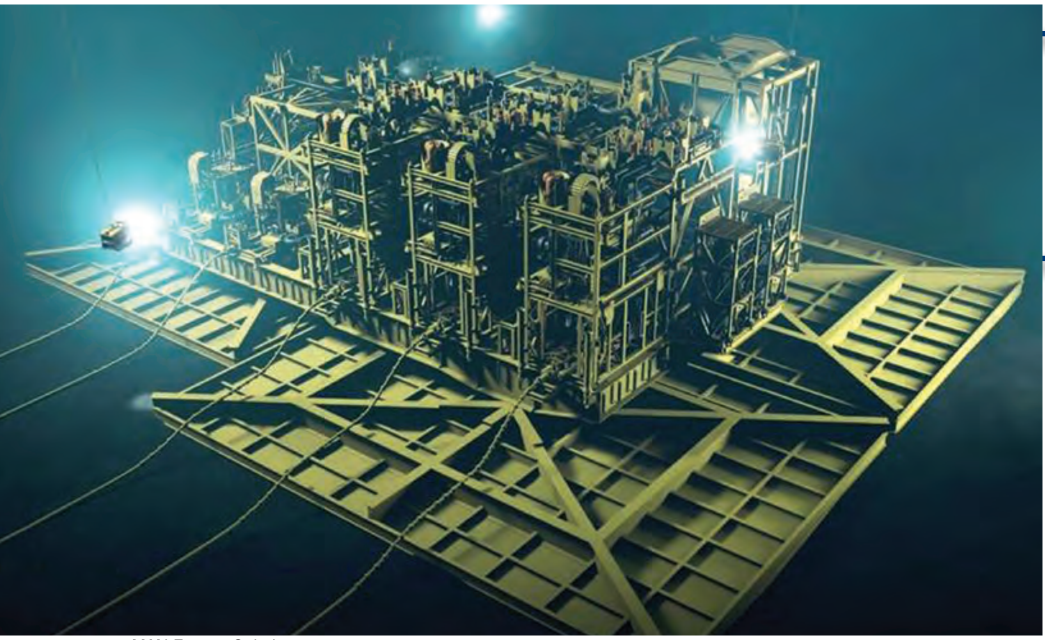
Moving the VSDs subsea would mean a 35-50% reduction in weight and footprint of the HISEP topside module.

"We have many reservoirs that may apply this technology in the future," Koelln told UTC, but acknowledges many challenges, not least in control and fluid dynamics and power control for load sharing and transient control, but also subsea cooling and wax control, high pressures, and wide temperature ranges.

Subhead Subsea seawater injection

Subsea water injection could also help reduce CO_2 emissions, says OneSubsea's Lindøen-Kjellnes. OneSubsea compared topside and subsea seawater treatment and injection systems and found that in a base case 400 m deep field, on a 30 km stepout, choosing a subsea system over a topside one could save about 70,000 tonnes of CO_2 over the life of the field; equivalent to 11.3% reduction potential.

On a cost basis, topside equipment was thought to be less costly than subsea, but once installation and modification costs were taken into account, the two options came close together. Subsea equipment also requires a lot less maintenance and attention during operations, he says, saving costs.



MAN Energy Solutions has been commissioned to supply five subsea compression units for the Chevron-operated Jansz-Io Compression (J-IC) Project.

MAN Energy Solutions

MAN Energy Solutions provided the compression units for Equinor's Asgard subsea compression project, delivered by Aker Solutions.

Adding offshore wind into the mix

OneSubsea also compared the CO_2 footprint if offshore wind power was brought into the mix.

"We found that driving such a system with a wind turbine alone wasn't a very attractive business case," he says. This was because, due to the availability of wind energy, more pumping capability (i.e. duplicate injection and water treatment systems) would be required for periods when power was available, to make up for the downtime. If offshore wind was combined with a more traditional subsea power topology, such as at Hywind Tampen, excess power generated could be used by other topside utilities, while, during low wind periods, local turbine-generated power would be available.

"Adding a wind turbine to the power system would add some complexity, but in a scenario when we're anticipating high growth in CO_2 tax, this turned out to be a very attractive business case. I think it represents the way we should think on putting together our systems in new ways to be efficient and to get our carbon emissions down."

All of these technologies fit into the subsea factory vision. However, while most of the pieces of the subsea factory puzzle are now there, Rystad's Vinje isn't convinced we'll see a full subsea factory development any time soon.

"It's unlikely we will see a full subsea factory going forward, with operators being very concerned about cutting costs," he says. "But I think the tools in this subsea processing toolbox will go forward on their own. There are benefits in terms of low carbon solutions, so it's a way to help operators in curtailing emissions from production."

MAN Energy Solutions

A technology that could increasingly support deep and long tieback projects is electric heating, specifically ETH (electric trace heating), thanks to a lower power demand than previous direct electrical heating technologies, says Rystad Energy analyst Erik Vinje.

