Brønnøysundregistrene

ÅRSREGNSKAPET FOR REGNSKAPSÅRET 2021 - GENERELL INFORMASJON

Enheten

Organisasjonsnummer:	983 426 417
Organisasjonsform:	Aksjeselskap
Foretaksnavn:	VÅR ENERGI NORGE AS
Forretningsadresse:	Vestre Svanholmen 6 4313 SANDNES

Regnskapsår

Årsregnskapets periode:	01.01.2021 - 31.12.2021

Konsern

Morselskap i konsern:	Ja
Konsernregnskap lagt ved:	Ja

Regnskapsregler

Regler for små foretak benyttet:	Nei
Benyttet ved utarbeidelsen av årsregnskapet til selskapet:	Regnskapslovens alminnelige regler
Benyttet ved utarbeidelsen av årsregnskapet til konsernet:	-

Årsregnskapet fastsatt av kompetent organ

Bekreftet av representant for selskapet:	Trygve Bø
Dato for fastsettelse av årsregnskapet:	01.06.2022

Grunnlag for avgivelse

År 2021: Årsregnskapet er elektronisk innlevert
År 2020: Tall er hentet fra elektronisk innlevert årsregnskap fra 2021

Det er ikke krav til at årsregnskapet m.v. som sendes til Regnskapsregisteret er undertegnet. Kontrollen på at dette er utført ligger hos revisor/enhetens øverste organ. Sikkerheten ivaretas ved at innsender har rolle/rettighet for innsending av årsregnskapet via Altinn, og ved at det bekreftes at årsregnskapet er fastsatt av kompetent organ.

Brønnøysundregistrene, 08.03.2024

Resultatregnskap

Beløp i: NOK	Note	2021	2020
RESULTATREGNSKAP			
Inntekter			
Salgsinntekt	3,5	10 016 533 576	5 801 830 362
Tariffinntekter		7 692 708	10 046 181
Andre inntekter	8	1 067 825 946	429 349 821
Sum inntekter		**11 092 052 230**	**6 241 226 364**
Kostnader			
Driftskostnader	10	959 116 824	1 717 066 993
Letekostnader		437 487 055	325 710 667
Lønnskostnad	6,7	120 734 728	158 867 008
Avskrivning på varige driftsmidler og immaterielle eiendeler	9	1 248 410 511	1 342 040 391
Annen driftskostnad	10	80 975 227	79 256 541
Sum kostnader		**2 846 724 345**	**3 622 941 600**
Driftsresultat		**8 245 327 885**	**2 618 284 764**
Finansinntekter og finanskostnader			
Renteinntekt fra foretak i samme konsern	8	0	5 236 042
Annen renteinntekt		7 314 366	33 047 992
Annen finansinntekt	3		55 697 530
Valutagevinst		210 849 383	940 749 437
Sum finansinntekter		**218 163 749**	**1 034 731 001**
Nedskriving av aksjer datterselskap		30 512 951	123 400 000
Rentekostnad til foretak i samme konsern	8	189 294 158	207 493 591
Annen rentekostnad		14 021 781	15 784 534
Valutatap		237 959 048	864 720 754
Annen finanskostnad	3	257 907 242	282 956
Sum finanskostnader		**729 695 180**	**1 211 681 835**
Netto finans		**-511 531 431**	**-176 950 834**
Ordinært resultat før skattekostnad		**7 733 796 454**	**2 441 333 930**
Skattekostnad på ordinært resultat	13	6 613 332 186	879 406 615
Ordinært resultat etter skattekostnad		**1 120 464 268**	**1 561 927 315**

Resultatregnskap

Beløp i: NOK	Note	2021	2020
Årsresultat		**1 120 464 268**	**1 561 927 315**
Overføringer og disponeringer			
Ordinært utbytte	14		1 556 500 000
Overføringer til/fra annen egenkapital	14	1 120 464 269	5 427 314
Sum overføringer og disponeringer		**1 120 464 269**	**1 561 927 314**

Balanse

Beløp i: NOK	Note	2021	2020
BALANSE - EIENDELER			
Anleggsmidler			
Immaterielle eiendeler			
Goodwill		463 076 822	531 680 795
Sum immaterielle eiendeler		**463 076 822**	**531 680 795**
Varige driftsmidler			
Maskiner og anlegg	9	21 973 395 945	18 898 100 607
Sum varige driftsmidler		**21 973 395 945**	**18 898 100 607**
Finansielle anleggsmidler			
Investering i datterselskap	16	0	66 289 675
Investeringer i aksjer og andeler	16	188 000	188 000
Finansielle instrumenter	3	91 147 040	9 800 751
Sum finansielle anleggsmidler		**91 335 040**	**76 278 426**
Sum anleggsmidler		**22 527 807 807**	**19 506 059 828**
Omløpsmidler			
Varer			
Boreutstyr, reservedeler	12	27 323 172	21 262 972
Sum varer		**27 323 172**	**21 262 972**
Fordringer			
Kundefordring fra operatør		493 895 653	302 384 116
Kundefordring	11	90 080 200	15 643 228
Andre fordringer	11	5 398 747 015	1 795 927 423
Betalbar skatt	13	0	1 051 073 702
Sum fordringer		**5 982 722 868**	**3 165 028 469**
Investeringer			
Andre finansielle instrumenter	3	147 474 161	65 609 353
Sum investeringer		**147 474 161**	**65 609 353**
Bankinnskudd, kontanter og lignende			
Bankinnskudd, kontanter og lignende	4	37 010 536	4 351 305

Balanse

Beløp i: NOK	Note	2021	2020
Sum bankinnskudd, kontanter og lignende		**37 010 536**	**4 351 305**
Sum omløpsmidler		**6 194 530 737**	**3 256 252 099**
SUM EIENDELER		**28 722 338 544**	**22 762 311 927**
BALANSE - EGENKAPITAL OG GJELD			
Egenkapital			
Innskutt egenkapital			
Aksjekapital	14,15	141 500 000	141 500 000
Overkurs	14	1 273 500 000	1 273 500 000
Sum innskutt egenkapital		**1 415 000 000**	**1 415 000 000**
Opptjent egenkapital			
Annen egenkapital	3,14	1 487 837 719	1 444 976 248
Sum opptjent egenkapital		**1 487 837 719**	**1 444 976 248**
Sum egenkapital		**2 902 837 719**	**2 859 976 248**
Gjeld			
Langsiktig gjeld			
Pensjonsforpliktelser	7	251 221 504	227 293 630
Utsatt skatt	13	10 862 570 429	7 942 327 388
Andre forpliktelser	10	4 374 730 297	4 124 639 481
Finansielle instrumenter	3	154 396 903	0
Sum avsetninger for forpliktelser		**15 642 919 133**	**12 294 260 499**
Annen langsiktig gjeld			
Langsiktig konserngjeld	11	3 373 000 000	3 373 000 000
Sum annen langsiktig gjeld		**3 373 000 000**	**3 373 000 000**
Sum langsiktig gjeld		**19 015 919 133**	**15 667 260 499**
Kortsiktig gjeld			
Leverandørgjeld	11	300 194 546	116 496 507
Betalbar skatt	13	3 227 651 209	137 091 424
Skyldige offentlige avgifter		43 326 251	77 448 947

Balanse

Beløp i: NOK	Note	2021	2020
Utbytte	14	0	1 556 500 000
Annen kortsiktig gjeld		1 200 094 147	1 993 818 274
Gjeld til operatør		868 341 461	177 233 122
Finansielle instrumenter	3	1 163 974 080	176 486 910
Sum kortsiktig gjeld		**6 803 581 694**	**4 235 075 184**
Sum gjeld		**25 819 500 827**	**19 902 335 683**
SUM EGENKAPITAL OG GJELD		**28 722 338 546**	**22 762 311 931**

Skattedirektoratet

Saksbehandler	Deres dato	Vår dato
Geir Johannessen	22.01.2015	03.02.2015
Telefon	Deres referanse	Vår referanse
22 07 73 25/22 66 11 14	Trygve Bø	2015/59797

GDF SUEZ E&P NORGE AS
Postboks 242 Forus
4066 STAVANGER

Tillatelse til å utarbeide årsregnskap og årsberetning på engelsk språk for GDF SUEZ E&P Norge AS, org.nr. 983 426 417

Vi viser til deres brev av 22. januar 2015 der det søkes om dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk for GDF SUEZ E&P Norge AS fra og med regnskapsåret 2014.

Skattedirektoratet gir på bakgrunn av en konkret helhetsvurdering GDF SUEZ E&P Norge AS dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk fra og med regnskapsåret 2014, jf. regnskapsloven § 3-4 tredje ledd. Dispensasjonen forutsetter at opplysningene som vedtaket baserer seg på ikke endres vesentlig.

Kopi av dette brevet må sendes Regnskapsregisteret i Brønnøysund sammen med årsregnskapet. Det påligger den regnskapspliktige å dokumentere ved dette brev at tillatelsen er gitt.

Bakgrunn
GDF SUEZ E&P Norge AS driver virksomhet innen leting etter og utvinning av olje og gass. Konsernets arbeidsspråk er engelsk. Konsernet opererer i sektorer, der engelsk er det klart dominerende språket. Morselskapets aksjonærer er utenlandske selskaper og personer, og morselskapet henvender seg jevnlig til potensielle investorer som er basert i utlandet. All kommunikasjon med konsernets primære kunder og kreditorer foregår på engelsk. I lys av selskapets og konsernets situasjon, der enkelte av selskapets investorer kun behersker engelsk, all kommunikasjon med konsernets primære kunder og kreditorer skjer på engelsk, samt at engelsk er både arbeidsspråket til konsernet og bransjespråket der selskapet og konsernet opererer, fremstår kravet i regnskapsloven § 3-4 om utarbeidelse av årsregnskap og årsberetning på norsk som unødvendig. Ettersom konsernets arbeidsspråk er engelsk vil alle ansatte forstå regnskapet og årsberetningen selv om disse dokumentene i fremtiden blir utarbeidet i sin endelige form på engelsk. Det samme vil være tilfelle for kunder og kreditorer.

Skattedirektoratets vurdering
Etter regnskapsloven § 3-4 tredje ledd skal *"årsregnskapet og årsberetningen ... være på norsk. Departementet kan ved ... enkeltvedtak bestemme at årsregnskapet og/eller årsberetningen kan være på et annet språk."*

Postadresse
Postboks 9200 Grønland
0134 Oslo

Besøksadresse:
Se www.skatteetaten.no
Org.nr: 996250318
E-post: skatteetaten.no/sendepost

Sentralbord
800 80 000
Telefaks
22 17 08 60

I Ot. prp. nr. 42 (1997-1998) Om lov om årsregnskap m.v., er det uttalt følgende om regnskapslovens formål, jf. pkt. 1.1:

> *"Regjeringen har som siktemål at regnskapsloven skal bidra til informative regnskaper for ulike grupper av regnskapsbrukere. Regnskapsbrukerne er dels investorer og kreditorer som tilfører kapital til foretakene, og dels andre grupper som har interesse av å vite hvordan foretaket drives, f.eks. de ansatte og lokalsamfunnet. Informasjonen til kapitalmarkedet skal gi grunnlag for riktig prising av finansielle objekter. Riktig prisdannelse på aksjer er en forutsetning for at ressursbruken i samfunnsøkonomien skal bli best mulig. Gode regnskaper vil også gjøre det vanskeligere for markedsdeltakere å ta ut spekulasjonsgevinster med basis i skjevt fordelt informasjon."*

Det fremgår således at et av hovedformålene med regnskapsloven er å bidra til *"informative regnskaper for ulike grupper av regnskapsbrukere"*. Regnskapsbrukere vil omfatte, jf. uttalelsen i proposisjonen, blant andre investorer, kreditorer, ansatte og lokalsamfunnet.

Det er etter Skattedirektoratets vurdering derfor avgjørende ved vurdering av om dispensasjon fra kravet til å utarbeide årsregnskap og/eller årsberetning på norsk kan gis, at det ikke foreligger mulige brukere av regnskapsinformasjon som blir vesentlig berørt negativt ved en eventuell dispensasjon.

Det er særlig hensynet til brukerne av regnskapsinformasjon som skal vurderes ved en dispensasjonssøknad. I denne vurderingen har Skattedirektoratet lagt særlig vekt på at selskapet inngår i et utenlandsk konsern og at arbeidsspråket er engelsk. Videre er det vektlagt at selskapet driver virksomhet i en internasjonal bransje der alle vesentlige aktører behersker og benytter engelsk språk.

Vennligst oppgi vår referanse ved henvendelser i saken.

Med hilsen

Rune Tystad
Seniorrådgiver
Rettsavdelingen, foretaksskatt
Skattedirektoratet

Geir Johannessen

Dokumentet er elektronisk godkjent og har derfor ikke håndskrevne signaturer

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Saksbehandler
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Telefon
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Neptune Energy

Annual Report and Accounts 2021

Neptune Energy is an independent energy company with operations across Europe, North Africa and Asia Pacific.

We aim to store more carbon than is emitted from our operations and the use of our sold products by 2030.

Visit our website at *neptuneenergy.com*

Except as otherwise noted, the figures in this report are stated in US dollars or euros. All references to dollars or $ are to the US currency. We use adjusted profit measures, which exclude the impact of exceptional items and remeasurements. These are used by management to assess the underlying performance of the business.

Except as the context otherwise indicates, Neptune or Neptune Energy, Group, we, us, and our, refer to the group of companies comprising Neptune Energy Group Midco Limited (the Company) and its consolidated subsidiaries and equity-accounted investments.

Designed for the energy transition

Our portfolio is gas-weighted and lower carbon. We have a visible growth path with significant projects under way and an inventory of discoveries for future development. Our focus is on producing lower carbon gas and oil efficiently and using existing infrastructure to integrate energy systems.

Read more about Our business on **pages 10-31**.

Powering social and economic development

The energy we produce helps keep people warm, the lights on and the world moving. Our activities enable economic growth, helping to create jobs, support supply chains and contribute to national tax reserves.

Read more in Our society on **pages 32-43**.

Delivering robust performance

Our strong financial performance in 2021 was driven by higher economic production and commodity prices. As gas and oil supplies remained tight, we focused on maximising safe and efficient operations to supply energy to our key markets.

Read more about our operational and financial performance on **pages 44-69**.

At a glance

Geographically diverse and gas-weighted

Neptune Energy is one of the most diverse European exploration and production companies. We provide secure supplies of energy, with a portfolio that is OECD-focused and >70% gas-weighted.

What we do

Explore
Focus exploration on shorter-term, material value-creating prospects, targeted around existing infrastructure

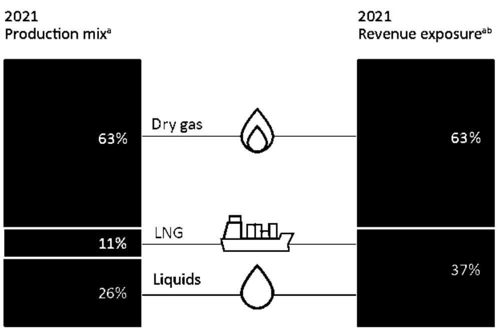
Develop
Develop fields at pace, preferably as operator, with innovative low cost solutions

Integrate
Integrate gas, oil, electrification, carbon capture and storage and hydrogen into energy systems

Produce
Produce fields safely and efficiently to maximise recovery, lower unit costs and reduce carbon intensity

Repurpose
Repurpose existing infrastructure to accelerate the energy transition

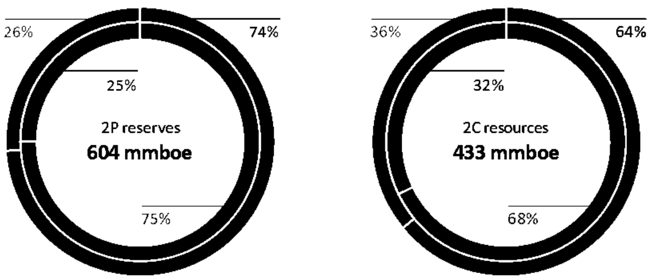
Gas-weighted by volume, balanced by revenue



a. Includes wholly owned affiliates and equity-accounted affiliates.
b. Calculated based on revenue from commodity sales net of hedging impact, excludes other income and production-equivalent insurance income.

Long life, material growth potential

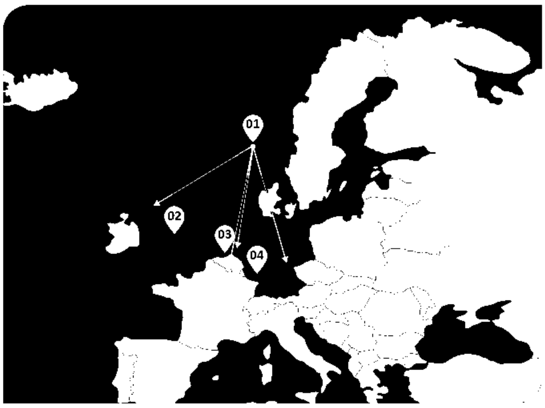
Three-quarters of our proved and probable reserves are located in well-established markets in Europe while 32% of our contingent resources are in existing areas of operation across North Africa and Asia Pacific. Our 2P reserve life is 13 years.



~1 billion barrels of 2P reserves and 2C resources

● Gas ● Oil ● Europe ● North Africa and Asia Pacific

Europe



01 Norway (35%)*
The Gjøa gas and oil field is powered using low carbon hydroelectricity and we have interests in another six producing fields. Gas from Norway goes to the UK, Germany, Belgium and the Netherlands.

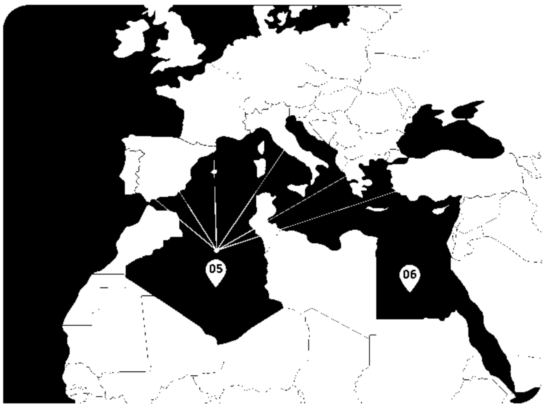
02 UK (12%)
We operate the Cygnus Alpha and Bravo facilities, producing gas from the Cygnus field. Cygnus is capable of meeting around 6% of UK gas demand.

03 The Netherlands (16%)
We are the largest gas producer in the Dutch North Sea, with key infrastructure providing scalable hubs for lower carbon opportunities.

04 Germany (14%)
With a presence in the country for more than 130 years, we operate and develop oil and gas fields with our partners in the northwest, east and south of Germany.

* Proportion of production from each country.

North Africa



05 Algeria (4%)
As part of a joint venture with Sonatrach and ENGIE, we are producing gas from the Touat plant, which is an important source of supply for mainland Europe.

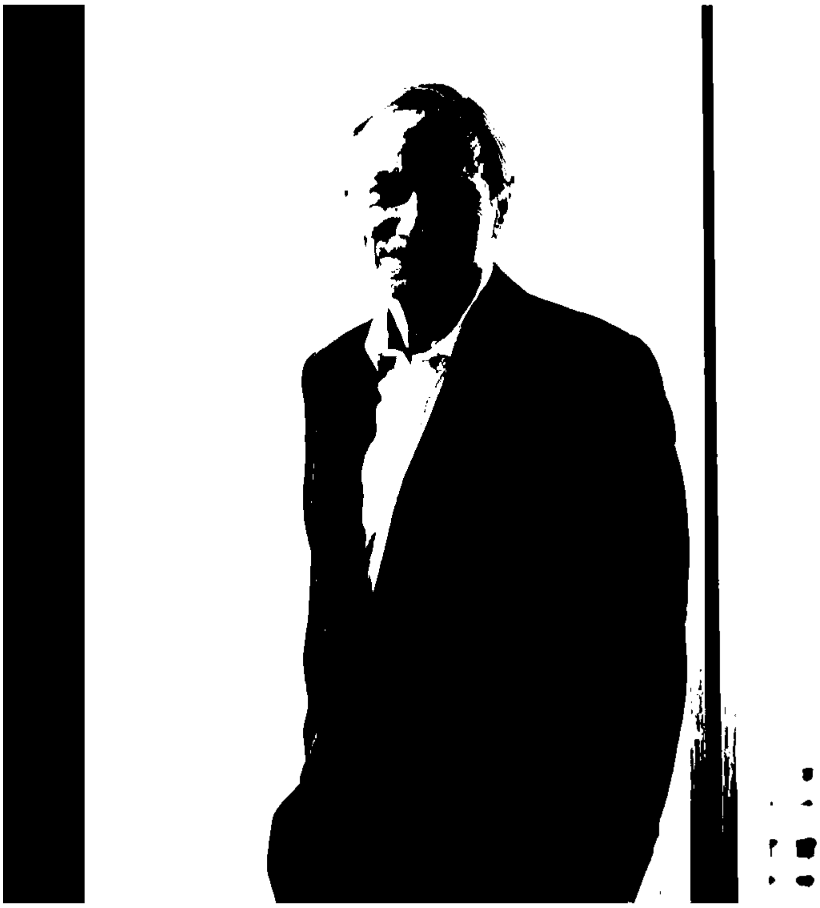
06 Egypt (3%)
We have interests in an offshore oil field in the Gulf of Suez, an oil and gas field in the Egyptian desert and an operated exploration licence for the Gulf of Suez.

Asia Pacific

07 Indonesia (16%)
Working with Eni and other partners, we produce LNG for export to the region under long-term contracts and gas for the domestic market to help meet the country's growing energy needs.

08 Australia
We are evaluating development concepts for Petrel, a large gas field located in the Timor Sea, which is one of the main gas-producing regions in Australia.

Executive Chairman's message



Sam Laidlaw
Executive Chairman

Leading the way

"— Neptune enters 2022 from a position of strength, with a portfolio that supports near-term cash flow and growth."

More than any other period, 2021 was perhaps the year that crystallised the energy challenge. Amid the ongoing pandemic, world leaders gathered in Glasgow for the COP26 climate summit. As they did so, European gas prices spiked to levels never seen before, in part because of historic underinvestment in energy infrastructure.

It threw into stark relief the crucial need to balance reducing carbon emissions while securing energy supplies at affordable prices.

Managing that balance is one of the most important and challenging issues of our time. Go too fast, and we risk exposing consumers to higher carbon emissions and insecure energy supplies at volatile prices. Go too slow, and we might lose the opportunity to curb temperature rises and meet climate change goals.

To find the right path, we must acknowledge, therefore, that the energy transition is just that: a transition.

Existing infrastructure will be critical in deploying low carbon technologies, such as hydrogen and carbon capture and storage (CCS) – from depleted gas reservoirs to transportation networks and storage facilities. Meanwhile, returns on renewables investments – at least in the short term – are not sufficient on their own to finance the capital requirements of ever-larger low carbon projects. So investors need to recycle returns from existing production to capitalise renewable investment.

Energy projects, whether they be oil, gas or renewables, are hugely capital intensive and often take years to build, during which time investors' capital is at risk. Investors will only be prepared to take that risk if they have confidence in a stable fiscal and regulatory regime.

We therefore need to find the right balance – between investing in existing energy projects while moving to renewables. Doing so will protect energy security, jobs, critical infrastructure, tax revenues and supply chains as we move through the transition.

Built for the energy transition

It is vital, however, that finding the right balance is not used as an excuse to procrastinate and stall investment in low carbon energy. Quite the opposite.

We created Neptune with the energy transition in mind. The fact that our portfolio is already lower carbon is down to the steps taken over the years to electrify production and reduce operational emissions. Indeed, by the end of 2022, more than 35 kboepd of our net production will be electrified, with more to come in the years ahead.

And we have experience with CCS, both in Norway and the Netherlands. So, we have the infrastructure, capability and project pipeline to accelerate the transition. That is why we are setting out a new ambition to store more carbon than we emit by the end of this decade.

Turning this ambition into reality will require collaborative partnerships and significant investment. That means maximising returns from gas and oil in the near term so we can progress more quickly with developing our CCS projects, along with accelerating our plans for green hydrogen production and further electrification of our existing production.

Beyond financial value

This is very much aligned with our vision to meet society's changing energy needs and create value for all our stakeholders. Since 2018, we have invested more than $6 billion in development, exploration and acquisitions to grow the business. As a result, we have built a diverse, gas-weighted portfolio of high-quality, lower carbon and long life assets, with growth opportunities across the business that will support future cash flows.

Crucially, our investment supports socio-economic development. In 2021, our activity in Europe alone supported more than 9,700 jobs and contributed more than $3.3 billion to the economies of Norway, the Netherlands, Germany and the UK.

Resilience as normal

I visited our operations across Europe and North Africa in 2021 and I am hugely proud of the resilience, dedication and energy our people showed in safely managing the fast-changing set of circumstances. Throughout, our team has stayed true to our values of excellence in HSE, accountability, integrity and teamwork.

Our people also play an active part in the communities in which we work, and it is thanks to their energy and passion that we are able to bring broader benefits to society.

Leadership

In February 2022, we announced the tragic death of Engineer Mohamed Mounes Shahat, Managing Director of our business in Egypt. Throughout his career, he gained the respect from stakeholders across Egypt and will be much missed.

Having played a formative role in building Neptune, Jim House retired from his role as CEO at the end of 2021. I am grateful to him for his contribution and for laying the foundations for the future growth of the business. It is a testament to the strength and depth of the management team that he built that we were able to choose his successor from within the business.

Pete Jones took on the role of CEO at the beginning of 2022. Pete brings a wealth of experience and energy as we enter a period of growth in both production and lower carbon opportunities. I look forward to working with him and his management team to capitalise on these growth opportunities.

Providing secure supplies of energy

While the market was already tight due to demand recovery and underinvestment, the Russian invasion of Ukraine and related sanctions in 2022 have caused sharp dislocations in energy markets, which has tightened oil and gas markets further. In an increasingly polarised world, our significant Northwest European gas and oil production is an important contributor to Europe's energy security.

A better way

I appreciate all the hard work of the Neptune team during uncertain times. The commitment of our people, the quality of our portfolio and our strong cash flows, position us well for future growth in the energy transition and will continue to create sustainable value for our stakeholders.

Sincerely,

Sam Laidlaw

Sam Laidlaw Executive Chairman
16 March 2022

Chief Executive Officer's message

Accelerating the transition

Pete Jones
Chief Executive Officer

As I took up the role of CEO at the beginning of the year, the challenges around energy security and supply, intensified quickly with Russia's invasion of Ukraine.

First and foremost, Neptune shares the condemnation and horror at Russia's invasion of Ukraine and the unfolding humanitarian catastrophe. While we do not have any operations in the country, we do have employees who are affected personally and we are doing all we can to support them. We believe that it is our duty – and fundamental to our business values – to ensure that our activities play no part in funding or legitimising the Russian state.

Navigating uncertainties

The uncertainties facing the energy sector are significant. Companies across the sector are having to reassess their plans around more volatile energy prices, rising national concerns on energy security, and the need to continue progress towards global climate change goals in a more uncertain geopolitical environment.

In response, we have taken an honest look at our business to assess our strategy and navigate our way successfully through these macro trends.

Neptune is already positioned well, with our geographically diverse and gas-weighted portfolio, investment in low carbon projects and strong balance sheet all combining to provide strong foundations for growth.

But it is clear that maintaining the status quo is not the answer to our long-term future. Continued investment in gas and oil production will play a crucial role in decarbonisation and in securing energy supplies long into the energy transition. But this must not be used as an excuse for inaction on the path to net zero.

Because of the actions we have taken already to reduce our operational emissions, our carbon intensity is already one of the lowest in the sector. Not only does that position us well today, but it provides a strong platform from which to build.

Now is the right moment to accelerate our low carbon plans. This is why we have set out a clear ambition to store more carbon than is emitted from our operations (Scope 1) and the use of our sold products (Scope 3) by 2030. We also plan to reduce our emissions by increasing electrification to 50 kboepd by 2027.

These are bold ambitions that go beyond many in our sector. They do not, however, represent a pivot for Neptune, but rather an acceleration of what we've been doing for several years in Norway and the Netherlands.

That is not to say that achieving our ambitions will be straightforward; there remain many regulatory and fiscal uncertainties that will be key determinants of our success. But watching and waiting will erode value and we will squander the strong position that we start from.

Focusing on safety

I believe that a strong safety culture is the foundation of our business. I'm proud of the significant improvements we've made on safety in the past four years. We introduced a process safety key performance indicator in 2019, and, in 2021 saw our best performance to date.

However, while we had no serious personal injuries this year, our personal safety metrics are not where I'd like them to be. As I take up my new role as CEO, I want to drive a further step change so that our safety performance isn't just better but the best.

Organisational changes

Early in 2022, we announced changes to our executive leadership team to support our refreshed strategy and more focused activity set. Mark Richardson, VP Projects and Engineering, and Kaveh Pourteymour, CIO, will leave the business, having helped to develop the foundations upon which Neptune operates. I am grateful to them both for their contribution.

It was with great sadness that we announced the tragic death of Engineer Mohamed Mounes Shahat, Managing Director of Neptune Energy, Egypt on 17 February 2022. Engineer Mounes was a well-known and well-respected figure across the industry and beyond and we will all miss his guidance, good humour and wise counsel.

Delivering value

Neptune delivered a strong operating and financial performance in 2021, as we benefited from higher commodity prices and increased economic production, with three new projects coming online during the year.

As a result, we head into 2022 with a higher production base, stronger cash flows and lower leverage.

We cannot avoid the uncertainty and geopolitical challenges ahead. But the hard work and determination demonstrated by our teams all across the company will serve us well as we accelerate into the energy transition.

Pete Jones Chief Executive Officer
16 March 2022

> "— The hard work and determination demonstrated by our teams will serve us well as we accelerate into the energy transition."

The global context

Record commodity prices highlight the need for continuing investment

After a year of unprecedented disruption in 2020, there was continued volatility and uncertainty in world commodity markets in 2021. The price rises at the end of 2020 only accelerated in 2021, with Brent crude averaging $71 per barrel over the course of the year. Meanwhile, TTF gas in Europe hit €180 per MWh at the end of 2021. At the same time, November's COP26 summit in Glasgow focused attention on the huge challenges that the world faces to shift global energy systems to a low emissions pathway.

Economic recovery drives soaring commodity prices

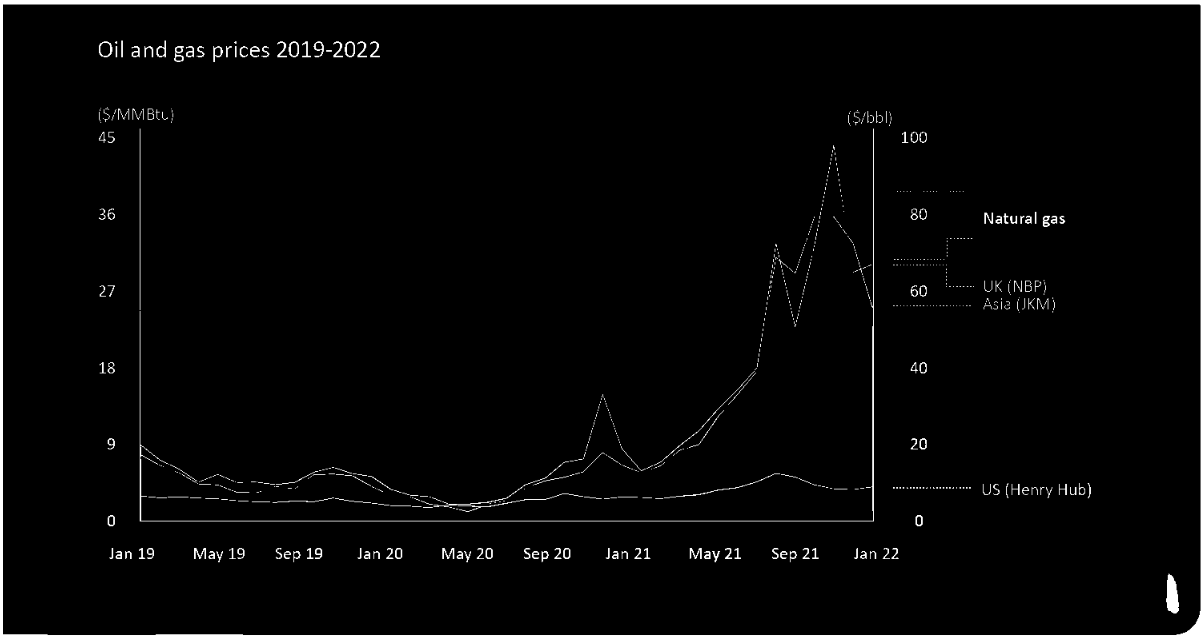
In 2021, increasing COVID-19 vaccination rates and the loosening of pandemic-related restrictions spurred economic recovery, which led to rising energy demand and the tightening of commodity markets.

Crude oil prices rose to more than $85 per barrel in October 2021, up from $20 per barrel seen in the immediate aftermath of the pandemic in mid-2020. Spot natural gas prices increased around the world and reached their highest-ever levels in Europe during the second half of 2021.

On the supply side, rising natural gas consumption was accompanied by a series of planned and unplanned outages, at levels 30% higher than average. Weather-related factors, including a cold winter in China, low wind generation in Europe and heatwaves in Asia, also boosted demand from the power and buildings sectors. Gas storage levels in Europe, meanwhile, fell to record lows, meaning that the 2021/22 winter season began with the lowest stocks since 2013.

The ongoing conflict in Ukraine means that the global economic outlook is now subject to extreme unpredictability. Commodity prices have gone up further with crude oil over $100 per barrel and the TTF gas price trading up to €200 per MWh in early March 2022. Threats of disrupted energy supplies, rising inflation and supply chain dislocations are likely to drive high price levels and volatility for some time to come.

These price pressures are exacerbated by more than a decade of underinvestment across the oil and gas industry, triggered by price declines in 2014-15 and 2020, and the failure to sanction new developments to offset natural declines. To meet near-term demand, Wood Mackenzie estimates that upstream oil and gas investment needs to rebound from $350 billion in 2020 to $430 billion by 2023. Supply chain bottlenecks, cost inflation and constrained access to capital may result in supply struggling to catch up with demand for several years.

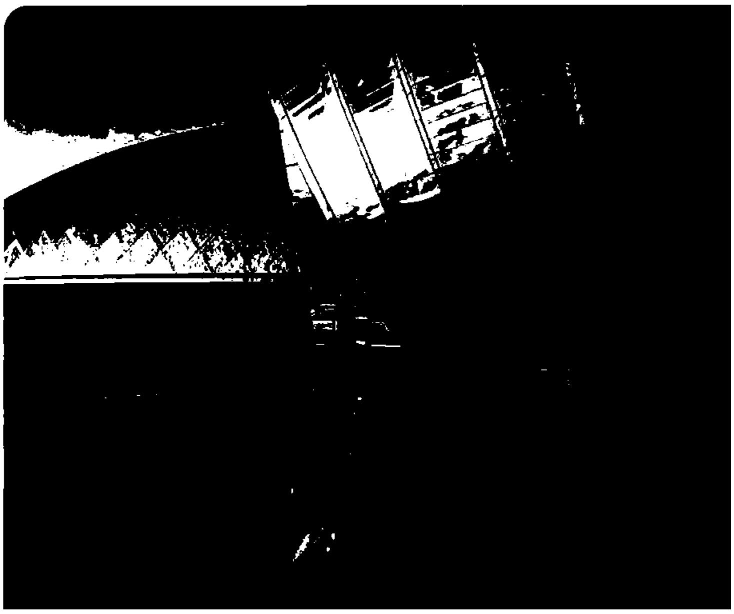


COP26 – significant success but with much left to do

Economic growth and higher energy use in 2021 saw carbon dioxide (CO_2) emissions bounce back to their second-largest rise in history, up 4% from 2020. Against this backdrop, government, business and societal representatives from countries around the world gathered in Glasgow for COP26 to progress the global response to climate change. New commitments, set out at the summit, mean that 90% of the global economy is now covered by net zero pledges. And key elements of the Paris rulebook were completed, such as Article 6, which creates a framework for voluntary carbon markets.

Numerous international agreements were signed on issues such as deforestation and the acceleration of green technology. The Global Methane Pledge, signed by more than 100 countries and with which Neptune is fully aligned, marks a crucial step in tackling climate change, with countries committing to reduce methane emissions by 30% by 2030.

Closing the gap between these ambitious pledges and actual progress will require a significant amount of concrete policy, investment and interim targets. In recognition of this, COP26 participants agreed to revisit and strengthen their pledges annually, rather than every five years.



Energy outlook to 2050

Longer term, and as the world recovers from the disruptions of COVID-19, energy will remain inseparable from the livelihoods of a global population that is set to grow by two billion people by 2050. Rising incomes push up demand for energy, and many developing economies are navigating an emissions-intensive period of urbanisation and industrialisation.

Natural gas has an important role here and has already demonstrated it can help reduce emissions quickly and at scale by replacing high-emitting fuels such as coal. This has driven emissions cuts in Europe and the US.

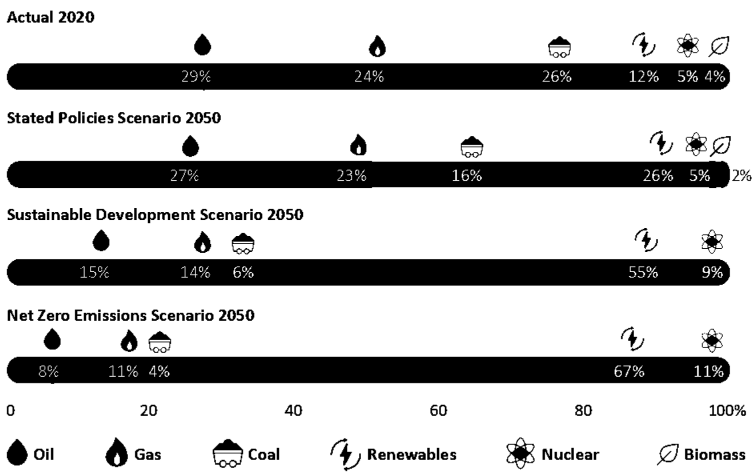
The benefits could be larger still for the growing markets of non-OECD Asia, where substituting coal with gas can happen relatively quickly and without the need for significant capital investment.

Natural gas demand, therefore, increases in most IEA scenarios until 2030. In the Stated Policies Scenario (STEPS), for instance, natural gas demand in 2030 is 15% higher than in 2020. Beyond 2030, however, there are divergences across the IEA's different scenarios, sectors and regions. For example, in STEPS, the total share of natural gas in the global energy mix is 23% in 2050, but falls to 11% in the Net Zero Emissions Scenario.

The reduction in the share of gas in the overall energy mix may not mean much less gas is consumed, however, as demand for energy will continue to grow in the coming decades.

Existing gas infrastructure and industry experience will be critical to progress the deployment of technologies such as green hydrogen and CCS. The costs of these technologies are coming down, but prudent policy support, access to financing and an entrepreneurial spirit from both incumbent and new industry players are needed for these technologies to reach the scale required to meet climate targets.

Shares of energy – 2050 scenarios



Stated Policies Scenario
Reflects current policies that have been announced by governments around the world.

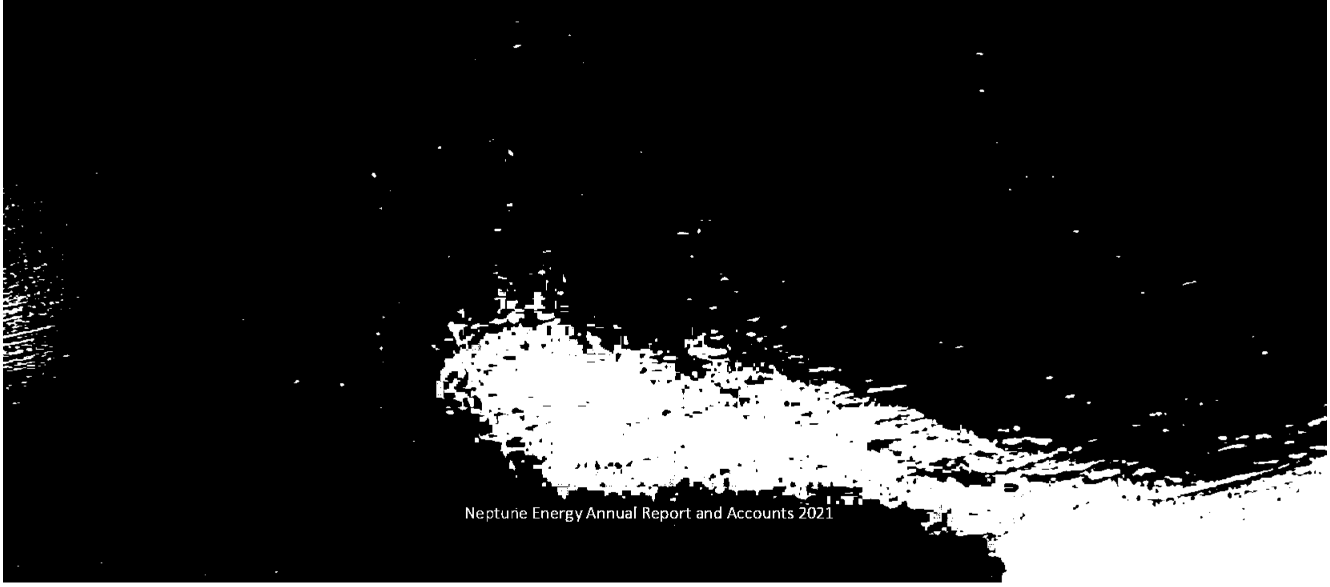
Sustainable Development Scenario
Maps out a pathway consistent with the well below 2°C goal of the Paris Agreement, while achieving universal access to energy and improving air quality.

Net Zero Emissions Scenario
Sets out a pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, with the emissions trajectory consistent with limiting global temperature rise to 1.5°C.

Source: *IEA World Energy Outlook 2021.*
Note: The sum of the energy shares may not equal 100% due to rounding.

Designed for the energy transition

Our portfolio is gas-weighted and lower carbon. We have a clear growth path with significant projects under way and an inventory of discoveries for future development. We aim to go beyond net zero by storing more carbon than is emitted from our operations and the use of our sold products by 2030.



74%

GAS-WEIGHTED

... of our production and 2P reserves is gas

Top 3%

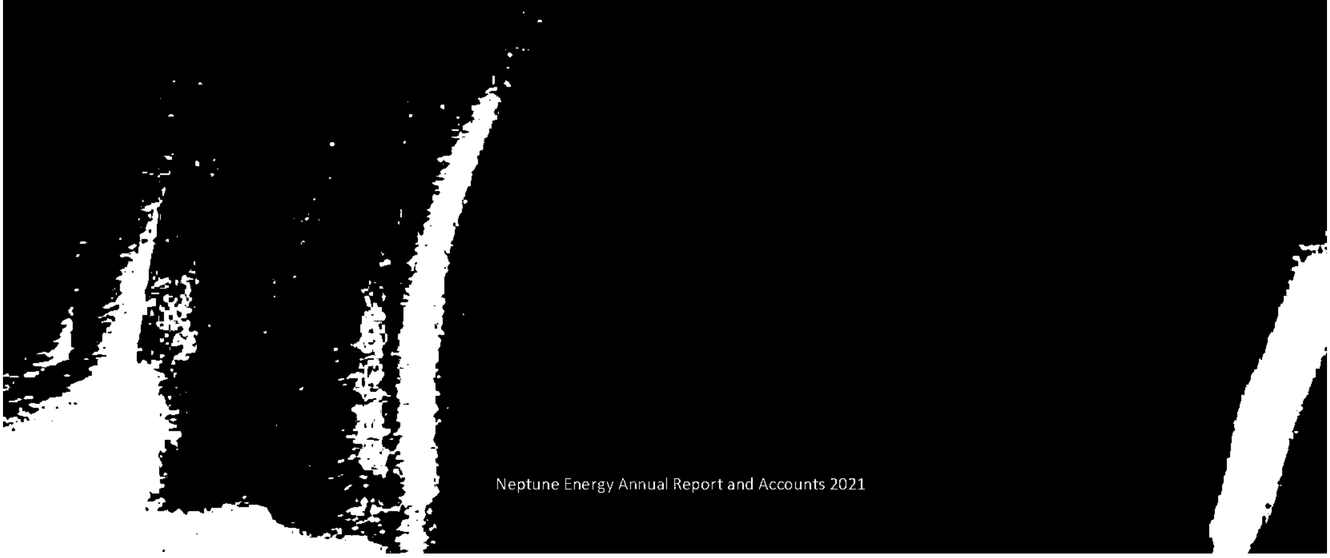
ESG RATING

... of all global E&P companies rated by Sustainalytics

6.4 kg CO_2/boe

CARBON INTENSITY

... almost 60% lower than the industry average



Our story so far...

Our long-term growth strategy is supported by a gas-weighted production portfolio, which includes assets such as Cygnus in the UK, which has a carbon intensity of <2 kg CO_2/boe

- **Backed by strong sponsors** Carlyle, CIC and CVC
- **Completed EPI acquisition,** with further growth via VNG Norge, Seagull and Isabella acquisitions
- **Strengthened management team,** systems and processes to establish standalone energy platform

We transformed the organisational structure of what was a subsidiary of a large European utility to become a standalone independent energy company

- **Focused growth in core hubs**
- **Awarded** West Ganal licence and **acquired** interests in the East Sepinggan and East Ganal licences in **Indonesia**
- **Sanctioned Seagull, Duva and Gjøa P1** operated developments
- **First gas** at Touat, Algeria
- **Exploration success** at Echino South and Sigrun East
- Aligned with the **UN Sustainable Development Goals**

Our L10 project could store 120-150 million tonnes of CO_2 for third-party industrial customers

Looking ahead, in 2022 electricity for our German assets will be sourced from renewable energy, saving around 11,000 tonnes of CO_2 emissions annually

Delivering fundamental operating improvements

Since our formation, we've improved safety and grown our reserve base.

Improved total recordable injury rate (number of total recordable injuries per million hours worked)

4.80	2.07
2017	2021

Improved lost time injury frequency (number of lost time injuries per million hours worked)

2.40	1.09
2017	2021

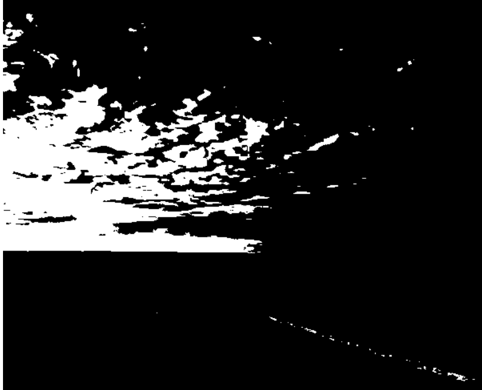
Grown 2P+2C reserve base (mmboe)

934	1,037
2017	2021

Extended reserve life (years)

9.8	13.0
2017	2021

- **Maintained free cash flow generation** through cost savings and deferrals of $350 million
- **Further material resource growth** through Isabella and Dugong discoveries
- **ESG strategy launched,** with ambitious carbon and methane intensity targets
- **Established a team to accelerate lower carbon opportunities** such as carbon capture and storage, and hydrogen



- **Delivered pipeline of projects** with Gjøa P1, Duva and Merakes onstream
- **Sustained low cost growth** with Blasto exploration discovery and bolt-on M&A in Germany and UK
- **Achieved top quartile ESG ratings** from Sustainalytics and EcoVadis
- **Joined UN Global Compact** and aligned with the **Task Force on Climate-related Financial Disclosures**

Business model and strategy

Focused, lower carbon strategy

Our vision is to be the leading independent E&P company by meeting society's changing energy needs and creating value for our stakeholders. Our strategy sets out how we will achieve this.

1 Lower carbon energy production

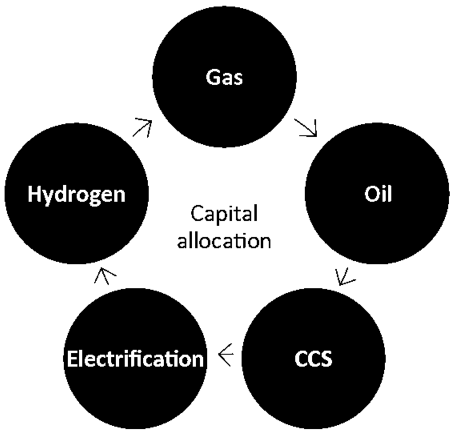
2 Integrated energy hubs

- Focus where we have experience and infrastructure (electrification, carbon capture and storage and hydrogen)
- Maintain gas-weighted and OECD-focused portfolio
- Use higher returns from gas and oil to invest incrementally in low carbon energies
- Structure the organisation around focused activity set; optimise portfolio for near-term value
- Underpin activity set with sound governance and a responsible approach

Our difference

Long life, low cost, lower carbon

How we do it



Creating value for...

Shareholders

We have built a strong track record and have distributed c.$1.6 billion to our ultimate shareholders since 2018.

Partners

We have strong relationships with our partners, which include major energy companies and national oil companies.

Employees

We have an entrepreneurial and innovative culture, with almost 1,300 employees.

Communities

We help create jobs, support local supply chains and contribute to national tax reserves.

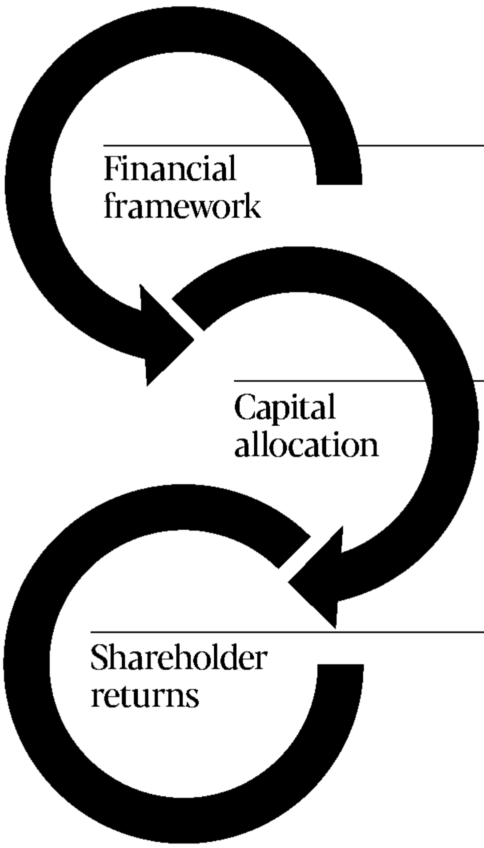
Delivering near-term returns within a disciplined financial framework

> Strong capital structure provides liquidity to support growth, while maintaining low leverage

> Capex to focus on shorter-cycle projects for nearer-term value creation

> Lower exploration expenditure, adding reserves around existing, operated hubs

> M&A focused on existing production and integration with low carbon developments



Financial framework

- Strong liquidity, low leverage
- Maintain or improve current credit ratings
- Cash flow protection through hedging and insurance

Capital allocation

- Near-term returns, balanced with investment
- Invest in profitable lower carbon production growth and low carbon developments
- Full cycle break-even pre-tax costs of <$30/bbl

Shareholder returns

- Create near-term value for stakeholders
- Maintain track record of free cash flow generation
- Grow distributions in line with value creation

Environmental, social and governance

Our ESG strategy is key to our ability to create value for all our stakeholders.

Our ESG strategy sets out the actions we are taking to produce energy in a safe, sustainable and responsible way. It is aligned with the UN Sustainable Development Goals (SDGs) and overseen by our ESG Committee, whose members include our Executive Chairman and CEO. See page 91.

Top 3% of all global E&P companies rated by Sustainalytics

Top 25% of all 75,000 global organisations assessed by EcoVadis

Our ESG roadmap

With all actions in our roadmap complete or under way, we will set out our new roadmap in 2022. This will include our near-term plans to 2025, complementing our 2030 ambitions.

2020
- ✔ **TCFD recommendations adopted**
- ✔ **Social purpose defined**
- ✔ **Equality, diversity and inclusion charter developed**

2021
- ✔ **Equity share emissions reported**
- ✔ **Human rights assessment completed**
- ✔ **Economic impact study extended to Indonesia**

2022
- ✔ **Top quartile ESG rating achieved a year early**
- — **ISO certification of operated assets**
- — **Supplier audit plan**

— In progress

Our material issues

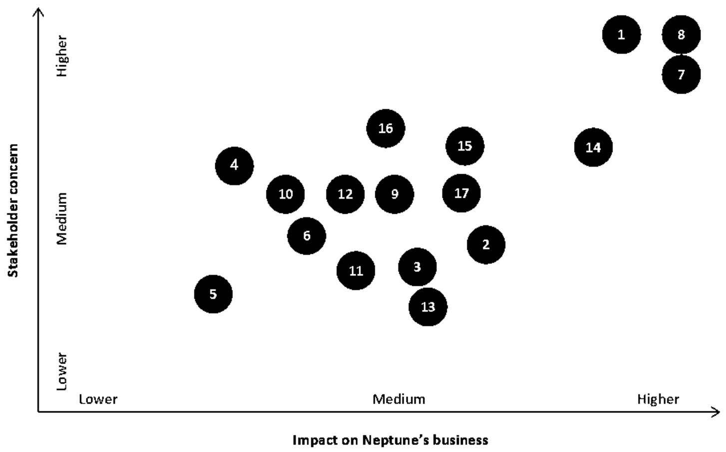
We conduct a materiality assessment each year to identify the ESG issues that have the greatest impact on our business and are of greatest concern to our stakeholders.

We talk to a range of internal and external stakeholders, including investors, NGOs, partners and government representatives, to assess our key issues. For example, in April 2021, we held a bondholder ESG roadshow and heard a common request to disclose our equity share emissions and emissions from the use of our sold products. As a result, we are reporting these emissions for the first time this year.

We also examine topics in their broader context by analysing upcoming regulation and sustainability frameworks, such as the UN SDGs, the Global Reporting Initiative (GRI) and the Task Force on Climate-related Financial Disclosures (TCFD).

We then prioritise the issues according to the impact on our business and the level of stakeholder concern. Our ESG strategy includes issues we have assessed as high/medium importance. We publish additional data, for example on waste, on our website.

Overall, our key issues in 2021 remained consistent with those in 2020. Climate change and the energy transition gained even greater prominence due to COP26, which focused the world's attention on actions needed to meet global climate goals.



Environmental
1. Climate change and the energy transition
2. Biodiversity
3. Other air emissions
4. Water
5. Waste
6. Decommissioning

Social

7. Process safety
8. Personal safety
9. Equality, diversity and inclusion
10. Social investment
11. Community engagement
12. Economic impact
13. Training

Governance

14. Corporate governance
15. Ethical conduct
16. Human rights
17. Supply chain

Our ESG strategy and targets

Environmental

Our aims	What we did in 2021	What we plan to do next
Reduce operational emissions and meet intensity targets	• On track at 6.4 kg CO_2/boe and 0.02% methane intensity. • Completed joint scientific project with EDF on methane emissions. • Awarded 'Gold Standard' status for our reporting to the Oil and Gas Methane Partnership. • Endorsed Zero Routine Flaring by 2030 initiative. See pages 20-21 and 24-27.	• Meet our carbon intensity target of 6 kg CO_2/boe by 2030. • Achieve net zero methane emissions by 2030 and 0.015% methane intensity by 2025. • Ensure zero routine flaring by 2030. • Progress electrification projects in Norway.
Create value from lower carbon opportunities	• Feasibility study under way for a large-scale offshore CCS project (L10) in the Netherlands. • Agreement signed with RWE Renewables to initiate a new large-scale offshore green hydrogen project (H_2opZee). • Funding awarded for study on renewable energy and offshore gas in the UK. See pages 20-23.	• Target L10 CCS project to be FEED-ready by the end of 2022, with FID in 2023. • Store more carbon than is emitted from our operations and the use of our sold products by 2030.
Minimise environmental impacts	• Biodiversity strategy launched and water management plan developed. • Conducted gap analysis for ISO 14001 and 50001 certification and appointed verification partner.	• Achieve a net positive impact on biodiversity. • Zero spills. • Certify all operated countries to ISO 14001 and 50001.

Social

Our aims	What we did in 2021	What we plan to do next
Maintain a focus on health and safety	• No serious injuries, but personal safety metrics exceeded our targets. Our process safety event rate improved. • Conducted gap analysis for ISO 45001. See pages 30-31.	• Zero accidents. • Aim for top quartile safety performance in our operated regions. • Implement ISO 45001 certification in the UK, the Netherlands and Germany in 2022.
Deliver socio-economic benefits	• \$3.3 billion gross value added contribution to the GDPs of our European countries. We also assessed our economic impact in Indonesia. • Doubled our social investment spend, with partnerships on mental health and biodiversity. See pages 40-43.	• \$7.0 billion gross value added contribution to GDPs of countries where we work in the three years to 2025. • Enhance scientific understanding of marine biodiversity, and community awareness of mental health support and services available.
Be an employer of choice, promoting ED&I	• 73% employee engagement (70% in 2020). • ED&I charter progressed and first global ED&I month held, with 352 employees participating. See pages 34-37.	• Target employee engagement of at least 75%. • Improve gender diversity across the organisation. • Increase participation in ED&I sessions by 25% in 2022. • Increase the number of young people who have access to training and skills development.

Governance

Our aims	What we did in 2021	What we plan to do next
Conduct our business with integrity and good governance	• New Code of Conduct approved. • 96% of employees completed ethics training. • Continued adherence to the Wates Principles. See page 36 and pages 82-92.	• Provide training on new Code of Conduct. • Promote whistleblowing channels in our workforce and supply chain. • Launch new counterparty screening process.
Respect the rights and dignity of all people	• Human rights assessment completed. • Human Rights Policy developed. See page 42.	• Progress alignment with the UN Guiding Principles on Business and Human Rights. • Implement supplier ESG monitoring framework by 2023.
Be transparent in our disclosure	• Scope 3 emissions (use of sold product) and equity share emissions reported. • Evolved TCFD and GRI reporting. See *neptuneenergy.com/esg*. • Joined UN Global Compact.	• Scope 3 reporting of additional categories. • Enhance TCFD reporting.

Key performance indicators

We assess our performance using a range of operational, ESG and financial metrics that are consistent with our strategy. We use these metrics to evaluate our performance and to inform our decision making.

Operational

1. Production[a]

(kboepd)

2021	**130.0**
2020	142.4
2019	143.9
2018	161.8

○ In 2021, production was 148.3 kboepd including production-equivalent insurance income.

Description The volume of oil, gas and other natural gas liquids produced at Neptune's operations, including equity-accounted entities. Production is measured on an oil equivalent basis and shown as an average rate per day.

Performance Outages at Snøhvit and Touat offset the contribution from new projects brought onstream. Economic production increased year-on-year.

See **page 44** for more information on our operating performance.

2. Production efficiency

(%)

2021	**82**
2020	81
2019	85
2018	88

Description Production efficiency is a measure of actual production relative to maximum production potential and includes our operated assets in Norway, the Netherlands, the UK and Germany. Actual production is impacted by both planned and unplanned production interruptions.

Performance Production efficiency improved slightly, due to stronger performances in Germany and the Netherlands, which more than offset third-party related issues in the UK.

