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Frontier Regions

Offshore Engineer • December 2013

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Feature

Opening new frontiers

ON THE COVER

Self-installing tower. GMC Inc. provides this illustration, done by designer Jeff Whitely, of their new buoyant tower concept, which is currently deployed offshore Peru at BPZ Energy's CX15 project in the Corvina field.

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Departments & Columns

"What role should national governments have in funding research and development in the oil and gas industry?"

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Online Exclusive

Is it safe?

NASA Astronaut William McArthur talks about balancing risks against what you want to achieve. Nina Rach reports.

What's Trending

First gas at Jasmine

First gas has been produced from the Jasmine field in the central UK North Sea.

People

Aberdeen universities found institutes

Aberdeen's two universities have both now founded energy institutes to build on their existing oil and gas expertise.

Whitepaper

Exclusive Schnitger Corporation white paper: The Race for More Oil

Discover how offshore engineers are utilizing modern design and simulation technologies to design safer, stronger offshore structures and achieve engineering breakthroughs in the offshore environment.

What's Trending

PetroChina buying Peruvian assets from Petrobras

Beijing-based PetroChina Co. Ltd. announced that two of its subsidiaries will purchase the Peruvian assets of Petrobras for US$2.6billion

Voices

A helping hand. When it comes to new technology, OE asked:

"What role should national governments have in funding research and development in the oil and gas industry?"

Research and development is key to competition, innovation and attracting financial investment in oil and gas. In emerging markets, the role of national government is to support business, by equipping a young, evolving workforce with the necessary skills to succeed in the industry. In hubs such as Aberdeen and Houston, the economic benefits of state investment in education are already evident. These cities have understood the need for specialist programs and are net exporters of technology and expertise. The Transforming Futures Programme at UOG 2014, a pioneering skills exchange initiative, will promote training for young people and encourage further funding in this area.

Joshua Beagelman,
COO,
Universal Oil & Gas

It is in the interest of governments to provide an element of support for the development of new technologies for the oil & gas sector to enable the planet to make the best use of the reserves available. The technology-led solutions delivered by supply chain companies are invaluable in helping to discover and recover increasingly hard-to-reach hydrocarbon reserves and further investment in research and development by these companies and government working in partnership can only benefit the sector.

George Rafferty,
CEO,
NOF Energy

The Federal government's role is critically important in early-stage technology development, both as a catalyst and as an eliminator of risk. Government support is typically required to advance a technology to the point where it is commercially viable. For first-of-a-kind technologies with heavy upfront costs, government support is often required to eliminate risk and encourage private investment. Support need not be monetary. An example would be in streamlined permitting and regulatory approvals that can provide the necessary of assurance for those investing their own business development funds. Government cooperation with industry can help secure market acceptance of early adoption of new technologies.

Charles D. McConnell
Executive Director,
Energy and Environment Initiative (e2i)

It is an immense national advantage to have oil and gas resources. Research and development funding from national governments is essential to create wealth and to meet national and corporate production targets. Technology development is a joint commitment; government fostering knowledge creation through incentives and financial support, with industry facilitating delivery to access profits, security, and sustainable growth.

David Liddle,
Business Development Executive,
Society for Underwater Technology

We face large technological challenges in order to reach IOR targets, develop marginal fields and keep costs down. Commitment to R&D and innovation is crucial. Government funding in an early phase is vital in order to capture ideas and secure innovation. It triggers investments by the industry, and is highly profitable for both industry and society.

Erling Kvadsheim,
Director, industry policy,
Norwegian Oil and Gas Association
(Norse olje & gass)

Go to OEDIGITAL.COM and give us your opinion on this month's topic!

Editor's Column

Nina Rach

Colloquy

Waiting on Weather

A lot of time and money can be wasted waiting on weather. Down time is expensive. Wave height and period determine vessel motion and when they exceed operating limits, work slows or stops. Working in rough weather can lead to injuries and damage equipment.

Weather forecasts are particularly important for critical operations; metocean data is used to predict available weather windows.

Satellites carrying a new generation of equipment are providing increasingly better data and wider coverage.

The risks of inclement weather and related downtime can be managed. Downtime analysis tools incorporate statistical weather data to estimate the best time for operations. Typical records include wave height, wave period, wind speed, direction, currents, and spectral wave data. Typical output is the predictable number of WOW days/task, with results output at different levels of reliability (P50, P95, etc.).

Offshore simulators using weather models can be used to evaluate floating drilling rigs, anchor handling, installation, and pipelay vessels, as well as offshore tanker loading and other operations.

The Suomi National Polar-orbiting Partnership spacecraft lifted off on Oct. 28, 2011. Image: NASA/Bill Ingalls.

NOAA, NWS

The National Oceanic and Atmospheric Administration in the US is focused on the condition of the oceans and the atmosphere and its mission statement, in part, is "To understand and predict changes in climate, weather, oceans, and coasts [and to] share that knowledge and information with others."

Although NOAA was formed in 1970, its roots stretch back to 1807, when the first scientific agency of the US federal government, the Survey of the Coast, was established.

The National Weather Service is the largest single entity within NOAA and it provides climate forecasts for the US, its territories, and adjacent waters. NWS operates 122 weather forecast offices, 13 river forecast centers, 9 national centers, and other offices, in which 4700 employees gather and analyze global data. The Service uses an array of satellites, including Geostationary Operational Environmental Satellites (GEOS) that orbit 22,300mi. above the Earth's surface. NWS also gathers data from marine data buoys, surface observing systems, and instruments that monitor space weather and air quality.

JPSS

The Joint Polar Satellite System is the US' next-generation polar-orbiting environmental satellite system. JPSS is a collaborative program between NOAA and NASA.

The program includes three satellites (SNPP, JPSS-1, JPSS-2) and one experimental program (TCTE).

The Suomi National Polar-orbiting Partnership (SNPP) was named in honor of Verner E. Suomi, University of Wisconsin meteorologist, widely recognized as the "Father of Satellite Meteorology."

Suomi is the "first next generation" polar-orbiting satellite, launched in 2011 with a Delta-II mission launch vehicle from Vandenberg Air Force Base, California. It has a design life of five years and carries five instruments: VIIRS, CrIS, ATMS, OMPS, and CERES-FM6.

[The Delta II rocket is an expendable launch, medium-lift vehicle best known for launching Navstar global positioning system (GPS) satellites into orbit, but also used to launch civil and commercial payloads into low-earth, polar, geo-transfer and geosynchronous orbits. Delta II stands 125.9ft (37.8m) high, with different fairing diameters, 9.5ft or 10ft, to accommodate different payloads.]

Joint Polar Satellite System-1 will be the second of NOAA's polar-orbiting satellites and will carry the same five instruments as Suomi. It has a longer design life, seven years, and is scheduled to launch in 2017 aboard a Delta-II mission launch vehicle.

JPSS-2 is the third satellite

planned to provide continuity in the program. JPSS-2 will host VIIRS, CrIS, ATMS, and OMPS, but not CERES instruments.

The Total Solar Irradiance (TSI) Calibration Transfer Experiment (TCTE) is an instrument aboard Suomi that measures the sun's energy output.

Instruments

The Cross-track Infrared Sounder (CrIS) provides detailed atmospheric temperature and moisture observations for weather and climate applications. It's a high-spectral resolution infrared instrument measures the three-dimensional structure of atmospheric temperatures, water vapor, and trace gases. The CrIS instrument was developed by ITT Exelis, Fort Wayne, Indiana.

> "And all over the world
> Strangers
> Talk only about the weather.
> All over the world
> It's the same
> It's the same"
>
> – Tom Waites, "Strange Weather"

The Ozone Mapping and Profiler Suite (OMPS) measures the concentration of ozone in the atmosphere, showing how ozone concentration varies with altitude. The OMPS instrument was developed by the Ball Aerospace & Technologies Corp., Boulder, Colorado.

The Visible Infrared Imager Radiometer Suite (VIIRS) features multi-band imaging capabilities to support the acquisition of high-resolution atmospheric imagery and produces accurate measurements of sea surface temperature. The VIIRS instrument was developed by Raytheon Company, El Segundo, California.

The Advanced Technology Microwave Sounder (ATMS) is a next-gen, cross-track microwave sounder, hosting 22 microwave channels, and operates in conjunction with the CrIS to profile atmospheric temperature and moisture. The ATMS instrument was developed by Northrop Grumman Corp., Azusa, California.

The Clouds and the Earth's Radiant System (CERES-FM6) measurements help to improve weather forecast and climate model predictions, through understanding the effect of clouds on the Earth's energy balance. The overall goal of the CERES project "is to provide a long-term record of radiation budget at the top-of-atmosphere, within the atmosphere, and at the surface with consistent cloud and aerosol properties."

The CERES instrument (60x60x70cm) is reminiscent of a folded, paperboard oyster pail (Chinese-takeout box) wrapped in gold foil, with a horizontal cylinder at the base. It weighs 45kg.

Data

NOAA says the JPSS program "provides key products to the primary NOAA user community, including the National Weather Service, which requires data at low latency (not delayed) to ensure that weather forecasts and numerical simulations of weather patterns are supported in real time."

The National Ocean Service uses polar-orbiting satellite data in real-time to monitor changing sea surface temperatures and coastal hazards. JPSS provides worldwide weather and oceanic data coverage. Global operations forecasting relies heavily on NOAA's polar-orbiting satellite data. OE

Quick stats

OE's at-a-glance guide to offshore hydrocarbon reserves and key offshore infrastructure globally is updated monthly using data from leading energy analysts Infield Systems (www.infield.com).

New discoveries announced

Depth range	2010	2011	2012	2013
Shallow (<500m)	86	106	74	50
Deep (500-1500m)	28	26	23	14
Ultradeep (>1500m)	37	20	35	23
Total	151	152	132	87

Note: Operators do not announce discovery dates at the time of discovery, so totals for previous years continue to change.

Reserves in the Golden Triangle

by water depth 2013-17

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	17	893.75	680.00
Deep	17	3,260.75	2,255.00
Ultradeep	43	12,297.95	17,340.00
United States			
Shallow	28	128.30	356.50
Deep	23	1,378.71	1,624.87
Ultradeep	26	2,954.00	3,390.00
West Africa			
Shallow	149	3,461.55	18,097.59
Deep	47	5,504.00	6,370.00
Ultradeep	14	1,900.00	2,650.00
Total (last month)	364 (363)	31,779.01 (32,653.76)	52,763.96 (53,863.96)

Greenfield reserves

2013-17

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1,261 (1,275)	64,188.58 (65,189.99)	777,732.37 (787,740.02)
Deep (last month)	161 (159)	13,561.33 (13,507.58)	79,676.57 (79,626.57)
Ultradeep (last month)	101 (98)	17,370.95 (17,516.45)	66,697.00 (66,727.00)
Total	1,523	95,120.86	924,105.94

Pipelines

(operational and 2013 onwards)

	(km)	(last month)
<8in		
Operational/installed	41,963	(41,918)
Planned/possible	25,311	(25,292)
	67,274	(67,210)
8-16in		
Operational/installed	78,286	(77,695)
Planned/possible	49,070	(48,610)
	127,356	(126,305)
>16in		
Operational/installed	88,950	(89,156)
Planned/possible	48,755	(49,698)
	137,705	(138,854)

Production systems worldwide

(operational and 2013 onwards)

		(last month)
Floaters		
Operational	272	(273)
Under development	49	(50)
Planned/possible	334	(324)
	655	(647)
Fixed platforms		
Operational	9,664	(8,705)
Under development	114	(125)
Planned/possible	1,477	(1,475)
	11,255	(10,305)
Subsea wells		
Operational	4,406	(4,400)
Under development	421	(414)
Planned/possible	6,289	(6,220)
	11,116	(11,034)

Global offshore reserves (mmboe) onstream by water depth

	2011	2012	2013	2014	2015	2016	2017
Shallow (last month)	10,473.80 (10,474.81)	5,947.62 (5,998.15)	49,200.92 (49,549.97)	27,498.93 (27,950.84)	39,520.84 (39,766.34)	33,446.54 (34,249.15)	52,185.73 (53,103.15)
Deep (last month)	1,312.21 (1,312.21)	2,496.40 (2,500.15)	3,391.36 (3,387.61)	5,706.11 (5,706.11)	4,368.72 (4,368.72)	4,930.34 (4,930.34)	9,211.99 (9,153.17)
Ultradeep (last month)	199.94 (199.94)	737.15 (737.15)	3,240.07 (3,243.07)	2,931.43 (2,922.43)	2,124.98 (2,109.58)	5,536.17 (5,519.67)	15,355.44 (15,543.97)
Total	11,985.95	9,181.17	55,832.35	36,136.47	46,014.54	43,913.05	76,753.16

13 November 2013

Marcus Richards

ThoughtStream

Shifting dynamics: Industrializing economies are moving markets

The shift in oil demand from industrialized to emerging economies is one that we at Dana Petroleum know only too well.

An impressive North Sea success story with modest but ambitious beginnings in Aberdeen in the mid-1990s, Dana grew fast, becoming an emerging international oil and gas company with a footprint in the UK, Norway, the Netherlands, Egypt and North and West Africa.

In 2010, as Dana was pondering avenues for future growth, it was acquired by the Korea National Oil Corporation (KNOC). KNOC was on the lookout for exploration and production targets that would help meet South Korea's energy security needs and support the development of its emerging oil and gas sector. For that, it needed two things: reserves and expertise.

As a high-income developed country with almost non-existent native reserves, South Korea is one of the world's top energy importers.

Dana Petroleum was acquired by KNOC in 2010, as part of an ambitious plan to reach 1.2MM bbl production by 2030.

Looking back, we can say that South Korea was at the forefront of a trend that saw successive historical producers in the UK North Sea change hands to serve the growing appetite of emerging economies for resources, technology, skills and expertise.

This trend will undoubtedly be here to stay. Oil demand in the developing world is projected to overtake that in industrialized countries for the first time this year. This is a tipping point in the geography of oil demand and will no doubt have profound implications for the dynamics and structure of world energy markets.

In October, China reached the position

Our industry is fundamentally changing shape, a structural shift that is altering the balance of power amongst industry players.

of world's largest importer of crude oil, surpassing the US for the first time.

At a time of declining or stagnant demand from developed economies, it is becoming increasingly clear that virtually all the net growth in global energy consumption will, in the next few years, come from emerging economies.

Our industry is fundamentally changing shape, a structural shift that is altering the balance of power amongst industry players.

I believe that one of the key changes, and one that is in part a consequence of the shift in demand to the emerging economies, is the increasing prominence of national oil companies, or NOCs.

NOCs now control around 90% of the world's remaining oil and gas reserves.

As NOCs continue to expand beyond their home markets, they will naturally compete head on with international oil companies (IOCs) and independents to access new reserves. But in doing so, they are changing the dynamics and rules of the business.

I think that this has a series of consequences for the structure of world energy markets and the new patterns of investment in them.

Firstly, resource diplomacy will become the default way of seeking new opportunities in oil and gas.

IOCs, a growing variety of independents, of different size and focus, service companies and NOCs themselves, will be increasingly competing to build partnerships with governments and with each other to explore new opportunities.

Secondly, in an increasingly complex energy market, complementarity and common ground will be crucial. Competition will give way to complementarity as IOCs, NOCs and service companies become ruthlessly clear about their strengths, their weaknesses and how they can work together.

Finally, I think the current trend also means that we are likely to see more consolidation within the industry, as independents join forces and NOCs continue to acquire independents to build their position and capability in key markets. OE

This is a version of Mr. Richards' talk at Chatham House's The Changing Dynamics of Global Energy Markets Conference in November, in London.

***Marcus Richards** is group chief executive of Dana Petroleum. Until mid-2009, he held the role of senior vice president in BP corporate headquarters covering upstream E&P and downstream refining businesses. During his 27 year career to date, he has held a number of business leadership, functional and technical roles, with a significant proportion of his career spent outside the UK and Europe, including assignments in the US, Australia, China and Indonesia. He holds a BSc (Hons) and PhD, and is an alumnus of Harvard University. He is also a visiting professor at Aberdeen's Robert Gordon University.*

Global Briefs

A White Rose expansion planned offshore Canada

Husky Energy expects gas injection to start before year-end at the South White Rose extension offshore Newfoundland. South White Rose is tied back to the SeaRose FPSO, with first oil anticipated by end-2014. The company also signed a benefits agreement with the government of Newfoundland and Labrador for the West White Rose development aiming to boost oil production. Detailed engineering is under way for a new fixed wellhead platform. First oil is planned for West Whtie Rose in the 2017 timeframe.

B CGG surveys GOM for Pemex

CGG has been selected to carry out a large high-end seismic acquisition survey in the Gulf of Mexico on behalf of Pemex. The survey, in Mexican waters, is phase 5 in Pemex's Centauro program, the largest ever proprietary 3D wide-azimuth program to be conducted worldwide, says CGG. Phase 5 will add 6850sq km of data to the existing 25,000sq km already acquired since Centauro began in October 2010, bringing the total volume to almost 32,000sq km.

C Halvorsen sends WHRU to Mexico

Halvorsen Kanfa-Tec recently finished and shipped four 20MW Circular Waste Heat Recovery Units (WHRU) to Mexico. The highly efficient WHRUs, in terms of weight and volume, will be utilized by Pemex in the Cantarel Complex in the Gulf of Mexico. The Akal C4 units are recovering maximum heat from the gas turbine exhaust and therefore highly improving the environmental conditions on the platform.

D Aker supplies Jack/St. Malo umbilicals

Aker Solutions will provide umbilicals for the second stage of the Chevron' Jack and St. Malo developments, located in the US Gulf of Mexico. The two electro-hydraulic dynamic steel tube umbilicals will each measure 80,000ft (24,384m) in length and will be used to control a subsea production system. Aker will also provide hardware, including terminations, bend stiffeners and buoyancy modules. The umbilicals will be installed at a depth of 7,500ft (2,286m).

E Irish round opens 2014

Ireland's next Atlantic Margin oil and gas exploration licensing round is to be announced following a review of the country's oil and gas fiscal terms, due to be completed early 2014, the country's government has announced. The round is scheduled to open in April 2014, and will close in September 2015.

F Siri production to restart in 2014

Norwegian Energy Company ASA (Noreco) expected to restart production from the Siri platform, offshore Denmark, in Q2 2014. Production from the platform will be at reduced volumes until the Siri platform is permanently repaired, said Noreco. Denmark's DONG Energy is operator and 100% owner of Siri platform, which was shut in during June this year after a crack was discovered in a bulkhead inside the tank sponson. Oil from the Nini, Nini East and Cecilie fields, in which Noreco has 30%, 30% and 61% stakes respectively, is normally processed, stored and shipped by tanker from the Siri platform.

G First oil for Ekofisk

First oil on the Ekofisk South project in the Norwegian North Sea has started. The project will increase oil recovery in the Ekofisk field, located in the PL 018 license and operated by ConocoPhillips. Production capacity at Ekofisk South is 70,000 boe/d. Ekofisk South comprises the Ekofisk 2/4 Z wellhead platform with 35 production wells and a seabed installation for eight water injection wells. The platform was built by Aker Solutions in Egersund, Norway. Water injection started in May 2013, and is controlled from an operations center at ConocoPhillips' offices in Tananger, Norway.

H Noble surveys offshore Falkland Islands

Noble Energy Inc. and partner Falkland Oil & Gas (FOGL) have started a 3D seismic survey over its license areas to the south and east of the Falkland Islands using the PGS Ramform Titan. On completion of the latest survey, Noble and FOGL will have acquired more than 10,000km sq 3D data equivalent to more

than 40 North Sea blocks. Both companies plan to start drilling operations in the basin in late 2014.

I Wisting Alternative wildcat classified dry

A wildcat well drilled 5km northwest of the recent Wisting Central oil discovery in the Barents Sea has been classified as dry, says the Norwegian Petroleum Directorate. Well 7324/7-1 S, known as Wisting Alternative, is in production license 537 and was operated by OMV (Norway) AS. It was targeting petroleum in the Middle Triassic reservoir rocks (the Kobbe formation). A secondary exploration target was to prove petroleum in reservoir rocks from the Middle to Late Triassic (the Snadd formation). Reservoir rocks were encountered in the Kobbe and Snadd formations, but with poorer than expected properties.

J Shell consortium wins 35-yr PSC for Libra pre-salt

A consortium of companies, including Royal Dutch Shell plc, Petrobras, Total, CNPC and CNOOC, won today a 35-year production sharing contract to develop the giant Libra pre-salt oil discovery located in the Santos Basin, offshore Brazil. The Brazilian regulator, Agência Nacional do Petróleo (ANP), estimates Libra's recoverable resources at 8 billion to 12 billion bbl of oil.

K Papa Terra starts production

Chevron Corporation's Brazilian subsidiary and Petrobras have started crude oil production from Papa-Terra's floating production, storage and offloading vessel (FPSO) offshore Brazil. Papa-Terra is about 110km southeast of Rio de Janeiro in about 3900ft water depth (1,190m), and is a heavy oil development within Block BC-20 of the southern Campos basin. Papa-Terra has installed capacity to produce 140,000 bbl/d.

L PetroChina buys out Petrobras in Peru

Beijing-based PetroChina Co. Ltd. announced that two of its subsidiaries will purchase the Peruvian assets of Petrobras for US$2.6billion (HK$20.16billion). The PetroChina companies will take over two three blocks in Peru, two wholly owned by the Brazilian state-run Petrobras, and one jointly owned Petrobras and Repsol Exploración Perú S.A.

M Pura Vida enters Madagascar

Australia's Pura Vida has agreed a farm-in deal giving it a 50% stake in the Ambilobe area office Madagascar, east Africa. The firm has also finalized a farm-out deal offshore Morocco. Sterling Energy will retain 50% interest and operatorship. Pura Vida says the Ambilobe block has a variety of plays, relating to salt, with potential for large oil discoveries. New seismic data will now be acquired in the area.

N Exxon gets Madagascar extensions

ExxonMobil Corp. has received extensions on three of its production sharing contract licenses offshore Madagascar, the company announced on 6 November 2013. The supermajor said the extensions will enable the resumption of exploration activities on the Ampasindava, Majunga and Cap Saint Andre licenses.

O Cobalt International strikes offshore Angola

Cobalt International Energy has made two discoveries at its Lontra #1 and Mavinga #1 deepwater pre-salt exploratory wells offshore Angola. On Block 20, the Lontra #1 well confirmed an oil and gas discovery. Block 21 has made the Mavinga #1 pre-salt oil discovery. The well found about 100ft of net oil pay. The Mavinga discovery is expected to be tied-back to and become part of the planned Cameia development complex in Block 21.

P Pavilion Energy invests in Tanzania

Singapore-based investor Pavilion Energy is to take a 20% in a joint venture partnership with Ophir Energy to develop natural gas finds in Blocks 1, 3 and 4 off the Tanzanian coast. The deal is worth a maximum US$1.29 billion and is expected to close in Q1 2014.

Q Lamprell's jackup rigs enter the Caspian

Lamprell has completed and delivered the first of two Caspian Sea jackup rigs following tow out from the Astrakhan re-assembly yard. The new rig will now start its first contract in the Caspian Sea. Good progress is being made on a second Caspian Sea jackup, which is expected to be delivered in Q4 2014.

R Kirinskoye subsea production facility online

The first subsea production facility has been brought onstream offshore Russia, Gazprom announced. The Kirinskoye gas and condensate field, part of the Sakhalin III project, is a 28km subsea tie-back to shore, in the Kirinsky block in the Sea of Okhotsk. It is in 90m water depth and, once fully completed, will comprise seven wells connected to a single manifold, from which gas is then transported via pipeline to an onshore processing facility. Once fully onsteam, production from Kirinskoye is estimated to reach 5.5Billion cu m a year. Reserves at Kirinskoye are estimated to be 162.5 billion cu m of gas and 19.1MM tons of gas condensate.

S First gas from Ruby field

Production at Indonesia's Ruby field kicked off Oct. 27. The field has been in development since June 2011 and is expected to produce natural gas at a rate of 17,000boe/d. Located within the Sebuku Production Sharing Contract (PSC) 300km south of Balikpapan City, Ruby field lies in a water depth of 50-100km. Approximately 250 Bcf will be produced for sale to the domestic market over the life of the field.

T First oil from Balai field

Oil production from the Balai field in the Balai Cluster Risk Service Contract (RSC) (RSC) area commenced in early November. Balai is located in a water depth of 60m (198ft). The field's first oil was achieved utilizing an early production vessel as a part of the RSC area's extended well testing (EWT) program. The development area is located approximately 100-130km (60-80mi) northeast of Bintulu. The EWT is part of the Balai Cluster pre-development phase and is designed to provide additional production and reservoir performance information to support the field development planning process.

U CNOOC's Suizhong 36-1 Phase II starts production

China's CNOOC announced that the Suizhong 36-1 Phase II adjustment project has commenced production. The Suizhong 36-1 oil field is located in the south region of Liaodong Bay in Bohai in an average water depth of approximately 30m. Four additional platforms will be built as part of this adjustment project.

Contract Briefs

Statoil, Technip sign framework contract

Statoil has made a call-off for the framework contract Technip has with Statoil for diving services. The work will be performed in connection with the future Edvard Grieg oil pipeline as well as Utsira high gas pipeline. The project will help connect the oil pipeline from the Edvard Grieg platform to the existing Grane oil export pipeline, towards the Sture terminal. Moreover, the Utsira high gas pipeline will be connected from the Edvard Grieg platform to the Scottish Area Gas Evacuation (SAGE) pipeline. The contract is scheduled to be completed in the second half of 2015. The offshore campaigns will happen in 2013, 2014 and 2015 and will utilize diving support and construction vessels from Technip's fleet.

Viking, Chan partner on jackup

Viking Offshore & Marine will partner with Chan Kwan Bian (Chan) to construct a $180MM drilling jackup rig, marking Viking's entrance into the rig building and rig charter market. Executive Director Daniel Lin said that with this agreement, Viking has "initiated its move into the mainstream offshore and marine business.

Tullow Ghana to work on TEN project

Tullow Ghana Limited has awarded two contracts for work on the TEN project worth about US$1.23 billion. The contracts will be shared between Technip and Subsea 7, who are working as part of a consortium on the project.TEN consists of the Tweneboa, Enyenra and Ntomme fields, in the Deepwater Tano contract area, in 2000m water depth, 60km offshore Ghana. The development will comprise up to 24 development wells connected to the TEN MV25 floating, production, storage and offloading vessel (FPSO), moored in about 1500m water. Offshore installation is due to start in 2015 and be completed in the second half of 2016.