"We think this is potentially the biggest opportunity here and where we will see the most activity going forward," he says. "In deeper water and over longer distances, you have increased risk of wax formation. To keep up the flow and production, ETH is a very cost-effective solution for subsea tiebacks, and if you can improve the distance with this technology, I expect adoption to pick up going forward."

TechnipFMC's electrically trace heated pipe-in-pipe (ETH-PiP) technology, first deployed on the Islay subsea tieback in 2011, was recently installed on Neptune Energy's Fenja subsea tieback in the Norwegian North Sea. A 37km ETH-PiP pipeline – the longest in the world – was installed to tie the Fenja fields, in ca. 324 m water depth, back to Equinor's Njord A platform, and is due to be commissioned in 2022.

Last year, an electrically heat traced flowline (EHTF) pipe-in-pipe solution from Subsea 7 – the company's first – was deployed on the Ærfugl phase 1 tieback project, in the Norwegian Sea. Ærfugl was tied back with a 20.3 km long EHTF PiP system to the Skarv FPSO. Subsea 7 developed and installed a new EHTF fabrication line at its Vigra spoolbase for the project.

Meanwhile, Subsea 7 set out its second EHTF deployment in the Gulf of Mexico in an OTC paper. The project, BP's Manuel development, was in more than 2,000 m water depth, said Subsea 7, making it the deepest EHTF installed to date.

A Seismic Shift

Despite oil prices recently edging past $80 a barrel, scars from two recent oil industry downturns in five years have forced offshore seismic surveyors to look at ways to diversify.

By Bartolomej Tomic

Marine seismic survey companies provide essential data to offshore oil and gas explorers to make better-informed drilling decisions. However, with every oil industry downturn, seismic players are among the first to feel the pang, as exploration budgets usually get cut significantly and revenue streams for seismic data firms dry up.

This was particularly the case last year when the industry was hit with a double whammy: COVID-19 and a global lockdown that hit demand for oil plus a fallout between Russia and OPEC that flooded the market with oil, sending the prices down even further. As expected, exploration budgets were cut, and seismic players revenues were hit, with some of them, such as Polarcus, going out of business.

Now, with oil prices back up to around $80, the situation for explorers has improved, with Rystad Energy recently reporting that vessel utilization in the offshore oil and gas seismic data acquisition sector had reached pre-pandemic levels in the third quarter of 2021.

Rystad, which monitors the activity of 106 seismic vessels, said the seismic fleet's hibernation was over, with around 68% of the fleet now surveying or underway. According to Rystad, the seismic fleet matches the utilization levels of the first quarter of 2020, before the pandemic-induced slowdown hit the seismic industry.

The worst time for the fleet was from the third quarter of 2020 through March 2021, when 46% of the global fleet was inactive (either standby in port or stacked), Rystad said.

(Partial) Pivot

While the market sentiment seems to be improving, pessimistic long-term views on the future of oil, recent and frequent oil downturns, and environmental pressure, have forced seismic data companies to start looking beyond the oil and gas industry. In the past year, seismic firms have thus started working to diversify their offering, find their role in the accelerating energy transition towards renewables, and make themselves "futureproof," by not depending solely on offshore oil and gas.

One of the most active seismic companies in this push to diversify is Norway-based seismic data company TGS, which earlier this year formed the New Energy Solutions (NES) business unit, to pursue opportunities related to the energy transition, in industries contributing to the reduction of GHG emissions, such as Carbon Capture and Storage (CCS), Deep Sea Mining (DSM), geothermal energy, wind energy, and solar energy.

"Many of the investments required in renewable energy and CCS have long pay-back times. It is therefore critical to make well-informed and precise investment decisions. Our aim is to be the leading provider of data and insights that help de-risk investments and reduce the time-to-market," TGS, which doesn't own seismic vessels, but rents them as needed, said at the time.

Shortly after the formation of NES, TGS announced its entry into the offshore wind arena, buying 4C Offshore, a market intelligence and consultancy firm providing research and insights to the offshore wind industry. At the time of the acquisition, 4C Offshore, based in Lowestoft, UK, employed 29 people and provided data on more than 2,000 offshore wind projects, and had recurring revenue streams from a diversified base of almost 350 clients, serving 2,200 users.

In 2020, subscription payments for 4C Offshore's data services accounted for almost 80% of revenues, TGS said, without sharing info on the level of 4C Offshore's revenues.

TGS then, in the same month, signed an agreement with the Norwegian low-carbon tech company Horisont Energi to jointly work on the identification and classification of CO2 storage reservoirs and develop new Carbon Capture and Storage (CCS) technologies.

A few days later, TGS announced a collaboration with oilfield services giant Halliburton to bring advanced seismic imaging to fiber optic sensing to help oil firms boost output rates, but also explore carbon storage options, such as carbon storage monitoring, in another proof that the whole oil industry has taken note of the blowing energy transition winds.

Talking about winds, TGS in August announced its involvement in the growing U.S. offshore wind market, expanding its coverage of numerical weather prediction (NWP) model data for offshore wind off the East Coast U.S., extending from Massachusetts to North Carolina to create a higher resolution dataset than publicly available with coverage over the key offshore wind industry focus areas on the U.S. coast.