ESG

5. Total recordable injury rate[a]

(number)

2021	**2.07**
2020	1.43
2019	2.10
2018	2.60

Description TRIR measures the number of recordable employee and contractor injuries per one million hours worked.

Performance The increase in our TRIR was largely a result of relatively minor incidents in the category of slips, trips and falls. This was higher than our annual target of 1.64.

See **page 16** for more information on our ESG performance.

6. Process safety event rate[a]

(number)

2021	**1.68**
2020	2.37
2019	2.19

Description We introduced PSER as a key performance indicator in 2019. This measures the number of process safety events per one million hours worked and includes tier 1, 2 and 3 events.

Performance Our PSER improved significantly in 2021, against our target of 2.37. Of the 17 events that occurred, 16 were in the tier 3 category and considered to be 'leading events.'

Financial

10. Opex[a]

($/boe)

2021	**11.3**
2020	9.5
2019	10.3
2018	10.2

Description This is the average operating cost per barrel of oil equivalent produced.

Performance Operating costs in 2021 increased to $11.3/boe, reflecting lower production in the period, increased blending costs and the higher cost of CO_2 emissions permits in Europe.

See **page 64** for more information on our financial performance.

11. Operating cash flow[a]

($m)

2021	**1,697**
2020	915
2019	1,321
2018	1,219

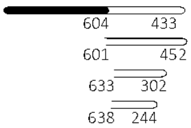
Description This includes cash flow from operations, after tax and excluding acquisition costs incurred in connection with the EPI and VNG Norge transactions.

Performance Despite a significant working capital outflow, operating cash flow increased substantially, driven by higher earnings and temporary tax changes in Norway.

(a) Metrics used in our **performance scorecards** for the Executive Team and all employees.

(b) This metric will be included in **performance scorecards** in 2022.

3. 2P reserves and 2C resources
(mmboe)



2021 1,037
2020 1,053
2019 935
2018 882

2P reserves
2C resources

Description Our 2P reserves is the best estimate of proved plus probable reserves. 2C resources is the best estimate of contingent resources and includes projects within the development pending, on hold and unclarified categories. See page 155 for an explanation of the inherent uncertainties surrounding 2C resources reporting.

Performance We achieved a strong reserves replacement in 2021, supported by positive revisions and successful appraisal of the Maha discovery.

4. Reserves life
(years)

2021 13
2020 12
2019 12
2018 11

Description This includes our 2P reserves life.

Performance Our reserves life increased to 13 years, reflecting higher 2P reserves and lower production.

7. Carbon intensity[b]
(kg CO_2/boe)

2021 6.4
2020 6.3
2019 5.8
2018 6.0

IOGP industry average was 15 kg CO_2/boe.

Description This includes Scope 1 and 2 emissions and is calculated on an operational control basis. This includes Germany, the Netherlands, Norway and the UK.

Performance Our carbon intensity remained stable at 6.4 kg CO_2/boe. We expect this to rise moderately in 2022, due to gas compression at Cygnus.

8. Methane intensity
(%)

2021 0.02
2020 0.01
2019 0.02
2018 0.01

OGCI industry average was 0.20%.

Description This refers to methane emissions from our production operations as a percentage of the volume of the total gas exported.

Performance Our methane intensity remained stable in 2021 and we remain on track to meet our target of net zero methane emissions by 2030.

9. Economic impact
($bn)

2021 3.3
2020 2.1
2019 2.8
2018 2.6

Description This includes our direct impact (employment and GDP generated from our activities), indirect impact (supply chain spend and employment) and induced impact (wage consumption in the wider economy) to the economies of Norway, the UK, the Netherlands and Germany.

Performance Our total economic impact increased significantly in 2021, primarily due to higher earnings and operating cash flow resulting in higher taxes paid.

12. Capex
($m)

2021 636
2020 741
2019 887
2018 517

Description This includes development capex, including equity-accounted entities.

Performance Development capex declined as we brought online three new projects at Gjøa P1, Duva and Merakes.

13. EBITDAX
($m)

2021 2,109
2020 940
2019 1,600
2018 1,883

Description This comprises net income for the period before income tax expense, financial expenses, financial income, impairment losses, other operating gains and losses, exploration expense and depreciation and amortisation. EBITDAX, as defined by the RBL, excludes our share of net income from Touat prior to 2020.

Performance EBITDAX more than doubled in 2021, driven by higher commodity prices and good cost control.

14. Net debt to EBITDAX
(times)

2021 1.00
2020 1.94
2019 0.93
2018 0.62

Description This includes net debt (excluding Subordinated Neptune Energy Group Limited Loan) to EBITDAX, as defined by the RBL facility and Shareholder Agreement.

Performance The increase in EBITDAX reduced our leverage ratio to 1.00 times at the end of 2021. This was well below our target of 1.50 times.

Our role in the energy transition

Fit for the future

Neptune Energy is a business built for the energy transition. Our portfolio is gas-weighted and has a significantly lower carbon and methane intensity than the industry average. We aim to go beyond net zero by storing more carbon than is emitted from our operations and the use of our sold products by 2030.

Our L10 project has the potential to store 120-150 million tonnes of CO_2 for third-party industrial customers within depleted gas fields

We support the goals of the Paris Agreement and net zero targets set by governments around the world. While these goals look to 2050, we are focusing on what we can do in the short to medium term, recognising that actions in the next 10 years will be crucial in curbing global temperature rises.

We reviewed our strategy in early 2022 and this reinforced the strengths of our business and increased our ambitions for pursuing lower carbon opportunities.

Our strategy is aligned with the ambitions of COP26, acknowledging that gas will continue to play an important role in the energy transition for many years to come. The mainstay of our business will remain lower carbon energy production, but we will accelerate our plans for integrated energy hubs, using existing infrastructure and leveraging our experience and capabilities. We aim to go beyond net zero by storing more carbon than is emitted from our operations (Scope 1) and the use of our sold products (Scope 3) by 2030. This builds on our existing experience and capabilities in CCS and electrification in both Norway and the Netherlands.

Our two areas of strategic focus are:

1. **Lower carbon energy production**
2. **Integrated energy hubs**

1 Lower carbon energy production: producing lower carbon gas and oil efficiently

We will continue to target new production opportunities in our key producing regions, maintaining our gas-weighted portfolio and lower carbon intensity. We plan to prioritise investment in gas as it is a cleaner transition fuel than oil, and optimise near-term returns to ensure we can invest in further lower carbon technologies while maintaining strong profitability overall. New developments that are consistent with our lower carbon strategy will be prioritised, along with those that provide opportunities to integrate energy systems.

We continue to drive improvements in the carbon intensity of our operated production, which, while low for our industry, will increase as our existing operations mature. Given our portfolio is lower carbon due to the actions we have taken already, further operational improvements are unlikely to have a material effect on our intensity. We will therefore pursue electrification to reduce emissions at some of our highest producing assets in areas where it is economic to do so and where the regulatory regime is supportive. Consequently, our short-term focus for electrification is on Norway.

Electrification

The electrification of offshore platforms can help reduce emissions, as gas turbines used to generate heat and power are replaced with an electricity supply. A total of 18% of our net production is already electrified. In Norway, our Gjøa field uses electricity delivered via a submarine cable from shore. We are looking at ways to increase the capacity of the power cable to electrify the platform fully, eliminating the need for its gas turbine. At our non-operated Gudrun platform, the electrification project is progressing well and remains on schedule to start up towards the end of 2022, saving around 60,000 tonnes of CO_2 a year. By the end of 2022, more than 35 kboepd of our net production will have been electrified. Plans to electrify Snøhvit and Njord in Norway are in development with our partners.

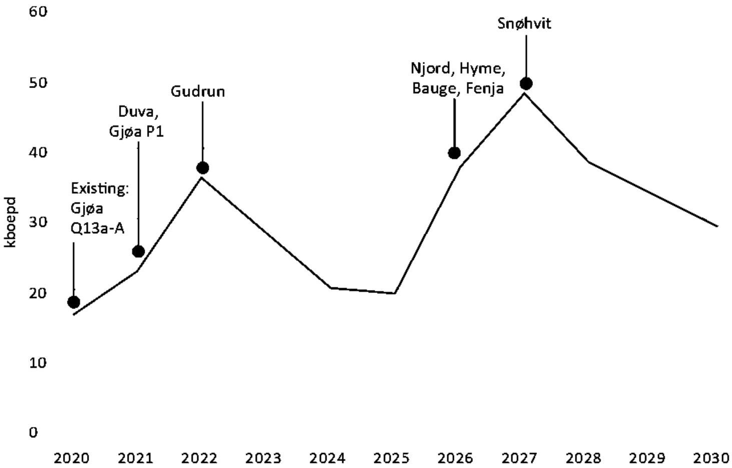
Our Q13a-A platform in the Netherlands is powered using electricity from shore, saving around 6,700 tonnes of CO_2 in 2021. We are reviewing further electrification opportunities in the Netherlands as part of our integrated energy hub strategy. By the end of 2027, we expect that around 50 kboepd of our net production will be electrified.

In the UK, we continue to explore options to electrify Cygnus. We are working with power company Ørsted and energy solutions firm Goal7 on a feasibility study to assess the use of renewable energy to power Cygnus. The study will explore the optimal technical design needed to provide a stable and reliable power supply from an offshore wind farm. We are also working with Ørsted to investigate how electricity from offshore wind could lead to wider integration of energy systems offshore, including hydrogen production.

Our Q13a-A platform in the Netherlands is powered using electricity from shore

Net production electrified

Potential to electrify ~50 kboepd by 2027



- Indicative timeline for future projects at Njord (including Hyme, Bauge and Fenja) and Snøhvit.
- Gudrun electrification project is due to start-up in late 2022.
- Production excludes Nova compensation.

Carbon intensity

While we currently have one of the lowest carbon intensities in the industry at 6.4 kg CO_2/boe, this will naturally increase as our assets mature. This is because more energy is needed to extract more mature oil and gas reserves. Without action, our carbon intensity would increase to 22 kg CO_2/boe in 2030. That is why we have set an ambitious target of 6 kg CO_2/boe by 2030.

Keeping our carbon intensity as low as possible helps us grow in line with our strategy, while focusing on improving efficiency to enable longer-term emissions reductions.

Methane intensity

Methane makes up 7% of our total GHG emissions on a CO_2e basis. Our methane intensity, which refers to methane emissions from our managed operations as a percentage of gas exported, was 0.02% in 2021, up marginally from 0.01% in 2020. We remain on track to reach our target of net zero methane emissions in 2030 and have set an interim target of 0.015% by 2025.

We were awarded 'Gold Standard' status for our reporting to the Oil and Gas Methane Partnership 2.0 framework in 2021. This achievement recognises our robust plans to report and reduce methane emissions for our operated and non-operated assets by 2024 and 2026, respectively.

See **page 26** for information on our joint science project with the Environmental Defense Fund on methane emissions.

Energy efficiency

Our operations in the UK and Germany are certified to the ISO 50001 energy management standard, and we are progressing plans to extend this to all our operated assets. As part of this, we are reviewing energy savings opportunities across our operations.

In 2021, improvements in energy efficiency led to a reduction in energy use of 247 MWh. The majority of this reduction was from Germany, and includes energy saved from optimising the combined heat and power unit at our Bramberge field and replacing pumps with control valves at some of our sites.

In the UK, we commissioned an external organisation to assess energy efficiency and emission reduction opportunities at our Cygnus field. Outcomes are expected in 2022.

Zero Routine Flaring by 2030

In 2021, we endorsed the World Bank's Zero Routine Flaring by 2030 initiative. This initiative brings together governments, companies and development institutions to eliminate routine gas flaring in oil production no later than 2030. We will develop targeted plans for priority assets in 2022.

Our role in the energy transition
continued

2 Integrated energy hubs: using existing infrastructure to integrate energy systems

Our integrated energy hub strategy provides an excellent opportunity to drive offshore decarbonisation through extending the life of offshore assets and repurposing them to facilitate CO_2 storage and hydrogen production, using domestic, lower carbon intensive gas or wind power. By extending field life, electrification could become more economic, helping to decarbonise existing production further.

CCS

Technologies such as CCS can help offset emissions in industries where the technical challenges or cost of decarbonisation are currently prohibitive, such as steel and cement manufacturing. We are a member of industry bodies, such as the Global CCS Institute and the CCSA, that are working to accelerate the deployment of carbon capture, use and storage.

We have 14 years' experience in CCS and are currently looking at large-scale offshore projects that use existing infrastructure. Together, they could help store many times more CO_2 than our own emissions.

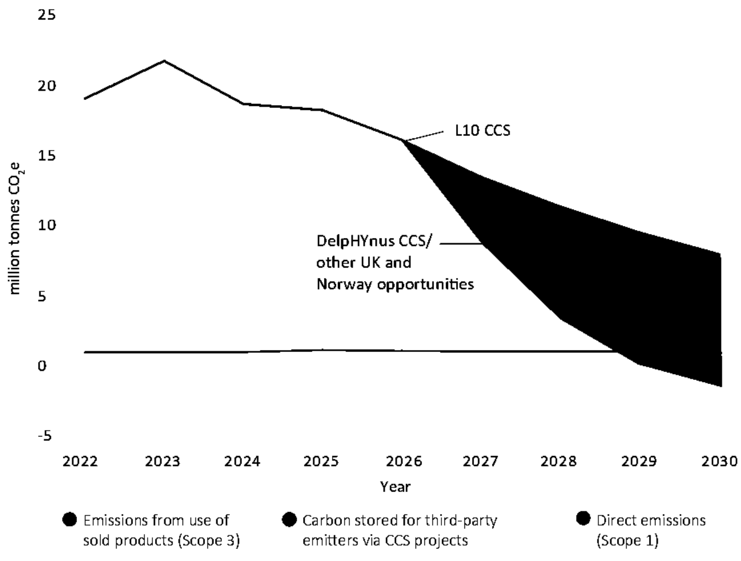
We made important progress with these projects in 2021, including an evaluation of the potential CCS project at L10 in the Netherlands. In early 2022, we introduced a digital twin for the L10-A complex (see page 39) to help progress these plans.

Our L10 project has the potential to store 120-150 million tonnes of CO_2 for third-party industrial customers within depleted gas fields around our operated L10-A, B and E areas.

We expect to have the L10 CCS project FEED-ready by the end of 2022, with the aim of taking a final investment decision in 2023. First carbon injection into the reservoir could be in 2026.

We are also pursuing a CCS storage and appraisal licence in the UK, and further potential opportunities in the UK and Norway.

Indicative emissions trajectory – aiming to store more carbon than we emit



- Assumes 100% ownership of CCS projects, with L10 commencing in 2026 and ramping up to full capacity (5 million tonnes of CO_2) in 2028, and DelpHYnus/other UK and Norway CCS opportunities commencing around 2027 and increasing to full capacity (4.5 million tonnes of CO_2) in 2029.
- Our calculation methodology for direct Scope 1 emissions follows the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions. These emissions are calculated on an equity share basis.
- Emissions from use of sold product are Scope 3 category 11 emissions. This includes 2P reserves and 2C resources.

Hydrogen

Hydrogen will play a vital role in the energy transition. It can provide long-term energy supplies at scale, help improve air quality and strengthen energy security.

We are a member of the European Clean Hydrogen Alliance, which supports the large-scale deployment of clean hydrogen technologies by 2030, as well as the Energy Institute's Hy2003 group which is assessing the environmental impacts of deploying hydrogen at scale.

We are working with partners to progress the development of hydrogen. We have signed a joint development agreement with RWE Renewables and will initiate a new large-scale offshore project in the Netherlands. The H_2opZee project aims to produce green hydrogen with wind energy and use existing pipeline infrastructure. We are planning a feasibility study to evaluate an initial 300-500 MW of generating capacity, with a pipeline to enable a future increase in capacity to 10-12 GW.

We expect to complete detailed design work for our PosHYdon project in 2022. This pilot project will include the installation of a green hydrogen-producing plant on our Q13a-A platform in the Dutch North Sea. The plant will convert seawater into demineralised water, then into green hydrogen via electrolysis, which will be blended with natural gas and transported to shore via an existing pipeline.

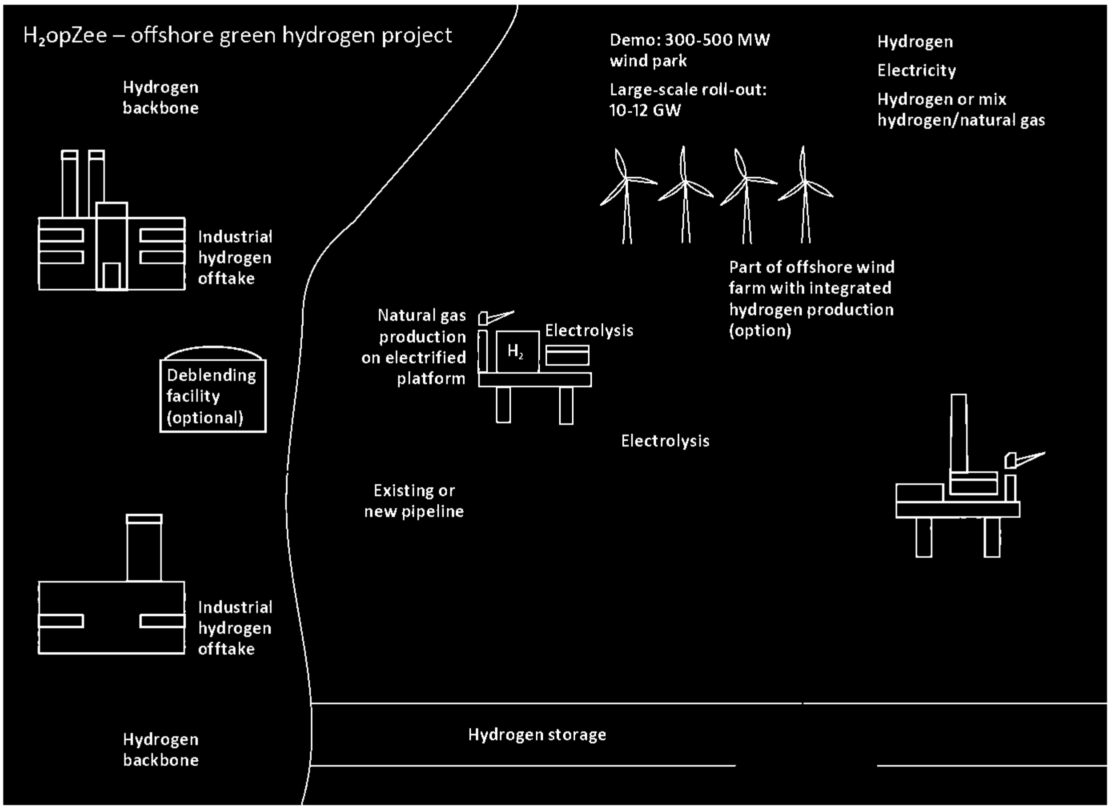
Transparent disclosure

We want to provide our stakeholders with data and information so that they can assess our performance and track our progress.

While we have the most influence and control to reduce emissions in the assets we operate, we have begun reporting our equity share emissions to provide a view of our total environmental footprint. We are working with our partners and suppliers to reduce these emissions. See page 39.

In 2021, our direct Scope 1 emissions on an equity share basis were 888,459 tonnes of CO_2e. Emissions are estimated based on 2021 data for assets we operate and 2020 data for non-operated assets (due to the availability of partner data within our reporting period). A total of 43% of our production was from non-operated ventures in 2021.

We recognise that the majority of emissions from oil and gas products come from their end use, which is why, for the first time this year, we are reporting our Scope 3 emissions from the use of our sold products (see page 25). As a purely upstream company we have less opportunity to reduce these emissions, but have included this metric to provide additional transparency on our product footprint.



Climate-related financial disclosures

We continue to align our disclosures with the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). We report against the TCFD recommendations below, with more information at *neptuneenergy.com/tcfd*.

Governance

TCFD recommendation: Disclose the organisation's governance around climate-related issues and opportunities.

Our Board oversees our approach to managing climate-related issues and opportunities. They are updated on these matters on a frequent basis and in 2021 reviewed potential lower carbon projects, our carbon and methane intensity performance and our climate-related financial disclosures. See pages 78 and 83 for more information on the Board's oversight of climate-related issues and opportunities.

The Executive Team is responsible for assessing and managing climate-related matters and is supported by our ESG Committee (see page 91). The Executive Team and country managing directors monitor our carbon and methane intensity performance each month. The Executive Team reviewed the development of our strategy and lower carbon ambitions, ahead of the Board's review, in early 2022.

From 2022, progress against our carbon intensity target will be a factor in determining bonuses for the Executive Team and employees.

Strategy

TCFD recommendation: Disclose the actual and potential impacts of climate-related risks and opportunities on the organisation's business, strategy and financial planning where such information is material.

We recognise the potential impacts of climate-related risks on our ability to deliver our strategy. Our principal risks include four climate-related risks: i) risks relating to host country and investor policy and regulation changes in response to climate change, ii) risks relating to the lack of viable lower carbon transition options, iii) the risk of increased litigation across the oil and gas industry, and iv) risks associated with the physical impact of climate change. See pages 73-77 for more information on how we are mitigating these risks and page 141 for information on potential financial implications related to climate change.

We also recognise the opportunities created by the energy transition. Neptune is already well positioned, with a portfolio that is gas-weighted and that has a significantly lower carbon and methane intensity than the industry average. We reviewed our strategy in early 2022, taking into account potential climate-related risks and opportunities. As a result, we are focusing on lower carbon energy production and integrated energy hubs. See pages 20-23 for more information on our strategy and how we are pursuing lower carbon opportunities.

Capital allocation for gas and oil developments will target opportunities close to our core hubs where we can drive integration with our lower carbon objectives. We see significant near-term growth potential for gas and oil in Norway and Indonesia, while the Netherlands is a priority for investments that will support our integrated energy hub strategy. Large, complex, higher carbon and higher cost developments with long-time horizons are less likely to meet our investment criteria.

Our role in the energy transition
continued

Strategy (continued)

To test the resilience of our portfolio, we conducted scenario analysis against IEA scenarios, using projected commodity and carbon prices out to 2050, given that price is a key variable in how transition risk materialises. This is our first year conducting this analysis and we will progress this in the years ahead.

The analysis showed that due to the significant difference in assumptions around commodity prices in the IEA scenarios, compared with our own, the net present value of Neptune's European portfolio was positively impacted across all scenarios. The net present value of our North Africa and Asia Pacific portfolio was most negatively impacted in the NZE Scenario.

The majority of our operated production is from jurisdictions where there is already a high CO_2 price and we have a carbon intensity of 6.4 kg CO_2/boe, which is significantly lower than the industry average of 15 kg CO_2/boe.

Due to this, changes in value are driven almost entirely by the oil and gas price assumptions made in the IEA scenarios.

Neptune uses consensus long-term oil and gas prices but also tests the robustness of projects at lower prices. In comparison, the IEA's *World Energy Outlook 2021* estimates future real energy prices at 2030 and 2050. Under STEPS, the projected 2030 real price is $77/bbl for oil with gas at around 55p/therm. The prices are lower under SDS (oil at $56/bbl and gas 30p/therm) and lower still for the NZE Scenario (oil at $36/bbl, gas 28p/therm). In the period from 2022 to 2030, energy prices are assumed to start at the actual average 2021 level and achieve the 2030 IEA estimate by using three different approaches – linear, forward curve and consensus.

In STEPS, which reflects the current policy landscape, the net present value of our entire portfolio is positively impacted. This is primarily because projected prices under STEPS are higher than Neptune's projected prices.

Under the SDS, which assumes a surge in clean energy policies for a pathway that is well below 2°C, our European portfolio is positively impacted. This is because prices are still higher under SDS in the short to medium term when production is at its highest. The impact is broadly neutral for the portfolio in North Africa and Asia Pacific.

In the NZE Scenario, which sets out a pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, European values remain robust. However, the North Africa and Asia Pacific portfolio would see a decline in value of around 10-25%, as pricing is mainly oil related, although production is primarily gas. Oil prices in this scenario fall a further 35%, while the reduction in gas prices is around 7%.

The findings from this initial analysis indicate that our focus on producing lower carbon gas and oil efficiently, and using existing infrastructure to integrate energy systems, will continue to strengthen the resilience of our portfolio.

Net present value (NPV) of portfolio	Stated Policies Scenario (STEPS)	Sustainable Development Scenario (SDS)	Net Zero Emissions Scenario (NZE)
Europe	+55% to +75%	+30% to +50%	+10% to +30%
North Africa and Asia Pacific	+5% to +20%	-10% to +5%	-10% to -25%

Risk management

TCFD recommendation: Disclose how the organisation identifies, assesses and manages climate-related risks.

We identify, assess and manage climate-related risks, including transitional and physical risks, through our enterprise risk management system.

We use an internal carbon price in our investment decisions. We operate in countries that already have well-established carbon pricing systems, such as Norway, and monitor potential changes in regulation to assess the likely impact on our portfolio. In 2021, for example, we assessed electrification projects in Norway, with higher carbon prices having a positive impact on their economic viability.

Our physical climate change risk assessments are based on the geographical location of our facilities. We assess each facility's exposure to environmental conditions such as flooding, extreme weather events, rising sea levels and water stress, using projections to mid-century. Our assessments in 2021 found that no changes to the design of our assets are required within their expected life spans. We will continue to monitor updated projections and assess any potential risks to our assets.

See **pages 70-76** for more information on climate change risks and mitigation actions.

Metrics and targets

TCFD recommendation: Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.

We set out our key metrics and targets to assess and manage climate-related risks and opportunities below. From 2022, progress against our carbon intensity target will be a factor in determining bonuses for the Executive Team and employees.

GHG and energy use performance table[a]

	2021	2020	2019	2018
Total scope 1 emissions (direct) (t CO_2e)[b]	**570,084**	512,113	530,300	588,195
UK scope 1 emissions (direct) (t CO_2e)[b]	**38,237**	32,396	–	–
Total scope 2 emissions (indirect) – location based (t CO_2e)[c]	**37,758**	43,701	31,586	27,854
UK scope 2 emissions (indirect) – location based (t CO_2e)[c]	**861**	478	–	–
Total scope 2 emissions (indirect) – market based (t CO_2e)[c]	**132,519**	–	–	–
Total scope 1 and 2 emissions (t CO_2e)[d]	**607,842**	555,814	561,886	616,049
UK scope 1 and 2 emissions (t CO_2e)[d]	**39,098**	32,874	–	–
Total carbon intensity (kg CO_2/boe)[e]	**6.4**	6.3	5.8	6.0
UK carbon intensity (kg CO_2/boe)[e]	**1.7**	1.3	–	–
Total carbon intensity (t CO_2e per kt hydrocarbon production)[f]	**56.3**	54.2	–	–
UK carbon intensity (t CO_2e per kt hydrocarbon production)[f]	**19.9**	10.9	–	–
Total methane intensity (%)[g]	**0.02**	0.01	0.02	0.01
Total energy consumption (MWh)[d]	**2,481,141**	2,538,760	2,546,503	2,992,184
UK energy consumption (MWh)[d]	**103,199**	104,331	–	–
Total reductions in energy use as a result of energy efficiency initiatives (MWh)	**247**	1,581	10,574	970
Total flaring (GJ)	**482,786**	393,682	437,152	458,984
Total scope 3 emissions (business travel) (t CO_2e)[h]	**439**	843	–	–
UK scope 3 emissions (business travel) (t CO_2e)[h]	**277**	225	–	–
Total scope 3 emissions (use of sold product) (Mte CO_2e)[i]	**13.5**	–	–	–

a We report our GHG emissions and energy consumption data on an operational control basis, reporting 100% of emissions from activities operated by Neptune Energy. This includes Germany, the Netherlands, Norway and the UK. This table includes disclosure to comply with the Streamlined Energy and Carbon Reporting requirements. Our calculation methodology follows the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions. In 2021, we changed our reporting boundary to include emissions from the flaring of our reservoir hydrocarbons during contractor drilling activities. Further information on our methodology is below and in our Basis of Reporting at *neptuneenergy.com/esg.*

b This includes CO_2, N_2O and methane emissions from combustion for energy, flare, direct hydrocarbon emissions, company cars, fleet vehicles and exclusive contract logistics from operations we own or control.

c This includes emissions from the purchase of electricity. Less than 1% of our Scope 2 emissions is for the purchase of heat, steam and cooling for our own use. Emissions are calculated using location based grid average emission factors supplied by UK Government Emissions Conversion Factors for Greenhouse Gas Company Reporting (Department for Business, Energy & Industrial Strategy, 2021) and for the remaining countries are purchased from the IEA. Scope 2 market based calculations use supplier specific emission factors where supplier specific data in the form of contractual agreements is available. Where this is not available, factors from AIB, using the European Residual Mix, are used.

d Scope 2 emissions for this metric are calculated using the location based method. Our total UK Scope 1 and 2 emissions were 6% of the total emissions from assets under our operational control. Our total UK energy consumption was 4% of the total. All of our emissions in the UK were emitted by entities in our Group incorporated in the UK.

e This includes Scope 1 and 2 emissions related to production/operations. We calculate intensity using wellhead production, in line with the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions.

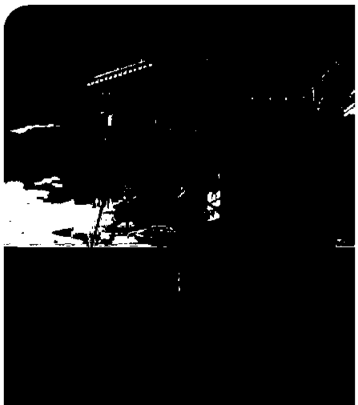
f As per SECR requirements, we are reporting tCO_2e per 1,000 tonnes hydrocarbon production. This includes emissions from production only.

g This metric, which is calculated using Oil and Gas Climate Initiative (OGCI) methodology, refers to methane emissions from our production operations as a percentage of the volume of the total gas exported.

h This includes car and air travel. Emissions from business travel cars only was 84 t CO_2e.

i This includes emissions related to Neptune's share of sold products for both operated and non-operated assets and is calculated using IPIECA/API/IOGP's final content method.

EY has provided limited independent assurance over all 2021 metrics in the table above. See *neptuneenergy.com/assurance* for EY's assurance statement.



Our Gjøa gas and oil asset in Norway has a carbon intensity of 2.8 kg CO_2/boe

Our targets

Our overarching ambition is to store more carbon than is emitted from our operations and the use of our sold products by 2030 (see page 22).

L10 CCS
project to be FEED-ready by the end of 2022

~50 kboepd
of net production electrified by 2027

9.0 Mte CO_2
stored for third-party emitters by 2030

6.0 kg CO_2/boe
carbon intensity by 2030

Zero
methane emissions by 2030

Zero
routine flaring by 2030

Our role in the energy transition
continued

“ — The study demonstrates how t best of new technolo can be harnessed and deployed to tackle the challenge of reducing methane emissions.”

Charles Tavner Chief Executive Officer, Flylogix

Excellence through innovation

Industry-leading research to improve the accuracy of offshore methane emissions measurements

Reducing methane emissions was recognised as the most effective way to limit near-term climate change at the COP26 summit in Glasgow in 2021. This is because, although short-lived in the atmosphere, methane is a potent greenhouse gas, retaining more than 80 times more heat than CO_2 in a 20-year timeframe. Taking meaningful action today, therefore, can bring positive results in as little as nine years.

We partnered with the Environmental Defense Fund (EDF) and global investment firm Carlyle in 2021 to use advance drone technologies to measure methane emissions at one of our operated offshore platforms in the UK.

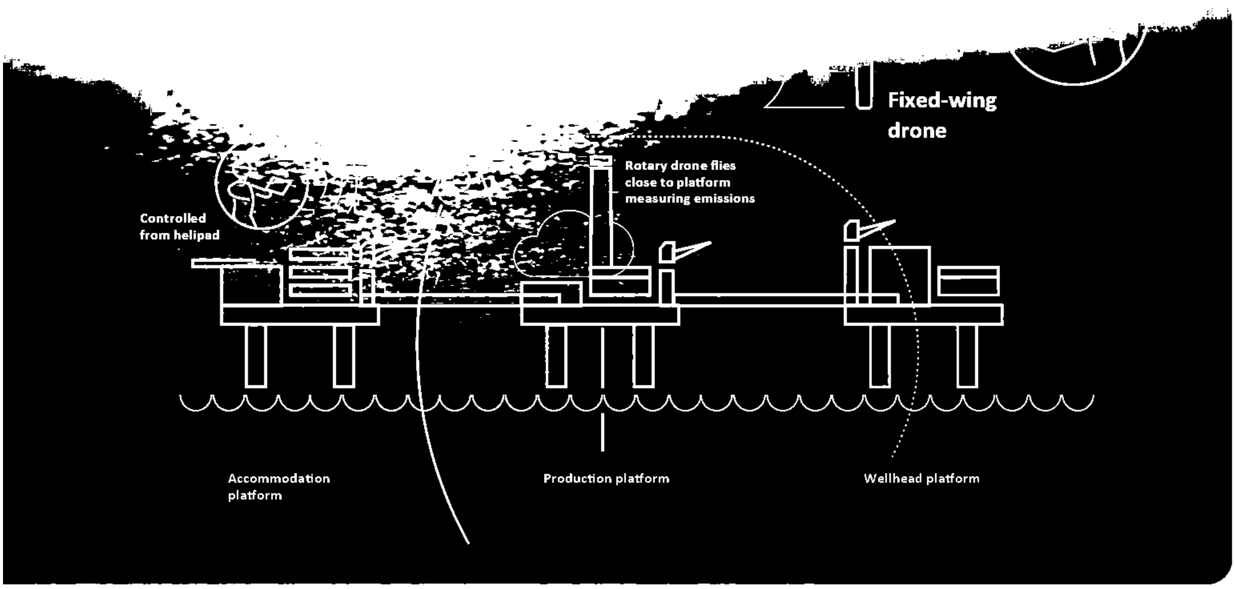
We used fixed wing and rotary drones equipped with methane-sensing equipment at our Cygnus gas production facility to assess advanced methods for identifying and quantifying facility-level offshore methane emissions, and to help determine the actions we can take to reduce them.

A key objective was to establish an accurate, scientific benchmark for measuring total methane emissions within an offshore environment to help develop best-practice approaches for the wider upstream industry.

EDF scientists coordinated the five-day study, which involved a team from UK-based drone platform provider TEXO DSI, operating a rotary drone provided by Scientific Aviation. Equipped with sensing technology, the drone measured emissions at multiple locations around the platform.

In parallel, an unmanned fixed-wing drone, carrying methane measuring and analytics technology provided by SeekOps, flew from an airfield in Norfolk to the Cygnus platform. Operated by Flylogix, the aircraft circled the facility and covered a total of more than 313 miles. We believe the flight is one of the longest of its kind in the UK North Sea.

For more information see *neptuneenergy.com*



Environment

Managing our environmental impact

We want to reduce the impact that our operations have on the environment. We prioritise issues set out in our environmental policy, such as energy efficiency, greenhouse gas and other air emissions, water, biodiversity and spill prevention.

Our environmental policy is supported by our environmental standards, which detail our requirements, ensuring a common understanding throughout Neptune. This includes requirements on consulting with stakeholders who may be affected by our activities. Our CEO is responsible for ensuring that the policy is followed across the business.

Our environmental management system is certified to ISO 14001 in the UK. In 2021, we conducted a gap analysis across our operated countries, appointed a global certification company and will progress certification for our remaining countries in 2022.

We carry out environmental impact assessments when planning new projects. This includes understanding the potential impact our activities could have on biodiversity, freshwater resources and air quality. We use the results to identify the actions we can take and the measures we can put in place in our project design and operations to lower that impact.

When our projects move into operations, we continue to assess and monitor the impact of our activities. We conduct environmental audits to ensure compliance with our standards and other regulations.

We work with our industry to share and learn from good practice on issues such as emissions reductions and biodiversity. We do this via our membership of trade associations such as the International Association of Oil and Gas Producers and IPIECA. In Germany, our Public Affairs Lead chairs the Sustainability and Environment Committee of BVEG, the German association for natural gas, petroleum and geothermal energy.

Other air emissions

In 2021, our nitrogen oxide (NOx) emissions were 701 tonnes (2020: 1,075 tonnes). We are working to reduce air emissions from our activities. In the Netherlands, for example, we are working towards meeting NOx emissions reduction targets as set out by national legislation. We have introduced low emission turbines and adjusted their running times. This has led to a reduction in our Dutch NOx emissions of 82% between 2018 and 2021.

Oil spill prevention

Our aim is to have zero operational spills. We assess the risk of spills at each of our assets, taking into account various spill scenarios. We put in place physical, technical and operational barriers to prevent and mitigate the risk of spills and have contingency plans in place to protect the environment in the event of a spill. We had no spills greater than one barrel in 2021.

Water

We use non-freshwater, such as sea water in our drilling and production processes. At our Cygnus offshore facility in the UK, we use reverse osmosis to convert sea water into drinking water. We also use freshwater, mainly in our offshore operations, for drinking, cooking and sanitation.

None of our operated assets were located in water scarce areas in 2021 and more than 80% of our production is offshore. We recognise, however, that the availability of water can vary in the different regions where we work. We developed water management plans in 2021 to identify measures we can take at a local level to minimise our impact.

In 2021, our total freshwater consumption decreased to 94,269 m^3 (2020: 107,466 m^3). Our water intensity (tonne of water per tonne of production) was 0.02%.

We are committed to monitoring and reducing hazardous contaminants in discharges to water. To minimise adverse effects on the environment, we treat produced water to remove contaminants prior to discharging.

Decommissioning

We consider environmental factors when decommissioning and closing a site. When decommissioning wells onshore, for example, we fill in the wells and dismantle the extraction and processing equipment. Well sites are cleared and refilled with topsoil to return the land to its original condition.

We support initiatives to promote economic development after site closure. We spent $38.5 million on decommissioning depleted fields and site restoration in 2021. Around $10 million of this was spent on remediating the Rühlermoor mud pit in Germany. This involved removing and disposing of more than 85,000 tonnes of material. The site has since been recultivated for agricultural use and reforestation.

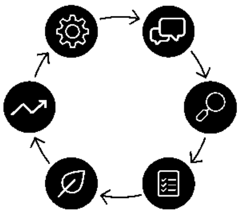
Waste

Waste is created at all stages of exploration and production. Therefore, we require all our projects and operations to establish a waste management plan to prevent waste as the first priority, followed by options for recycling and reuse.

For full performance data, including sulphur oxide emissions and waste, see *neptuneenergy.com/esg*

Biodiversity and ecosystem services (BES) management practices

- Build BES into governance and business processes
- Engage stakeholders and understand their expectations around BES
- Understand BES baselines
- Assess BES dependencies and potential impacts
- Mitigate and manage BES impacts and identify BES opportunities
- Select measure and report BES performance indicators



Number of sites within a protected area

Biodiversity

Our overall aim is to achieve a net positive impact on biodiversity by restoring and enhancing biodiversity in the areas where we work. We launched our biodiversity strategy in 2021, setting out our commitments to restore, preserve and enrich biodiversity in the countries where we work. The strategy is aligned with IPIECA's six biodiversity and ecosystem services management practices, a set of guidelines on the impacts, dependencies, risks and opportunities in the oil and gas sector.

Before starting any project, we assess whether a site will be located close to or within a protected area and apply the mitigation hierarchy to ensure appropriate site selection. We identify measures to reduce any potential negative effects and monitor our impact throughout an asset's operational life through to the decommissioning stage. In the Netherlands, for example, we are helping fund a study by Wageningen Marine Research that is assessing marine growth and food chains around offshore oil and gas platforms. The outcomes can be used to assess how the maintenance or removal of platforms may affect the marine environment.

In total, 17 of our operated assets are located within a protected area. Our Cygnus site in the UK, for example, is in a designated protected area due to the presence of harbour porpoises. Underwater noise from oil and gas activities, such as piling and drilling processes, has the potential to disrupt the species. We conduct passive acoustic sound monitoring when carrying out these kinds of activities to minimise any potential negative impact on the species.

Partnering with SOS Dolfijn to support marine conservation

We are working with the SOS Dolfijn Foundation, which rescues stranded dolphins, porpoises and whales on the Dutch coast and surrounding countries. Each year SOS Dolfijn responds to around 30 cases of stranded mammals.

As part of the three-year partnership, we are sharing our advanced emergency response systems so that the foundation can rapidly mobilise teams of volunteers to provide aid for sick or injured mammals. We also helped fund the foundation's new rehabilitation centre in the Netherlands, which is due to open in the first half of 2022.

The partnership is part of our commitment to support the UN Sustainable Development Goal 14: Life below water.

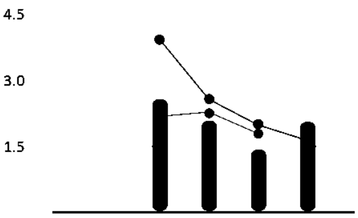
Looking ahead, we plan to provide SOS Dolfijn with acoustic monitoring data and recorded sightings of marine mammals from our offshore platforms in the Dutch North Sea. This will help increase the foundation's understanding of marine mammals and help protect populations in the wild.

Safety

A relentless focus on safety

Safety underpins all our business activities. Our priority is to make sure our people always go home safely, no matter where in the world they work.

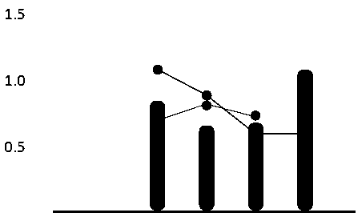
Total recordable injury rate[a]



	2018	2019	2020	2021
Workforce	2.60	2.10	1.43	2.07
Employees[b]	–	4.08	0.44	0.92
Contractors[b]	–	1.30	1.67	2.38

● Target TRIR ● IOGP average[c]

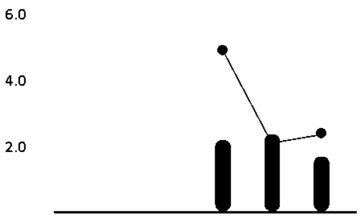
Lost time injury frequency rate[d]



	2018	2019	2020	2021
Workforce	0.85	0.66	0.68	1.09
Employees[b]	–	0.45	0.00	0.46
Contractors[b]	–	0.61	0.83	1.26

● Target LTIF ● IOGP average[c]

Process safety event rate[e]



	2019	2020	2021
Process safety event rate	2.19	2.37	1.68
Tier 1 events	0	0	0
Tier 2 events	1	2	1
Tier 3 events	28	25	16

● Target PSER

a The number of recordable injuries (fatalities, lost work day cases, restricted work day cases and medical treatment cases) per one million hours worked.
b We began reporting this data from 2019.
c IOGP – European average. 2021 data is not available until May 2022.
d The number of lost time injuries (fatalities and lost work day cases) per one million hours worked.
e The total number of tier 1, 2 and 3 process safety events per one million hours worked. This is a Neptune benchmark and is, therefore, not comparable to industry benchmarks. We began reporting this metric from 2019.

Zero
Tier 1 process safety events

>50%
improvement in TRIR and LTIF since 2017

827
people registered on our Thrive wellness portal

12 months
without a recordable injury in Norway

Having the right culture is key to good safety performance and we reinforce good practice through our group-led safety culture programme. Safety performance is a factor in determining bonuses for our employees, as well as the Executive Team. This includes targets for our total recordable injury rate (TRIR) and process safety event rate (PSER).

Our global operational integrity management standard and integrated management system outline our requirements on issues such as safety, health, emergency preparedness, environmental stewardship and risk management.

We identify and assess risks inherent to the oil and gas industry, such as loss of containment, fire, structural failure, helicopter accidents, dropped objects and loss of well control. And we put barriers in place to prevent them. See page 70 for more information on risk management.

All our employees and contractors are responsible for stopping unsafe work. They must follow the International Association of Oil & Gas Producers' (IOGP) nine life-saving rules, which protect our people from the most common causes of fatal incidents in our industry.

To share our experience and learn from others, we work with industry associations such as the IOGP, the Energy Institute and IPIECA, the global oil and gas industry association for advancing environmental and social performance.

We are also working with worldwide humanitarian landmine clearance organisation, The HALO Trust, to share good safety practice and further improve safety performance within both organisations. HALO's team members attended our emergency response exercises in 2021 and will participate in our process safety course in 2022. In turn, HALO has shared its experience of using training and supervision to support good safety practices among teams when clearing landmines.

Safety performance

Despite the restrictions imposed as a result of the ongoing COVID-19 pandemic, our health and safety performance in 2021 was stable. During the period, there were no serious personal injuries. However, our TRIR increased to 2.07 per million hours worked in 2021, largely as a result of relatively minor incidents in the category of slips, trips and falls. This was higher than our annual target of 1.64. Our LTIF rate was also higher than our target of 0.60 per million hours worked, at 1.09. We have put in place an increased training, awareness and remediation plan to address this.

We had no tier 1 process safety events – losses of primary containment with the greatest consequence – in 2021. Our PSER, which includes tier 1, 2 and 3 process safety events, improved significantly to 1.68 per million hours worked, against a target of 2.37. Of the 17 events that occurred, 16 were in the tier 3 category and considered to be 'leading events'.

We take a restorative justice approach to support continual improvement. This means we do not simply investigate what happened when an incident occurred, but how it happened. Understanding the decisions and actions that led to a near miss, for example, helps us learn and improve, so we can prevent more serious events from occurring. We ran a programme in 2021 to enhance our ability to identify and predict issues earlier by strengthening employee and contractor awareness of the IOGP's process safety fundamentals.

We will implement ISO 45001 certification in the UK, the Netherlands and Germany in 2022. Our safety data has been internally audited in 2021.

Well integrity

Maintaining the integrity of oil and gas wells is crucial to preventing harm to people or damage to the environment. Wells containing hydrocarbons at pressure are a major hazard that require systematic management.

Our global operating standards include requirements on well integrity that seek to ensure our wells are managed safely and with care for the environment throughout their lifecycle from well construction to operations to abandonment. At each phase, we use a combination of physical, operational and organisational barriers to prevent the uncontrolled release of well fluids.

Contractor safety

We are committed to keeping our whole workforce safe. Contractors carry out around 80% of the hours worked at Neptune and are fundamental to the safety of our operations.

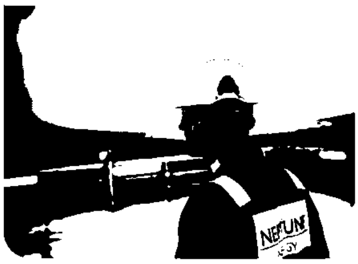
Health and safety criteria are included in our pre-qualification and selection processes for contractors, and our standard model contracts include health and safety clauses.

We monitor contractor safety performance through the life of the contract, using third-party tools and, where appropriate, our own safety audits. If there is a divergence between our own safety management system and those of our contractors, we put in place formal bridging systems to ensure a strong safety culture.

We also run safety workshops and forums for our contractors. In 2021, for example, we hosted bi-annual contractor safety forums in the Netherlands, with more than 30 key suppliers. The sessions covered best practices in process safety and occupational health.

Emergency preparedness and response

We do all we can to prevent incidents and have processes in place to enable the earliest detection and a prompt response to emergencies. We operate a four-tier management model for emergency response, which ensures Neptune delivers its duty of care, from an initial site incident to Board-level oversight.



Cyber security

To manage the increasing global threat of cyber attacks, we introduced new cyber security emergency response procedures and delivered training and awareness programmes for our employees. A total of 92% of employees completed e-learning on cyber security in 2021. In addition, we held sessions for each of our countries and functions on cyber risks and conducted simulated phishing exercises across the Group. Our digital security team delivered 726 hours of training on cyber security in 2021.

Health

Throughout 2021, we worked closely with our global health provider to maintain a detailed understanding of the changing COVID-19 developments to help protect our people. We saw a partial return to offices across our countries and took appropriate measures in line with government guidelines.

Our Thrive wellness portal is available to all our people, and provides information on a range of resources in four key areas – physical, mental, social and day-to-day wellbeing. Our people, and their family members, can access support and counselling through our Employee Assistance Programme, which is accessible 24 hours a day. To help improve our people's physical health, we held sessions with a fitness coach in 2021, with 370 people participating.

Recognising the effect that COVID-19 has had on people's mental health, we provided additional resources throughout the year. We shared information from our charity partner, Mental Health UK, on how to achieve better mental health and promoted Mental Health Awareness Week and National Schizophrenia Awareness Day. In addition, we are supporting the charity's project to ensure people living with mental illness in remote communities can get online and access the support services they need.

In Norway, we are supporting a new research centre that aims to reduce the number of sudden cardiac arrests by improving diagnostic and monitoring tools. The NEEDED centre opened in September 2021, and we are funding several PhD positions over the next three years to help support its research.

Powering social and economic development

The energy we produce helps keep people warm, the lights on and the world moving. Our activities enable economic growth, helping to create jobs, support local supply chains and contribute to national tax reserves.

$3.3bn

ECONOMIC IMPACT

... total gross value added contribution in Europe

1,294

EMPLOYEES

... working across Europe, North Africa and Asia Pacific to deliver our strategic ambitions

$571k

COMMUNITY INVESTMENT

... we doubled our investments in social initiatives in 2021

Our society

Our people

Our people are fundamental to our success. We have almost 1,300 employees in Europe, North Africa and Asia Pacific. We have a dynamic and unique culture, where new and different ways of thinking are part of our DNA.

Our team in Indonesia practiced yoga at an offsite in December 2021

EMPLOYEE PROFILE[a]

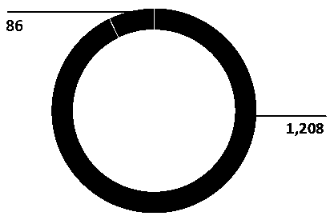
1,294
people

22%
female

38
nationalities

47
average age

Employees by region



a Based on full-time equivalent as at 31 December 2021

Supporting our people during COVID-19

Protecting the health, safety and wellbeing of our people remained a priority throughout 2021. We monitored changing restrictions and government guidance across our countries, maintained local support networks and continued to promote the use of our external Employee Assistance Programme for those who needed additional support.

We maintained frequent contact and provided regular updates to our people through country town halls. Our global occupational health service, International SOS, also led global webinars to discuss issues such as the impact of new variants.

During lockdowns, we ensured that those required to work at home were supported with the necessary home office equipment, and provided support for ergonomic assessments and guidance on maintaining mental health and wellbeing.

In Indonesia, we provided quarantine space for those unable to isolate in their homes and worked with a local doctor and pharmacies to ensure our employees could access medical supplies.

In Algeria, at our joint venture-operated Touat site, a COVID-19 crisis team maintained high standards of health and safety by carrying out daily assessments and proactively implementing mitigation measures, such as quarantine requirements onsite. The team worked closely with the Algerian authorities and medical health providers to establish a COVID-19 prevention plan and minimise the risk of infection.

As we moved to introduce long-term hybrid working arrangements, we developed new hybrid working policies that are tailored to specific countries. We also introduced an international remote working policy to provide clarity on how and when employees can work from another country.

For more information on how we supported our people and our communities during the pandemic, see pages 31 and 40 respectively.

Attraction and retention

We want to provide a great place to work. We offer competitive pay and rewards and our benefit packages include retirement plans, health and medical insurance, life assurance and paid parental leave.

Developing the skills and capabilities of both our existing and future workforce is essential to help us continue to grow and to support the wider energy transition.

In the Netherlands, we participate in the Young Energy Officers programme, an initiative launched in association with the Netherlands Oil and Gas Exploration and Production Association (NOGEPA). This aims to encourage discussion with young professionals about the energy transition and net zero goals.

We support our people to develop their careers at Neptune. As an example, in establishing a new team to assess strategic low carbon opportunities, we filled more than 50% of the roles through internal development moves.

Our training programmes, which range from building technical skills to developing leadership capabilities, include a mix of learning opportunities. These include on-the-job development, virtual classrooms, face-to-face learning and online modules.

Our first line manager training programme is aimed at employees who are new to leadership roles, and we run an online development programme for more experienced leaders which includes 360° feedback and coaching sessions.

We launched a new online mentoring platform in 2021, allowing employees to become either a mentor or mentee across any aspect of the business. More than 130 employees signed up to the platform in the first year. We also participate in external mentoring programmes run by the Engineering Construction Industry Training Board and the AXIS Network to share our experience and help mentees develop their skills.

We run multi-year apprenticeship and in-year intern programmes, providing opportunities to 29 people in 2021.

All employees take part in at least two formal performance and development reviews a year, discussing their personal goals, performance, areas for improvement and career development with their manager.

Our voluntary turnover rate rose to 5.3% in 2021 (2020: 2.7%), but remains lower than the industry average. The increase reflects the broader job market, with the easing of lockdown restrictions leading to increased job movement.

Employee engagement

To find out what our employees think about Neptune, we conduct an annual engagement survey. A total of 76% of employees participated in 2021 (2020: 72%). Our overall engagement score increased to 73% (2020: 70%).

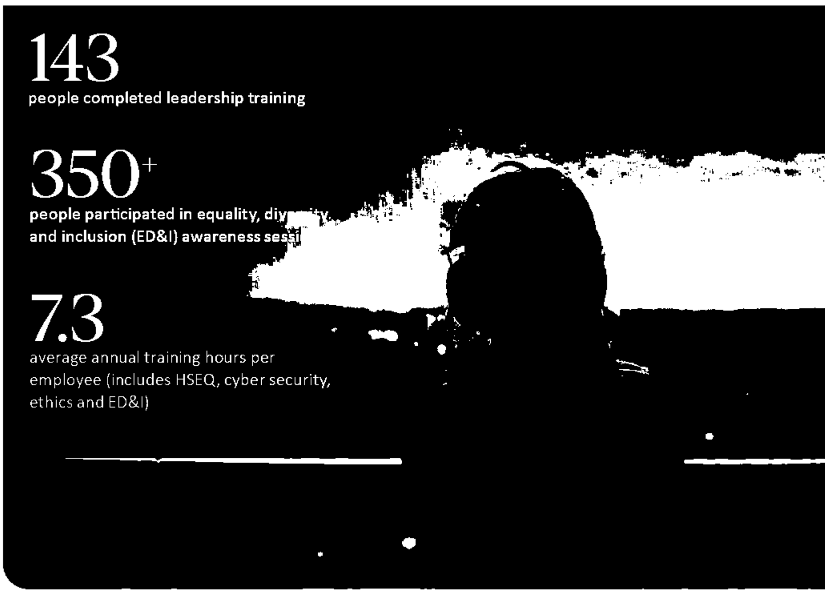
The results showed that our people are proud to work for Neptune and continue to take personal responsibility for maintaining high standards of safety. Scores on being treated fairly and Neptune being a diverse and inclusive workplace also increased. Training and development was an area highlighted for improvement, and we will work with employees to address this in 2022.

We maintain regular communication between our leadership teams and staff through town halls, webinars, weekly CEO blogs, Yammer, extended leadership meetings and many employee forums. Our leaders regularly visit sites to talk directly to those who are working in front-line roles. We have sought to maintain and prioritise these visits, while remaining compliant with COVID-19 regulations.

We engage proactively with works councils or employee forums in all of our operated locations, as well as with safety committees for both onshore and offshore sites.

We are members of the IOGP and Energy Institute's safety committees and hold frequent safety meetings, working with operational leaders and safety supervisors to implement safety campaigns. Our country Managing Directors and Heads of HR and HSEQ are the main contacts for these groups.

Our European Employee Engagement Forum (see next page) is chaired by our Group Human Resources Director and attended by our CEO and Group HSEQ Director.



Our society
continued

Our European Employee Engagement Forum creates opportunities for direct communication between employee representatives and our Executive Team. It meets twice a year to discuss topics such as health and safety, business performance and employee development and engagement.

As set out in our Human Rights Policy, we are committed to freedom of association and work with the trade unions and works councils that our employees wish to be represented by, within the appropriate national laws. Around 36% of our employees were covered by a collective bargaining agreement in 2021.

Code of Conduct

Our Code of Conduct sets out our expectations and commitment to act with the highest degree of ethics and integrity. It contains five principles:

- Acting in accordance with law and regulations.
- Establishing a culture of integrity.
- Behaving fairly and honestly.
- Respecting others.
- Speaking up.

We revised our code in 2021 to include examples and scenarios that help make it easier for our people to apply its principles in their daily work. The code applies to all employees, Directors and officers of Neptune Energy worldwide, as well as to contract staff. We also expect our suppliers and those working on behalf of Neptune to adopt equivalent standards.

Speaking up

We encourage our people to speak up if they are concerned about any inappropriate, illegal or corrupt behaviour in relation to our activities, as well as any actions that are, or could be, harmful to our business.

If a member of staff has a concern, they can raise it via one of several channels, including their line manager, local Ethics Champion, legal counsel or HR representative, as well as the Head of Global Ethics and Compliance, or their local employee, union or safety representative. They can also raise it via the Vault Platform app.

The Vault Platform allows our people to anonymously report any concerns of unethical or unfair behaviour in our business. We added new functionality in 2021 so that anyone working for one of our suppliers can also now raise a concern through the platform.

In 2021, 11 concerns were raised via the Vault Platform. We have taken action to address these, with 10 of the reports now closed, and one subject to ongoing investigation.

We do not tolerate retaliation in any form against any individual who speaks up in good faith.

Our ED&I charter

Build	Attract	Select	Support	Develop	Measure	Belonging
Grow capability that drives conscious inclusion	Encourage women and minorities into STEM careers	Promote equal hiring practices	Implement policies that support inclusion	Increase diverse representation at all levels	Communicate progress and celebrate success	Build networks that promote new connections

Excellence in HSE | Accountability | Integrity | Teamwork

Equality, diversity and inclusion

We want to create an environment where everyone is accepted and valued. A strong commitment to equality, diversity and inclusion (ED&I) is not just the right thing to do, it is essential. Diverse and inclusive companies perform better because they are able to understand different perspectives and make better, more informed decisions that accurately reflect societal expectations.

From recruitment to career development to promotion, we aim to ensure equal opportunities for all employees, regardless of age, gender, sexual orientation, ethnicity, marital status, religion or belief, disability or political views. It is our policy that people with disabilities should be given fair consideration for all vacancies against the requirements for the role.

We are committed to treating everyone with dignity and respect, and to providing a workplace that is free from discrimination, harassment and bullying. We expect our partners and suppliers to do the same.

Our ED&I Committee, which is led by our executive sponsor, Andrea Guerra, oversees group-wide progress on our ED&I charter. The charter, which is aligned with our values, groups the common themes that our people told us they'd like us to take action on.

Build
Grow capability that drives conscious inclusion

Throughout the year, we delivered focused communications to raise awareness of ED&I, including an ED&I month (see page 37), CEO blogs, town halls and Yammer discussions.

As well as helping our people develop their skills, our new mentoring platform aims to strengthen understanding among our people, as well as helping them share new perspectives and build better connections.

Attract
Encourage women and minorities into STEM careers

In the UK we are a member of AXIS, a not-for-profit member organisation that promotes diversity in the Aberdeen oil and gas industry. The network connects mentors and mentees across the region, and in 2021, we had three mentoring partnerships in the programme.