COSL signs ship-building contract

China Oilfield Services Limited (COSL) has signed construction contracts for two jack-up drilling rigs and a semi-submersible drilling rig. The contracts are with Dalian Shipbuilding Industry Offshore Co., Ltd. (DSIC Offshore) and China Merchants Heavy Industry (Shenzhen) Co., Ltd. The new units will be the HYSY982, HYSY943 and HYSY944. HYSY982 will be a sixth generation deepwater semisubmersible drilling rig equipped with DP3 dynamic positioning system, designed for a maximum operating depth of 5000 ft (1524m), and 30,000 ft (9144m) a maximum drilling depth. It is expected to be delivered in August 2016. HYSY943 will have 400 ft (122m) maximum operating depth and 35,000ft (10,668m) maximum drilling depth. HYSY944 will be CNOOC's first large pile shoe jack-up drilling rig. It will have maximum operating depth 400 ft (122m), with 30,000 ft (9144m) maximum drilling depth.

Subsea 7 awarded Petrobras contract

Subsea 7 SA's i-Tech division has been awarded a contract by Petrobras worth about US$60 million.

The contract is for the provision of ROV's and underwater positioning services on board the platform supply vessel (PSV) Far Saga, operating offshore Brazil, for a six year term, with options to extend for up to another six years. The contract will see the first deployment of i-Tech's new generation Centurion SP work class ROV on board the PSV.

Keppel FELS to construct jackup rigs for Transocean

Keppel FELS Limited (Keppel FELS) has won a US$1.1 billion contract from Transocean Ltd. (Transocean) to build five KFELS Super B Class jackup rigs. The rigs are scheduled to be delivered between Q1 2016 to Q3 2017. In addition, Transocean has options to build up to another five similar jackup rigs with Keppel FELS, a wholly-owned subsidiary of Keppel Offshore & Marine (Keppel O&M). The KFELS Super B Class rigs are designed to operate in 400ft water depth and drill to 35,000ft. The Super B has a two million pound drilling system and a maximum combined cantilever load of 3,700 kips. The rig will be installed with offline stand building features in its drilling system package, which allows drilling and the preparation of drill pipes to take place at the same time. The rig is capable of drilling at a 75ft outreach, allowing for coverage of a larger well pattern.

Self-installing tower offers production solution

FIG 1: FOUR (4) CELL BUOYANT TOWER W/SUCTION CAN UNDER CONSTRUCTION

GMC Inc.'s Clyde Crochet discusses a self-installing tower, currently deployed off Peru, which offers a new substructure solution compared to conventional jackets/piles.

The buoyant tower concept represents an innovative bridging design where floating (deepwater) and fixed (shallow water) substructure technologies merge to yield a new substructure scope for mid-water depth applications–50m to 260m. GMC Ltd. and subcontractor Horton Wison Deepwater (HWD) developed the design and markets the concept under the joint venture company, HortonGMC.

The tower was recently utilized by BPZ Energy to achieve production at its Corvina field offshore Peru. The CX15-1D well achieved an initial flow rate in November of 500 b/d, naturally flowing with no water production and normal gas oil ratio. A second development well was spud in early November with completion expected to follow in January.

The buoyant tower resembles a cell spar hull configuration with an attached suction can at its base that allows the tower to pivot about its imbedded base in a compliant manner while restraining the base from movement in vertical, lateral, and torsional directions. The topsides payloads are flexible with cell quantity configuration and sizing.

The tower is configured with upper void tanks for buoyancy, lower air over water ballast tanks for ballasting operations, and fixed ballast in the bottom tank sections. A net small downward force is maintained with ballasting operations applicable in response to topsides weight changes of significance.

Paralleling the design aspects of deep water spars, the buoyant tower configuration provides a center of buoyancy above its center of gravity and yields a hull scope unconditionally stable.

A key enabling attribute for the tower substructure is buoyancy and its availability for a mid-water depth scope. Compared to a conventional jacket/pile scope, buoyancy offers unique project execution flexibility.

The overall configuration and geometry for a four-cell tower scope under construction is illustrated in Fig. 1.

FIG 2: EARTHQUAKE LOADING FOR GLOBAL ANALYSIS

Event	Peak X (g)	Peak Y (g)	Peak Z (g)
2000year	1.28	0.79	0.77
200year	0.54	0.33	0.33
50year	0.27	0.17	0.16

FIG 3: ENVIRONMENTAL LOADING FOR GLOBAL ANALYSIS

Event	Hs (m)	Tp (sec)	Wind (m/s)
100 yr Swell	2.80	20.0	9.0
100 yr Sea	1.74	6.0	13.8
+ 95% Swell	1.50	12.5	
1 yr Swell	1.50	13.0	5.0
1 yr Sea	0.75	4.0	9.0
+ 50% Swell	0.60	10.5	

Challenge – CAPEX for Conventional Jacket Substructure

BPZ Energy assumed operator responsibility for Z-1 Block offshore Peru with its existing assets in 2005. BPZ's initial block activities represented reservoir assessments and modifications to existing scopes versus new facility construction/installation.

BPZ defined and pursued budgetary pricing for new facility scopes under a conventional jacket/piles/topsides model. BPZ's budgeting efforts quickly identified two project challenges specific to an offshore Peru installation site:

- Budget pricing revealed significant transportation and installation costs attributed to site distance from established fabrication/marine infrastructures
- Early jacket and pile sizing seismic conditions (Fig. 2) represented a significant cost risk; offshore Peru was known as an active earthquake location on the Pacific Ring of Fire. In May 1970, an earthquake measured 7.8 Ms, causing 41,000 deaths and 100,000 injuries.

Solution – Reducing CAPEX

Collectively, CAPEX costing, risk

FIG. 4 & 5: TRANSPORT ARRANGEMENT AND SKID-OVER MATING WITH TOPSIDE SUPPORT FRAME

assessments, and revenue forecasts combined to challenge BPZ's economics for project sanctioning. Embracing "necessity is the mother of invention," HortonGMC responded offering the buoyant tower with its unique features to address sanctioning challenges:

- A very compact substructure design enabling overall scope transport to be limited to a single marine asset
- A buoyant substructure design enabling the same transport marine asset to also perform the overall installation scope given a buoyant substructure and favorable site conditions for a topsides skid-over mating – Fig. 3.
- A compliant versus a rigid substructure design for favorably addressing an active, higher level seismic zone and eliminating a need for large pile/skirt pile scopes with accompanying jacket scopes.

Solution –Transport and install execution steps

Under the buoyant tower concept, all sanction challenges were addressed. A single heavy lift vessel transported the overall scope and accomplished most installation scopes. In proximity to the final installation site, tower float-off and topsides mating operations were performed with the assistance of regional tugs for tower movements following the below execution steps:

- Float-off and up-ending of the tower
- Installation of buoyant tower fixed ballast
- Return/adjacent positioning of the buoyant tower within the topsides support frame
- Topsides skid-over above the positioned buoyant tower
- Buoyant tower de-ballasting operation for mating tower and topsides
- Vertical tow of mated tower/topsides to install site
- At install site, two-hour ballasting effort for achieving 8m soil penetration of suction can

The transport arrangement of tower and topsides along with the topsides skid-over methodology with an elevated, cantilevered skidding frame are shown in Fig. 4 and 5.

Substructure benchmarking – Buoyant tower versus jacket

Fig. 6 benchmarks quantity of marine assets and respective durations for a buoyant tower versus a jacket scope. The transport and install economy of effort is obvious. Most notably, the requirements and expense for a derrick barge for jacket positioning, pile driving, and topsides installation are absent from the buoyant tower configuration.

Fig. 7 commercially addresses the buoyant tower marine asset advantage and benchmarks the transport and install costs. CX15 buoyant tower CAPEX costs are compared to budget estimates for a jacket/pile substructure execution. The buoyant tower transport and install advantage is evident.

Fig. 8 benchmarks buoyant tower and jacket earthquake bending moments. The

FIG. 6: MAJOR TRANSPORT/INSTALL ASSETS – TOWER VERSUS JACKET

	Buoyant tower asset durations				
Marine assets/scopes -ExChina	Loadout	Transport	Install	Demob	Total
Heavy lift vessel – all scopes	7	29	9	0	45
Assist – 3 tugs ExPeru	0	3	9	3	15

	Jacket asset durations				
Marine assets/scopes -ExUSA	Loadout	Transport	Install	Demob	Total
Launch barge (LB) w/2 tugs – jacket	7	28	7	28	70
Mat. barge (MB) w/2 tugs – topsides/piles	7	28	14	28	77
Derrick barge (DB) w/2 tugs	0	28	14	28	70
Pile driving/rigging spreads w DB	0	28	14	28	70

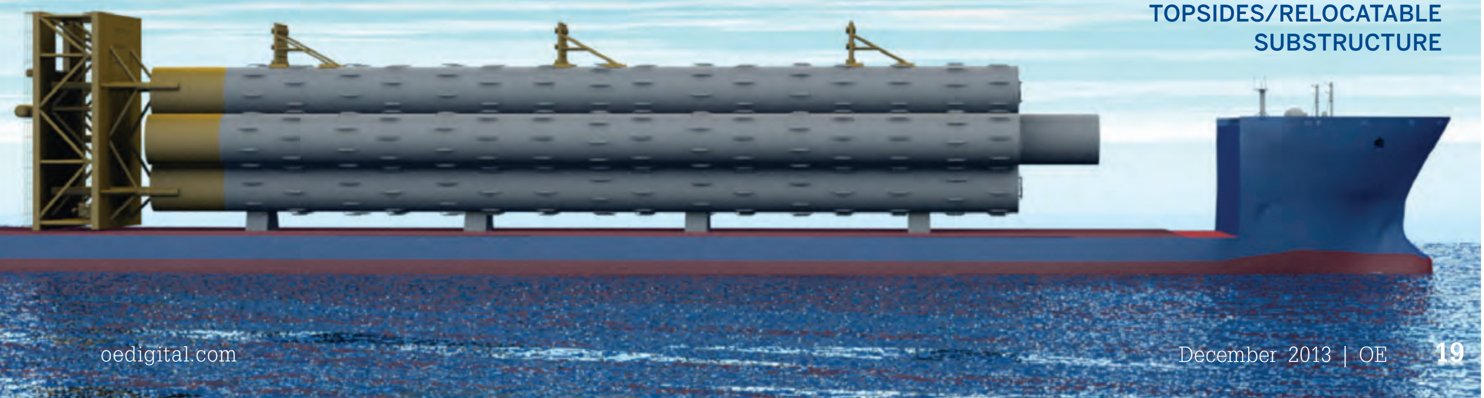
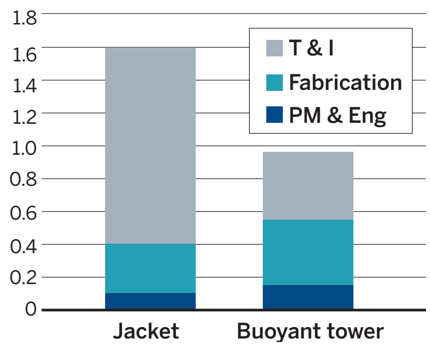


FIG. 11: MARGINAL FIELD DEVELOPMENT – INTEGRAL TOPSIDES/RELOCATABLE SUBSTRUCTURE

FIG. 7: NORMALIZED PROJECT COST – TOWER VERSUS JACKET



Data Courtesy Bpz Energy, Richard Spies

FIG. 8: BUOYANT TOWER AND JACKET EARTHQUAKE BENDING MOMENTS

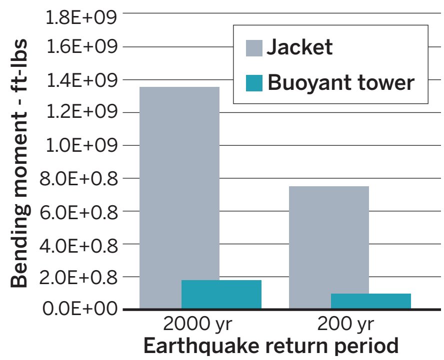


Chart Courtesy HWD, Lyle Finn

FIGURE 10: BUOYANT TOWER STEEL SAVINGS (TONS) FOR DEEPER WATER DEPTHS

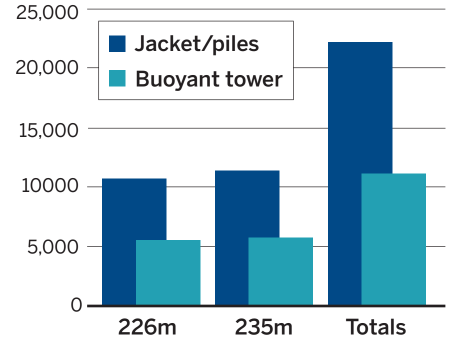


FIG. 9: BUOYANT TOWER FEATURES/ FEATURE IMPACTS FOR NEW SOLUTIONS

Buoyant tower features	Phase	Feature impact
Overall compact geometry	All	Facilitates overall handling
Buoyant structure (>100 m)	All	Tower savings (tons) for deeper water depths
Compliant structure	Design	Seismic friendly
Buoyant structure	Design	Adaptable to adjustable water depth concept
Buoyant structure	Design	Adaptable to limited production storage
Buoyant structure	Procure	Steel trends to mild and minimum thickness
Uniform, repetitive geometry	Fab	Achieves design for manufacture (DFM) objectives
Uniform, compact geometry	Fab	Facilitates subcontracting pre-fab if required
Buoyant structure	Loadout	Wet or dry loadout
Buoyant structure	Transport	Wet or dry transport to install site
Overall compact geometry	T&I	Multiple vs. single platform execution w/1-asset
Buoyant structure	Install	No piling requirement
Buoyant structure/topsides	Install	Float-over, lifted, or onshore integrated topsides
Buoyant structure/topsides	Install	Topsides mating can be remote to install site
Buoyant structure	Reuse	Less effort to retrieve/relocate/recycle

buoyant tower compliant advantage is evident.

Underlying features enable buoyant tower to address other project drivers

As presented above, the buoyant tower concept was uniquely configured to address BPZ's project drivers – transport and install costs for a remote location.

Supporting the buoyant tower capacity's to address/satisfy BPZ's project drivers were a set of unique underlying features inherent in its design. These underlying features are not limited to a single configuration/execution scenario. They offer new project execution flexibility and can be uniquely configured to address project drivers/challenges in any phase of the project execution – design, procurement, fabrication, transportation, and installation.

Fig. 9 identifies unique buoyant tower features and provides a listing of feature impacts that can offer new solutions for unique project drivers/challenges.

Each of the above "Feature Impacts" can offer a new solution. Fig. 10 and 11 and accompanying descriptions represent examples of "high-lighted" features offering new solutions to specific project drivers/challenges:

- Jacket versus buoyant tower sizing efforts for two (2) substructures, 226m and 235m water depth, yields a projected total steel savings in excess of 11,500mt as graphed below. (Topsides weight assumption: 4,500mt in each instance.)
- The buoyant tower may offer new solutions for marginal field development where minimal topsides and short design life prevail. A tower could potentially be configured for onshore topsides/hull integration and ease of relocation/reuse following its initial service life.

Fig. 11 (see previous page) depicts the transport of a topsides integrated with the buoyant tower.

What is the Risk?

While the buoyant tower does represent a new substructure concept, its core elements are established and do not possess "first of a kind" risks to design, build, install, operate, and decommission.

- The buoyant tower resembles a cell spar with its design and operational requirements well understood from floating deepwater scopes.
- As outlined in Fig. 9, the buoyant tower can offer additional flexibility/options in fabrication, loadout, transportation and installation phases with some options inherently safer and lower risk than a conventional jacket execution.

The risk level assessment for a buoyant tower is very low. However, there is a distinction of some note: the buoyant tower is not a fixed structure and does require ballasting operations for topsides load changes of significance.

A requirement for ballast operator training exists and is analogous to the requirement for operator training for production operations. Beyond this, the overall buoyant tower risk levels are believed to be on par or more favorable than a conventional jacket substructure.

Arguably, the overall buoyant tower represents a flexible concept that can uniquely facilitate maximizing the overall safety, quality, cost, schedule, and risk drivers for a project where a conventional execution may be challenged in design, procurement, fabrication, loadout, transportation, and/or installation. OE

Clyde Crochet *is a project manager for Houston-based GMC Inc., a wholly-owned subsidiary of UK-based GMC Ltd. His most recent project was the CX15 installed offshore Peru on BPZ Energy's Corvina Field. His career spans 40 years of worldwide offshore design, fabrication, and installation scopes.*

Managing frontier risks

Strategic decision-making in the boardroom is vital for those operating on the new frontiers, a new report says. Elaine Maslin reports.

"A single event can transform the fortunes of an entire industry," warns a recent report on frontier hydrocarbon exploration.

An oil spill on the scale of the *Deepwater Horizon* disaster, for example, would likely result in the imposition of another moratorium on drilling on the Outer Continental Shelf, or worse, it continues.

The report is by Marsh Risk Management Research, part of the Marsh & McLennan Companies, which provides risk management and insurance.

It warns that the danger of a "low-likelihood-but-catastrophic disaster" rises as demand pushes energy exploration into frontier areas such as deepwater, the Arctic regions and the Middle East. Shale gas exploration was also cited as a "frontier area."

Simultaneously, the requirement for more sophisticated risk management strategies becomes vital. Each frontier also poses its own set of risks.

Marsh identified both deep water and the Arctic regions as two areas pertinent to the offshore oil and gas industry that are new frontiers, or areas with previously untapped reserves due to reasons from high capital requirements or environmental concerns.

Deepwater Drilling

According to Marsh, within a decade, 40% of the world's oil is expected to come from deep water, defined as water depths greater than 1500m.

It notes that deepwater reserves are only available to nation states with offshore sovereignty. To date, it says that 60% of deepwater drilling has been in the US Gulf of Mexico, citing SubseaIQ.

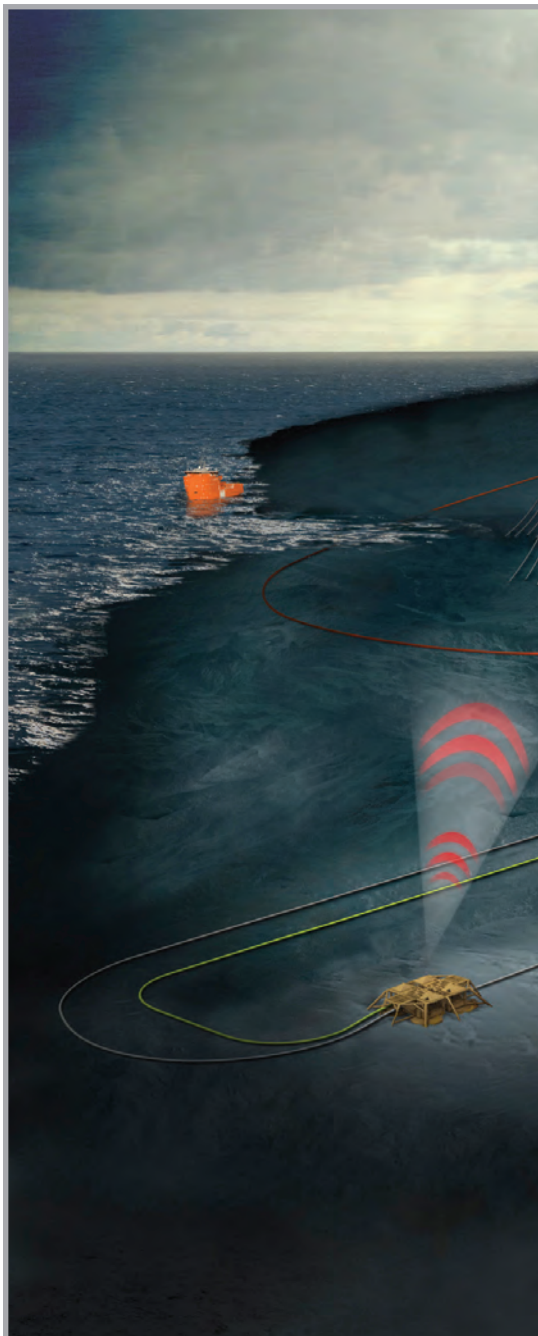
Although drilling technology has advanced, deepwater drilling is still too expensive to all but the largest companies. Just 13 companies produce 84% of worldwide deepwater capital expenditure in the next four years in three dominant regions, Latin America, Africa and North America, according to Infield Systems data, cited by Marsh.

One of the main costs are day rates, for suitable drilling units, which have significantly increased over the last decade, as availability has decreased and local jurisdictions limit the age of rigs allowed to drill in their territories, Marsh says.

The risks to companies from deepwater E&P activities has remained similar over the past decade, however, Marsh says. The main risks are: a well blowout; environmental liability; first-of-a-kind (FOAK) technology; availability of sub-sea expertise and equipment; supply chain disruption; regulatory compliance; environmental tax; and oil/gas price volatility.

Meanwhile, the perception of risk has increased, US regulations have become more stringent, and the contractual landscape has changed, due to the *Deepwater Horizon* oil spill in 2010.

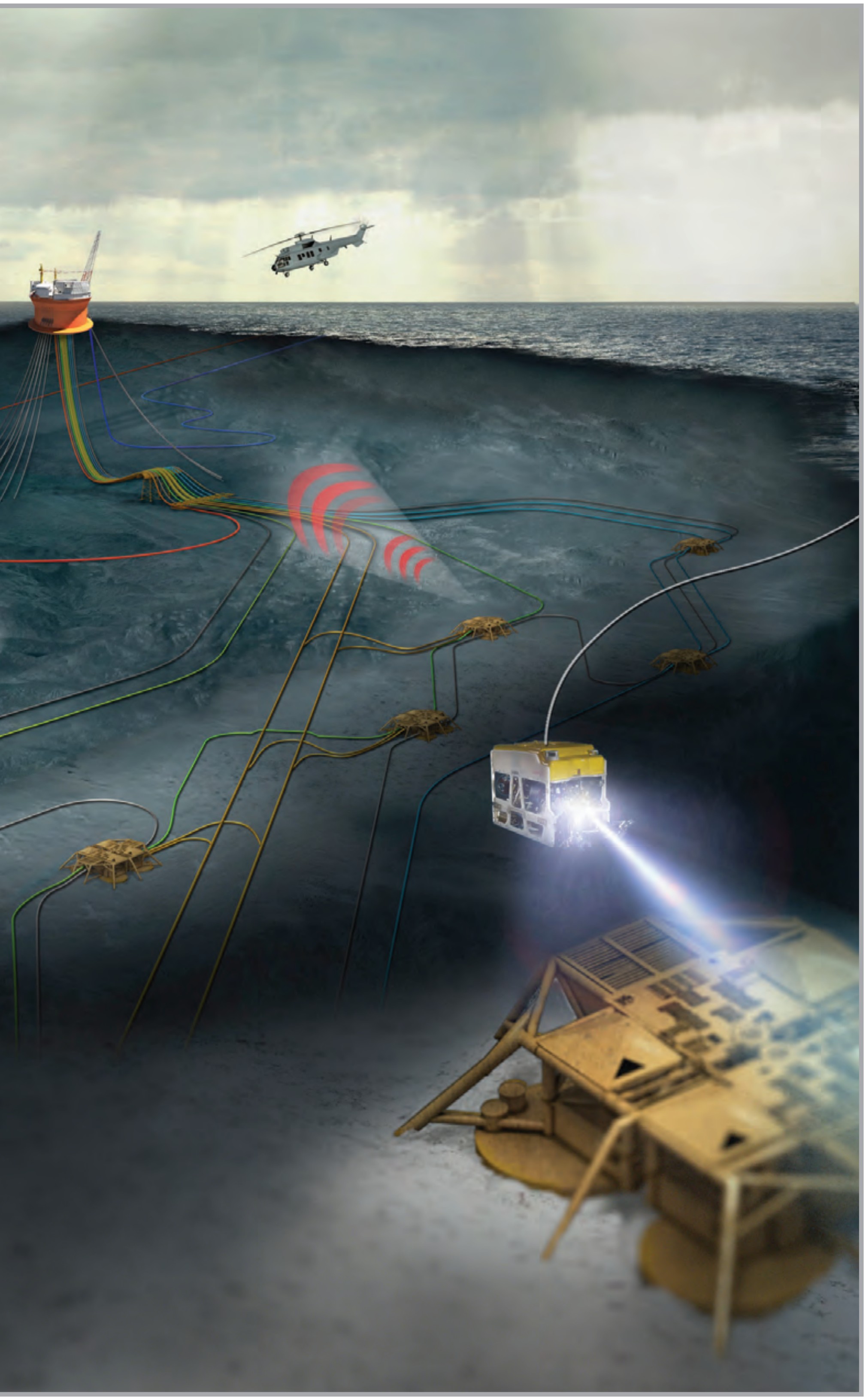
"Drilling contractors have organizational preservation as a main driver to ensure high standards of operational and process safety," the report said. "Another incident on the scale of Deepwater Horizon would likely change the contractual regime forever, pushing some liability back onto the contractor, prohibiting all but the largest contractors from operating."



MANAGING RISK: ENI NORGE HAS AN OIL SPILL RESPONSE SOLUTION FOR THE GOLIAT OIL FIELD. LAST YEAR, THE FIRM CARRIED OUT THE FIRST FULL-SCALE EXERCISE OF GOLIAT'S OIL SPILL CONTINGENCY OPERATIONS. IMAGE: ENI.

To manage the risk, Marsh advises:

1. Develop an approach to identify and evaluate risk exposure, from a top-down perspective (such as scenario analysis) that aims to assess risk and interdependencies across the whole organization. This approach should complement a bottom-up approach to risk management.



2. Evaluate risks derived from working with third parties and explicitly seek reassurance as to the efficacy of partners' approaches to risk management.

3. Establish risk exposures derived from the supply chain by mapping supply chain dependencies.

4. Build crisis management and recovery plans in conjunction with third parties to improve response planning and resilience to an incident.

Arctic Extraction

Estimates suggest that the Arctic region currently has 136.6 billion boe, according to Infield Systems data. A US Geological Survey report from 2008, estimates a further 346 billion boe remain undiscovered.

Risks in the region are the climate and its isolated geography. Ice, storms, engineering, and electrical communication complications, as well as high costs, are all challenges. Only 22 of 174 fields discovered have produced hydrocarbons, with an average lag time of 13 years, says Marsh, citing Infield. Just 38 new fields are expected to come into production between 2012 and 2018.

"Arctic exploration has the problem that 85% of the estimated reserves are natural gas (the majority of which is expected to be in the Russian segment)," says the report, amid a market currently favoring oil.

Further complicating drilling operations in the Artic are the extreme risk-mitigation requirements, such as having a standby rig to drill relief wells in the event of a blowout.

"Reputational damage from a blowout in the Arctic would likely be irreparable," says Marsh, with a moratorium on drilling inevitable.

Despite these risks and costs, an estimated US$20 trillion will be spent in the region between 2011-2035, led by companies from Norway, Russia, Canada, and the US, according to the International Energy Agency World Energy Outlook 2011.

If Arctic ice continues to retreat and engineering competence is advanced through technological improvements, exploration of Arctic reserves will more likely become less expensive.