DedMityay/AdobeStock

Seabed Minerals

Another Norwegian seismic company, SeaBird Exploration, has in the past year announced forays into deepsea mining and offshore wind. It launched Green Minerals, a company focused on deep-sea mining of marine minerals and Rare Earth Elements (REE) "key to the green shift," and "eliminating the social costs in onshore mining while reducing the environmental footprint."

The company said that medium-term, Green Minerals' plan is to win licenses to survey, explore, and produce Marine Minerals on the Norwegian Shelf, "thereby "capitalizing on $79 billion worth of resource potential.

Norway could license companies for deep-sea mining as early as 2023, potentially becoming one of the first countries to harvest seabed metals for electric vehicle batteries, wind turbines, and solar farms, according to a Reuters article, published in January.

In November 2020, the American Bureau of Shipping's Vice President of Global Offshore Markets Matt Tremblay said the world demand for metals required for new forms of transportation and electrical storage is increasing. "Metals such as copper, cobalt, nickel, and manganese exist on land, but are increasingly difficult to extract sustainably. Subsea mining, with the abundant resources on the seabed, offers an alternative," he said.

Green Minerals expects to have its marine minerals production system ready to start pilot production in 2026. Apart from the seabed minerals push, SeaBird Exploration in April this year announced its first foray into the offshore wind industry, with a contract secured for its Petrel Explorer vessel, to serve as an accommodation vessel for a wind farm maintenance campaign in the Baltic Sea. According to the vessel's spec sheet, the Petrel Explorer offers 54 berths in 40 cabins.

Monitoring from Space

French seismic company CGG has been transforming for a few years now, going asset-light, but also delving into new non-traditional business areas.

It sold its vessels to Shearwater in January 2020, with the deal including a five-year vessel capacity agreement for marine seismic acquisition services between the two companies. While the sale was dubbed CGG's exit from the marine data acquisition business, CGG is still conducting seismic surveys, but it is doing so using Shearwater's vessels.

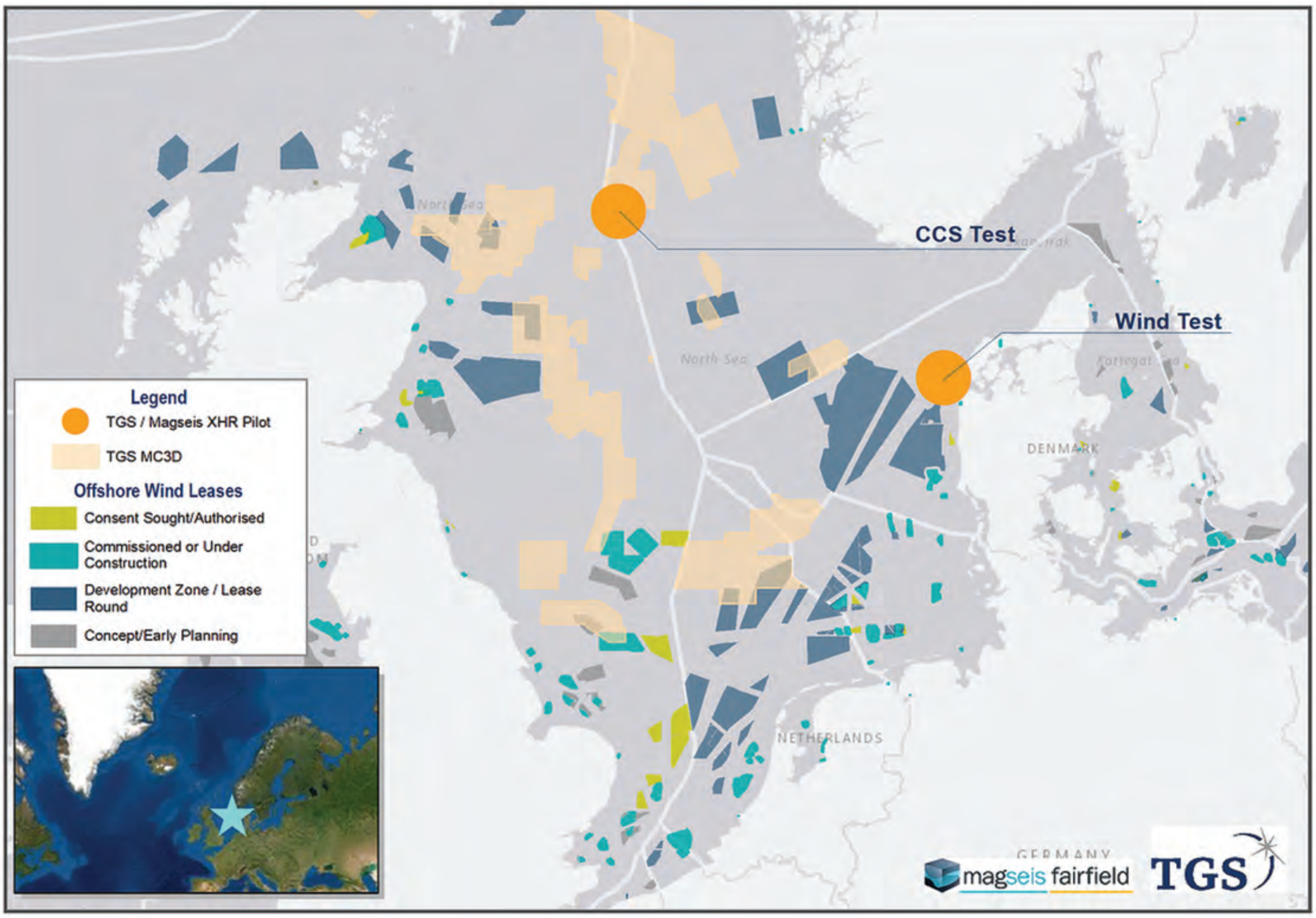
CGG also this year announced deals not typical for an oil and gas seismic data company.