In Indonesia, we participated in a programme for university students on gender diversity in the oil and gas industry to mark Kartini Day, which commemorates Indonesia's national heroine of women's empowerment. One of the programme's key messages was that diversity is vital for driving innovative and inclusive solutions for clean energy transitions all over the world.

In the Netherlands, we participated in a pilot programme in 2021 with the Klapstoel Academy. Five of our young female employees participated in the career coaching programme, which connects young women at the start of their careers to women working in senior-level roles. This gave them the opportunity to discuss their ambitions and to get actionable career advice.

Select
Promote equal hiring practices

We want to attract diverse candidates into Neptune. One of the ways we can do this is by making our commitment to ED&I clear in our recruitment processes. We challenge our leaders, HR teams and external recruitment agencies to ensure we have access to a diverse pool of candidates. This diversity can take many forms, such as age, race, gender, sexual orientation, belief and cognitive diversity.

We tailor our approach depending on the role. For example, we may be looking for stronger female representation for operational roles or stronger local national representation for rotational roles in our joint venture operations. In every case, we seek to ensure that both long and short lists for candidates include a diverse pool before we proceed to the interview stage.

Support
Implement policies that support inclusion

In 2021, we reviewed our maternity, paternity and parental leave policies across our countries and implemented new measures, where appropriate. In the UK, for example, we doubled our paid paternity leave to four weeks and increased the number of weeks of 100% paid maternity leave from 12 to 26 weeks.

We revised our ED&I Policy in 2021 to highlight our key commitments and align with our charter. We also launched our Anti-Bullying, Harassment and Discrimination Standard.

Develop
Increase diverse representation at all levels

We want our senior leaders to represent the communities in which we work, which is why our country operations are led by Managing Directors who are nationals of their countries.

With women making up just 22% of our workforce, we are working to address our gender imbalance. This includes ensuring diversity in job application short lists and identifying high-potential female talent at middle management levels to encourage progression into senior roles. Women made up 27% of those identified as potential successors for executive-level roles in 2021.

We conducted reviews across our countries in 2021 to check that equality exists in jobs of equal value and took action where necessary to ensure fair pay. Our assessment confirmed that we have a strong commitment to equal pay principles. We will continue to conduct these reviews on an annual basis. We have also started to assess gender pay reporting for some of our European operations, which considers average pay across the employee population.

For more information on the diversity of our Board, and that of our parent company, see **pages 85 and 90.**

Gender diversity[a]

Board

Female	Male
2	3

40%

(2020: 40%)

Executive Team

Female	Male
4	15

21%

(2020: 20%)

Senior leaders

Female	Male
28	136

17%

(2020: 13%)

All employees

Female	Male
291	1,294

22%

(2020: 22%)

New hires

Female	Male
57	139

29%

(This is our first year of reporting this information)

a Based on full-time equivalent as at 31 December 2021.

Measure
Communicate progress and celebrate success

We held our first global ED&I month in November 2021, running a range of activities to showcase and promote ED&I. We invited external and internal speakers who spoke on topics such as the effects of racial parity, the importance of a speak-up culture and lessons learned on overcoming bias. We also partnered with training provider, AKD Solutions, to offer employees game-based ED&I learning. In the sessions, participants worked in teams to discuss real-life scenarios and consider dilemmas.

Belonging
Build networks that promote new connections

We have established ED&I groups in each of our countries to drive the issue at a local level. Each of these employee-led groups have developed country-specific actions that are aligned to our ED&I charter. We also have employee-led groups dedicated to specific topics. For example, our Women in Hi Tech group focuses on embedding digitalisation and encouraging future female generations to pursue a career in IT.

Staff at our Römerberg field in Germany, where we support the 'She Drives Energy' initiative, which aims to increase the visibility of women in the sector

Our society
continued

Our partners and suppliers

We aim to work to the highest safety and ethical standards and expect our suppliers to do the same.

We build mutually beneficial relationships with our partners and suppliers that help drive technical excellence and enable us to maintain safe operations.

Our Supply Chain Policy sets out our expectations and commitment to work with our suppliers to create value for all our stakeholders. It includes communicating and embedding our health, safety, environment and quality requirements within our supply chain to create the right conditions and behaviours to protect people and the environment. It also includes our commitment to work with suppliers on ESG matters, such as the energy transition, emissions reductions and ethical working practices.

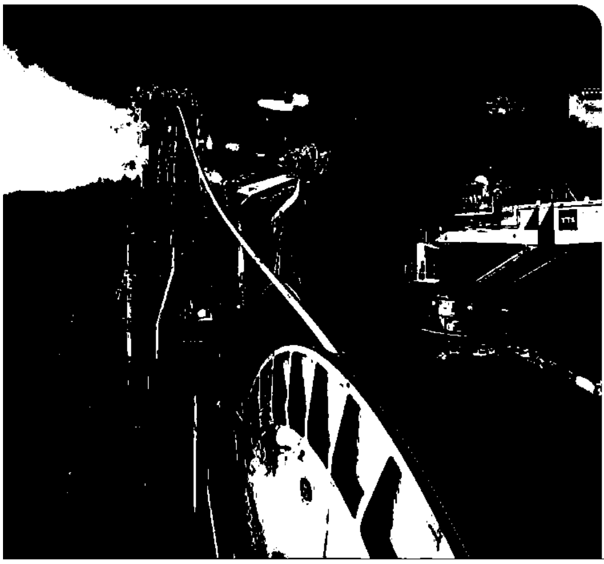
This is backed up by our Code of Conduct, which sets out our expectations that business partners and suppliers will adhere to the same ethical standards.

Engaging with our partners

We work with our joint venture partners via regular formal meetings, such as joint operating and technical committees, as well as ongoing informal engagements.

Before working with a supplier, we carry out a risk assessment and due diligence. We use a screening platform that identifies issues such as sanctions, criminal convictions and any adverse media reports in respect of suppliers. The platform allows us to evaluate the results before deciding whether to work with a supplier.

Throughout the contract lifecycle, we aim to maintain open and transparent dialogue with suppliers. We talk to them via one-to-one discussions, as well as through supplier conferences on topics such as health and safety and ethical conduct. We have performance measures in place with all our major suppliers, which are discussed at weekly and monthly calls. We also hold quarterly performance reviews and six-monthly relationship-level meetings with our suppliers.



Working together to drive excellence in exploration and production

A collaborative approach is key in helping us deliver our strategy and supports new ways of working in exploration and production. For example, our alliance agreement with one of our key subsea contractors, TechnipFMC, promotes safe operations and enables us to share efficiencies and cost savings. It is supported by a commercial model in which collective positive performance is rewarded.

Working collaboratively in 2021 allowed us to execute three major capital projects in the UK and Norway safely while successfully overcoming technical and COVID-19 logistical challenges. In Norway, for example, this included installing and testing an innovative electrical heat-traced pipe-in-pipe production pipeline at Fenja and completing all subsea construction activities for P1 and Duva for first production in 2021.

The partnership has led to outstanding operational performance, with all project delivery goals met and a safety record that is best-in-class.

4,500+
suppliers of goods and services

80%
of hours worked at Neptune are by contractors

We work with our suppliers to help them apply our standards, including health and safety. This helps set expectations and identify mutual opportunities to learn from one another.

Sustainable procurement

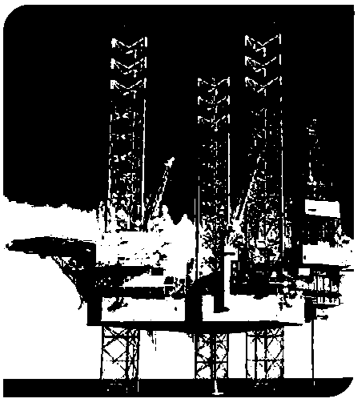
We are progressing our multi-year sustainable procurement action plan, which includes working with our suppliers to maximise efficiency and reduce operational emissions, and enhancing our due diligence procedures on human rights.

To raise awareness of ESG issues in our supply chain, we held sessions with around 80 people in our procurement teams in 2021. We are reviewing our contract standards to ensure agreements comply with our ESG requirements. All new agreements are now subject to our updated standards. We will refresh existing agreements, where required, in 2022/23. This will be followed by the implementation of a supplier ESG monitoring framework in 2023.

Environmental footprint

In 2021, we awarded Borr Drilling a contract to consolidate development and exploration activities in the Dutch and UK sectors of the North Sea. This will help reduce costs and operational emissions, as the Prospector 1 rig we plan to use is equipped with technologies that reduce carbon and nitrogen emissions by up to 95%.

In Norway, we worked with our partners and contractors to install subsea infrastructure at our Duva development using the vessel Far Samson, operated by Solstad Offshore. By using a vessel instead of a rig, we reduced emissions by more than 60% during the operation.



We have also been working with logistics suppliers to reduce emissions from the transport of materials and equipment. In the UK, we worked with one of our suppliers to consolidate truck journeys into weekly deliveries. As a result, we reduced the number of journeys from 270 in 2019 to 74 in 2021, saving 29 tonnes of CO_2 a year.

Ethical conduct

We are a signatory to Offshore Energies UK's Supply Chain Code of Practice. This sets out best practice guidelines on working with suppliers to reach the highest standards of health, safety, ethical and environmental performance.

Suppliers can report any concerns about ethical conduct to their Neptune Energy contract representative or via the Vault Platform website at *app.vaultplatform.com/neptune/Open-reporting*

Assessing modern slavery risk

We are committed to maintaining effective controls to ensure modern slavery is not taking place anywhere in our own business or our supply chains. Our commitments are outlined in our Anti-Slavery and Human Trafficking Policy.

We are opposed to all forms of modern slavery and do not tolerate child, forced or bonded labour in any of our operations or by contractors working for us, as stated in our Code of Conduct.

As part of our pre-contractual due diligence, we ask our suppliers to confirm that they comply with legislation relating to modern slavery.

We make every effort to prevent our activities having a negative impact on human rights and take steps to remedy situations when they arise.

We carry out periodic ethics-related risk assessments throughout our business, including assessing the risk of slavery and human trafficking in our business.

Following a human rights assessment that we commissioned in 2021 (see page 42), we are taking several supply chain-related actions to align with the UN Guiding Principles on Business and Human Rights (UNGPs). These include:

- Introducing a new due diligence screening platform, where, for high-risk business partners, we carry out due diligence with respect to labour and human rights risks.
- Adding a human rights and modern slavery clause in Neptune Energy's standard forms of contract.
- Developing an action plan to improve post-contractual due diligence on suppliers and assess compliance with the terms and conditions of the contract, including the terms of the human rights and modern slavery clause.

See *neptuneenergy.com* for our Anti-Slavery and Human Trafficking Statement.

Borr Drilling's Prospector 1 rig is fitted with technology to reduce emissions

Collaborating on digital innovation

We are working with our technology partners to embed innovative solutions into our business and drive our digitalisation strategy.

We've continued to build our relationship with leading UK-based 3D technology specialist, Eserv, to increase the use of 'digital twins' across our network of operated assets. Seven of our platforms now have a digital twin.

The first five platforms were digitalised in the UK, Norway and the Netherlands in early 2021, allowing engineers and integrity specialists to carry out an estimated 4,100 hours of work from onshore locations. This led to improved efficiency and lower carbon emissions associated with offshore travel.

Two platforms have since been added with digitalised versions of the L10-A complex's drilling and production platforms in the Netherlands. This will support planning for our major carbon capture and storage project in the L10 area.

We are also partnering with oil and gas data visualisation specialist InformatiQ, to digitalise subsea wells in Norway. The developer's GeologiQ cloud-based software combines raw exploration and production data in 3D and 2D environments and uses 3D gaming technology. This allows us to monitor drilling and production operations in real time and gain better understanding of the wells' history.

Through our partnership with PaleBlue, we completed a virtual reality (VR) pilot at our operated Gjøa platform in Norway, enabling teams to visit the facility using a VR headset. The technology, which is also used to train astronauts for the International Space Station, helps our people build their knowledge of the complex multi-level facility. This allows us to reduce transport emissions and plan work operations more efficiently.

In the UK Southern North Sea, we are working with geo-data specialist Fugro to use state-of-the-art remote monitoring and communications tools to inspect subsea structures at our Cygnus gas field.

We are also using technology to reduce the times and costs associated with decommissioning. We are partnering with Maersk Supply Service to remove subsea infrastructure at the Juliet field. A remotely operated tool carrier will recover subsea equipment, reducing the need for multiple vessels and equipment providers to carry out the complex work.

Our society
continued

Our communities

We want to maximise the value we bring to the societies in which we operate. One of the ways we do this is through our social investment programmes, which take into account local community needs and are aligned with the UN Sustainable Development Goals (SDGs).

We partner with non-governmental organisations and local community groups to support programmes that have long-lasting benefits.

Providing support to Ukraine

Following Russia's invasion of Ukraine and the unfolding humanitarian catastrophe, we undertook a number of actions in early 2022:

- We donated $2 million to charities to help with humanitarian relief efforts.
- We also matched contributions made by our employees to the Red Cross Ukraine Crisis Appeal.
- We have committed to terminate any offtake agreements we have with subsidiaries of Russian-owned entities as soon as possible, even if they are not themselves sanctioned.
- We contacted our banks, law firms, financial advisors, audit firms, insurance companies and other suppliers asking them to set out their position with regard to activities in Russia or in support of Russian assets and interest.
- We requested these parties set out the steps they are taking to stop support for the Russian state, Russian companies or interests.

We more than doubled our spend on social investment initiatives in 2021 to $571,089 (2020: $231,339). The majority of this spend was in the UK, Norway, the Netherlands and Germany, where we have operated assets.

As a result of what we've heard from our interactions with local community members, we target our programmes on initiatives in four key themes: health, education, local economic development and environment.

Our social investment standard, which forms part of our management system, includes an assessment of how social projects contribute to these areas and the SDGs, along with our ethics and compliance requirements. We work with our community partners to develop key performance indicators for the initiatives and measure our impact over their lifetime.

1 Health

We want to promote healthy lives and improve the wellbeing of people in our communities.

As well as improving awareness of the importance of health and wellbeing in our workplace, we are working to increase access to support in the wider community.

We entered a second year of partnership with Mental Health UK in 2021 and are supporting a project that provides individuals in rural communities with the skills, access and support to find the help they need to manage their mental health.

As part of the project, the charity delivered mental health awareness training to 42 rural workplace and community organisations in Scotland in 2021. A total of 96% of participants felt more confident to talk about their mental health with their colleagues, following the training.

In Algeria, we donated oxygen concentrators to a hospital near our Touat gas plant to help respond to increasing pressure caused by COVID-19's Delta variant. We also supported the Abu El-Rish hospital in Egypt, which provides healthcare to people who could not otherwise afford it.

In Indonesia, we worked with geoscience graduates to drill a water well for a village in West Java that routinely suffers from acute drought conditions. The new well provides villagers with access to a clean and reliable source of fresh water.

In October 2021, ahead of the European winter, we supported Sheltersuit UK, a not-for-profit organisation that creates products to protect homeless people from the elements.

350

shelterbags and sheltersuits funded to support homeless people in London and Aberdeen

2 Education

We support programmes that encourage young people to consider careers in science, technology, engineering and mathematics (STEM).

We have worked closely with the Scottish Schools Education Research Centre to establish a partnership project to enhance STEM learning in Aberdeen. The project helps companies link with local schools and colleges to engage teachers and students on STEM. As part of the programme, we delivered mentoring to local secondary schools.

Also in the UK, we donated new laptops to two local schools in London. This was following reports of a national shortage of computers which were needed to support pupils' online learning during the lockdown in early 2021.

In Norway, we support a summer school programme, run by social enterprise Forskerfabrikken, that aims to get more young people interested in natural science. We supported 10 courses, with around 250 school children participating in 2021.

We also participate in initiatives to engage young people in the energy transition. See page 35 for information on the Young Energy Officers programme in the Netherlands.

10

courses run by social enterprise Forsakerfabrikken

250+

school children participated in 2021

3 Local economic development

We contribute to the economic development of the countries in which we work by providing training and skills development.

In the UK, we are a member of Movement to Work, a coalition committed to helping young people not in education, employment or training connect with the world of work. The initiative is helping us identify opportunities, such as work placements, to help break the 'no experience, no job' cycle that many young people face.

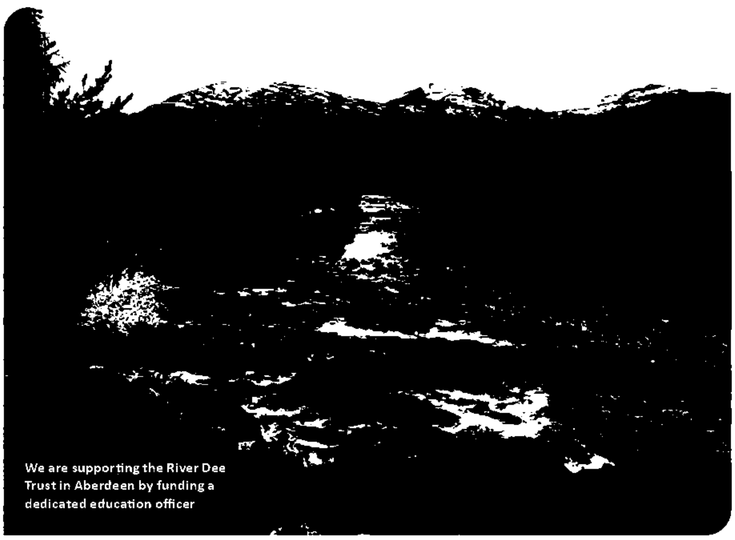
In Egypt, we are supporting Tawasol for Developing Istabl Antar, a non-governmental organisation (NGO) that is helping low-income communities in deprived areas of Cairo. The NGO has a vocational centre with more than 150 students, where students can learn skills to help them secure jobs and generate income, with a focus on Egyptian handicraft skills.
In 2021, we helped fund digital cutter plotting machines for the vocational centre. The machines were used to make tote bags for the El Gouna Film Festival, with proceeds going to local community development projects.

4 Environment

Our aim is to create a net positive impact on biodiversity and support initiatives that advance understanding of species and habitats.

We are partnering with the SOS Dolfijn Foundation, which rescues stranded dolphins, porpoises and whales on the Dutch coast and surrounding countries. See page 29 for more information on the partnership and our biodiversity strategy.

In the UK, we are supporting the River Dee Trust, a charity that focuses on improving the biodiversity and ecosystem of the river and preserving it for future generations.



We are supporting the River Dee Trust in Aberdeen by funding a dedicated education officer

Our society
continued

Community engagement

We consult with local communities throughout the different stages of our operations to help us understand their priorities and address their concerns.

We are committed to ongoing dialogue with local communities and host governments and to ensuring there are channels for local communities to provide feedback. Our engagement is guided by our Code of Conduct, which sets out our expectations on community involvement. This is backed up by our stakeholder engagement framework, which sets out our process for identifying key stakeholders and implementing engagement plans for our projects and operations.

We also have additional guidance specific to certain topics. For example, our biodiversity strategy requires us to engage with local stakeholders to identify any risks to habitats and species from our activities.

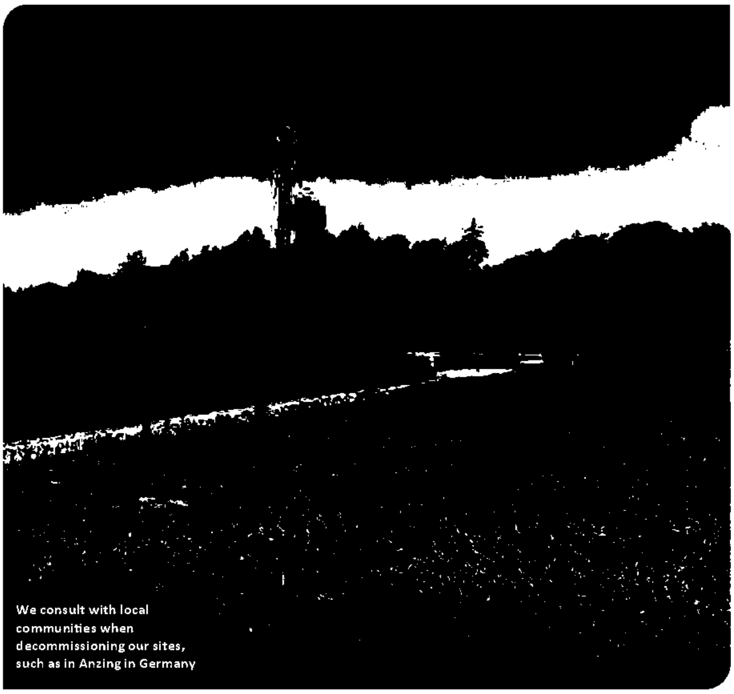
While the majority of our production is offshore, we have dedicated stakeholder and community liaison managers in countries where we have onshore operations.

In Germany, we have a dedicated local stakeholder manager for each district where we operate. Stakeholders can also raise any concerns or questions via a telephone hotline or by email. The majority of concerns raised in 2021 related to noise, transport and timings for drilling activity.

In 2021, in the process of decommissioning a gas site in the wider Munich region, the Forest Authority requested that the site be developed into a conservation area. We partnered with the Nature Conservation Foundation in Emsland to enhance the habitat of local species, including endangered orchids.

In Adorf, where we are developing an onshore gas field located near populated areas, we organised a site visit for the local mayor and the city council, who were interested in seeing the ongoing drilling and construction works first hand.

At our Touat gas plant in Algeria, our community liaison manager engages with local authorities and community members to identify social investment opportunities. In 2021, we supported a range of initiatives, including donations of food to the local community during Ramadan and medical equipment to a hospital in Adrar.



We consult with local communities when decommissioning our sites, such as in Anzing in Germany

Human rights

We respect individual human rights as set out in the United Nations Universal Declaration of Human Rights and the core conventions of the International Labour Organization.

We commissioned an external organisation to conduct an independent human rights assessment of our performance against the UN Guiding Principles on Business and Human Rights and our compliance with the UK Modern Slavery Act 2015.

The assessment found that employee rights were addressed well in our existing policies and that we have appropriate health and safety policies in place. It also identified areas for improvement, such as strengthening our contracts with business partners to cover the full range of human rights issues and providing training on human rights and modern slavery to ensure greater understanding across the business.

As a result of the assessment, we have taken a number of actions. For example, we have:

- Published our Human Rights Policy.
- Rolled out our new Code of Conduct, which includes enhanced sections on human rights and modern slavery, and requires business partners to adhere to the same ethical standards.
- Introduced a new due diligence screening platform for labour and human rights risks.
- Developed an action plan to align further with the UN Guiding Principles on Business and Human Rights.

See pages 38-39 for information on how we are working with our suppliers.

Tax and transparency

We are committed to acting with honesty and integrity in respect of tax laws and regulations, and to paying our taxes in the countries where we work. We report payments to governments on a country-by-country and project basis under the UK's national reporting regulations.

During 2021, we worked with the Norwegian oil and gas trade association and continued to benefit from the temporary tax regime that was introduced to ensure continued activity during the pandemic, while maintaining investment levels for the medium term.

We are committed to the Extractive Industries Transparency Initiative (EITI), which is designed to improve accountability for the revenues paid and received for a country's oil, gas and mineral resources. We submitted data for publicly available EITI reports in the UK, the Netherlands and Indonesia in 2021.

We support tax transparency and publish information about the taxes we pay

Economic impact

Our contribution to the communities and countries where we operate extends well beyond the provision of heat, light, mobility and power. Our work helps create jobs, supports local supply chains and contributes to national tax reserves.

We quantify our total economic impact using modelling from Oxford Economics. This modelling uses three core channels (direct, indirect and induced impact), which together comprise the economic footprint of our assets.

We supported an estimated $3.3 billion gross value added (GVA) contribution to the gross domestic product of our European countries – Germany, the Netherlands, Norway and the UK – in 2021, and some 9,720 jobs. For every Neptune employee in Europe, around eight jobs are supported in total in the economy.

Our total economic impact in Europe increased significantly in 2021, primarily due to higher earnings and operating cash flow, driven by higher commodity prices and good cost control.

Oxford Economics also assessed our economic impact in Indonesia, where we work with Eni and other partners to produce LNG for export to the region and gas for the domestic market. We supported an estimated $478 million gross value added contribution to the gross domestic product of Indonesia, and some 13,640 jobs, principally through the supply chain in the wholesale/retail trade, mining services and transportation sectors.

$478m

total gross value added contribution to the gross domestic product of Indonesia

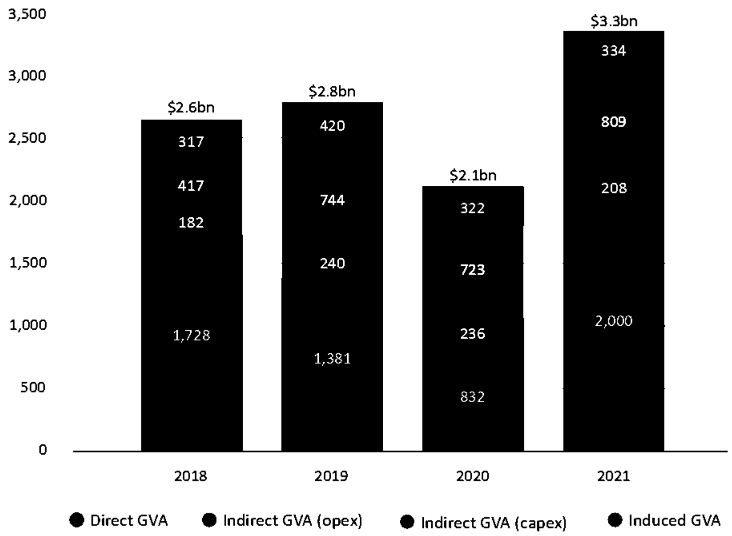
13,640

jobs supported through the direct, indirect and induced channels in Indonesia

Our impact on the European economy in 2021

	Our direct impact		Our indirect impact		Our induced impact		Our total impact
	The people we employ + the GDP our operations generate.		The money we spend with suppliers who employ people, generate GDP and use other suppliers.		Wages spent by employees – ours and our suppliers – in the wider economy, generating more GDP and jobs.		Direct + indirect + induced = our total economic impact.
GVA	$2.0bn	+	$1.0bn	+	$334m	=	$3.3bn
Employment	1,208	+	5,425	+	3,087	=	9,720

Economic impact – gross value added (GVA) contribution in Europe ($m)



UK economic impact today and in 2030: supporting a just transition

We commissioned Oxford Economics to conduct an economic impact analysis on our UK operations and projects in 2021 and over the coming decade.[a] The study also looked at the impact of increasing gas production on CO_2 emissions and the costs of domestic gas compared with imported LNG.

a This study was based on the gross, rather than net, impact of the assets, so is not directly comparable to the economic impact assessment of our European operations.

Our UK operations supported a £931 million GDP contribution and 4,440 jobs. By 2030, this economic footprint is projected to grow to £2.1 billion (in 2021 prices) and 6,410 jobs.

Increasing domestic gas production could help lower CO_2 emissions. Oxford Economics estimates that our UK operations could avoid 559,000 tonnes of CO_2 emissions by 2030 by displacing higher carbon imported gas.

Our UK operations contribute to the UK Balance of Trade. Domestic gas production lowers the UK's reliance on imports, as well as supporting CCS services and know-how to create export opportunities for the UK.

Increasing domestic gas production could help lower gas prices for UK consumers. In 2030, this could amount to a total annual savings of £164.4 million.

Our operations

Delivering robust performance

Our strong financial performance in 2021 was driven by higher production and commodity prices. As gas and oil supplies remained tight, we focused on maximising safe and efficient operations to supply energy to our key markets.

130.0 kboepd

PRODUCTION

... 148.3 kboepd including production-equivalent insurance income

604 mmboe

2P RESERVES

... with 433 mmboe of 2C resources

$862.7 m

FREE CASH FLOW

... up from $70.9 million in 2020

Our operations

Progress in 2021

123%

Four-year reserves replacement ratio

Strong operating environment in 2021, with production to increase in 2022

- Good HSE performance with lower process safety event rate. Targeting further improvements in personal and technical safety in 2022.
- FY 2021 production of 130.0 kboepd (148.3 kboepd including production-equivalent insurance income), reflecting outages at Touat and Snøhvit.
- Guidance of 135-145 kboepd for 2022 (140-150 kboepd including production-equivalent insurance income), dependent upon Snøhvit restart timing and Touat performance.
- All sanctioned projects expected online before the end of 2023, increasing production to ~170 kboepd.

Acceleration of lower carbon projects, aim to store more carbon than we emit

- Aim to store more carbon than is emitted from our operations and the use of our sold products by 2030, through accelerating plans for integrated energy hubs, including CCS where we can store carbon at scale.
- Focus on reducing operational emissions through electrification, with more than 35 kboepd of net production electrified by the end of 2022, before increasing to around 50 kboepd by 2027.
- Target L10 CCS project (NL) to be FEED-ready by the end of 2022, with FID due in 2023. Gudrun electrification project on track for completion by the end of 2022.

Long life, low cost and lower carbon portfolio

- 2P reserves increased to 604 mmboe, with a higher proportion of reserves developed. Four-year reserves replacement ratio of 123%. 2C resources of 433 mmboe, providing material future growth potential.
- Carbon intensity from managed production stable at 6.4 kg CO_2/boe, methane intensity from managed production of 0.02%. On track to hit 2030 targets.
- Project pipeline to deliver medium-term reduction in opex to <$11/boe.

Growing cash flow, strong balance sheet

- Operating cash flow of $1.7 billion, EBITDAX of $2.1 billion and underlying operating profit of $1.4 billion. Strong earnings and cash flow enabled dividends and capital distributions totalling $1.0 billion by Neptune Energy Group Limited.
- Total available liquidity of $1.1 billion at end of the period. RBL borrowing base of $2.3 billion reconfirmed in March 2022.
- Net debt to EBITDAX of 1.0 times at 31 December 2021. Aim to maintain a ratio of <1.5 times through the cycle.
- Expect to generate further strong cash flow in 2022, notwithstanding higher taxes. Development projects fully funded from operating cash flow.

Disciplined capital allocation, focused on near-term growth

- Continued restraint on capital expenditure, with development capex of ~$600 million in 2022. Focus on shorter cycle projects and near-term returns.
- Lower exploration spend of ~$130 million in 2022, in line with focused strategy targeting lower risk exploration and appraisal opportunities close to existing infrastructure.
- Total tax charge for 2021 of $1.0 billion, representing an effective tax rate of 72%.

Financial summary

Neptune Energy	2021	2020
Revenue ($m)	**2,490.1**	1,560.1
Operating profit/(loss) before financial items ($m)	**1,514.7**	(95.4)
Profit/(loss) before tax ($m)	**1,392.4**	(333.1)
Net profit/(loss) after tax ($m)	**387.2**	(399.0)
Net cash flows from operating activities ($m)	**1,696.8**	915.4
Non-GAAP measures		
Total daily production (kboepd) (note a)	**130.0**	142.4
Total daily production (kboepd) including production-equivalent insurance income (note a, b)	**148.3**	143.8
Operating costs ($/boe) (note c)	**11.3**	9.5
EBITDAX ($m) (RBL basis) (note d)	**2,109.3**	939.8
Underlying operating profit ($m) (note e)	**1,368.3**	287.3
Adjusted development cash capital expenditure ($m) (note f)	**635.8**	741.4
Free cash flow ($m) (note g)	**862.7**	70.9
Net debt ($m) (book value) (RBL basis) (note h)	**2,103.9**	1,821.4
Net debt/EBITDAX (RBL basis) (note h)	**1.00x**	**1.94x**

a) Production figures are for wholly owned affiliates and equity-accounted affiliates.

b) Including business interruption insurance income, converted to a net entitled production equivalent.

c) Operating costs for the purpose of per boe expense are increased by $20.3 million for the year ended 31 December 2021 (2020: $70.2 million reduction) to exclude changes in the value of over/under-lifted entitlement to production, to net-off income from tariffs and services which serve to recover costs, to exclude predevelopment costs and to exclude abandonment costs incurred on non-producing fields.

d) EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, impairment reversals/losses, other operating gains and losses, exploration expense and depreciation and amortisation. EBITDAX as defined by the RBL and Neptune Energy Group Limited Shareholder Agreement (Shareholder Agreement) includes our share of net income from Touat in 2020 following the repayment of the Touat Vendor Loan.

e) Underlying operating profit is calculated as operating profit/(loss) before the impact of impairment reversals/losses, restructuring costs and pension settlements or curtailments. A full calculation is shown to the right.

f) Includes capital expenditure of $20.1 million for the year (2020: $24.1 million) in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.

g) Free cash flow is calculated as net cash flow from operating activities less net capital investments during the period including repayments under leases. A full calculation is shown to the right.

h) Net debt excludes Subordinated Neptune Energy Group Limited Loan and Touat project finance facility as defined by the RBL and Shareholder Agreement. The Touat project finance facility was repaid at the end of September 2020.

Underlying operating profit is calculated before the impact of impairment reversals/losses, restructuring costs, pension curtailment credits and certain one off costs, as follows:

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Operating profit/(loss) before financial items	**1,514.7**	(95.4)
Adjusted for:		
Impairment (reversal)/loss in share of net income/(loss) from investments using equity method	**(32.2)**	32.7
Impairment (reversals)/losses	**(113.6)**	325.7
Net restructuring (release)/cost	**(0.5)**	25.3
Legacy licence cost	**4.0**	–
Pension scheme curtailment credit	**(4.1)**	(1.0)
Underlying operating profit before financial items and tax	**1,368.3**	**287.3**

Free cash flow calculated as net cash flow from operating activities less net capital investments during the period including repayments under leases:

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Net cash flows from operating activities	**1,696.8**	915.4
Adjusted for:		
Expenditure on exploration and evaluation assets	**(127.7)**	(84.5)
Expenditure on property, plant and equipment	**(619.4)**	(717.3)
Net investment made in equity-accounted investments	**(0.5)**	25.9
Repayment of obligations under leases	**(107.4)**	(69.4)
Proceeds from sale of assets and subsidiary	**20.9**	0.8
Free cash flow	**862.7**	**70.9**

$1.4bn

Underlying operating profit

Group overview

$2.1bn
EBITDAX

The terrible recent events in Ukraine have shocked the world and caused a humanitarian crisis in eastern Europe, leading to many countries and businesses to reassess their relationships with Russia and their reliance on Russian energy supplies. The events have increased geopolitical risks and provided a stark reminder of the importance of energy security, with potential shortages of oil and gas to global markets now a possibility. Wide ranging sanctions and boycotts imposed on Russia have caused disruption to international trade and dislocations in energy markets, tightening oil and gas markets significantly and causing prices to spike higher. Gas prices, in particular, have hit record levels reflecting the reliance on Russia to supply European gas markets and the limited alternatives.

While our operations are unaffected, we are providing support to staff and contractors from the region. Furthermore, we have committed to terminate the few offtake agreements we have with subsidiaries of Russian-owned entities as soon as possible.

These events put at risk the global economic recovery seen in 2021, which had pushed oil demand higher and oil prices back above pre-pandemic levels. Gas prices also recovered strongly in 2021, particularly in the second half of the year, as high demand from Asia pulled LNG cargoes from Europe, reducing supply on the continent, which was already suffering from lower levels of gas in storage due to the colder winter in 2020/21.

As a result of these economic conditions, Neptune delivered a strong financial performance, with EBITDAX of $2.1 billion and operating cash flow of $1.7 billion, enabling dividends and capital distributions by our parent company totalling $1.0 billion in 2021. A material increase in EBITDAX resulted in a reduction in leverage to 1.0 times at the end of the year, well below our guidance of <1.5 times and comfortably within covenants.

Neptune's production increased throughout the year as new projects in Norway and Indonesia added 26 kboepd of new production on a normalised basis. However, an extension to the outage at the Equinor-operated Hammerfest LNG facility, which processes gas produced from Snøhvit (Norway), and a further outage at the joint venture-operated Touat gas plant (Algeria) in the fourth quarter reduced full year production to the lower end of guidance, at 130 kboepd. We are working with our partners to bring these assets back online safely and swiftly.

Despite a high level of operational activity in 2021, we maintained a strong environmental performance. Carbon intensity from our operated portfolio remained modest at 6.4 kg CO_2/boe, almost 60% lower than the industry average. To increase transparency, we have improved our reporting disclosures further and are working with our partners to reduce CO_2 emissions. We continued to progress our lower carbon development opportunities and will accelerate these in 2022, with the aim of advancing our L10 CCS project to be FEED-ready by the end of this year. Longer term, we aim to go beyond net zero and store more carbon than we emit by 2030 through repurposing existing infrastructure and using our capabilities to store emissions from third parties that exceed our direct emissions and emissions from the use of our sold products. We will also aim to reduce operational emissions through electrification (see pages 20-23).

With a full year's contribution from the three new fields we brought onstream in 2021, we expect production in 2022 to be higher, averaging 135-145 kboepd, subject to Snøhvit restarting in May and production efficiency at Touat. Longer term, we expect the completion of projects in development in Norway and the UK to increase production to around 170 kboepd in 2023, with additional unsanctioned development opportunities across the portfolio to provide further growth. In 2021 we replaced 107% of production, ending the period with 2P reserves of 604 mmboe, and providing a reserves to production ratio of 13 years.

Increasing production and higher commodity prices, coupled with continued restraint on development and exploration expenditure, are likely to result in another strong financial performance in 2022. Our long-term hedging strategy will continue to protect and stabilise cash flows through the cycle. Cash flows in 2022 will be impacted by higher taxes in Norway due to the timing of tax payments related to our 2021 operations.

Organisation

In December 2021, we announced that Jim House had decided to retire from his role of Chief Executive Officer and that Pete Jones, previously Neptune's VP of Operations, Europe, would succeed him.

Early in 2022, we announced changes to our executive leadership team to support our refreshed strategy and more focused activity set. Having made significant progress in maturing our technical and project execution capabilities, and delivering our digital transformation programmes, Mark Richardson, VP Projects and Engineering, and Kaveh Pourteymour, CIO, will both leave the business. The functions now report to our CFO and VP, HSEQ and Technical Services, respectively.

On 17 February 2022, we announced the tragic death of Engineer Mohamed Mounes Shahat, Managing Director of Neptune Energy, Egypt. Engineer Mounes was highly respected both at Neptune and across the industry in Egypt. We are grateful for his leadership in his short time with Neptune, and we will miss him dearly.

Neptune's Managing Director, UK, Alexandra Thomas has taken up the role as Managing Director, Egypt. Our UK and Norwegian businesses have been brought together and now report to Odin Estensen, in his new role as Managing Director, Norway and UK. We will retain our offices in both countries, with local leadership teams remaining in country.

Production

Summary of production by area – wholly owned and equity-accounted affiliates

Total production (kboepd)	2021	2020
Norway	**45.7**	54.7
UK	**15.1**	18.3
The Netherlands	**21.2**	21.1
Germany	**18.8**	17.0
North Africa	**8.7**	12.5
Asia Pacific	**20.5**	18.8
Total production (kboepd)	**130.0**	142.4

Total Group production for 2021 averaged 130.0 kboepd, within our guidance range of 130-135 kboepd, but lower than in 2020 due to production outages at Snøhvit and Touat. However, economic production, which includes production-equivalent insurance income, averaged 148.3 kboepd, up 3% from 2020.

At Touat, repairs were completed in July with production increasing to plateau in September. Output from the plant averaged 8 kboepd in the second half of the year, demonstrating a good performance, although the plant was temporarily shut-in again from 19 November 2021 as a precaution to enable an upgrade of the plant's mercury removal unit. The facility continues to be managed carefully and plans are advancing to improve production reliability.

Repairs at Snøhvit continued throughout 2021 and the operator, Equinor, is now guiding restart in May 2022 returning around 15 kboepd of net production. The revised restart timing reflects poor weather conditions during the autumn and winter, along with COVID-19-related disruptions. Also in Norway, production was impacted by planned shutdown activities related to our development activities at Gjøa. During the period we brought onstream Gjøa P1 in February and the Duva project in August, contributing around 16 kboepd of new production.

Output in the UK was curtailed by export constraints at the Bacton terminal and a lack of blend gas availability due to shutdowns at third-party fields, particularly during the first half of 2021. A temporary gas blending arrangement with National Grid was utilised successfully from mid-June into July, enabling increased Cygnus production during this period. Start-up of our compression project was delayed until 2022.

In the Netherlands, our recent focus on improving safety and facility integrity resulted in higher production efficiency in 2021, helping to offset natural decline. Production in Germany was boosted by the acquisition of additional interests in six oil and gas fields from Wintershall Dea at the start of 2021, as well as a full year's contribution from the Adorf-Z15 well, which started up in October 2020. In Egypt, production was lower due to the relinquishment of the Ashrafi concession in late 2020.

Start-up of the Merakes field in April increased production in Indonesia materially, utilising available ullage at the Jangkrik FPU, which operated at close to capacity in the second half of the year. Output declined slightly towards the end of the year, reflecting operational difficulties with the Merakes 7 well. Gas demand in Asia was strong throughout the period and the business is positioned well for strongly growing markets as gas is replacing coal in the region increasingly.

Production efficiency at our operated assets was 82% in 2021 and slightly ahead of our performance in 2020. Taking into consideration planned shutdowns, including activities for our new projects, production efficiency was 87%. Production efficiency at our non-operated and joint venture assets continued to be impacted by the disruptions at Snøhvit and Touat. We are taking further steps to improve production efficiency across the portfolio and target opportunities where we can best influence performance to deliver value over volume. This includes enhanced production surveillance, predictive maintenance, shutdown optimisation and inventory management.

Production in 2022 is expected to increase compared with 2021 due to full year contributions from our projects brought onstream in 2021 and the restart of Snøhvit and Touat. Output will be reduced in March due to an extended shutdown planned at Gjøa for the Nova development. Shutdowns are also planned at Cygnus in August and Touat in September.

Projects

We made good progress with our development projects in 2021 and brought onstream successfully Gjøa P1, Duva and Merakes. Since start-up, all three projects have performed well, adding approximately 26 kboepd of new production. Our remaining upstream projects in development at Njord, Fenja and Seagull are expected to contribute a further 47 kboepd, when they come online in 2023.

In Norway, onshore construction activities at the Njord A FPU are being completed and sail-away is expected in the first half of 2022. The operator, Equinor, has advised that Njord is expected to start-up in the fourth quarter of 2022, following completion of offshore activities and commissioning. At our operated Fenja project, which will be tied back to Njord, the subsea infrastructure programme was completed in 2021 and the second development drilling campaign is under way. Start-up is expected in H1 2023.

At our Seagull project, development drilling commenced in early 2021 and the first two wells have been drilled, with results in line with prognosis. In the third quarter of 2021 we also completed the subsea infrastructure campaign. In early 2022, a Flotel was attached to the BP ETAP host facility and the first well was completed and tested. Spool tie-ins are scheduled for April and we plan to complete drilling the remaining two development wells before the end of the year. First production from Seagull is due in the first half of 2023.

Reserves

Reserves summary	Proved plus probable reserves (mmboe)
2P reserves at 31 December 2020	**601**
Production	(47)
Revisions, extension and discoveries	51
Acquisitions and divestments	0
2P reserves at 31 December 2021	**604**
Total reserves replacement ratio	107%
Total reserves to production ratio	13 years

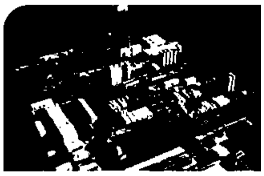
1. The above are management estimates, the majority of which are independently audited by ERCe.
2. Numbers may not add up due to rounding differences.
3. On 19 February 2021, Neptune announced a sale and purchase agreement with Wintershall Dea for the acquisition of interests in six producing oil and gas fields in Germany. The effective date of this transaction was 1 January 2020; hence the acquired reserves were already included in the year-end 2020 figures.

At the end of 2021, our proved plus probable reserves (2P) were 604 mmboe and we replaced 107% of our production in the year. Over a four-year period, from the inception of Neptune, our reserves replacement ratio is 123%. Our 2P reserves to production ratio was 13 years, up from 12 years at the end of 2020.

Within 2P reserves, engineering revisions added 10 mmboe of new reserves, with positive contributions from the Netherlands and Norway. A further 38 mmboe of 2P reserves were added due to new additions, mainly related to the Maha discovery in Indonesia, the Touat debottlenecking project in Algeria as well as electrification projects in Norway. Price effects added an additional 2 mmboe.

~1bn

barrels of 2P reserves and 2C resources



Three

projects brought onstream, adding 26 kboepd of new production

13years

reserve life

Our operations
continued

Contingent resources

Contingent resource summary	2C resources (mmboe)
2C resources at 31 December 2020	**452**
Revisions, extension and discoveries	(11)
Acquisitions and divestments	(8)
2C resources at 31 December 2021	**433**

1. The above are management estimates, the majority of which are independently audited by ERCe.
2. Numbers may not add up due to rounding differences.

At the end of 2021, our best estimate of contingent resources (2C) was 433 mmboe. The decrease is due mainly to moving the Maha project and our electrification projects in Norway to reserves, along with the disposal of our Danish business.

Exploration and appraisal

Our refocused exploration strategy delivered positive results in 2021 as we targeted lower risk, value-creating opportunities close to existing infrastructure. During the year we announced new discoveries in Norway, the Netherlands and Egypt and successfully appraised existing discoveries in Norway and Indonesia. Following analysis of results, we expect Maha (Indonesia) to progress to development, with first gas targeted in 2024. A new discovery at Assil C105 (Egypt) was brought onstream in the third quarter and will be followed up with further drilling in 2022.

In Norway, we followed up the Dugong and Echino South discoveries announced in 2020, with further drilling activity in 2021. In early 2021, we successfully appraised the Dugong discovery and flow tested the appraisal well in September. An exploration well targeting the Dugong Tail prospect was unsuccessful and our subsurface team are evaluating the best development option for the field. Close to the Echino South discovery, we announced a new material discovery at Blasto.

2021 drilling results

Country	Licence	Well	Working interest	Outcome
Norway	PL882	Dugong	45%	Oil discovery[3]
Norway	PL882	Dugong Tail	45%	Dry
Norway	PL090	Blasto	15%	Oil discovery
Norway	PL090	Apodida	15%	Dry
Norway	PL970	Ommadawn	30%	Dry[2]
Norway	PL1041	Lyderhorn	30%	Oil discovery
Netherlands[1]	N4	Turkoois	22.4%	Gas discovery
Egypt	AESW	Assil C105	25%	Gas discovery
Egypt	AESW	Bahga C101 Deep	25%	Oil discovery
Indonesia	West Ganal	Maha-2	30%	Gas discovery[3]

Notes: Includes exploration and appraisal drilling.

1. Joint well drilled in the Netherlands by operator ONE-Dyas. Neptune's equity relates to the share of the prospect in the H&L licence in Germany, where Neptune's equity is 40%.
2. The primary objective was unsuccessful, but a minor oil discovery was made in a secondary zone.
3. Appraisal wells.

In 2022, we plan to drill up to 11 new exploration and appraisal wells, including key wells in Norway, the UK and Egypt. In Norway we are participating in three wells, including the Ofelia and Hamlet prospects, which are located within tie-back distance to Gjøa and the Calypso prospect located within tie-back distance to Njord or Draugen. In the UK, the high impact Isabella appraisal well is due to spud in the second half of the year, with results due in mid-2023. Results from the well will support our evaluation of the commerciality of a potentially significant future development.

In the Netherlands, we have four wells planned in 2022. This includes the F5-A well that had been deferred from our 2021 programme and has follow up potential in the F5-B prospect.

In Egypt, we expect to drill the Yakoot prospect in the fourth quarter of 2022. The well is our first in the North West El Amal Concession and follows the acquisition of advanced 3D seismic in 2020. We have identified a number of prospects and leads within the licence area.

We are also progressing planning activities for a high impact exploration drilling campaign in Indonesia in 2023, which has the potential to create opportunities for a new hub development.

2022 drilling programme

Country	Licence	Well	Working interest	Type
Norway	PL929	Ofelia	40%	Exploration
Norway	PL153	Hamlet	30%	Exploration
Norway	PL938	Calypso	30%	Exploration
Netherlands	F5	F5-A	28.33%	Exploration
Netherlands	F3c	Pollux	15%	Exploration
Netherlands	L11d	Clover	20%	Exploration
Netherlands	F5	F5-B	28%	Exploration
UK	P1820	Isabella	50%	Appraisal
Egypt	AESW	Assil C104	25%	Exploration
Egypt	AESW	Assil C106	25%	Exploration
Egypt	NWEA	Yakoot	100%	Exploration

Notes: Drilling schedule subject to change.

Financial performance

Neptune delivered materially stronger financial results in 2021, reflecting higher commodity prices and production in the second half of the year, a robust operational performance and continued good cost control. As a result, EBITDAX of $2.1 billion and operating cash flows (after working capital and tax) of $1.7 billion were higher than in 2020 and leverage declined to well below targeted levels. Continued restraint on development capex increased free cash flow from $71 million in 2020 to $863 million in 2021.

In 2021, our financial performance was supported by temporary changes to the upstream fiscal regime in Norway, as well as the timing of our tax assessments, which will result in higher tax payments in 2022. We also recognised $129 million of other operating income in relation to business interruption insurance income in Norway. While commodity prices increased significantly in 2021, our hedging strategy, which protected our financial performance in 2020, reduced our full exposure to this upside. Despite this, our post-hedge oil and gas realisations increased strongly and averaged above our expectations. Production remains appropriately hedged in both 2022 and 2023, but we have adjusted some of our positions to increase our upside exposure in the near term.

Operating costs in 2021 increased to $11.3/boe, reflecting lower production in the period, increased blending costs and the higher cost of CO_2 emissions permits in Europe. G&A costs were higher at $78 million due to temporarily higher costs for employees allocated to our Algerian joint venture and one-off costs related to office relocations in Germany and the Netherlands. Despite inflationary pressures, we remain focused on limiting increases in both operating and G&A costs in our business in 2022.

During the year we recognised net pre-tax impairment gains of $114 million, partially reversing impairment charges recognised in Indonesia and the Netherlands in 2020 as longer-term price forecasts improved and we upgraded reserves estimates. We also recognised a post-tax impairment reversal of $32 million within our equity-accounted entities. Excluding these exceptional items, we delivered an underlying operating profit of $1.4 billion in 2021 compared with a $287 million profit in 2020.

While we continued to make significant investment in our developments in 2021, development capex compared with 2020 declined as we brought online three new projects. Adjusted development capex, which includes our share of capex at Touat, was $636 million, with our spend mainly at Njord, Fenja, Duva, Seagull and Merakes. In addition, we invested a further $154 million in exploration and pre-development activities, which was higher than in 2020, due to positive drilling results and an increase in expenditure related to maturing our project pipeline. Decommissioning expenditure was $39 million.

At year end, net debt increased to $2.1 billion, reflecting payment of a dividend in December. While net debt increased during 2021, the increase in 12-month rolling EBITDAX reduced our net debt to EBITDAX leverage ratio from 1.9 times at the end of 2020 to 1.0 times at the end of 2021, well below out RBL covenant of 3.5 times and our target of 1.5 times. Headroom under the RBL of $930 million, together with cash of $126 million, provided available liquidity of $1.1 billion at year end. In March 2022, our annual RBL redetermination was successfully completed and the borrowing base of $2.3 billion was reconfirmed.

Our robust operational performance and strong financial results are reflected in our corporate credit rating outlooks, which were raised by both S&P and Moody's during the year to 'positive'. Fitch raised our outlook to 'stable' earlier in 2021.

Outlook for 2022

While it is too early to determine how long the conflict in Ukraine may last, continued disruptions in energy markets seem likely as buyers seek alternative oil and gas supplies to Russia, with gas prices expected to remain at very high levels in the medium term.

The surge in gas prices towards the end of 2021 and in early 2022 had already illustrated the implications of under-investment in upstream projects and supply side policy restrictions. Similar price spikes in oil markets are also possible following several years of lower investment in new projects and a reduction in spare production capacity and inventories.

We continue to operate our business prudently to protect our people, reputation and operations during this period of uncertainty, including ongoing COVID-19 risks. Health and safety remains our highest priority and in 2022 we are targeting improvements in our safety performance by raising employee and contractor awareness.

We expect production to increase to 135-145 kboepd in 2022 as we benefit from higher production availability at Touat, as well as the full year contribution of our projects brought onstream during 2021. The restart of operations at Snøhvit in May 2022 is the only material addition to production in 2022, with the expected start-up of Njord in the fourth quarter to make a material contribution to growth in 2023 and 2024 as production from the field ramps up.

Reflecting completion of the Gjøa P1, Duva and Merakes projects, we expect adjusted development capex to decline to around $600 million in 2022, with investment mainly at Njord, Fenja and Seagull. We are also investing in our existing producing assets at Cygnus, Gudrun, Adorf and Jangkrik as we target incremental near-term production opportunities. As we bring onstream our remaining development projects in 2023, we expect group production to increase to around 170 kboepd. While a slightly lower peak than previous guidance, we expect our 2P production profile to be flatter, with higher output in 2024 and a slower decline.

Exploration and pre-development spend in 2022 is likely to be lower at around $130 million, as we maintain a focused level of near-term drilling activity and continue to mature new projects towards sanction. Decommissioning spend is expected to increase to around $85 million and will be focused largely on the UK, the Netherlands and Germany.

In addition to our upstream activities, we are also increasing our investment in lower carbon projects and are driving forward plans for our L10 CCS project to be FEED-ready by the end of 2022. Our near-term carbon intensity is expected to rise moderately in 2022 due to the delay to gas compression at Cygnus, but will remain significantly lower than our sector peers.

Operating costs are expected to increase modestly in 2022, reflecting higher industry costs, including transportation, CO_2 taxes and royalties. As a result, while opex remains low, it is expected to average $11.5-12.5/boe for the full year, before falling to around $11/boe in 2023 as our remaining new projects are brought onstream. Stronger production, together with high commodity prices and a continued focus on cost control, is expected to support operating cash flow (before working capital) generation of more than $1.2 billion in 2022. Operating cash flows will be impacted by hedging losses and higher taxation due to a tax overhang from 2021. Cash taxes in 2022 are expected to be around $1 billion. Leverage is expected to remain below targeted levels of 1.5 times throughout 2022.

We retain a disciplined approach to capital allocation and will invest selectively in new opportunities, including through M&A, where it makes strategic sense and delivers strong returns and near-term cash flow generation.

Our operations
continued

Norway and the UK

Country overview – Norway

We have interests in seven producing fields and operate the Gjøa gas and oil field, which is powered using low carbon hydroelectricity from shore.

Norway daily average production

Gas production
(kboepd)

2021	**20.2**
2020	21.3
2019	24.1

Gas production for sale as LNG
(kboepd)

2021	**–**
2020	8.0
2019	13.3

Liquid production[1]
(kbpd)

2021	**25.5**
2020	25.4
2019	30.3

Total production
(kboepd)

2021	**45.7**
2020	54.7
2019	67.7

1 Liquid includes oil and condensate and other natural gas liquids

Country overview – The UK

We operate the Cygnus Alpha and Bravo facilities, producing gas from the Cygnus field. Cygnus is capable of meeting around 6% of UK gas demand.

UK daily average production

Gas production
(kboepd)

Liquid production[1]
(kbpd)

Total production
(kboepd)

1 Liquid includes oil and condensate and other natural gas liquids.

Odin Estensen
Managing Director,
Norway and the UK

Norway

Production

In Norway, production averaged 45.7 kboepd in 2021, reflecting the outage at Snøhvit and extended planned shutdowns at the Gjøa field to enable the Gjøa P1 and Duva projects to be brought onstream and to progress the Nova development. Excluding planned shutdowns, production efficiency was 97%, with good performances at both Gjøa and Gudrun. Our new fields also performed well, with Gjøa P1 brought onstream in February and Duva in August, adding 16 kboepd.

Our strong operational performance in Norway is reflected in its HSE KPIs in 2021, which demonstrate a material improvement with no lost time injuries or process safety events during the year. Initiatives are in place to support continuation of this performance.

Repairs at the Hammerfest LNG facility are progressing, but due to poor weather during the autumn and winter, along with COVID-19-related disruptions, the operator, Equinor, is now guiding a restart of operations in May 2022. Production from Snøhvit is expected to add back around 14 kboepd of net production at plateau. Neptune benefitted from business interruption insurance income totalling $129 million in 2021, with further insurance payments to be received in 2022.

Including production-equivalent insurance income, total economic production for Norway was 59.0 kboepd in 2021, slightly higher than in 2020. We expect production to increase materially in 2022 as we benefit from a full year of production from Gjøa P1 and Duva and the restart of Snøhvit. Towards the end of 2022, the Njord project is expected to start-up, providing further production growth going into 2023.

In 2022, an extended three-week shutdown is planned at Gjøa (including Gjøa P1, Duva and Vega) as part of the Nova development programme. Deferred production from this period will be recovered in 2022 and 2023 following start-up of Nova in August 2022. A shutdown is also planned at Gudrun in July.

In late 2021, we announced the disposal of a portfolio of non-core assets, including our non-operated interests in the Ivar Aasen Unit, the Draugen field, the Brage Unit, the Edvard Grieg Oil Pipeline and the Utsira High Gas Pipeline to OKEA and M Vest.

Operating costs in Norway increased in 2021 to $8.6/boe, reflecting lower production in the period. In 2022, we expect opex per barrel to remain stable as higher production offsets increases in transportation, tariff and CO_2 emission taxes.

Development

In 2021 we made important progress with our development projects in Norway and successfully completed both the Gjøa P1 and Duva projects, which were brought onstream on schedule and budget. Our remaining two sanctioned projects at Njord and Fenja also moved forward and are expected onstream in the next 18 months.

At Njord, onshore construction at the Njord A Floating Production Unit is being completed and, following planned sea trials, sail-away is anticipated in the first half of 2022. Offshore hook-up and commissioning is scheduled for the second and third quarters. The Njord B Floating Storage and Offloading unit construction was completed in late 2021 and the vessel has been towed to Kristiansund for final commissioning, prior to deployment offshore. The operator, Equinor, has advised that Njord is expected to start-up in the fourth quarter of 2022, with production progressively increasing through 2023 and 2024 as the Hyme and Bauge fields are tied-in and additional infill wells are brought onstream. At peak, Njord is expected to add around 20 kboepd.

At our operated Fenja project, the second development drilling campaign is currently under way. During 2021, the subsea infrastructure programme was completed, including the laying of our ground-breaking electrically trace-heated pipe. The first drilling campaign was also completed. Fenja is scheduled to start-up in the first half of 2023 and is expected to add 10 kboepd at plateau.

In Norway, development capex declined to $397 million in 2021, reflecting completion of our Gjøa P1 and Duva development projects during the year. We expect development spending to fall further in 2022, with investments mainly at Njord and Fenja.

We continue to evaluate our recent discoveries and have a disciplined approach to advancing new projects, which must meet strict investment criteria. Our priority is to progress projects that create the most value around our key hubs and can offer shorter cycle returns. Key learnings from our recent operated projects will benefit the delivery of our next sanctioned operated developments, including earlier project manning, a greater focus on delivering topside modifications and an earlier commitment to critical components.

In 2021, we sanctioned the Askeladd Vest development, which will develop 134 mmboe of gross reserves and maintain output from Snøhvit. The project is due onstream in 2024.