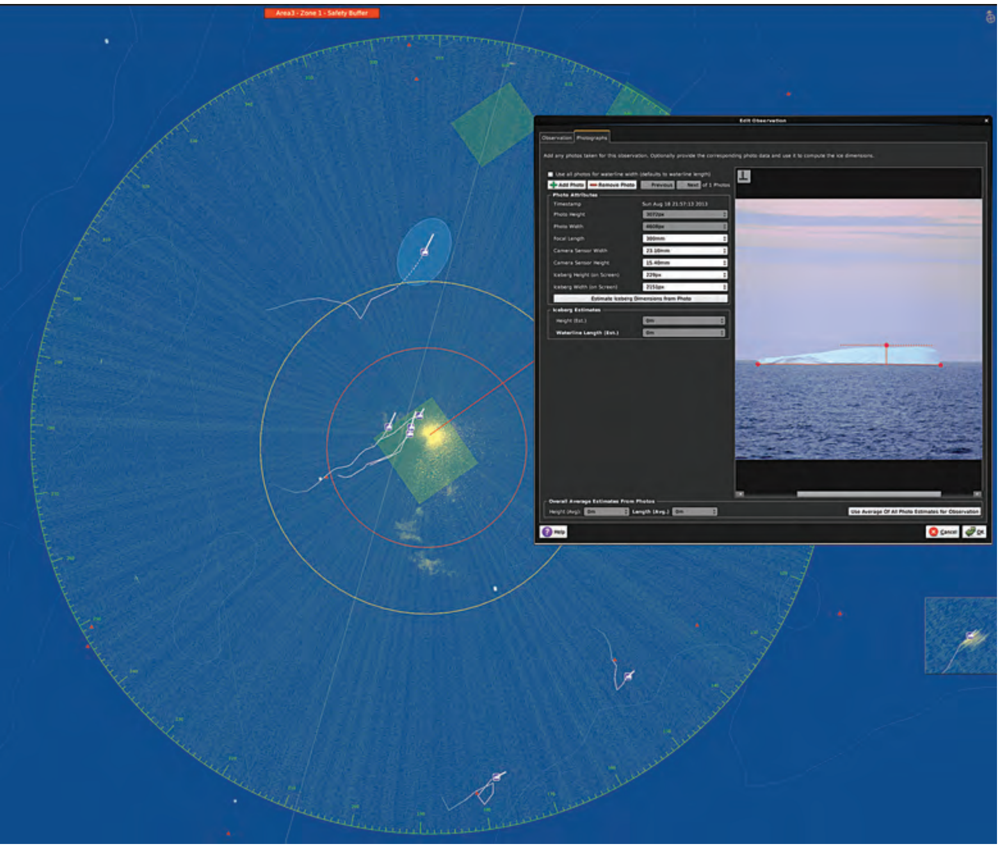
To manage the risks, Marsh suggests:

1. Introduce an enterprise-wide approach to risk management to view and evaluate the risks of a field development. This approach allows an integrated and holistic view of likely risk exposures and opportunities and helps to avoid assessing exposures in narrow silos.

2. Apply quantitative risk analysis (QRA) techniques to identified risk exposures to add a degree of rigor and robustness to otherwise subjective assessments of impact and likelihood. QRA can determine likely risk impacts at varying degrees of confidence and help evaluate the effectiveness of mitigation measures in controlling those exposures.

"Firmly embedding strategic decision-making in the boardroom is a benefit for all organizations, but for those operating on the new frontiers of energy exploration, it is vital," concludes Marsh. OE

Understanding the ice environment is critical to Arctic success



Ice alert system for a range of operating scenarios.
Image: ION.

By Scott Cameron,
ION Geophysical

Declining reserves from mature fields worldwide, the ongoing demand for oil, and retreating sea ice have brought a flurry of exploration activity to the Arctic. The US Geological Survey estimates undiscovered Arctic petroleum resources of 90 billion bbls of oil and 1,669 tcf of natural gas—roughly a quarter of the world's undiscovered, technically recoverable, hydrocarbons. Russian scientists suggest Arctic resources may be comparable to those of the Persian Gulf or Western Siberian basins. Given the size of the prize, international oil companies and governments are initiating new Arctic ventures. However, operators and service companies face daunting technical and environmental challenges. Extreme weather and encroaching ice threaten and often curtail costly Arctic operations. In a recent example, sea ice unexpectedly delayed access to several drilling locations, and at another site, drilling was suspended one day after commencing due to a huge ice sheet drifting toward it.

The challenges of Arctic ice navigation

Dangerous ice conditions limit the Arctic operating season to less than a year. To maximize the operational window and optimize their ice defense strategies, ice observers and analysts onshore and aboard seismic vessels and drilling rigs must track and predict the movement of ice floes and icebergs. If ice begins to encroach beyond a certain perimeter, operators need to make well-informed decisions to ensure the safety of personnel, equipment, and the environment.

Historically, the primary task of an Arctic ice observer has been to manually record ice conditions in logs or spreadsheets by directly observing ice from the bridge. However, accurately monitoring and predicting ice movement requires additional information including live radar, satellite images, weather reports, and ice and navigation charts. In the past, ice specialists printed reports, maps and images on paper and attempted to make sense of disparate data. This complex process was largely manual and mental.

Later, rudimentary ice navigation software enabled ice analysts to view limited electronic ice charts, satellite images, and radar in one place—a good first step. However, they still had to download files from multiple sources via FTP, QC the data and manage it in a timely manner. Some information was not time-stamped or georeferenced, so they could not overlay and correlate all maps and images. What's more, certain types of data—vessel positioning, weather, metocean, maps of currents, wind, sea temperature and so on—remained separate and inaccessible from within the software.

Early ice navigation technology became fairly standard in Arctic operations, but lacking automation, the process of integrating diverse information remained complex and time-consuming. As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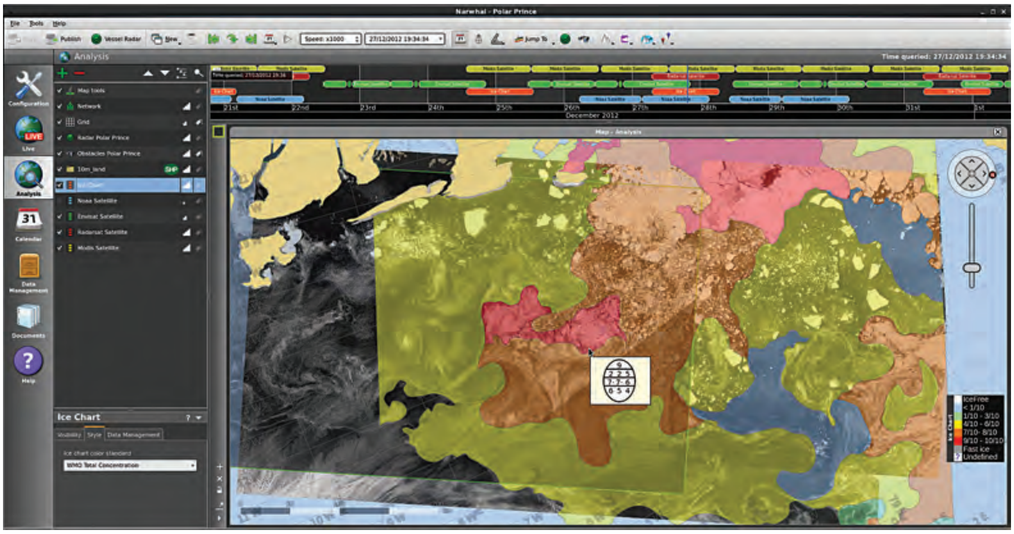

Visualization and analysis - integration of satellite imagery, ice charts and more. Image: ION.

Captain Norm Thomas of the Canadian Coast Guard put it: "Alone on the bridge, ice data management systems should not take observers away from looking out the window."

A modern, integrated ice management solution

ION Geophysical has been operating in the Arctic since 2006. Conducting 15 projects over eight operating seasons, approximately 65,000 km of seismic data has been acquired in or near ice, and over 30,000 km under ice. Using conventional ice navigation software, ION's ice observers became frustrated with the software's inability to combine or visualize key ice information required for operational effectiveness.

As a result, ION's Concept Systems developed a new integrated ice management solution, named Narwhal™ for Ice Management.-

Released commercially in September 2013, Narwhal provides visualization, analysis, tracking, monitoring, prediction, and risk mitigation tools for offshore Arctic seismic and drilling operations. This modern GIS-based system automatically downloads a variety of ice data products via satellite from ION's data hosting service. It organizes, loads, timestamps, and georeferences every piece of information. Ice analysts and observers can rapidly and easily configure an unlimited number of GIS layers. They can blend ice charts, satellite images, live radar, weather forecasts, metocean and other data, and log ice observations—all on a single map, combined with the operational picture.

Unique new ice management capabilities include multi-vessel sharing and visualization, automated alerts for approaching ice, animation of both ice and vessel trajectories through time (past and near future), and a complete audit trail at the end of the operating season.

2013 field trials and results

During its voyage through the Northwest Passage last summer, the *Polar Prince*, an ice-classed seismic survey vessel, put the software to the test. As it began to automatically receive ice charts from the Canadian Ice Service, the ice specialist turned on Narwhal's "trafficability" system. This capability allowed the analyst to compare the *Polar Prince*'s specific ice classification with sea ice conditions to determine go/no go areas. Narwhal indicated that the *Queen Maud Gulf* would be impassible. Rather than sailing onward, the captain made the strategic decision to shelter for a week until it became passable.

"Navigating without Narwhal," he said, "the increased propulsion needed to break through the ice would have increased our fuel usage. That would have lowered our weight (momentum), consuming even more fuel and increasing overall costs."

Elsewhere in the Arctic, operators have been conducting site surveys of potential drilling locations in Baffin Bay on the west coast of Greenland. After using traditional ice navigation software for several years, one international oil company decided to field test the Narwhal system.

During the survey, ice analysts accessed more than 20 different ice data products. In addition, observers manually entered information about ice fragments known as "bergy bits" and "growlers" that were too small to show up on ice data products. Plotting their location, speed, and direction, analysts used Narwhal's time-slide animations to predict where the ice would move in the coming days. Personnel working in hazardous areas specified by a pre-set alarm perimeter could proactively move elsewhere until it was clear again, ensuring safe and efficient deployment of costly resources.

Although it had been installed originally as a secondary ice management system, Narwhal quickly became embedded in daily decision-making processes.

"Narwhal enables integration of various data sources," said the operator's metocean specialist. "It allows quick review of historical data, and efficient sharing of ice information." Due to automation, he added, "Narwhal reduces time spent handling and processing data by 25 percent, allowing observers to spend more time looking out the window and interacting with marine crews."

As operations continue to increase in more Arctic areas, both oil and service companies will need integrated ice management capabilities to ensure safe, efficient, and environmentally responsible exploration and drilling projects throughout the short operating season. OE

***Scott Cameron**, Narwhal Product Manager, ION Concept Systems. Based in Edinburgh, Scotland, Scott joined Concept Systems in 1994 after graduating with an honours degree in Computer Science. Scott has been involved in the design and development of ION Concept Systems command and control systems in the seismic exploration arena for many years. These days Scott is the chief architect and product manager for ION's Narwhal Ice Management Solution, bringing together years of system design and command and control experience while working closely with the ice community to design and develop a solution fit for 21st century Arctic operations.*

Applying real-time magnetic declination in arctic marine seismic acquisition

By Curt Schneider, ION Geophysical and Noel Zinn, Hydrometronics

Marine seismic surveying in the Arctic presents many challenges. Conducting streamer surveys in the presence of high ice concentrations eliminates the ability to safely tow a conventional GPS tail buoy. When conducting 2D surveys under these conditions, the tail buoy is typically removed, which leaves only compasses as a means to calculate the cable position.

Compass data must be corrected for declination caused by the Earth's magnetic field. As a first order correction to the raw compass bearings, the navigation software can apply a gridded declination. That is, a gridded World Magnetic Model (WMM) or Enhanced Magnetic Model (EMM) declination is applied as the seismic vessel sails through the model. However, this method is not adequate at high latitudes, due to temporal variations in the Earth's magnetic field. Instead, a shipboard declinometer has been developed that measures real-time magnetic declination, which is then applied to the cable compasses in an open traverse from the vessel to the tail.

On November 1, 2012, the declinometer observed a geomagnetic event in the Beaufort Sea during which the peak declination changed 12 degrees (12°) in 6 minutes. Magnetic observatories at Point Barrow and Deadhorse confirmed the event. This article discusses the improvement of real-time declinations over modeled declinations for marine seismic streamer positioning in the Arctic.

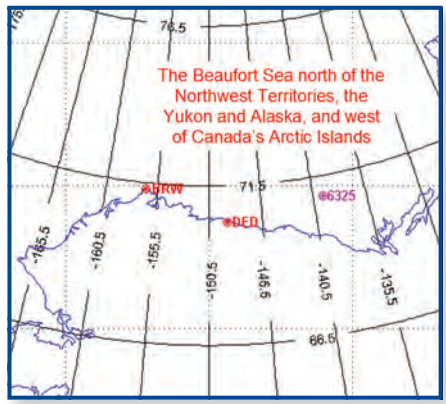

Fig. 3: Beaufort Map with location of line 6325, DED and BRW INTERMAGNET Observatories. Source: ION.

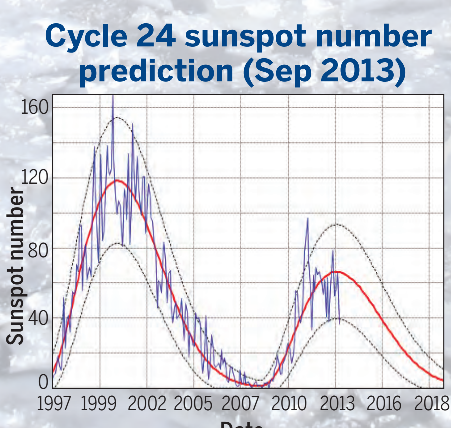

Fig. 1: Sunspot number fluctuations in the 11-year solar cycle. Source: ION.

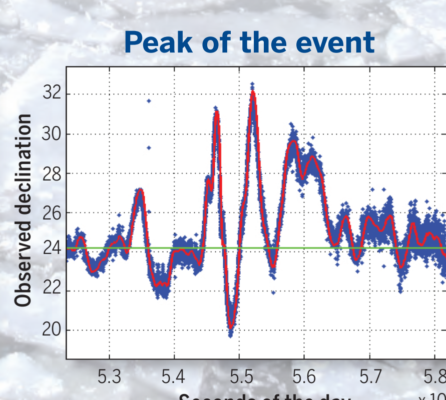

Fig. 2: Observed declination on November 1, 2012. Blue dots are raw declinometer data, red line is a filtered version used to correct compasses. Green line is modeled WMM declination. Source: ION.

Characterizing Arctic geomagnetism

The Earth's magnetic field is a composite of several magnetic fields generated by a variety of sources. These fields are superimposed on each other and through inductive processes interact with each other (www.ngdc.noaa.gov). The most important of these geomagnetic fields are:

The main magnetic field $\mathbf{F}_{core}(\boldsymbol{s},\boldsymbol{t})$ generated in the Earth's fluid outer core, which varies in both time (***t***) and space (***s***);

The crustal field $\mathbf{F}_{crust}(\boldsymbol{s})$ generated in Earth's crust and upper mantle, which varies spatially but is considered constant in time for the time-scales of the models;

The combined disturbance field $\mathbf{F}_{disturbance}(\boldsymbol{s},\boldsymbol{t})$ from electrical currents flowing in the upper atmosphere and magnetosphere, varying in space and rapidly in time.

The observed magnetic field $\mathbf{F}(\boldsymbol{s},\boldsymbol{t})$ is then:

$$\mathbf{F}(\boldsymbol{s},\boldsymbol{t}) = \mathbf{F}_{core}(\boldsymbol{s},\boldsymbol{t}) + \mathbf{F}_{crust}(\boldsymbol{s}) + \mathbf{F}_{disturbance}(\boldsymbol{s},\boldsymbol{t})$$

Magnetic models only represent the main geomagnetic field ($\mathbf{F}_{core}$) which accounts for over 95% of the field strength at the Earth's surface. Temporal and small wavelength disturbances are not computed by these models.

Groves (2013) describes the accuracy of these models. He states that "regional variations, correlated over a few kilometers, occur due to local geology. Global models are typically accurate to about 0.5°, but can exhibit errors of several degrees in places. There is a diurnal (day-night) variation in the geomagnetic field of around 50 nT. Short-term temporal variations in the Earth's magnetic field also occur due to magnetic storms caused by solar activity. The effect on the declination angle varies from around 0.03° at the equator to more than 1° at latitudes over 80°."

We will see later that magnetic events with declination changes of more than 1° are common in the Arctic. We can also expect these events to fluctuate in frequency as we progress through the 11-year solar cycle (Fig. 1). At the time this was written, the Earth was progressing into the peak of a solar cycle.

In the absence of a positioning tail buoy due to ice, as explained earlier, special care must be taken with declination to adjust the compass-to-compass positioning traverse along the streamer by measuring the combined geomagnetic field.

Declinometer

ION Geophysical has developed a declinometer to observe magnetic declination in real time on a seismic vessel. The declinometer consists of a fluxgate magnetometer and an inertial measurement unit (IMU) disciplined by dual-antenna GPS. A calibration maneuver is required to measure and compensate for the hard and soft iron effects that a steel vessel imparts on a magnetometer. The measurements from the declinometer are then passed to the navigation system and applied when processing the positioning data. Details can be found in patent application US 20120134234 (see references).

Observed Magnetic Event

While shooting seismic line 6325 in the Beaufort Sea on November 1, 2012, the seismic vessel *GeoArctic* experienced a significant magnetic event. The declinometer recorded hours of disruption and a change in magnetic declination of 12° in 6 minutes at the event's peak about 55,000 seconds into the day (about 15:16 UTC) as illustrated in Fig. 2. The blue dots in Fig. 2 are the raw declinometer observations that come at about 3Hz. These are particularly noisy data during this period. The red line is an alpha-beta filtering of the raw observations that is used to correct the cable compasses from magnetic azimuth to true azimuth. The green line at about 24° is the declination determined by the World Magnetic Model (WMM) for the time and position of the vessel. The *GeoArctic* was towing a 9km-long cable at the time of this event. If a modeled declination instead of the declinometer data were used to correct the compasses, the tail of the cable would "wag" as much as almost 2km during the period of the event (12° in radians x 9km).

Observatory data

INTERMAGNET is a "global network of observatories, monitoring the Earth's magnetic field" (www.intermagnet.org).

The INTERMAGNET observatory nearest to line 6325 is Deadhorse (DED), about 350km away. Point Barrow observatory (BRW) is farther away. Fig. 3 is a map of the Beaufort showing the location of the event (line 6325), DED and BRW.

The declination measured at DED on November 1, 2012 is plotted in Figure 4, where the horizontal axis is measured in seconds of the day. This also shows the peak of the event at about 55,000 sec into the UTC day. The WMM modeled grid for DED this day is 21.10°. The EMM modeled grid for DED this day is 20.47°. The day begins quietly, but most of the rest of the day is dominated by the magnetic storm with a difference of almost 10° in declination at its peak.

To assess the simultaneity of the peak events at DED and the declinometer, the data between 50,000sec and 60,000sec were cross correlated resulting in a peak at about 1 min. of lag. BRW and the declinometer were also cross correlated resulting in a peak (less well defined) at about 6 min. of lag, consistent with the lag between BRW and DED of about 5 min.

How common is an event of the size measured on line 6325 on November 1, 2012 (henceforth JD306), DED 1-minute declination data are available from July 26, 2012, onward. To answer the question of the frequency of events, the authors parsed the DED 1 minute records from July 26, 2012, to July 13, 2013 (the last available at the time of writing this paper). Fig. 5 shows the range in declination for each of the 353 days plotted against the sequential day of the period. JD306, the day of the event analyzed in this paper, is plotted in red. Its declination range is 9.49°, a bit less than observed by the declinometer on the vessel (12°).

In this 353-day period at DED there are 19 days with declination ranges equal to or larger than that of JD306, one as much as 25°. There are 54 days with declination ranges larger than half that of JD306. For the *GeoArctic* in the Beaufort that would be four or five days/month with a cable "wag" of almost 1km-long if not for real-time declination corrections from the declinometer.

Cable compass delays and alpha-beta filtering

Declinometer declinations are an enormous improvement over gridded model declinations for this event, but the scale and rapidity of this event exposed several deficiencies in the system. The compass birds used on the *GeoArctic* internally record a magnetic azimuth every 2 seconds, but an average of the available readings are passed upstream. The average is taken when the compasses are polled, but it is the last average (and not the current average) that is passed upstream at the time of the polling. On this project the compasses were polled every 16 to 18 seconds. In effect then, the compass data is one and a half polling intervals old when it is finally available for use by the navigation system, or about 25 seconds. Recall that this is a rapidly varying event, changing 2°/ min. sustained for more than an hour, peak to trough to peak.

On the declinometer side, an alpha-beta filter is applied to the raw 3Hz

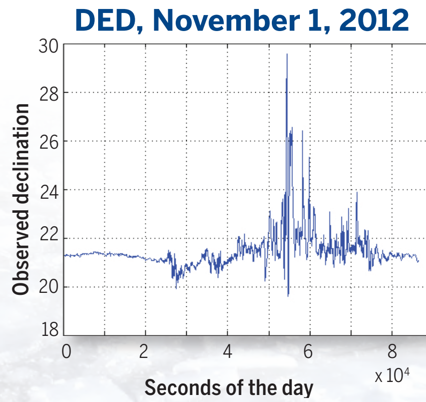

Fig. 4: Declination (adjusted for baseline) measured at DED on the day of the event analyzed. Source: ION.

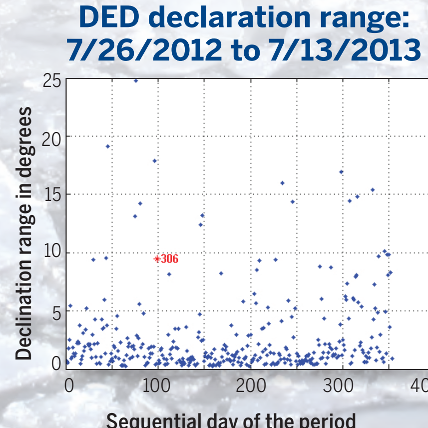

Fig. 5: Range in declination for 353 days of DED data. JD306 is plotted in red. Source: ION.

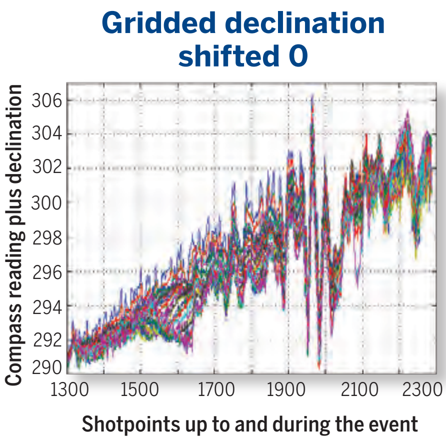

Fig. 6: Compass readings corrected with gridded declination versus shotpoints
Source: ION.

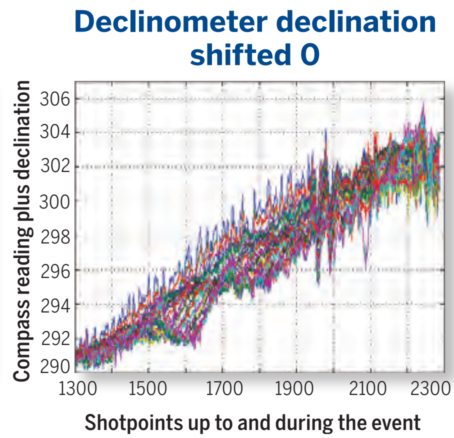

Fig. 7: Compass readings corrected with measured declination vs. shotpoints
Source: ION.

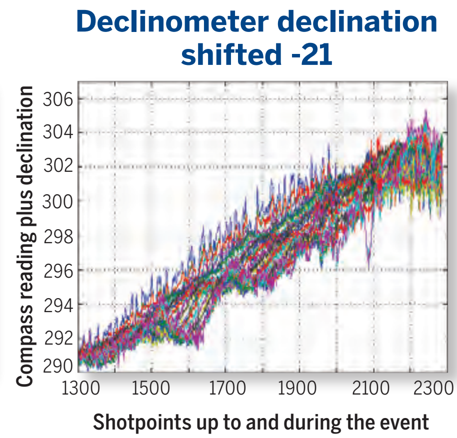

Figure 8: Compass corrected with measured declination adjusted for time delay vs. shotpoints Source: ION.

declinations to provide slowly varying readings to the navigation system. This is an "optimal" filter (Benedict 1962) where alpha is fixed in the declinometer at 0.0131 and beta is defined as alpha^2/(2-alpha). Although all causal filters have delay, the alpha-beta filter has a rate term that accelerates change. A close examination of the "Peak of the Event" plot in Fig. 2 will show that the red filtered curve leads as well as lags the blue raw data. In fact, a cross correlation of the raw and filtered data shows no net delay at all. But the leading and the lagging are not good. The alpha-beta filter in the declinometer was just not tuned for an event such as this. Upon experimentation, the alpha parameter was changed to 0.0394 to better fit the excursions of this event and to give good performance in normal times, too. An alpha-beta smoother (forward and backward filter combined) gives marginally better results, but is not a real-time solution.

After retuning the alpha-beta filter and searching for the best fit between the declinometer declinations and the compass azimuths, the net delay was determined to be 21 seconds. That is, a declinometer declination that is 21 seconds old should be applied to the compass data when it arrives. Cross correlations among the compasses themselves revealed no significant differences.

Applying declination

The vessel was configured with a 9km-long cable and 33 seismic compass-birds attached, roughly one every 300m. Figs. 6-8 are plots of the cable compass data for a section of line 6325 around the time of the event.

Fig. 6 shows the compass readings versus shotpoint number with the gridded declination applied. The event can clearly be seen with wild excursions around shotpoint 2000.

Fig. 7 shows the application of the real-time declination data to the compass data as they are time stamped in the navigation data.

Since the compass data are delayed as explained earlier, there are remnant disturbances that have not been compensated for, but the majority of the event has been removed.

Fig. 8 shows the compass data after an appropriate delay for the compass measurement has been applied, removing the magnetic anomaly entirely.

The orientation of the cable was slowly changing in a current during the 1000 or so shotpoints of these figures which accounts for the gradual increase of the azimuths of these 33 compasses.