It in April it partnered with dCarbonX, a company looking to develop offshore geothermal energy and storage sites for CO2, hydrogen, and ammonia in Ireland and UK.

CGG will bring its geoscience solutions to help identify and de-risk subsurface storage, sequestration and geothermal energy sites using its expertise in geological, geophysical, engineering, modeling and monitoring technologies, including instrumentation from Sercel, its equipment division, it said.

Also in April, a consortium led by CGG was picked by the European Space Agency's Space Solutions initiative for a study aimed at developing new environmental monitoring technology and services to help combat the global marine litter crisis.

CGG will collaborate with Mott MacDonald, a global engineering, management and development consultancy, and Bru-



Credit: TGS

nel University London to develop new environmental monitoring solutions based on CGG's analysis and processing of Earth observation data and using its artificial intelligence models.

The first 12-month phase of the study will focus on establishing the technical feasibility and commercial viability of new satellite-based services for detecting large aggregations of floating plastics to improve understanding of the sources, pathways and trends of plastic pollution in marine and coastal environments.

Apart from this, CGG in May launched a maritime pollution monitoring solution named SeaScope.

CGG said SeaScope would help a range of offshore industries mitigate risks, respond quickly to events, and support their environmental and operational transparency measures.

The solution was developed with the support of the European Space Agency together with a group of energy companies and emergency response organizations. CGG earlier this year via its Satellite Mapping group completed a high-resolution hydrocarbon seeps study commissioned by the Norwegian Petroleum Directorate (NPD).

The study aimed to increase petroleum system knowledge across a relatively data-poor area of the northern Barents Sea.

CGG Satellite Mapping's SAR satellites acquired a large collection of high-spatial-resolution SAR imagery at a high revisit frequency. Ensuing processing and analysis by its CGG specialists identified the presence of small-scale naturally occurring seepage slick features, unlocking, what CGG says is valuable subsurface intelligence.

Also, in July this year, CGG, with the Norwegian marine seismic data acquisition company PGS, announced a plan to combine its seismic MultiClient products and technical capabilities applied to the Carbon Capture Utilization and Storage (CCUS) industry.

"Together, the companies intend to explore, conceptualize and create new derivative data products using existing seismic data to facilitate screening and evaluation of carbon storage sites," the two companies said.

Carbon capture and storage

Carbon capture and utilization seems to be a running theme among seismic data companies. OBN seismic contractor Magseis Fairfield recently formed a subsidiary focused on the energy transition, called Magseis Renewables.

Magseis Renewables in August announced two initiatives focused on carbon capture.

First, it entered an agreement to join the Greensand carbon capture and storage (CCS) project in the Danish North Sea. The project entails transporting CO2 by ship to the Nini West reservoir off Denmark, and injecting it via the offshore wellhead platform. The CO2 will be stored in depleted oil and gas sandstone reservoirs 1500m below the seabed, and existing infrastructure will be repurposed from oil and gas production to CO2 injection. Magseis Renewables will provide its OBN technology and imaging solutions to contribute to the development of CCS monitoring technologies.

Separately, the company entered two technology pilot projects for carbon capture and storage (CCS) and offshore wind in partnership with TGS.

The first project will use high-resolution 3D seismic acquisition in Norway at a carbon storage area to demonstrate technology for highly detailed imaging of the full section from the seabed to the targeted storage reservoir.

The second project will utilize ultra-high-resolution 3D seismic acquisition in Denmark over an offshore wind farm with known near seabed challenges to demonstrate applying a high-frequency source coupled with TGS' data processing technologies, the partners said.

Full pivot (eventually)?

Oslo-listed seismic surveyor Axxis Geo-Solutions recently changed its name to Carbon Transition, reflecting its new strategy. Cabon Transition said it would focus on investing in private companies and have "a goal of positively impacting the value creation of its investments."

As for its seismic business, the company said it would continue going forward but will be subject to requirements for satisfactory rates of return.