In August, the Norwegian Government proposed to revise the special petroleum tax system as of 1 January 2022, replacing the rules on depreciation and uplift with immediate investment expensing. The total tax rate will remain at 78%, but since corporation tax will be deductible from the special tax base, the special tax rate will effectively increase from 56% to 71.8%. The proposed new tax regime has yet to be approved by parliament, but, if approved, it would enhance liquidity through faster paybacks. The changes will not impact investments with PDO submissions before the end of 2022, which will continue to benefit from the temporary rules introduced in response to COVID-19.

Our Gudrun electrification project is progressing as planned and remains on schedule to start-up in the fourth quarter of 2022. The project is expected to reduce CO_2 emissions by approximately 60,000 tonnes. We are also evaluating the potential to electrify our Snøhvit and Njord operations.

Exploration

During 2021 we made three new discoveries through our exploration programme and also successfully appraised the Dugong discovery. The Blasto discovery, announced in March, followed the Echino South discovery made in 2020 and adds a material new development close to our Fram field. While further well testing of the Apodida prospect was unsuccessful, considerable resource potential has been identified in the Fram area and we are maturing several additional prospects for future drilling.

At our Dugong discovery, we successfully completed appraisal drilling in the first quarter of 2021. Results from the well and a drill stem test carried out in the third quarter are being evaluated. An exploration well targeting the Dugong Tail prospect was unsuccessful. The results from this well are being incorporated into our evaluation of the latest seismic data and will be used to optimise future development plans.

Further exploration wells were drilled at Lyderhorn, resulting in a non-commercial discovery, and at Ommadawn, which also resulted in a small discovery in a secondary objective. The Ommadawn primary objective was dry.

In early 2022, Neptune was awarded two licence extensions in the APA 2021 licensing round. PL882B is contiguous to our existing PL882 licence (Neptune 45%), containing the Dugong discovery, while PL586B (Neptune 30%), is located close to our Fenja field and adjacent to exploration acreage operated by Neptune. Neptune is operator of both licence extensions and the initial two-year work programme will be executed in conjunction with our ongoing work programmes to mature future drilling prospects in both areas.

In 2022, we plan to drill up to three lower risk exploration wells located close to existing infrastructure. The Ofelia and Hamlet prospects are due to be drilled in the first half of the year and are within potential tie-back distance to Gjøa. The Calypso prospect is due to be drilled in late 2022 and is a potential tie-back to Njord or Draugen.

The UK

Production

Export constraints at the Bacton onshore receiving terminal and limited blend gas availability had a significant impact on production from the Cygnus field in 2021. As a result, production in the UK averaged 15.1 kboepd in 2021. In June 2021, a two-week shutdown was completed safely and on schedule. Our HSE performance across the year was good with no process safety events recorded in the period.

During 2021, a temporary gas blending arrangement with National Grid was utilised successfully from mid-June into July, enabling increased Cygnus production during a period of planned outage of its principal blend source. We continue to support plans for a permanent change in UK gas entry specifications, which is required to maintain reliable indigenous gas supplies into the UK and to unlock additional potential reserves and resources from the Southern North Sea. Parliamentary approval of these proposed changes is expected in the second half of 2022.

In 2022, we plan to drill two new production wells at Cygnus, with the first of these expected to come onstream in July. The second well is due to be drilled in the fourth quarter and is expected onstream in the first quarter of 2023, with both wells helping to maintain production from the field and offset natural decline. An 18-day shutdown at Cygnus is planned in August 2022 to align with a planned SEAL outage. The Cygnus compression project is due to start-up in April 2022.

Unit operating costs in the UK increased to $9.3/boe in 2021, reflecting lower production in the period. Operating costs are expected to increase in 2022 due to higher National Transmission System charges and CO_2 taxes.

Development

At our Seagull project, we continued to make good progress and start-up remains on schedule for the first half of 2023. In early 2021 we commenced the development well programme with results from the first two wells completed, in line with prognosis. The first of the two wells has been completed and tested and the second well is due to be completed and tested by the end of the first quarter of 2022.

The Flotel's bridge was attached to the BP ETAP host asset in February, spool tie-ins are scheduled for April and we expect to drill the remaining two development wells by the end of the fourth quarter. The topside modifications are scheduled for completion in early 2023. The Seagull project is expected to add more than 17 kboepd of new production net to Neptune.

In the fourth quarter of 2021, a request to extend the partner operated P1724, P1727 and P2128 licences was refused by the UK Oil and Gas Authority and the licences expired in December. As a result, the Pegasus West development will not proceed in its current form.

At our DelpHYnus CCS and blue hydrogen project, we continue to review funding options to progress the project, including, possibly, the pending BEIS-led Cluster Sequencing Track 2 Process. In May 2021, we submitted plans to the UK Oil & Gas Authority for a Carbon Dioxide Appraisal and Storage Licence and continue to await the outcome of this application. The development of a well-designed regulatory framework that supports both legal and commercial requirements is still needed for progressing our lower carbon projects and increasing investment.

During 2021, we invested $62 million in development activities in the UK, with the majority of the investment at our operated Seagull project. We expect development capex to increase in 2022, reflecting the ongoing development of Seagull and our Cygnus drilling programme.

Exploration

Our exploration and appraisal activities in the UK are focused on progressing the significant Isabella discovery, located in the Central North Sea, towards development. We are currently advancing plans to drill an appraisal well in the second half of 2022, which will test an up-dip location and confirm key petrophysical characteristics. The results from the well will support our commercial evaluation and potential development.

Our operations
continued

The Netherlands

Country overview

We are the largest gas producer in the Dutch North Sea, with key infrastructure providing a scalable hub for lower carbon opportunities

Daily average production

Gas production
(kboepd)

2021	**19.9**
2020	19.5
2019	19.9

Liquid production[1]
(kbpd)

2021	**1.3**
2020	1.6
2019	1.8

Total production
(kboepd)

2021	**21.2**
2020	21.1
2019	21.7

1 Liquid includes oil and condensate and other natural gas liquids.

Lex de Groot
Managing Director,
The Netherlands

Production

Production from the Netherlands averaged 21.2 kboepd in 2021, as improvements in production efficiency offset expected declines from some of our mature fields. During the period the L5-D, G-Hub and K2b-A fields performed well, reflecting good uptime and the results of our optimisation strategy. The K9ab-A4 well, drilled in the second quarter, was unsuccessful and the Sillimanite South B3 well was suspended following early water breakthrough. Production efficiency in 2021 improved to 79% from 71% in 2020.

Our PSER in the Netherlands improved significantly in the second half of 2021, but remains higher than we would like. All our process safety events were small tier three events and below the reportable threshold. We have put in place a plan to drive further improvements in our performance.

In 2022, production is expected to be slightly lower, reflecting natural field decline and our continued focus on enhanced maintenance and integrity management programmes, which will improve production efficiency in the longer term. Optimisation initiatives will target incremental production growth opportunities and upgrading of compression on platforms. We also plan to side-track the existing K2b-A8 well in the first half of 2022, targeting undrained gas reserves. Planned shutdowns at the L5, L10, K12 and G17 platforms will result in seasonally lower production in the second quarter. A planned shutdown of the NOGAT export line will also reduce output in September.

Operating costs increased in the Netherlands in 2021 to $16.6/boe, reflecting higher production costs and CO_2 taxes. We expect opex per barrel to increase in 2022 due to lower production.

Development

Neptune has a large acreage footprint in the Netherlands and operates several key hubs. We expect to increase activities in the near term to add reserves and potentially extend the life of key infrastructure, which will also support our longer-term lower carbon plans. As part of this programme, we have identified possible infill locations and are maturing exploration opportunities offering near-term cash flow potential.

In 2021, we continued to progress our F17 development concept and expect to agree a commercial approach and timetable with our partners in 2022. A development, via our operated F3 hub, has the potential to achieve significant capex reductions and lower carbon emissions.

We invested $15 million in development capex in the Netherlands in 2021 as we continued to focus on growth around our existing infrastructure. We expect spending to remain modest in 2022, before increasing in 2023 as we step up infill drilling and near field development opportunities.

We also plan to increase investment in our lower carbon projects as we see considerable potential for green hydrogen, CCS and electrification at several of our existing Dutch hubs.

Recently, we announced the formation of a potential new large-scale offshore green hydrogen project. The H2opZee project aims to produce green hydrogen with wind energy and utilise existing pipeline infrastructure. A feasibility project to evaluate an initial 300-500 MW of generating capacity is planned in 2022, with an existing pipeline to enable a future increase in capacity to 10-12 GW.

We continue to make good progress with our L10 CCS project, which has the potential to inject 5-8 million tonnes of CO_2 per annum into depleted gas fields around our L10 platform. Studies to assess the technical viability of reusing existing offshore infrastructure including wells and pipelines were completed in 2021. We expect our L10 CCS project to be FEED-ready by the end of 2022.

At our PosHYdon project, the consortium agreement was finalised in the third quarter of 2021 and the project is being defined. We expect to complete detailed project designs in 2022.

In 2021 we plugged and abandoned several wells and we expect to continue this programme in 2022, with spending increasing to around $25 million. To deliver greater synergies, we are collaborating with Nexstep in a joint campaign with regional operators and suppliers to improve planning and optimise our decommissioning strategy.

Exploration

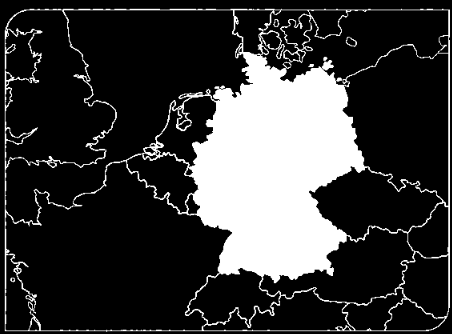
In April 2021 we announced a gas discovery at the Turkoois prospect, located offshore on the Netherlands/German border and adjacent to planned infrastructure. Results from the well have been evaluated and the discovery is progressing to development. Additional leads and prospects have been identified, which may provide further upside in this area.

We expect a material increase in activity in 2022, with four exploration and appraisal wells planned as we target reserve additions close to our operated hubs. In early 2022, we will drill the F5-A prospect. The F5-B well will target a similar shallow gas prospect and is due to be drilled in the third quarter, with both F5-A and F5-B located within tie back distance to our F3 hub. The Pollux prospect, due to be drilled in the first quarter, is also located within this area, but is targeting an oil prospect up-dip from oil shows encountered in a well drilled in 1971.

In the second quarter, we plan to drill the Clover gas prospect, which is located within tie-back distance to our operated L15 platform.

Our operations
continued

Germany



Country overview

With a presence in the country for more than 130 years, we operate and develop oil and gas fields with our partners in the northwest, east and south of Germany.

Daily average production

Gas production
(kboepd)

Liquid production[1]
(kbpd)

Total production
(kboepd)

1 Liquid includes oil and condensate and other natural gas liquids.

Andreas Scheck
Managing Director, Germany

Production
Production in Germany averaged 18.8 kboepd in 2021, an increase compared with 2020, following the acquisition of additional interests in six oil and gas fields. Production also benefitted from a full year of operations from the Adorf field, which was brought onstream in late 2020 and has performed strongly, and higher uptime at the Altmark field. Production efficiency in Germany improved from 87% in 2020 to 91% in 2021.

In 2022, production in Germany is expected to decline slightly as new production from the Adorf-Z16 and Römerberg-6 wells is offset by natural decline. Gas sales from the Altmark field, which was previously expected to cease at the end of 2021, are now expected to continue until April 2022. A power generation project is due to commence operation at Altmark in April 2022 and we are evaluating options to extend operations beyond 2022.

Our HSE performance in Germany remained stable with no reportable incidents in 2021.

Operating costs, excluding royalties, were stable at $13.2/boe in 2021 as higher production costs were offset by increased production at lower cost fields. Opex per barrel is expected to increase in 2022, reflecting higher production costs and lower volumes. To maintain production and help to drive unit opex reductions at our mature fields, we are simplifying processes, modernising existing facilities and automating more operations.

Development
In 2021, we continued development of the Adorf field, drilling the Adorf-Z16 well, and planning the expansion of surface facilities to enable further wells to be drilled. The Adorf-Z16 well, which was brought onstream in early January 2022, is performing well and has increased total production from the Adorf field to around 4 kboepd. Construction of a new well pad is under way, which will be used for the Adorf-Z17 and Adorf-Z18 wells. Drilling is due to commence mid-year, with the Adorf-Z17 well likely to be brought onstream in the first half of 2023.

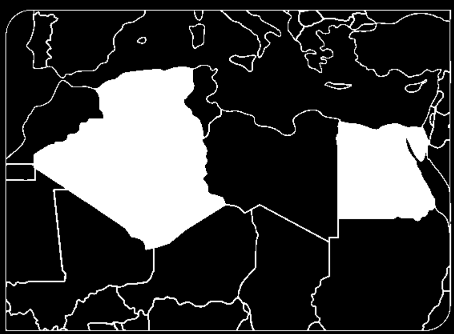
At Römerberg a full field development plan is being matured to enable surface facility upgrades, the drilling of new wells and the end of permanent flaring. A workover of the Römerberg-8 artificial lift system was completed in the fourth quarter of 2021. In 2022, we plan to drill the Römerberg-6 well, which is due onstream in the third quarter of 2022.

Development capex in Germany increased to $45 million in 2021 as we continued to invest in development wells and infrastructure programmes. Investment in 2022 is expected to increase further as we continue to develop the Adorf and Römerberg fields. We also expect to complete the Bramberge surface facility programme.

We are continuing to strengthen our decommissioning capabilities in Germany as we reshape our decommissioning organisation away from an existing hub operating model to meet future requirements. These changes will help increase expertise and sharing of knowledge across the group. In 2022, we expect to complete decommissioning activities at Anzing and Moosach.

Our operations
continued

Algeria and Egypt



Daily average production

Gas production
(kboepd)

2021	**8.1**
2020	11.0
2019	4.5

Liquid production[1]
(kbpd)

2021	**0.6**
2020	1.5
2019	1.4

Total production
(kboepd)

2021	**8.7**
2020	12.5
2019	5.9

1 Liquid includes oil and condensate and other natural gas liquids

Country overview

As part of a joint venture with Sonatrach and ENGIE, we are producing gas from the Touat plant in Algeria, which is an important source of supply for mainland Europe.

In Egypt, we have interests in an offshore oil field in the Gulf of Suez, an oil and gas field in the Egyptian desert and an operated exploration licence for the Gulf of Suez.

Mehdi Bouguetaia
Managing Director,
Algeria

Alexandra Thomas
Managing Director,
Egypt

Algeria

Production

During 2021, we completed repairs at our joint venture-operated Touat processing facility successfully and gas exports recommenced in July. Output returned to plateau capacity in September and the plant continued to perform well for most of the fourth quarter, but was shut-in on 19 November 2021 as a precaution to enable an upgrade to the plant's mercury removal unit. The Touat gas processing facility continues to be carefully managed and plans are progressing to further optimise phase one production and improve longer-term reliability.

As a result of the outage in the first half of the year, production at Touat averaged 5.2 kboepd in 2021. Output is expected to increase in 2022 as we benefit from greater uptime. A two-week shutdown is planned in September for amine fluid replacement.

The Touat organisation continues to strengthen, resulting in recent operational improvements, with a decline in PSER reported in the second half of 2021. We continue to focus on delivering further improvements, by enhancing operating discipline, targeting preventative maintenance and ensuring inventory is available.

Operating costs in Algeria averaged $16.9/boe in 2021, reflecting the production outage during the first half of the year. Opex is expected to be lower in 2022 due to an increase in expected production and an improved operating performance.

Development

Capital expenditure associated with Touat was $20 million in 2021, reflecting the remaining costs to replace the cold box. Investment is expected to increase slightly in 2022 as we progress plans for phase two development, along with debottlenecking and plant upgrades. FEED is expected to commence in 2022, with phase two start-up anticipated in 2026. The phase two development plan will extend plateau production until the late 2020s and will include the drilling of 16 production wells.

Egypt

Production

In Egypt, production averaged 3.5 kboepd in 2021, slightly lower than in 2020 due to the relinquishment of the Ashrafi concession, but in line with expectations. During 2021, we brought onstream four new wells and delivered positive results from our workover programme. The Karam-11 well was delayed until the end of the year and will be brought onstream in the first quarter of 2022. Production is expected to be maintained in 2022 through our planned infill and workover campaigns.

Our health and safety performance in Egypt remains excellent with no total recordable injuries.

Operating costs in the Egypt region declined to $6.9/boe in 2021, reflecting the relinquishment of higher cost production from the Ashrafi concession. In 2022, we expected opex to remain around current levels.

Development

We invested $3 million of development capex in 2021 and expect an increase in expenditure in 2022 as activity rises. As part of this programme we expect to drill up to nine development wells at our Assil, Bahga, Magd and Karam fields. The Karam-12 well is due onstream in December.

Exploration

During 2021 we drilled two exploration wells confirming a liquids rich gas discovery in the Assil-C105 well and a technical oil discovery in the Bahga-C101 Deep well. The Assil-C105 discovery was quickly brought onstream and has been performing well. We expect to drill two further wells in 2022, targeting the Assil-C104 and Assil-C106 prospects.

We are also progressing plans to drill the Yakoot prospect in the second half of 2022. The Yakoot prospect is located in the North West El Amal Concession in the southern Gulf of Suez and follows the acquisition of a OBN seismic survey in early 2020.

Our operations
continued

Indonesia and Australia

Country overview

In Indonesia, we are working with Eni and other partners to produce LNG for export to the region under long-term contracts and gas for the domestic market to help meet the country's growing energy needs.

In Australia, we are evaluating development concepts for Petrel, a large gas field located in the Timor Sea.

Daily average production

Gas production
(kboepd)

Gas production for sale as LNG
(kboepd)

Liquid production[1]
(kbpd)

Total production
(kboepd)

1 Liquid includes oil and condensate and other natural gas liquids.

Eko Lumadyo
Managing Director,
Asia Pacific

Indonesia

Production

Production in Indonesia increased to 20.5 kboepd in 2021, reflecting strong gas demand and start-up of the Merakes project in April. Since coming onstream, the Merakes field has performed strongly and exports from the Jangkrik FPU have been maintained at close to capacity. Towards the end of the year, the Merakes-7 well was shut-in temporarily due to sand production issues. The impacted subsea flow module was replaced in early January 2022, allowing production from Merakes-7 to resume at a controlled rate.

In 2022, production is expected to remain stable, with a two-week maintenance partial shutdown planned for March and September. In the fourth quarter, we plan to side-track the existing Jangkrik-12 well, with the well expected onstream in early 2023.

Operating costs increased to $10.6/boe in 2021, reflecting a higher production contribution from Merakes and increased requirements for C3/C4 for gas blending. Operating costs are expected to increase in 2022 due to higher production expenses and C3/C4 costs.

Development

Following successful appraisal drilling, plans are progressing for development of the Maha field, which will be a subsea tie-back to the Jangkrik FPU. In 2022, we expect to submit a plan of development and commence a tendering process. A final investment decision is expected in 2023.

Gas production from Maha is likely to commence in late 2024 and will help maintain export capacity from the Jangkrik FPU for a further two years. The Merakes East discovery and infill wells at Jangkrik provide additional longer-term development opportunities. In late 2021, we commenced the tendering process for the Jangkrik booster compression module, which is expected to start-up in mid-2024.

Development capex in Indonesia declined to $94 million in 2021, reflecting completion of the Merakes project, with spending likely to fall further in 2022.

Exploration

In June 2021, we announced that the Maha-2 appraisal well, drilled in the West Ganal licence, had encountered a 43m gas column with excellent reservoir characteristics. A drill stem test flowed at 34 mmcfpd, which was limited by surface facilities. Post-well analysis has confirmed a material commercial discovery and we have upgraded contingent resources to reserves.

We are advancing plans to drill up to two new exploration wells in 2023. The high impact Geng North prospect has the potential to create a new hub, with multi-TCF potential and material follow-on opportunities. The second well is likely to target the Jangkrik South West prospect, which is located within tie-back distance to the Jangkrik FPU.

Australia

Exploration

During 2021, we made important progress maturing technical work and advancing commercial studies to define the Petrel resource range and development concept. Incorporating the latest seismic data, the contingent resource range of the Petrel field has been narrowed to 0.8-1.9 TCF. With the Petrel project now FEED-ready, we have paused activity pending gas contract negotiations.

Financial review

Robust financial results

$2.1bn
EBITDAX

$1.7bn
Operating cash flow

1.00x
Net debt/EBITDAX

$13.2/mmbtu
Average realised gas price (pre hedging)

This report includes the Group results for the year ended 31 December 2021.

Results of operations

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Revenue	**2,490.1**	1,560.1
Operating profit/(loss) (note a)	**1,514.7**	(95.4)
Underlying operating profit (note b)	**1,368.3**	287.3
Profit/(loss) before tax	**1,392.4**	(333.1)
Taxation charge	**(1,005.2)**	(65.9)
Net profit/(loss) after tax	**387.2**	(399.0)
EBITDAX (RBL basis) (note c)	**2,109.3**	939.8
Net cash flows from operating activities	**1,696.8**	915.4
Adjusted development cash capital expenditure (note d)	**635.8**	741.4
Net debt (book value) (RBL basis) (note e)	**2,103.9**	1,821.4
Net debt/EBITDAX (RBL basis) (note e)	**1.00x**	1.94x

a) Operating profit/(loss) comprises current operating income after share in net income of entities accounted for using the equity method and is stated before tax and finance costs, but after mark-to-market on commodity contracts and non-recurring items.

b) Underlying operating profit is calculated as operating profit/(loss) before the impact of impairment reversals/losses, restructuring costs and pension settlements or curtailments. A full calculation is shown on page 66.

c) EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, impairment reversals/losses, other operating gains and losses, exploration expense and depreciation and amortisation.

d) Includes capital expenditure of $20.1 million for the year (2020: $24.1 million) in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.

e) Net debt excludes Subordinated Neptune Energy Group Limited Loan and Touat project finance facility as defined by the RBL and Shareholder Agreement.

Revenue for the year was $2,490.1 million (2020: $1,560.1 million), reflecting total production from wholly owned subsidiaries of 45.5 mmboe (2020: 49.3 mmboe). Realised prices, before and after hedging are shown in the table on page 65. Production for the year was lower than 2020, notably in the first half of 2021, reflecting the outage at Snøhvit and extended planned shutdowns at the Gjøa field, but this has been more than offset by higher commodity prices in 2021.

The Brent crude price averaged $70.9 (2020: $43.2) per barrel for the year and our average realised oil price (pre hedging) was $72.2 per barrel (2020: $40.3) for the year. Including hedging, our average realised oil price was $65.5 per barrel (2020: $46.1) for the year. During 2021, prices maintained their upward trajectory from the COVID-19 lows seen in 2020 and the market tightened driven by the recovery of the global economy.

The average realised gas price was $13.2 (2020: $3.0) per mmbtu (pre hedging) and $9.5 (2020: $4.2) per mmbtu (post hedging) for the year. The European gas market prices rose significantly to record highs in the second half of the year driven by tight supply and low gas storage stocks, combined with strong international demand, political tensions in Eastern Europe and lower renewable energy output. Inventory levels remain low, which further added to the strong market sentiment and increased volatility.

LNG sales prices are linked to a combination of movements in oil and gas market prices, depending on the commercial contract.

Realised prices for wholly owned affiliates:

	Fourth quarter 2021	Fourth quarter 2020	Year ended 31 December 2021	Year ended 31 December 2020
Excluding impact of hedging:				
Average realised gas price ($/mmbtu)	**24.6**	4.6	**13.2**	3.0
Average realised LNG price ($/mmbtu)	**9.7**	5.6	**8.2**	5.6
Average realised oil price ($/bbl)	**77.6**	41.8	**72.2**	40.3
Average realised price, other liquids ($/bbl) (note a)	**52.5**	27.3	**48.6**	21.9
Average realised price of all production ($/boe)	**114.5**	30.9	**70.5**	24.5
Including impact of hedging:				
Average realised gas price ($/mmbtu)	**15.0**	5.1	**9.5**	4.2
Average realised LNG price ($/mmbtu)	**9.7**	6.4	**7.5**	6.0
Average realised oil price ($/bbl)	**71.6**	46.4	**65.5**	46.1
Average realised price, other liquids ($/bbl) (note a)	**52.5**	27.3	**48.6**	21.9
Average realised price of all production ($/boe)	**78.7**	33.9	**55.4**	30.1

a) Other liquids include condensate and other natural gas liquids.

In 2021, $128.6 million (2020: $9.0 million) of other operating income was recognised in relation to business interruption insurance proceeds for loss of revenue in relation to an incident at Hammerfest LNG plant in Norway where Neptune is a non-operated joint venture partner.

Operating costs were $512.5 million (2020: $467.0 million) for the year to 31 December 2021 and our average operating cost per boe produced was $11.3/boe compared with $9.5/boe for 2020. Operating costs for the purpose of per boe expense are increased by $20.3 million for the year ended 31 December 2021 (2020: $70.2 million reduction) to exclude changes in the value of over/under-lifted entitlement to production, to net-off income from tariffs and services which serve to recover costs, to exclude predevelopment costs and to exclude abandonment costs incurred on non-producing fields. The higher operating cost per barrel is principally due to the effect of lower production from Norway, the UK and Egypt, and increased operating costs driven by higher prices for carbon emissions allowances in Europe and increased blending cost in Indonesia.

The depreciation and amortisation expense was $575.1 million (2020: $584.7 million). The charge represents $12.6/boe produced compared with $11.9/boe produced for the year ended 31 December 2020. The lower overall depreciation charge is primarily due to lower production in Norway, the UK and Egypt.

Exploration expense for the year was $67.7 million (2020: $91.2 million), which includes costs incurred on geological and geophysical studies (G&G) to review strategic growth opportunities as well as seismic costs. 2021 includes $32.2 million of unsuccessful well evaluations costs principally in relation to Norway. The higher 2020 charge was primarily due to increased seismic cost in Egypt and higher G&G studies cost. The costs recognised for unsuccessful well evaluations in 2020 included $11.5 million in Norway, $8.8 million in Germany and $10.2 million in the UK.

General and administrative (G&A) expense of $78.4 million (2020: $69.1 million) for the year to 31 December 2021 consists primarily of costs that are not directly incurred for production or capital projects (including exploration), such as staff employment costs related to corporate functions and selling expenses, office costs and fees for services provided to us. The increased G&A costs in 2021 are due to one-off higher costs in Germany for the office relocation and additional headcount costs for employees allocated to our equity-accounted Algerian joint venture.

Share in net income of entities accounted for under the equity method was $61.1 million (2020: $20.0 million loss) for the year ended 31 December 2021. This represents the share of net income from the Touat joint venture of $62.4 million income (2020: $21.6 million loss), netted off by the share of net loss of one of our Dutch pipeline interests of $1.3 million (2020: $1.6 million income). The increased income from the Touat joint venture reflects $32.2 million of impairment reversal (2020: $32.7 million impairment) recognised due to improved macroeconomic conditions, recognition of business interruption insurance proceeds for loss of revenue from the production outage, and the impact of higher revenue as a result of increased gas prices. Lower income from the Touat joint venture in 2020 reflects the loss of production in the year to date.

Group net impairment reversals (pre-tax and excluding our share of the Touat impairment reversal mentioned above) for the year were a total of $113.6 million (2020: $325.7 million impairment loss). The impairment reversals in 2021 include a $43.4 million impairment reversal for a single Cash Generating Unit (CGU) in Indonesia and a reversal of a PP&E impairment of $96.5 million for a single CGU in the Netherlands due to an upward reserves revision. This is partially offset by a PP&E impairment of $18.7 million for a second CGU in the Netherlands due to a deterioration of underlying reservoir performance, a $6.7 million impairment in the UK as the planned Pegasus West development will not proceed, and an impairment to intangibles in Denmark of $0.9 million due to the sale of a legacy asset.

Total impairment losses for 2020 were $325.7 million. Impairment losses in relation to PP&E were $301.5 million; these included $197.7 million for a single CGU in Indonesia, $91.1 million for a single CGU in the Netherlands and $12.7 million for a single CGU in Germany. These impairments were primarily due to decreases in the long-term price assumptions and underlying reservoir performance. Goodwill impairments in Egypt and Denmark were $14.4 million. There were also $9.8 million of net impairments to intangible assets, including $10.0 million for the relinquishment of an exploration licence in Indonesia and $7.7 million for a single CGU in Denmark, partly offset by the reversal of an impairment to intangibles in Norway of $7.9 million due to a discovery. The goodwill and CGU in Denmark were acquired as part of the VNG acquisition in 2018.

Financial review
continued

Other operating losses were $65.4 million (2020: $33.6 million loss) for the year to 31 December 2021. The 2021 loss includes a loss on mark-to-market on commodity contracts other than trading instruments of $73.8 million, release of contingent consideration of $2.5 million, pension schemes curtailment credit of $4.1 million, net restructuring release of $0.5 million, a net movement in provision for inventory deterioration and obsolescence of $1.0 million and other gains of $2.3 million. Other gains include gains recognised on the completion of the sales for the disposal of two properties in Germany, this is offset by a legacy licence cost and a loss in relation to the sale of 100% of the shares in Neptune Energy Denmark ApS, which included the Solsort exploration licence.

The 2020 loss included a loss on mark-to-market on commodity contracts other than trading instruments of $4.0 million, a restructuring charge $25.3 million, release of contingent consideration of $20.3 million, unsuccessful business combination termination fees $5.0 million, a net movement in provision for inventory deterioration and obsolescence of $1.6 million and other losses of $19.0 million. The net restructuring costs recorded in the year to 31 December 2020 include a charge of $33.1 million in relation to the reduction of positions across our business and closure of offices in Oslo in Norway and Lingen in Germany, offset by a release of $7.8 million relating to 2019 reorganisations. The release of contingent consideration in 2020 was in relation to two assets in Denmark and Norway that were part of the VNG acquisition in 2018. Other losses in 2020 principally related to a $17.9 million write off of a JV partner debtor.

The Group's operating profit for the year to 31 December 2021 was $1,514.7 million (2020: $95.4 million loss) before net finance costs. Underlying operating profit is calculated before the impact of impairment reversals/losses, restructuring costs, pension curtailment credits and certain one-off costs. For 2021, underlying operating profit was $1,368.3 million (2020: $287.3 million). The increase in the operating profit and underlying operating profit was mainly due to the significant increase in the commodity prices.

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Operating profit/(loss) before financial items	**1,514.7**	(95.4)
Adjusted for:		
Impairment (reversal)/loss in share of net income/(loss) from investments using equity method	**(32.2)**	32.7
Impairment (reversals)/ losses	**(113.6)**	325.7
Net restructuring cost/(release)	**(0.5)**	25.3
Legacy licence cost	**4.0**	–
Pension scheme curtailment credit	**(4.1)**	(1.0)
Underlying operating profit before financial items and tax	**1,368.3**	287.3

Net financing expenses were $122.3 million (2020: $237.7 million) for the year and main components include $119.4 million (2020: $132.7 million) of interest expense, unwinding of discount on provisions of $35.4 million (2020: $36.1 million), $5.7 million (2020: $7.1 million) interest expense in relation to right-of-use lease liabilities, reduced by a foreign exchange gain of $46.8 million (2020: $59.8 million loss). The decrease in net financing expense in 2021 is driven by a large foreign exchange movement, with a gain in 2021 compared to a loss in 2020, aided by a lower interest cost due to the repayment of the Touat Vendor Loan in September 2020. The net foreign exchange gain and loss arises on the revaluation of loans and working capital balances for internal funding purposes across the Group and is principally impacted by the exchange rates for Euros, Norwegian Kroner, Sterling and US Dollars.

The Group's profit before tax for the year to 31 December 2021 was $1,392.4 million (2020: $333.1 million loss). EBITDAX (as defined by the RBL and the Neptune Energy Group Shareholder Agreement) for the year was $2,109.3 million, compared with $939.8 million for the year ended 31 December 2020. The increase in EBITDAX principally reflects higher realised commodity prices in the year.

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Profit/(loss) before tax, after financial items	**1,392.4**	(333.1)
Add back:		
Net financing expenses	**122.3**	237.7
Other operating gains	**65.4**	33.6
Net impairment (reversals)/losses	**(113.6)**	325.7
Exploration expense	**67.7**	91.2
DD&A	**575.1**	584.7
EBITDAX (RBL basis)	**2,109.3**	939.8

The Group's total tax charge for 2021 is $1,005.2 million (2020: $65.9 million), comprising a current tax charge for the year of $427.8 million (2020: $286.9 million credit) and a deferred tax charge for the year of $577.4 million (2020: $352.8 million charge). The total tax charge for the year represents an effective tax rate of 72.2% (2020: (20)%). The effective tax rate for the year is mainly impacted by Norway being subject to a statutory tax rate of 78% and deferred tax asset not recognised on the UK tax loss due to insufficient future taxable profits, following first utilisation of the future taxable profits by the hedging losses.

Net profit for the year ended 31 December 2021 was $387.2 million (2020: $399.0 million loss) on a reported basis.

For the year ended 31 December 2021, $8.0 million (2020: $8.1 million) of additional capital and operating expenditure was incurred in relation to COVID-19. The organisation will continue to monitor significant COVID-19 expenditure.

Hedging

Group policy is to seek to reduce risk related to commodity price fluctuations by using hedging instruments to set a floor for the sales realisations for a proportion of forecast revenues on a rolling basis, with reducing levels of hedging for each of the next three years. The Group actively manages this hedging programme using, among others, swaps and options.

As at 31 December 2021, the approximate share of post-tax production (which adjusts for different tax rates on physical sales and hedge gains and losses, meaning that effective post-tax hedges can be achieved through hedging contracts for volumes which may be significantly less than anticipated sales) hedged for future periods is shown in the table below. For oil, weighted average downside protection is $51.2/barrel for 2022 and $41.8/barrel for 2023, with upside capped at around $87.4/barrel for 2022 and uncapped for 2023.

For gas, hedging provides weighted average floor prices of $5.8/mmbtu for 2022 and $5.9/mmbtu for 2023 with upside caps at $6.6/mmbtu and $13.1/mmbtu respectively.

The average hedge prices are reflective of open hedge positions, in the event positions have been closed out, these are not included in the average hedge prices. The average hedge prices do not include the effect of bought calls, certain of our existing capped hedges will reparticipate in higher market environments.

Aggregate pre-tax hedge ratio:

	2022	2023	2024
Oil	23%	14%	–
Gas	41%	19%	–
Total weighted average	**31%**	**16%**	**–**

Aggregate post-tax hedge ratio:

	2022	2023	2024
Oil	37%	23%	–
Gas	62%	30%	–
Total weighted average	**49%**	**26%**	**–**

1. Oil price hedges include hedges of realisations for gas production sold as LNG and priced in relation to oil prices.
2. Post-tax hedge ratios adjust for different tax rates on physical sales and hedge gains and losses, which means that effective post-tax hedges can be achieved through hedging contracts for volumes which may be significantly less than anticipated sales.
3. Hedge percentages are based on total Group forecast production volumes including Algeria.

The estimated net fair value (comprised of current and non-current assets and liabilities) on a mark-to-market basis of all our commodity derivative instruments at 31 December 2021, was a net liability of $1,123.2 million (2020: $6.8 million asset), of which contracts with a net liability of $974.5 million expire in 2022.

Cash flow

Operating cash flow, after cash taxes, for the year to 31 December 2021 was $1,696.8 million (2020: $915.4 million). Cash taxes were $57.6 million received (2020: $70.2 million received). The net cash tax refunds result predominately from our 2020 Norwegian investment programme and the temporary Norwegian fiscal changes. The effective rate of cash tax as a percentage of pre-tax operating cash flow was (3.5)% (2020: (8.3)%).

Capital expenditure

Cash capital expenditure for the year to 31 December 2021, was $747.1 million (2020: $801.8 million), including $118.7 million (2020: $84.5 million) of capitalised exploration expenditure and pre-development capital expenditure. The 2021 figure includes expenditure in Norway on Njord, Duva/Gjøa P1, Fenja and Gudrun projects, the Seagull project in the UK as well as expenditure in Indonesia on the Merakes development project. This excludes expenditure at Touat in Algeria, where the joint venture is accounted for under the equity method of accounting as a joint venture. Our statement of cash flows includes net investment at Touat in terms of the cash injections and capital reductions made with the joint venture company, which were $2.8 million cash outflow in 2021 (2020: $20.6 million inflow).

In millions of US$	**Year ended 31 December 2021**	Year ended 31 December 2020
Investing cash flows:		
Development capex (note a)	**615.7**	717.3
Acquisitions – development assets	**3.7**	–
Exploration and pre-development capex	**118.7**	84.5
Acquisitions – exploration assets	**9.0**	–
Total cash capital expenditure	**747.1**	801.8

a) 2020 includes Saka carry reimbursement of $2.5 million.
b) Capex figures are for wholly-owned affiliates only.

Total exploration expenditure of $154.1 million (2020: $145.4 million) comprised the $118.7 million (2020: $84.5 million) cash exploration and pre-development capex and $35.4 million (2020: $60.9 million) expensed in respect of G&G and seismic costs. Capex expenditure in 2021 has primarily been in Norway, Indonesia, the Netherlands and the UK.

Development cash capex was $615.7 million (2020: $717.3 million). The majority of expenditure was in Norway on the Njord, Duva/Gjøa P1, Fenja and Gudrun projects, the Seagull project in the UK as well as the Merakes project in Indonesia.

We incurred $38.5 million (2020: $40.5 million) on decommissioning cash expenditure in the year to 31 December 2021, this was in the UK, the Netherlands and Germany.

Disposals

The Group signed a sale and purchase agreement for the sale of 100% of the shares in Neptune Energy Denmark ApS, which includes the Solsort exploration licence with a current book value of $2.6 million, the transaction completed on 1 October 2021.

On 12 November 2021, the Group announced the disposal of a portfolio of non-core Norwegian assets for an aggregate consideration of up to $35 million to OKEA ASA and M Vest Energy AS. The assets the Group is divesting include the producing Draugen, Brage and Ivar Aasen fields, as well as the Edvard Grieg Oil Pipeline and the Utsira High Gas Pipeline. All decommissioning liabilities will be transferred to the buyers. The effective date for the agreements is 1 January 2022, with an expected completion date of 31 March 2022, subject to Norwegian Ministry of Petroleum and Energy approval.

Financing and liquidity

Management's financing strategy is to manage Neptune's capital structure with the aim that, across the business cycle, net debt (excluding vendor loans) to EBITDAX, as defined by the RBL and Shareholder Agreement, remains below 1.50 times. This ratio, as at 31 December 2021, was 1.00 times. The RBL covenants require this ratio to remain below 3.50 times.

We funded our business mainly with cash generated from operations and debt facilities. At 31 December 2021, we had the following debt outstanding:

- $1,360 million drawn under the $2.6 billion committed RBL facility, which matures in 2024;
- $850 million 6.625% senior notes, maturing in 2025;
- $100 million 7.250% Subordinated Neptune Energy Group Limited vendor loan with ENGIE E&P International S.A., maturing in 2024; and
- $60 million drawn under short-term bilateral borrowing facilities.

At 31 December 2021, our cash balance totalled $125.5 million (2020: $92.5 million) and our available and undrawn headroom under the RBL facility was $930 million. We also had $11 million of letters of credit drawn under an ancillary facility to the RBL and $158 million in surety bonds outstanding. Our weighted average cost of borrowing for the Group equalled 4.4%. Our Corporate Credit Rating with Moody's, S&P and Fitch remain at Ba3, BB- and BB respectively. The outlook from S&P was upgraded to positive in December, with Moody's outlook remaining positive and Fitch's outlook remaining stable. We will continue to seek to strengthen these ratings over time.

All debt, except for the debt drawn under the RBL facility, is carrying a fixed interest rate. As at 31 December 2021, 43% of the debt portfolio was fixed.

Financial review
continued

Financial condition

Operating cash flows were $1,696.8 million (2020: $915.4 million) with the increase primarily reflecting higher commodity prices partly offset by lower production. Investing cash used was $724.4 million (2020: $765.0 million) for the year, being covered by operating cash flows. Net cash flows used in financing activities was $939.1 million (2020: $143.3 million) primarily consists of:

- the settlement of the $544.7 million of dividends, represented by $80 million and $264.7 million of interim dividends and $200 million of 2019 dividend;
- loan advanced to parent company of $455.3 million; and
- slightly netted off by net proceeds of borrowings of $60.9 million (2020: $143.3 million repayment) during the year.

This resulted in a net cash inflow of $33.3 million for the year to 31 December 2021 (2020: $7.1 million). As at 31 December 2021, gross interest-bearing debt was $2,329.4 million (book value) and net debt on an RBL basis, (excluding Subordinated Neptune Energy Group Limited loan) was $2,103.9 million. Net debt on an RBL basis has increased due to the RBL facility increasing to $1,330.7 million in 2021 from $1,028.6 million in 2020. This represents a net debt to EBITDAX ratio of 1.00 times for the 12 months ended 31 December 2021 (2020: 1.94 times).

2022 outlook

We expect production to increase to 135-145 kboepd in 2022 as we benefit from higher production availability at Touat, as well as the full year contribution of our projects brought onstream during 2021. The restart of operations at Snøhvit in May 2022 is the only material addition to production in 2022, with the expected start-up of Njord in the fourth quarter to make a material contribution to growth in 2023 and 2024 as production from the field ramps up.

Stronger production, together with high commodity prices and a continued focus on cost control, is expected to support operating cash flow (before working capital) generation of more than $1.2 billion in 2022. Operating cash flows will be impacted by hedging losses and higher taxation due to a tax overhang from 2021. Cash taxes in 2022 are expected to be around $1 billion. Leverage is expected to remain below targeted levels of 1.5 times throughout 2022.

We retain a disciplined approach to capital allocation and will invest selectively in new opportunities, including through M&A, where it makes strategic sense and delivers strong returns and near-term cash flow generation. Operating costs are expected to increase modestly in 2022, reflecting higher industry costs, including transportation, CO_2 taxes and royalties. As a result, while opex remains low, it is expected to average $11.5-12.5/boe for the full year, before falling to around $11/boe in 2023 as our remaining new projects are brought onstream.

Risks and uncertainties

Investment in Neptune involves risks and uncertainties, these are summarised in detail in the risk management section, see pages 72-76.

As an oil and gas, exploration and production company, exploration results, reserve and resource estimates, and estimates for capital and operating expenditures involve inherent uncertainties. A field's production performance may be uncertain over time. The Group is exposed to various forms of financial risks, including, but not limited to, the impact of climate change, fluctuations in oil and gas prices, currency exchange rates, interest rates and capital requirements. The Group is also exposed to uncertainties relating to cyber threats, political risks, the international capital markets and access to capital and this may influence the speed with which growth can be accomplished.

Going concern

Given the total available liquidity as at 31 December 2021 of $1.1 billion, comprising our cash balance ($125.5 million) and available and undrawn headroom under the RBL facility ($930.0 million), and capital resources arrangements in place (see note 20), the consolidated accounts have been prepared on a going concern basis.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2023. The cash flow forecasts reflect forecast production consistent with our Board-approved plans and externally published guidance and base case commodity prices that are slightly below current market conditions.

In reaching the conclusion that the going concern basis is appropriate, we have stress tested future cash flow forecasts and covenant compliance for the Group to evaluate the impact of plausible downside scenarios. These include scenarios that reflect short-term commodity price forecasts significantly below current market conditions as well as scenarios that consider the impact of unforeseen production outages. We have also performed a reverse stress test to inform our judgement, which demonstrated that we are resilient to sustained low commodity prices up to 50% below our conservative base case cash flow forecast.

Under all plausible scenarios, it was concluded that the Group retains sufficient liquidity and headroom over its covenant ratio, and that the going concern basis remains appropriate. The likelihood of the commodity prices identified in the reverse stress test materialising is considered remote on the basis of market consensus for short-term commodity prices and relative to historic market lows.

Dividend

Given the improving commodity and economic outlook, the Board of Directors of Neptune Energy Group Midco Limited declared a 2021 interim dividend of $80.0 million on 24 February 2021 which was initially settled by the issue of an $80.0 million promissory note. The $80.0 million promissory note was settled in full for cash on 15 December 2021.

On 10 December 2021, the Board of Directors of Neptune Energy Group Midco Limited declared a second 2021 interim dividend of $264.7 million which was settled on 15 December 2021 by the Company.

The $200.0 million promissory note issued in respect of the final 2019 dividend announced on 11 December 2019 was also settled on 25 February 2021.

The aggregate amount of the dividends paid in the year:

In millions of US$	2021
2019 declared dividend paid	200.0
2021 Interim dividend declared and paid	80.0
2021 Second Interim dividend declared and paid	264.7
Aggregate amount of dividends paid in the year	**544.7**

The aggregate amount of the dividends paid by Neptune Energy Group Midco Limited of $544.7 million and the loan of $455.3 million in the year made to its ultimate parent entity, Neptune Energy Group Limited (NEGL), represents a $1.0 billion total contribution to NEGL. This enabled dividends and capital distributions totalling $1.0 billion by NEGL, made up of a first 2021 interim dividend settlement and capital redemption settlement of $200.0 million on 25 February 2021 and a second interim dividend and capital redemption settlement of $800.0 million on 15 December 2021 to the ultimate shareholders of NEGL.

No dividends were declared or paid in 2020.

General dividend considerations

- Neptune's investment proposition is aimed at providing both yield and growth for bondholders and shareholders throughout the cycle, with capital investment allocated to exploration, development and production assets. Dividends form part of such expected shareholder returns, although the Group does not have a formal dividend policy.
- When determining a potential dividend and the level of such dividend, the Board takes into account the following metrics: Production/Capex profile, Leverage (Net Debt/EBITDAX), total net debt, acquisitions or divestments, projected liquidity under different commodity price scenarios, as well as any potential impact on Credit Rating of the Group and bonds issued.
- Any dividend shall be sustainable in the context of allowing the Company to continue to pursue its organic growth strategy and to develop its contingent resources whilst maintaining a conservative gearing ratio and retaining an appropriate liquidity position within its available credit lines.

The Company and/or its affiliates may purchase Neptune Bond Notes in the open market on an opportunistic basis.

Armand Lumens Chief Financial Officer
16 March 2022

How we manage risk

Risk management framework

Taking a systematic approach to risk management enables us to deliver our vision and strategy. Risk management is integrated in the way we think, plan and act as a business. Effective risk management supports Neptune as we strive to be a safer, faster and better business. It enables us to identify potential hazards, uncertainties and scenarios, and take them into account when we make decisions.

Our strategy, which is discussed and approved by the Board, guides the organisation in considering the risks we face when pursuing business opportunities. This helps us decide which risks to take to increase business value, which to avoid as they destroy value, and which to mitigate to protect value.

Our common risk management process is embedded in everything we do, from capital allocation to individual operational activities, which allows us to continuously and consistently analyse and make appropriate risk-informed decisions.

The Board exercises its oversight of risks and the risk management process via our Audit and Risk Committee. The committee oversees and discusses key enterprise risks at a strategic level and monitors the effectiveness of Neptune's enterprise risk management process.

The committee regularly reviews Neptune's enterprise risk portfolio following a review by the executive-level Enterprise Risk Committee. This enables the committee to better understand the risk profile, inter-dependencies between the risks and get assurance over alignment between the Board, our Executive Team and risk owners.

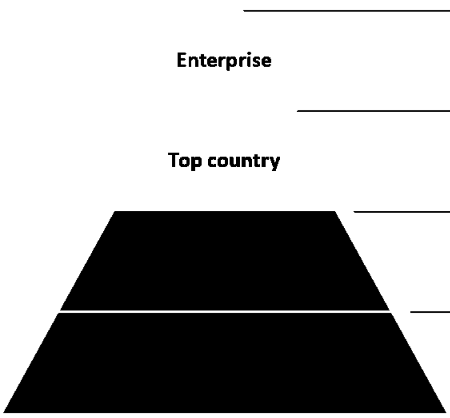
At a country level, each business maintains its top-country risk registers, which country leaders review regularly. These registers are also embedded in our business planning and business performance reviews, during which they are also reviewed and challenged by the Executive Team.

Top-country risk registers are based on functional, asset and project-level risk registers, which are fundamental to effective bottom-up risk identification.

Oversight responsibilities for other Group-wide risks are delegated to other committees or cross-functional teams to ensure the right level of expertise and focus:

- **Investment Committee** assesses risks related to our new investment opportunities and major contracts.
- **Hedging Committee** reviews the way we implement our hedging strategy in light of prevailing market conditions.
- **Treasury Committee** oversees treasury, trading, finance, tax and other financial risks.
- **Operational Integrity Committee** oversees health, safety and operational integrity risks.
- **ESG Committee** oversees environmental, social and governance risks.
- **Remuneration Committee** oversees remuneration policies and practices, including a specific focus on equal pay and executive pay.
- **Equality, Diversity and Inclusion (ED&I) Committee** oversees implementation of Neptune's ED&I charter.
- **Incident Management Committee** oversees learning reviews and investigation processes in response to safety and misconduct events.
- Neptune's General Counsel, Group Human Resources Director and Head of Ethics and Compliance meet quarterly to review the status and outcome of investigations into informal and formal grievances.

Our risk governance



Enterprise	Audit and Risk Committee of the Board, Executive Enterprise Risk Committee and other risk forums
Top country	Country leadership and executive planning and business performance reviews
	Function VPs and in-country function heads
	Asset project leads

The regular conversations in these committees are fundamental to keeping the organisation focused on the risks that matter both in the short term and over a longer-term planning horizon. They are also fundamental to ensuring diverse views on risk are considered in order to reduce personal bias.

A risk management calendar is supported by a network of risk coordinators who support their Country Managing Directors and Function VPs in ensuring a strong focus on risk is maintained.

Risk management

While it is essential that our leaders focus on risk management, we expect everyone at Neptune to manage risks in their respective areas of responsibility.

The Risk Management Policy and the Group Risk Management Standard set out the Board's expectations on sound risk management processes, as well as common risk management principles. These provide the foundation for Neptune's integrated management system, which defines more specifically how we manage particular risks.

Each risk has an owner who is responsible for assessing, controlling and mitigating it. Risk owners are accountable for implementing effective risk reduction actions when required.

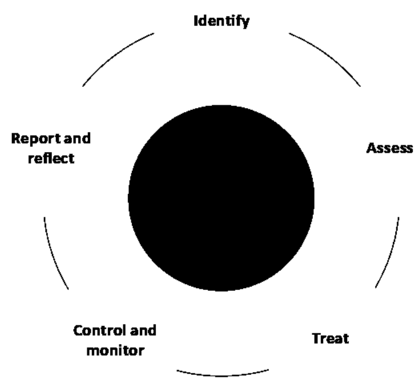
Risk owners follow a common risk management process to identify risks and the effectiveness of existing risk mitigations.

Using our common risk assessment criteria, risk owners assess the current level of probability and potential impact of each risk. If a risk is assessed as too high, then further risk reduction measures are identified to bring the risk to the target/acceptable level.

We classify risks into one of four categories: improve, manage, monitor and operate. This helps us to prioritise risk discussions and guide leaders in focusing their time on the risks that require their attention, support or awareness.

All enterprise risk information is stored in a single system and is available to leadership teams in real time via interactive risk dashboards. This allows them to perform relevant risk analyses and generate additional functional or business risk insights. Further risk reduction actions are monitored in the system to ensure opportunities to reduce Neptune's risk exposure are implemented.

Our risk management process



How we manage risk
continued

Neptune's risk profile

Summary of developments in Neptune's risk profile in 2021

2021 continued to provide significant challenge to the business primarily due to the ongoing COVID-19 pandemic and increasing political and social pressures regarding climate change. Our risk analysis demonstrated that while many risks are interdependent, COVID-19 and climate change-related risks were the most dominant. They have the potential to drive up other enterprise risks and affect Neptune's production and project delivery, which would ultimately have a negative impact on our cash flow.

Neptune remained resilient throughout 2021 to the threats posed by new COVID-19 variants and the resulting government restrictions on travel and business activity in countries where we and our partners operate. While we recognise that future outbreaks are possible and restrictions may be reimposed by governments, we continue to assess the risk through our preventive and response measures.

Meanwhile, global economic recovery, prompted by national vaccination programmes and the easing of lockdowns, saw oil and gas prices rally, which significantly reduced our exposure to financial risks associated with liquidity, commodity prices and inability to access capital markets.

As a result of the oil and gas industry's improved financial performance, the risk of joint venture partners defaulting on financial obligations reduced and that risk was removed from our enterprise risk register. It also reduced the likelihood of financial distress in our joint venture partner portfolio.

Environmental, social and governance

ESG risks are a significant and important part of Neptune's risk management system. These risks are essential elements of Neptune's strategic, stakeholder, people, HSEQ and compliance risk categories. We outline key ESG risks in the principal risks section.

The Board recognises the strategic importance of risks relating to climate change and the energy transition and the challenges and opportunities they present to Neptune. We identify, assess and manage climate-related risks through our enterprise risk management system (see page 71). In 2021, we further developed our response to these risks from a disclosure, regulatory, policy and business resilience perspective, as well as identifying business development opportunities. We will continue to develop our response throughout 2022.

In 2021, we re-evaluated our risks relating to climate change. As a result, we identified four distinct risks:

1) Risks relating to host country and investor policy and regulation changes in response to climate change (see page 73).
2) Risks relating to the lack of viable lower carbon transition options (see page 74).
3) The risk of increased litigation across the oil and gas industry (see page 76).
4) Risks associated with the physical impact of climate change (see page 76).

Identifying these risks means we are able to better understand their nature and respond to them effectively should they occur.

Emerging risks

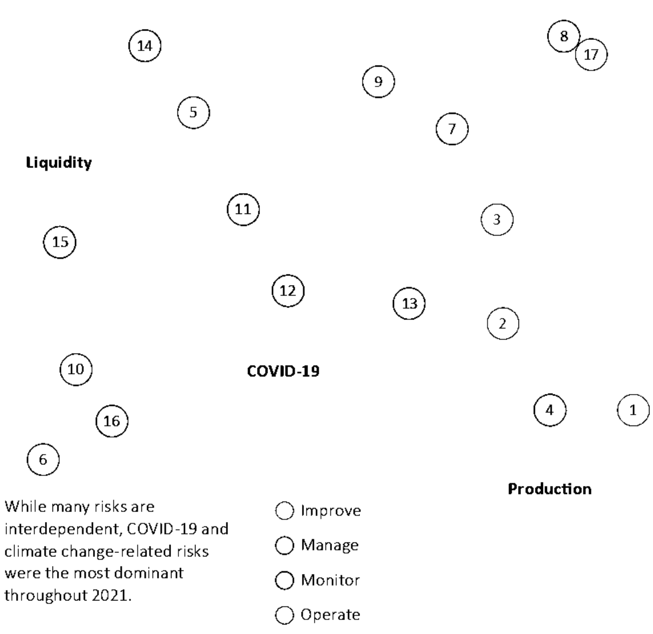
In 2021, we monitored the risk of inflation in the cost of materials against the backdrop of the global economic recovery and ramp-up of oil and gas production, as well as against lower carbon projects, which compete for similar resources and materials.

While we may not always be able to prevent or influence emerging risks, we recognise the importance of sound risk governance, organisational culture and risk management processes to enable us to tackle emerging risks if they materialise.

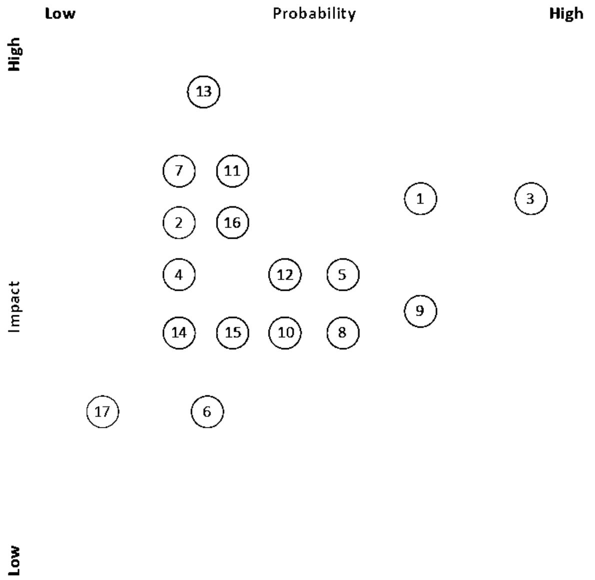
In early 2022, the Russian invasion of Ukraine has resulted in a humanitarian crisis and led to severe economic sanctions against the Russian Federation, Russian entities and designated nationals. While the direct impact on Neptune is limited, we will continue to monitor potential impacts over the short, medium and long term. We recognise that the conflict could escalate further and have assessed our preparedness accordingly.

Over the medium term, our ability to attract and retain talent may be adversely affected by changing sentiment towards the oil and gas industry. To mitigate this risk, we have built a distinctive company culture, with strong levels of employee engagement and a robust focus on ESG (including equality, diversity and inclusion). We are also increasing our efforts to provide further employee development opportunities.

Interdependencies of risks



While many risks are interdependent, COVID-19 and climate change-related risks were the most dominant throughout 2021.



Principal risks

① Host country and investor policy and regulation changes in response to climate change
② Cyber attack on information systems
③ Third-party and host project delivery

④ Production loss impairing external market outlook
⑤ LNG contract renegotiations
⑥ External financial reporting error
⑦ Replenishment of reserves
⑧ Lack of viable lower carbon transition options
⑨ Political and economic instability in countries in North Africa and Asia Pacific
⑩ Breach of ethical and compliance requirements

⑪ Significant oil/gas price volatility
⑫ Disruption to business due to the COVID-19 pandemic
⑬ Health, safety or environmental incident
⑭ Inability to access capital markets
⑮ Liquidity
⑯ Climate change class action/litigation

⑰ Physical impact of climate change

Principal risks and uncertainties

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2021
IMPROVE				
① **Host country and investor policy and regulation changes in response to climate change** Host country energy policies may undermine Neptune's strategy, add cost and reduce profit margins. They may ultimately challenge the economic viability of projects/assets. Governments may decide not to sanction new licences for gas and oil exploration in order to reach their climate goals. This may affect a country's licensing policies and lead to more stringent regulatory regimes that could negatively affect Neptune's ability to grow and sustain business.	Stakeholder/Country and government	3, 7, 8, 11	Lower carbon strategy in place. Gas-weighted production portfolio. Continued focus on meeting ambitious carbon and methane intensity targets. Internal carbon cost incorporated into investment decisions.	⬆ Green recovery arguments became more pronounced, increasing the negative sentiment around fossil fuels. In the UK, development risk increased due to the North Sea Transition Deal and the prospect of a carbon compatibility test for new developments. However, this creates opportunities for investment in electrification, CCS and hydrogen.
② **Cyber attack on information systems** Malicious attack on information systems or networks may lead to their unavailability, lack of access to systems or loss of data.	Information systems/ System security	1, 2, 10	Security standards defined and used by Group-wide assets. Regular risk assessments and vulnerability scanning. Continuous review and refinement of the effectiveness of our cyber security barriers.	➡ We observed a number of high-profile ransomware incidents across industries and geographies in 2021. This demonstrated a heightened level of underlying threat to systems and networks in general. Neptune remained focused on cyber risk throughout the year, reinforcing prevention, detection and response procedures and systems. This helped to improve cyber risk awareness across the organisation and improved user behaviour.
③ **Third-party and host project delivery** Neptune relies on other joint venture operators to deliver key development projects. Delays to the delivery of non-operated projects may result in delays to the realisation of value.	Business/Project and decommissioning	1, 9, 13, 14	Senior stakeholder engagement with operators and contractors, resulting in more realistic target costs and schedules. Neptune secondees embedded in project teams to ensure more direct involvement and influence.	⬆ We delivered three major projects that are performing above plan. However two major non-operated capital-intensive projects continue to underperform against present plans. Stakeholder engagement at all levels continues to apply pressure and focus to maximise Neptune's influence.