Conclusion

The ION Geophysical declinometer is a significant improvement over gridded magnetic models for streamer positioning during marine seismic acquisition in the Arctic. Some improvements in the application of declinometer measurements will be implemented in the future by ensuring that the declinometer filter is tuned less stiffly and the application of observed declinations are matched to the true measurement time of the compass data. **OE**

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***Curt Schneider** manages the Geophysical Support group within ION Geophysical's GeoVentures business unit. He has worked at ION for 8 years and has more than 30 years of industry experience in seismic acquisition. Schneider studied geophysics and electrical engineering at the Pennsylvania State University and the University of Pittsburgh.*

***Noel Zinn** began Hydrometronics LLC in 2010, to indulge his enthusiasm for developing navigation and positioning software, following a long career with a navigation contractor, two seismic contractors, and a major oil company. Zinn studied surveying, geodesy, geoscience and programming at the University of California at Berkeley and the University of Houston.*

Arctic operations
at what temperature?

By James Bond and
Dan Oldford, ABS

The concept of temperature seems simple enough. Everyone knows that a thermometer can be used to measure the temperature of a substance such as air and that by knowing the forecast, people can adequately prepare for the day's outdoor activities. While it might be marginally problematic to be underdressed or overdressed for the weather conditions, there are no serious repercussions if the forecast is wrong. For Arctic oil and gas operations, however, poorly developed predictions can have catastrophic consequences if the equipment does not function reliably when the temperature drops.

While some work has been done in this field, there is much more to be done to actually define the temperature that should be used for design, equipment procurement specification, and operational risk management for Arctic operations.

The most recognized definition/selection of a design service temperature comes from the International Association of Classification Societies (IACS) Unified Requirement (UR) S6 for structural steel intended for service at lower temperatures. IACS UR S6 and the ABS Low Temperature Environment (LTE) Guide require that the design service temperature (DST) be selected as the lowest mean daily average (LMDAT) for the operational window and geographical location. The LMDAT, which has been in use for many years and is widely recognized in the industry, is easy to calculate using temperature data for the operational area.

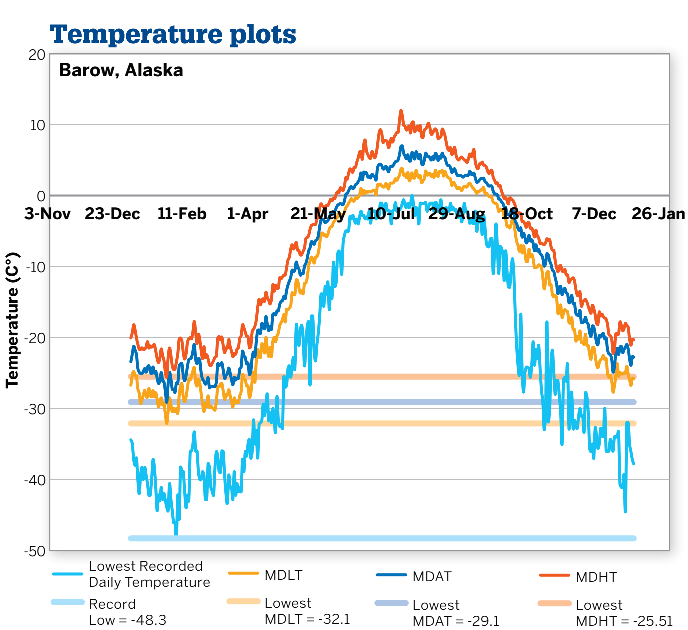
Prediction and problems

Inaccurate temperature prediction has the potential to impact many operational elements. If an engineer designing a new support vessel or offshore platform to operate in a specific location has the wrong DST, the designs are wrong. If an equipment manufacturer designing and building equipment for cold environment applications uses the wrong DST, the equipment may not be reliable. And if a regulatory body developing guidance for Arctic operations applies the wrong numbers, the regulatory guidance will not facilitate safe operations.

Before engineering a unit for Arctic operations, a temperature specification has to be established based on measured data from the work site or from a site as close to that location as possible. Then, all of the systems on the unit, including the equipment to be supplied from vendors, have to be designed and manufactured to operate at that temperature.

The problem lies in answering the question, "What is the temperature for the location?" Temperature varies minute to minute, hour by hour, day by day, and even decade by decade. Often, temperature is expressed as an average of all the temperatures ever recorded in a particular area, the historic average temperature for the day on which operations are expected to take place.

To further complicate calculations, materials vary in their sensitivity to temperatures and temperature fluctuation. A sudden drop in temperature for a few hours will have significantly less effect on the hull material (with its



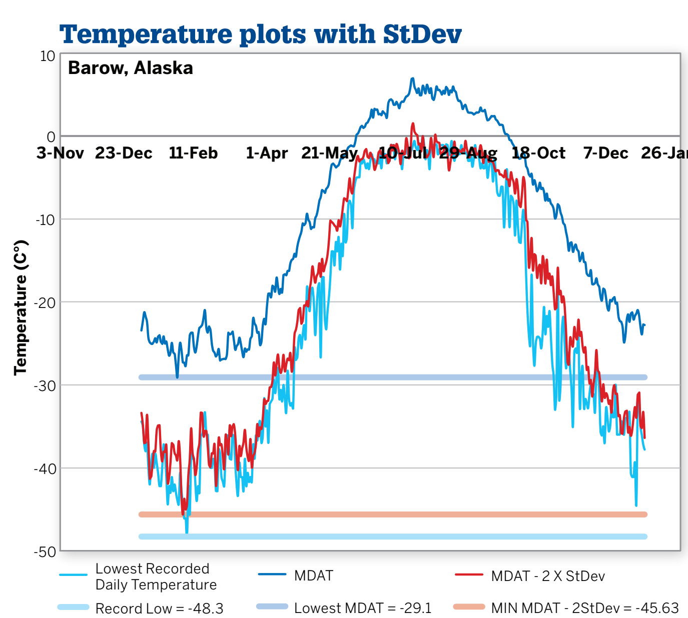


Fig. 1: Temperature data for Barrow, Alaska, from 1999 to 2011.

thermal bulk inertia) than it will have on an exposed, 100mm diameter freshwater pipe.

While a unit will be required to have a certified design service temperature, there has to be cognizance that every unit is a combination of all its systems. So the question of how those systems will be tested to verify functionality at the design temperature must be answered. And consideration has to be given to whether an additional temperature safety factor should be required for testing and certification.

Research efforts

The DST is applied to the unit's structural steel; however, a second temperature is required for machinery, namely the minimum anticipated temperature (MAT), which currently can be defined by the owner, operator, shipyard, or designer—or taken as 20°C colder than the DST. There is very little guidance offered to define the MAT with greater accuracy.

Certain systems that are exposed to a sudden, but temporary, low temperature, such as when polar lows move, require a design temperature value that incorporates the probability and duration of such an occurrence. Probability of occurrence is a risk concept that the marine and offshore industry understands well, but duration of occurrence is new.

A simple analogy helps to illustrate the concept. A man living where the outside temperature is cold but who works indoors probably would find it unnecessary to don an expensive, extreme harsh environment jacket if he only needs to run a short distance to a nearby building. On the other hand, for someone who works outdoors all day in that same cold environment, it might make very good sense to invest in the expensive jacket.

This same philosophy can be applied to an installation. There is no need to winterize the entire unit for a temperature that may occur for only a few minutes. Winterization can be applied selectively on the basis of the probability of occurrence and duration of occurrence. Further, it would be possible to delay some operations if there were an understanding that the duration of the cold occurrence would be short and that the delay would not reduce safety levels.

A temperature analysis concept, resulting from collaborative research by ABS Harsh Environment Technology Center

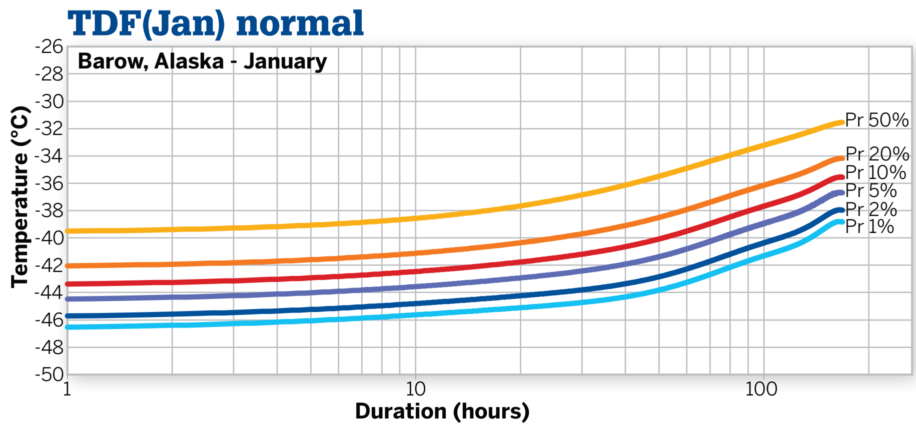


Fig. 2: Comparing Figs. 1 and 2, one first notices that the lowest point on the 1% return line from Fig. 2 does not go as low as the record low in Fig. 1, but Fig. 2 is for the month of January and Fig. 1 is for an entire year. The record lows are observed in February. Fig. 1 provides a graphical representation of temperatures recorded in the past, while Fig. 2 takes those temperatures and projects them forward to give a probability of a temperature return and the time over which that temperature can be expected to last.

and Memorial University, in St. John's, NL, Canada, is offering a new rational statistical method for defining a minimum anticipated temperature.

Analysis

A temperature data set, spanning 1999 to 2011, for Barrow, Alaska, demonstrates the concept (Fig. 1). The mean daily average temperature line, shown in green, would be used per IACS UR S6 to determine the design service temperature for a unit operating in Barrow. The DST would be selected as the LMDAT, equal to -29.1°C. The blue line, the lowest recorded daily temperatures, would be used to set the minimum anticipated temperature (MAT), here equal to -48.3°C. Note that this data set justifies the practice of setting the MAT 20°C colder than the DST.

Consider a crane on an OSV as an example for the use of the TDF plot (Fig. 2). If the crane was designed for a temperature of -45°C, the unit should not be used at times when the ambient temperature is below -45°C. The statistical temperature data indicate that there is about a 2% probability of having colder than -45°C lasting seven hours and a 1% probability of having it last for 20 hours.

The way forward

A statistical representation of temperature feeds directly into a risk-based approach to winterization. Knowing the probabilities of a temperature occurring and the temperature at which operational degradation begins to occur allows engineers to determine a probability of failure. A risk level can be defined based on the criticality of the equipment under consideration. A design can be modified to achieve an acceptable risk level if the probability of temperature occurrence is known and an acceptable risk level for the system has been defined.

As experience and more data are brought to bear, progress will take place more rapidly. Recognizing that further research is required, ABS is working with the Harsh Environment Technology Center in St. John's on collaborative efforts that will help move the industry forward. OE

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***Dan Oldford**, P.Eng, worked as an ABS surveyor in Canada before joining the ABS Harsh Environment Technology Center in St. John's, NL, where he is involved in R&D efforts targeting Arctic issues, including winterization. He is a graduate of the Ocean and Naval Architectural Engineering program Memorial University in St. John's.*

Proposed advancements in probabilistic ice gouge analysis

Alternate probability distributions could provide a better fit for Arctic ice gouge depth data, impacting design depths for future subsea pipeline projects.

By Jonathan Caines, INTECSEA

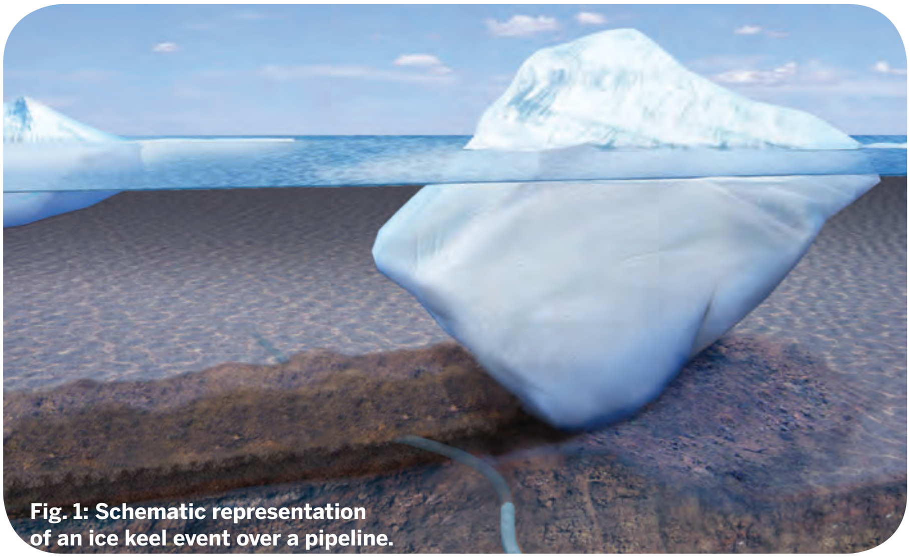


Fig. 1: Schematic representation of an ice keel event over a pipeline.

Pipelines installed in ice-prone regions require specialized designs for the unique environmental conditions. When the keels of icebergs and ice formations impact the seabed with sufficient driving force, the seabed can be disturbed, leading to seabed deformations called ice gouges or ice scours (Fig.1).

In a paper presented to the International Society of Offshore and Polar Engineers, INTECSEA studied extensive repetitive seabed ice gouge data collected along the Northstar pipeline route in Alaska's Beaufort Sea. The route has been surveyed for multiple years, both before and after the pipeline bundle was installed in 2000.

Probabilistic assessment of ice gouge depth statistics has been utilized to predict extreme ice gouge depths. Beginning in 1977, single parameter exponential distributions were shown by researchers to be effective, but conservative, in predicting design gouge depths. Exponential distributions, however, have generally been used to describe time-based events, such as waiting times or queuing problems.

Later research examined the use of different probability density functions and found the Weibull or gamma functions to more accurately fit ice gouge depth data from the Beaufort Sea. Other research investigated data specific to the Northstar pipeline route and found the lognormal distribution more accurately fit the historical data set.

After examining data available from the Northstar Development Annual Pipeline Route Monitoring Program annual survey reports, INTECSEA concluded that the lognormal distribution (Fig. 2 and 3) provided the best fit. In water depths less than 4.9m (16ft), a 3-parameter lognormal distribution was marginally better (Fig. 2).

Analysis using observed maximum annual gouge depths only was also investigated. Comparative analysis using all available, known-age gouge depth data vs. known age annual maximums shows that analysis of maximum gouge depth data could lead to over-conservatism in design. Analyzing a dataset containing only the single deepest ice gouges observed annually in a survey area did not reflect the true statistical ice gouge distribution crossing a pipeline route centerline.

Another key finding was the importance of repetitive mapping programs. Using similar equipment and procedures each year brings improved extreme event gouge depth prediction accuracy. INTECSEA suggested that additional evaluation of subgouge seabed deformation and active gouge infilling is merited to diminish gouge depth uncertainty and provide a better understanding of ice-soil-pipe interaction. Having confidence in statistical models from multiple years of regional survey evaluation can reduce conservatism in predicted extreme gouge-depths, potentially resulting in reduced trenching and burial costs for Arctic and harsh-environment pipelines.

The impact of ice gouges

Ice gouge protection typically involves trenching and burying the pipeline to some depth below the maximum ice gouge depth to protect the pipeline from direct contact and to mitigate subgouge soil displacement bending strains.

Annual variability in the ice gouging regime may be a significant factor in defining the design depth. Increased summer open water fetch lengths may contribute to driving multiyear ice floes into shallow waters and create deeper gouges.

Predicting the original gouge depth at the time of the event is often problematic since the gouges are not measured while the ice keel is moving and deforming the seabed. These measurements are often taken sometime after the event has occurred using summertime seabed surveying techniques and instrumentation, such as sidescan and multibeam sonar.

This makes measuring or predicting the initial gouge depth difficult since weathering and natural backfilling or sedimentation can occur post-gouge. This alters the record preserved on the seabed. However, when studies are performed over multiple years, previously observed gouges can be remeasured and the amount of backfill that has occurred can be compared.

Tracking known ice gouge occurrences also allows for better predictions. The depth and backfill amount also are dependent on the region's physical, environmental and ice regime characteristics.

A pipeline is not affected by ice gouges that do not cross it and this must be addressed when defining the design gouge depth. Additional factors can influence a pipeline's response to seabed ice gouging including pipeline operating conditions; seabed soil characteristics; gouge width; gouge orientation with respect to the pipeline; trench backfill conditions; and detailed interactions between the pipe, soil and ice keel.

Studying the Northstar pipeline system

The BP Exploration (Alaska) Northstar offshore Arctic pipeline system was installed as a bundle and includes a nominal pipe size (NPS) 10-in. oil export pipeline and a NPS 10-in. line supplying gas to the field for reservoir pressure maintenance. These pipelines extend outside the Alaskan coastal barrier islands and are exposed to more significant seabed ice gouge conditions than two other subsea Arctic pipeline systems operating in the Beaufort Sea.

Two primary load conditions controlled design and trenching requirements: ice/seabed interaction in the deeper water zone outside the coastal barrier islands, and seabed permafrost thaw subsidence in the shallow lagoons.

Seabed ice gouging was observed from 1995 through 1999, during each of the yearly pipeline route bathymetry summer surveys carried out before construction. Since installation, there have been 12 yearly surveys conducted. At the time the BP Northstar design was completed in 1998, there were a total of 8 years of seabed ice gouge survey data in the vicinity of the pipeline route.

Limit state design procedures for pipe bending were used to calculate the minimum pipeline depth of cover to resist ice keel loads. A 2.13m (7ft) minimum depth of cover was calculated based on a 100-year return period maximum ice keel gouge depth of 1.07m (3.5ft) using an exponential gouge depth distribution. The minimum depth of cover ranged from 1.83-2.74m (6-9 ft), depending on location.

INTECSEA studied three sets of data – the annual pipeline route monitoring surveys performed by Coastal Frontiers Corporation (CFC) along the route between 2000 and 2011, the entire set of CFC surveys conducted along the route between 1995 and 2011, and the full set of all available ice gouge data from all surveys in the area. These data sets were further divided at the 4.9m (16ft) water level for consistency with the original design analyses. The 'All Data Sets' collection included gouges of both known and unknown age whereas the two collections of Northstar-specific data included only new (or known age) gouges.

The qualitative goodness-of-fit of investigated probability distribution functions (PDFs) was assessed by comparing them against both the ice gouge depth data distribution histogram and the ice gouge depth empirical cumulative distributions (see Fig. 2 and 3). Where qualitative assessment could not distinguish the best fit, final selection of the PDF was based on an Anderson-Darling (A-D) test.

The maximum ice gouge incision depths observed along the route centerline plus two, or more, offset survey lines are recorded annually in the Northstar Development Pipeline Route Monitoring Program reports that are available to the public.

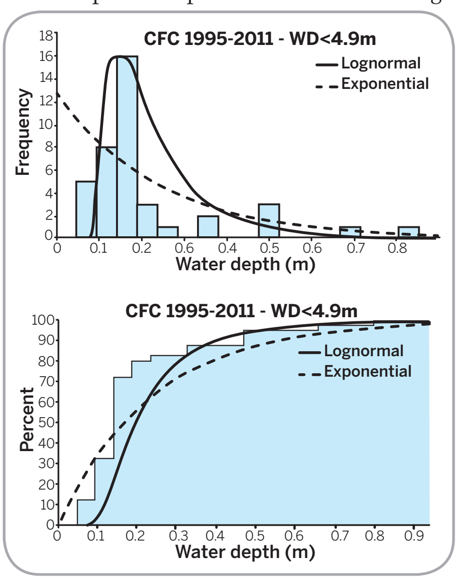


Fig. 2 Histogram and empirical cumulative distribution

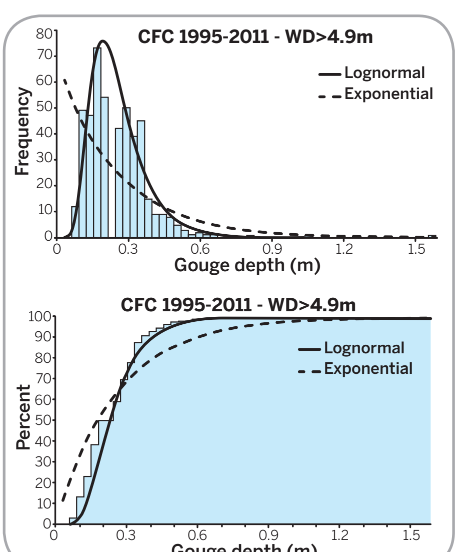


Fig. 3 Histogram and empirical cumulative distribution

Surveys use sidescan for ice gouge detection, with a range of 50m on either side of the survey vessel trackline (100m swath width). Multibeam sonar is then used to map identified ice gouges with effective swath widths ranging from 7.6 to 42.7m, depending on the water depth and returned acoustic beam signal.

The surveys in 2007 and 2011 showed very significant seabed gouging during the preceding 12-month period. INTECSEA reported that an intense storm during October 2006 produced high winds, waves and a negative storm surge, while multiyear ice floes were present near the pipeline route.

The deepest observed 2007 ice gouge was 1.55m (5.1ft), exceeding the 100-year design ice gouge depth by a factor of 46%. However, the 1.55m (5.1ft) deep ice gouge observed in 2007 was located 55m (180ft) east of the pipeline centerline. The maximum gouge depth observed directly above the pipeline that year was only 0.24m (0.8ft).

The 2011 survey reported 130 new gouges – more than double the previous highest record of 54 in 2002 – but no gouges exceeded the 100-year design ice gouge depth. The deepest ice gouge observed in 2011 was located near the pipeline centerline, but not directly over top of the pipeline and did not reduce the minimum trench backfill soil thickness above the pipeline.

Going forward

INTECSEA's research shows that having confidence in statistical models from multiple years of regional survey evaluation can reduce conservatism in predicted extreme gouge-depths, potentially resulting in reduced trenching and burial costs.

INTECSEA concluded that since many years of site-specific seabed ice gouge data will not be available for new pipeline projects, a balanced approach towards defining reasonably conservative (deeper than expected) design gouge depths and other design parameters affecting the pipeline safety is warranted. **OE**

Jonathan Caines *is a pipeline engineering specialist and manager of small projects with INTECSEA Canada in St. John's, Newfoundland. Caines holds a B.Eng. in Mechanical Engineering and an M.Eng. in Oil and Gas Engineering, both from Memorial University of Newfoundland.*

An FSRU first

The *Toscana* became the world's first permanently moored floating storage and regasification unit earlier this year. Nick Palmer talks more about the unit and its external turret mooring system.

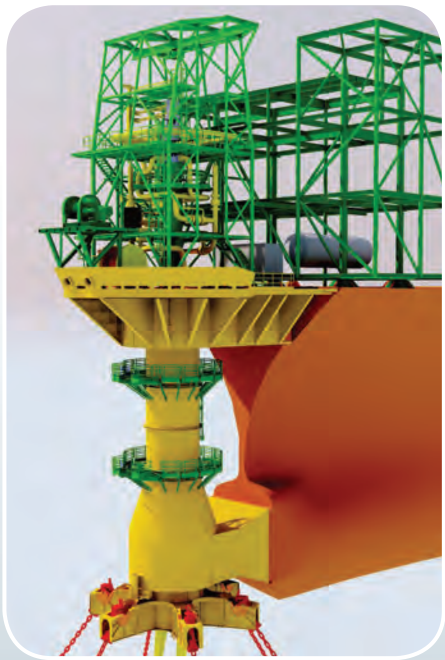
This August saw the final installation and hook up of the floating, storage and regasification unit (FSRU) *Toscana*.

The *Toscana* is a 288m-long converted LNG carrier moored using an external turret mooring system 19km (12mi) off Livorno, Italy, in 120m water depth.

This is the world's first permanently moored offshore FSRU. It has a storage capacity of 137,500 cu m of liquefied natural gas (LNG), with capability to supply 3.75 billion cu m per year natural gas to shore, representing about 4% of Italian demand.

The vessel is a steel monohull with four Moss type LNG tanks arranged in its center, the regasification plant at the forward end, and accommodation with central control room and utility machinery in the aft end.

LNG shuttle carriers will berth alongside *Toscana* so that direct side-by side loading of LNG to the FSRU can be performed. The FSRU then converts the LNG back to gas using the regasification plant. Gas is exported through the turret swivel stack down to the seabed via a flexible subsea riser system and then on shore via subsea pipeline.



A schematic of LMC's external turret system design for the FSRU *Toscana*. Image: LMC.

The subsea system consists two 14in. gas export lines and one umbilical, positioned over a mid-water arch. The gas send out-line will go through the turret swivel down to the seabed and, from there, directly to the onshore users' tie-in points via a single 32in. subsea line.

The bow-mounted, column turret system, supplied by UK-based London Marine Consultants (LMC), is one of five systems designed by LMC. It is LMC's ninth external turret mooring system in service.

This system is an evolution of designs LMC developed for the *Farwah* FPSO (2003), installed offshore Libya, and for Saipem's *Firenze* floating production vessel (2011), installed on ENI's Aquila field offshore eastern Italy. It is a passive mooring system, allowing the vessel to weathervane around the turret and align itself with the prevalent environmental conditions.

The FSRU and turret mooring system are designed to remain on station for 20 years. The mooring system uses six equally spaced mooring chains (four at 140mm, and two at 103mm diameter) and embedment anchors, in 112m water depth. It is designed for a mooring load of up to 1250-tonne.

The basic design of the column turret differs from traditional external cantilever designs most notably through the turret connection to the vessel, which is provided at two locations at the vessel bow: one at main deck level and one at the level of the bulbous bow.

Structural integration of the turret to the vessel at these locations is through upper and lower cantilever steel constructions, which are joined together by a steel outer column to create a rigid, "portal-frame" structure. LMC was the first designer to include such an outer column.

The part of the turret fixed to the vessel surrounds an inner column connected at its base to the chain table, to which the mooring lines attach via articulated chain stoppers.

The inner column is connected to the vessel-fixed part of the turret with two bearings. A 4m-diameter roller-type

Rotterdam-based Fairmount Marine's tugs *Fairmount Summit* and *Fairmount Alpine* towed the *Toscana*, previously the LNG tanker *Golar Frost*, into position offshore Italy. Photo: Fairmount Marine.

slewing bearing is used at the upper connection, similar in type to those employed in LMC's external cantilever turret designs. At the level of the lower cantilever, a radial plane bearing is used, comprising polymeric bearing pads positioned on the outer column and a machined Inconel rubbing surface on the inner column.

Using two bearings allows for dissociation of the horizontal and vertical loads imparted by the mooring system, with the lower plane bearing carrying the majority of the horizontally-imparted loads, and the upper slewing bearing taking the vertical loads.

This separation of the load components allows for the bending moment on the main slewing bearing—a design driver in the case of many external cantilever turrets—to be hugely reduced, and allows for this critical item to be smaller in diameter and cross section than the equivalent bearing required in an external cantilever turret exposed to the same mooring loads.

The fabrication of a column turret requires a number of additional key elements over and above those of a cantilever turret. Most significantly, these include the control of very fine tolerances required in fabrication of the inner and outer columns (in terms of ovality and concentricity of the circular section component steel rings), and high-precision machining of the supporting surfaces for the slewing and lower plane bearings.