"The board of directors considers the new strategy of the company to allow for its current seismic business area to be included in Carbon Transition in such manner for a transition period. Seismic contracts and seismic data library are expected to generate revenues to finance the new strategy.

"It is essential that the costs related to operating this part of Carbon Transition's business are kept low. Over time the objective is to utilize revenue from the node technology and multi-client revenues to new investments within the "energy transition" area," Carbon Transition said in July.

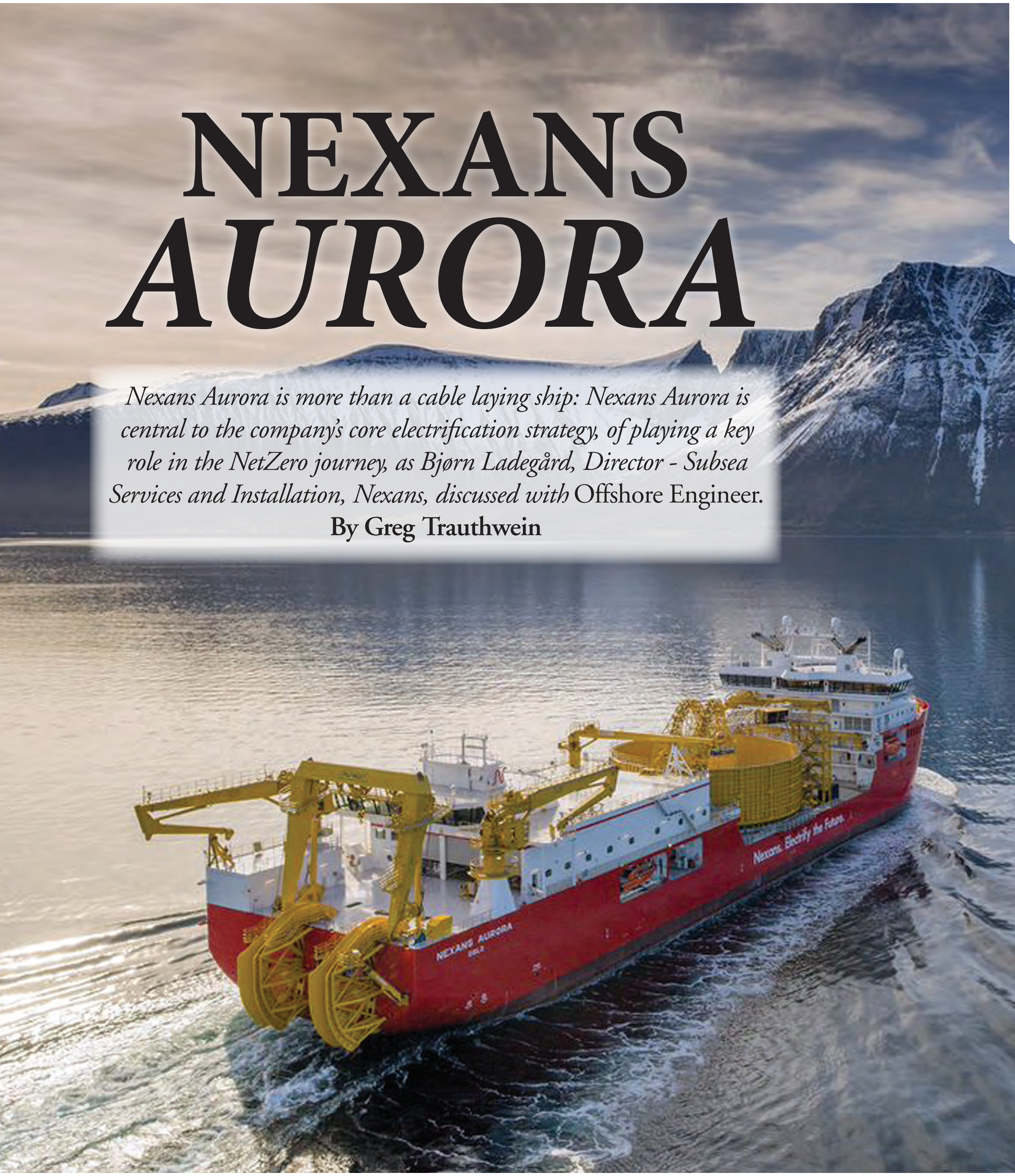
However, while other seismic companies are looking at carbon capture, seabed minerals, space monitoring, offshore wind, Carbon Transition has invested in black pellets.

Namely, the company has invested a Arbaflame AS that has developed a patented technology that enables the production of black pellets from biowaste - called ArbaCore - which can, reportedly, "fully replace coal in coal-fired power plants worldwide," and cut CO2 emissions by around 90% compared to coal.

NEXANS *AURORA*

Nexans Aurora is more than a cable laying ship: Nexans Aurora is central to the company's core electrification strategy, of playing a key role in the NetZero journey, as Bjørn Ladegård, Director - Subsea Services and Installation, Nexans, discussed with Offshore Engineer.