Principal risks and uncertainties
continued

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2021
MANAGE				
④ **Production loss impairing external market outlook** Failure to meet production target range advised to stakeholders. The risk of additional curtailment and possible disruption to operations due to COVID-19 remains.	Business/Operational	1, 2, 10, 11, 13, 14	Loss of production insurance in place. Regular production monitoring and reporting.	➡ P1 and Duva delivered and performing above plan, achieving production volumes above the volumes promised to investors. Production from Indonesia, Egypt and the Netherlands was in line with, or exceeded, our expectations. However, Neptune's production continued to be affected by the lack of availability of the Hammerfest LNG plant, which impacts production from Snøhvit in Norway. In Algeria, the Touat gas plant experienced production issues, which resulted in an unplanned shutdown. Neptune was able to recover most of the lost value and cost from insurance cover. In the UK, we focused on progressing the resolution of Bacton performance/blend issues, which could otherwise affect Cygnus in the longer term.
⑤ **LNG contract renegotiations** Our LNG contracts, particularly in Indonesia, Algeria and Norway (Snøhvit) are renewed from time to time and, depending on expected market conditions, may expose Neptune to changes in price formulae, which may result in lower prices.	Stakeholder/Customers	11	The Board monitors LNG contract management. In case of renewals, we ensure early planning and negotiation strategy preparations are in place with regular Steering Committee oversight and reporting to the Board. Senior stakeholder engagement with relevant counterparties.	⬇ Following the recovery of oil and gas prices, the risk of a negative impact of price renegotiations fell.
⑥ **External financial reporting error** The Group is inherently exposed to external regulatory or legislative penalties and reputational consequences as a result of inaccurate external reporting and associated tax filings.	Financial/Financial information and reporting		Internal control over financial reporting framework defined, including competence, organisational and process controls.	⬇ Management of financial reporting risk improved throughout 2021 with the finalisation of our internal control documentation project, automation and system enhancements. We provided training on key accounting issues and internal controls to staff.
⑦ **Replenishment of reserves** We may be unable to replenish resource base and reserves, which may prevent sustained levels of production in the longer term and, therefore, affect Neptune's strategic targets.	Business/Portfolio	3, 4	Strategic country focus on reserves replacement. Investment Committee selectively approves best development opportunities. Continuous opportunities screening for selective acquisitions.	⬇ Neptune's four-year reserves replacement was strong at 123% with a plan to continue replenishing reserves over the next five-year period, in particular with progress at Maha in Indonesia, Dugong in Norway and F-5 in the Netherlands.
⑧ **Lack of viable lower carbon transition options** Due to the gap between European governments' decarbonisation policies and relevant regulation, plus uncertainty around fiscal/economic regimes, options for investing in lower carbon activities may not be economically viable. This may reduce Neptune's attractiveness to potential investors, increase cost of financing and expose it to negative publicity.	Strategy/Business model	7, 8, 13, 14	Lower carbon strategy is now in place. We have established a pipeline of projects in line with the strategy. It requires maturation and rigorous prioritisation to ensure projects remain viable.	**NEW** The Group has developed its lower carbon strategy and progressed a number of pilots to test the investment case for lower carbon projects.

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2021
⑨ **Political and economic instability in countries in North Africa and Asia Pacific** Political and economic instability in host countries may undermine Neptune's strategy, add to cost and reduce profit margins and ultimately challenge the economic viability of projects/assets.	Stakeholder/Country and government	3, 4, 10, 11, 13	Ongoing commercial engagements with respective host countries and monitoring of relevant political and economic situations, including election results and fiscal regimes. Close monitoring and interventions, where required.	➡ In North Africa, further weakening of national economies, as a result of COVID-19 disruptions and costs, has increased instability. Indonesia has taken a positive approach to support oil and gas companies through policy changes.
⑩ **Breach of ethics and compliance requirements** A breach of ethics and compliance requirements could lead to reputational loss, financial losses, additional costs and civil and/or criminal liabilities.	Compliance/Ethics and conduct	11	We have policies and standards outlining our requirements on ethical conduct and compliance. We provide regular training and awareness campaigns for employees, contractors and suppliers. New third-party due diligence platform to screen business partners launched. Ethics whistleblowing hotline and misconduct and loss investigation processes in place.	➡ We are implementing a longer-term compliance programme with company-wide ethics training. We addressed increased external threats of fraud, bribery and corruption caused by disruption to pre-COVID-19 ways of working through increased communication with Neptune staff. This included raising awareness of the threats and asking them to remain vigilant and report any suspicious activity.
MONITOR				
⑪ **Significant oil/gas price volatility** Profits could be affected by movements in oil and gas prices. If left unmanaged, this has the potential to put the solvency of the company at risk.	Financial/Market	3, 4, 11, 13, 14	We actively manage this risk by executing our hedging strategy, which is overseen by the Board and targets a minimum hedge ratio of 50%, 30% and 15% for years one, two and three.	⬇ Commodity prices improved during the year, with gas prices at 14-year highs and crude prices at levels last seen in September 2018. Crude averaged $71 per barrel during the year.
⑫ **Disruption to business due to the COVID-19 pandemic** Uncertainty around COVID-19 may affect employee and contractor wellbeing, as well as their availability to work. It also increases business risks around suppliers, customers and partners, leading to delays, losses, additional costs and increased volatility.	Business/Operational	1, 2, 5, 11	Pandemic response procedures in place and tested. Continued to monitor COVID-19 developments and country guidelines. Continued to comply with health and safety recommendations. Regular monitoring in place for key sources of business risk (suppliers, customers, partners and financial counterparties).	⬇ Despite increased infection rates, Neptune's prevention and detection system protected our people, as well as our operations and projects from major disruption, which resulted in a lower than expected impact. We continued monitoring pandemic developments with help from our global occupational health service, International SOS. However, uncertainty about the behaviour of the virus and the potential for subsequent waves and further disruptions remained.
⑬ **Health, safety or environmental incident** Risk of a health, safety or environmental incident leading to loss of life, loss of reputation and additional costs and liabilities.	HSE/Health, safety and security	5, 6, 10, 11	Ongoing programme to maintain and reinforce safety culture throughout Neptune. Rolled out process safety fundamentals programme to employees and contractors.	➡ We recognised the potential risk of a drift from good HSE performance towards failure caused by the COVID-19 crisis, during which attention may be diverted. We therefore introduced a new KPI in our monthly reporting on the number of safety observations relative to the hours worked. We believe that when this KPI falls it may indicate reduced focus on safety. In 2021, the results were stable and consistent with pre-COVID-19 data.

Principal risks and uncertainties
continued

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2021
⑭ **Inability to access capital markets** Neptune may be unable to access debt capital markets or equity capital markets, which may affect capital structure and funding.	Financial/Liquidity and solvency	14	Group Treasury monitors the market continuously in order to remain in a state of preparedness.	⬇ The bond markets have improved and it is currently relatively straightforward for Neptune to issue bonds. However, changes in investor appetite for fossil fuel investments could impact our medium and longer-term access to capital as well as the cost of capital. That being said, on balance, the short-term situation has continued to improve.
⑮ **Liquidity** Neptune may not able to service its debt and pay its suppliers as invoices become due.	Financial/Liquidity and solvency	14	Treasury Policy in place. Group Treasury monitors the market continuously.	⬇ We successfully completed our borrowing base redetermination in March 2021, leading to a similar amount as in March 2020. Group liquidity remained above $1bn during 2021. Debt capital markets have continued to improve, leaving Neptune with funding optionality.
⑯ **Climate change class action/litigation** Since 2019, there has been a rise in climate-related litigation globally against major carbon emitting corporations, including oil and gas majors and states. Litigation of this kind may increase in frequency with the potential to affect the business, both financially and reputationally.	Compliance/Legal, Contract/Disputes HSE/Environment/ Climate change	10	We monitor climate change-related litigation with legal advice on the potential future impact on the industry and our business.	**NEW** A number of high-profile climate change-related court cases were brought in the Netherlands, Germany and the UK. Should such measures become common in the gas and oil industry, this could significantly increase the Group's costs, limit its ability to develop new gas and oil reserves, decrease the value of its assets, or reduce the demand for hydrocarbons and refined petroleum products.
OPERATE				
⑰ **Physical impact of climate change** The potential for, and adverse impact of, more frequent severe weather conditions, rising sea levels and other physical effects on our operating installations and future projects could rise.	HSE/Environment/ Climate change	10	We have expanded our physical impact climate change scenarios beyond the projected life of existing operations. All new projects need to comply with current regulatory requirements, which include provisions for climate change and may evolve over time.	**NEW**

Internal control monitoring and assurance

In order to manage risk, we define and implement internal controls through our integrated management system to ensure our control requirements are consistent and kept live. Our internal control system is linked to our enterprise risk management process and is subject to assurance activities through multiple 'lines of defence' to confirm that we have implemented our key controls and that they are operating effectively.

The first line of assurance is provided by asset-level operational and project teams and in-country functions. Group functions and Group internal audit provide additional layers of monitoring and assurance. For the whole system to work, all assurance levels must be effective.

In 2021, we integrated assurance planning activities across Neptune to ensure appropriate coverage, frequency and depth of audits and reviews across the whole spectrum of risks.

The audits conducted by our Group internal audit team and carried over from the 2020 audit plan were finalised in 2021 and we completed all key audits in the 2021 plan. A number of audits were reprioritised due to travel restrictions, and are now due to be completed in 2022. Our Audit and Risk Committee has approved the 2022 Group internal audit plan, giving priority to assurance over financial controls, IT risks, business continuity and disaster recovery as well as contracting and procurement.

In 2021, we strengthened our assurance coverage in three risk areas, clarifying in each the responsibilities between the second and third lines of defence and defining our assurance approach:

- **Operational integrity assurance** – aims to assure our Executive Team that the elements in our global operational integrity management standard (GOIMS) are complied with. On top of routine assurance activities carried out by the business, it is centred on annual self-assessments carried out by the business to confirm GOIMS compliance, along with a common audit programme delivered consistently across our operated assets.
- **Assurance over internal controls over financial reporting** – in 2021, our Group finance team completed a project to document key financial controls across core business processes. The project laid the foundations for consistent, fit-for-purpose coverage of controls in our Group internal audit activities as well as integration with internal control monitoring and reporting to the Audit and Risk Committee.
- **Non-financial data assurance** – we refined our model in 2021, building on Neptune's Basis of Reporting of non-financial information in the Annual Report and website (see *neptuneenergy.com/esg*). The assurance model makes our Group Function VPs accountable for consolidating and validating the information they oversee. The data we publish according to respective laws and regulation requires external independent assurance to the Board. Independent assurance over other data elements is provided to our Audit and Risk Committee by Group internal audit as part of a three-year rolling audit programme.

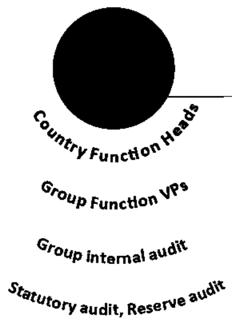
Our approach to assurance needs to be flexible to allow Neptune to adapt to the changing risk landscape. We will continue to assess how we can optimise and refine our approach. We plan to enhance the way in which our IT solutions can support integrated assurance in 2022 to ensure consistent monitoring and reporting on assurance activities and outcomes across the Group, as well as timely monitoring of improvement actions.

Our assurance lines of defence

Tier 4
- Shareholders
- Other external stakeholders

Tier 3
- Board
- Audit and Risk Committee
- Other sub-committees of the Board

Tier 2
- CEO
- Executive Team



Tier 1
- Country Managing Director
- Group Function VP

Tier 0
- Country Function Head
- Project Director/Manager

Companies Act 2006 – Section 172(1) statement

The Directors are required by law to act in a way that promotes the success of the Company for the benefit of its shareholders as a whole. While carrying out this duty, the Directors must also consider the wider consequences of their decisions in the long term and how those decisions might affect other groups of stakeholders, including those listed in section 172(1) of the Companies Act 2006.

Long-term strategy and vision

During 2021, the Board's response to the ongoing COVID-19 pandemic remained an immediate priority in order to secure the long-term success of the Group. The Board achieved this by ensuring that the facilities operated by the Group and its offices continued to function, while complying with applicable COVID-19 regulation and guidance for both offshore and onshore operations. As restrictions eased during the year, the Board recognised the importance of reinstating face-to-face interactions, where possible, while respecting those who were not yet ready or able to meet in person. The policies and practices that we introduced across the Group recognise this balance, with an emphasis on encouraging physical attendance in office locations only when legally allowed and when individuals felt ready. Given the technical and scientifically complex nature of the Group's business (for example, in subsurface analysis and projects and engineering activities), the Board recognises the continued importance of in-person collaboration to maximise employee engagement as well as the potential for the business.

The Board also continued to recognise that specific environmental factors are relevant to the Group's success and such considerations rose in prominence during 2021. While acknowledging the essential nature of the Group's activities to the societies in which we operate (for example, for power generation, transport and heating), the Board also recognised the need to invest significant time and resources into the Group's lower carbon business. To this end, the Group assessed more than 20 lower carbon projects in 2021 and has initiated and pursued development on various hydrogen and CCS projects. See pages 20-24 for more information.

During 2021, the Board approved a revised Equality, Diversity and Inclusion Policy, as well as a new Code of Conduct and various other compliance policies. The Board considers these policies as central to its ambition of being the leading exploration and production company that meets society's changing energy needs in that they set out our expectations as to how we achieve this ambition. The Board and Executive Team monitor relationships with stakeholders on an ongoing basis in recognition of their importance to Neptune's long-term success. Below we set out how the Board and Executive Team considered stakeholders when making their decisions.

How we engage	Outcomes	Further details
Employees and contractors		
Engagement survey ('Pulse')	The Group used feedback from our annual Pulse survey to inform engagement and action plans. For example, following survey results, in 2021 we increased the amount of leadership training in all our operated locations, introduced policies and support to best enable ongoing flexible working, improved direct access to personal data for all of our employees, and introduced a structured mentoring programme and supporting online platform. We continued our efforts to increase communications and resources to raise awareness of the importance of mental health, and to embed our Employee Assistance Programme.	See pages 35-37.
Interaction with works councils and employee forums	We held regular meetings with representatives of our works councils and employee forums during 2021. The works councils in Germany, the Netherlands and Norway provide a formal setting through which our employees can provide feedback and raise concerns with senior management. Similarly, our UK and European employee forums give employees the opportunity to provide input on the Group's strategy and our approach to employee engagement. As the world adapted to COVID-19, the subject of flexible and hybrid working came up regularly during employee forums. The Group adapted its policies in light of what we heard, for example, by developing new hybrid working policies that are tailored to our specific countries.	See pages 35-36.
Visits to operating assets	Members of the Board and Executive Team visit operating assets and overseas offices to talk with employees and contractors, ensuring they can consider their views and circumstances when making decisions. Given the travel restrictions that affected all the countries where we work for much of 2021, it was more difficult to carry out these visits compared to previous years. However, the Directors and other members of senior management spent more than 200 days making visits to, or working from, our onshore and offshore sites. For example, Amanda Chilcott (a Director of the Company and Group Human Resources Director) visited the Gjøa platform in Norway for two days in November 2021. During her visit, Amanda spoke to line managers, HSEQ representatives, employees and contractors to hear their experiences of working with Neptune. As a result of this visit, we simplified the management of HR systems access and have started a longer-term review of options to improve the Group's learning portal.	
Direct engagement	As COVID-19 restrictions continued, virtual and online communications remained an important way of engaging with employees to understand their views and concerns, share news and good practice and to celebrate successes. As restrictions partially eased during the year, some face-to-face engagements resumed. Examples of engagement between our senior leaders and employees include: • Virtual and in-person town hall meetings for all employees or groups of employees. • Informal virtual coffee meetings between colleagues from different countries or functions to help maintain communications between those who might otherwise have felt lost without in-person contact. • Weekly blog from our CEO to all our employees.	
Equality, diversity and inclusion (ED&I) awareness sessions	The Group ran events throughout the year to promote its approach to ED&I. This included an ED&I month in November, during which several internal and external speakers hosted events and ED&I presentations. Our focus on ED&I has led to: • A review of internal policies, with a revised ED&I Policy developed in 2021 and revised parental leave periods for certain countries. For example, we have extended paid paternity leave in the UK to four weeks. • Partnerships with external organisations, such as the AXIS Network, to promote gender equality in the oil and gas sector. • A new mentoring platform to help our people better understand new perspectives and build connections.	See pages 36-37.

How we engage	Outcomes	Further details
Suppliers		
'Time out for safety' and logistics planning with suppliers	Acknowledging the inherent risks that affect our business, we used 'time out for safety' discussions with our logistics service providers (for example, helicopter, maritime and quay-side services) to share good practice on health, safety and environmental (HSE) matters. We also kept suppliers informed about upcoming activities to help them improve demand planning. This was particularly relevant given the supply chain challenges caused by the pandemic and Brexit. These conversations reinforce Neptune's expectations on HSE matters and help us plan lead times for purchasing and transporting equipment offshore. During 2020 and 2021, we carried out an extensive review – internally and with our suppliers – to understand the potential impact on our supply chain of the UK leaving the EU. The review found that we had taken the necessary steps to mitigate risks by engaging with our suppliers.	See pages 38-39 for more information on how we engage with our suppliers.
Customers		
Provision of vital products and services	Most of our direct customers are large multinational corporations, traders or government entities. The Directors recognise that Neptune's products are vital for the daily lives of the end-consumers served by our own customers. Notwithstanding the difficulties associated with working in confined environments (such as offshore platforms), the Board ensured that the Group continued to operate safely during the COVID-19 pandemic and recognised the importance of maintaining stable production during periods of exceptional commodity price volatility during 2021.	
Communities and the environment		
Community consultation	We consult with local communities throughout the different stages of our operations to help us understand their priorities and address their concerns. In Germany, for example, we have a dedicated local stakeholder manager for each district where we operate. In the process of decommissioning a gas site in 2021 in the wider Munich region, the Forest Authority requested that the site be developed into a conservation area. So, we partnered with the Nature Conservation Foundation in Emsland to enhance the habitat of local species, including endangered orchids.	See page 42 for more information.
Social investment activities	We seek to participate in activities that address local community development priorities and government needs, and that are also connected with our business activities and consistent with the UN Sustainable Development Goals. These activities help give us a better understanding of local priorities and ambitions. During 2021, our community activities included: • Continuing to support our charity partner, Mental Health UK, to support people affected by mental health problems. • Supporting a children's summer school in Norway promoting natural sciences. • Supporting other programmes for school children and students in the UK and Indonesia, with a focus on science, technology, engineering and mathematics. • Working with Developing the Young Workforce North East in the UK, which aims to help young people prepare for the workplace and gain apprenticeships. • Supporting the Abu El-Rish hospital in Egypt, which provides healthcare to people who could not otherwise afford it. • Supporting a project in Indonesia to drill a well for drinking water in a remote community.	See pages 40-41 for more information on our community investments in 2021.
Environmental consultation	We recognise the environmental issues associated with the production and use of gas and oil and continue to focus on minimising the environmental impact of our existing operations while investing in lower carbon opportunities. During 2021, this work included: • Achieving industry-leading carbon intensity of 6.4 kg CO_2/boe and methane intensity of 0.02% from our operated assets and remaining on track to meet our carbon intensity target of 6 kg CO_2/boe and net zero methane emissions by 2030, noting that reducing methane emissions was a key issue at the COP26 summit. • Participating in innovative hydrogen and CCS projects in the UK and the Netherlands. • Launching our Biodiversity Policy, with a commitment to having a net positive impact on biodiversity.	See pages 20-29 for more information on our environmental strategy.
Joint venture partners		
Regular meetings	Almost all of our assets are operated as joint ventures with other industry partners. Depending on the asset and the stage in its lifecycle, we hold weekly, monthly or quarterly meetings with our partners. Our collaboration with joint venture partners allows us to align their expectations with ours (for example, in routine matters such as budgets, maintenance, operations or projects) and to better manage extraordinary situations when they occur. For example, in the UK we worked with stakeholders and downstream infrastructure owners to ensure production at our Cygnus platform could continue while gas was unavailable. Considerable preparation was put in place to enable the network operator, National Grid, to implement changes before the shutdowns to ensure gas was blended at their terminal before onward transmission to customers. Where we are not the operator of a facility, we seek to work with our partners, sharing our experiences and practices. We do this, for example, through our representation at operations committee meetings and technical committee meetings. In 2021, we engaged with our joint venture partner in Algeria to explore options for the development of solar power generation in the vicinity of the Touat gas site.	See page 38 for more information on our engagement with joint venture partners.

Companies Act 2006 – Section 172(1) statement
continued

How we engage	Outcomes	Further details
Financial stakeholders		
Shareholder engagement	The Company has a single shareholder, Neptune Energy Group Limited, but recognises the need to engage with – and act fairly between – its other financial stakeholders, including its ultimate shareholders, bondholders, banks and other finance service providers. Members of our Executive Team held numerous meetings with the Group's ultimate shareholders in 2021 to hear their feedback on matters such as our business plan and budget, strategy and other high-value matters.	See page 69 for information on dividends.
Interactions with banks, credit agencies and insurers	We held regular meetings with the core group of banks that are part of our reserve base lending facility, as well as with other banks and financial advisers. We also met with S&P, Moody's and Fitch to discuss funding arrangements, 2021 company performance and progress on ESG matters. Our banks advise us on the debt and equity matters that drive value for all of our stakeholders. The credit agencies provide credit assessments and ratings on Neptune Energy on a regular basis, all of which are publicly available. Due to business interruptions at Snøhvit, Norway and Touat, Algeria in 2021, we held multiple meetings with our insurance broker and insurance syndicate, resulting in regular reporting to the insurance companies on the nature and progress of our loss of production insurance (LOPI) claims. The Touat claim was settled with the insurance syndicate and the Snøhvit claim is still in progress given that start-up of the Snøhvit facility is expected in May 2022.	
Meeting our bondholders and other lenders	We hold regular meetings with our bondholders and present formal quarterly results presentations. During 2021, we conducted four formal quarterly updates and had approximately 30 virtual or face-to-face meetings with bondholders, potential bondholders and lending banks. The Company guarantees the bonds issued by its subsidiary, Neptune Energy Bondco plc. The feedback we receive from bondholders ensures that their interests are considered when making decisions that might affect the Group's ability to meet its obligations towards bondholders and other creditors. We also consider our bondholders' views on ESG matters. Among other things, we held a roadshow with bondholders in April 2021 to get feedback on our ESG strategy and have incorporated this feedback into our ESG disclosures.	See pages 16-17 for information on our ESG strategy.
Host governments and regulators		
Meetings with representatives and embassies	We engage with all host governments directly and through meetings with representatives of the Group in our countries of operation and indirectly through their embassies in London and, where relevant, British embassies in country. We play an active role in the development of energy policy in each jurisdiction through briefings and consultation responses. In Indonesia, for example, we held meetings with SKK Migas, the Indonesian oil and gas regulator, and the Ministry of Energy and Mineral Resources in 2021, to discuss Neptune's plans to mature new opportunities and grow our business in line with Indonesia's strategic energy policy.	

Maintaining high standards of business conduct

We engage with our employees and other stakeholders on ethics and compliance matters. In early 2021, the Group asked Deloitte to carry out a maturity assessment of our ethics and compliance function. Later in the year, INCAS Consulting carried out a human rights and modern slavery assessment on our operations. These assessments, along with our ongoing compliance initiatives, helped inform our compliance programme for 2021, which included:

- A series of detailed compliance risk assessments, carried out across all Group operations.
- Publishing a new Human Rights Policy.
- An awareness campaign to highlight the importance of speaking up.
- Preparing our new Code of Conduct, which was approved by the Board in 2021.
- Introducing a new third-party due diligence screening platform.
- A campaign to raise awareness of our whistleblowing tools and policies.

Following these initiatives, we saw a slight increase in the number of reported incidents in 2021 as well as an increase in general questions about compliance issues.

See pages 91-92 for further information on our ethics and compliance programme.

For further details of the Group's engagement with stakeholders, see pages 32-43.

The Board delegates day-to-day management of the Group and various stakeholder engagement activities to members of the Executive Team and senior management, who report back to the Board. The Board regularly reviews the health, safety and environmental performance of the Group as well as operations and financial performance. The Board also reviews, assesses, challenges and ultimately approves the Group's strategy. It also reviews the Group's approach to matters such as risk management and mitigation, equality, diversity and inclusion, as well as legal, compliance, governance and social responsibility matters.

The Board acknowledges that not every decision it makes will benefit all our stakeholders all of the time and evaluates each key decision from the perspective of the stakeholders most affected by that decision. By considering the Company's purpose and values alongside its strategic priorities, and by having a clear process in place to make key decisions, the Board does, however, aim to make sure that its decisions are consistent and predictable.

As a result, the Board has had an overview of engagement with stakeholders and other factors that allow the Directors to understand the nature of their stakeholders' concerns while complying with their duty under section 172 of the Companies Act 2006 to promote the success of the Company. See page 83 for a summary of some of the key decisions made by the Board in 2021.

This Strategic report, consisting of pages 1-80 was approved by the Board on 16 March 2022.

By order of the Board.

Pete Jones Chief Executive Officer
16 March 2022

Governance

We are committed to the highest standards of governance, ethics and integrity throughout our operations.

Contents

Pages 82-93 comprise the Directors' report, including:

Governance

During 2021, the COVID-19 pandemic continued to pose significant governance challenges. These included continued restrictions on holding face-to-face Board and other meetings for much of the year, as well as difficulties associated with engaging with our stakeholders in lockdown or socially distanced scenarios. The Board recognised that these circumstances posed even greater difficulties and concerns for our employees and contractors working in operational environments, which, given the nature of our industry, often involves working in close quarters.

Notwithstanding these headwinds, the Group remained committed to high standards of corporate governance. For the year ended 31 December 2021, the Company continued to apply the Wates Corporate Governance Principles for Large Companies, published by the Financial Reporting Council in 2019. The following section describes how the Company has applied the Wates Principles in 2021.

“ — In 2021, the Group continued to provide vital energy supplies to our host communities, despite the challenges faced by the ongoing pandemic. Throughout, the Group achieved the highest standards of corporate governance through its commitment to the Wates Principles and stakeholder engagement.”

Sam Laidlaw Executive Chairman

Principle 1 – Purpose and leadership

The Group's vision is to be the leading independent exploration and production company by meeting society's changing energy needs and creating value for all stakeholders. We set out our new ambition in early 2022 to store more carbon than is emitted from our operations and the use of our sold products by 2030.

During the early part of 2021, the priority of the Board and the Executive Team was to ensure the longer-term success of the Group as we entered the second period of extensive international restrictions caused by the COVID-19 pandemic.

The Group held virtual meetings for the extended leadership team, comprising some 150 people, to ensure a consistent understanding of the Group's purpose, strategy and developments. The Executive Team met virtually on a weekly basis to discuss safety and operational matters and continued to engage with employees via a weekly CEO blog. There were also all-company events and site visits by Directors. These and other initiatives ensured close communications throughout the year, despite COVID-19 restrictions.

Recognising the increasing importance of environmental, social and governance (ESG) matters to our stakeholders (including shareholders, bondholders, host governments and employees), we made further progress in delivering our three-year ESG roadmap. For example, we started reporting our equity share emissions and completed a review of human rights in our business and supply chain. See pages 16-17 for more information.

Our continuing guiding principle is to carry out all of our activities in a manner that is 'safer, faster and better' than our peer group and our own past performance. In 2021 we:

- Improved our process safety event rate to 1.68 per million hours worked (2020: 2.37). There were no serious personal injuries during 2021. However, our total recordable injury rate (TRIR) increased to 2.07 per million hours worked in the year (2020: 1.43), largely as a result of relatively minor incidents in the category of slips, trips and falls. An increased training, awareness and remediation plan has been put in place.
- Delivered our P1 and Duva wells on time and under budget, receiving recognition from the Norwegian government. Both wells contributed significant additional volumes to the Group's production from February and August 2021 respectively.
- Progressed our Equality, Diversity and Inclusion (ED&I) charter and held events throughout the year, including our first ED&I month in November, during which internal and external speakers hosted discussions and other events aimed at increasing awareness and understanding of ED&I.

For more information on our Board, and that of our parent company, see **pages 85 and 90.**

Board activities during the year

While COVID-19 continued to pose governance challenges in 2021, we were, once again, well placed to respond. With state-of-the-art technological solutions, we switched between near-universal home-working for office-based members of staff to cautious reopening of offices, in line with relevant regulations and guidance.

For some of the year, we adopted a hybrid approach, with Board and other meetings taking place with some participants attending in person and others virtually. The Group continued to work strictly in accordance with its management and compliance framework.

During 2021, the Board of Directors met frequently before or shortly after the meetings of the Neptune Energy Group Limited (NEGL) Board and Audit and Risk Committee and held numerous ad-hoc update meetings with other members of the Executive Team and extended leadership team.

The Group's HSE performance continued to be the main item considered and reviewed by the Board and Executive Team during 2021, with particular focus on metrics that showed declining or stable performance and how those metrics could be improved.

The Board also continued to monitor and adapt to the changing regulations relating to the COVID-19 pandemic and associated government measures to ensure that the Group continued to comply with relevant laws and guidance. In particular, the Board recognised the difficulties associated with offshore working and the mental health impact of prolonged periods of enforced home working, and provided support for employees facing these challenges, for example, via our Employee Assistance Programme.

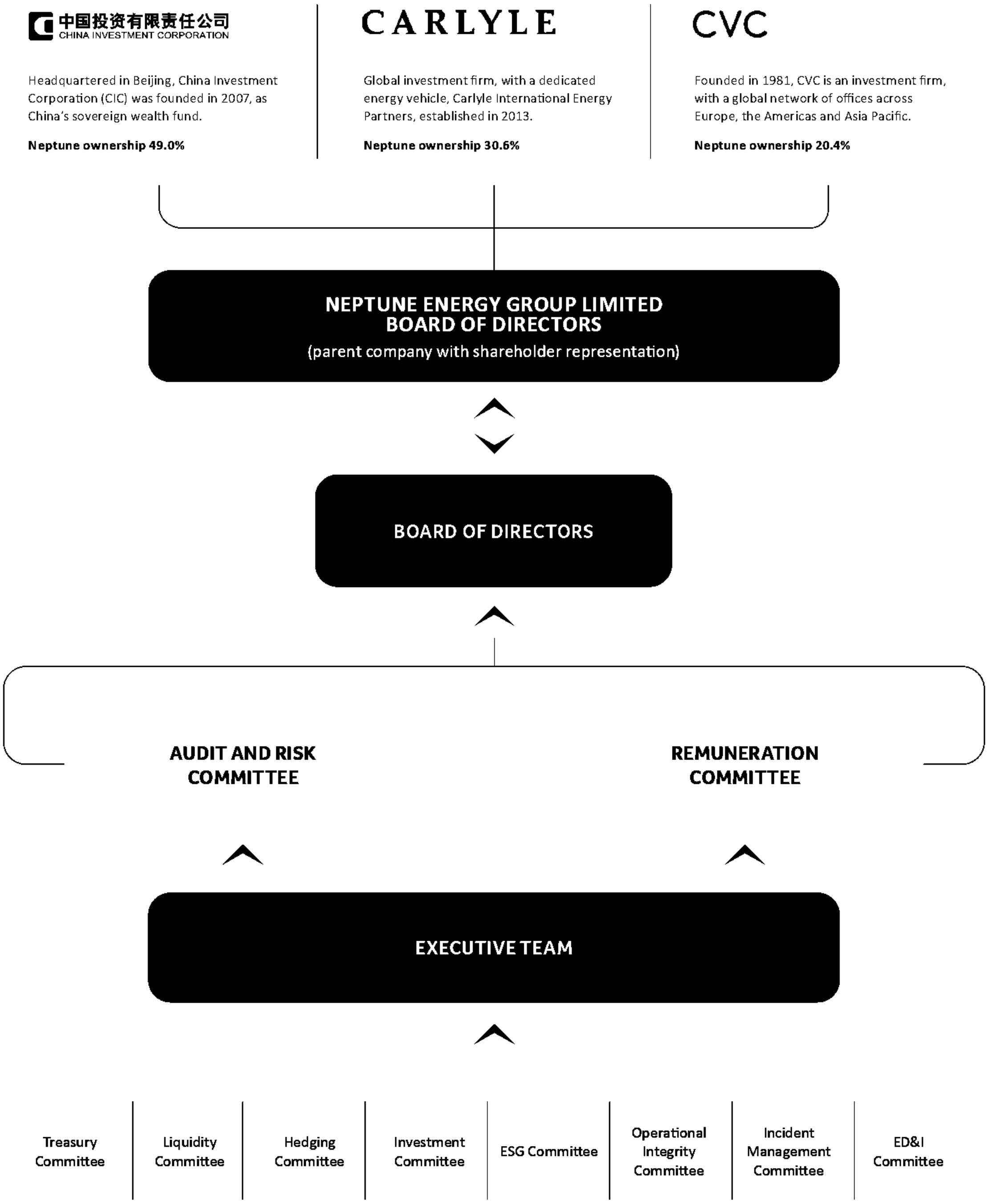
In addition, each of our businesses participated in performance reviews with the Executive Team and other members of the senior leadership team on two occasions in 2021.

Other matters considered by the Board in 2021 included:

- Assets coming into production, notably P1, Duva and Merakes.
- The Group's hedging programme and associated risks in high and low commodity price environments.
- The 2022 budget and business plan, including the Group's capital expenditure programme and operating expenditure.
- The Group's financing arrangements, including a review of the Group's liquidity position and repayment of certain debt facilities.
- Various commercial contracts, relating to the sale of commodities produced by the Group.
- The Group's strategy in light of the challenges posed by the ongoing pandemic and macro environment.
- The Group's ESG strategy and the expectations of external stakeholders with regard to ESG matters.
- The Group's lower carbon opportunities and the different initiatives to be pursued by the Group, including CCS and hydrogen projects.
- The impact of climate change on the Group's operations, both directly and indirectly, as a result of changes in law and societal expectations.
- Various employee engagement and retention initiatives, including a review of the results of the 2020 employee engagement survey.
- The 2020 Annual Report and Accounts as well as the quarterly earnings releases in 2021.
- Various M&A opportunities, including projects to divest certain Norwegian and Danish assets, which were agreed during the year.
- Various disputes to which members of the Group were party as well as various insurance claims.
- IT and cyber security matters, particularly in light of the increasing prevalence of hacking and ransomware attacks.
- Updated compliance policies and procedures including an updated Equality, Diversity and Inclusion Policy and a new Code of Conduct.

Governance
continued

Our governance structure



Principle 2 – Board composition

The Company's Board of Directors comprises Sam Laidlaw (Executive Chairman), Pete Jones (Group Chief Executive Officer), Armand Lumens (Group Chief Financial Officer), Amanda Chilcott (Group Human Resources Director) and Andrea Guerra (Vice President, Subsurface).

Biographies of the Directors are set out on pages 88-89. During 2021, we implemented our succession plan when Pete Jones succeeded Jim House as Group Chief Executive Officer on 1 January 2022, following Jim's decision to leave the Group and return home to the US. Prior to his appointment, Pete was VP Operations for the Group's European business and before that he was Managing Director of the Group's UK business. With his strong operational background, keen focus on safety and good commercial acumen, we had identified Pete in our Group succession planning process prior to Jim's decision to leave Neptune.

The Board continues to work closely with the Board of its parent company, NEGL, and operates to a similar agenda of standing and extraordinary items.

NEGL is the entity through which our investors own their interests in the Group. The directors of NEGL are nominated by our investors and are experienced business leaders with the skills necessary to help the business deliver its strategy. For further detail on our investors see page 90. In addition to their roles as Directors of NEGL, certain members of the NEGL Board also sit on the Audit and Risk Committee, Remuneration Committee, Liquidity Committee and Hedging Committee.

The Board and the NEGL Board are supported by the Audit and Risk Committee and the Remuneration Committee. The activities of these committees are described on pages 91 and 92.

The day-to-day management of the Group is delegated to the executive leadership team (the Executive Team).

Audit and Risk Committee

The Group's Audit and Risk Committee (ARC) consists of the members of the NEGL Board as well as members of the Executive Team. The ARC helps the Board (and the NEGL Board) carry out governance responsibilities with respect to external audit, internal audit, risk and internal control and to oversee the integrity of the Group's financial reporting and associated narrative statements. For details of the ARC's activities in 2021, see page 91.

Remuneration Committee

The Group's Remuneration Committee (RemCo) consists of the members of the NEGL Board as well as our Group Human Resources Director, with our Group CEO attending by invitation. The RemCo's primary purpose is to develop, maintain and implement remuneration policies. For details of the RemCo's activities in 2021, see page 92.

Executive Team

The Group is managed by the Executive Team. This consists of senior management, together with the heads of other functions and the Managing Directors of the countries in which we operate.

The Executive Team meets weekly in person or by video conference. HSE is always the first agenda item but other operational matters are also discussed, such as production, exploration and projects, and overall Group performance. During the weekly meeting, the team also discusses industry developments and key emerging risks, such as cyber security matters. The Investment Committee, ESG Committee, Operational Integrity Committee, Incident Management Committee and Hedging Committee, all comprising members of the Executive Team (and shareholder representatives in the case of the Hedging Committee), together with other members of the extended leadership team, help inform the Executive Team's decision-making processes.

For information on the Executive Team and their biographies, see **pages 88-89**.

Senior management

Our depth and breadth of experience

We have a highly committed and high-quality management team which is invested in the business, has deep experience and an excellent track record in the international energy sector.

See **biographies** overleaf

1	2	3
4	5	6
7	8	9

1 – Sam Laidlaw
Executive Chairman

2 – Pete Jones
Chief Executive Officer

3 – Armand Lumens
Chief Financial Officer

4 – Andrea Guerra
VP Subsurface

5 – Julian Regan-Mears
Director of Corporate Affairs

6 – Ben Walker
General Counsel

7 – David Hemmings
VP Business Development and Commercial

8 – Philip Lafeber
VP HSEQ and Technical Services

9 – Amanda Chilcott
Group Human Resources Director

Senior management
continued

1 – Sam Laidlaw
Executive Chairman

A C E I R

Sam is a founder of Neptune Energy and became its first Chairman in 2015. He is an experienced energy industry executive, with a strong international operational track record of more than 30 years in the oil and gas sector.

Previously, Sam has served as Chief Operating Officer of Hess Corporation, with responsibility for global upstream, CEO of Enterprise Oil Plc, Executive VP of Chevron Corporation and CEO of Centrica Plc.

Sam has also been a member of the UK Government's Energy Advisory Panel, President of the UK Offshore Operators Association, a member of the Prime Minister's Business Advisory Group, the Senior Director for the Department of Transport and a non-executive director of both HSBC Holdings Plc and Hanson Plc.

Sam is a non-executive director of Rio Tinto plc and Chairman of the National Centre for Universities and Business.

2 – Pete Jones
Chief Executive Officer

A C E I

Pete became Neptune's CEO in January 2022 and has more than 25 years' experience in the upstream oil and gas sector. He joined Neptune in 2018 as Managing Director for the UK and was Neptune's VP Operations for Europe from October 2019.

During his tenure in the UK and Europe, Pete transformed the Netherlands and Germany businesses and delivered organic and inorganic growth in Norway and the UK. He also drove an improvement in safety culture, while improving production efficiency.

Pete gained a degree in engineering operational research from the University of Birmingham and joined Marathon Oil, where he spent the first 16 years of his career working in various operational, technical and functional roles across the UK and the US, before being appointed Managing Director of its UK business in 2009. He went on to become the Managing Director of TAQA Europe.

During 2015 and 2016, Pete was on the Board of Oil & Gas UK and a member of the Energy Jobs Taskforce. Between 2017 and 2020, he was Honorary Professor at Aberdeen University's Business School.

3 – Armand Lumens
Chief Financial Officer

A C E I

Armand joined as CFO in December 2018. He has worked in the oil and gas sector for more than 25 years and provides Neptune with deep knowledge and experience of energy and capital markets.

Before joining the company, Armand was Group CFO at Louis Dreyfus Company. Prior to this, he spent more than 20 years with Shell in various senior financial roles, including as CFO of Shell Trading and Supply.

Armand is a non-executive director at Oryx Energies S.A. and V-Labs S.A.

4 – Andrea Guerra
VP Subsurface

C I

Andrea joined Neptune in August 2018 and has more than 20 years' international oil and gas sector experience.

Her extensive knowledge combines both managerial and technical experience addressing portfolio optimisation, prospect generation and maturation, reservoir management as well as exploration, appraisal and development drilling.

She directs the corporate reserve reporting function and is responsible for Neptune's global exploration portfolio.

Previously she worked at Apache, with senior management responsibilities for its North Sea Reservoir Engineering division, South America New Ventures, Corporate International Planning, and Corporate Reserves and Economics.

5 – Julian Regan-Mears
Director of Corporate Affairs

A E I

Julian joined Neptune in September 2018 and is responsible for investor relations, public affairs, media relations, internal communications and ESG.

Julian has more than 15 years' experience leading international corporate communications functions, mostly in the energy and mining sectors, holding senior management positions with Centrica plc and The De Beers Group. Earlier in his career, Julian led communications for Britvic plc's listing.

Key to committee membership

- A Audit and Risk Committee
- C Company Director of Neptune Energy Group Midco Limited
- E Environmental, Social and Governance Committee
- I Investment Committee
- R Remuneration Committee
- Committee Chair

“ — None of the progress we have made to date would have been possible without a world-class management team.”

Sam Laidlaw Executive Chairman

6 – Ben Walker
General Counsel

A E I

Ben joined Neptune in September 2019 from Vivo Energy plc, a pan-African fuel retailer and distributor, where he was General Counsel and Company Secretary.

Prior to Vivo Energy, he held the roles of Senior Legal Counsel with Centrica plc and Associate with Slaughter and May. Ben is a qualified solicitor in England and Wales and has significant experience in the oil and gas industry.

7 – David Hemmings
VP Business Development and Commercial

I

David joined Neptune in July 2018 with more than 20 years' experience in corporate finance in the oil and gas sector. David has a strong knowledge of capital markets in the energy sector, having advised oil majors, exploration and production companies and national oil companies on mergers and acquisitions and debt and equity financing.

Previously, he was a Managing Director in the energy and power advisory group at Rothschild.

8 – Philip Lafeber
VP HSEQ and Technical Services

I

Philip has more than 30 years' upstream energy experience, predominantly in Europe, the Middle East and West Africa. He joined Neptune from DONG Energy, where he was Country Manager for Norway. As its UK Technical Director he led the OGA West of Shetland Task Force Work Group.

At Amerada Hess, he was Global Strategic Planning Manager and Pre-Developments Manager for Europe, North Africa and Southeast Asia. He has worked in Oman for Shell International and in West Africa for Schlumberger Wireline.

9 – Amanda Chilcott
Group Human Resources Director

C E R

Amanda joined Neptune in December 2018 and is responsible for the development and delivery of our people strategy. She has been working in human resources for more than 20 years, and has significant specialist experience in the areas of organisation design, reward and employee relations.

She has worked with Ford Motor Company, BP and Aggreko in a variety of global roles, including assignments in the UK, continental Europe, China and the US.

Directors' report

Neptune Energy Group Limited Directors

The Board of Directors of our parent company, Neptune Energy Group Limited (NEGL), comprises Directors nominated by the Group's ultimate shareholders and is chaired by our founder, Sam Laidlaw. The Directors of the NEGL Board are respected industry leaders and provide valuable insight into management and governance matters, working closely with members of the Board and Executive Team.

Sam Laidlaw (Executive Chairman): see page 88 for Sam's biography.

Fang Bo (CIC nominee): Mr Fang serves as Senior Vice President in the Investment Department at CIC. He has been an investment professional in various sectors, including energy, infrastructure, telecoms, power and renewables. Mr Fang graduated from Peking University with a master's degree.

Jianmin Bao (CIC nominee): Mr Bao is a member of the Executive Committee of CIC. He oversees investment projects in infrastructure, real estate, energy, oil and gas, minerals and related investment funds at CIC. Previously, he managed North American fund investments and private credit market investments in the private equity department of CIC. Before his role at CIC, Mr Bao held a variety of senior roles in China Construction Bank, the Export-Import Bank of China and HSBC. Mr Bao graduated from Shanghai Jiaotong University with a master's degree.

Chenye Wang (CIC nominee): Mr Wang joined the Board in July 2021. He is a Senior Vice President within the Investment Department of CIC. Previously, Mr Wang was a Director at CLSA, where he participated in various corporate finance and principal investment transactions, and a VP with the global M&A practice at Barclays Capital. Mr Wang holds an MBA from the Kellogg School of Management and a Juris Doctor from the Northwestern University School of Law. He is a member of the New York State Bar.

Marcel van Poecke (Carlyle Group nominee): With more than 25 years of experience in the energy sector, Mr van Poecke is Head and Managing Director for Carlyle International Energy Partners (CIEP). He is also Chairman of AtlasInvest, a private holding company he founded in 2007 that is engaged in investments across the broad energy spectrum, and Chairman of ONE-Dyas, which owns and operates oil and gas assets. Mr van Poecke has a degree in agricultural business administration from the University of Wageningen and a master's in business administration from the William E. Simon School of Management of the University of Rochester, US.

Robert Maguire (Carlyle Group nominee): Mr Maguire is a Managing Director and Partner at The Carlyle Group, with responsibility for Carlyle International Energy Partners, L.P., a $2.5 billion fund focused on Europe and Africa. Mr Maguire has been active in the global energy markets for more than 35 years in a variety of senior roles at Perella Weinberg Partners, Basin Capital Partners and Morgan Stanley. He was involved in numerous significant transactions in the energy space, including mergers such as BP/Amoco, Elf/Total and Equinor/Norsk Hydro, privatisations such as Equinor, Rosneft, Gazprom and Sinopec, acquisitions such as BP/ARCO and Shell/Enterprise and joint ventures such as TNK-BP and LUKArco. He holds an AB from Princeton University, an MA from Oxford University and a JD from the University of Virginia School of Law.

James Mahoney (CVC Capital Partners nominee): Mr Mahoney is a Partner at CVC Capital Partners, a world leader in private equity and credit with $122 billion of assets under management, $165 billion of funds committed and a global network of 24 local offices. He has responsibilities in both the private equity and strategic opportunities platforms, including the firm's current investments in Neptune Energy, Ontic and Moto. Mr Mahoney has been active in the private equity industry for more than 20 years, with experience of making and managing equity investments across a range of industries and geographies. Prior to joining, Mr Mahoney was a Managing Director with Investcorp. He has a bachelor's degree in engineering from the University of Auckland.

Principle 3 – Director responsibilities

The Board meets regularly around the time of NEGL Board or ARC meetings. Members of the Board also engage on a regular basis with other members of the Executive Team, including through the weekly Executive Team meeting.

In addition, the Board attended two strategic planning meetings (one of which was virtual) with all of the Executive Team in 2021. Through these lines of communication, the Board was kept updated on the Group activities, enabling the Directors to discharge their responsibilities.

The Directors bring a wide range of experience to inform Board discussions and discharge those responsibilities. In keeping with best corporate governance practice, the roles of the Chair and CEO are distinct and the functional responsibilities of the other Directors (CFO, Group Human Resources Director and VP Subsurface) ensure that there are diverse viewpoints in Board discussions.

Decisions within the Group are made in accordance with the NEGL shareholders' agreement, as well as the articles of association of the Company and an approved delegation of authority standard.

In reaching their decisions, the Directors considered these arrangements as well as their responsibilities under section 172 of the Companies Act 2006 (see page 78 for further information).

Principle 4 – Opportunity and risk

The Board seeks opportunities to enhance the Group's business in a sustainable and responsible manner while also mitigating risk to the greatest extent possible. The Group's approach to strategic opportunities and the key risks affecting the Group (and the respective mitigating actions) are set out in our Strategic report on pages 70-77.

The Group continues to recognise both the risks and the opportunities associated with the energy transition while acknowledging the continued importance of gas and oil in the energy mix in the medium term. Gas and oil prices rose significantly during 2021 and international commodity markets experienced a great deal of volatility, particularly towards the end of the year. The Group continues to believe that, together, its lower carbon intensity exploration and production business, its gas-weighted portfolio and its growing lower carbon developments, position the Group well as the energy transition accelerates.

Audit and Risk Committee

The Audit and Risk Committee (ARC) reports to the NEGL Board but also informs the Board. It comprises the Executive Chairman (who chairs the ARC), the other members of the NEGL Board (or their representatives), the CEO, the CFO, General Counsel, VP HSEQ and Technical Services and Director of Internal Audit. The Group's Director of Corporate Affairs, Director of External Reporting, Group Financial Controller, as well as the Group's external auditor, also attend ARC meetings.

The ARC works to a standing agenda, which includes updates on reporting, technical accounting, internal controls, internal audit activities, the enterprise risk register, disputes and ethics and compliance. The ARC also provides the opportunity for the Director of Internal Audit and the Chairman to provide private feedback to ARC members and the Group's external auditors.

The ARC reviewed the terms of appointment of the Group's external auditors, Ernst & Young (EY). The ARC also considered EY's report on the Group financial statements for 2020 and EY's conclusions both on financial statements and agreed audit focus areas, as well as EY's proposed materiality thresholds for reporting purposes.

Financial reporting and technical accounting

As in previous years, ARC meetings coincided with the Group's quarterly results reporting to its bondholders and other stakeholders. ARC meetings provided an opportunity for the results and accompanying presentations to be reviewed and challenged by committee members ahead of publication.

In particular, the ARC reviewed the Group's financial statements and bondholder presentations for the six-month period ended 30 June 2021, which were also reviewed by EY.

During ARC meetings, the financial reporting and technical accounting teams gave updates on the processes for preparing the financial statements and the accounting areas of judgement supporting the positions taken by the Group. This was supported by accounting review papers, for example, in relation to impairments – and reversals thereof – receivables, acquisitions and discount rates.

The ARC also approved various updates to our Group Accounting Policy Manual – our key reference document for the Group's accounting policies.

Risk management and internal control

Committee members reviewed the Group's enterprise risk register as a standing item at each ARC meeting, as well as specifically reviewing the Group's finance risk register. COVID-19 remained a key risk throughout the year and the committee continued to monitor the pandemic and the Group's response to it carefully. The committee identified other key emerging risks during the year, including the increasing risks associated with cyber attacks and cyber security, volatile commodity markets, climate change and regulatory change.

During 2021, the Group continued to embed its internal control processes, which include a quarterly confirmation from the finance managers within the Group. In the event of any financial control incidents, these are reported to the ARC in detail.

As another standing item on the ARC agenda, the Director of Internal Audit reported the activities of the internal audit function to the ARC, as well as progress on closing out identified audit actions. During 2021, these included:

- Completing audits on hydrocarbon reporting, ethics and compliance, and IT.
- Audits on well control management, requisition to pay, treasury and banking and information risk management.
- Various ad-hoc audits, including on joint venture matters.

To further strengthen the Group's assurance processes, the internal audit function recruited two new members in 2021, with an additional member joining the team in early 2022.

Disputes and compliance

ARC members received regular updates in relation to the disputes to which entities of the Group were party as well as updates on matters relating to the Group's ethics and compliance programme. This included updates on investigations and approval of new policies and procedures as well as training programmes for compliance matters.

The ARC also approved the Group's 2020 Anti-Slavery and Human Trafficking Statement, which was subsequently approved by the Board and the NEGL Board and published on our website.

ESG Committee

In 2021, the Group's Environmental, Social and Governance (ESG) Committee consisted of the Executive Chairman, CEO, CFO, Director of Corporate Affairs, Group HSEQ Director, Group Human Resources Director, Head of ESG, Director of Internal Audit, Global Head of Ethics and Compliance, Director of New Energy, Vice President, Operations, Europe and the General Counsel.

The ESG Committee continued to implement the Group's three-year ESG roadmap and considered a range of matters, including:

- Outcomes of ESG ratings and the link between ESG performance and finance matters.
- Matters related to climate change management and disclosures, including the reporting of Scope 3 and equity share emissions.
- Endorsement of external initiatives including the UN Global Compact and the World Bank's Zero Routine Flaring by 2030 initiative.
- Outcomes from stakeholder engagement on our ESG strategy and reporting.
- Proposals to certify the Group's operated assets against ISO 14001, 50001 and 45001.
- Gender diversity data and initiatives to increase female representation at senior levels within the Group.
- The Group's new biodiversity strategy, and initiatives with environmental non-governmental organisations to support UN Sustainable Development Goal 14: Life below water.
- The Group's sustainable procurement action plan.
- Matters related to the internal assurance of non-financial information.

Ethics and compliance

Maturity assessment

In 2021, the Group's internal audit function, together with Deloitte, carried out a maturity assessment of Neptune Energy's ethics and compliance programme across 11 economic crime domains, with a particular focus on fraud, bribery and corruption. Each area was assessed against four criteria and below we set out the key findings: (i) top-level commitment, (ii) risk assessment, (iii) proportionate procedures, and (iv) due diligence.

Top-level commitment

The leadership team has strong awareness of the ethics and compliance risks that Neptune Energy faces, supported by evidence of senior management's engagement in training on a variety of ethics and compliance topics. Areas for improvement included ensuring that the Board had overall responsibility for the governance of ethics and compliance matters, and ensuring that senior management proactively communicated on ethics and compliance.

Neptune has since taken action to address these areas, including: (i) assigning responsibility for the ethics and compliance programme to the Board of Directors in our new Code of Conduct, and (ii) rolling out a bi-monthly programme of talks on ethics and compliance topics, including speaking up, conflicts of interest, bribery and corruption, the conduct of investigations and data protection.

Risk assessment

Neptune has conducted a high level of risk assessment in previous years. The assessment recommended that we conduct more comprehensive risk assessments, at an agreed frequency, to help the Group better assess its risk exposure. In response to these findings, we carried out a comprehensive ethics and compliance risk assessment in each country where Neptune Energy has assets, between June and October 2021. This led to a number of actions to mitigate risks, including: (i) developing a new Code of Conduct, (ii) holding a quarterly discussion forum in our North Africa and Asia Pacific countries to discuss how to raise awareness of ethics and compliance topics, (iii) revising our third-party due diligence

Directors' report
continued

procedures, to make them more robust, including introducing a new due diligence screening platform, run by Dow Jones, and (iv) carrying out various initiatives to raise awareness about speaking up, including a training session for employees on how investigations are conducted.

Proportionate procedures

The majority of the ethics and compliance domains assessed have a governing policy in place. Following the maturity assessment, we have since published additional policies, including a global Grievance Procedure, a Human Rights Policy and a Code of Conduct, which covers all of the ethics and compliance domains examined by the maturity assessment.

Due diligence

Neptune Energy's due diligence procedures covered many, but not all, of the 11 economic crime domains. We have since revised our due diligence procedures and introduced the new Dow Jones platform so that our due diligence now covers Neptune's key ethics and compliance risk areas.

Training and communications

While the assessment found a strong commitment to training and communications on ethics and compliance, it also highlighted that increased resource would help the team monitor training participation more effectively. We have since addressed this by recruiting a new member of the team, who will play a key role in monitoring compliance with training, policies and procedures.

Monitoring and review

While the assessment found that we have fraud and wider ethics and compliance monitoring controls in place, it also highlighted a lack of resource that prevents effective monitoring. Our new member of the ethics and compliance team will play a key role in regularly testing control effectiveness and compliance with internal requirements, such as adherence to the due diligence procedures.

In addition, in April 2021 we introduced an annual certification process, requiring all employees to confirm that they have (i) read and understood our Code of Conduct, (ii) completed all ethics and compliance e-learning, and (iii) registered any conflicts of interest and/or gifts and hospitality, in the appropriate registers.

Human rights and modern slavery assessment

INCAS Consulting carried out an independent human rights compliance assessment of Neptune's performance against the UN Guiding Principles on Business and Human Rights (UNGPs), as well as its compliance with the UK Modern Slavery Act 2015 (MSA). INCAS mapped existing policies and due diligence processes in relation to salient human rights issues and against the UNGPs and MSA requirements. INCAS found that employee rights were addressed well in Neptune Energy's employee manuals, and that we have appropriate health and safety policies in place.

However, the review highlighted that Neptune Energy's contracts with business partners did not cover the full range of human rights issues and that there was a lack of labour risk management in our supplier due diligence processes. In addition, training on human rights and modern slavery would be beneficial to ensure greater understanding across the business. INCAS also recommended putting in place a human rights policy, to give a clear statement on Neptune Energy's position.

Since receiving the INCAS report, we have taken several actions including:

- Publishing a Human Rights Policy.
- Rolling out a new Code of Conduct, which includes enhanced sections on human rights and modern slavery, and requires business partners to adhere to the same ethical standards.
- Implementing a new due diligence screening platform, where, for high-risk business partners, due diligence is carried out in respect of labour and human rights risks.
- Adding a human rights and modern slavery clause in Neptune Energy's standard forms of contract.
- Developing an action plan for improving post-contractual due diligence on suppliers, to assess compliance with the terms and conditions of contract, including the terms of the human rights and modern slavery clause.

Promoting a speak-up culture

We have encouraged people, through training and awareness sessions, to speak up if they have concerns about unethical practices. This follows the launch in October 2020 of our whistleblowing reporting tool, the Vault Platform app. In addition, as part of our ED&I month in November 2021, the CEO of Vault gave a presentation to our people on the importance of speaking up. This has led to increased awareness across the Group of the value of raising concerns and the channels available to do so. There was a slight increase in the number of concerns raised to 11 in 2021 (2020: nine). We have taken action to address the concerns raised, with 10 of the reports now closed, and one subject to ongoing investigation.

Principle 5 – Remuneration

The Group's Remuneration Committee (RemCo) consists of members of the NEGL Board as well as the Group Human Resources Director, with the Group CEO attending by invitation. The RemCo generally meets twice a year and on an ad-hoc basis, when required, to review and recommend matters relating to remuneration and benefits. During 2021, the Remco considered a range of issues, including:

- Output from the 2020 Group scorecard for the purpose of determining the Group performance element for bonuses paid in relation to 2020.
- Bonuses payable to members of the Executive Team.
- Design of the 2021 scorecard.
- The Group's long-term incentive plan.
- Remuneration payable to employees joining or leaving the Group.
- Gender pay gap and pay ratios and actions to improve further in these areas.
- Market data on reward in comparable companies.

The RemCo's primary purpose is to develop, maintain and implement remuneration policies. The overriding objective of these policies is to attract and retain high-calibre individuals with a competitive reward package based on the achievement of corporate performance targets. These are linked to individual performance and accountability and are designed to support the Group's commitment to exemplary safety standards and ethical values while rewarding long-term sustainable value creation.