Given these fabrication requirements, selection of a column turret is not appropriate in all circumstances. For offshore floating units with a limited number of risers (typically fewer than eight) and exposed to onerous weather conditions, the column turret provides advantages over a cantilever turret, including a reduction in slewing bearing size and cost, and a reduction in overall turret steel weight.

The external turret system after integration at Drydocks World, Dubai. Photo: LMC.


Installation of the external turret system at Drydocks World. Photo: LMC.

A column turret design is often preferred where incident weather environments and associated mooring loads are high enough for an internal turret to also be considered.

Other advantages include space; no space is taken up within the vessel hull, allowing the space to be used for other items, such as storage or ballast tanks. The swivel stack is maintained at the forward end of the vessel, away from accommodation blocks and other personnel areas, an important consideration, especially on gas production vessels, or with products containing high hydrogen sulfide (H2S).

In addition, a vessel being converted will require less time in dry dock, compared to an FPSO with an internal turret. The external column turret can be fabricated separately to the vessel conversion, and integrated at the end of the conversion work. The turret can, if desired, also be built by a different company to the FPSO conversion contractor.

For the FSRU *Toscana*, it was particularly impracticable to install an internal turret because the LNG tanks on the existing LNG carrier occupy most of the hull. An external column turret mooring system was selected over an external cantilever due to high environmental loads, including predicted 100-year return storm conditions of significant wave height (greater than 8m), coupled with the very fine lines and light scantlings (steelwork) at the main deck areas in the bow of the LNG carrier. It would have been difficult to stiffen this area to carry

OLT Offshore LNG Toscana is operator of the FSRU *Toscana*. Its owners are E.ON Ruhrgas (46.79%) and IREN Mercato (41.71%). The conversion of the LNG tanker *Golar Frost* into the FSRU *Toscana* was undertaken at Drydocks World, Dubai, under contract to Saipem, which also carried out installation and commissioning.

As well as installing and integrating the forward external turret, Drydocks World's work included structural fabrication and installing an aft thruster compartment, crane foundations, bilge keel, lay down area and equipment foundations.

New cryogenic piping work and insulation, were installed, along with loading arms, regasification module, nitrogen module and cargo pumps. The vessel's rudder, steering system and bow thruster was removed and an azimuth thruster installed, along with a wave monitoring and berthing system, a new fire and gas alarm system and public address and communication system in new compartments.

The power generation system was also upgraded with the installation of two turbo generators.

The FSRU *Toscana* moored offshore Livorno, Italy. Photo: LMC.

the loads from an external cantilever turret.

The *Toscana's* column turret, weighing 950-tonne, was fabricated in Dubai before being integrated to the FSRU bow structure in the Drydocks World's Dubai Yard. **OE**

Nick Palmer *is a director at London Marine Consultants (LMC). In addition to managing a large number of turret projects, Nick also leads the naval architecture department at LMC. He has experience in mooring and riser design, as well as experience in offshore installation and hook-up of turret mooring and riser systems. He is graduate in naval architecture from the University of Southampton.*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FPSO technology evolves

Ensuring the structural and marine integrity of floating production installations over their lifetime was the overall theme of a technical session at Offshore Europe in Aberdeen this fall. Meg Chesshyre reports.

Floating production storage and offloading (FPSO) vessels have been a part of UK Continental Shelf industry for more than two decades. In that time, there have been incidents with both mooring systems and hull structural integrity that required corrective action.

Advances in turret design

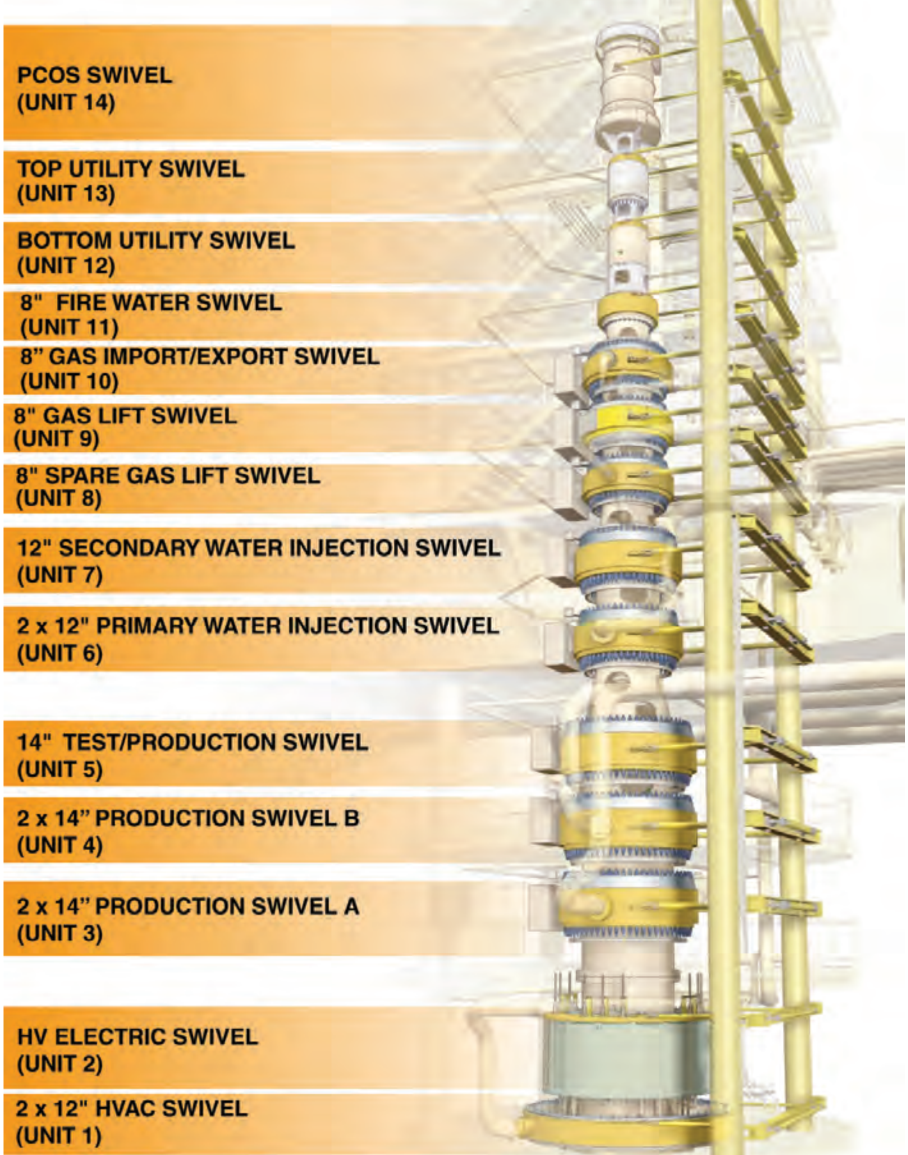
The *Quad 204* turret design sets a new standard and base case for the new generation of very large internal turret systems, according to a joint BP/SBM paper presented by Philippe Lavagna, SBM Offshore's project engineering – mooring EPM manager. The paper compared the main features of the *Schiehallion*, onstream in 1998, with the turret mooring system of the vessel due to replace it, the *Quad 204*, being built by Hyundai Heavy Industries in South Korea. Both FPSOs are supplied by SBM Offshore, considered a leader in mooring technology with approxiimately 50 turret mooring systems under its belt.

The *Quad 204* turret will be one of the largest in the world, with a mooring force of 2250tonne to meet 100-year environmental conditions. SBM Offshore's contract, awarded in June 2010, is for the engineering, procurement, construction and transportation of the turret modules including the swivels, mooring lines and suction anchors.

Since the new unit will be moored in the same location as the original *Schiehallion* FPSO, Block 204/20, west of Shetland, most of the existing subsea infra-structure will continue operations. It will weigh more than 10,000-tonne and will be 94m high – about the same height as London's Big Ben – making it more than 50% taller than the *Schiehallion* turret. It will contain significantly more equipment and have a larger throughput. The weathervaning transfer system for fluids (live production, water for injection, gas, various chemicals), power (electrical and hydraulic) and signals (electrical and optical) will be enabled by the world's largest swivel stack, comprised of 14 swivel units, weighing 265-tonne and measuring 26m. (see Fig. 1).

The *Quad 204* turret is based on SBM Offshore's proprietary bogie-bearing design and will be moored in 450m water depth. The area's environmental conditions make mooring challenging, with extreme design sea states of up to 100-year significant wave height, about 18m, and high fatigue loading of of one-year

The *Quad 204* swivel stack

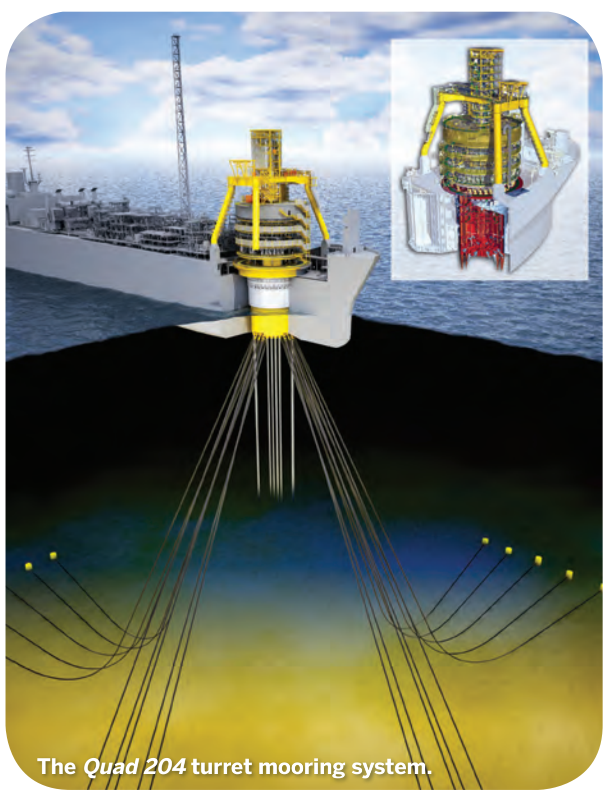


All images: SBM Offshore.

Scaffold access for extensive steel renewals at height.

significant wave height of about 13m. As a result of experiences on *Schiehallion* over the last 15 years, the design maturity of the mooring line components, such as steel wire rope and chain, is now quite advanced for the water depth.

Future Atlantic Frontier developments will be further west in even deeper waters, which will present new challenges to the industry. The combination of deepwater (deeper than 1000m) and the extremely harsh environment will represent a first-ever for the mooring industry, requiring tailored modifications. For example, in some countries, the wire rope component will have to be replaced by polyester rope. Although polyester ropes have been used for more than 10 years in the deep waters of Brazil, the sea conditions are significantly less stringent there, compared with the area west of Shetland.



The *Quad 204* turret mooring system.

BP awarded the contract for the disconnection of the *Schiehallion* and the installation of the new FPSO to Technip UK. Technip UK in turn awarded SBM Offshore an additional subcontract in November 2012, which includes phases I-III. Phase I consists of the disconnection and removal of the existing *Schiehallion* and mooring lines and its subsequent tow to Rotterdam, now currently ongoing. Phase II, occurring in 2014, is the recovery of the old mooring system and installation of the new FPSO anchoring system, including the 20 new piles and chain and spiral strand wire mooring system. Phase III includes *Schiehallion*'s tow to field and the mooring of the new FPSO, to be carried out in 2015. *Schiehallion* was decommissioned earlier this year.

The new turret design will provide sufficient space for process sub-systems and utility support for the subsea control system. The turret will comply with a reduced mooring offset envelope for more onerous specified weather conditions, with the existing riser arrangement and new overall subsea production system layout. This includes design requirements for up to 28 riser slots, against 24 for the *Schiehallion* FPSO, and for the anchor legs to be grouped into four clusters of five mooring lines each, to suit the existing subsea infrastructure.

The turret system's arrangement will allow anchor lines and risers installation to be diverless – an enhanced safety feature, compared with previous designs. The turret structure has been designed for a minimum 25-year service life. Swivel seals change-out will be possible in-situ, without interruption to production, due to SBM Offshore's technology. The bogie-bearing weathervaning system can also be repaired, and main components, such as wheels, replaced in-situ, were this ever to be necessary. This system operated for 15 years on the *Schiehallion* turret and the bogies performed their function without incident.

In addition to handling the full crude production, water injection and water injection, gas lift, export and import flows, the swivel system will provide for all ancillary services required on the turret fixed part, including electric power and control, chemical injection, water deluge, and air, for turret equipment room pressurization.

"This 10,000-tonne *Quad 204* turret is the most critical component of the FPSO," stated Jeff Mace, BP's turret delivery manager. The next important milestone, after delivery of the manifold and gantry structures in Korea, will be the mechanical completion of the integrated turret, planned for Q3 2014. BP will manage this process with the assistance of SBM Offshore.

Safety standards based on systematic in-depth analysis and improved reliability for operations are the key enhancements of the *Quad 204* turret mooring system over the original *Schiehallion*. Some key improvements are the riser top-mounted emergency shutdown valves and wind shielding, which could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no longer be one complete structure due to the increased size of the *Quad 204* turret. Improved operability and reliability aspects are key design drivers to improving technology. The mooring force increased due to the larger size of the vessel and therefore larger safety factors, which contribute largely to a higher reliability.

For the installation of the new mooring system in Q2 2014 and the new FPSO hook-up in 2015, the close interface between SBM Offshore teams optimizes both the mooring system and turret ergonomics. It also facilitates the interfaces for delivery of mooring equipment and readiness of the installation spread. The turret design is tied into to the mooring design and to installation requirements: from the pre-tension of the anchor points up to the hook-up of mooring lines, as well as requirements for maintenance and/or change-out.

"This is the most complex turret SBM has ever supplied to the oil and gas industry. The project combines unique skill sets to the industry; turret mooring supply, field life extension, technology development and offshore contracting" says Laurent Agussol, SBM Offshore major project manager. SBM Offshore says it is the only company in the industry that can complete all stages in-house – engineering, procurement, construction and installation.

At the top end of the market, the requirements of complex mooring systems, such as the *Quad 204* turret mooring system, are continually being extended because of deeper water, more severe weather conditions, larger vessels to be moored, higher throughputs, increased pressures and longer design lives. The industry continues to adapt and tailor solutions for safer and more efficient operations offshore, says SBM.

Hotwork repairs

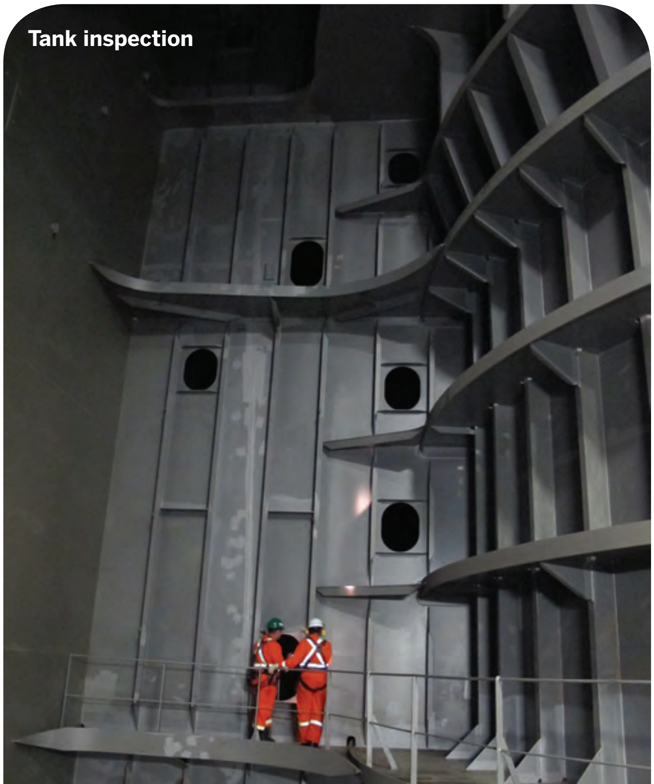
The feasibility of achieving hull structural hotwork repairs on board an operational FPSO was explored in a presentation by Calum MacLean, projects director with Marine Technical Limits. He stressed the importance of forward planning for on-station hotwork repair and demonstrated how major repair work scopes, traditionally requiring completion in a dry dock, can be carried out while the FPSO is producing.

Although, in theory, FPSOs can be taken off station, the reality is that this has huge cost implications and reservoir issues may also make it technically very difficult. Even if the FPSO has a detachable turret, dry docking is likely to result in a minimum of eight weeks off station.

While periodic dry docking can be easily scheduled for sailing ships, FPSO operators are increasingly looking for solutions that will enable them to keep their asset on station and in production for more than 20-25 years. This being the case, it is inevitable that regardless of advances in integrity management strategies, structural hot work repairs will be required on-station.

The relatively small numbers of FPSOs mean that operators may have limited experience with hull structural issues and standard procedures. For example, confined space entry procedure may not adequately address the unique issues presented by working in the enclosed but large space FPSO tanks. Clearly defined procedures are necessary for emergency responses to incidents, IP rescue, fire and muster, isolation standards, boundary hotwork management and tank cleaning.


Tank cleaned and ready for hotwork


Tank inspection

While a great deal of effort is required to put a safe system of work in place and to organize and execute the repairs, MacLean stressed that the effort required to explain to senior management that often repairing a ship by welding cannot be avoided, should not be underestimated.

In principle, preparation for on-station hotwork repair needs to start before the FPSO arrives on station. Operations management teams should account for in-tank welding in the design, as that is certain to happen in the future, but, more importantly in the development of policies and the safety management system for the installation.

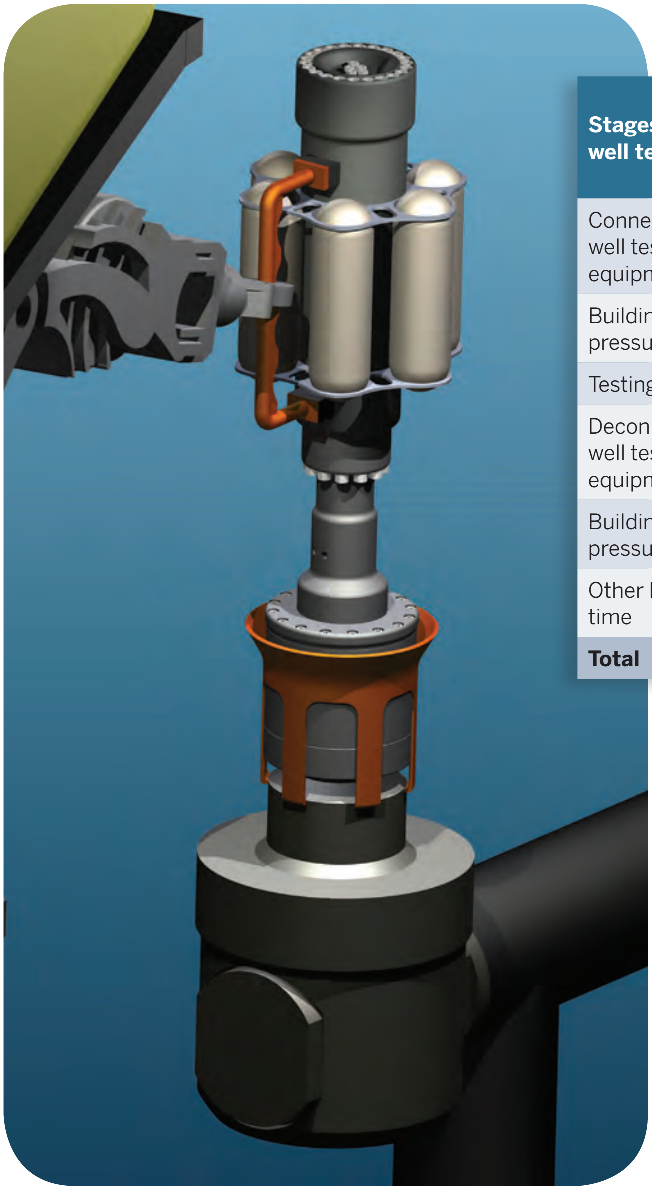
According to MacLean, it was paradoxical to consider that working within the tanks involves work at height and that these very large tank spaces are categorized as "confined spaces." The key to executing hotwork repairs, while in ,production is fully understanding these hazards and developing an appropriate safe system of work for entry and working in tanks.

MacLean concluded that maintaining the hull structure of an FPSO while on station is not impossible if an appropriate level of planning is carried out. There are solutions available for many of the issues which may arise throughout the life of an ageing installation, however, it is wise to fully understand the work involved long before it is necessary to implement it.

In particular, agreeing on and establishing the parameters for a safe system of work within the operating company, partners, contractors, crew, and any other stakeholder needs careful and detailed consideration and can take a significant amount of time. OE

Subsea multiphase sampling

Subsea sampling can help increase PVT accuracy and improve subsea multiphase meter performance. Test lines for subsea well testing cost as much as US$60 million and come with logistical and well intervention challenges. Eivind Gransaether explains.



Computer-aided image of the sampling system. Image: Mirmorax.

Stages in well testing	Time taken (hours)	Time affecting production (hours)
Connecting well test equipment	2 to 4	3
Building up pressure/flow	2 to 4	1.5
Testing	2 to 4	0
Deconnecting well test equipment	2 to 4	3
Building up pressure/flow	2 to 4	1.5
Other lost time	3	3
Total	**9 to 17**	**12**

The steps needed to conduct a well test, and the period of time production is lost. Source: Mirmorax.

The deployment of permanent subsea multiphase meters as an alternative to well testing and as a way to increase recovery has become a priority for many operators.

Subsea multiphase meters are viewed as a more flexible, cost-effective and accurate option, compared to large and maintenance-intensive test separators.

To be effective and accurate, subsea multiphase meters, which can cost up to US$400,000 to buy and integrate, need to be calibrated through quality, volumetric sampling over the field's lifetime.

This is particularly important as fields age and more reservoir variables come into play, leading to an increase in the uncertainty of metering systems. The majority of multiphase meters, for example, use a gamma source that must be configured with the fluid properties of oil, water and gas, and ideally must reflect changing reservoir data over time.

Fluctuations in PVT Data

One of the most important sources for evaluating fluid properties and predicting reservoir performance is pressure, volume and temperature (PVT) data, which is likely to change significantly over the lifetime of the reservoir as fluid and process conditions change.

Changes can include increased liquid and water in the gas flow, higher water cuts, commingled well streams from subsea tie backs, changes in water properties from sea- or freshwater-flooded wells, or differences in salinity between injected and reservoir water.

These changes are likely to result in significant variations in PVT properties. Effective volumetric subsea sampling and the accurate tracking of PVT data can have a positive effect on the meters' performance and operators' production strategies in these cases.

The dangers of inaccurate PVT analysis were outlined in an SPE paper by Adel M. Elsharkawy of Kuwait University (SPE 37441). It illustrated how inaccurate PVT analysis resulted in an underestimation of the ultimate oil recovery from a particular field by as much as 40%.

Well test separators play an important role in capturing PVT data by determining the volumetric behavior of reservoir fluids as they pass through the separator. However, production often has to be ceased in order to conduct a well test, which has a negative impact on the field's economics.

The process can also lead to potential inaccuracies on longer pipelines, and where lower pressures decrease PVT accuracy.

Subsea sampling, the alternative to well testing, has also come with limitations. These include samples being taken randomly and topside; little consideration for flow dynamics; an inability to track and react to fluctuating reservoir conditions, such as high gas volume fractions (GVF), oil in water content and increased salinity; and a failure to maintain original pressure conditions in the laboratory.

Conventional PVT analysis can take weeks to be delivered and can be based on a limited number of samples, which are retrieved through wireline sampling or flow tests. While oil is relatively stable, water conductivity may change between the sample being taken and results received by the laboratory, resulting in questionable accuracy.

Subsea sampling can only be effective if it meets four key criteria:

1. The sample needs to be maintained at its original pressure condition from extraction to delivery to the laboratory.

2. Sampling needs to take place regularly, and repeated on the same well.

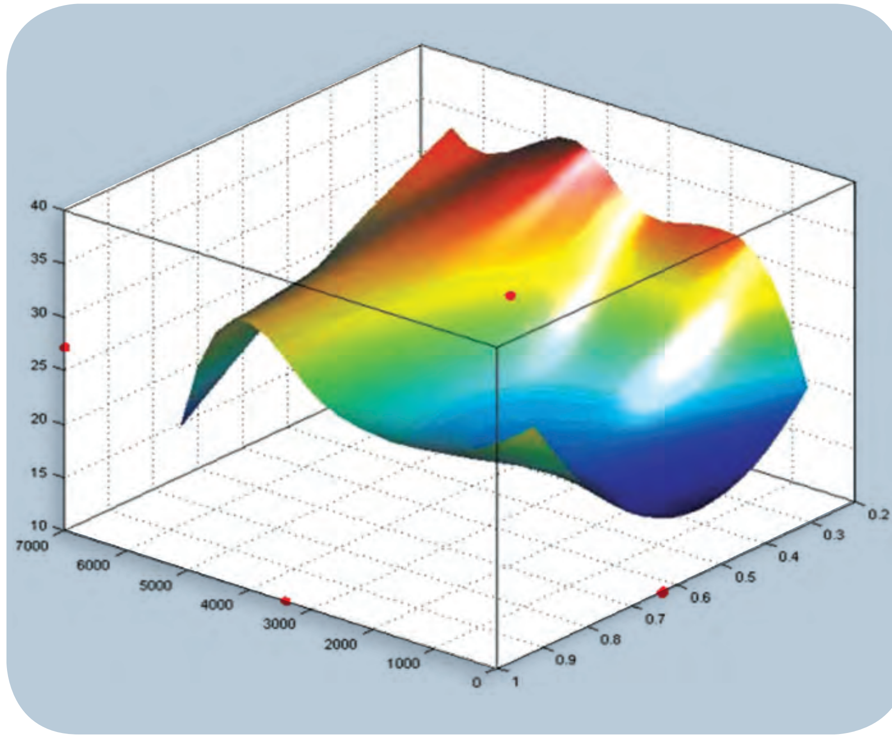
3. Sampling must take place as close to the wellhead as possible, so that samples captured are representative of the fluid flowing through the meter.

4. Sampling must take place without interruption to production, and must generate PVT data and online, on-demand, fractions of oil, gas, water, salinity and density, without the need for subsea intervention.

These criteria have formed the basis for the Mirmorax Subsea Multiphase Sampling System.

It delivers sampling through phase-representative samples and in-situ analysis, which are integrated to allow both fractional and salinity data.

The system is built around a remotely-operated vehicle (ROV) operated docking sampling unit, containing a hydraulic sample extraction system and sampling bottles. Via an ROV, the subsea sampling system extracts and transports the sample into sampling bottles under isobaric conditions and transports them to surface.