By Greg Trauthwein



Bjørn Ladegård
Director, Subsea Services & Installation, Nexans

All images courtesy Nexans

Electrification is at the heart of what Nexans does, and its latest fleet addition – Nexans Aurora which has been four years in the making – is designed to help effectively extend the company's capabilities globally, particularly in regards to the laying of increasingly complex and deep cable arrays to serve the growing offshore wind industry.

With the arrival of Aurora – designed by Skipsteknisk and built at Ulstein Yard – Nexans effectively doubles the physical fleet size, but the story on additional capabilities transcends the addition of one ship. Aurora is the company's second main cable-laying vessels joining the 1976-built Skagerrak, as well as a pair of high-capacity storage and installation barges called the UR141 and the EB32.

"We pride ourself in being a turnkey solution provider for cabling solutions for offshore wind power and interconnector. We needed to add a vessel to be able to make up for all cable projects we saw coming," said Ladegård. Nexans Skagerrak was the starting point of the design of Aurora. "A lot of the main parameters have been replicated in order to build on the success of this ship, but to do it bigger and better, quicker and cheaper, so we could continue supporting bigger projects."

The quest to design Aurora was dictated largely by the size and quantity of equipment and capability needed onboard. "We needed to make the ship wrap around the equipment rather than equipment fit on the ship," said Ladegård, "and I think we got the best of both worlds."

Some of these enhanced capabilities are related to the carrying capacity of the cables. "We can have 10,000 tons carrying capacity in the turntable, in addition, we have 450 tons of fiber optic key cable capacity. For interconnectors and HVDC, it's equipped with a dual turntable and laying lines for bundled DC applications," a new capability.

Another highlight of Aurora is its shallow water capabilities, as it is here that difficult seabed topography and adverse weather conditions can really impact operations. "This is extremely important because we are normally ending up with a cable end in the landing operation, and the closer you can get to the shore and have safe operations while landing the cable, the better," said Ladegård

As it is designed to operate globally, Nexans Aurora had to be powerful enough to safely transit the high seas, but to transit efficiently, courtesy of a 20,000 kW diesel-electric powerplant running on low sulfur MGO, a system that is future-proofed with the ability to add batteries when the technology matures further. In addition, it has Dynamic Position for station-keeping abilities in rough weather.

Once delivered Aurora is scheduled to get to work immediately, an interconnector project in Greece that will provide a link between mainland Greece and the island of Crete in depths of up to 1600m.

The first project in the offshore wind segment will be the Seagreen wind farm in Scotland. In addition, the company is looking to build on its existing presence in the US with its cable manufacturing plant in Charleston, which will produce high voltage subsea cables.

"We have followed projects in the US for many years and we anticipate ongoing growth in the US's offshore wind sector, especially with the federal Government's strong support for the sector," Nexans said in a release introducing Aurora. "As preferred supplier for Equinor's Empire Wind, and our frame agreement with Orsted for the US market, Nexans is well placed to support the US with further energy transition projects."

Viking Lady

Image courtesy Eidesvik

Power from Shore

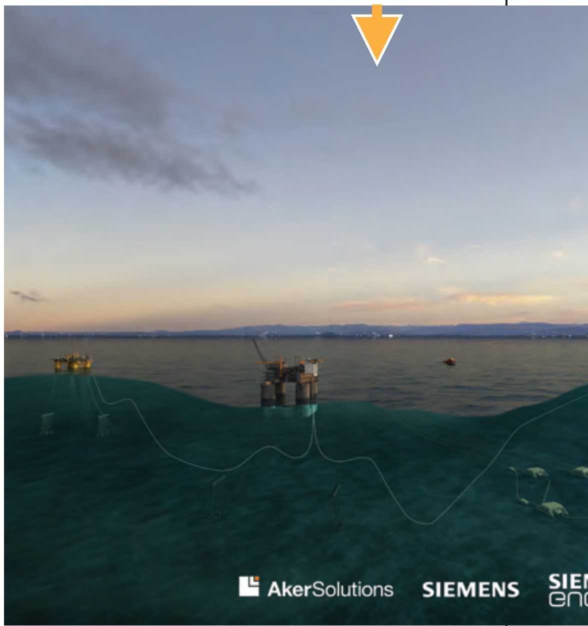


Image courtesy Siemens Energy

Offshore Power Play

Here Offshore Engineer looks at recent power generation news in the offshore energy space, particularly in light of the accelerating energy transition and pressure on oil and gas companies and suppliers to reduce emissions. What does this mean? We'll be hearing more and more about batteries, methanol, ammonia, electricity, and other alternative energy sources.