The RemCo aims to ensure that levels of remuneration across the Group are sufficiently competitive to retain talent within the Group, as well as benchmarking our Executive Team remuneration packages. The RemCo also reviews the Group's performance against diversity and inclusion criteria, including benchmarking the Group against other industry players, while making recommendations on how to improve in these areas.

Principle 6 – Stakeholders

The Directors recognise the need to consider the views of stakeholders when coming to their decisions, particularly in the context of the Group's ambition to be a leading player in the energy transition through its gas-weighted portfolio and lower carbon developments.

We listen to the views and concerns of our stakeholders, which inform the decisions we make – from day-to-day business-level decisions to longer-term strategic matters considered by the Board and our ultimate shareholders. We set out examples of how we engage with our key stakeholders on pages 34-43 and in our Section 172(1) statement on pages 78-80.

Directors' statements

Directors' and officers' liability

Qualifying third-party indemnity provisions (as defined by section 234 of the Companies Act 2006) were in force during the course of the financial year ended 31 December 2021 for the benefit of the then Directors and, at the date of this report, are in force for the benefit of the Directors in relation to certain losses and liabilities which they may incur (or have incurred) in connection with their duties, powers or office. In addition, the Company maintains Directors' & Officers' Liability Insurance, which gives appropriate cover for legal action brought against its Directors. The insurance does not provide cover in the event that the Director is proved to have acted fraudulently.

Directors' statement of disclosure of information to the auditor

The Directors who held office at the date of approval of this report confirm that, so far as they are aware, there is no relevant audit information of which the Company's auditors are unaware. They also confirm they have taken all necessary steps as Directors to make themselves aware of any relevant audit information and to establish that the Company's auditors are aware of that information.

The Company has chosen to include certain matters in its Strategic report that would otherwise be required to be disclosed in a Directors' report. For information relating to:

- Dividends, see page 69.
- The financial risk management objectives and policies of the Company and the exposure of the Company to price risk, credit risk, liquidity risk and cash flow risk, see page 66 hedging and note 25 on page 141.
- Likely future developments in the business of the Company, see page 51.
- The research and development activities carried out by the Company, see pages 22-23.
- Employment of disabled persons, see page 36.
- Employee engagement, see page 35 and 78.
- Greenhouse gas emissions, energy consumption and energy efficiency, in respect of Streamlined Energy and Carbon Reporting (SECR) requirements, see pages 21 and 25.
- Our engagement with suppliers, customers and others with whom we do business, see pages 38-39.

Conflicts of interest

Directors have a statutory duty to avoid situations in which they may have interests that conflict with those of the Company.

The Board has adopted procedures as provided for in the Company's articles of association for authorising existing conflicts of interest and for the consideration of and, if appropriate, authorisation of new situations that may arise.

Political donations

The Group did not make any political donations (2020: $nil) or incur any political expenditure (2020: $nil) during the year.

By order of the Board.

Sam Laidlaw

Sam Laidlaw Executive Chairman
16 March 2022
Company number: 10684661

Statement of Directors' responsibilities

The Directors are responsible for preparing the Strategic report, Directors' report and the financial statements in accordance with applicable UK law and regulations. Company law requires the Directors to prepare financial statements for each financial year. Under that law the Directors have elected to prepare the financial statements in accordance with UK adopted international accounting standards ('IFRSs'). Under company law, the Directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of the Company and of the profit or loss of the Company for that period.

In preparing these financial statements, the Directors are required to:

- Select suitable accounting policies and apply them consistently.
- Make judgements and accounting estimates that are reasonable and prudent.
- State whether UK adopted international accounting standards ('IFRSs') has been followed, subject to any material departures disclosed in and explained in the financial statements.
- Prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Company will continue in business.

The Directors are responsible for keeping adequate accounting records that are sufficient to show and explain the Company's transactions and disclose, with reasonable accuracy at any time, the financial position of the Company and enable them to ensure that the financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Financial statements

Delivering near-term returns, within a disciplined financial framework

Contents

Independent Auditor's Report to the Members of Neptune Energy Group Midco Limited

Opinion

We have audited the financial statements of Neptune Energy Group Midco Limited ('the parent company') and its subsidiaries (the 'Group') for the year ended 31 December 2021 which comprise the Consolidated income statement, Consolidated statement of other comprehensive income, Consolidated and Parent statement of financial position, Consolidated and parent statement of changes in equity, Consolidated and Parent cash flow statement and the related notes 1 to 31, including a summary of significant accounting policies. The financial reporting framework that has been applied in their preparation is applicable law and UK adopted International Accounting Standards and as regards the parent company financial statements, as applied in accordance with section 408 of the Companies Act 2006.

In our opinion:

- the financial statements give a true and fair view of the Group's and of the parent company's affairs as at 31 December 2021 and of the Group's profit for the year then ended;
- the Group financial statements have been properly prepared in accordance with UK adopted International Accounting Standards;
- the parent company financial statements have been properly prepared in accordance with UK adopted International Accounting Standards as applied in accordance with section 408 of the Companies Act 2006; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the financial statements section of our report. We are independent of the Group in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the FRC's Ethical Standard, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Conclusions relating to going concern

In auditing the financial statements, we have concluded that the directors' use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the Group and parent company's ability to continue as a going concern for the period to 30 June 2023, sixteen months from when the financial statements are authorised for issue.

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant sections of this report. However, because not all future events or conditions can be predicted, this statement is not a guarantee as to the Group's ability to continue as a going concern.

Other information

The other information comprises the information included in the annual report, other than the financial statements and our auditor's report thereon. The directors are responsible for the other information contained within the annual report.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the course of the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether this gives rise to a material misstatement in the financial statements themselves. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

Opinions on other matters prescribed by the Companies Act 2006

In our opinion, based on the work undertaken in the course of the audit:

- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and directors' report have been prepared in accordance with applicable legal requirements.

Matters on which we are required to report by exception

In the light of the knowledge and understanding of the Group and the parent company and its environment obtained in the course of the audit, we have not identified material misstatements in the strategic report or directors' report.

We have nothing to report in respect of the following matters in relation to which the Companies Act 2006 requires us to report to you if, in our opinion:

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Responsibilities of directors

As explained more fully in the directors' responsibilities statement as set out on page 93, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the Group's and the parent company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or the parent company or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

Explanation as to what extent the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect irregularities, including fraud. The risk of not detecting a material misstatement due to fraud is higher than the risk of not detecting one resulting from error, as fraud may involve deliberate concealment by, for example, forgery or intentional misrepresentations, or through collusion. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below. However, the primary responsibility for the prevention and detection of fraud rests with both those charged with governance of the entity and management.

- We obtained an understanding of the legal and regulatory frameworks that are applicable to the Group and determined that the most significant are those that relate to the reporting framework (International Accounting Standards and the Companies Act 2006) and the relevant tax compliance regulations in the jurisdictions in which the Group operates. In addition, the Group has to comply with laws and regulations relating to its domestic and overseas operations, including those related to health and safety, employee matters, data protection, environmental and anti-bribery and corruption practices;
- We understood how the Group is complying with those frameworks by making inquiries of those charged with governance, management, internal audit and those responsible for legal and compliance procedures. We corroborated our inquiries through reading Board minutes, papers provided to the Audit and Risk Committee and correspondence received from regulatory bodies and noted there was no contradictory evidence;
- We assessed the susceptibility of the Group's financial statements to material misstatement, including how fraud might occur by inquiring of management to understand where they considered there was susceptibility to fraud. We also considered performance targets and their propensity to influence efforts made by management to manage earnings. Where this risk was considered to be higher, we performed audit procedures to address each fraud risk or other risk of material misstatement. These procedures included those on revenue recognition and testing journal entries and were designed to provide reasonable assurance that the financial statements were free from material fraud or error; and
- Based on this understanding we designed our audit procedures to identify non-compliance with such laws and regulations identified above. Our procedures involved inquiries of both Group and local management; inquiries of those charged with governance; and journal entry testing, with a focus on journals meeting our defined risk criteria.

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at https://www.frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Ernst & Young LLP

Steven Dobson – Senior statutory auditor
for and on behalf of Ernst & Young LLP,
Statutory Auditor
London
16 March 2022

Consolidated financial statements

For the year ended 31 December 2021

Consolidated income statement – Group

Group – in millions of US$	Notes	Year ended 31 December 2021	Year ended 31 December 2020
Revenue from contracts with customers	3	**2,490.1**	1,560.1
Other operating income	4	**128.6**	9.0
Revenue and other income		**2,618.7**	1,569.1
Cost of sales	6	**(1,067.2)**	(1,124.9)
Gross profit		**1,551.5**	444.2
Exploration expenses	6	**(67.7)**	(91.2)
General and administration expenses	6	**(78.4)**	(69.1)
Share of net income/(loss) from investments using equity method	15	**61.1**	(20.0)
Operating profit after equity-accounted investments	5	**1,466.5**	263.9
Net impairment reversals/(losses)	5	**113.6**	(325.7)
Other operating losses	8	**(65.4)**	(33.6)
Operating profit/(loss) before financial items		**1,514.7**	(95.4)
Finance income	9	**53.1**	12.4
Finance costs	9	**(175.4)**	(250.1)
Profit/(loss) before tax		**1,392.4**	(333.1)
Taxation	11	**(1,005.2)**	(65.9)
Net profit/(loss)		**387.2**	(399.0)

All profits and losses arise as a result of continuing operations. The accounting policies on pages 104-114 together with the notes on pages 114-154 form part of these accounts.

Consolidated statement of other comprehensive income – Group

Group – in millions of US$	Notes	Year ended 31 December 2021	Year ended 31 December 2020
Profit/(loss) for the year		**387.2**	(399.0)
Other comprehensive (loss)/income:			
Items that may be reclassified to the income statement:			
Hedge adjustments net of tax(1)	24	**(681.8)**	(138.3)
Share of hedge adjustments within equity-accounted investments(2)	24	**(4.2)**	(3.1)
Foreign currency translation		**(101.8)**	141.7
		(787.8)	0.3
Other items not reclassified to the income statement:			
Remeasurement of defined pension obligations, net of tax(3)		**14.8**	(4.2)
Net loss on equity instruments designated at fair value through other comprehensive income(4)	24	**(4.3)**	–
Foreign currency translation		**(1.6)**	–
		8.9	(4.2)
Other comprehensive loss		**(778.9)**	(3.9)
Other comprehensive loss for the year, net of tax		**(391.7)**	(402.9)

(1) Income tax related to hedge adjustments is $480.2 million credit (2020: $32.5 million credit) and is shown net of amounts reclassified to profit or loss or included in finance costs.
(2) Income tax related to share of hedge adjustments within equity-accounted investments is $2.4 million credit (2020: $1.0 million credit).
(3) Income tax related to defined benefit obligations is $4.3 million debit (2020: $2.5 million credit).
(4) Within the net loss on equity instruments designated at fair value through other comprehensive income is $0.2 million of deferred tax charge.

Consolidated statement of financial position – Group

Group – in millions of US$	Notes	31 December 2021	31 December 2020
Non-current assets			
Goodwill	12	**610.0**	649.7
Intangible assets	13	**282.0**	194.9
Property, plant and equipment	14	**4,748.8**	4,566.2
Derivative instruments	24	**21.0**	19.6
Investments in entities accounted for using the equity method	15	**606.3**	557.6
Other non-current assets	24	**69.5**	99.5
Equity instruments	24	**15.4**	21.1
Deferred tax assets	11	**852.3**	577.3
Total non-current assets		**7,205.3**	6,685.9
Current assets			
Derivative instruments	24	**60.7**	55.1
Trade and other receivables	17	**1,384.8**	526.6
Inventories	16	**83.0**	79.0
Cash and cash equivalents	18	**125.5**	92.5
Income tax receivable		**33.4**	153.4
		1,687.4	906.6
Assets held for sale	19	**134.9**	–
Total current assets		**1,822.3**	906.6
Total assets		**9,027.6**	7,592.5
Share capital	26	**1,977.2**	1,977.2
Hedging reserve	24	**(708.6)**	(22.6)
Foreign currency translation		**(67.1)**	34.7
Fair value reserve of financial assets at FVOCI		**(5.9)**	–
Retained earnings/(deficit)		**(449.4)**	(506.7)
Total equity		**746.2**	1,482.6
Non-current liabilities			
Provisions	23	**1,778.0**	1,870.9
Long-term borrowings	20	**2,269.4**	1,971.8
Derivative instruments	24	**169.7**	11.5
Income tax payable		**82.5**	71.5
Other non-current liabilities	21	**95.2**	131.3
Deferred tax liabilities	11	**1,357.1**	988.8
Total non-current liabilities		**5,751.9**	5,045.8
Current liabilities			
Provisions	23	**123.5**	114.9
Short-term borrowings	20	**60.0**	50.0
Derivative instruments	24	**1,029.3**	60.1
Trade and other payables	21	**329.4**	333.5
Income tax payable		**378.8**	28.6
Other current liabilities	21	**507.6**	477.0
		2,428.6	1,064.1
Liabilities directly associated with the assets held for sale	19	**100.9**	–
Total current liabilities		**2,529.5**	1,064.1
Total equity and liabilities		**9,027.6**	7,592.5

The accounts on pages 98-154 were approved by the Board and signed on its behalf by:

Armand Lumens Chief Financial Officer

Consolidated financial statements

For the year ended 31 December 2021

Statement of financial position – Company

Company – in millions of US$	Notes	31 December 2021	31 December 2020
Non-current assets			
Investments	15	**1,977.2**	1,977.2
Inter-company loan receivable	17	**938.7**	943.2
Total non-current assets		**2,915.9**	2,920.4
Current assets			
Trade and other receivables	17	**471.8**	216.2
Total current assets		**471.8**	216.2
Total assets		**3,387.7**	3,136.6
Share capital	26	**1,977.2**	1,977.2
Retained earnings		**1.9**	1.4
Total equity		**1,979.1**	1,978.6
Non-current liabilities			
Inter-company loan payable	21	**938.7**	943.2
Total non-current liabilities		**938.7**	943.2
Current liabilities			
Other current liabilities	21	**469.9**	214.8
Total current liabilities		**469.9**	214.8
Total equity and liabilities		**3,387.7**	3,136.6

As permitted by Section 408 of the Companies Act 2006, no income statement or statement of comprehensive income is presented for the Company. Profit for the year was $345.2 million (2020: $0.4 million).

Consolidated statement of changes in equity – Group

Group – in millions of US$	Share capital	Hedging reserve[1][3]	Foreign currency translation[2]	Fair value reserve of financial assets at FVOCI[4]	Retained earnings	Total
At 1 January 2020	1,977.2	118.8	(107.0)	–	(103.5)	1,885.5
Loss for the year	–	–	–	–	(399.0)	(399.0)
Other comprehensive (loss)/income	–	(141.4)	141.7	–	(4.2)	(3.9)
Total comprehensive (loss)/income	–	(141.4)	141.7	–	(403.2)	(402.9)
Transactions with owners of the Company:						
Dividends declared (note 10)	–	–	–	–	–	–
At 31 December 2020	1,977.2	(22.6)	34.7	–	(506.7)	1,482.6
Profit for the year	–	–	–	–	387.2	387.2
Other comprehensive (loss)/income[5]	–	(686.0)	(101.8)	(5.9)	14.8	(778.9)
Total comprehensive (loss)/income	–	(686.0)	(101.8)	(5.9)	402.0	(391.7)
Transactions with owners of the Company:						
Dividends declared (note 10)	–	–	–	–	(344.7)	(344.7)
Balance 31 December 2021	**1,977.2**	**(708.6)**	**(67.1)**	**(5.9)**	**(449.4)**	**746.2**

(1) The hedging reserve represents gains and losses on derivatives classified as effective cash flow hedges stated net of tax.
(2) The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries.
(3) Included in the hedging reserves other comprehensive loss is $4.2 million (2020: $3.1 million) net of tax related to hedging undertaken by associated entities.
(4) The fair value reserve of financial assets at fair value through OCI (FVOCI) represents the fair value movements in the year associated with the non-listed equity investments classified as equity instruments designated at fair value through other comprehensive income; refer to note 24.
(5) As at 31 December 2021, the $686.0 million other comprehensive loss recognised in the hedging reserve relates to the effect of the significant increase in commodity prices on the company's hedging positions.

Statement of changes in equity – Company

In millions of US$	Share capital	Retained surplus/ (deficit)	Total
At 1 January 2020	1,977.2	1.0	1,978.2
Profit for the year	–	0.4	0.4
Total comprehensive income for the year	–	0.4	0.4
Transactions with owners of the Company:			
Dividends declared (note 10)	–	–	–
At 31 December 2020	1,977.2	1.4	1,978.6
Profit for the year	–	345.2	345.2
Total comprehensive income for the year	–	345.2	345.2
Transactions with owners of the Company:			
Dividends declared (note 10)	–	(344.7)	(344.7)
Balance 31 December 2021	**1,977.2**	**1.9**	**1,979.1**

Consolidated financial statements

For the year ended 31 December 2021

Consolidated cash flow statement – Group

Group – in millions of US$	Notes	Year ended 31 December 2021	Year ended 31 December 2020
Cash flows from operating activities			
Profit/(loss) before taxation		**1,392.4**	(333.1)
Adjustments to reconcile profit before tax to net cash flows:			
Depreciation and amortisation	6	**575.1**	584.7
Unsuccessful exploration costs written off	6	**32.2**	30.3
Impairment (reversals)/losses		**(113.6)**	325.7
Finance costs	9.2	**175.4**	250.1
Finance income	9.1	**(53.1)**	(12.4)
Share of net (income)/loss from equity investments		**(61.1)**	20.0
Other non-cash income and expenses[1]		**1.3**	25.9
Mark-to-market on currency and commodity contracts	8	**73.8**	4.0
Movement in provisions including decommissioning expenditure	23	**(98.4)**	(85.3)
Working capital movements[2]		**(284.8)**	35.3
Income tax received (net)		**57.6**	70.2
Net cash flows from operating activities		**1,696.8**	915.4
Cash flows from investing activities			
Expenditure on exploration and evaluation assets		**(127.7)**	(84.5)
Expenditure on property, plant and equipment		**(619.4)**	(717.3)
Proceeds from sale of assets and subsidiary		**20.9**	0.8
Dividends received		**1.4**	2.4
Finance income received		**0.9**	7.7
Net investment made in equity-accounted investments	15	**(0.5)**	25.9
Net cash flows used in investing activities		**(724.4)**	(765.0)
Cash flows from financing activities			
Loan advanced to parent company	17	**(455.3)**	–
Proceeds from loans and borrowings		**2,959.5**	1,371.5
Repayment of loans and borrowings		**(2,667.4)**	(1,307.7)
Repayment of obligations under leases		**(107.4)**	(69.4)
Finance costs paid		**(123.8)**	(137.7)
Dividends paid to parent company	10	**(544.7)**	–
Net cash flows used in financing activities		**(939.1)**	(143.3)
Net increase in cash and cash equivalents		**33.3**	7.1
Cash and cash equivalents at 1 January		**92.5**	85.4
Net foreign exchange differences		**(0.3)**	–
Cash and cash equivalents at 31 December	18	**125.5**	92.5

1. Other non-cash income and expenses mainly includes restructuring provision costs, pension curtailment credits, release of contingent consideration and other losses and gains; see note 8.
2. Working capital movements include movements in trade and other receivables, trade and other payables, and inventory.

Cash flow statement – Company

Company – in millions of US$	Notes	Year ended 31 December 2021	Year ended 31 December 2020
Cash flows from operating activities			
Profit before taxation		**345.2**	0.4
Adjustments to reconcile profit before tax to net cash flows:			
Finance costs		**68.6**	69.1
Finance income	9	**(410.4)**	(66.1)
Other non-cash items		**(3.4)**	(3.5)
Working capital movements		**(0.5)**	(0.4)
Net cash flows used in operating activities		**(0.5)**	(0.5)
Cash flows from investing activities			
Dividends received from subsidiary		**544.7**	–
Finance income received		**66.2**	66.0
Net cash flows from investing activities		**610.9**	66.0
Cash flows from financing activities			
Loan made to parent company	10, 17	**(455.3)**	–
Repayment of loan to parent company		**(7.9)**	–
Proceeds from subsidiary loan	21	**455.3**	–
Repayment of loan from subsidiary		**7.9**	–
Finance costs paid		**(65.7)**	(65.5)
Dividends paid to parent company	10	**(544.7)**	–
Net cash flows used in financing activities		**(610.4)**	(65.5)
Net increase in cash and cash equivalents		**–**	–
Cash and cash equivalents at 1 January		**–**	–
Cash and cash equivalents at 31 December		**–**	–

The notes on pages 104-154 form part of these accounts.

Notes to the consolidated financial statements

General information

Neptune Energy Group Midco Limited is a limited company, incorporated and domiciled in the United Kingdom. The registered office is located at Nova North, 11 Bressenden Place, London SW1E 5BY.

The consolidated financial statements of Neptune Energy Group Midco Limited and its subsidiaries (collectively, the Group) for the year ended 31 December 2021 were authorised for issue in accordance with a resolution of the Board on 16 March 2022.

The Group is principally engaged in oil and gas exploration and production, including energy transition projects.

1. Basis of preparation

The consolidated financial statements for the year ended 31 December 2021 have been prepared in accordance with UK adopted International Accounting Standards, which, for the accounting policies adopted by the Group, also remain fully aligned with EU IFRS.

The preparation of financial statements requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, are disclosed below in note 1.3.

The Group has not early-adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Going concern

Given the total available liquidity as at 31 December 2021 of $1.1 billion, comprising our cash balance ($125.5 million) and available and undrawn headroom under the RBL facility ($930.0 million), and capital resources arrangements in place (see note 20), the consolidated accounts have been prepared on a going concern basis.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2023. The cash flow forecasts reflect forecast production consistent with our Board approved plans and externally published guidance and base case commodity prices that are slightly below current market conditions.

In reaching the conclusion that the going concern basis is appropriate, we have stress tested future cash flow forecasts and covenant compliance for the Group to evaluate the impact of plausible downside scenarios. These include scenarios that reflect short-term commodity price forecasts significantly below current market conditions as well as scenarios that consider the impact of unforeseen production outages. We have also performed a reverse stress test to inform our judgement, which demonstrated that we are resilient to sustained low commodity prices up to 50% below our conservative base case cash flow forecast.

Under all plausible scenarios, it was concluded that the Group retains sufficient liquidity and headroom over its covenant ratio, and that the going concern basis remains appropriate. The likelihood of the commodity prices identified in the reverse stress test materialising is considered remote on the basis of market consensus for short-term commodity prices and relative to historic market lows.

1.1 New standards, interpretations and amendments adopted by the Group

Interest Rate Benchmark Reform – Phase 2 Amendments to IFRS 9, IAS 39, IFRS 7 and IFRS 16

The amendments provide temporary reliefs which address the financial reporting effects when an interbank offered rate (IBOR) is replaced with an alternative nearly risk-free interest rate (RFR). The amendments include the following practical expedients:

- A practical expedient to require contractual changes, or changes to cash flows that are directly required by the reform, to be treated as changes to a floating interest rate, equivalent to a movement in a market rate of interest
- Permit changes required by IBOR reform to be made to hedge designations and hedge documentation without the hedging relationship being discontinued
- Provide temporary relief to entities from having to meet the separately identifiable requirement when an RFR instrument is designated as a hedge of a risk component.

These amendments had no impact on the consolidated financial statements of the Group as our principal financial assets and liabilities have either fixed rate interest or have a short-term maturity. The Group intends to use the practical expedients in future periods if they become applicable.

Several other financial reporting amendments and interpretations apply for the first time in 2021, but do not have a significant impact on the consolidated financial statements of the Group.

1.2 Measurement and presentation basis

The consolidated financial statements have been prepared on a historical cost basis, except for derivative financial instruments, debt and equity financial assets and contingent consideration that have been measured at fair value. The carrying values of recognised assets and liabilities that are designated as hedged items in fair value hedges that would otherwise be carried at amortised costs are adjusted to recognise changes in the fair value attributable to the risks that are being hedged in effective hedge relationships.

The consolidated financial statements are presented in US dollars and rounded to millions, except where otherwise indicated.

1.3 Significant judgements and estimates

Estimates and judgements are continually evaluated and are based on historical experiences and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

1.3.1 Estimates

The preparation of consolidated financial statements requires the use of estimates and assumptions to determine the value of assets and liabilities and contingent assets and liabilities at the reporting date, as well as revenues and expenses reported during the period.

The key estimates used in preparing the Group's consolidated financial statements relate mainly to:

- measurement of the recoverable amount of property, plant and equipment, other intangible exploration assets and goodwill;
- calculations of depreciation and amortisation which involve estimates of volumes of commercial reserves of oil and gas;
- measurement of provisions, particularly for decommissioning, pensions and post-employment obligations; and
- measurement of recognised tax loss carry-forwards.

Each of these categories of key estimates are described further below. Due to uncertainties inherent in the estimation process, the Group regularly revises its estimates in light of currently available information. Final outcomes could differ from those estimates.

Recoverable amount of intangible assets and property, plant and equipment and goodwill

The recoverable amounts of intangible assets and property, plant and equipment and goodwill are based on estimates and assumptions, regarding in particular the expected market outlook (including future commodity prices) used for the measurement of cash flows, estimates of the volume of commercially recoverable reserves and resources of oil and gas future production rates and costs to develop reserves and resources, and the determination of the discount rate. Where relevant these estimates are based on life of field projections and generally only include sanctioned fields and projects.

Any changes in these assumptions may have a material impact on the measurement of the recoverable amount and could result in adjustments to any impairment losses to be recognised.

See notes 12, 13 and 14 for further information.

Commercial reserves and depreciation of oil and gas production assets

Charges for depreciation and amortisation of oil and gas producing properties are calculated on a unit of production rate based on production as a proportion of estimated quantities of proved and probable oil and gas reserves. The Group has adopted the definitions and guidelines presented in the Petroleum Resources Management System (SPE-PRMS 2018) for the classification and reporting of commercial reserves and resources of oil and gas. Commercial reserves are those in the proved and probable categories of reserves. See note 14 for further information on the depreciation and amortisation of the Group's assets.

Estimates of reserves is a subjective process involving estimating underground resource accumulations and recovery rates, and is a function of many factors, such as the properties of the reservoir rock and petroleum fluid. Changes in the estimates of commercial reserves will consequently impact depreciation and amortisation expense. Changes in factors or assumptions used in estimating reserves could include:

- changes due to revised estimates of volumes in place and recovery factors;
- the effect on proved and probable reserves of differences between actual commodity prices and assumptions;
- unforeseen operational issues; and
- see Supplementary Information Gas and Oil (unaudited) on page 155 for further information on reserves replacement.

Estimates of decommissioning provisions

Parameters having a significant influence on the amount of provisions for decommissioning costs include the forecast of costs to be incurred to decommission facilities, plug wells and restore sites used for production and drilling, the anticipated scope of such decommissioning obligations, which may depend on laws and regulation in force at the time, the timing of such expenditure and the discount rate applied to forecast cash flows. These parameters are based on information and estimates deemed to be appropriate by the Group at the current time.

The modification of certain parameters could involve a significant adjustment to these provisions.

See note 23 for further information.

Pensions and post–employment benefit obligations

Pension commitments are measured on the basis of actuarial assumptions. These include assumptions in respect of mortality rates and future salary increases, as well as appropriate discount rates. The Group considers that the assumptions used to measure its obligations are appropriate and documented. However, any changes in these assumptions may have a material impact on the resulting calculations.

Pension costs for interim periods are calculated on the basis of the actuarial valuations performed at the end of the prior year. If necessary, these valuations are adjusted to take account of curtailments, settlements or other major non-recurring events that have occurred during the period.

See note 29 for further information.

Notes to the consolidated financial statements
continued

Measurement of recognised tax loss carry-forwards

Deferred tax assets are recognised on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilised. The estimates of the taxable profit that will be available against which the unused tax losses can be utilised, are based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimated future taxable profits. These estimates are based on life of field projections and generally only include sanctioned fields and projects. Unsanctioned wells and fields may be included if future profits are considered to be probable in the relevant circumstances. The estimates use underlying assumptions on prices, capital and operating expenditure and reserves which are consistent with those used for asset impairment review. For example, oil and gas prices are based on internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2025 of $65/bbl for Brent crude oil and 50p/therm for NBP gas thereafter inflated by 2% per annum. See note 11 for further information.

Climate change

The Group recognises that there may be potential financial implications in the future from changes in legislation and regulation implemented to address climate change risk. Whilst these changes will result in intended benefits, they are likely to increase associated costs and administration requirements and could potentially also reduce the investment capital available to the industry. Over time these changes may well have an impact across a number of areas of accounting including asset impairment, increased costs, onerous contracts and contingent liabilities. However, as at the balance sheet date, the Group believes there is no material impact on balance sheet carrying values of assets or liabilities. Although this is an estimate, it is not considered a critical estimate.

1.3.2 Judgements

As well as relying on estimates, the Directors make judgements to define the appropriate accounting policies and decisions to apply to certain activities and transactions, including when the effective IFRS standards and interpretations do not specifically deal with the related accounting issues. Key areas of judgement include:

Carrying value of intangible exploration and evaluation assets: the amounts capitalised for exploration and evaluation assets represent cost in respect of active exploration and appraisal projects. These amounts will be written off to the income statement as exploration expense unless commercial reserves are established or the determination process as to the success or otherwise of the activity is not yet completed and there are no indications of impairment in accordance with the Group's accounting policy. The process of determining whether there is an indicator of impairment or calculating the impairment requires critical judgement, including: the Group's intention to proceed with a future work programme for a prospect or licence; the likelihood of licence renewal or extension; the assessment of whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale; and the success of a well result.

Commercial reserves: the estimation of commercial reserves of oil and gas in accordance with SPE-PRMS guidelines, as outlined above, involves complex technical judgements. These complex technical judgements include estimates of oil and gas in place, recovery factors and future commodity prices which have an impact on the total amount of recoverable reserves. Future development costs are estimated taking into consideration the level of development required based on internal functional specialists or operator assessments, where applicable.

Significant accounting policies

1.4 Basis of consolidation

Subsidiaries and business combinations

Subsidiaries are all entities over which the Group has control. The Group consolidates an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group (the acquisition date).

Inter-company transactions, balances and unrealised gains on transactions between Group companies are eliminated. Unrealised losses are also eliminated.

Where necessary, amounts reported by subsidiaries have been adjusted to conform with the Group's accounting policies.

The Group applies the acquisition method to account for business combinations. The consideration transferred for the acquisition of a subsidiary is the fair value of the assets transferred, the liabilities incurred to the former owners of the acquiree, and the equity interests issued by the Group. The consideration transferred includes the fair value of any asset or liability resulting from a contingent consideration arrangement.

Identifiable assets acquired, and liabilities and contingent liabilities assumed in a business combination, are measured initially at their fair value at the acquisition date. The fair value of acquired oil and gas properties is based on the post-tax net present value of expected future cash flows. The fair values of assets and liabilities acquired which are initially recognised at provisional amounts may be adjusted within 12 months of the acquisition date based on the assessment of additional data relating to the conditions of items as at the acquisition date.

Acquisition-related costs of a business combination are expensed as incurred.

Any contingent consideration to be transferred by the Group is recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration are recognised in accordance with IFRS 9 in profit or loss.

Goodwill arising in a business combination is recognised as an asset at the acquisition date. Goodwill is measured as the excess of the sum of the consideration transferred over the net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed. After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's Cash Generating Units (CGUs) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill has been allocated to a CGU and part of the operation within that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained. The carrying value of goodwill is reviewed at least annually at the end of the financial year or following a trigger event.

If the Group's interest in the fair value of the acquiree's identifiable net assets exceeds the sum of the consideration transferred, the excess is recognised immediately in net income.

For the Company, fixed asset investments, including investment in subsidiaries, are stated at cost and reviewed for impairment if there are any indications that the carrying value may not be recoverable.

Investments in joint operations and joint ventures

A Joint Arrangement is one in which two or more parties have joint control and may take the form of a joint operation or a joint venture. Joint control is the contractually agreed sharing of control of an arrangement, which exists when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Most of the Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have rights to the underlying assets, and obligations for the liabilities, relating to the arrangement. The Group reports its share of the assets, liabilities, income and expenses of the joint operation within the equivalent items in the consolidated financial statements, on a line-by-line basis. Certain of the Group's joint operations derive from production sharing contracts (PSCs), entered into with host governments or their agencies. PSCs typically result in economic rights similar to other licence and concession arrangements and are accounted for using the same line-by-line basis, with the Group using an appropriate unit of production basis to recognise its share of production and reserves attributable to the PSC.

A joint venture, which normally involves the establishment of a separate legal entity, is a contractual arrangement whereby the parties that have joint control of the arrangement have the rights to the arrangement's net assets. The results, assets and liabilities of a joint venture are incorporated in the consolidated financial statements using the equity method.

Interests in associates

An associate is an entity over which the Group has significant influence, through the power to participate in the financial and operating policy decisions of the investee, but which is not a subsidiary or a Joint Arrangement. Interests in associates are accounted for using the equity method.

1.5 Foreign currency translation

Presentation and functional currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which each Group company operates (its functional currency). The financial statements are presented in US dollars, which is the Company's presentation and functional currency.

Transactions and balances

Foreign currency transactions are translated into the functional currency using exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are remeasured at the end of each accounting period. Foreign exchange gains and losses resulting from the settlement or revaluation of monetary assets and liabilities denominated in foreign currencies are recognised in the income statement, except when deferred in other comprehensive income as qualifying cash flow hedges and qualifying net investment hedges (if applicable). Foreign exchange gains and losses included in net income are presented within 'Foreign exchange gain/loss' as part of financial income/expense.

Group companies

The results and financial position of all of the Group entities (none of which has the currency of a hyper-inflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet;
- income and expenses for each income statement are translated at average exchange rates (unless this average is not a reasonable approximation of the rates prevailing on the transaction dates, in which case income and expenses are translated at the rate on the dates of each transaction);
- the exchange differences arising on translation for consolidation are recognised in other comprehensive income; and
- any goodwill arising on the acquisition of a foreign operation and any fair value adjustments to the carrying amounts of assets and liabilities arising on the acquisition are treated as assets and liabilities of the foreign operation and are translated at the spot rate of exchange at the reporting date.

Notes to the consolidated financial statements
continued

1.6 Intangible assets

Intangible assets (other than goodwill and exploration and evaluation rights) are carried at cost less any accumulated amortisation and any accumulated impairment losses. These assets principally comprise IT software and are amortised on a straight-line basis over their useful economic lives, typically three to five years.

1.7 Assets relating to the exploration and production of mineral resources

i) Acquisition costs of unproved properties: exploration licences and concessions correspond to licences or rights acquired in areas in which the existence of oil and gas reserves has not yet been demonstrated. The costs of acquiring such exploration licences are capitalised within intangible assets.

ii) Exploration and evaluation costs: the Group adopts the successful efforts method of accounting for exploration and evaluation costs. Costs incurred prior to the award of a licence are expensed in the period in which they are incurred. The costs of geological and geophysical surveys and studies are expensed in the period incurred. Exploration and appraisal drilling costs are capitalised in cost centres by well, field or exploration area, as appropriate, pending the results of the exploration activities. Internal costs are expensed unless directly attributed to drilling operations. Costs are then written off as exploration expense in the income statement unless commercial reserves have been established or if the determination process has not been completed and there are no indications of impairment. When the exploratory phase has resulted in the recognition of commercial reserves, the related costs are first assessed for impairment and (if required) any impairment recognised, then the remaining balance is transferred to property, plant and equipment.

iii) Property, plant and equipment: expenditure on the acquisition of proved properties and on the construction, installation or completion of facilities such as platforms, pipelines and the drilling of development wells, including any development or delineation wells, is capitalised within oil and gas properties – PP&E. In accordance with IAS 16, the initial cost of assets relating to the exploration and production includes an initial estimate of the costs of decommissioning and restoring the site on which the facilities are located when production operations cease, when the entity has a present legal or constructive obligation for decommissioning or to restore the site. A corresponding provision for this decommissioning obligation is recorded for the amount of the asset component.

iv) Borrowing costs that are directly attributable to the construction of the qualifying asset are capitalised as part of the cost of that asset.

v) Depreciation of production assets: the depreciation of production assets, including decommissioning costs, starts when the oil or gas field is brought into production, and is based on the unit of production method. According to this method, the depletion rate is equal to the ratio of oil and gas production for the period to proved and probable reserves, as applied to the capitalised cost plus future estimated costs to develop those reserves.

Pipeline assets are depreciated on a straight-line basis over a period not exceeding the projected useful economic life of the asset.

vi) Recognition and derecognition of assets: acquired assets are valued at their purchase price and assessed for impairment (if required). An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognised.

1.8 Other property, plant and equipment

Items of property, plant and equipment are recognised at cost and are subsequently carried at their historical cost less any accumulated depreciation and any accumulated impairment losses.

1.9 Depreciation

Property, plant and equipment, other than assets related to exploration and production of mineral resources, is depreciated using the straight-line method over the following useful lives:

Main depreciation periods (years)	
Office and computer equipment	3 to 5 years
Freehold and leasehold improvements[1]	up to 50 years
Plant and machinery	5 to 40 years

(1) Leasehold improvements are depreciated over the shorter of the useful life and lease term.

1.10 Impairment of property, plant and equipment and intangible assets including goodwill and equity-accounted investments

In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information.

Impairment indicators

Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes to the environment in which the assets are operated or when asset performance is worse than expected.

The main impairment indicators used by the Group are described below:

- external sources of information:
  - significant changes in the economic, technological, political or market environment in which the entity operates or to which an asset is dedicated;
  - fall in demand; and
  - changes in energy prices and exchange rates.
- internal sources of information:
  - evidence of obsolescence or physical damage not budgeted for in the depreciation/amortisation schedule;
  - worse-than-expected production or cost performance;
  - reduction in reserves and resources, including as a result of unsuccessful results of drilling operations;
  - pending expiry of licence or other rights; and
  - in respect of capitalised exploration and evaluation costs, lack of planned future activity on the prospect or licence.

Measurement of recoverable amount

In order to review the recoverable amount in an impairment test, the assets are grouped, where appropriate, into Cash Generating Units and the carrying amount of each unit is compared with its recoverable amount.

For operating entities that the Group intends to hold on a long-term and going concern basis, the recoverable amount of an asset corresponds to the higher of its fair value less costs to sell and its value in use. The recoverable amount is primarily determined based on the fair value less cost of disposal method. Standard valuation techniques are used based on the discount rates based on the specific characteristics of the operating entities concerned; discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

Any impairment loss is recorded in the consolidated income statement under 'Impairment losses'.

Impairment losses recorded in relation to property, plant and equipment may be subsequently reversed if the recoverable amount of the assets subsequently increases above carrying value. The increased carrying amount of an item of property, plant or equipment attributable to a reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortisation) had no impairment loss been recognised in prior periods. Impairment losses in respect of intangible assets may not be reversed on a future change in circumstances that led to the impairment.

Goodwill

Goodwill is not amortised but is reviewed for impairment at least annually. For the purpose of impairment testing, goodwill is allocated to each of the Group's Cash Generating Units (CGUs) expected to benefit from the business combination. Country groups of CGUs to which goodwill has been allocated are tested for impairment annually, or more frequently when there is an indication the unit may be impaired. If the recoverable amount of the group of CGUs is less than the carrying amount of the unit, the impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the unit and then to the other assets of the unit pro-rata on the basis of the carrying amount of each asset in the unit. An impairment loss recognised for goodwill is not reversed in a subsequent period.

On disposal of a subsidiary, the attributable amount of goodwill is included in the determination of the profit or loss on disposal.

1.11 Leases

The Group assesses at contract inception whether a contract is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Group as a lessee

The Group applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets. The Group recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

1.11.1a Right-of-use assets

The Group recognises right-of-use assets at the commencement date of the lease (i.e. the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. Right-of-use assets are depreciated on a straight-line basis over the lease term, as follows:

Right-of-use assets depreciation periods (years)	
Land	up to 23 years
Buildings	2 to 10 years
Transportation	2 to 5 years
Property, plant and equipment	5 years

The right-of-use assets are also subject to impairment.

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1.11.1b Right-of-use assets – assets within Joint Arrangements

The Group recognises the gross value of any right-of-use assets within Joint Arrangements where it is the sole signatory of the lease unless the arrangement between the Group and the joint operation represents a sub-lease. Where a sub-lease exists, and the Joint Arrangement receives substantially all the risks and rewards incidental to ownership then the Group derecognises the portion of the right-of-use asset that is sublet and recognises a Joint Arrangement receivable. Where the Group is a co-signatory to a Joint Arrangement, the Group recognises the Group's Joint Arrangement share of the right-of-use-asset. Where the Group is not a signatory to a Joint Arrangement lease, the Group recognises the Group's Joint Arrangement share of the right-of-use-asset only when it has a right to control the use of the asset. Where the Group has no control then no Joint Arrangement asset is recognised.

1.11.2a Lease liabilities

At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating the lease, if the lease term reflects the Group exercising the option to terminate. Variable lease payments that do not depend on an index or a rate are recognised as expenses in the period in which the event or condition that triggers the payment occurs. In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g. changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset. The Group's lease liabilities are included in note 22.

1.11.2b Lease liability – Joint Arrangement liabilities

The Group recognises the gross value of any right-of-use Joint Arrangement lease liability where it is the sole signatory. Where the Group is a co-signatory to a lease in a Joint Arrangement, the Group recognises the Group's Joint Arrangement share of the right-of-use lease liability. Where the Group is not a signatory to a Joint Arrangement lease, the Group recognises the Group's Joint Arrangement share of the right-of-use lease liability only when it has a right to control the use of the lease. Where the Group has no control, then no right-of-use lease liability is recognised.

1.11.3 Short-term leases and leases of low-value assets

The Group applies the short-term lease recognition exemption to its short-term leases of machinery and equipment (i.e. those leases that have a lease term of 12 months or less from the commencement date and do not contain a purchase option). It also applies the lease of low-value assets recognition exemption to leases of office equipment that are considered to be low value. Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

1.12 Inventories

Inventories of equipment and materials are measured at the lower of cost and net realisable value. Cost is determined based on the first-in, first-out method or the weighted average cost formula.

An impairment loss is recognised when the net realisable value of inventories is lower than their weighted average cost.

Hydrocarbon inventories are stated at net realisable value with movements in value recognised in the profit and loss account. Net realisable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

See also 1.20 'Revenue', regarding volumes of under and over lifted entitlement to production.

1.13 Financial instruments

Financial instruments are recognised and measured in accordance with IFRS 9.

1.14 Financial assets

Financial assets comprise loans and receivables carried at amortised cost, including trade and other receivables and receivables from joint venture partners, and financial assets measured at fair value through income, including certain derivative financial instruments. Financial assets are analysed into current and non-current assets in the consolidated statement of financial position.

Loans and receivables carried at amortised cost

This item primarily includes loans and advances to associates or non-consolidated companies, guarantee deposits, trade and other receivables.

On initial recognition, these loans and receivables are recorded at fair value plus transaction costs. At each statement of financial position date, they are measured at amortised cost using the effective interest rate method.

Leasing guarantee deposits are recognised at their nominal value.

On initial recognition, trade and other receivables are recorded at fair value, which generally corresponds to their nominal value. Impairment losses are recorded based on the estimated risk of non-recovery. Trade receivables are stated net of provisions. The Group has used the simplified approach in calculating expected credit losses for trade receivables that do not contain a significant financing component. Trade receivables are generally settled on a short time frame and the Group's other financial assets are due from counterparties without material credit risk. The Group applies the practical expedient to calculate expected credit losses using a provision matrix considering how current and forward-looking information may affect our customers' historical default rates and, consequently, how the information would affect their current expectations and estimates of expected credit losses.

Financial assets are derecognised when the rights to receive cash flows from the financial assets have expired or have been transferred and the entity has transferred substantially all the risks and rewards of ownership. If the entity neither retains nor transfers substantially all the risks and rewards, but has not retained control of the financial assets, it also derecognises the assets.

The Group considers a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit arrangements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

1.15 Derivatives and hedge accounting – Assets and Liabilities

Derivative financial instruments are contracts: (i) whose value changes in response to the change in one or more observable variables; (ii) that do not require any material initial net investment; and (iii) that are settled at a future date. Derivative instruments include swaps, options, futures and swaptions, as well as forward commitments to purchase or sell listed and unlisted securities, and firm commitments or options to purchase or sell non-financial assets that involve physical delivery of the underlying.

The Group uses derivative financial instruments to manage and reduce its exposure to market risks arising from fluctuations in interest rates, foreign currency exchange rates and commodity prices including emissions, mainly for oil and gas. The use of derivative instruments is governed by a Group policy for managing interest rate, currency and commodity risks.

The Group's hedging policy is to ensure that in relation to its debt facilities and the borrowing base assets, the Group has:

a) appropriate controls governing its use of financial derivative transactions; and
b) a prudent and cost-efficient approach to mitigating its exposure to fluctuations in:
   i) commodity prices in energy markets; and
   ii) foreign exchange and interest rates in capital markets.

Hedging instruments: recognition and presentation

Derivative instruments qualifying as hedging instruments are recognised in the consolidated statement of financial position within current assets or liabilities if expiry is less than 12 months, or as non-current items if expiring after 12 months and measured at fair value.

Cash flow hedges

A cash flow hedge is a hedge of the exposure to variability in cash flows that could affect the Group's profit or loss. The hedged cash flows may be attributable to a particular risk associated with a recognised financial or non-financial asset or a highly probable forecast transaction.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised directly in other comprehensive income (OCI), net of tax, while the ineffective portion is recognised as part of 'other operating losses/gains' in the consolidated income statement. The gains or losses accumulated in OCI are reclassified to the consolidated income statement under the same caption as the loss or gain on the hedged item – i.e. within current operating income for operating cash flows and financial income or expenses for other cash flows – in the same periods in which the hedged cash flows affect profit or loss.

If the hedging relationship is discontinued, the cumulative gain or loss on the hedging instrument remains recognised in OCI until the forecast transaction occurs. However, if a forecast transaction is no longer expected to occur, the cumulative gain or loss on the hedging instrument is immediately recognised in the consolidated income statement.

Identification and documentation of hedging relationships

The hedging instruments and hedged items are designated at the inception of the hedging relationship. The hedging relationship is formally documented in each case, specifying the risk management strategy, risk management objective, the hedged risk, sources of hedge ineffectiveness and the methods used to assess hedge effectiveness. Sources of hedge ineffectiveness include mismatch in payment dates and off-market hedges for acquired hedges. Only derivative contracts entered into with external counterparties are considered as being eligible for hedge accounting.

The Group establishes its hedge ratio by considering hedging items as a proportion of post-tax production. Hedge effectiveness is assessed and documented at the inception of the hedging relationship and on an ongoing basis throughout the periods for which the hedge was designated. Hedge effectiveness is demonstrated prospectively using various methods, based mainly on a qualitative assessment of the critical terms of the hedging instrument and the hedged item as to whether their values will generally move in the opposite direction because of the same risk being hedged. Methods based on a regression analysis of statistical correlations between historical price data are also used.

Upon the designation of option instruments as hedging instruments, the intrinsic and time value components are separated, with only the intrinsic component being designated as the hedging instrument and the time value component is deferred in OCI as a cost of hedging.

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Derivative instruments not qualifying for hedge accounting: recognition and presentation

These items mainly include derivative financial instruments used in economic hedges that have not been or are no longer documented as hedging relationships for accounting purposes.

When a derivative financial instrument does not qualify or no longer qualifies for hedge accounting, changes in fair value are recognised directly in net income, under 'Mark-to-market on commodity contracts other than trading instruments', below the current operating income, for derivative instruments with non-financial assets as the underlying, and in financial income or expenses for currency, interest rate and equity derivatives.

Derivative instruments not qualifying for hedge accounting and other derivatives expiring in less than 12 months are recognised in the consolidated statement of financial position in current assets and liabilities, while derivatives expiring after this period are classified as non-current items.

Fair value measurement

The fair value of instruments listed on an active market is determined by reference to the market price. In this case, these instruments are presented in Level 1 of the fair value hierarchy.

The fair value of unlisted financial instruments for which there is no active market, and for which observable market data exist, is determined based on valuation techniques such as option pricing models or the discounted cash flow method.

Models used to evaluate these instruments take into account assumptions based on market inputs:

- the fair value of interest rate swaps is calculated based on the present value of future cash flows. Cash flows are discounted using standard valuation techniques and observable market-based inputs, including interest rate curves, having regard to the timing of the cash flows; and
- commodity derivatives contracts are valued by reference to observable market-based inputs based on the present value of future cash flows (commodity swaps or commodity forwards) or option pricing models (options), which factor in market price volatility. Contracts with maturities exceeding the depth of transactions for which prices are observable, or which are particularly complex, may be valued based on internal assumptions.

These instruments are presented in Level 2 of the fair value hierarchy except when the evaluation is based mainly on data that are not observable; in this case they are presented in Level 3 of the fair value hierarchy.

Equity investments are valued using the market approach based on a multiple of EBITDA consistent with the valuation obtained for transactions involving investments similar in nature.

To comply with the provisions of IFRS 13, the Group incorporates credit and/or debit valuation adjustments to reflect appropriately both its own non-performance risk and the respective counterparty's non-performance risk in the fair value measurements. In adjusting the fair value of its derivative contracts for the effect of non-performance risk, the Group has considered the impact of netting and any applicable credit enhancements, such as collateral postings, thresholds, mutual puts, and guarantees.

Equity investments held at fair value through OCI

Where the Group holds an equity investment primarily for strategic purposes, the Company may on initial recognition elect to recognise any change in the fair value through OCI. Under this method, changes in the valuation of the investment are never reclassified to profit and loss, even if the asset is impaired, sold or otherwise derecognised. Where the Company holds an equity investment that is not for strategic purposes, following its initial recognition, any subsequent change in the valuation is recognised through fair value profit and loss.

1.16 Financial liabilities

Financial liabilities include borrowings, trade and other payables, derivative financial instruments and other financial liabilities.

Financial liabilities are broken down into current and non-current liabilities in the consolidated statement of financial position. Current financial liabilities primarily comprise:

- financial liabilities with a settlement or maturity date within 12 months after the reporting date;
- financial liabilities in respect of which the Group does not have an unconditional right to defer settlement beyond 12 months after the reporting date;
- derivative financial instruments qualifying as fair value hedges where the underlying is classified as a current item (see note 1.15); and
- commodity trading derivatives not qualifying as hedges (see note 1.15).

Measurement of borrowings

Borrowings are measured at amortised cost using the effective interest rate method. On initial recognition, any issue or redemption premiums and discounts and issuing costs are added to/deducted from the nominal value of the borrowings concerned. These items are taken into account when calculating the effective interest rate and are therefore recorded in the consolidated income statement over the life of the borrowings using the amortised cost method.

1.17 Cash and cash equivalents

Cash and cash equivalents in the statement of financial position comprise cash at banks and on hand, short-term deposits with a maturity of three months or less and highly liquid investments which are subject to an insignificant risk of changes in value. For the purpose of the consolidated statement of cash flows, cash and cash equivalents consist of cash and short-term deposits, as defined above, net of outstanding bank overdrafts, as they are considered an integral part of the Group's cash management.

1.18 Non-current assets held for sale

The Group classifies non-current assets and disposal groups as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use. Non-current assets and disposal groups classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Costs to sell are the incremental costs directly attributable to the disposal of an asset (disposal group), excluding finance costs and income tax expense. The criteria for held for sale classification is regarded as met only when the sale is highly probable, and the asset or disposal group is available for immediate sale in its present condition. Actions required to complete the sale should indicate that it is unlikely that significant changes to the sale will be made or that the decision to sell will be withdrawn. Management must be committed to the plan to sell the asset and the sale expected to be completed within one year from the date of the classification. Property, plant and equipment and intangible assets are not depreciated or amortised once classified as held for sale. Assets and liabilities classified as held for sale are presented separately as current items in the statement of financial position.

1.19 Provisions

1.19.1 General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and the amount of the obligation can be estimated reliably.

Provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate. If it is no longer probable that an outflow of economic resources will be required to settle the obligation, the provision is reversed. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. When discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost.

1.19.2 Provisions for post-employment benefit obligations and other long-term employee benefits

Depending on the laws and practices in force in the countries where the Group operates, Group companies have obligations in terms of pensions, early retirement payments, retirement bonuses and other post-employment benefit plans.

The Group's obligations in relation to pensions and other employee benefits are recognised and measured in compliance with IAS 19. Accordingly:

- the cost of defined contribution plans is expensed based on the amount of contributions payable in the period. The Group's legal or constructive obligation for these plans is limited to the contributions paid; and
- the Group's obligations concerning pensions and other employee benefits payable under defined benefit plans are assessed on an actuarial basis using the projected unit credit method. These calculations are based on assumptions relating to mortality, staff turnover and estimated future salary increases, as well as the economic conditions specific to each country or subsidiary of the Group. Discount rates are determined by reference to the yield, at the measurement date, on high-quality corporate bonds in the related geographical area (or on government bonds in countries where no representative market for such corporate bonds exists).

Provisions are recorded when commitments under these plans exceed the fair value of plan assets. Where the value of plan assets (capped where appropriate) is greater than the related commitments, the surplus is recorded as an asset under 'Other assets' (current or non-current).

As regards post-employment benefit obligations, actuarial gains and losses are recognised in other comprehensive income. Where appropriate, adjustments resulting from applying the asset ceiling to net assets relating to overfunded plans are treated in a similar way. The Group's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognised in profit or loss in the period in which they arise.

Net interest on the net defined benefit liability (asset) is presented in net financial expense (income).

1.19.3 Decommissioning costs

A provision is recognised when the Group has a present legal or constructive obligation to plug wells, dismantle facilities or to restore a site. An asset is recorded simultaneously by including this decommissioning obligation in the carrying amount of the facilities concerned. Adjustments to the provision due to subsequent changes in the expected outflow of resources, the decommissioning date or the discount rate are deducted from or added to the cost of the corresponding asset. The impact of unwinding the discount (accretion) is recognised in financial expenses for the period.

Provisions with a maturity of over 12 months are discounted when the effect of discounting is material. The discount rate (or rates) used reflect current market assessments of the time value of money, based on the relevant risk-free rate, adjusted if appropriate for any risks specific to the liability concerned.

1.20 Revenue

Revenue is recognised when the Group satisfies a performance obligation by transferring oil and gas to a customer. The title to oil and gas typically transfers to a customer at the same time as the customer takes physical possession of the commodity, which is when the performance obligation is fully satisfied.

Differences may arise in a joint operation between the Group's share of production entitlement from an oil or gas field and the volume which has been lifted and sold. Such 'under or over lift' entitlements are recognised in current assets or liabilities, respectively, at net realisable value, with a corresponding adjustment through production costs. As a result, the reported operating result for each period reflects the Group's share of actual sales of production in that period.

The Group recognises its share of LNG revenues in respect of its Indonesian production sharing contracts based on its contractual share of actual liftings. Revenues include volumes allocated to the Group for sale as reimbursement of costs of operation of the LNG processing facility, with corresponding costs included as operating expenses.

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The Group enters into take-or-pay arrangements where customers have a right to take make-up product in the future. The Group recognises deferred revenue equal to the amount paid for the 'undertake' as it represents an obligation to provide the product in the future. The Group only recognises revenue once the product has been taken by the customer. Only once the make-up period has expired or it is clear that the purchaser has been unable to take the product, would the liability be eliminated and revenue recognised.

Under IFRS 15, if the Group expects to be entitled to a breakage amount, the expected 'breakage' would be recognised as revenue in proportion to the pattern of rights exercised by the customer. Otherwise, breakage amounts would be recognised when the likelihood of the customer exercising its right becomes remote.

Other operating income includes income that is associated with a company's activities but that falls outside the definition of revenue. Amounts shown in other operating income are typically incidental to the main activities of the company or are different in nature from amounts included in revenue. Loss of production insurance proceeds are recognised as other operating income when their recovery is deemed to be virtually certain.

Further information regarding segmental analysis is contained in note 5.

1.21 Government grants

Government grants are recognised where there is reasonable assurance that the grant will be received, and all attached conditions will be complied with. When the grant relates to an expense item, it is recognised as income on a systematic basis over the periods that the related costs, for which it is intended to compensate, are expensed.

1.22 Consolidated cash flow statement

The consolidated statement of cash flows is prepared using the indirect method starting from profit before tax. 'Interest received on non-current financial assets' is classified within investing activities because it represents a return on investments. 'Interest received on cash and cash equivalents' is shown as a component of financing activities because the interest can be used to reduce borrowing costs. This classification is consistent with the Group's internal organisation, where debt and cash are managed centrally by the treasury department.

Cash flows relating to the payment of income tax are presented on a separate line of the consolidated statement of cash flows.

1.23 Taxation

Current tax, including corporation tax and foreign tax, is provided at amounts expected to be paid (or recovered) using the tax rates and laws that have been enacted or substantively enacted by the balance sheet date. Tax is recognised in the income statement, except to the extent that it relates to items recognised directly in equity. In this case, the tax is recognised in equity. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax is recognised in respect of all temporary differences identified at the balance sheet date, except to the extent that the deferred tax arises from the initial recognition of goodwill or the initial recognition of an asset or liability in a transaction which is not a business combination and at the time of the transaction affects neither accounting profit nor taxable profit and loss. Temporary differences are differences between the carrying amount of the Company's assets and liabilities and their tax base. Deferred tax assets are recognised only to the extent that the deductible temporary differences will reverse in the future and it is probable that there will be sufficient taxable profit available against which the temporary differences can be utilised. The amount of deferred tax provided is using tax rates that have been enacted or substantively enacted at the balance sheet date. Deferred taxes are reviewed at least annually at the end of the financial year to take into account factors including the impact of changes in tax laws and the prospects of recovering deferred tax assets arising from deductible temporary differences. Deferred tax assets and liabilities are not discounted.

Current and deferred income tax expense for interim periods is calculated at the level of each tax entity by applying the average estimated annual effective tax rate for the current year to the taxable income for the interim period, with the exception of significant exceptional items. Significant exceptional items, if any, are recognised using their specific applicable taxation rates.

1.24 Dividends

The Group and Company recognise a liability to pay a dividend when the distribution is authorised and the distribution is no longer at the discretion of the Group and Company. As per the corporate laws of England and Wales, a distribution is authorised when it is approved by the shareholders. A corresponding amount is recognised directly in equity.

2. Financial risk management

Group financial risk factors

The Group's activities expose it to a variety of financial risks: market risk (e.g. foreign exchange risks), credit risk and liquidity risk. The Group's overall risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance.

Market risk (foreign exchange risk)

The Group operates internationally and is therefore exposed to foreign exchange risk arising from various currency exposures, primarily with respect to the Pound Sterling (GBP), Norwegian Krone (NOK) and Euro (EUR). Foreign exchange risk arises from future commercial transactions, recognised assets and liabilities and net investments in foreign operations.

Credit risk

Currently credit risk only arises from cash and cash equivalents, sales receivables and hedging derivatives. For banks and financial institutions, only independently rated parties with a minimum rating of 'BBB' are accepted.