This landscape 3D plot illustrates the correlation curve between two core data inputs and the output value. The red point places the 3D plot of the meter in reference at a fixed point, with PVT data then needed to ensure that all values correlate.
Image: Mirmorax.

The operation takes place a number of times on the same well. The operator is able to obtain multiple sample points on one single ROV operation in order to have a fully representative sample over a set period, and to provide the accumulated volume needed to perform analysis topside.

At the center of the system is a permanently installed analyzer module, which consists of a sampler, an analyzer, which reviews the content of the sample, and an electronics control module. If installed subsea, the analyser should be positioned near the subsea choke.

Oil, gas and water fractions can be read directly from the sampling bottles taken at a specific time window, via a BUS communications protocol to a customer control system. This enables the operator to access a phase fractional set of data that can be compared to the metering data for the same time period.

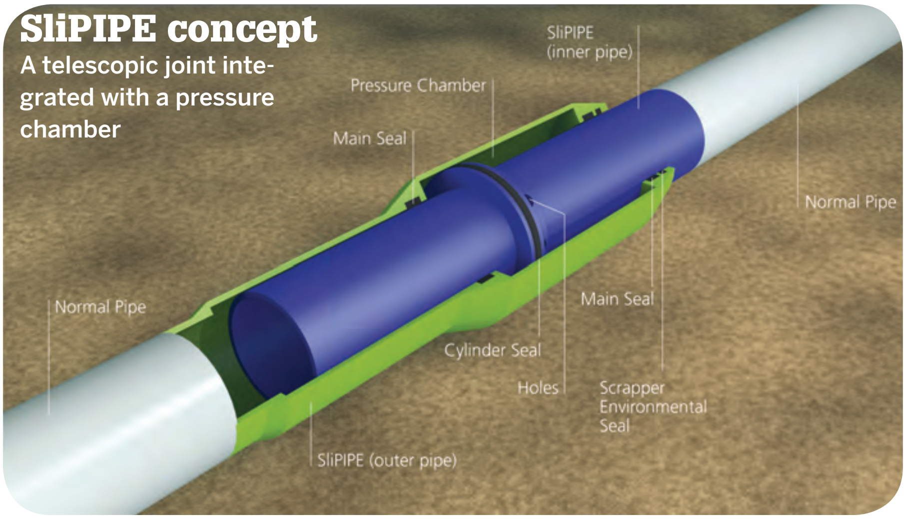
By calibrating this fixed point, at given pressure, temperature and volumetric fractions, the operator can provide the multiphase meter with a fixed point, and increase the meter's accuracy in relation to the pressure and temperature conditions the sample was taken under.

The data generated provides information to the operator when quality checking samples, before they are extracted and transported to surface, and can determine when full PVT compositional analysis is required.

Recent Testing

The system was recently tested at the Christian Michelsen Research (CMR) Multiphase Flow Loop in Bergen, and is now being trialled at Statoil's K-Lab facilities. During CMR testing, the system delivered water liquid ratio results in an absolute error of less than 1% and within a 90% confidence interval. Two salinity levels were also tested on the sampler, with the system able to quantify water salinity successfully. **OE**

Eivind Gransaether *is CEO of Mirmorax AS, which he founded in 2009. Before founding Mirmorax, Gransaether had a number of roles at Roxar (now Emerson Process Management), including commercialization manager and global subsea sales manager. Eivind has a Master's Degree in Marine Science & Subsea Engineering from the Norwegian University of Science & Technology (NTNU).*



SliPIPE consists of an outer pipe connected alongside to a pressure chamber and an inner pipe that can slide inside them. Seals are placed at the contacts between the pressure chamber and the inner pipe.

Dealing with pipeline expansion

DNV GL has developed a new concept to deal with HPHT pipeline expansion design. Chia Chor Yew explains.

Transporting oil and gas through pipelines from high pressure and high temperature (HPHT) reservoirs continues to be a major challenge as the industry pushes into new energy frontiers. This poses greater issues for pipeline systems and their integrity.

Depending on whether the pipeline is fully restrained or unrestrained, HPHT pipelines laid on or buried in the seabed can experience a wide variety of reliability and safety issues. Frictional resistance from the soil can result in a combination of axial displacement, lateral buckling, upheaval buckling, and pipeline walking, to an extent that varies with seabed soil resistance. These pipeline movements can cause failures in the midline, or at the tie-ins connected to the pipeline end, and thus are critical to pipeline integrity.

The ability to limit these effects is vital. Current preventative measures, such as conventional post-lay intervention at midline, rock dumping and the installation of giant spools at the pipeline end, are often time consuming, requiring longer offshore time to accomplish and may be extremely costly.

DNV GL, working with a team of engineers from Singapore, Oslo, Perth and Groningen, developed SliPIPE to control the expansion at the end of a pipeline operating under HPHT conditions.

During development, the team considered comments from the offshore pipeline industry, academia, personnel from two major installation contractors, and a seal company.

At this stage, SliPIPE is conceptual and will require refinement, engineering and qualification before it can be realized in an actual project.

SliPIPE consists of an outer pipe connected to a pressure chamber. An inner pipe can slide inside them.

Seals are placed at the contacts between the pressure chamber and the inner pipe. The inner pipe slides in or out of the outer pipes in response to an axial stress that can either be more or less than a certain value.

The axial stress value is pre-determined in the SliPIPE design and causes an axial tension in the pipe wall to develop, which opposes the effective axial compressive force component arising from the inner fluid pressure.

The axial tensile pipe-wall force is produced by letting fluid pressure in, through holes in the inner pipe, to one side of the pressure chamber, separated from the other side of the pressure chamber by an annular partition wall. As the pressure in that side of the chamber freely builds up, it pushes against the partition wall and the pressurized end of the chamber in opposite directions to one another until an equilibrium is reached.

This in turn develops a tensile force in the pipe wall, which can be scaled to a desired value by pre-sizing the cross-sectional area of the pressure chamber.

Between the outer pipe/pressure chamber and the inner pipe of the SliPIPE are two main seals, a partition wall seal, an environmental seal, and a scraper seal.

Each main seal consists of a pair of chevron seals (made of thermoplastic) and T-seals (made of elastomer) with backup rings, capable of preventing a single failure from causing the loss of both barriers. Other equivalent double barrier seals may be used.

Around the rim of the annular partition, which moves within the pressure chamber, is a set of double T-seals. Each T-seal is reinforced with backup rings on either side and these provide efficient resistance to extrusion of the seals.

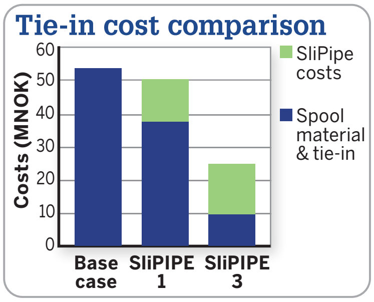
The seals are made of materials that allow them to function at high temperatures up to 150°C and pressures of 100-400 bar. Environmental seals and scraper seals remove marine growth and other contamination on the surface of the inner pipe before it makes contact with the main seal.

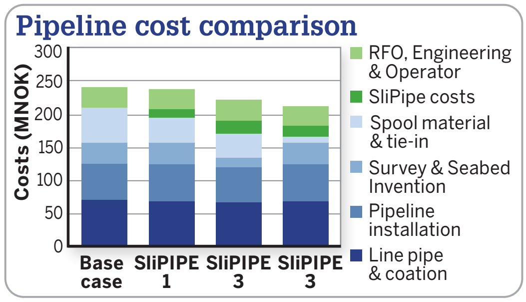
Before use, all seals must first be qualified for HPHT conditions and to ensure the long-term reliability of the seals to function under the frequent two-directional sliding of the surfaces that come into contact with them.

Traditionally, a giant tie-in spool would normally be required to absorb large pipeline end expansion to a level low enough for economic design of the tie-in. Alternatively, or additionally, expensive post-lay subsea intervention work that limits expansi.on would be deployed.

SliPIPE could minimize financial implications by avoiding the spool material procurement costs, handling costs and offshore installation time associated with giant spools. Preliminary cost estimates indicate that direct tie-in of a pipeline with SliPIPE at the ends can lead to potential savings in CAPEX for installing the pipeline of up to US$5.2 million.

This represents an approximate 50% reduction in CAPEX for a conventional tie-in compared to using the giant spool





Base Case – conventional flowline with lateral buckling design and long spools.
SliPIPE 1 – same as base case but SliPIPE at ends and short spools
SliPIPE 2 – same as SliPIPE 1 but lateral buckling design replaced by midline SliPIPE components.
SliPIPE 3 – same as SliPIPE 1 but spools entirely replaced by "direct tie-in".

method, or 10% compared to a typical installation of 10km pipeline using conventional lateral buckling design and tie-in methods.

Several practical issues that will influence how SliPIPE operates have been studied, and ways to overcome these are being looked into.

As a concept, SliPIPE is suitable for installing tie-ins between a submerged rigid pipeline and a subsea well, subsea structure, or riser, typically from 10.75- to 24in (273-610mm) in diameter.

This may be pre-installed on a pipeline end termination (PLET), which is then transported and installed offshore on the end of the pipeline, lowered onto the seabed and connected to a manifold, or riser via a short tie-in spool. A misalignment flange may be included. This is designed to minimize end expansion, external forces, and bending movements acting on it. Alternatively, a direct tie-in (without a PLET and short tie-in spool) is also feasible, with the use of a suitable subsea installation guide.

In the direct tie-in method, SliPIPEs have to be locked to restrict any uncontrolled movement and the lock released before tie-in. SliPIPE must be designed to have at least the same capacity as the adjacent linepipe, which has already been designed to resist the maximum tensile forces and bending movements.

As a relatively simple yet effective alternative to traditional giant tie-in spools and expensive post-installation subsea intervention, analysis shows SliPIPE could potentially offer cost savings in material and offshore installation.

In constructing this concept, DNV GL has taken into account comments from industry and academia to address and overcome challenges around this issue, and is determined to further develop the SliPIPE technology through to commercialization and deployment. **OE**

Chia Chor Yew is head of department, subsea, structures and pipelines, DNV GL Singapore. He has 31 years' experience in structural, civil and pipeline engineering, mainly related to the offshore and marine industry. He has a BSc and MSc in civil engineering from the National University of Singapore.

Flow measurement gets high-pressure treatment


Inside NEL's flow measurement facility.

Scotland's NEL center will launch a new multiphase flow measurement test facility by year's end. A second, able to operate at up to 150bar, is under development. Elaine Maslin paid a visit to learn more.

NEL's laboratories were originally set up in the 1940s, as the National Engineering Laboratory (NEL).

It was one of several large government-funded research laboratories, staffed by scientists and engineers, with a remit to research subjects from early wind turbines to control systems.

While the scope of its once-wide range of activities has become more focused, since it was privatized in 1995, and bought by Germany's TÜV SÜD Group, the research has not stopped.

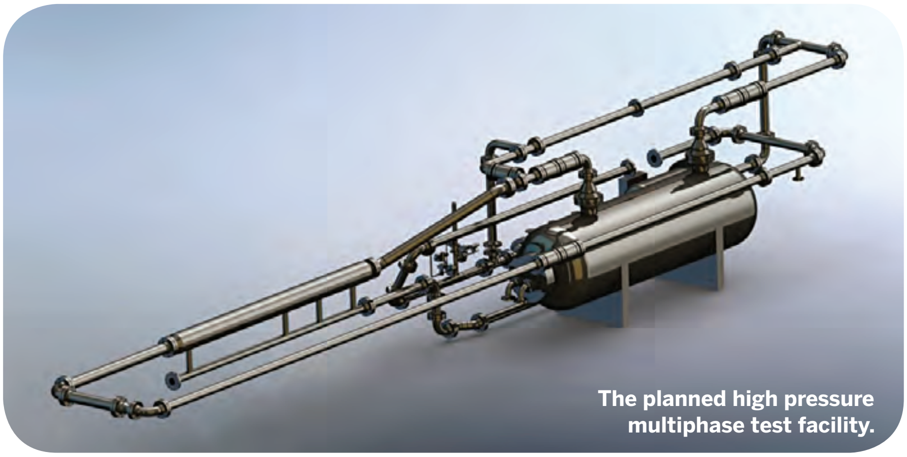
Flow measurement and fluid mechanics are now the main foci for NEL, which holds the UK's National Standards for Flow Measurement and is a United Kingdom Accreditation Service (UKAS) accredited laboratory.

Multiphase metering has been one of its areas of research since the 1980s, and multiphase testing since the 1990s, when the world's first traceable calibration facility was developed.

By the end of this year, the center at East Kilbride, near Glasgow, will launch a new multiphase flow measurement test facility, able to operate at up to 60bar g. Next year, NEL will start construction of a second multiphase facility, able to operate at guage pressures up to 150 bar.

The upgrades are to meet future demand for higher pressure testing and meters verification, because production is moving into deeper waters, says Phil Mark, sales and marketing director, NEL.


We're here...
...to help you
produce from THERE


The planned high pressure multiphase test facility.


Phil Mark, sales and marketing director, NEL

Use of multiphase flow meters is increasing, driven by the need to monitor individual flow streams where fiscal monitoring is required on fields with multiple ownership, and where test separation facilities are impractical or uneconomical. Deepwater and remote facilities are also strong candidates for multiphase metering, for the same reasons.

Developing accurate multiphase flow meters for simultaneous measurement of commingled oil, gas and water streams has long been a key issue for the oil and gas industry, however. Metering inaccuracy, even when marginal, can result in significant errors when billions of barrels are involved.

A key issue is measurement uncertainty. A manufacturer can claim single-figure uncertainties for a multiphase flow meter under certain conditions, but independent experts, including NEL and Det Norske Veritas (now part of DNV GL), suggest 10% would be more optimistic as a practical figure, especially considering the potential for fluid phase properties to change by the second.

Where a test separator is unavailable to verify flow meter results, operators have limited options to verify a flow meter's results.

Uncertainty of a multiphase flowmeter can be claimed to be as low as 2.5%. "If you could get 10% in service you would be doing well," says Richard Harvey, lead multiphase flow engineer, at NEL. "They will have sweet spots, but 10-15% would be a good result."

"Measurement uncertainty is a big issue," Phil Mark says. "You can have constantly varying mixtures of gas, water, oil, fluids and other material going through a pipe at any one time, from all gas to all liquid, and anywhere in between. Take that to the bottom of the ocean, and there are additional complexities. So accurate multiphase metering technology is taking a long time to develop, but it is getting better."

Multiphase upgrade

To create its new high-pressure multiphase facility, NEL converted an existing two-phase (gas/liquid) separator into a gravity-based three phase separator. It operates with nitrogen, water, and oil (Exxsol D80, a kerosene substitute), at up to 60bar g, and typically 20°C, with a gas volume fraction up to 100% and water cut of 0-100%.

Its flow range rate is up to 1800cu m/hr for dry gas, and up to 80cu m/hr for both water and kerosene. The test section, which can be orientated horizontally or vertically, is 18m long and 8in (200mm) in diameter.

The second upgrade will be on a multiphase flow test facility, built around a full-scale three phase test separator, which also provides storage for the oil and water phases. Each phase is pumped as a separated single-phase stream and measured separately before being recombined into a multiphase flow and transported through the test loop. It can be constructed in vertical, horizontal or inclined piping configurations.

The current facility operates at pressures of 0-15bar g, but the new facility, currently being designed by NEL, will increase this to up to 150bar. Temperatures can be 5-40°C on 1-6in. line sizes with a 30m test section, or 10m when in a horizontal configuration.

The facility will operate with crude oil (API 30) at up to 145cu m/hr (22,000bbl/d), salt water at the same rate, and nitrogen gas at up to 1500cu m/hr (1.3MMcf/d), at gas volume fraction (GVF) and water cuts of 0-100%.

Both facilities are to be used for testing and development as well as performing certification, factory acceptance and calibration services.

NEL determines the performance of a meter by measuring the single-phase flows to a very low uncertainty, and combining the understanding of different multiphase flow regimes at the given process conditions. Based on its UKAS accreditation, liquid phases are measured within 1.5% uncertainty for gas under most conditions, and within 1% for liquid, which ensures that we can assess multiphase flow very well and to a traceable standard, says Muir Porter, business manager, NEL.


Muir Porter, business manager, NEL

The overall "uncertainty budget" consists of the summed uncertainty of measurement of various controlled elements of the process, including temperature, pressure, physical properties, and accuracy of secondary instrumentation.

"It is not possible to test flowmeters under the variable conditions they will see in the field, but we can measure them under very precise conditions through very careful control of the single phases," Porter says. "We know how multiphase fluid flow regimes can change according to flow rate, gas volume fraction (GVF), pressure, temperature and even in-line disturbances and installation effects."

Erosion and research

NEL also has a recently opened erosive flow test facility, and is involved in a number of joint industry projects (JIPs), from temperature and pressure effects on Coriolis flow meters to sampling needs for water-in-oil.

NEL's High Viscosity Fluids JIP recently completed and resulted in the upgrade of an existing facility at NEL to allow it to test viscous fluids up to 1500 centistokes (cSt).

To date, the most appropriate technologies for viscous flow measurement have not been defined, NEL says.

The JIP saw established flowmetering technologies (Coriolis, Venturi and ultrasonic devices) evaluated across a Reynolds number (Re) range of

200–100,000 at kinematic viscosities of 20cSt, 100cSt, 175cSt, 300cSt and 500cSt.

A second stage of test work addressed gas entrainment, which has the potential to lead to substantial mis-measurement, at a kinematic viscosity of 500cSt with a GVF range of 0-5%.

The research found that viscosity effects are significant and must be taken account, as most meter technologies have a high dependence on Reynolds number, particularly at low Reynolds numbers.

They must be calibrated at the viscosity/Reynolds number range they will be operated at. Pressure drop is significantly higher than for conventional oils, and therefore means meters are more costly to operate.

"Alternatively, they are oversized (to reduce velocity and hence pressure drop). However, this means they are operating at the low end of their turndown, i.e. the place they are most inaccurate—it's a balancing act," NEL says.

Recently, the Temperature and Pressure Effects on Coriolis Flow Meters JIP was launched, with participation from Shell, BP, Nexen Petroleum, ConocoPhillips, Talisman-Sinopec, TAQA, and CNR. It is due to complete next year.


NEL's laboratories at East Kilbride, near Glasgow.

NEL says the standard practice for calibrating Coriolis flowmeters for the oil and gas industry has been to match the fluid viscosity and, if possible, the fluid temperature and pressure.

However, matching all parameters is seldom possible, due to the limitations set by the calibration facilities test fluids. Because of this, the parameter that is most often matched is the fluid viscosity.

A limitation of this approach is that temperature and pressure variations are known to influence properties, other than fluid viscosity, that may also be critical to measurement uncertainty.

Although there has been some research into the performance of Coriolis flow meters at high temperature and pressure, only a small amount of independent and traceable data exist on certain meter types and diameters. The JIP will look at the performance of Coriolis flow meters with onboard temperature and pressure compensation to provide traceable data. OE

Advanced epoxy coating can be used for coating all subsea equipment, including jumpers. All images: Bredero Shaw

Subsea custom coatings

By Suresh Choudhary, Adam Jackson, Paul Kleinen

Bredero Shaw discusses the various factors and challenges behind high-temperature subsea custom coating.

Due to the increased technical requirements within new well development, the proportion of subsea products requiring insulation suited to high-temperature operating conditions is increasing. It is required to thermally insulate not only the field joint area of offshore pipelines, but also various custom fabricated parts of subsea production systems, such as bends and spools, pipelines and terminations (PLETs), jumpers, goosenecks, etc. Any new product for high-temperature insulation must not only perform at the desired temperature ranges, but also easily assimilate into the contractors' technology and process. This includes application processes, installation procedures, and cycle times to properly fit the work flow, which adds a high level of difficulty to the product development process.

Challenges of existing solutions for custom coating and field joints

The existing solutions for custom coating and field joints include polyurethane (PU), injection-molded polypropylene (IMPP), and syntactic epoxy-based, silicone-based, among others. PU and IMPP are widely used for insulating subsea production structures and field joints. PU-based systems are best suited to low-temperature applications (<80°C) and generally have problems with hydrolysis at higher temperatures. IMPP-based systems have been used in harsh environments with operating temperatures up to 150°C, but prove to be expensive for mid-range temperature (80-120°C) applications.

Although a very popular insulation material for subsea structures, PU is not suitable at higher temperatures due to hydrolysis, poor adhesion to polypropylene and other thermoplastics, and high dependence on mix ratio. Existing systems face other challenges such as long demold times, high exothermic energy release, and cracking under casting.

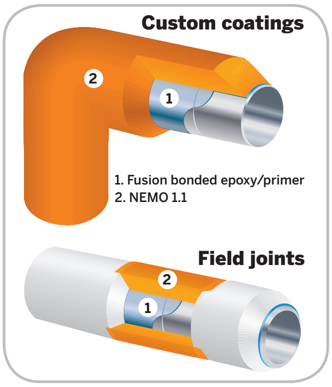


Fig. 1: **Cross section of NEMO 1.1 — operating temperatures of up to 95°C.**

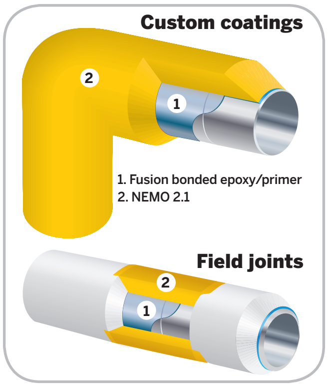


Fig. 2: **Cross section of NEMO 2.1 — operating temperatures of up to 120°C.**

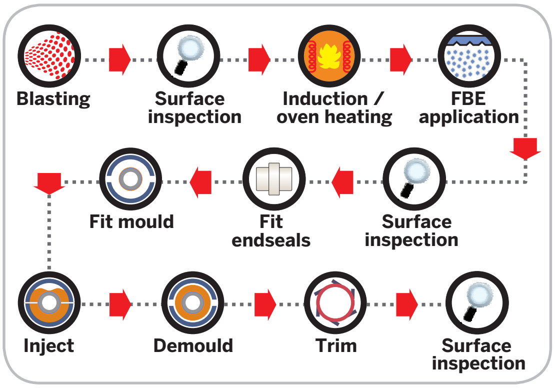


Fig. 3: **The NEMO system coating application process.**

There have been attempts to formulate high-heat, hot-wet polyurethane systems, but this led to relatively stiff and low-ductility products.

Advanced epoxy chemistry solution

Proper selection of insulation material can offer significant advantages in terms of reduced risk and reliable continuous operation of the subsea production structures. In order to achieve this goal, the new chemistry uses a two-pronged approach that combines superior material chemistry and ease of application.

The advanced epoxy chemistry lowers the heat released during the curing reaction and the material remains ductile during installation. This low-curing exotherm also provides better cast-to-cast bond strength.

The formulation also allows for a subsequent in-service cure to a product with further enhanced hydrothermal stability, under the effect of the process heat experienced during operation. The high hydrothermal stability at elevated temperature ensures reliable mechanical performance over the field life, while the low water absorption of the material provides stable and predictable thermal performance. The solid material is also incompressible and performs well under high pressure, guaranteeing stable thermal performance of the applied coating.

Finally, the residual reactivity of the material provides high bond strength to flame/corona modified polystyrene/polypropylene and unmodified polyurethane, and enables its use in a wide range of applications.

The flexibility of the application process allows it to be used in various configurations – on spoolbases, fabrication yards or offshore on pipelaying vessels. The application process utilizes standard equipment as used in PU systems and personnel can be easily trained.

Table 1: Mechanical and thermal properties of the NEMO system at ambient temperatures

Property	Standard	Typical values		Unit
		NEMO 1.1	NEMO 2.1	
Mechanical properties				
Initial modulus	BS ISO 37:2005	>110	>550	MPa
2% secant modulus	BS ISO 37:2005	>110	>500	MPa
Tensile strength at break	BS ISO 37:2005	14	30	MPa
Tensile elongation at break	BS ISO 37:2005	>100	>30	%
Uniaxial stress at 5% compression	BS ISO 604:2003	>4	>15	MPa
Density		1040	1150	Kg/m³
Hardness (fully cured)	BS ISO 7619 - 1:2004	>50 (Type D)	>65 (Type D)	° Shore
Hardness (demold)	BS ISO 7619 - 1:2004	>55 (Type A)	>50 (Type D)	° Shore
Thermal properties				
Thermal conductivity	ISO 8301	0.195	0.185	W/m/K
Specific heat capacity	ISO 11357-4	1800	1700	J/kg/K

Table 2: NEMO system mechanical properties

Property	Typical value		Unit
	NEMO 1.1	NEMO 2.1	
Interface adhesion to polypropylene/polystyrene/polyurethane	>5	>5	MPa
Interface adhesion to itself	N/A	>15	MPa
Ring shear adhesion	>8	>8	MPa

NEMO coatings for specific needs

Network epoxy modified olefin (NEMO) is an elevated-temperature insulation product that can be easily applied for subsea custom coating and field joint application. The NEMO product family currently comprises NEMO 1.1 and NEMO 2.1 and can be used on applications up to 120°C (tests are ongoing for 130°C and 140°C).

NEMO 1.1 is an epoxy-urethane hybrid system, developed for subsea pipeline and structure installation. It is a plural component suitable for low-pressure casting applications. It can be used up to a maximum continuous operating temperature of 95°C. NEMO 1.1 material overcomes the challenges associated with traditional PU systems and at the same time allows for cycle times similar to PU systems (Fig. 1).

NEMO 2.1 is an epoxy-olefin hybrid system, allowing processing speed and demold times comparable to PU. A novel latent additional cross-link system provides high ductility for deployment. In-service curing allows the formation of a highly cross-linked system, capable of handling continuous operation of at least 120°C. The molecular architecture provides improved hydrolytic resistance in the subsea environment, while ensuring a good bonding to adjacent olefinic, styrenic and urethane-based wet insulation systems (Fig. 2).

The system can be applied to fusion bonded epoxy (FBE) or to a suitable

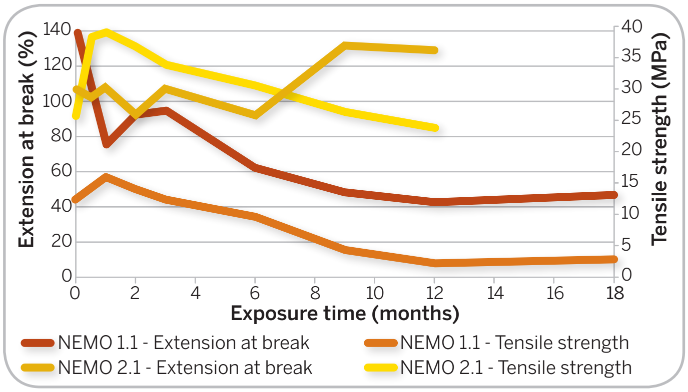


Fig. 4: Aging tests for NEMO 1.1 at 95°C and NEMO 2.1 at 120°C.