Viking Lady

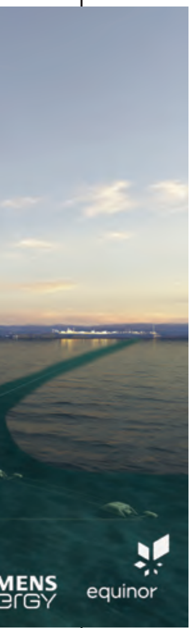
In Norway Eidesvik and Aker BP are working on a project called Retrofit, which aims to reduce emissions from existing offshore supply vessels. Retrofit's mission is to capture emission reductions of 70 percent or more on selected vessels, and the project will evaluate various solutions for converting existing supply vessels to low-emission units, making them as climate and environmentally friendly as Eidesvik's Viking Energy platform supply vessel.

Namely, the Viking Energy vessel will be equipped with an ammonia fuel cell in 2024 as part of the EU-funded ShipFC project. Initially, the ship will be fitted with a 2-megawatt (MW) ammonia fuel cell, allowing it to operate for at least 3,000 hours annually on clean fuel. After completing that phase, the project will ramp up to qualifying 20MW fuel cell solutions for oceangoing vessels.

As part of the Retrofit project, Aker BP-owned supply vessels NS Orla and NS Frayja, which are managed by Eidesvik, are potential candidates for the 'green' upgrades, in addition to others owned by Eidesvik.

Power from Shore

Elsewhere in Norway, we'll soon see both platforms and offshore drilling rigs powered by floating wind, but



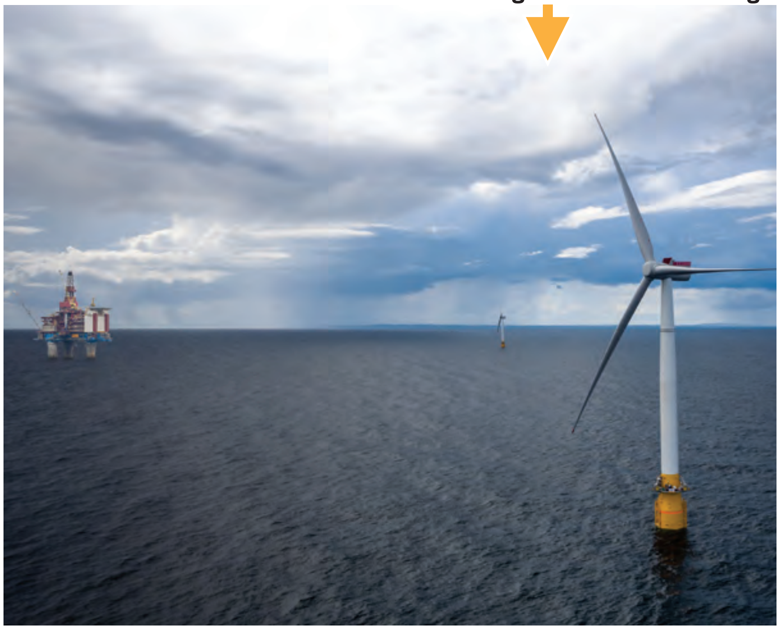


Image courtesy Equinor

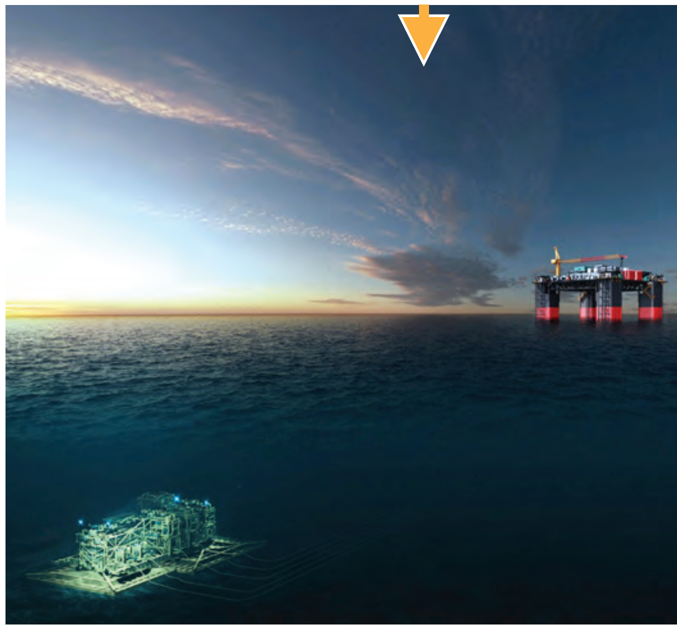


Image courtesy ABB

first, let's give a mention to power from shore. Norway already has several offshore fields powered by hydro-power-generated electricity from shore, with more to come. One of them is Troll West electrification project, for which Siemens Energy recently won a contract with Aker Solutions to supply the complete packages for the electrical transmission, distribution, and power management system (PMS). Siemens Energy said that a key objective of the Troll West electrification project is to reduce NOx and CO2 emissions by replacing existing gas turbine-driven generators and compressors on the Troll B and C facilities with power from shore.