Liquidity risk

Liquidity risk is the risk that the Group might not have sources of funding to meet its business needs. The Directors believe that the Group has sufficient cash, undrawn committed funds under its borrowing base facility and expected sources of liquidity to meet the business's forecast requirements.

Capital risk

The Company and/or affiliates will continue to explore opportunities to optimise and strengthen its capital structure by refinancing debt, repaying (vendor) loans and/or potentially repurchasing its bonds. The Group and its shareholders continue to explore strategic options for the business to support further development and growth, including the possibility of an IPO.

Climate change risk

Climate change risk is the risk that the Group fails to manage the impact of climate change due to evolving regulatory policies. Subsequent related commodity price volatility or access to markets could affect portfolio commerciality, our licence to operate and impact Neptune's access to capital funding.

See pages 70-77 for more information on our risk disclosure.

3. Revenue from contracts with customers

Set out below is the reconciliation of the revenue from contracts with customers with the amounts disclosed in note 5.

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Gas	**1,522.8**	711.1
Oil	**517.7**	449.4
LNG	**253.6**	258.3
Other liquids	**151.7**	88.1
Total production revenue	**2,445.8**	1,506.9
Others	**44.3**	53.2
Total Group revenue	**2,490.1**	1,560.1

There are no right of return assets and refund liabilities held within the Group and costs to obtain contracts are negligible.

Included in revenue from external customers are revenues of $910.6 million, $456.9 million and $327.7 million (2020: $238.2 million, $188.6 million and $153.8 million) relating to the Group's customers who each contribute more than 10% of total revenue. As sales of oil and gas are made on global markets and are highly liquid, the Group does not place reliance on the largest customers mentioned above.

3.1 Performance obligations

Oil and gas sales

The performance obligation is satisfied by the delivery of the product at an agreed delivery point in the distribution chain, often either at the well head or delivery terminal. Payment is generally due within 30 days from delivery or offtake but can be as much as 90 days. Variation in the specification of the product is reflected in the contract price as an increase or decrease against a quoted benchmark product such as Brent (oil) or NTS (gas).

4. Other operating income

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Loss of production insurance	**128.6**	9.0
Total	**128.6**	9.0

On 26 October 2020, Equinor, the operator of the Hammerfest LNG plant in Norway announced to its joint venture partners that the LNG plant will be closed for up to 12 months for repairs following an incident. The plant processes production from the Snøhvit, Albatross and Askeladd fields. The operator has subsequently advised that the estimated date to restart production will be 17 May 2022. Neptune's loss of revenue is partially being recovered through business interruption insurance, after an initial period of 60 days in 2020.

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5. Segmental information

5.1 Net operating profit after equity-accounted investments

Neptune Energy's reportable segment is that used by the Group's Board and management to run the business. The Board is responsible for allocating resources and assessing performance of the segment.

The Group's activities consist of a single class of business (upstream), representing the acquisition, exploration, development and production of the Group's own oil and gas reserves and resources and is focused on two geographical regions comprising seven areas: UK, Norway, Netherlands, Germany, North Africa, Asia Pacific and Corporate.

	Year ended 31 December 2021							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Production revenue by origin	**239.1**	**1,160.4**	**363.4**	**333.0**	**30.4**	**319.5**	**–**	**2,445.8**
Other revenue	**6.7**	**(0.6)**	**25.5**	**2.0**	**–**	**–**	**10.7**	**44.3**
Revenue from contracts with customers	**245.8**	**1,159.8**	**388.9**	**335.0**	**30.4**	**319.5**	**10.7**	**2,490.1**
Other operating income	**–**	**128.6**	**–**	**–**	**–**	**–**	**–**	**128.6**
Revenue and other income	**245.8**	**1,288.4**	**388.9**	**335.0**	**30.4**	**319.5**	**10.7**	**2,618.7**
Current operating profit/(loss)	**81.7**	**974.0**	**155.8**	**131.4**	**2.7**	**78.0**	**(18.2)**	**1,405.4**
Share of net income/(loss) from investments using equity method	**–**	**–**	**(1.3)**	**–**	**62.4**	**–**	**–**	**61.1**
Net operating profit/(loss) after equity-accounted investments	**81.7**	**974.0**	**154.5**	**131.4**	**65.1**	**78.0**	**(18.2)**	**1,466.5**
Net impairment reversal								**113.6**
Mark-to-market on commodity contracts other than trading instruments (note 8)								**(73.8)**
Restructuring cost								**0.5**
Other gains								**7.9**
Profit before financial items								**1,514.7**
Financial income								**53.1**
Finance costs								**(175.4)**
Profit before tax								**1,392.4**

	Year ended 31 December 2020							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Production revenue by origin	209.8	617.2	232.2	154.9	34.0	258.8	–	1,506.9
Other revenue	6.0	17.8	22.4	3.7	–	–	3.3	53.2
Revenue from contracts with customers	215.8	635.0	254.6	158.6	34.0	258.8	3.3	1,560.1
Other operating income	–	9.0	–	–	–	–	–	9.0
Revenue and other income	215.8	644.0	254.6	158.6	34.0	258.8	3.3	1,569.1
Current operating profit/(loss)	44.9	278.7	44.7	(48.5)	(21.9)	3.0	(17.0)	283.9
Share of net (loss)/income from investments using equity method	–	–	1.6	–	(21.6)	–	–	(20.0)
Net operating profit/(loss) after equity-accounted investments	44.9	278.7	46.3	(48.5)	(43.5)	3.0	(17.0)	263.9
Net impairment loss								(325.7)
Mark-to-market on commodity contracts other than trading instruments (note 8)								(4.0)
Restructuring release								(25.3)
Other losses								(4.3)
Loss before financial items								(95.4)
Financial income								12.4
Finance costs								(250.1)
Loss before tax								(333.1)

5.2 EBITDAX by country

EBITDAX as a non-GAAP measure is the group performance metric used to measure our ability to produce income from our operations in any given year. The Group uses EBITDAX as it is a principal key performance metric under the Group's RBL borrowing facility.

	Year ended 31 December 2021							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
EBITDAX (including equity-accounted affiliates)	**159.8**	**1,168.2**	**256.3**	**220.7**	**82.5**	**237.5**	**(15.7)**	**2,109.3**

	Year ended 31 December 2020							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
EBITDAX (including equity-accounted affiliates)	151.2	461.0	129.7	48.2	(8.1)	171.8	(14.0)	939.8

Reconciliation of EBITDAX as a non-GAAP measure to profit/(loss) before tax, after financial items:

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Profit/(loss) before tax, after financial items	**1,392.4**	(333.1)
Add back:		
Net financing expenses	**122.3**	237.7
Other operating gains	**65.4**	33.6
Net impairment (reversals)/losses	**(113.6)**	325.7
Exploration expense	**67.7**	91.2
DD&A	**575.1**	584.7
EBITDAX (RBL basis)	**2,109.3**	939.8

5.3 Net impairment reversal/(loss) by country

	31 December 2021							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Intangible assets (note 13)	**(6.7)**	**(0.9)**	**–**	**–**	**–**	**–**	**–**	**(7.6)**
Property, plant and equipment (note 14)	**–**	**–**	**77.8**	**–**	**–**	**43.4**	**–**	**121.2**
Total impairment reversal/(loss)	**(6.7)**	**(0.9)**	**77.8**	**–**	**–**	**43.4**	**–**	**113.6**

	31 December 2020							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Goodwill (note 12)	–	(4.2)	–	–	(10.2)	–	–	(14.4)
Intangible assets (note 13)	–	0.2	–	–	–	(10.0)	–	(9.8)
Property, plant and equipment (note 14)	–	–	(91.1)	(12.7)	–	(197.7)	–	(301.5)
Total impairment loss	–	(4.0)	(91.1)	(12.7)	(10.2)	(207.7)	–	(325.7)

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5.4 Net assets

	31 December 2021							
In millions of US$	UK	Norway[1]	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Balance sheet								
Assets	**1,465.5**	**3,534.8**	**937.7**	**648.8**	**692.2**	**1,203.9**	**544.7**	**9,027.6**
Liabilities	**(916.3)**	**(2,651.7)**	**(1,315.4)**	**(715.9)**	**(34.6)**	**(227.5)**	**(2,420.0)**	**(8,281.4)**
Net assets/(liabilities)	**549.2**	**883.1**	**(377.7)**	**(67.1)**	**657.6**	**976.4**	**(1,875.3)**	**746.2**

1. As at 31 December 2021, Norway segment net assets includes assets held for sale of $134.9 million and liabilities directly associated with the assets held for sale of $100.9 million.

	31 December 2020							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Balance sheet								
Assets	1,329.8	3,205.2	636.4	576.0	628.6	1,131.8	84.7	7,592.5
Liabilities	(357.2)	(1,876.0)	(672.9)	(704.9)	(17.2)	(153.8)	(2,327.9)	(6,109.9)
Net assets/(liabilities)	972.6	1,329.2	(36.5)	(128.9)	611.4	978.0	(2,243.2)	1,482.6

Corporate net liabilities includes amounts of a corporate nature and not specifically attributable to a reportable segment. The liabilities comprise the Group's external debt and other non-attributable corporate liabilities.

5.5 Net capital investment

	Year ended 31 December 2021							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Investments accounted under equity method (note 15)	**–**	**–**	**(12.3)**	**–**	**61.0**	**–**	**–**	**48.7**
Capital expenditure	**134.7**	**537.7**	**62.9**	**165.4**	**11.0**	**131.5**	**–**	**1,043.2**
	134.7	**537.7**	**50.6**	**165.4**	**72.0**	**131.5**	**–**	**1,091.9**

	Year ended 31 December 2020							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Investments accounted under equity method (note 15)	–	–	(1.8)	–	(45.3)	–	–	(47.1)
Capital expenditure	98.2	576.5	60.0	56.0	7.9	142.5	–	941.1
	98.2	576.5	58.2	56.0	(37.4)	142.5	–	894.0

5.6 Underlying operating profit

Underlying operating profit as a non-GAAP measure is the group performance metric used to measure our ability to produce income from our operations in any given year. The Group uses underlying operating profit as it removes the effects of non-business as usual events, such as impairments, restructuring costs and curtailment gains/losses that might otherwise distort comparability between periods. For the Group's single class of business (upstream), the underlying operating profit is as below:

In millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Operating profit/(loss) before financial items	**1,514.7**	(95.4)
Adjusted for:		
Impairment (reversal)/loss in share of net income/(loss) from investments using equity method	**(32.2)**	32.7
Impairment (reversals)/losses	**(113.6)**	325.7
Net restructuring (release)/cost	**(0.5)**	25.3
Legacy licence cost	**4.0**	–
Pension scheme curtailment credit	**(4.1)**	(1.0)
Underlying operating profit before financial items and tax	**1,368.3**	287.3

6. Operating profit/(loss) before financial items

Included within the Group's operating costs were the following items:

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Cost of sales		
Movements in over/under lift balances	**(92.0)**	43.4
Production, insurance and transportation costs	**507.4**	470.1
Depreciation of property, plant and equipment	**570.1**	581.0
Amortisation of intangible assets	**5.0**	3.7
Other operating costs	**76.7**	26.7
Exploration expenses		
Exploration and evaluation expenditure	**35.5**	60.9
Unsuccessful exploration expenditure written off	**32.2**	30.3
General and administration expenses include		
Employee costs	**41.9**	39.0
Auditor's remuneration:		
Fees payable to the Company's auditor for the audit of the Company's annual accounts	**2.0**	1.8
Audit of the accounts of subsidiary companies	**0.5**	0.4
Non-audit fees	**0.6**	0.6

Ernst & Young LLP has served as Neptune Energy's independent external auditor for the five-year period ended 31 December 2021. The external auditor is subject to reappointment at the year-end Board meeting and has been reappointed for the 2022 period end.

7. Staff costs

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Wages and salaries	**200.1**	196.3
Social security costs	**26.6**	29.8
Pension costs – defined benefit schemes	**5.0**	4.8
Pension costs – defined contribution schemes	**16.0**	19.0
Other long-term benefits	**3.9**	2.9
Total	**251.6**	252.8

The average number of persons employed during the year (including Directors) was 1,300 (2020: 1,446).

The Group operates defined contribution pension schemes for staff. The contributions are payable to external funds which are administered by independent trustees. Contributions during the year amounted to $16.0 million (2020: $19.0 million).

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7.1 Total Directors' remuneration

The total Directors' remuneration is:

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Short-term employee benefits	**6.7**	5.7
Other long-term benefits – post-employment benefits	**0.3**	0.1
Total	**7.0**	5.8

Highest paid Director's remuneration

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Short-term employee benefits	**2.3**	2.7
Total	**2.3**	2.7

8. Other operating losses/(gains)

Other operating losses/(gains) are those that need to be disclosed separately by virtue of their nature, size or incidence. These include certain remeasurements, business restructuring costs, business combination activity, pension change costs or credits and asset impairments/write backs.

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Mark-to-market on commodity contracts other than trading instruments:		
Loss/(gain) on commodity derivative instruments at fair value through profit and loss	**84.3**	(23.3)
(Gain)/loss on emissions derivative instruments at fair value through profit and loss	**(19.1)**	(2.5)
(Gain)/loss on foreign exchange forward at fair value through profit and loss	**(5.9)**	–
Loss/(gain) on foreign exchange swaps at fair value through profit and loss	**–**	11.1
Loss/(gain) on ineffectiveness on commodity contracts designated as hedges	**–**	0.4
Loss/(gain) on excluded components on commodity contracts designated as hedges	**14.5**	18.3
	73.8	4.0
Restructuring (release)/cost (note 23)	**(0.5)**	25.3
Pension schemes curtailment credit (note 29.4)	**(4.1)**	(1.0)
Release of contingent consideration	**(2.5)**	(20.3)
Unsuccessful business combination termination fees	**–**	5.0
Net movement in provision for inventory deterioration and obsolescence	**1.0**	1.6
Other (gains)/losses	**(2.3)**	19.0
Total other operating losses	**65.4**	33.6

Other gains in 2021 are principally in relation to a gain recognised on the disposal of two properties in Germany, this is offset by a legacy licence cost and a loss in relation to the sale of 100% of the shares in Neptune Energy Denmark ApS, which included the Solsort exploration licence. In 2020, other losses were principally in relation to the write off of a JV partner debtor.

9. Finance income and costs

9.1 Finance income

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Interest income[1]	**3.4**	7.7
Interest income from Joint Arrangements for right-of-use assets	**1.5**	2.3
Dividend income[2]	**1.4**	2.4
Net foreign exchange gain[3]	**46.8**	–
Total finance income	**53.1**	12.4

1. Interest income in 2020 included $1.0 million gain on the settlement of the Touat Vendor loan in September 2020.
2. Dividend income relates to a Level 3 non-listed equity instrument.
3. The net foreign exchange gain/loss for the year ended 31 December 2020 was a loss of $59.8 million shown in finance cost.

In the Company, finance income of $410.4 million (2020: $66.1 million) includes dividend income of $344.7 million (2020: $nil).

9.2 Finance cost

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Interest expense	**119.4**	132.7
Commitment fees	**14.9**	14.4
Unwinding of discount on decommissioning and other provisions	**35.4**	36.1
Interest expense lease liabilities	**5.7**	7.1
Net foreign exchange losses[1]	**–**	59.8
Total finance costs	**175.4**	250.1

1. The net foreign exchange gain/loss for the year ended 31 December 2021 was a gain of $46.8 million shown in finance income.

10. Dividend

	Group		Company	
In millions of US$	31 December 2021	31 December 2020	31 December 2021	31 December 2020
Aggregate amount of dividend declared in the year	**344.7**	–	**344.7**	–
Aggregate amount of dividend paid in the year	**544.7**	–	**544.7**	–

The Board of Directors of Neptune Energy Group Midco Limited declared a 2021 interim dividend of $80.0 million on 24 February 2021 (4.05 cents per fully paid ordinary share registered) which was initially settled by the issue of an $80.0 million promissory note. The $80.0 million promissory note was settled in full for cash on 15 December 2021.

On 10 December 2021, the Board of Directors of Neptune Energy Group Midco Limited declared a second 2021 interim dividend of $264.7 million (13.39 cents per fully paid ordinary share registered) which was settled on 15 December 2021 (2020: $nil) by the Company.

Furthermore, the $200.0 million promissory note issued in respect of the final 2019 dividend announced on 11 December 2019 was also settled on 25 February 2021.

The aggregate amount of the dividends paid by Neptune Energy Group Midco Limited of $544.7 million and the loan of $455.3 million (see note 17) in the year made to its ultimate parent entity Neptune Energy Group Limited (NEGL) represents a $1.0 billion total contribution to NEGL. This enabled dividends and capital distributions totalling $1.0 billion by NEGL, made up of a first 2021 interim dividend settlement and capital redemption settlement of $200.0 million on 25 February 2021 and a second interim dividend and capital redemption settlement of $800.0 million on 15 December 2021 to the ultimate shareholders of NEGL.

No dividends were declared or paid in 2020.

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11. Taxation

The major components of income tax expense in the consolidated income statement are:

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Current taxation:		
Charge/(credit) for the period	**418.1**	(240.2)
Adjustment in respect of prior years	**9.7**	(46.7)
	427.8	(286.9)
Deferred taxation:		
Origination and reversal of temporary differences	**577.4**	352.8
Total income tax expense recognised in income statement	**1,005.2**	65.9

11.1 Reconciliation between theoretical income tax expense and actual tax expense

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Profit/(loss) before taxation	**1,392.4**	(333.1)
Expected tax charge/(credit)	**886.9**	(0.5)
Effects on tax charge of:		
Expenses/(income) taxed or relieved at rates different to the headline statutory rate[1]	**15.4**	(127.3)
Non tax-deductible expenditure	**20.7**	62.4
Income not subject to taxation	**(23.1)**	(15.9)
Utilisation of previously unrecognised deferred tax assets	**–**	(4.7)
Adjustments in respect of prior years	**9.5**	(46.7)
(Recognition)/derecognition of deferred tax assets	**56.3**	158.6
Non-recognition of deferred tax assets	**46.5**	52.3
Other items	**(7.0)**	(12.3)
Total income tax charge	**1,005.2**	65.9

1. Includes the impact of capital uplift allowances, Norway $56.3 million credit, and finance and hedging results taxed or relieved at rates lower than the headline statutory rate.

The Group operates in a number of jurisdictions. Across these jurisdictions, there is a broad variation in statutory tax rates. The Group's expected tax charge reflects the applicable rates for the countries in which the Group earned profits. The tax charge will vary depending on a number of factors, such as the geographic mix of profits and changes to tax rates. During the year, the Group has earned profits in the operating countries applying higher statutory tax rates, especially Norway where the statutory tax rate applicable is 78%.

The effective tax rate for the Group for 2021 was 72.2% (2020: (19.7)%). The difference between the expected tax charge and the actual tax charge is mainly impacted by:

- non-tax-deductible expenditures which are generally recurring adjustments relating primarily to Indonesia PSC adjustments and a non-recurring impairment adjustment for Denmark;
- income not subject to taxation relates mainly to the disposal of the Denmark business not being subject to tax in Norway, the Netherlands fiscal unity and special tax rate adjustments and non-taxable foreign exchange gains in the UK;
- deferred tax asset not recognised relating mainly to Norway onshore tax losses, the Netherlands interest deductions and the UK asset retirement obligations; and
- Net derecognition of deferred tax asset relating primarily to derecognition of UK tax losses offset by recognition of tax losses in Germany and Netherlands which were previously not recognised, as further described below.

11.2 Analysis of deferred tax income/expense recognised in other comprehensive income, by type of temporary difference

Group – in millions of US$	Year ended 31 December 2021	Year ended 31 December 2020
Difference type		
Actuarial gains/(losses)	**(4.3)**	2.5
Cash flow hedges	**480.2**	32.5
Net deferred tax income	**475.9**	35.0

11.3 Changes in deferred taxes

The net movement in deferred tax assets and (liabilities) is shown below:

Group – in millions of US$	PP&E	Asset retirement obligations	Pensions	Tax losses	Other	Total
At 1 January 2021	**(1,580.1)**	**432.3**	**49.4**	**787.2**	**(100.3)**	**(411.5)**
Reclassification	**94.8**	**–**	**–**	**(94.8)**	**–**	**–**
Transfers to assets held for sale (note 19)	**45.2**	**(67.8)**	**–**	**–**	**–**	**(22.6)**
Credit/(charge) for the year	**(405.1)**	**13.4**	**1.3**	**(97.2)**	**(89.9)**	**(577.5)**
Charge to equity and other comprehensive income	**–**	**–**	**(4.3)**	**–**	**480.2**	**475.9**
Currency translation adjustments	**60.9**	**(15.3)**	**(2.9)**	**(15.1)**	**3.3**	**30.9**
At 31 December 2021	**(1,784.3)**	**362.6**	**43.5**	**580.1**	**293.3**	**(504.8)**

Deferred tax asset	**852.3**
Deferred tax liabilities	**(1,357.1)**
Deferred tax liabilities net	**(504.8)**

Group – in millions of US$	PP&E	Asset retirement obligations	Pensions	Tax losses	Other	Total
At 1 January 2020	(1,315.8)	361.1	43.9	957.6	(105.9)	(59.1)
Reclassification	(20.6)	(0.4)	–	16.1	4.9	–
Credit/(charge) for the year	(179.2)	54.7	–	(201.4)	(26.9)	(352.8)
Charge to equity and other comprehensive income	–	–	2.5	–	32.5	35.0
Currency translation adjustments	(64.5)	16.9	3.0	14.9	(4.9)	(34.6)
At 31 December 2020	(1,580.1)	432.3	49.4	787.2	(100.3)	(411.5)

Deferred tax asset	577.3
Deferred tax liabilities	(988.8)
Deferred tax liabilities net	(411.5)

The movement in the PP&E relates mainly to Norway and Indonesia tax depreciation being significantly greater than the accounting depreciation increasing the deferred tax liability.

The movement on tax losses is due to the recognition of the deferred tax assets based on future taxable profits forecasts enabling deferred tax assets to be recognised on the tax losses for Germany and the Netherlands. This has been offset by the deferred tax on the tax loss not recognised in the UK as there are insufficient future taxable profits, following first utilisation of the future taxable profits by the hedging losses.

Deferred tax assets have been recognised in other comprehensive income for the hedging losses in the UK and the Netherlands on the basis of future taxable profit forecasts.

The presentation in the balance sheet takes into consideration the offsetting of deferred tax assets and deferred tax liabilities, where this is permitted. The net deferred tax asset of $852.3 million relates to UK, Norway and the Netherlands and primarily includes deferred tax asset on tax losses, hedging losses and asset retirement obligations of $1,164.3 million offset against a deferred tax liability on PP&E of $312.0 million.

There were no net deferred tax assets and liabilities recognised in the Company for 2021 or 2020.

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11.4 Temporary differences for which no deferred tax asset has been recognised

Group – in millions of US$	31 December 2021	31 December 2020
Unused tax losses	**2,315.0**	2,440.3
Other deductible temporary differences	**808.7**	681.4
Total temporary difference for which no deferred tax asset is recognised	**3,123.7**	3,121.7

Of the above unrecognised deductible temporary differences, $3,123.7 million (2020: $3,089.9 million) are not subject to time limits for utilisation. Other deductible temporary differences not recognised relate predominantly to the UK where deferred tax on investment allowances and the ARO liability is not fully recognised.

12. Goodwill

Group – in millions of US$	31 December 2021	31 December 2020
Cost at 1 January	**664.5**	640.8
Transfers to assets held for sale (note 19)	**(14.4)**	–
Currency translation adjustments	**(25.6)**	23.7
Cost at 31 December	**624.5**	664.5
Impairment losses at 1 January	**(14.8)**	–
Impairment loss	**–**	(14.4)
Currency translation adjustments	**0.3**	(0.4)
Impairment losses at 31 December	**(14.5)**	(14.8)
Net book value at 31 December	**610.0**	649.7

In 2021, the transfer of goodwill to assets held for sale is in relation to an element of the VNG Norge AS assigned goodwill following the initial acquisition in 2018.

The goodwill from business combinations is reviewed for impairment prospectively at each reporting date, or earlier if there are indications of impairment. For the purpose of impairment testing, goodwill is allocated to groups of Cash Generating Units (CGUs); these represent the lowest level at which goodwill is monitored. The recoverable amounts are determined based on the fair value less cost of disposal method. The key assumptions in estimating the recoverable amounts are disclosed in note 1.3.1.

Country of CGU – in millions of US$	Trigger for 2020 impairment	2020 impairment	Post-tax discount rate	2020 CGU recoverable amount
Egypt	**a**	**10.2**	**12%**	**–**
Denmark	**b**	**4.2**	**10%**	**–**
Total		**14.4**		

a. Decrease due to long-term price assumptions.
b. Changes in the field development plan.

During 2020, goodwill relating to Denmark and Egypt was fully impaired. The remaining goodwill is assigned to the Netherlands and Germany group of CGUs. The carrying amount of the goodwill allocated to these cash-generating units is not significant in comparison with the Group's total goodwill.

The goodwill assigned to Norway is $528.9 million. The discount rate applied in determining the recoverable amount is 8%. No reasonable possible change in any of the key assumptions would cause Norway's carrying amount to exceed its recoverable amount.

The Group uses the fair value less cost of disposal method to calculate the recoverable amount of the CGUs consistent with a Level 3 fair value measurement as defined in note 24.1. In determining the fair value, the Group has used a post-tax discount rate of 8% (31 December 2020: 8-12%) based on a country-based weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2025 of $65/bbl (31 December 2020: 2024 at $60/bbl) for Brent crude oil and 50p/therm (31 December 2020: 2024 at 50p/therm) for NBP gas thereafter inflated by 2% per annum.

The Group's recoverable value of assets is sensitive, inter alia, to oil and gas prices. The Group has run sensitivity analysis on the prices outlined above. The recoverable amount of one of the country's group of CGUs to which goodwill is allocated exceeds the aggregate amount of the carrying values by $226 million (2020: $95 million). If the prices were to decrease by approximately 18% (2020: 9%), the recoverable amount of this country's group of CGUs would equal the aggregate of the carrying values. The above sensitivity has flexed revenues and tax cash flows but operating costs and capital expenditures have been kept constant. No reasonable possible change in any other of the key assumptions would cause the carrying amount of the CGU to exceed its recoverable amount.

13. Intangible assets

Group – in millions of US$	Exploration and evaluation	Other	Total
Cost at 1 January 2020	138.6	28.6	167.2
Additions	82.7	1.9	84.6
Unsuccessful exploration expenditure	(30.3)	–	(30.3)
Impairment loss	(17.7)	–	(17.7)
Reversal of impairment loss	7.9	–	7.9
Transfers (to)/from property, plant and equipment	(3.8)	0.1	(3.7)
Currency translation adjustments	6.7	1.4	8.1
Cost at 31 December 2020	184.1	32.0	216.1
Additions	131.5	1.7	133.2
Disposals	(2.6)	(0.2)	(2.8)
Unsuccessful exploration expenditure	(32.2)	–	(32.2)
Impairment loss	(7.6)	–	(7.6)
Transfers from property, plant and equipment	6.9	–	6.9
Currency translation adjustments	(5.4)	(1.1)	(6.5)
Cost at 31 December 2021	**274.7**	**32.4**	**307.1**
Amortisation at 1 January 2020	–	(16.3)	(16.3)
Charge for the year	–	(3.7)	(3.7)
Currency translation adjustments	–	(1.2)	(1.2)
Amortisation at 31 December 2020	–	(21.2)	(21.2)
Charge for the year	–	(5.0)	(5.0)
Elimination on disposals	–	0.2	0.2
Currency translation adjustments	–	0.9	0.9
Amortisation at 31 December 2021	**–**	**(25.1)**	**(25.1)**
Net book value at 31 December 2021	**274.7**	**7.3**	**282.0**
Net book value at 31 December 2020	184.1	10.8	194.9

Unsuccessful exploration expenditure relates to costs associated with licence relinquishments and uncommercial well evaluations.

Country of CGU – in millions of US$	Trigger for 2021 impairment	2021 Impairment	Post-tax discount rate assumption	2021 CGU Remaining recoverable amount
Denmark[a]	**a**	**0.9**	**8%**	**–**
UK[b]	**b**	**6.7**	**8%**	**–**
Total		**7.6**		**–**

a. Due to the sale of the asset (note 8).
b. Licence relinquishment.

Country of CGU – in millions of US$	Trigger for 2020 impairment/ (reversal)	2020 impairment/ (reversal)	Post-tax discount rate	2020 CGU recoverable amount
Norway	a	(7.9)	8%	26.3
Denmark	b	7.7	10%	2.5
Indonesia	c	10.0	11%	–
Total		9.8		

a. Due to a new discovery within the area.
b. Changes in the field development plan.
c. Licence relinquishment.

Notes to the consolidated financial statements
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14. Property, plant and equipment

Group – in millions of US$	Oil and gas properties	Other fixed assets	Total
Cost at 1 January 2020	5,627.3	85.8	5,713.1
Additions	853.3	3.2	856.5
Asset derecognition[1]	(6.6)	–	(6.6)
Disposals	(21.3)	(1.1)	(22.4)
Transfers from intangible assets	3.0	0.7	3.7
Currency translation adjustments	266.1	6.0	272.1
Cost at 31 December 2020	6,721.8	94.6	6,816.4
Additions	891.7	18.3	910.0
Asset derecognition[1]	–	(5.7)	(5.7)
Disposals	(0.7)	(8.9)	(9.6)
Transfers to intangible assets	(6.9)	–	(6.9)
Transfers	(4.2)	4.2	–
Transfers to assets held for sale (note 19)	(133.7)	–	(133.7)
Currency translation adjustments	(236.2)	(4.3)	(240.5)
Cost at 31 December 2021	**7,231.8**	**98.2**	**7,330.0**
Accumulated depreciation at 1 January 2020	(1,268.4)	(13.9)	(1,282.3)
Charge for year[2],[3]	(587.6)	(11.7)	(599.3)
Impairment loss	(301.3)	(0.2)	(301.5)
Asset derecognition	3.8	–	3.8
Disposals	21.3	1.1	22.4
Currency translation adjustments	(91.7)	(1.6)	(93.3)
Amortisation at 31 December 2020	(2,223.9)	(26.3)	(2,250.2)
Charge for year[2],[3]	(591.9)	(9.7)	(601.6)
Impairment loss	(18.7)	–	(18.7)
Reversal of impairment loss	139.9	–	139.9
Asset derecognition	–	5.7	5.7
Disposals	–	2.4	2.4
Transfers to assets held for sale (note 19)	56.7	–	56.7
Currency translation adjustments	85.5	(0.9)	84.6
Amortisation at 31 December 2021	**(2,552.4)**	**(28.8)**	**(2,581.2)**
Net book value at 31 December 2021	**4,679.4**	**69.4**	**4,748.8**
Net book value at 31 December 2020	4,497.9	68.3	4,566.2

1. The derecognition of assets arises in Norway in relation to the fire at the non-operated Hammerfest LNG facility.
2. Includes capitalised depreciation of $31.5 million (2020: $18.3 million) related to right-of-use assets in Norway and the UK.
3. Refer to note 22 for depreciation charge related to right-of-use assets.

The Group uses the fair value less cost of disposal method to calculate the recoverable amount of the cash generating units (CGU) consistent with a Level 3 fair value measurement. In determining the fair value, the Group has used a post-tax discount rate of 8-10% (2020: 8-12%) based on a country specific weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2025 of $65/bbl (31 December 2020: 2024 at $60/bbl) for Brent crude oil and 50p/therm (31 December 2020: 2024 at 50p/therm) for NBP gas thereafter inflated by 2% per annum.

Country of CGU – in millions of US$	Trigger for 2021 impairment	2021 Impairment (reversal)/ charge	Post-tax discount rate	2021 CGU recoverable amount (post-tax)[d]
Indonesia	**a**	**(43.4)**	**10%**	**1,037.2**
Netherlands (1)	**b**	**(96.5)**	**8%**	**120.4**
Impairment reversal total		**(139.9)**		**1,157.6**
Netherlands (2)	**c**	**18.7**	**8%**	**–**
Total		**(121.2)**		**1,157.6**

a. Increase due to updated assumptions on future commodity prices and change in discount rate.
b. Increase due to upward reserves revision.
c. Decrease due to underlying reservoir performance.
d. CGU recoverable amount (post-tax) is calculated as at testing date.

Incremental price and discount rate sensitivity impairment analysis on CGU recoverable amount (post-tax):

	2021 CGU recoverable amount	Oil and Gas price		Post-tax discount rate	
Country of CGU – in millions of US$		Plus 10%	Minus 10%	Plus 1%	Minus 1%
Netherlands (1) (a)	**120.4**	**18.6**	**(24.2)**	**(1.0)**	**1.1**
Indonesia (b)	**1,037.2**	**108.6**	**(105.8)**	**(39.3)**	**42.2**

a. The 10% price increase of $18.6 million and the minus 1% post-tax discount increase of $1.1 million would not have resulted in an additional post-tax impairment reversal.
b. The 10% price increase of $108.6 million would be restricted to an additional impairment reversal of $37.0 million and the minus 1% post-tax discount increase of $42.2 million would be restricted to an additional impairment reversal of $14.5 million.

For the Netherlands (1) CGU, sensitivity analyses indicate that if reserves were to fall by 10%, the post-tax impairment reversal recognised would have been $24.2 million lower. An increase of reserves by 10% would have increased the recoverable amount by $18.6 million, but would not have resulted in an additional post-tax impairment reversal.

For the Indonesia CGU, sensitivity analyses indicate that if reserves were to fall by 10%, the post-tax impairment reversal recognised would have been $124.0 million lower. An increase of reserves by 10% would have increased the recoverable amount by $120.7 million, but would not have resulted in a full post-tax impairment reversal.

Country of CGU – in millions of US$	Trigger for 2020 impairment	2020 pre-tax impairment	Post-tax discount rate	2020 CGU recoverable amount (post-tax)[c]
Netherlands (1)	a	91.1	10%	92.8
Indonesia	a	197.7	11%	533.2
Germany	b	12.7	10%	–
Total		301.5		

a. Decrease due to long-term price assumptions and underlying reservoir performance.
b. Decrease due to long-term price assumptions.
c. CGU recoverable amount (post-tax) is calculated as at testing date.

2020 incremental price and discount rate sensitivity impairment analysis on CGU recoverable amount (post-tax):

	2020 CGU recoverable amount	Oil and Gas price		Post-tax discount rate	
Country of CGU – in millions of US$		Plus 10%	Minus 10%	Plus 1%	Minus 1%
Netherlands (1)	92.8	25.4	(21.1)	(1.6)	1.8
Indonesia	533.2	44.5	(46.5)	(15.5)	16.5
Germany	–	–	–	–	–
Total	626.0	69.9	(67.6)	(17.1)	18.3

For the Indonesia CGU, sensitivity analyses indicate that if reserves were to fall by 10% an additional post-tax impairment of $50.5 million would have occurred and an increase of reserves by 10% would have led to a reduction of the post-tax impairment of $42.5 million. For the Netherlands CGU, sensitivity analyses indicate that if reserves were to fall by 10% an additional post-tax impairment of $21.1 million would have occurred and an increase of reserves by 10% would have led to a reduction of the post-tax impairment of $25.2 million.

Notes to the consolidated financial statements
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15. Investments

Investments in entities accounted for using the equity method

Group – in millions of US$	Total
Cost at 1 January 2020	604.7
Net movements	(47.1)
Cost at 31 December 2020	557.6
Net movements	48.7
Cost at 31 December 2021	**606.3**

Interest in joint ventures

The Group has an 18.57% interest in Noordgastransport B.V. and a 54% interest in Neptune Energy Touat B.V. ('Touat').

Group – in millions of US$	31 December 2021	31 December 2020
At 1 January	**557.6**	604.7
Share of results in the year	**61.1**	(20.0)
Hedging recognised in other comprehensive income	**(4.2)**	(3.1)
Dividends paid	**(2.3)**	(5.2)
Equity injection contribution	**19.0**	26.2
Share capital repayment	**(16.2)**	(46.9)
Net investment in equity-accounted investments	**0.5**	(25.9)
Currency translation adjustments	**(8.7)**	1.9
At 31 December	**606.3**	557.6

Neptune Energy Touat B.V. as a material joint venture, has an interest in the Touat production sharing contract in Algeria. The Group's interest in Touat is accounted for using the equity method in the consolidated financial statements. Summarised financial information of the joint venture, based on its IFRS financial statements, and reconciliation with the carrying amount of the investment in the consolidated financial statements are set out below:

Neptune Energy Touat B.V. – in millions of US$	31 December 2021	31 December 2020
Non-current assets	**1,087.8**	1,045.7
Current assets	**132.1**	79.9
Current liabilities	**(71.8)**	(86.6)
Non-current liabilities	**(42.2)**	(46.1)
Equity	**1,105.9**	992.9
Group's share of equity – 54%	**597.2**	536.2
Group's carrying amount of the investment	**597.2**	536.2

Neptune Energy Touat B.V. – in millions of US$	2021	2020
Revenue	**73.9**	116.8
Other income	**93.4**	32.0
Cost of sales	**(90.3)**	(116.2)
Gross profit	**77.0**	32.6
General and administration expenses	**(4.0)**	(11.6)
Operating profit	**73.0**	21.0
Impairment reversal/(loss)	**59.6**	(60.6)
Other operating (losses)/gains	**(3.9)**	–
Operating profit/(loss) before financial items	**128.7**	(39.6)
Finance income	**3.1**	8.7
Finance costs	**(3.4)**	(8.4)
Profit/(loss) before tax	**128.4**	(39.3)
Taxation	**(12.8)**	(0.8)
Profit/(loss) for the year	**115.6**	(40.1)
Other comprehensive loss that may be reclassified to profit or loss in subsequent periods, net of tax	**(7.7)**	(5.7)
Total comprehensive income/(loss) for the year	**107.9**	(45.8)
Group's share of profit/(loss) for the year – 54%	**62.4**	(21.6)
Group's share of other comprehensive loss – 54%	**(4.2)**	(3.1)
Group's share of total comprehensive income/(loss) – 54%	**58.2**	(24.7)

Included within current assets are cash and cash equivalents of $11.1 million (2020: $12.2 million) and derivative contracts of $nil (2020: $1.4 million).

Included within current liabilities are derivative contracts of $nil (2020: $7.3 million).

Included within cost of sales is depreciation of oil and gas assets of $39.3 million (2020: $68.7 million).

Neptune Energy Touat B.V. had capital commitments of $4.2 million (2020: $43.1 million) for which the Neptune Group has a corresponding commitment of $2.3 million (2020: $23.3 million), as disclosed in note 27.

The investments held in the Company during the year are its direct interests in Neptune Energy Group Holdings Limited and Neptune Energy Bondco plc.

Company – in millions of US$	Total
Cost at 31 December 2020 and 31 December 2021	**1,977.2**

16. Inventories

Group – in millions of US$	31 December 2021	31 December 2020
Hydrocarbons stock	**4.9**	3.8
Raw materials and consumables	**78.1**	75.2
Total	**83.0**	79.0

The Company held no inventories in 2021 or 2020.

Included within raw materials and consumables is $21.5 million (2020: $20.5 million) in respect of provisions for deterioration and obsolescence.

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17. Trade and other receivables

Group – in millions of US$	31 December 2021	31 December 2020
Amounts falling due within one year		
Trade receivables	**445.9**	184.6
Under-lift position	**136.9**	57.4
Other taxes receivable	**8.7**	8.3
Receivables from joint venture partners	**159.4**	120.6
Other receivables	**175.5**	151.5
Loan to parent company	**455.3**	–
Prepayments and accrued income	**3.1**	4.2
Total	**1,384.8**	526.6

Trade receivables are stated net of credit loss provisions of $0.4 million (2020: $6.3 million). When management considers the recovery of a receivable to be improbable, a provision is made against the carrying value of the receivable. The movement through the income statement is included in other operating gains and losses (see note 8).

Company – in millions of US$	31 December 2021	31 December 2020
Amounts falling due within one year		
Receivable from subsidiaries	**16.5**	216.2
Loan to parent company	**455.3**	–
Current assets	**471.8**	216.2
Amounts falling due after one year		
Inter-company loans receivable	**938.7**	943.2
Non-current assets	**938.7**	943.2
Total	**1,410.50**	1,159.4

The loan to parent company as at 31 December 2021 is due for repayment on 31 December 2022 and is interest free.

Included within amounts receivable from subsidiaries in 2020 was $200.0 million in respect of a promissory note issued on 11 December 2019 from Neptune Energy Group Holdings Limited in respect of an interim dividend declared. This amount was settled in full on 25 February 2021. The inter-company loans are receivable from Neptune Energy Group Holdings Limited, a 100% owned subsidiary of Neptune Energy Group Midco Limited.

18. Cash and cash equivalents

Group – in millions of US$	31 December 2021	31 December 2020
Cash at bank and in hand	**107.3**	79.7
Restricted cash	**18.2**	12.8
Total cash and cash equivalents	**125.5**	92.5

Cash and cash equivalents comprise cash in hand and deposits with maturity of three months or less. Restricted cash includes monies held for decommissioning obligations.

The Company held $nil cash and cash equivalents at 31 December 2021 (31 December 2020: $nil).

19. Assets held for sale

On 12 November 2021, the Group announced the disposal of a portfolio of non-core Norwegian assets for an aggregate consideration of up to $35 million to OKEA ASA and M Vest Energy AS ('the buyers'). The assets the Group is divesting include the producing Draugen, Brage and Ivar Aasen fields, as well as the Edvard Grieg Oil Pipeline and the Utsira High Gas Pipeline (collectively, the 'disposal group'). All decommissioning liabilities will be transferred to the buyers. The effective date for the agreements is 1 January 2022, with an expected completion date of 31 March 2022, subject to the Norwegian Ministry of Petroleum and Energy approval. At 31 December 2021, the related assets was classified as a disposal group held for sale. The disposal group forms part of the Norway reportable segment presented in note 5 Segmental information.

The major classes of assets and liabilities of the Group as held for sale as at 31 December 2021, are as follows:

Group – in millions of US$	31 December 2021
Assets	
Goodwill (note 12)	**14.4**
Property, plant and equipment (note 14)	**77.0**
Deferred tax asset (note 11)	**22.6**
Trade receivables and other working capital	**18.7**
Currency translation adjustments	**2.2**
Assets held for sale	**134.9**
Provisions (note 23)	**(89.9)**
Trade and other payables	**(9.3)**
Currency translation adjustments	**(1.7)**
Liabilities directly associated with assets held for sale	**(100.9)**
Net assets directly associated with disposal group	**34.0**

Immediately before the classification of the disposal group as assets held for sale, the recoverable amount was estimated for the disposal group and no impairment loss was identified. The assets in the disposal group are held at the lower of their carrying amount and fair value less costs to sell. As at 31 December 2021, there was no further write down as the carrying amount of the disposal group did not fall below its fair value less costs to sell.

20. Borrowings

Group – in millions of US$	Interest rate 2021 %	Interest rate 2020 %	Maturity	31 December 2021	31 December 2020
Non-current interest-bearing loans and borrowings					
Reserve Based Lending facility	**2.857**	2.647	2024	**1,330.7**	1,028.6
Subordinated Neptune Energy Group Limited loan	**7.750**	7.750	2024	**100.0**	107.9
Senior Notes	**6.625**	6.625	2025	**838.7**	835.3
Total non-current				**2,269.4**	1,971.8
Current interest-bearing loans and borrowings					
DNB uncommitted facility	**1.800**	1.830	2022	**50.0**	50.0
Citibank uncommitted facility	**0.874**	–	2022	**10.0**	–
Total current				**60.0**	50.0
Total				**2,329.4**	2,021.8

The movements in borrowings are described in the table below:

Group – in millions of US$	31 December 2021
At 1 January 2021	**2,021.8**
Associated cash flows	
Repayment of borrowings	**(2,667.4)**
Drawdown of borrowings	**2,959.5**
Non-cash movements	
Amortisation of debt arrangement fees	**15.5**
At 31 December 2021	**2,329.4**

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continued

Changes in liabilities arising from financing activities:

Group – in millions of US$	1 January 2021	Cash flows	Currency translation adjustments	Additions	Other[1]	31 December 2021
Reserved Based Lending Facility	1,028.6	290.0	–	–	12.1	**1,330.7**
Subordinated Neptune Energy Group Limited Loan	107.9	(7.9)	–	–	–	**100.0**
Senior Notes	835.3	–	–	–	3.4	**838.7**
Uncommitted facilities	50.0	10.0	–	–	–	**60.0**
Total borrowings	**2,021.8**	**292.1**	**–**	**–**	**15.5**	**2,329.4**
Dividends payable (note 10)	200.0	(544.7)	–	344.7	–	**–**
Leases	188.1	(107.4)	(1.0)	52.9	(0.9)	**131.7**
Total liabilities from financing activities	**2,409.9**	**(360.0)**	**(1.0)**	**397.6**	**14.6**	**2,461.1**

1. Includes amortisation of arrangement fees and disposal of leases.

Certain subsidiaries within the Group have a Reserve Based Lending facility (RBL) with total aggregate commitments of $2.6 billion at the start of the year. The outstanding debt is repayable in line with the amortisation of bank commitments over the period from 1 April 2022 to the final maturity date of 11 May 2024, or such time as is determined by reference to the remaining reserves of the assets, whichever is earlier. No amounts are repayable within the next 12 months. The maximum amount that the relevant subsidiaries (the RBL Group) can draw down under this facility (the borrowing base) is subject to a consolidated cash flow and debt service projection, which is subject to an annual redetermination process in March. On this date, there is a redetermination of the available size of the facility, which takes into account, among other things, the most up-to-date forecast of the RBL Group's production. The facility was a multi-currency facility and incurred interest on outstanding debt at US dollar and Sterling LIBOR, EURIBOR or NIBOR plus an applicable margin. Following the March 2021 redetermination, the borrowing base remained at $2.3 billion and will remain at this level until the completion of the next redetermination in April 2022. The facility was also amended during 2021 and now only allows for USD drawdowns priced at USD LIBOR plus an applicable margin. The facility is secured over the shares of certain companies within the RBL Group, and certain of its oil and gas assets.

21. Trade payables and other liabilities

Group – in millions of US$	31 December 2021	31 December 2020
Trade and other payables	**329.4**	333.5
Other current liabilities	**386.7**	327.6
Lease liabilities	**73.9**	98.5
Wages and social security	**47.0**	50.9
Current trade payables and other liabilities	**837.0**	810.5
Other non-current liabilities	**37.4**	41.7
Lease liabilities	**57.8**	89.6
Non-current liabilities	**95.2**	131.3
Total	**932.2**	941.8

Trade payables are usually paid within 30 days of recognition. The carrying amount of financial liabilities approximates their fair value and they are all due within one year.

Other current liabilities in 2021 principally related to hedging liabilities and joint venture funding. Included within other current liabilities in 2020 was $200.0 million in respect of a promissory note, issued on 11 December 2019, to the immediate and ultimate parent undertaking for a 2019 interim dividend declared (see note 10). This was settled in full for cash on 25 February 2021.

During the year, the Group received a grant of $0.2m, which is included within other current liabilities, for reimbursement of certain revenue expenditures related to a pilot offshore Hydrogen Scheme in the Netherlands, the work for which is due to commence in 2022. There are no unfulfilled conditions or contingencies attached to this grant.

Company – in millions of US$	31 December 2021	31 December 2020
Loan from subsidiary	**455.3**	–
Amounts due to parent company	**7.1**	207.4
Interest payable to subsidiary	**7.5**	7.4
Current liabilities	**469.9**	214.8
Subordinated Neptune Energy Group Limited loan	**100.0**	107.9
Inter-company loan payable	**838.7**	835.3
Non-current liabilities	**938.7**	943.2
Total	**1,408.6**	1,158.0

The loan from subsidiary is payable to Neptune Energy Group Holdings Limited, a 100% owned subsidiary of Neptune Energy Group Midco Limited. The loan is repayable on 31 December 2022 and is interest free.

Included within amounts due to parent company in 2020 was $200.0 million in respect of a promissory note issued on 11 December 2019 to the immediate and ultimate parent undertaking in respect of the interim dividend declared. This was settled in full for cash on 25 February 2021.

The inter-company loan is payable to Neptune Energy Bondco plc, a 100% owned subsidiary of Neptune Energy Group Midco Limited.

22. Leases

Group as a lessee

The Group has lease contracts for land, buildings, plant, equipment and transportation assets used in its operations. Leases of land and buildings have lease terms between one and 23 years; PP&E leases are less than two years, while transportation assets have leases between two and three years. The Group's obligations under its leases are secured by the lessor's title to the leased assets.

The Group also has certain leases of machinery with lease terms of 12 months or less and leases of office equipment with low value. The Group applies the 'short-term lease' and 'lease of low-value assets' recognition exemptions for these leases.

Set out below are the carrying amounts of right-of-use assets recognised (included within property, plant and equipment) and the movements during the period:

Group – in millions of US$	Oil and gas properties	Other fixed assets	Total
At 1 January 2020	66.8	42.6	109.4
Additions	29.5	2.1	31.6
Depreciation expense	(31.7)	(8.2)	(39.9)
Currency translation adjustments	3.1	2.0	5.1
At 31 December 2020	67.7	38.5	106.2
Additions	**19.2**	**15.8**	**35.0**
Depreciation expense	**(45.4)**	**(7.3)**	**(52.7)**
Currency translation adjustments	**(1.9)**	**(2.3)**	**(4.2)**
At 31 December 2021	**39.6**	**44.7**	**84.3**

Set out below are the carrying amounts of lease liabilities (included under trade payables and other liabilities) and the movements:

Group – in millions of US$	31 December 2021	31 December 2020
At 1 January	**(188.1)**	(172.0)
Additions	**(52.9)**	(84.2)
Disposals	**0.7**	0.9
Interest[1]	**(6.0)**	(8.0)
Payments[2]	**113.4**	77.4
Other	**0.2**	1.3
Currency translation adjustments	**1.0**	(3.5)
At 31 December	**(131.7)**	(188.1)

1. Includes $0.3 million (2020: $0.9 million) of capitalised interest.
2. The payments include $6.0 million (2020: $8.0 million) relating to interest and $107.4 million (2020: $69.4 million) relating to principal repayments.

Group – in millions of US$	31 December 2021	31 December 2020
Within one year	**73.9**	98.5
Current trade payables and other liabilities (note 21)	**73.9**	98.5
Between two and five years	**37.5**	68.1
More than five years	**20.3**	21.5
Non-current trade payables and other liabilities (note 21)	**57.8**	89.6

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The following are the amounts recognised in profit or loss:

Group – in millions of US$	31 December 2021	31 December 2020
Depreciation expense of right-of-use assets	**(52.8)**	(39.9)
Interest income from Joint Arrangements for right-of-use assets	**1.5**	2.3
Interest expense right-of-use assets	**(6.0)**	(8.0)
Expense relating to short term leases	**(0.1)**	(0.1)
Expense relating to variable lease payments	**(1.3)**	–
Expense relating to leases of low-value assets	**(0.7)**	(0.6)
Total amount recognised in profit and loss	**(59.4)**	(46.3)

The Group has total cash outflows for leases of $113.4 million (2020: $77.4 million). The future cash outflows relating to leases that have not yet commenced are disclosed in note 27.1.

23. Provisions

Group – in millions of US$	Decommissioning	Restructuring	Total employee benefit obligations	Other	Total
At 1 January 2021	**1,683.8**	**74.1**	**223.0**	**4.9**	**1,985.8**
Charge for the year	**17.6**	**1.3**	**8.9**	**5.7**	**33.5**
Unwinding of discount	**34.1**	**–**	**1.3**	**–**	**35.4**
Additions	**114.8**	**–**	**–**	**4.0**	**118.8**
Change in discount rate	**75.3**	**–**	**(19.1)**	**–**	**56.2**
Reclassifications	**–**	**–**	**0.5**	**–**	**0.5**
Transfers to assets held for sale (note 19)	**(89.9)**	**–**	**–**	**–**	**(89.9)**
Utilisation/paid	**(38.5)**	**(48.5)**	**(10.7)**	**(0.7)**	**(98.4)**
Unused provisions released to income statement	**(13.3)**	**(1.8)**	**(4.1)**	**(0.7)**	**(19.9)**
Currency translation	**(102.2)**	**(2.8)**	**(15.3)**	**(0.2)**	**(120.5)**
At 31 December 2021	**1,681.7**	**22.3**	**184.5**	**13.0**	**1,901.5**

There were no provisions for the Company in both 2021 and 2020.

Group – in millions of US$	31 December 2021	31 December 2020
Current		
Restructuring	**20.1**	52.7
Post-employment benefit and other long-term benefits	**9.7**	11.3
Decommissioning	**86.4**	46.0
Other	**7.3**	4.9
Current total	**123.5**	114.9
Non-current		
Restructuring	**2.2**	21.4
Post-employment benefit and other long-term benefits	**174.8**	211.7
Decommissioning	**1,595.3**	1,637.8
Other	**5.7**	–
Non-current total	**1,778.0**	1,870.9
Total	**1,901.5**	1,985.8

The Group makes full provision for the future cost of decommissioning oil production facilities and pipelines on a discounted basis on the installation of those facilities. The decommissioning provision represents the present value of decommissioning costs relating to oil and gas properties, which are expected to be incurred up to the end of the operations. These provisions have been created based on the Group internal estimates.

The restructuring provision is in relation to the decision in 2019 to close the corporate office in France and also the announcement in June 2020 to reduce 400 positions across our business including proposals to close offices in Oslo in Norway and Lingen in Germany.

Assumptions, based on the current economic environment, have been made which management believe are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required which will reflect market conditions at the relevant time. The discount rate used for discounting decommissioning liabilities is based on the future timing of decommissioning, expected currency of decommissioning expenditure and was in the range 0.7% to 3.2% (2020: year-end range 1.1% to 3.5%). The oil and gas price assumptions used to determine the field life cessation of production are consistent with those applied for the impairment assessment.

Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

This provision is matched with an entry to property, plant and equipment. The depreciation charge on this asset is included within current operating income and the cost of unwinding of discount is booked in financial expenses.

24. Financial assets and liabilities

Financial risk management objectives

The Group's activities expose it to a variety of financial risks including market risk (commodity price risk, foreign currency risk, interest rate risk) credit risk and liquidity risk. The Group's overall risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance. The Group holds a portfolio of commodity, interest rate and foreign currency derivative contracts, with various counterparties. The use of derivative financial instruments is governed by the Group's policy approved by the Board of Directors and exposure limits are reviewed internally on a regular basis. The Group does not enter into or trade financial instruments, including derivatives, for speculative purposes.

Fair values of financial assets and liabilities

With the exception of hedging derivatives, the Group considers the carrying value of all of its financial assets and liabilities to be materially the same as their fair value. Derivatives and contingent consideration are measured at fair value through profit and loss, while equity instruments are designated as fair value through other comprehensive income. All other financial assets and liabilities are measured at amortised cost.

Fair values of derivative instruments

All fair values are recognised at fair value on the balance sheet with changes in valuation recognised immediately in the income statement, unless the derivatives have been designated as a cash flow hedge. Fair value is the amount for which the asset or liability could be exchanged in an arm's length transaction at the relevant date. Fair values, where available, are determined using quoted prices in active markets. To the extent that market prices are not available, fair values are estimated by reference to market-based transactions or using standard valuation techniques for the applicable instruments and commodities involved.

Set out below is an overview of financial assets, other than cash and short-term deposits, held by the Group as at 31 December 2021 including their maturity. For items held at amortised cost there is no significant difference between their fair value and amortised cost value.

	31 December 2021			
Group – in millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial assets at fair value				
Commodity derivatives at fair value through profit and loss	**6.0**	**5.0**	**–**	**11.0**
Commodity derivatives in qualifying hedging relationships[1]	**48.8**	**16.0**	**–**	**64.8**
Foreign forward exchange contracts at fair value through profit and loss	**5.9**	**–**	**–**	**5.9**
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	**–**	**–**	**15.4**	**15.4**
Financial assets at amortised cost				
Trade and other receivables	**1,384.8**	**–**	**–**	**1,384.8**
Other non-current assets[2]	**–**	**69.5**	**–**	**69.5**
Total	**1,445.5**	**90.5**	**15.4**	**1,551.4**

1. Of the $48.8 million due under one year, $34.3 million is due within six months.
2. Other non-current assets mainly represents amounts receivable from joint venture partners.

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Group – in millions of US$	31 December 2020 Less than one year	Between two and five years	More than five years	Total
Financial assets at fair value				
Commodity derivatives at fair value through profit and loss	2.4	0.6	–	3.0
Commodity derivatives in qualifying hedging relationships[1]	52.7	19.0	–	71.7
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	–	–	21.1	21.1
Financial assets at amortised cost				
Trade and other receivables	526.6	–	–	526.6
Other non-current assets[2]	–	99.5	–	99.5
Total	581.7	119.1	21.1	721.9

1. Of the $52.7 million due under one year, $21.0 million is due within six months.
2. Other non-current assets mainly represents amounts receivable from joint venture partners.

Company – in millions of US$	31 December 2021 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Inter-company loan receivable	**–**	**938.7**	**–**	**938.7**
Receivable from parent company	**455.3**	**–**	**–**	**455.3**
Receivable from subsidiaries	**16.5**	**–**	**–**	**16.5**
Total	**471.8**	**938.7**	**–**	**1,410.5**

Company – in millions of US$	31 December 2020 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Inter-company loan receivable	–	943.2	–	943.2
Receivable from subsidiaries	216.2	–	–	216.2
Total	216.2	943.2	–	1,159.4

There are no significant sources of hedge ineffectiveness other than for off-market hedging relationships for hedging instruments as well as for credit risk being included on the hedging instrument and not the hedged item in accordance with IFRS 9.

Set out below is an overview of financial liabilities, held by the Group as at 31 December 2021 including their maturity. The Senior Notes held by the Group have a fair value of $871.0 million, compared with the carrying amount of $838.7 million (2020: a fair value of $825.3 million, compared with the carrying amount of $835.3 million). This financial liability would be classed as Level 1. For all other items held at amortised cost there is no significant difference between their fair value and amortised cost value.