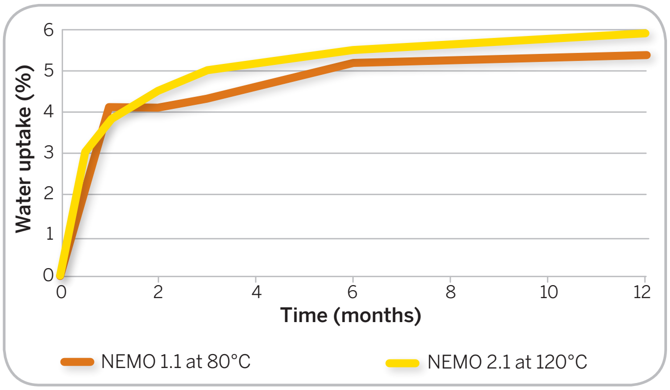


Fig. 5: Water uptake in NEMO 1.1 and 2.1 during hot-wet exposure at 80°C and 120°C, respectively.

Fig. 6: **Shore A Hardness Durometer is used to measure the hardness of the joint after demold time and after 24hr. The acceptance criterion is ≥55 at demold and 90±10 Shore A after 24hr.**

Fig. 7: **A 100mm x 100mm test specimen of NEMO 1.1 was immersed in the water bath at 80°C for 48hr. There was no edge disbondment and passed the acceptance criteria with Rating 1.**

Fig. 8: **A 100mm x 100mm test specimen of NEMO 1.1 was setup for a cathodic disbondment test for 28 days at 95°C in 3% NaCl solution and -1.5V. The average disbondment was 8.8mm and met the acceptance criteria of ≤20mm.**

Fig. 9: **Two series of six plaques measuring 150x45x13mm were machined from NEMO 2.1 material to establish the elastic modulus of the material. Tensile bar dimensions were as per ASTM D638-03 Type IV.**

primer. The surface preparation steps are same as for PU or IMPP systems. A mold is placed over the field joint or the subsea structure and NEMO material is injected into the annulus. The exact demold time is specific to the dimensions of the field joint but can be as low as six minutes (Fig. 6). The excess material is trimmed and the surface is inspected for quality (Fig. 3).

Technical performance

Mechanical and thermal properties of the cured system are given in Table 1.

The mechanical performance of the system has been verified through interface adhesion testing, system to substrate testing and cast-to-cast interface testing. Values at ambient temperature are given in Table 2.

Mechanical performance of the field joints was verified through simulated reeling testing, where a 60 mm FJ on a 10.75in.-diameter pipe was successfully reeled (4 cycles) with no incident at 0°C on a 7.6m radius former.

NEMO 1.1 and 2.1 were exposed to 18 months and 12 months, respectively, of aging under hot-wet conditions (95°C for NEMO 1.1, 120°C for NEMO 2.1). The properties of the system were measured at various intervals during the testing.

For NEMO 1.1, Fig. 4 shows the same trend as can be seen in polyurethane materials: a period of plasticization due to water absorption leads to a reduction in tensile strength and a reduction in ductility. After a period of 10 months, NEMO 1.1 entered a plateau state with no further loss in ductility or tensile strength (Fig. 9). For NEMO 2.1, Fig. 4 also shows an initial increase in tensile strength due to continued bond formation. This is followed by the effects of plasticization in the material, and reduction in tensile strength close to the initial value and approaching a plateau phase. The ductility of the material to this point is sustained or even slightly increased during the exposure period.

In conventional PU systems, high water uptake results in loss of thermal and mechanical properties. The uptake of water in the NEMO system has also been measured over time. The results are shown in Fig. 5. Limited water uptake at higher temperature is one of the key advantages that NEMO has over the PU systems.

Additional tests were conducted on the NEMO system, including the hot water soak test (Fig. 7) and the cathodic disbondment test (Fig. 8).

Conclusion

NEMO is tailored to meet the increasing technical demands of new well developments that require subsea products to operate continuously and reliably at higher temperature operating conditions. Based on technical performance, NEMO helps meet the performance void created by problems associated with the PU systems and offers a reliable solution for 80-120°C temperature range. OE

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***Dr. Adam Jackson,** Vice President of Technology for global flow assurance, is the technical authority for the development of new products in the flow assurance group. Adam has a Ph.D. in chemistry from the University of Hull, UK. He is based in Orkanger, Norway and has more than 25 years of experience in materials technology for the offshore oil and gas industry.*

***Paul Kleinen, P.E.**, Vice President of Engineering and Technology, is responsible for capital projects and process technology at Bredero Shaw. Paul earned a BS in civil engineering from the University of California, Berkeley and is a registered professional engineer in California.*

Exploration challenges in Arctic

The Arctic hosts harsh environments, minimal daylight and HSE concerns. Anthresia McWashington examines a case study and explains the data acquisition methods necessary to explore in one of the world's most brutal regions.

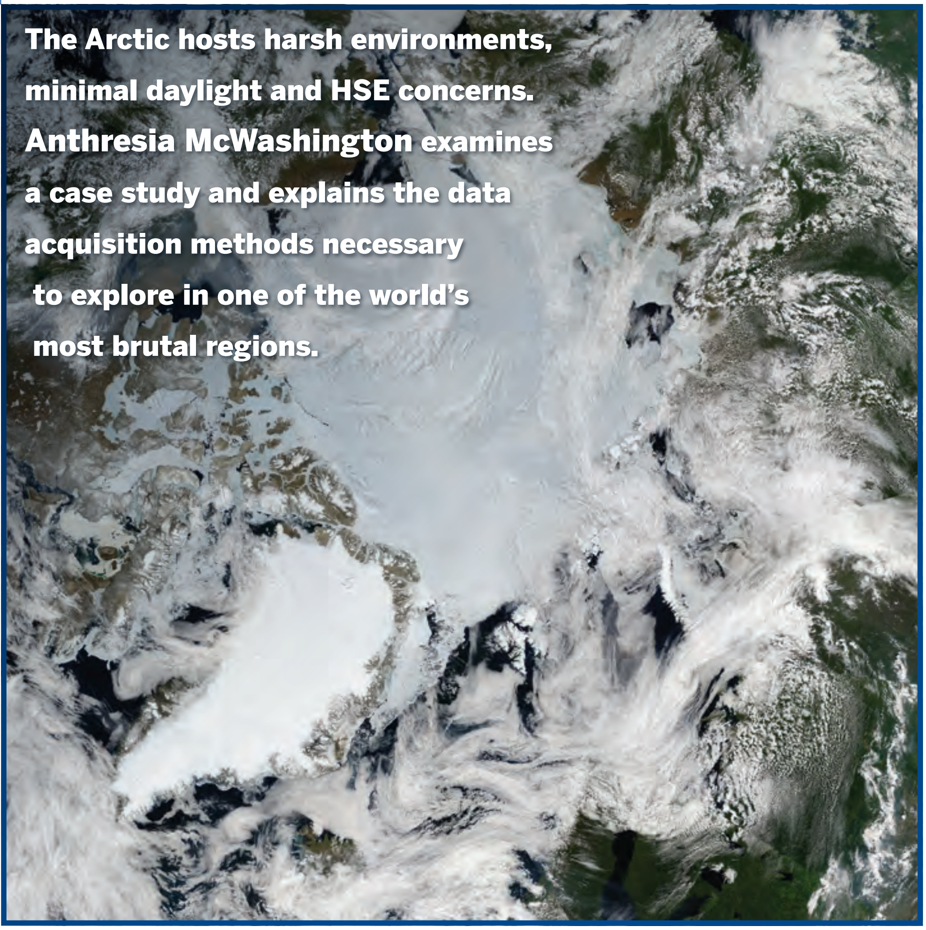


Photo: NASA

Exploration challenges in the Arctic stress the need for more robust methods of oil extraction from these harsh areas. Innovative technology, coupled with more accurate methods of data acquisition, has benefitted efforts to locate and recover more resources from these rigid, wintry conditions located across the globe.

Alaskan North Slope

Acquisition of seismic data in the North Slope of Alaska can only be executed when there is a sufficient covering of snow in the region. Because of this, the season is limited to the first few months of the year, which drives the need for detailed project planning to maximize and ensure the accuracy of the data recorded.

For years, the preferred method of data acquisition in the region has been seismic vibroseis, which permits data retrieval in deeper targets that form the majority of Alaskan oil and gas production. Now that operators have begun looking at pay zones in the Brookian sectors above the classic plays, high-productivity techniques are required to complete programs of adequate size within the available operations window, in order to image these shallower zones.

The weather challenges of the region dictate the method of exploration. The North Slope has an abbreviated summer, that occurs from July to September, and allows for offshore exploration in the accompanying open water. Onshore exploration can take place beginning around December, and ending around May. During this period, there is a sufficient snow coverage that allows vehicles to traverse the ground without damaging the tundra.

Between February and April 2012, CGGVeritas acquired the first production high density, high productivity vibroseis survey on the North Slope. This survey was executed successfully without increased HSE risk exposure. Some of the goals of the project included improving imaging of the mid and deeper sections these previous surveys had targeted, which meant changing the standard acquisition model used on the North Slope.

Using slip-sweep techniques allowed for an increase in trace density, while keeping equipment and manpower manageable. Slip-sweep acquisitions are common in North Africa and the Middle East, but new to Alaska (Rosemond, 1998, Sambell, 2010).

Data results highlighted the benefits of higher density and wider source frequency range. The source line spacing reduction helped shallow target imaging, while tighter source intervals and smaller arrays preserved high-frequencies and fully sampled the noise. The broadband data, with added low-frequency content, penetrates to deeper targets, improving illumination and thin bed separation through the inversion process (Winter, Maxwell, Schmid, Watt, 2013).

According to CGG, as seismic technology improves, tighter geometries and efficient seismic acquisition should become the norm on the North Slope, delivering better imaging while respecting and preserving the environment.

Labrador Basin

Exploration in the Labrador basin is in the midst of transitioning from the shelf to the deepwater region, following the progression of exploration in similar settings. Nalcor Energy investigated how analogues can be used to understand the pressure organization in the un-tapped areas of the Labrador basin in Canada.

The vigorous use of analogues is necessary to understand the pressure history in this frontier area. Analogues can also be used to provide insight into the petroleum system, in terms of seals, migration and fluid flow. Using analogues such as the Mid-Norway shelf to deepwater transition can aid safe drilling within the Labrador basin. Significant discoveries can be made in these deepwater settings, including the deep-sea Nise formation fan reservoirs.

The Nise formation consists of deep-sea fan deposits that are combined locally so that overpressures in the aquifer are the same or similar, and are considered to form part of the hydrodynamic system, despite the deep burial depth. In more stratigraphically-isolated areas of the fans, overpressures can be similar to the encasing shale pressures. These differential pressures, similar to deepwater complexes found in the Labrador region, enhance seal capacity and create opportunities for hydrodynamic trapping—reducing hydrocarbon permeability to near zero. The Base Tertiary Ormen Lange reservoir is hydrodynamic, with a tilted contact, affecting estimates of reserves and development of the field.

Mud weights in several Labrador Shelf wells are low, but there are instances of high kicks taken, suggesting that the pore pressure regime was misunderstood and the wells may have been drilled underbalanced. Many basins in Eastern Canada, such as Jeanne d'Arc, Flemish Pass, and Orphan, are similarly associated with kicks. This approach could possibly be used in the Labrador basins to give an indication of shale pressures, based on picking the seismic Base Tertiary reflector.

Oil Spill Detection Under Sea Ice

Arctic freshwater ecosystems' rapid response to climate changes, over the last 50 years, has caused thinning of lakes and rivers during seasonal ice cover. This increases winter-water supply for industrial withdrawal, and permafrost degradation.

The radar development team at Boise State University (BSU) custom-designed a ground penetrating radar (GPR) system of a higher grade than the commercial products currently available. The new system operates in a frequency range optimized for measuring oil under sea ice with antennae designed to increase the directionality of the transmitted signal.

The GPR project focused on the development of new hardware for higher-powered, directional radar systems that can be tested in arctic field environments using light helicopters. The goal of the project was to expand the operating window for oil detection with GPR, to cover a wider range of sea ice and climate conditions, extending to thicker and warmer ice sheets in late winter.

Tests done on crude oil spilled underneath an artificially-grown 92cm-thick ice sheet at the US Army Cold Regions Environmental Laboratory (CRREL) in New Hampshire, and over natural sea ice ranging between 1.7-2m thick off Prudhoe Bay, revealed weak currents within the underlying water body can produce strong anisotropy in the sea ice crystal structure. Containment skirts inserted during ice growth appeared to alter water circulation patterns. Similar effects were also experienced in natural sea ice and were noted for utilization in future radar design and operation.

Following completion of the radar surveys, CRREL personnel recorded the temperature and salinity of the ice, ice thickness, oil thickness, and the distribution of oil through a series of cores and drill holes. When a hole was drilled completely through the sample sheet of ice, it was possible to detect the bottom of the parent ice (at the time of the spill), and the top of the new ice layer, which measured the depth of the oil layer. This made it possible to distinguish between drill holes encountering oil and drill holes that did not.

According to a report from the CRREL, the utility of the system could be improved by developing a third prototype based on what was learned from the trials. Increasing oscillator frequencies and reducing levels at critical mixers will both increase the order of the spurious products, reduce their magnitude—which will move them further from frequency and amplitude regions that could result in false responses. OE

Drilling in the Barents Sea comes with wintry conditions—life aboard the semi-

Frosty prospects

Plans for arctic exploration and development continue apace—but will there be resources available? Elaine Maslin reports.

The size of the arctic offshore challenge is significant, both in scale and complexity, with relatively little activity carried out to date.

Technology, resources, environmental protection and project economics, not to mention the harsh conditions, are just some of the challenges faced by operating in arctic regions.

In some cases this has led to projects delays and cost overruns, however, activity continues.

To date, acreage has been offered under license off the US state of Alaska, Canada, Greenland, Norway and Russia.

The largest acreage offered has been off Russia, at 1.5 million sq km, or 77% of the total, most of which is in the hands of Rosneft, says Geir Utskot, arctic manager, Schlumberger.

"To put this into context, the total size of the US Gulf of Mexico is 445,000sq km, and of this area, only about 155,500sq km has been licensed," he told the recent SPE Arctic & Extreme conference in Moscow. "The entire Gulf of Mexico could fit inside the Kara Sea and is roughly equivalent to 5% of the arctic region."

Exploration

Drilling has been undertaken in the Barents, Baffin Bay, and Chukchi Seas. Seismic acquisition has been carried out in the Kara, Barents, Laptev and Chukchi Seas.

Most of the drilling has been offshore Norway, with more than 20 wells in the last three years, compared to two wells off Greenland and one off Russia, according the Maxim Nachaev, director, consulting/Russia, IHS Cera.

Most recently, OMV opened a new oil play, with its Wisting Central discovery in the Hoop area in the Barents Sea. Activity levels are expected to remain high, following the award of licenses in the 22nd round, and plans to open the Barents southeast area in the next licensing round.

More than 40 wells are likely to be drilled in the arctic by 2020, depending on the economic situation, said Nachaev, who also spoke at the SPE Moscow event.

Among those planning to drill in the region in 2014 is Statoil, which plans to drill two operated wells in the same area as Wisting Central—the Atlantis and Apollo prospects, along with further appraisal drilling around the Johan Castberg fields (Skrugard/Havis).

To date, Shell has yet to confirm if it will go ahead with a drilling program in the Chukchi Sea, offshore Alaska,

submersible ***Polar Pioneer*** **during drilling on Skrugard.** Photo: Harald Pettersen, Statoil.

Transocean's semisubmersible *Polar Pioneer* facility was used to drill on Skrugard in the Barents Sea and is lined up to support Shell's potential 2014 drilling campaign in the Chukchi Sea. Image: Harald Pettersen, Statoil.

in 2014. Last month [November], the company submitted revisions to its previously approved exploration plan, in order to "keep the company's 2014 exploration options viable."

ExxonMobil, in partnership with Rosneft, plans to drill in the Kara Sea in the summer of 2014, Utskot says. Cairn Energy, with joint venture partners, has yet to determine (as of press time) whether the Pitu prospect will be drilled in 2014.

Development

Currently, there are four groups of projects being developed in the arctic, Nachaev says.

These are: the Snøhvit (Snow White) field in the Barents Sea; fields developed through inclined drilling in Russia; Prirazlomnoye, in the Pechora Sea, Russia; and fields in north Alaska, also developed through inclined drilling. Of those, only Snøhvit, a 140km subsea tieback to shore, and Prirazlomnoe are offshore.

Next year, ENI's Goliat oil field is due to come on stream. It will be the first Norwegian Barents Sea oil development, produced through a subsea development connected to a Sevan floating production system.

Goliat was due to be followed by the Barents Sea Johan Castberg development, previously known as Skrugard – Havis. Operator Statoil recently said it was delaying its investment decision, setting likely first production back from 2018 to 2020, Utskot says.

In the Russian sector, the Shtokman project has been repeatedly set back, due to low gas prices. Statoil pulled out of the project in 2012.

Delays

All arctic projects, on- and offshore, endure huge delays in all phases, from exploration to commissioning, Nachaev says, with projects taking 10-25 years to be brought onstream. Budgets have also been extended, by factors of two to three, and even four, of the original plan.

Prirazlomnoye, for example, was budgeted at under US$1 billion in 1996. The final cost is about US$4 billion, four times higher than the original estimate, Nachaev says. "This is not unique," he says, pointing to delays and cost overruns offshore Norway.

"Most arctic fields take about 40 years to get to production," says Utskot, including dates for some early Canadian onshore developments. Norman Wells, onshore Canada, took 64 years from discovery, in 1921, to production. Offshore, Snøhvit took 23 years from discovery to first production, Goliat will have taken 14 years when it comes onstream next year, while Shtokman, if it comes online

Discovery to production dates and estimates of onshore and offshore arctic developments, presented by Geir Utskot, Schlumberger.

Country	Field	Discovery	Start development	Start production	Discovery to production
Canada	Norman Wells	1921	1980	1985	64
Canada	Ben Horn	1974	*1980*	1985	11
Canada	Amauligak	1984	*2023*	*2027*	43
Norway	Snøhvit	1984	2002	2007	23
Norway	Goliat	2000	2012	2014	14
Norway	Skrugard/Havis	2011	2016	2020	9
Russia	Shtokman	1988	*2016*	*2022*	34
Russia	Bovanenkovskoye	1971	2008	2012	41
Russia	Tambeyskoye	1974	2011	2018	44

*Italic numbers are estimates

An artist's illustration of Sevan floating production unit being built for ENI's Goliat field in the Barents Sea.
Courtesy ENI.

Shtokman, facing delays.

in 2022, its latest estimated date, will have taken 34 years.

Not all projects take so long. "Bent Horn [onshore Canada] was put on production very fast in arctic terms [11 years]. The idea was for it to power a mine in the high arctic," Utskot says. "Skrugard-Havis [Johan Castberg] will be a fast development [nine years], even when delayed to 2020, because Statoil has developed a plug and play system for fields with specific parameters."

Resources

The level of resources required for operating in the arctic could be hindrance to activity in the icy region.

Shell's 2012 Alaska drilling campaign involved 22 vessels and 2000 personnel, Mitch Winkler, manager, arctic, Shell International Exploration and Production Inc., told SPE Arctic & Extreme. "There are not that many vessels available offshore Russia," says Utskot. The number could be reduced to 10, using purpose built vessels, but without them the vessels available have to be used, which means more are needed, he says.

Russia, where a majority of the estimated arctic resources are predicted to be found, has a number of ice-breakers under construction, but the country does not have a significant offshore support vessel operator, because of the limited offshore operations carried out to date, Mikko Niini, managing director of Finland's Aker Arctic says. Longer term, Niini, who also spoke at SPE Moscow event, predicts the existing small operators could be built up, or a global player could establish operations in the region.

Before then, the level of resources could be tested. "Next summer ExxonMobil will be drilling in the Kara Sea, and this is going to take up a lot of the resources," Utskot says. Norway's Westshore predicts vessels could leave the North Sea and Norwegian Sea to meet the demand, with up to 12 support vessels required for the Kara 2014 drilling campaign.

ExxonMobil has a contract to use the West Alpha semisubmersible in Norway/Russia from August 2014 to July 2016, on a US$527,000 day rate, with an option out to July 2017, at a higher $549,000 rate.

Utskot says there is reason to believe there will not be as much activity as hoped in Norwegian sector, due to lack of resources, specifically rigs, qualified to work in the area, exacerbated by some of those resources moving to Russia.

Project economics, specifically where the resource is gas, will also hold projects back, Nachaev says. While gas is cheaper in other regions, such as the US, due to shale gas, expensive offshore Russian arctic gas will be held back.

Low gas prices have not helped Russia's Shtokman development. A second phase at Snøhvit is on hold awaiting additional reserves to underpin its viability. Johan Castberg was due to come onstream in 2018 but its first production date was set back by Statoil earlier this year, due to uncertainties related to the resource estimate and investment level and an increase in petroleum taxation levels by the Norwegian government.

The Federal government in Russia is considering tax breaks for projects on the arctic shelf, Nachaev says. The proposal is for the rate to be set at between 1-30%, with gas in the most difficult seas receiving the minimum 1%, starting January 1, 2016, on new offshore fields.

Despite this, major production in the Russian arctic shelf will not start until after 2025, he says, due to international markets, with production ramping up after 2030.

Changing the tax rate will be important to incentivize investment, he says. However, although the reduced rates for new fields have been proposed, the tax system in Russia has been very volatile, he impeding confidence. Localization requirements and insufficient logistics capability also provided limitations.

Public acceptance is also a requirement for arctic operations, says Statoil's Helge Lund. "These days we have to own up to a fair amount of public skepticism about our industry, and especially surrounding increased activity in the Arctic," he told the recent Arctic Safety, Managing Risk in the High North conference in Norway.

"So, to succeed in these areas, we have to embrace an approach that is prudent and demonstrates that we can exploit resources responsibly. I believe we are best served by maximum transparency in and understanding of our activities." OE

FURTHER **READING**

Read more on www.OEDigital.com - The arctic technology challenge, Russia's arctic production needs, Arctic exploration challenges.

Arctic resources

- More oil-prone than gas-prone
- High potential, high uncertainty
- Key role in long-term global energy supply?

400+	discoveries
200+	BBOE proven
~150	BBOE yet-to-find

Untested opportunities

E&P majors BP and Statoil presented their views on future exploration prospects in the Arctic. Meg Chesshyre reports.

Representatives from BP and Statoil discussed both the challenges associated with and future plans for developing Arctic properties at a conference held at Imperial College London this fall.

"The biggest issue for international oil companies, in terms of Arctic exploration, is the public response, both to the exploration itself and to the companies that work there, according to Dr. Michael C. Daly, BP's vice president of exploration.

"The Arctic is perceived as the last pristine part of our planet," he told the event, called told the event, called 100 Years and Beyond: Future Petroleum Science and Technology Drivers.

"The Arctic has specific technical challenges to overcome. In particular, the industry should seek to assure proper oil spill response capability in ice-bound marine environments. Yet many of the owners of the Arctic waters and the

Statoil— The Barents Sea

"The Barents Sea seems to be finally taking off, 30 years on into the exploration of the province," Tony Doré, Statoil senior advisor and a member of the international exploration management team, told the conference.

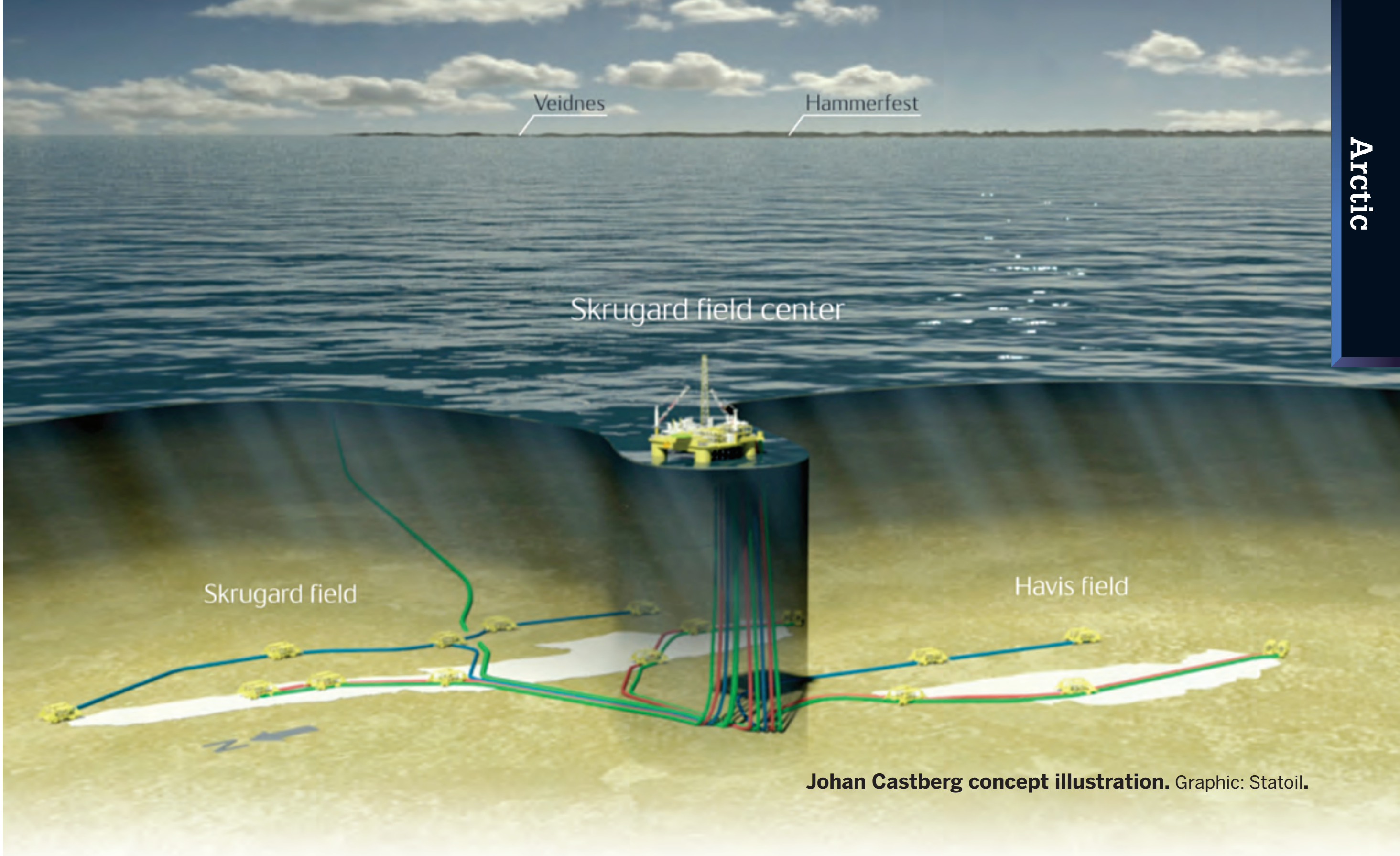
Statoil made the Skrugard discovery in 2011, and the Havis discovery in 2012, in the western part of the Barents Sea. This is now classified as one province—Johan Castberg, containing 400- 600 million bbl of light oil—and it is a potential hub for other discoveries. Two more very different oil discoveries were announced this year—Tullow's Wisting (7324/8-1), in which Statoil has a 15% stake, and Lundin's Gohta (7120/1-3).