The plan is to supply electrical power to Equinor's Troll B and Troll C semisubmersibles with a 40-mile (65-km), 150-MW subsea transmission cable from the Kollsnes natural gas processing plant on the island of Ona. The electrification of Troll B and Troll C platforms is expected to reduce annual carbon emissions by approximately 500,000 tons – an amount equivalent to about 1% of all emissions from Norway. Also, NOx emissions from the field will also be reduced by an estimated 1,700 tons per year.

Siemens AG is also part of the project consortium and will provide static frequency converter systems, large-scale drive trains, and special frequency converters, which will allow power to flow bi-directionally for normal and island operation. The PMS provided by Siemens Energy will help maintain a safe balance between power demand and consumption, thus ensuring overall grid stability, the company said. Installation and commissioning of the electrical equipment for the Troll West project are scheduled for 2022 – 2023.

Floating Wind Powers Rigs

From late 2022 or early 2023, Equinor will bring online the 88MW Hywind Tampen floating wind farm, which will power five Equinor's offshore oil and gas platforms in Norway, Snorre A and B, and Gullfaks A, B and C. The eleven 8 MW floating turbines will have a total capacity of 88 MW and meet about 35 percent of the annual power demand of the five platforms, which is expected to save 200,000 tons per year of CO2 emissions. The wind turbines will be connected in a loop by a 2.5 km-long, 66 kV dynamic inter-array cable system. JDR will provide cables, and Subsea 7 will install them. Wood Group will be responsible for modifications on the Snorre and Gullfaks platforms.

As for offshore wind-powered drilling rigs and platforms, offshore drilling contractor Odfjell Drilling is working on this, and not just to power its rigs but to offer its floating wind solution for rent to others.

The drilling firm in 2020 invested in Oceanwind AS, a company working on developing harsh environment floating offshore wind turbines. The investment gave birth to Odfjell OceanWind, a company working to build floating wind turbines to power offshore drilling rigs.

Methanol, Batteries for WTIV

Image courtesy Van Oord

In June this year, DNV completed Odfjell Ocean-Wind's WindGrid system for Mobile Offshore Wind Units (MOWUs). DNV's review confirmed the technical feasibility of the WindGrid system, and that expected reductions in CO2-emissions for North Sea applications are in the range of 60-70%, compared to the generation of electricity from conventional gas turbines.

Odfjell's WindGrid is a solution for providing an uninterrupted power supply from Mobile Offshore Wind Units (MOWUs) to micro-grids. It combines energy storage, grid converters, and floating wind turbines in order to enable gas turbine generators to be shut down during peak wind power production. Interestingly, Odfjell OceanWind floaters, first of which could be available in 2024, are expected to feature Siemens Gamesa's 11MW but also the giant 14MW turbines. The whole system is also expected to use Siemens Energy's BlueVault energy storage solution which includes batteries, AC PowerGrids, transformers, switchboards, and power control system.

Down Under & Subsea

There's no electrification news without ABB. In August, ABB secured a contract worth some $120 million to supply the overall Electrical Power System (EPS) for Chevron's multi-billion-dollar Jansz-Io Compression (J-IC) project, offshore W. Australia. The Jansz-Io field is located around 200 km offshore the north-western coast of Australia, at water depths of approximately 1,400 meters.

The project will involve constructing and installing a 27,000-ton (Topside and Hull) normally unattended floating Field Control Station (FCS), approximately 6,500 tons of subsea compression infrastructure, and a 135km submarine power cable linked to Barrow Island.

ABB will provide the majority of the electrical equipment, both topside and subsea, for J-IC. The project will combine two core ABB technologies – power from shore and Variable Speed Drive (VSD) long step-out subsea power – for the first time. The electrical system will be designed to transmit 100 megavolt-amperes over a distance of approximately 140 km and at depths of 1,400 meters.

The contract was awarded following concept development and a front-end engineering and design (FEED) study. Work will start immediately, and the subsea compression system is expected to be in operation in 2025, ABB said.

ABB is working on a floating wind project too, through its Hitachi ABB Power Grids JV. The company recently launched a portfolio of transformer products to be installed on floating offshore substations and floating wind turbines in deep waters, where traditional solutions are not feasible.

According to the company, its transformers are designed to overcome the challenging offshore environment and withstand the physically demanding conditions on floating structures.

Hitachi ABB Power Grids' portfolio introduces collector step-up transformers, earthing transformers, and shunt reactors for floating substations plus wind turbine transformers for floating wind turbines, including WindSTAR units.

Methanol, Batteries for Giant WTIV

In the Netherlands, Van Oord in October ordered a new offshore wind turbine installation vessel that will be able to install next-generation wind turbines of up to 20MW. The vessel will be built by Yantai CIMC Raffles Shipyard in China. Van Oord said the vessel would have a very low CO2 footprint as it will be able to operate on methanol, which reduces the ship's CO2 footprint by more than 78%.

Also, the vessel will be equipped with an advanced active emissions control technology (Selective Catalytic Reduction) to reduce the NOx emission "to an absolute minimum."

Further, an installed 5,000 kWh battery pack can take the peak loads and regenerate energy to reduce the fuel consumption and corresponding emissions even further," Van Oord said.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