Giving an overview of recent activity in arctic waters, he said Cairn has been drilling an eight well program off West Greenland, from 2010. The Norway-Russian border settlement in Barents Sea came in 2010, allowing exploration in that area. The East Greenland licensing rounds were in 2012 and 2013. Norway followed up with a successful Barents Sea licensing round last year. Then there have been big license awards in Russia—a landmark award to an ExxonMobil joint venture with Rosneft in South Kara Sea in 2011, with the first well due to be drilled there next year, followed by Statoil and ENI agreements with Rosneft in the former Barents disputed zone in 2012. The biggest award, to the ExxonMobil and Rosneft partnership, was then made in the North Kara, Laptev and Chukchi Seas.

"The Arctic is an area where the geology is seductive, but there have been setbacks, largely through cost issues," Doré says (see pages 60-62).

Yet, the Arctic is already a major province, Doré says. There have been 200 billion bbl of discoveries so far, almost all on land—in Siberia, and the North Slope. There is high potential, he says, but also high uncertainty.

"Geology isn't the main challenge in the Arctic," he says. "Geology basically gives the bottom of the pyramid,



Johan Castberg concept illustration. Graphic: Statoil.

communities along the Arctic littoral [part of the sea, close to shore] want investment and development.

"It is widely acknowledged that the Arctic is a sensitive natural environment, upon which some communities depend for subsistence and cultural heritage. Therefore, an open and transparent dialogue is required, based on good science and knowledge transfer, between all stakeholders."

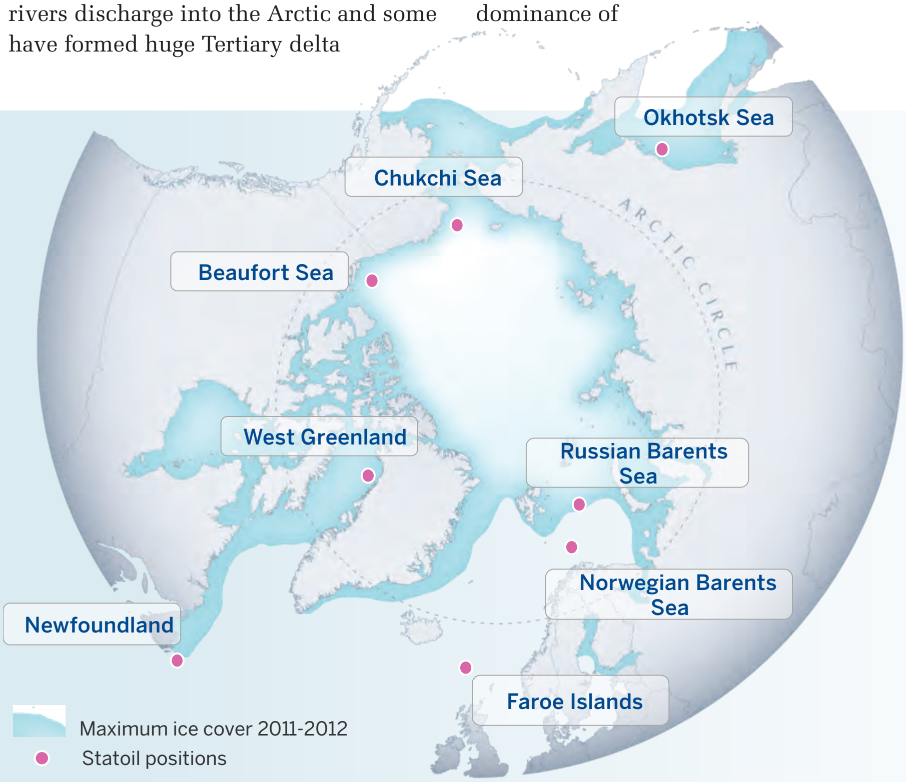
He noted that, "from an engineering perspective the issue is clearly the ice, the temperature, and to a lesser degree, the lack of daylight for half of the year. To access these great, partially ice-bound prospects will not be easy, cheap or fast."

The ice-bound continental shelf and slope of the Arctic remains largely unexplored, yet 10% (19) of the world's rivers discharge into the Arctic and some have formed huge Tertiary delta systems. Those in front of the Canadian Mackenzie, Russian Lena and other rivers are well known. There are also the prolific West Siberian and Timan Pechora basins, which plunge northwards below the icy Kara Sea.

The latter basins, together with the fact that 60% of the Arctic continental margin is in Russian waters, explains the dominance of

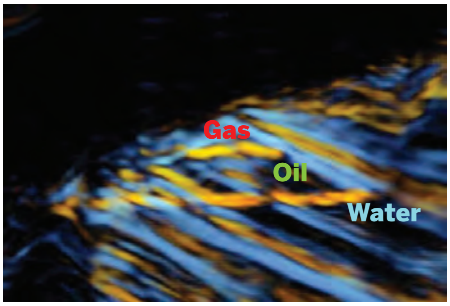
the resource base, but all the other things—environment, technology, market and infrastructure, license terms, stakeholders, and having enough money—have to be in place before we get to the top of the pyramid in order to go out and explore."

He stressed that the focus in the Arctic has been on environmental protection. "People say we don't know about oil spills in ice. Actually, that's not true. We've studied it for a long, long time. There are research consortia who

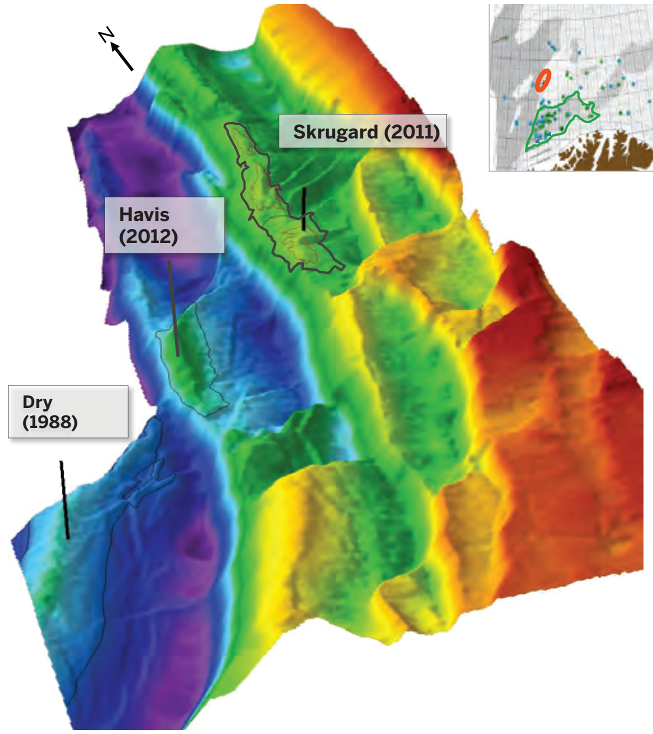


Statoil Arctic presence – significant drilling campaigns in Barents Sea and Grand Banks. All images: Statoil.

Johan Castberg



- A new oil province in the Barents Sea
- 400 - 600mboe
- Potential hub for other discoveries



Russia, in terms of estimates of yet to be found resources.

The Kara Sea contains an estimated 127 billion boe compared to 62 billion boe estimated in the Barents. Alaska, Beaufort, North Slope and Chukchi Seas contain approximately 72 billion boe, according to figures from the United States Geological Survey.

Russia has recently licensed much of its frontiers at favorable terms, with drilling scheduled to commence next year, potentially making Arctic exploration a Russia-led exercise.

The opportunity in the Kara Sea aside, Daly says that the Arctic possibility is significant, citing two untested basins; the Laptev Sea, in Russia, and the deepwater Beaufort, in Canada. The Laptev Sea basin is an up to 10km-deep completely-unexplored rift basin, well-illuminated by seismic reflection data. Its age is uncertain, but regionally, prolific Mesozoic source rocks are well known.

The challenge is that the Lapdev Sea is covered in multi-year ice, nine to ten months a year. This basin is due to be tested by the end of the decade by the Rosneft and Exxon partnership.

Single year ice covers the Beaufort Sea for nine months of the year, and BP's 3D seismic coverage remains the northern-most survey yet acquired. The geology seems favourable, even outside the Kara Sea, responding well to modern seismic and with some big unknowns to be explored.

Daly concludes: "The Arctic has significant potential, but the license to operate remains uncertain outside Russia. Rosneft, in Russia, will lead in Arctic offshore exploration, but it is unclear how fast the rest of the world will follow?" OE

But geology isn't the main challenge in the Arctic

have been working on this for decades. There is a lot of information. On the other hand, we have not actually had a real one."

He pointed out that Arctic development takes time. There had been a quarter of a century between discovery and development of the Snøhvit field, in a relatively shallow water area of the Arctic Barents Sea was opened up for exploration in 1980. The Askeladd gas discovery was made in 1981. Albatross in 1982, and Snøhvit in 1984. The Snøhvit project was finally approved in 2002, and started up in 2007.

"There is not just one Arctic," he added. There are different types ranging from the workable, where solutions can be based on existing technology, such as the Barents Sea, through to the stretch, where solutions are expected to be achieved with focused technology investment in the medium to long-term, e.g. the Beaufort Sea, to the extreme, requiring long-term focus and investment in technology, to achieve solutions, such as northeast Greenland.

Another difficulty is the length of the licensing periods. Is there enough time to operate? The license term for the US offshore (Gulf of Mexico and Alaska) is 10 years, but during that decade the effective operating period in the Chukchi Sea is only two and a half to three years. The license term offshore Canada is nine years, but the effective operating period is only one and half to two years.

Doré concluded that Arctic exploration and development will be stepwise and that nobody can do it alone. Partnership models are critical, company plus government, company plus company, company plus local stakeholders. ▪

Solutions

Explosion-proof heaters

Outdoor instrument protection specialist Intertec recently requalified all ATEX and IECEx explosion-proof heaters and controllers. These heaters are now suitable for use in extremely cold or hazardous environments, including those in the Arctic polar region. All Intertec ATEX and IECEx heaters and controllers are now certified as complying with the latest editions of the relevant parts of the IEC/EN 60079 safety standard for electrical equipment in explosive atmospheres. The materials, construction and performance of these products have been thoroughly tested by an independent third-party certification agency and verified against the most up-to-date criteria that is available. Representative samples of every ATEX and IECEx heater and controller currently manufactured by Intertec were tested under the auspices of Germany's national metrology institute, the Physikalisch-Technische Bundesanstalt (PTB), which is a notified body for ATEX and IECEx conformity assessment.

www.intertec.info

R.STAHL introduces FX15 signals for harsh environments

R. STAHL introduces a new signaling solution that withstands extreme environmental conditions, e.g. a wide operating temperature range of 55°C (133° F) to more than 70°C (158°F). The light source is a xenon tube providing a high light output. FX15 beacons flash at a rate of one per second. Operating voltages range from 24 and 48 VDC to 115 and 230 VAC. All units feature 3 x M20 cable entries that enable a variety of wiring and mounting options. The beacons are ATEX- and IECEx-certified, with other relevant approvals (GOST, PESO, Inmetro and North American listing) to follow soon. Essential installation material such as mounting brackets, straps, glands, tag and duty labels, along with replacement parts are also available at launch.

www.rstahl.com.

Dialight LED fixture

Dialight unveiled the SafeSite LED Linear Fixture - Class 1. It is an efficient solution for Class I, Div. 2 certified hazardous applications. The fixture is intended to replace traditional fluorescent and HID lighting fixtures. It is also available for non-classified general purpose industrial applications. With 80 CRI models also available, the new SafeSite linear provides optimum visibility for process, testing and inspection areas. It is L70 rated for more than 100,000 hours of continuous performance even in the harshest conditions.

www.dialight.com.

Oil in water monitors package

Turner Designs Hydrocarbon Instruments launched the 4100 E09 electronics package for its existing TD-4100XD and TD-4100XDC oil in water monitors. Turner Designs added on-board control and monitoring of two sample streams, including individual calibrations for each stream. Both the TD-4100XD and the TD-4100XDC can be equipped with sample switching valves mounted on existing skid. New features included to enhance functionality are high-resolution color LCD graphics local display with menu-driven functions, and display modes, local controls, and USB back up and download of all data. It also allows automatic installation of firmware upgrades and the reinstatement of complete set up and calibration on replacement or repaired instruments. Dry-contact relays (6 amp, 250 VAC) for control of the TDHI Sample Switching System for two sample streams, Automatic Cell Cleaning System (available on the XDC), alarm enunciations and on/off control of auxiliary devices were also added. The new package also holds two separate calibrations, one for each sample stream in the Dual Stream mode.

www.oilinwatermonitors.com

Subsea Piling services

Conductor Installation Services Ltd (CIS), an Acteon company, launched a new service line: Subsea Piling services, which coincides with CIS's new Subsea Piling system, a remotely-operated system that the company developed to drive piles as large as 36in diameter, in water depths to 300m. Initially, the company plans to establish a foothold in the offshore subsea European market. The range of services provided by CIS supports the Acteon Group's commitment to defining subsea services across a range of interconnected disciplines.

www.c-i-services.com

Activity

Eni Norge opens new Hammerfest ops center

Eni Norge has opened a new operations center in Hammerfest as part of its expansion in northern Norway and the Barents Sea. The Italian company has been active in the region since the start of the 1990s and is developing the Goliat oil field - the first oil field to be developed in the Barents Sea.

Goliat is due to come on stream next year. Management of the field will be aided by about 60 Eni Norge personnel in Hammerfest. The office will also be responsible for future field developments in the area and has capacity for up to 120 people.

Eni Norge managing director Andrea Forzoni believes strongly that new oil and gas discoveries will be made in the Barents Sea, and that the establishment of an operations center in Hammerfest is crucial if Eni Norge is to keep pace with the industrial growth anticipated in the region.

In addition to Goliat, Eni Norge is a stakeholder in 17 licenses in the Barents Sea, and operator in ten, including a 30% stake in Johan Castberg field.

UK report calls for new regulator

A government-commissioned report regarding the future of the UK's oil and gas industry has recommended the creation of a new industry-funded regulatory body with powers similar to those seen in Norway and The Netherlands.

The new regulator's work would include developing and implementing strategies for exploration, third party access to infrastructure, production efficiency and decommissioning. The recommendations are contained within an interim report on the government-commissioned "UKCS Maximising Recovery Review," led by Sir Ian Wood, founder and former chairman of Wood Group. The review's aim is an independent assessment of UK offshore oil and gas recovery and regulation.

The new regulator would work independently of the Energy Department. Wood said the review recognized the complex nature of the UK's maturing offshore industry, where an increasingly diverse range of operators are investing at record levels in new developments, yet exploration and production rates are falling, and activity is fragmenting into a "patchwork" of smaller fields with a lack of strong stewardship.

OIL & Gas UK Awards 2013 announced in Aberdeen

The winners of the Oil & Gas UK Awards 2013 were announced at an awards ceremony attended by more than 600 in Aberdeen, Scotland.

The Oil & Gas UK Awards is the annual showcase event for the UK offshore oil and gas industry, honoring the top performing people and companies.

The winners across five categories were:

- The Oil & Gas UK Award for People Development (sponsored by the University of Aberdeen) – AMEC
- The Oil & Gas UK Award for Business Efficiency (sponsored by Apache) – Apache/OGN Project Team
- The Oil & Gas UK Award for Mentoring (sponsored by Chevron) – Archie Crawford, Bilfinger Salamis UK
- The Oil & Gas UK Award for Young Technician of the Year (sponsored by BP) – James Gladden, BG Group
- The Oil & Gas UK Award for Overall Excellence (sponsored by ECITB) – Kenny Baxter, Chevron North Sea Limited.

Ocean Rig, Energean to form JV

Ocean Rig and Energean Oil & Gas will create a joint venture called OceanEnergean to participate in new bid rounds for hydrocarbon exploration and exploitation in Greece and abroad in more than 1000m deep water.

Each company will hold 50% of the share capital.

Energean said the company's aim is to create an operator that will bid for new blocks in the Mediterranean, the Black Sea and Africa, as well as in Western Greece and Crete.

OceanEnergean will draw on Energean's expertise in exploration, development and operation of oil and gas fields, and Ocean Rig's international experience in deepwater drilling.

Ikon Science acquires software division of Terra Geotech

Geoprediction firm Ikon Science has acquired the software, services and intellectual property of Bergen-headquartered Terra Geotech AS. Eamonn Doyle, the founder of Terra Geotech, has joined Ikon Science as VP real-time operations, bringing with him Terra's real-time pore pressure prediction consulting business.

Doyle said the move would accelerate the firm's business growth and R&D in real-time pore pressure prediction.

The move would also benefit from integrating Terra's real-time data and monitoring with Ikon's existing reservoir monitoring, geomechanics and pore pressure prediction capabilities.

Remote and real-time well monitoring software and services are available from Ikon with immediate effect.

Ikon, based in London, was formed in 2001, with Enterprise Oil plc and Tullow Oil as founding shareholders.

Spotlight

By Audrey Leon

Polk picked for RWE's UK branch

Hans-Joachim Polk took over as managing director for Hamburg-based RWE Dea AG's UK subsidiary in August. Polk, a 22-year veteran of the German exploration company, began his career in 1991 as a production operations engineer. He eventually became head of operations for production for Germany's largest offshore oilfield, Mittelplate, which is located off the country's northern coast. He has also previously served as senior vice president, field development for RWE Dea.

Polk said he has had a rich experience with the company. "[RWE Dea] has offered me a variety of interesting positions, countries and projects, where I could perfectly develop my technical as well as leadership skills," he said. "The acquaintance with so many enthusiastic RWE Dea people in different locations and cultures has spiced up my business life in addition and kept me motivated all the time."

RWE has taken Polk to company outposts in Egypt, spending three and a half years in Cairo. He later transferred to Norway, where he most recently served as managing director of RWE Dea Norge. Hugo Sandal, who previously ran the company from 1995 to 2011, succeeded Polk at RWE Dea Norge in June. Despite obvious differences in running businesses in foreign lands, Polk says one thing stays the same: RWE's people.

"One outstanding similarity is the motivated and experienced staff that we fortunately have got in all our OPCO's," Polk said. "The culture is definitely different, but with the open mind-set, which I have seen in Egypt as well as Norway, it was always possible to build bridges respectively fruitful relations. Hence, I hope my experience from my previous assignments will help me to succeed here in UK."

RWE's Breagh field went into production in mid-October. (Photo: RWE Dea AG)

Polk listed the startup of the RWE-operated Breagh field (70%) as one of his top priorities for the short-term. RWE Dea UK announced in mid-October that the field was brought online, with three wells producing an initial flow rate of 2.75 MMcm/d of natural gas. Total reserves of the Breagh field are estimated at approximately 19.8 Bcm. The Breagh gas field is located in Blocks 42/13a and 42/12a in the UK sector of the Southern North Sea, about 65km off the coast of north east England where water depths are approximately 60m.

Jarand Rystad, the head of consultancy Rystad Energy, and Hans-Joachim Polk, Managing Director of RWE Dea UK. (Photo: RWE Dea AG)

Following the Breagh's startup, Polk says he's excited to launch and further develop the Breagh Phase II project, as well as take lessons learned from RWE's successful production in the Clipper South field and utilize that knowledge on on other tight gas reservoirs.

In addition to production goals, Polk says he intends to further develop RWE's HSEQ standards. "I see RWE Dea's safety culture and its efforts to achieve safety goals at a high industry level," he says.

Polk said RWE's safety culture focuses on awareness and behavior, with staff encouraged to share observations and make proposals.

"Concerning our operations in the UK, I'm proud to see the excellent safety performance in our projects as well as drilling operations, which speaks for a well-functioning safety culture. I'll do my best to continue this positive trend and support my people to develop our safety culture even further," he says. OE

Entrance and Egress

- Ensco Chairman, President and CEO **Dan Rabun** will retire after nearly eight years of service. Rabun will continue to serve in his current role as Chairman, President and CEO until the Board of Directors has completed the succession process and a new CEO has been appointed.
- **Merrill A. "Pete" Miller, Jr.**, chairman and CEO of National Oilwell Varco Inc., will step down from his positions concurrent with the completion of plans to spin off to its shareholders its distribution business as an independent, publicly traded company. Clay Williams has been appointed to the Board of Directors and he will succeed Miller as NOV's Chairman and CEO.
- **Stephen M. Johnson** will retire as McDermott International, Inc.'s chairman of the board, president and chief executive officer— and as a director of McDermott this month. David Dickson will succeed Johnson as president and chief executive officer. Dickson has been appointed executive vice president and chief operating officer, a position he will hold until December.

Editorial Index

Advertiser Index

Advertising sales

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Numerology

US$20 trillion will be invested in the Arctic between 2011-2035, according to the International Energy Agency World Energy Outlook 2011. See page 22.

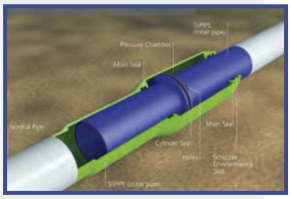
32,000,000 barrels of crude oil are delivered daily by sea, with 9,000,000 barrels of oil products delivered daily, according to Joint Stock Company Sovcomflot.

1250 tonnes

The mooring load limit capacity of the Toscana FSRU. See page 38.

3,055 is the total available rig count in the US according to NOV's Annual Rig Census for 2013. *Image of the Transocean Leader: Harald Pettersen/ Statoil ASA*

150°C (302°F) The maximum temperature at which a seal within DNV GL's new pipeline can function. See page 48.



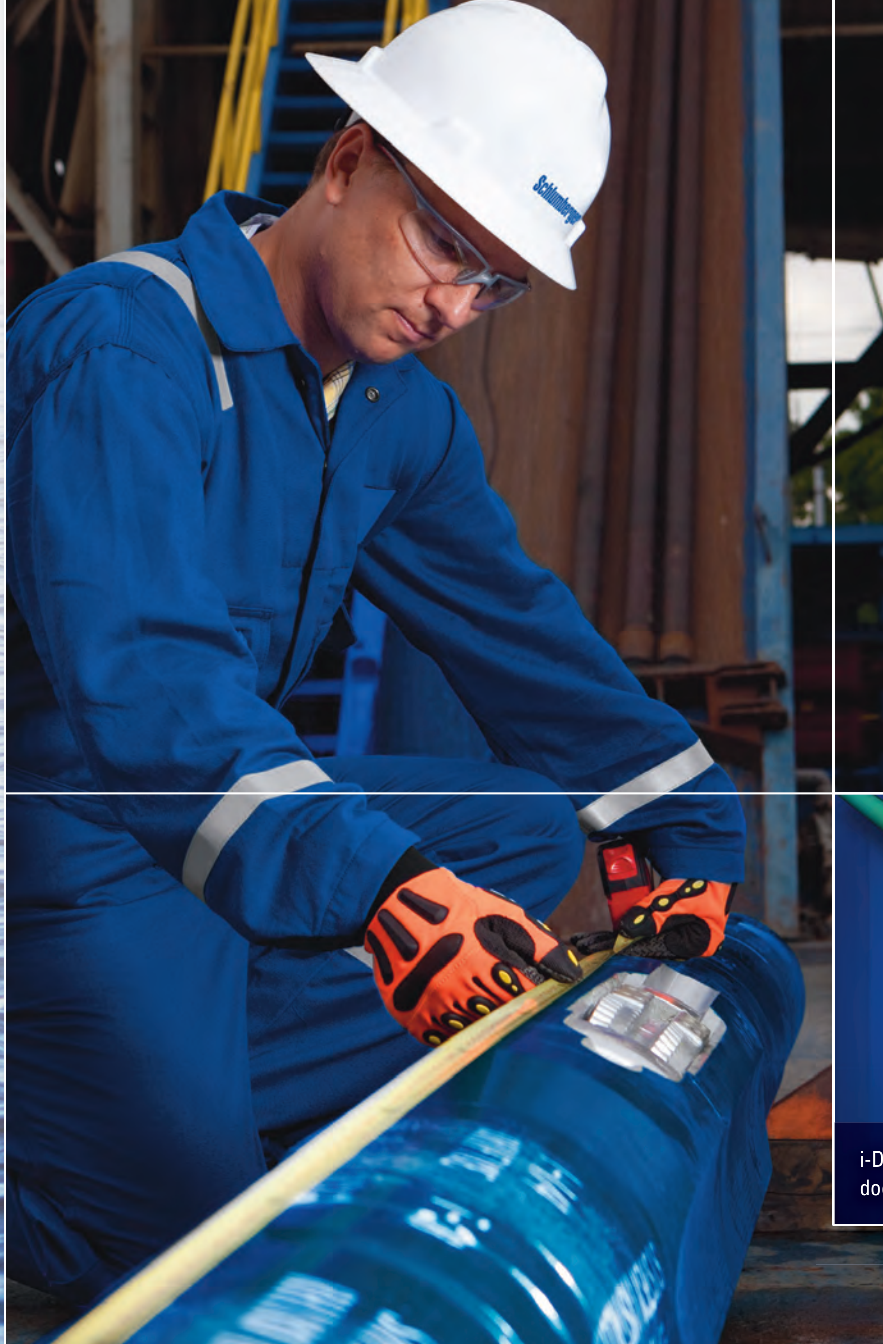
US$4 billion The final cost of the Pechora Sea's Prirazlomnoye field. See page 60.

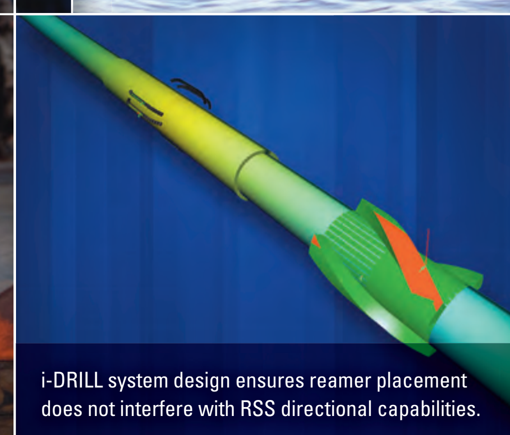
1.5% is the level of uncertainty under which Scotland's NEL Center can measure gas. See page 52.

-260°F (-132°C) is the temperature that gas condenses into LNG.

168,372,788 The number of LinkedIn members in the US, Europe and UK.

LinkedIn





i-DRILL system design ensures reamer placement does not interfere with RSS directional capabilities.