	31 December 2021			
Group – in millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial liabilities at fair value				
Commodity derivatives in qualifying hedging relationships[1]	**1,029.3**	**169.7**	**–**	**1,199.0**
Contingent consideration of the VNG Norge AS acquisition	**1.1**	**4.0**	**–**	**5.1**
Financial liabilities at amortised cost				
Short-term borrowings				
DNB uncommitted facility	**50.0**	**–**	**–**	**50.0**
Citibank uncommitted facility	**10.0**	**–**	**–**	**10.0**
Long-term borrowings				
Reserve Based Lending facility	**–**	**1,330.7**	**–**	**1,330.7**
Senior Notes	**–**	**838.7**	**–**	**838.7**
Subordinated Neptune Energy Group Limited loan	**–**	**100.0**	**–**	**100.0**
Trade and other payables	**329.4**	**–**	**–**	**329.4**
Wages and social security	**47.0**	**–**	**–**	**47.0**
Lease liabilities	**73.9**	**37.5**	**20.3**	**131.7**
Other liabilities	**385.6**	**33.4**	**–**	**419.0**
Total	**1,926.3**	**2,514.0**	**20.3**	**4,460.6**

1. Of the $1,029.3 million, $576.1 million is due within six months.

	31 December 2020			
Group – in millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial liabilities at fair value				
Commodity derivatives in qualifying hedging relationships[1]	54.0	11.5	–	65.5
Commodity derivatives at fair value through profit and loss	2.4	–	–	2.4
Interest rate derivatives in qualifying hedging relationships	3.7	–	–	3.7
Contingent consideration of the VNG Norge AS acquisition	2.6	–	–	2.6
Financial liabilities at amortised cost				
Short-term borrowings				
DNB uncommitted facility	50.0	–	–	50.0
Long-term borrowings				
Reserve Based Lending facility	–	1,028.6	–	1,028.6
Senior Notes	–	835.3	–	835.3
Subordinated Neptune Energy Group Limited loan	–	107.9	–	107.9
Trade and other payables	333.5	–	–	333.5
Wages and social security	50.9	–	–	50.9
Lease liabilities	98.5	68.1	21.5	188.1
Other liabilities	325.0	41.7	–	366.7
Total	920.6	2,093.1	21.5	3,035.2

1. Of the $54.0 million, $25.7 million is due within six months.

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Company – in millions of US$	31 December 2021 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at amortised cost				
Inter-company loan payable	**–**	**938.7**	**–**	**938.7**
Payable to parent company	**7.1**	**–**	**–**	**7.1**
Loan from subsidiary	**455.3**	**–**	**–**	**455.3**
Payable to subsidiary	**7.5**	**–**	**–**	**7.5**
Total	**469.9**	**938.7**	**–**	**1,408.6**

Company – in millions of US$	31 December 2020 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at amortised cost				
Inter-company loan payable	–	943.2	–	943.2
Payable to parent company	207.4	–	–	207.4
Payable to subsidiary	7.4	–	–	7.4
Total	214.8	943.2	–	1,158.0

24.1 Fair value measurements

Valuation

All financial instruments that are initially recognised and subsequently remeasured at fair value have been classified in accordance with the hierarchy described in IFRS 13 Fair Value Measurement.

Fair value measurement hierarchy

The fair value hierarchy, described below, reflects the significance of the inputs used to determine the valuation of financial assets and liabilities measured at fair value.

Level 1 fair value measurements are those derived directly from quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 fair value measurements are those including inputs other than quoted prices included within Level 1 that are observable for the asset or liability directly or indirectly. The fair value of the Group's interest rate and currency exchange rate derivatives and the majority of the Group's commodity derivatives are calculated from relevant market prices and yield curves at the balance sheet date and are therefore based solely on observable price information. These instruments are not directly quoted in active markets and are accordingly classified as Level 2 in the fair value hierarchy.

Level 3 fair value measurements are those derived from valuation techniques that include significant inputs for the asset or liability that are not based on observable market data. Where observable market valuations of commodity contracts are unavailable, the fair value on initial recognition is the transaction price and is subsequently determined using the Group's forward planning assumptions for the price of gas, other commodities and indices.

Equity investments are valued using the market approach based on a multiple of EBITDA consistent with the valuation obtained for transactions involving investments similar in nature.

All of the Group's derivatives are Level 2 and 3. There were no financial derivatives held by the Company in 2021 and 2020.

The following table provides the fair value measurement hierarchy of the Group's assets:

Group – in millions of US$	31 December 2021 Date of valuation	Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Assets measured at fair value				
Derivative financial assets				
Commodity derivatives in qualifying hedging relationships	**31-Dec-21**	**64.8**	**64.8**	**–**
Commodity derivatives at fair value through profit and loss	**31-Dec-21**	**11.0**	**11.0**	**–**
Foreign forward exchange contracts at fair value through profit and loss	**31-Dec-21**	**5.9**	**5.9**	**–**
Non-listed equity instruments				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	**31-Dec-21**	**15.4**	**–**	**15.4**
Total		**97.1**	**81.7**	**15.4**

Group – in millions of US$	31 December 2020 Date of valuation	Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Assets measured at fair value				
Derivative financial assets				
Commodity derivatives in qualifying hedging relationships	31-Dec-20	71.7	71.7	–
Commodity derivatives at fair value through profit and loss	31-Dec-20	3.0	3.0	–
Non-listed equity instruments				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	31-Dec-20	21.1	–	21.1
Total		95.8	74.7	21.1

The valuation of Neptune's interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster has been calculated based on an enterprise value/EBITDA multiple taking into account recent transactions involving suitable comparative infrastructure companies.

The following table provides the fair value measurement hierarchy of the Group's liabilities:

Group – in millions of US$	31 December 2021 Date of valuation	Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Liabilities measured at fair value				
Derivative financial liabilities				
Commodity derivatives in qualifying hedging relationships	**31-Dec-21**	**1,199.0**	**1,199.0**	**–**
Contingent consideration	**31-Dec-21**	**5.1**	**–**	**5.1**
Total		**1,204.1**	**1,199.0**	**5.1**

Group – in millions of US$	31 December 2020 Date of valuation	Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Liabilities measured at fair value				
Derivative financial liabilities				
Commodity derivatives in qualifying hedging relationships	31-Dec-20	65.5	65.5	–
Commodity derivatives at fair value through profit and loss	31-Dec-20	2.4	2.4	–
Interest rate derivatives in qualifying hedging relationships	31-Dec-20	3.7	3.7	–
Contingent consideration	31-Dec-20	2.6	–	2.6
Total		74.2	71.6	2.6

There were no transfers between fair value levels in the year for either assets or liabilities.

24.2 Level 3 fair value movements

The movements in the year associated with the non-listed equity investments classified as equity instruments designated at fair value through other comprehensive income in accordance with Level 3 are shown below:

In millions of US$	Group 31 December 2021	Group 31 December 2020	Company 31 December 2021	Company 31 December 2020
Fair value at 1 January	**21.1**	19.3	**–**	–
Fair value loss on equity instruments designated at FVOCI	**(4.1)**	–	**–**	–
Currency translation adjustments	**(1.6)**	1.8	**–**	–
Fair value at 31 December	**15.4**	21.1	**–**	–

A 5% change in the EBITDA multiple to the Level 3 instrument above as applied would result in a $0.8 million change in valuation (2020: $1.1 million).

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The movements in the year associated with the contingent consideration at fair value through profit and loss in accordance with Level 3 are shown below:

	Group		Company	
In millions of US$	31 December 2021	31 December 2020	31 December 2021	31 December 2020
Fair value at 1 January	**(2.6)**	(23.2)	**–**	–
Additions in the period	**(6.0)**	–	**–**	–
Utilisation/cash paid	**0.7**	2.6	**–**	–
Gains recognised in the income statement	**2.5**	20.3	**–**	–
Gains/(losses) recognised in other comprehensive income	**0.3**	(2.3)	**–**	–
Fair value at 31 December	**(5.1)**	(2.6)	**–**	–

The contingent consideration on 1 January 2021 related to an asset in Denmark that was part of the VNG acquisition. This has now been derecognised with a gain of $2.5 million recognised in the income statement as the assets to which the liability related was disposed of during the year.

During 2021, contingent consideration of $6.0 million has arisen on assets acquired in Germany from Wintershall Dea. This would be payable based upon satisfaction of certain criteria, of which $0.7 million has been settled as at the end of December. The possible outcome of the remaining contingent consideration ranges from $nil to $10.2 million. The contingent consideration is based on unobservable inputs and are Level 3 in the IFRS 13 hierarchy.

Further currently unprovided contingent consideration of between $nil and $5 million is payable based on the timing of any future submission of a plan for development and operation in relation to the Company's acquisition of an additional 5% of the PL882 (Dugong) licence in Norway.

The gain on the derecognition of contingent consideration payable in 2020 arose as certain project milestones, related to two assets in Denmark and Norway that were part of the VNG acquisition, will not be achieved.

24.3 Hedging reserve

The hedge reserve represents the portion of deferred gains and losses on hedging instruments deemed to be effective cash flow hedges. The movement in the reserve for the period is recognised in other comprehensive income. The following table summarises the hedge reserve by type of derivative, net of tax effects.

Group – in millions of US$	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Cash flow interest rate hedge reserve	Total hedge reserve
At 1 January 2021	**11.5**	**7.4**	**3.7**	**22.6**
Add: costs of hedging deferred and recognised in OCI[1]	**1,761.9**	**84.4**	**(3.7)**	**1,842.6**
Less: reclassified from OCI to profit or loss or included in finance costs[1]	**(666.1)**	**(14.5)**	**–**	**(680.6)**
Less: deferred tax[1]	**(459.5)**	**(20.7)**	**–**	**(480.2)**
Less: share of hedge adjustments within equity-accounted investments deferred and recognised in OCI	**4.2**	**–**	**–**	**4.2**
At 31 December 2021	**652.0**	**56.6**	**–**	**708.6**

1. Hedge adjustments net of tax are $681.8 million.

Group – in millions of US$	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Cash flow interest rate hedge reserve	Total hedge reserve
At 1 January 2020	(123.7)	(0.7)	5.6	(118.8)
Add: costs of hedging deferred and recognised in OCI[1]	(149.4)	57.3	(1.9)	(94.0)
Less: reclassified from OCI to profit or loss or included in finance costs[1]	283.1	(18.3)	–	264.8
Less: deferred tax[1]	(1.4)	(31.1)	–	(32.5)
Less: share of hedge adjustments within equity-accounted investments deferred and recognised in OCI	2.9	0.2	–	3.1
At 31 December 2020	11.5	7.4	3.7	22.6

1. Hedge adjustments net of tax are $138.3 million.

The table above excludes hedge ineffectiveness; this is taken directly into the income statement and in 2021, was $nil (2020: $0.4 million). The value of any credit valuation adjustment (CVA) and debit valuation adjustment (DVA) for 2021 was $2.3 million (2020: $nil).

There were no financial derivatives held by the Company in 2021 and 2020.

24.4 Fair value reserve of financial assets at FVOCI

Group – in millions of US$	31 December 2021	31 December 2020
At 1 January	**–**	–
Fair value loss on equity instruments designated at FVOCI	**4.1**	–
Currency translation adjustments	**1.6**	–
Deferred tax	**0.2**	–
At 31 December	**5.9**	–

There were no fair value reserve of financial assets at FVOCI in the Company during 2021 and 2020.

25. Financial risk factors

The Group did not enter into any enforceable master netting arrangements.

The Group's senior management oversees the management of financial risk. The Group's senior management ensures that financial risk-taking activities are governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with Group policies and risk objectives. All derivative activities for risk management purposes are carried out by specialist teams, both internal and external, that have the appropriate skills, experience and supervision.

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: commodity price risk, interest rate risk and foreign currency risk. Financial instruments is mainly affected by market risk including loans and borrowings, deposits and derivative financial instruments.

The sensitivity analyses have been prepared on the basis that the amount of financial instruments are all constant. The sensitivity analyses are intended to illustrate the sensitivity to changes in market variables on the composition of the Group's financial instruments at the balance sheet date and show the impact on profit or loss and shareholders' equity, where applicable.

The following assumptions have been made in calculating the sensitivity analyses:

- the sensitivity of the relevant profit before tax item and/or equity is the effect of the assumed changes in respective market risks for the full year based on the financial assets and financial liabilities held at the balance sheet date;
- the sensitivities indicate the effect of a reasonable increase in each market variable. Unless otherwise stated, the effect of a corresponding decrease in these variables is considered approximately equal and opposite;
- fair value changes from derivative instruments designated as cash flow hedges are considered fully effective and recorded in shareholders' equity, net of tax; and
- fair value changes from derivatives and other financial instruments not designated as cash flow hedges are presented as a sensitivity to profit before tax only and not included in shareholders' equity.

25.1 Liquidity risk

Liquidity risk is the risk that the Group might not have sources of funding to meet its business needs. The Group manages its liquidity risk using both short- and long-term cash flow projections, supplemented by debt financing and active portfolio management. The Board of Directors, who have ultimate responsibility for liquidity risk management, believe that the Group has sufficient cash, undrawn committed funds under its borrowing base facility and expected sources of liquidity to meet the business's forecast requirements for the short, medium and long term.

The Group assessed the concentration of risk with respect to refinancing its debt and concluded it to be low. The Group has access to a sufficient variety of sources of funding and debt maturing within 12 months can be rolled over with existing lenders.

25.2 Credit rate risk

Credit risk is managed on a Group basis. Currently, credit risk only arises from cash and cash equivalents, sales receivables, receivables from joint venture partners and hedging derivatives. For banks and financial institutions, only independently rated parties with a minimum rating of 'BBB' are accepted. The Group does not have any significant credit risk exposure to any single counterparty or any group of counterparties. Joint Venture partners are predominantly international oil and gas market participants. Counterparty evaluations are conducted utilising information provided by international credit rating agencies, credit insurance companies and financial assessments. Where considered appropriate, security in the form of trade finance instruments from financial institutions with an appropriate credit rating, such as letters of credit, bank guarantees and credit insurance, are obtained to mitigate the risks.

The Group's maximum exposure to credit risk for the components of the statement of financial position at 31 December 2021 and 2020 is the carrying amounts as illustrated in note 24.

25.3 Climate change risk

Climate change risk is the risk that the Group fails to manage the impact of climate change due to evolving regulatory policies. Subsequent related commodity price volatility or access to markets could affect portfolio commerciality, our licence to operate and impact Neptune's access to capital funding. Please see pages 20-27 for more information on how the Group is managing climate change risk and what it is doing in ESG areas.

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25.4 Market risk

Financial instruments used by the Group that are affected by market risks primarily comprise cash and cash equivalents, borrowings and derivative contracts. Due to the nature of its operations, the Group carries a natural exposure to gas and oil prices, generating commodity-market-related volatility on its earnings.

The Group identifies, governs and manages this market price exposure through a dedicated market risks policy.

One of the elements of the Group market risks policy is to implement a hedging programme on forecasted sales of produced gas and oil products. The hedging programme aims at smoothening the impact of gas and oil price volatility on earnings by reducing exposure to market prices. It thereby improves the earnings predictability of the Group.

The Group's hedging programme is focused on reducing volatility of the net earnings, taking into account the underlying pricing structure of sales contracts, production uncertainties and fiscal impacts of hedging.

This hedging programme applies to price exposures of the major affiliates of the Group: Neptune Energy Norge AS, Neptune Energy Nederland B.V., Neptune Energy E&P Holdings Netherlands B.V., Neptune Energy Deutschland GmbH, Neptune E&P UK Ltd, and Neptune Energy Touat B.V., an equity-accounted investment.

The Group held the following commodity forward contracts for its wholly owned subsidiaries as at the respective balance sheet date:

	31 December 2021					
Group	Volumes	Swap	Bought put	Sold call	Bought call	Period of hedge
OIL HEDGES VS BRENT	mmbbl	$/bbl	$/bbl	$/bbl	$/bbl	
Put options	**7.0**	–	**47.0**	–	–	**up to 2 years**
Collars	**2.8**	–	**47.0**	**87.4**	–	**up to 2 years**
Three-ways collars (call-spread)	**1.7**	–	**47.0**	**87.4**	**95.4**	**up to 1 year**
Total/(weighted average)	**11.5**	–	**47.0**	**87.4**	**95.4**	
GAS HEDGES VS NBP	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Call options	**2,100**	–	–	–	**15.5**	**up to 0.5 year**
Collars	**12,060**	–	**6.2**	**15.0**	–	**up to 2 years**
Swaps	**27,000**	**5.7**	–	–	–	**up to 2 years**
Total/(weighted average)	**41,160**	**5.7**	**6.2**	**15.0**	**15.5**	
GAS HEDGES VS TTF	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Collars	**29,164**	–	**6.2**	**11.7**	–	**up to 2 years**
Swaps	**24,455**	**5.4**	–	–	–	**up to 2 years**
Total/(weighted average)	**53,619**	**5.4**	**6.2**	**11.7**	–	
EMISSION HEDGES VS EUA	000's tonnes	€/tonnes	€/tonnes	€/tonnes	€/tonnes	
Commodity forward	**200**	**33.4**	–	–	–	**up to 2 years**

Group	31 December 2020 Volumes	Swap	Bought put	Sold call	Bought call	Period of hedge
OIL HEDGES VS BRENT	mmbbl	$/bbl	$/bbl	$/bbl	$/bbl	
Collars	5.0	–	41.3	50.4	–	up to 1 year
Swaps	0.5	49.7	–	–	–	up to 0.5 year
Total/(weighted average)	5.5	49.7	41.3	50.4	–	
GAS HEDGES VS NBP	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Collars	27,450	–	6.4	8.6	–	up to 1.5 years
Swaps	39,960	5.7	–	–	–	up to 1.5 years
Total/(weighted average)	67,410	5.7	6.4	8.6	–	
GAS HEDGES VS TTF	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Collars	21,589	–	6.4	7.8	–	up to 1.5 years
Swaps	20,268	5.9	–	–	–	up to 2 years
Total/(weighted average)	42,271	5.9	6.4	7.8	–	
EMISSION HEDGES VS EUA	000's tonnes	€/tonnes	€/tonnes	€/tonnes	€/tonnes	
Commodity forward	400	27.45	–	–	–	up to 2 years

There were no financial derivatives held by the Company in 2021 and 2020.

Aggregate post-tax hedge ratio

The Group establishes its hedge ratio by considering hedging items as a proportion of post-tax production. Post-tax hedge ratios adjust for different tax rates on physical sales and hedge gains and losses, which means that effective post-tax hedges can be achieved through hedging contracts for volumes, which may be significantly less than anticipated sales.

The Group's hedge ratio for commodity derivatives is calculated after applying a 10% headroom against entitlement forecast production and is designed to protect post-tax revenues.

At 31 December 2021 the aggregate post-tax hedge ratio for the Group's wholly owned subsidiaries was:

	2022	2023	2024
Oil	37%	23%	–
Gas	62%	30%	–
Total weighted average	49%	26%	–

At 31 December 2020 the aggregate post-tax hedge ratio for the Group's wholly owned subsidiaries was:

	2021	2022	2023
Oil	40%	–	–
Gas	70%	43%	–
Total weighted average	53%	18%	–

Oil price hedges include hedges of realisations for gas production sold as LNG and priced in relation to oil prices.

Sensitivities of the commodity-related financial derivatives portfolio used as part of the portfolio management activities at 31 December, are detailed in the table below and are reasonably foreseeable market movements to the Group's financial instruments. They are not representative of future changes in consolidated earnings and equity, in so far as they do not include the sensitivities relating to the purchase and sale contracts for the underlying commodities, only the effect on the underlying derivative itself.

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Group – in millions of US$	Price movement	31 December 2021 Pre-tax loss/(gain) on income	31 December 2021 Pre-tax loss/(gain) on equity	31 December 2020 Pre-tax loss/(gain) on income	31 December 2020 Pre-tax loss/(gain) on equity
SENSITIVITY ANALYSIS Effect on profit before tax and on pre-tax equity					
Gas price	+10% pence/therm increase	**–**	**163.2**	–	57.9
Gas price	–10% pence/therm decrease	**–**	**(163.2)**	–	(58.0)
Brent oil price	+10%/bbl increase	**–**	**12.9**	1.9	20.1
Brent oil price	–10%/bbl decrease	**–**	**(12.8)**	(1.5)	(15.2)
Carbon dioxide European Union Allowance	+10%/eua increase	**(1.9)**	**–**	(1.6)	–
Carbon dioxide European Union Allowance	–10%/eua decrease	**1.9**	**–**	1.6	–

25.5 Foreign currency risk

The Group conducts and manages its business predominantly in US dollars, the operating currency of the oil and gas industry. However, as the Group operates internationally it is therefore exposed to foreign exchange risk arising from various currency exposures, primarily with respect to the Euro, Sterling and Norwegian Krone (NOK). Foreign exchange risk arises from future commercial transactions, recognised assets and liabilities and net investments in foreign operations.

The Group is exposed to currency risk, defined as the impact on its statement of financial position and income statement of fluctuations in exchange rates affecting its operating and financing activities. Currency risk comprises: (i) transaction risk arising in the ordinary course of business, (ii) specific transaction risks related to investments, mergers-acquisitions projects, and (iii) the risk arising on the consolidation in USD of subsidiary financial statements with a functional currency other than the USD.

The Group held $210.0 million of USD NOK forwards as at 31 December 2021 (2020: $nil), with the key objective to hedge tax payments in NOK for 2022.

The table below illustrates the indicative pre-tax effects on the income statement and other comprehensive income of applying reasonably foreseeable market movements to the Group's currency related financial instruments at the balance sheet date.

Group – in millions of US$	31 December 2021 Pre-tax loss/(gain) on income	31 December 2021 Pre-tax loss/(gain) on equity	31 December 2020 Pre-tax loss/(gain) on income	31 December 2020 Pre-tax loss/(gain) on equity
SENSITIVITY ANALYSIS Effect on profit before tax and on pre-tax equity:				
+10% NOK	**19.6**	**–**	–	–
–10% NOK	**(24.0)**	**–**	–	–

25.6 Interest rate risk

The Group is exposed to the impact of interest rate fluctuations on its consolidated statements. The Group monitors its exposure to fluctuations in interest rates and may use interest rate derivatives to manage the fixed and floating composition of its borrowings.

The Group held no interest rate derivative contracts as at 31 December 2021 (2020: $400.0 million):

Group	31 December 2021 Currency	31 December 2021 Terms	31 December 2021 Period of hedge	31 December 2020 Currency	31 December 2020 Terms	31 December 2020 Period of hedge
Interest rate swaps	–	–	–	$400.0 million	Average 2.59%	Within 1 year

The Group entered into interest rate derivatives to manage its exposure to fluctuations in the US$ interest rate. The impact on reported income and on equity of a 100 basis-point movement in the US$ year-end interest rate would be as follows:

Group – in millions of US$	31 December 2021 Pre-tax loss/(gain) on income	31 December 2021 Pre-tax loss/(gain) on equity	31 December 2020 Pre-tax loss/(gain) on income	31 December 2020 Pre-tax loss/(gain) on equity
SENSITIVITY ANALYSIS Effect on profit before tax and on pre-tax equity:				
+100 basis points	**–**	**–**	–	(1.5)
-100 basis points	**–**	**–**	–	0.2

26. Called up share capital

Group and Company	Number	US$ million
Allotted, called up and fully paid $1 shares		
At 31 December 2020 and 31 December 2021	**1,977,175,201**	**1,977.2**

27. Commitment and contingencies

27.1 Lease commitments

The Group has lease contracts that have not yet commenced as at 31 December 2021. The future lease payments for these non-cancellable lease contracts are $2.8 million (2020: $3.5 million) within one year, $nil (2020: $5.1 million) within two to five years and $nil (2020: $5.3 million) in more than five years.

The Group has several lease contracts that include extension and termination options. These options are negotiated by management to provide flexibility in managing the leased-asset portfolio and to align with the Group's business needs.

The Group has financial commitments in respect of capacity bookings as at 31 December 2021. The future payments for these contracts are $30.3 million (2020: $23.4 million) within one year, $39.8 million (2020: $56.3 million) within two to five years and $0.8 million (2020: $8.2 million) in more than five years.

27.2 Capital commitments

	Group		Company	
In millions of US$	31 December 2021	31 December 2020	31 December 2021	31 December 2020
Amounts due:				
Within one year	**307.7**	428.4	**–**	–
After one year but within two years	**20.0**	52.3	**–**	–
After two years but not more than five years	**51.7**	14.3	**–**	–
More than five years	**–**	5.3	**–**	–
Total	**379.4**	500.3	**–**	–

1. Values are inclusive of IFRS 16 lease contracts that are yet to commence as disclosed in note 27.1.
2. Includes the Group's share of $2.3million (2020: $23.3 million) of capital commitments related to Neptune Energy Touat B.V. (see note 15).

As at 31 December 2021, the Group had commitments for future capital expenditure amounting to $379.6 million (2020: $500.3 million). Where the commitment relates to a Joint Arrangement, the amount represents the Group's net share of the commitment. Where the Group is not the operator of the Joint Arrangement, then the amounts are based on the Group's net share of committed future work programmes.

27.3 Contingencies

As at 31 December 2021, the Group has no contingent liabilities (2020: $nil). As at 31 December 2021, a contingent asset existed in Norway in relation to loss of production and future recovery through business interruption insurance (2020: Norway and Algeria, being our equity-accounted investment, both in relation to loss of production and future recovery through business interruption insurance). At 31 December 2021 (and also previously in 2020), due to several variable factors (including principally the ultimate length of the outages), it is not possible to provide an estimate of the amount of the associated contingent assets.

The Company had no contingencies in either 2021 or 2020.

27.4 Legal proceedings

During the normal course of its business, the Group may be involved in disputes, including tax disputes. Where applicable the Group has made accruals for probable liabilities related to litigation and claims based on management's best judgement and in line with IAS 37 and IAS 12.

In 2021 and 2020 the Group has not identified any material contingent liabilities as all are deemed remote in nature.

There are no material pending legal proceedings for the Company as at 31 December 2021 (2020: none).

28. Related party transactions

The note describes the material transactions between the Group and its related parties.

The Group's main subsidiaries are listed in note 30.

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Related party undertaking	Principal activities	Country of incorporation	% Equity interest
Neptune Energy Group Holdings Limited	Management and technical services	United Kingdom	100

The ultimate holding parent is Neptune Energy Group Limited, which is based in London, United Kingdom.

During 2021 and 2020, the Group undertook the following transactions with related parties:

In millions of US$ Related party undertaking	Nature of transactions	2021 Purchases	2021 Accounts payable	2020 Purchases	2020 Accounts payable
TMF Norway Energy AS (CVC investor)	Services	**2.9**	**0.3**	2.4	0.2
Essential Project Solutions	Services	**0.3**	**–**	0.3	–
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	**6.9**	**–**	2.0	–
PA Consulting (Carlyle investor)(1)	Services	**0.1**	**–**	–	–
Black Platinum Energy(2)	Oil and Gas	**–**	**–**	7.3	–

1. PA Consulting ceased to be a related party from March 2021.
2. Black Platinum Energy ceased to be a related party from April 2021.

In millions of US$ Related party undertaking	Nature of transactions	2021 Sales	2021 Accounts receivable	2020 Sales	2020 Accounts receivable
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	**8.4**	**0.6**	7.7	0.5

Terms and conditions of transactions with related parties

The finance income and expenses from related parties are made on terms equivalent to those that prevail in arm's length transactions. Outstanding balances at the year-end are unsecured. There have been no guarantees provided or received from any related party receivables or payables. For the years ended 31 December 2021 and 31 December 2020, the Group has not recorded any impairment of receivables relating to the amounts owed by related parties. This assessment is undertaken throughout the financial year through examining the financial position of the related party and the market in which the related party operates.

Other transactions with related parties

At 31 December 2021, there was a loan receivable balance of $455.3 million due from the parent company Neptune Energy Group Limited as described in note 17.

At 31 December 2020, there was a promissory note for $200.0 million payable to the parent company Neptune Energy Group Limited in respect of an interim dividend declared on 11 December 2019. This was settled in full for cash on 25 February 2021 (see note 10 and note 21).

Compensation of key management personnel of the Group

Key management includes the Directors of the Company and its subsidiaries. The compensation paid or payable to key management for employee services is shown below:

In millions of US$	2021	2020
Short-term employee benefits	**6.7**	5.7
Long-term employee benefits – post-employment benefits	**0.3**	0.1
Total compensation to key management personnel	**7.0**	5.8

There are no other related party transactions.

Company

There are no related party transactions other than inter-company interest, loans and the promissory note as described in note 10 and note 21.

Terms and conditions of transactions with related parties

The finance income and costs from related parties are made on terms equivalent to those that prevail in arm's length transactions. Outstanding balances at the year end are unsecured. There have been no guarantees provided or received from any related party receivables or payables. For the years ended 31 December 2021 and 31 December 2020, the Company has not recorded any impairment of receivables relating to the amounts owed by related parties. This assessment is undertaken throughout the financial year through examining the financial position of the related party and the market in which the related party operates.

Compensation of key management personnel of the Company

There is no compensation for key management or Directors included in Neptune Energy Group Midco Limited. There were no other related party transactions.

29. Post employment benefit obligations and other long-term employee benefits

29.1a Post employee benefit obligations – description of the main pension plans

Pension commitments are measured on the basis of actuarial assumptions. These include assumptions in respect of mortality rates and future salary increases, as well as appropriate discount rates. The Group considers that the assumptions used to measure its obligations are appropriate and documented. However, any changes in these assumptions may have a material impact on the resulting calculations.

The Group provides pension benefits to its employees that are in line with common market practice in the countries where Neptune operates. These consist of both defined contribution and defined benefit arrangements. The latter are either career average or final salary based on employee pensionable earnings and length of service. The plan in the UK is defined contribution.

The Group also provides other post-employment benefits and these are mainly end-of-service gratuities and energy price subsidies, commonly provided by the industry in France.

Germany

Neptune Energy Deutschland has seven defined benefit plans and two long term benefit plans, corresponding to different groups of employees successively incorporated in the Company. The defined benefit plans are financed by book reserves and only one plan is open to new entrants. In 2020, the Group conducted a restructuring exercise in Germany resulting in a large number of employees no longer being covered by the plans. This gave rise to an income statement gain in 2020 of $1.0 million. Part of this exercise was finalised in 2021 and a number of members are no longer covered under this plan (the Jubilee plan). This has resulted in a curtailment gain of $1.0 million for 2021 which has been recognised through the income statement. As the Jubilee plan is a long term provision, this event and all actuarial gains and losses are recognised in the income statement.

France

Since 1 January 2005, the CNIEG (Caisse Nationale des Industries Électriques et Gazières) has operated the pension, disability, death, occupational accident and occupational illness benefit plans for 'Energy' employees and retirees in electricity and gas industry companies. The CNIEG is a social security legal entity under private law placed under the joint responsibility of the ministries in charge of social security, budget and energy. Energy employees and retirees have been fully affiliated to the CNIEG since 1 January 2005. The Group Company covered by this plan is Neptune Energy International S.A. Pension benefit obligations and other 'mutualised' obligations are assessed by the CNIEG.

In 2019, a decision was made to close the corporate office in France. As a result of this, except for the ANE (Avantage en Nature Energie) plan, the majority of defined benefit plan liabilities were removed for employees who had been made redundant reflecting the fact that commitments for Neptune only cover employees while on the Industries Électriques et Gazières (IEG) payroll. During 2021, it has been concluded that Neptune no longer has any liabilities in the Indemnites, Invalidite, Rentes, Retraites, Medailles, Capital Deces or Aide aux Frais d'education plans. The remaining liabilities for these plans have been removed from the balance sheet, resulting in a settlement gain of $3.0 million. The ANE is the only plan now remaining.

Two of the defined benefit plans were funded. In 2021, the Group was able to recover the surplus for the IFC/IMR (retirement indemnity) arrangement, valued at $1.4m. For the Retraites plan, Neptune has no further obligations.

Norway

Neptune Energy Norge is required to have a funded occupational pension scheme in accordance with Norwegian law. This plan is administered by and holds insurance assets with DNB. There are five other unfunded plans which are also administered by DNB. Effective from 1 July 2021, Neptune Energy Norge switched its pensions provider from Storebrand to DNB.

Indonesia

This year is the first year that the Indonesian Labour Law plan has been included in the pension disclosures. The actuary has calculated the liabilities at the year end to be $0.5m.

The Netherlands

At the end of 2019, the Group closed its defined benefit pension plan, which covered the majority of employees of Neptune Energy Nederland B.V. and its Dutch subsidiaries and which was administered by ASR Netherland N.V., and replaced it with a defined contribution plan. The liabilities built up in the plan, as estimated at 31 December 2021, are $224m and are fully covered by an insurance policy. It has been determined that negligible risk remains to the Group for this plan and therefore the liabilities have been treated as fully settled since 2020 as they were fully covered by the insurance policy asset. This event had no income statement or net balance sheet impact for 2021.

Other

The Group also operates a number of defined contribution plans which receive fixed contributions from Group companies. The Group's legal or constructive obligation for these plans is limited to the contributions paid. Further details of the amounts paid into these arrangements can be found in note 7.

29.1b Other long-term employee benefits – description of the long-term incentive plan

A number of employees participate in a long-term incentive plan, under which they can receive cash payments spread over a period of three years dependant on a number of performance criteria having being met over a three year assessment period. There are employees in this plan from several different territories. Awards are made on an annual basis at the discretion of the Board.

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29.2 Pension governance

The Group's externally funded plans are established under trusts, or similar entities such as insurance contracts. The operation of these entities is governed by local regulations and practice in each country as is the relationship between the local country management and the Trustees, or their equivalent, and the composition of these bodies. Where Trustees or their equivalents are in place they generally act on behalf of the plan's stakeholders. Periodic reviews are carried out on the solvency of the plans in accordance with local legislation and play a role in the long-term investment and funding strategy.

Plans are externally funded except within those countries where it is common practice to use book reserves, for example, in Germany. Very few of the Group's plans are now funded.

29.3 Defined benefits plans

29.3.1 Change in benefit obligations and plan assets

The table below shows the amount of the Group's projected benefit obligations and plan assets, changes in these items during the periods presented, and their reconciliation with the amounts reported in the statement of financial position:

Group – in millions of US$	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligation[3]	Total employment benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2021	(227.4)	(5.4)	(8.8)	(241.6)
Transfers	(0.5)	–	–	(0.5)
Service cost	(5.1)	–	(3.6)	(8.7)
Past service cost	–	–	–	–
Settlements/curtailments[4]	1.8	2.5	1.3	5.6
Interest cost on benefit obligations	(1.5)	–	–	(1.5)
Financial actuarial gains and losses	12.4	0.2	0.1	12.7
Actuarial gains and losses due to demographic assumptions	4.4	–	–	4.4
Actuarial gains and losses due to experience	4.4	1.9	(0.3)	6.0
Benefits paid	8.3	–	2.0	10.3
Other including translation adjustments	15.4	0.2	0.3	15.9
Projected benefit obligation at 31 December 2021 (A)	**(187.8)**	**(0.6)**	**(9.0)**	**(197.4)**

Group – in millions of US$	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligation[3]	Total employment benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2021	18.6	–	–	18.6
Transfers	–	–	–	–
Interest income on plan assets	0.3	–	–	0.3
Settlement/curtailments[4]	(1.5)	–	–	(1.5)
Financial actuarial gain and losses	(4.2)	–	–	(4.2)
Contributions received	8.7	–	2.0	10.7
Benefits paid	(8.3)	–	(2.0)	(10.3)
Other including translation adjustments	(0.7)	–	–	(0.7)
Fair value of plan assets at 31 December 2021 (B)	**12.9**	**–**	**–**	**12.9**

Group - In millions of US$				
C – Funded status (A+B)				
Net benefit obligation	**(174.9)**	**(0.6)**	**(9.0)**	**(184.5)**

1. Pensions and retirement bonuses.
2. Gratuities and other post-employment benefits.
3. Length of service awards and other long-term benefits.
4. Included in settlement/curtailments in 2021 is the derecognition of liabilities of $4.1m. Refer to note 29.4 for further details.

At 31 December 2021, the pre-paid benefit cost was $nil (2020: $nil).

Group – in millions of US$	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligation[3]	Total employment benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2020	(430.8)	(7.4)	(7.6)	(445.8)
Transfers	(6.6)	–	–	(6.6)
Service cost	(5.9)	–	(2.7)	(8.6)
Past service cost	–	–	(1.0)	(1.0)
Settlements/curtailments[4]	231.5	–	–	231.5
Interest cost on benefit obligations	(2.6)	(0.1)	–	(2.7)
Financial actuarial gains and losses	(8.6)	(0.3)	(0.1)	(9.0)
Actuarial gains and losses due to experience	3.3	2.5	–	5.8
Benefits paid	9.5	0.4	3.1	13.0
Other including translation adjustments	(17.2)	(0.5)	(0.5)	(18.2)
Projected benefit obligation at 31 December 2020 (A)	**(227.4)**	**(5.4)**	**(8.8)**	**(241.6)**

Group – in millions of US$	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligation[3]	Total employment benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2020	250.8	–	–	250.8
Transfers	–	–	–	–
Interest income on plan assets	0.2	–	–	0.2
Settlement/curtailments[4]	(230.5)	–	–	(230.5)
Financial actuarial gain and losses	(3.1)	–	–	(3.1)
Contributions received	9.8	0.4	3.1	13.3
Benefits paid	(9.5)	(0.4)	(3.1)	(13.0)
Other including translation adjustments	0.9	–	–	0.9
Fair value of plan assets at 31 December 2020 (B)	**18.6**	**–**	**–**	**18.6**

Group – in millions of US$				
C – Funded status (A+B)				
Net benefit obligation	**(208.8)**	**(5.4)**	**(8.8)**	**(223.0)**

1. Pensions and retirement bonuses.
2. Gratuities and other post-employment benefits.
3. Length of service awards and other long-term benefits.
4. Included in settlement/curtailments in 2020 is the derecognition of matching scheme assets and liabilities of $230.5 million following the closure in 2019 of the Dutch defined benefit pension scheme.

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29.4 Components of net pension cost

Group – in millions of US$	31 December 2021	31 December 2020
Current service cost	**8.7**	8.6
Past service cost	**–**	1.0
Net interest expense	**1.2**	2.5
Actuarial gains and losses on long-term benefit obligations	**–**	0.4
Non-recurring items[1]	**(4.1)**	(1.0)
Total	**5.8**	11.5

1. Non-recurring items includes settlement and curtailment gains of $4.1 million, $3.0 million arising in France, $1.0 million arising in Germany and $0.1 million arising in Norway (2020: $1.0 million all arising in Germany).

29.5 Reconciliation of balance sheet deficit over the year

Group – in millions of US$	31 December 2021	31 December 2020
Deficit at 1 January	**(223.0)**	(195.0)
Expense (charge)/credit	**(5.8)**	(11.5)
Employer contributions	**10.7**	13.3
Transfers	**(0.5)**	(6.6)
Actuarial gain/(loss) recognised in OCI	**19.1**	(6.7)
Currency translation gain/(loss)	**15.0**	(16.5)
Deficit at 31 December	**(184.5)**	(223.0)

29.6 Funding

The funding of these obligations at 31 December 2021 can be analysed as follows:

Group – in millions of US$	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans[1]	**(14.5)**	**12.9**	**(1.6)**
Unfunded plans[2]	**(182.9)**	**–**	**(182.9)**
At 31 December 2021	**(197.4)**	**12.9**	**(184.5)**

Group – in millions of US$	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans[1]	(17.9)	17.3	(0.6)
Unfunded plans[2]	(223.5)	–	(223.5)
Plans in surplus[3]	(0.2)	1.3	1.1
At 31 December 2020	(241.6)	18.6	(223.0)

1. An underfunded plan relates to those schemes where resource is set aside in advance to provide the benefit but where the current amount set aside is less than the current value of the liability.
2. An unfunded plan relates to those schemes where no resources are set aside in advance to provide the benefit.
3. An overfunded plan or plan in surplus relates to those schemes where resource is set aside in advance to provide the benefit but where the current amount set aside is in excess of the current value of the liability.

The allocation of plan assets by principal asset category can be analysed as follows:

% of total	31 December 2021	31 December 2020
Cash	**–**	1
Bonds	**–**	9
Equity investments	**–**	4
Convertible bonds	**–**	1
Insurance contracts	**100**	85
Total	**100**	100

The majority of the scheme assets are held in an insurance contract in Norway.

29.7 Actuarial assumptions

With the objective of presenting the assets and liabilities of the pension and other post-employment benefit plans at their fair value on the balance sheet, assumptions under IAS 19 are set by reference to market conditions at the valuation date. The actuarial assumptions used to calculate the benefit liabilities vary according to the country in which the plan is situated.

The discount rate applied is determined based on the yield, at the date of the calculation, on top-rated corporate bonds with maturities mirroring the term of the plan.

2021 assumptions:

Eurozone

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	0% to 1.05%	0% to 1.05%	0% to 0.45%
Inflation rate	1.80%	1.80%	1.80%

Norway

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	1.90%	–	–
Inflation rate	1.75%	–	–

Indonesia

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	7.30%	–	–
Inflation rate	3.00%	–	–

2020 assumptions:

Eurozone

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	0% to 0.50%	0% to 0.70%	0%
Inflation rate	1.80%	1.80%	1.80%

Norway

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	1.70%	–	–
Inflation rate	1.50%	–	–

1. Pensions and retirement bonuses.
2. Gratuities and other post-employment benefits.
3. Length of service awards and other long-term benefits.

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Discount and inflation rates

Eurozone:

The discount rate applied is determined based on the yields on AA corporate bonds with maturities matching the durations of the plans at 31 December 2021. The inflation assumption is based on the long-term target of the European Central Bank for inflation. Plans have been grouped by duration into four categories: very short (on average three years' duration), short (on average eight years' duration), medium (on average 14 years' duration) and long (on average 20 years' duration).

Norway:

The discount rate and inflation assumptions in Norway have been set in line with the Norwegian Accounting Standards Board's guidance as at 31 December 2021.

Indonesia:

The discount rate has been set by the local actuary using a cash flow-weighted approach. As there is no deep market for high quality corporate bonds in Indonesia, government bonds have been used instead. The benefits in the plan are not linked directly to inflation but depend on salary growth. In setting the salary growth assumption an estimate for future inflation has been determined by taking an average of observed inflation over the last seven to eight years.

Pension risk analysis

The main risks the Group faces are:

The majority of defined benefit liabilities are unfunded arrangements, which increases the chance that the benefits cannot be paid as they fall due.

A decrease in bond yields has the effect of increasing plan liabilities. For funded plans any movement in liabilities may not be matched by a movement in assets.

The majority of the plans' obligations are to provide benefits for the life of each retired member and his/her spouse, so increases in life expectancy result in an increase in the plans' liabilities.

Sensitivity to key assumptions

The table below illustrates how the Group's defined benefit liabilities would change (excluding the impact of inflation rate and interest rate hedging), as at 31 December 2021, in the event of the following changes in the key assumptions.

Sensitivities to key assumptions – in millions of US$	31 December 2021
Increase of 0.5% rate in discount assumption	**(12.3)**
Decrease of 0.5% rate in discount assumption	**13.6**
Increase of 0.5% rate in inflation assumption	**10.2**
Decrease of 0.5% rate in inflation assumption	**(10.2)**
Increase in 1 year of life expectancy	**11.5**
Decrease in 1 year of life expectancy	**(11.4)**

Future benefit payments

The aggregate duration of the Group's defined benefit obligations is 16 years at 31 December 2021. The expected future benefit outgo is as follows:

Future benefit payments – in millions of US$	31 December 2021
Next year: paid from scheme assets	**0.2**
Next year: paid directly by employer	**9.7**
Expected in year 2023	**10.3**
Expected in year 2024	**10.2**
Expected in year 2025	**8.7**
Expected in year 2026	**8.2**
Expected in year 2027 to 2031 (total)	**41.7**

The amount expected to be paid by the Group in 2021 is $9.7 million. These payments are to meet benefits expected from unfunded plans.

30. Principal subsidiary undertakings, joint ventures, associates

At 31 December 2021, the principal subsidiary undertakings, joint ventures and associates of the Company were:

Company name	Country of incorporation	Registered office	Holding	Proportion of voting rights and shares held	Main activity
Neptune Energy Australia Pty Ltd	Australia	A	100%	100%	Oil and gas
Neptune Energy Bonaparte Pty Ltd	Australia	A	100%	100%	Oil and gas
Neptune Energy Brasil Participacoes Ltda	Brazil	B	100%	100%	Oil and gas
Neptune Energy France SAS	France	D	100%	100%	Oil and gas
Neptune Energy International S.A.	France	D	100%	100%	Holding Company
BHKW Manschnow GmbH i.L.	Germany	E	50%	50%	Oil and gas
Gewerkschaft Küchenberg Erdgas und Erdöl GmbH	Germany	F	50%	50%	Oil and gas
Neptune Energy Deutschland GmbH	Germany	G	100%	100%	Oil and gas
Neptune Energy Holding Germany GmbH	Germany	G	100%	100%	Holding Company
Westdeutsche Erdölleitung GmbH	Germany	F	50%	50%	Oil and gas
Gaz de France Exploration Libya B.V.	Netherlands	H	100%	100%	Oil and gas
GDF SUEZ E&P Eastern Indonesia B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Alam El Shawish B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Arguni I B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Ashrafi B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy CCUS B.V.	Netherlands	H	100%	100%	Energy
Neptune Energy E&P Holding Netherlands B.V.	Netherlands	H	100%	100%	Holding Company
Neptune Energy East Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy East Sepinggan B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Egypt B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Exploration B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Facilities Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Germany B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Hydrogen B.V.	Netherlands	H	100%	100%	Energy
Neptune Energy Holding Netherlands B.V.	Netherlands	H	100%	100%	Holding Company
Neptune Energy Jakarta B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Muara Bakau B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands Administration B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North West El Amal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Participation Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Touat B.V.	Netherlands	H	54%	54%	Oil and gas
Neptune Energy Touat Holding B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy West Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
ENGIE Sud Est Illizi B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Norge AS	Norway	C	100%	100%	Oil and gas
Neptune E&P UK Ltd	UK	I	100%	100%	Oil and gas
Neptune E&P UKCS Ltd	UK	I	100%	100%	Oil and gas
Neptune Energy Bondco plc	UK	I	100%	100%	Financing Company
Neptune Energy Capital Limited	UK	I	100%	100%	Financing Company
Neptune Energy Finance Limited	UK	I	100%	100%	Financing Company
Neptune Energy Group Holdings Limited	UK	I	100%	100%	Holding Company
Neptune Energy Group Resourcing Limited	UK	I	100%	100%	Service Company
Production North Sea Netherlands Ltd	USA	H	100%	100%	Oil and gas

Notes to the consolidated financial statements
continued

Registered office addresses

A	Level 2, 5 Mill Street, Perth WA 6000, Australia
B	Avenida Presidente Vargas, No. 309, 21 floor (part), Centro, City and State of Rio de Janeiro, Zip Code 20040-010, Brazil
C	Vestre Svanholmen 6, 4313 Sandnes, Norway
D	c/o REGUS, 191-195 Avenue Charles de Gaulle, 92200 Neuilly-sur-Seine, France
E	Langewahler Straße 60, 15517 Fürstenwalde/Spree, Germany
F	Riethorst 12, 30659 Hannover, Germany
G	Ahrensburger Straße 1, 30659 Hannover, Germany
H	Prinses Beatrixlaan 5, 2595 AK The Hague, The Netherlands
I	Nova North, 11 Bressenden Place, London SW1E 5BY, UK

31. Events after the reporting period

Following the completion of the March 2022 Reserve Based Lending facility (RBL) redetermination, the borrowing base remained at $2.3 billion and will remain at this level until the next redetermination in March 2023.

Supplementary information Gas and oil (unaudited)

Reserves

The geographical allocation of reserves is as below:

	Proved plus probable reserves (mmboe)		
	Europe	North Africa and Asia Pacific	Total Neptune Energy
2P reserves at 31 December 2020	465	136	601
Acquisitions	–	–	–
Revisions, extensions and discoveries	23	28	51
Production	(37)	(11)	(47)
2P reserves at 31 December 2021	**451**	**153**	**604**

	Contingent resources (mmboe)		
	Europe	North Africa and Asia Pacific	Total Neptune Energy
2C resources at 31 December 2020	273	180	452
Disposals[1]	(8)	–	(8)
Revisions, extensions and discoveries	32	(43)	(11)
2C resources at 31 December 2021	**296**	**137**	**433**

1 In June 2021, Neptune disposed of its interest in the Solsort field in Denmark to Danoil Exploration A/S. The effective date of this transaction was 1 January 2021.

Notes:

- The above are management estimates, the majority of which are independently audited by ERCe.
- Numbers may not add up due to rounding differences.
- 2P denotes the best estimate of reserves which is the sum of proved plus probable reserves.
- ***Proved reserves*** are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term 'reasonable certainty' is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
- ***Probable reserves*** are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.
- 2C denotes best estimate of contingent resources and reflects the same level of technical uncertainty as 2P reserves.
- ***Contingent resources*** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development projects not currently considered to be commercial owing to one or more contingencies.
- At year end 2021, our proved plus probable reserves (2P) were 604 mmboe and we replaced 107% of our production in the year ended 31 December 2021. Over a four-year rolling period, from the inception of Neptune, our reserves replacement ratio (RRR) is 123%.

Glossary of terms

2C resources are the best estimate of contingent resources
2P reserves are the best estimate of proved plus probable reserves
ARC the Group Audit and Risk Committee
bbl barrel of oil
boe barrel of oil equivalent
capex capital expenditure
carbon intensity the amount of carbon dioxide emissions per boe
CCS carbon capture and storage
CGU cash generating unit
E&P exploration and production
EBITDAX an indicator of financial performance used when reporting earnings for oil and mineral exploration companies' earnings before interest, taxes, depreciation (or depletion), amortisation, and exploration expense
ED&I equality, diversity and inclusion
EPI the business of ENGIE E&P International S.A. and its direct or indirect subsidiaries which we acquired on 15 February 2018
ESG environmental, social and governance
EUA carbon dioxide European Union Allowance
FEED front end engineering and design
FID final investment decision
FTE full-time equivalent
FVOCI fair value through other comprehensive income
G&A general and administration expenses
G&G geological and geophysical
GHG greenhouse gas
GVA gross value added
HSE health, safety and environment
HSEQ health, safety, environment and quality
IEA International Energy Agency
IOGP International Association of Oil & Gas Producers
IPIECA the global oil and gas industry association for advancing environmental and social performance
kboepd thousand barrels of oil equivalent per day
kbpd thousand barrels per day
LNG liquefied natural gas
LTIF lost time injury frequency
M&A mergers and acquisitions
mcf thousand cubic feet of natural gas
methane intensity methane emissions from production operations as a percentage of the total gas exported
mmboe one million barrels of oil equivalent
mmbtu one million British thermal units
mscf a unit of measurement for gases, million standard cubic feet
mmcfpd million standard cubic feet per day
MWh megawatt hour, one million units of electrical power used for one hour
NEGL Neptune Energy Group Limited, the entity though which our investors own their interests in the Group
NOx nitrogen oxide, a source of air pollution
OCI other comprehensive income, an accounting term
OGMP Oil and Gas Methane Partnership
opex operating expenditure
PSER process safety event rate
RBL our Reserves Based Lending facility
SDGs UN Sustainable Development Goals
TCFD Task Force on Climate-related Financial Disclosures
t CO_2e tonnes of carbon dioxide equivalent, a measure that allows you to compare the emissions of other greenhouse gases relative to one unit of CO_2
TRIR total recordable injury rate, a measure of safety performance

Non-GAAP measures

The Group uses certain non-GAAP and non-IFRS measures and ratios that are not required by, or presented in accordance with, any generally accepted accounting principles (GAAP) or IFRS. These non-IFRS and non-GAAP measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS or GAAP. Non-IFRS and non-GAAP measures and ratios are not measurements of our performance or liquidity under IFRS or GAAP and should not be considered as alternatives to operating profit or profit from continuing operations or any other performance measures derived in accordance with IFRS or GAAP or as alternatives to cash flow from operating, investing or financing activities. These non-GAAP measures are defined below:

- **EBITDAX:** EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, impairment reversals/losses, other operating gains and losses, exploration expense and depreciation and amortisation. EBITDAX as defined by the RBL and Neptune Energy Group Limited Shareholder Agreement (Shareholder Agreement) includes our share of net income from Touat in 2020 following the repayment of the Touat Vendor Loan. EBITDAX is the performance metric used to measure our ability to produce income from our operations in any given year. The Group uses EBITDAX as it is a principal key performance metric under the Group's RBL borrowing facility.
- **Underlying operating profit:** Underlying operating profit is the performance metric used to measure our ability to produce income from our operations in any given year. The Group uses underlying operating profit as it removes the effects of non-business as usual events, such as impairments, restructuring costs and curtailment gains/losses that might otherwise distort comparability between periods.
- **Adjusted development cash capital expenditure:** Reflects the cash expenditure on property, plant and equipment, excluding acquisitions and exploration, but including capital expenditure of our equity-accounted entity – Touat. The Group uses adjusted development cash capital expenditure to monitor investing activities on a cash basis.
- **Free cash flow:** Free cash flow is calculated as net cashflow from operating activities less net capital investments during the period including repayments under leases. The Group uses free cash flow to evaluate cash available for financing activities, including dividend payments, after investments in maintaining and growing our business.
- **Operating cost per barrel:** Operating costs for the year divided by production of wholly owned affiliates. Operating costs for the purpose of per barrel expense excludes changes in the value of over/under-lifted entitlement to production, to net-off income from tariffs and services which serve to recover costs, to exclude predevelopment costs and to exclude abandonment costs incurred on non-producing fields. This is a useful indicator of ongoing operating costs from the Group's producing assets.
- **DD&A per barrel:** Depreciation and amortisation of oil and gas properties and right-of-use assets for the year divided by production of wholly owned affiliates. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.
- **Net debt:** The net of cash and cash equivalents and debt recognised on the balance sheet. Net debt excludes Subordinated Neptune Energy Group Limited Loan and Touat project finance facility as defined by the RBL and Shareholder Agreement. This is an indicator of the Group's indebtedness and is a principal key performance metric under the Group's RBL borrowing facility.
- **Net debt/EBITDAX:** The ratio enables investors to see how significant net debt is relative to EBITDAX, it is a principal key performance metric under the Group's RBL borrowing facility.
- **Liquidity:** The sum of cash and cash equivalents on the balance sheet, and the undrawn amounts available to the Group on our principal facilities. This is a key measure of the Group's financial flexibility and ability to fund day-to-day operations.

General information

In this report, unless otherwise indicated, our production, reserves and resources figures are presented on a basis including our ownership share of volumes of companies that we account for under the equity accounting method, in particular, for the interest held in the Touat project in Algeria through a joint venture company. Production for interests held under production sharing contracts is reported on an appropriate unit of production basis.

Forward-looking statements

The discussion in this report includes forward-looking statements which, although based on assumptions that we consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to materially differ from those expressed or implied by the forward-looking statements. While these forward-looking statements are based on our internal expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information, including, among other things, assumptions with respect to production, future capital expenditures and cash flow, we caution you that the assumptions used in the preparation of such information may prove to be incorrect and no assurance can be given that our expectations, or the assumptions underlying these expectations, will prove to be correct. Any forward-looking statements that we make in this report speak only as of the date of such statement or the date of this report.

Alternative performance measures

This report contains non-GAAP and non-IFRS measures and ratios that are not required by, or presented in accordance with, any generally accepted accounting principles (GAAP) or IFRS. These non-IFRS and non-GAAP measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS or GAAP. Non-IFRS and non-GAAP measures and ratios are not measurements of our performance or liquidity under IFRS or GAAP and should not be considered as alternatives to operating profit or profit from continuing operations or any other performance measures derived in accordance with IFRS or GAAP or as alternatives to cash flow from operating, investing or financing activities. Refer to 'Glossary – non-GAAP measures'.

Get in touch

Neptune Energy Group Midco Limited is a private limited company registered in England and Wales (No. 10684661).

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Contact details for other offices can be found on our website.

Website

See ***neptuneenergy.com*** for annual reports and results announcements, as well as information on our operations and our ESG performance.

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Neptune Energy Norge AS
Board of Directors' Report 2021

Neptune Energy Norge AS ("the Company") is engaged in the exploration for and production of oil and gas on the Norwegian Continental Shelf (NCS). The Company's head office is located in Sandnes. The company also has an offices in Florø . At year end the Company had 292 employees.

Neptune Energy Norge AS is active within the full Exploration & Production value chain; from organic growth through Awards in Predefined Areas (APA rounds), exploration license maturation and drilling activity, development projects and production.

The Company is the operator of the Gjøa and Duva fields, and the Fenja development project , as well as partner in several producing fields.

Exploration

Neptune Energy holds interests in about 30 exploration licenses in Norway. In 2021 the Company participated in drilling of eight exploration wells, of which two were operated, and had a discovery rate of 50%. One of these is the Dugong appraisal well, confirming the Dugong discovery done in 2020. Discovered resources in Dugong is still between 40 and 108 mill boe (gross, recoverable) .

The most important discovery was the Blasto discovery located in the Fram core area operated by Equinor. Blasto is expected to be commercial with a resource potential between 76 and 120 mmboe close to Fram. The two last discoveries Lyderhorn (5 mmboe gross, AkerBP operator) and Ommadawn (unspecified volume potential, OMV operator) is located in non-core areas for Neptune and commercial potential remain to be confirmed. In January 2021, the company was awarded six new licenses in the APA 2020 licensing round. The licenses, three as operator and three as partner, are mainly located in core areas like Gjøa (two licenses), Fenja (two licenses) and Dugong (one license).

The exploration activity is a key part of the Company's strategy for organic growth. For 2021 exploration spend was high due to an increased numbers of wells drilled. For the next two years the exploration spend will be reduced due to the revised exploration strategy for Norway, further focusing in existing core production areas.

Development

Duva and Gjøa P1
The Duva reservoir is located approximately 14 km North-East of the Gjøa Field in the North Sea.

P1 started production February 2021 whilst Duva came onstream in August 2021. Some topside works remain to be completed before the Duva project is closed in 2022.

Fenja
The Fenja field is located 36 km south west of the Njord field in the Norwegian Sea and will be developed with two four slot templates tied back to the Njord A platform.

The project schedule has been significantly delayed by the challenges with the host platform Njord A.

In 2022 production drilling will commence and hook-up and commissioning to the Njord A platform. Expected start-up is Q1 2023 following the completion and startup of the host Njord.

Njord and Bauge
The Njord Future Project, operated by Equinor, will perform the redevelopment of the Njord and Hyme fields. Both units have left its respective yards and Njord A is currently being towed to the field where the final hook-up and commissioning activities will happen throughout Summer and Autumn 2022. Njord B is currently in Kristiansund where final commissioning activities are being performed before it also will be towed to the field, for hook-up. Equinor as the operator of Njord indicates a production start-up of Njord in Q4 2022. Shortly after

Njord start-up, Bauge/Hyme and Fenja will also see first production. Njord will in the coming years continue to drill a number of infill wells that were sanctioned under the Njord Future project, in addition to maturing further infill and near field exploration opportunities.

Grosbeak
The Grosbeak was discovered in 2009 and is located 6 km northeast of Fram and 23 km southwest of Gjøa. Grosbeak is located across three licenses, of which Neptune Energy is partner in two.

Operations

Gjøa
Net production from the Gjøa field in 2021 was 7.6 mmboe. The overall regularity was 86% including both planned and unplanned shutdowns. The main contributor to the downtime was a 32-day scheduled shutdown in April and May for the Duva and Nova development projects. In addition, there was a planned 4-day turbine wash SD in November that was extended to allow for Duva and Nova project scope. Different initiatives were taken in 2021 to optimize annual production. Amongst others, production optimization gave increased well rates and extended well life, continuous focus on operations gave higher regularity, and the total number of planned shutdown days were reduced from 45 to 36 days.

Vega
Vega is a subsea tie-back to Gjøa, operated by WintershallDEA. Net production from the Vega Unit in 2021 was 0.33 mmboe.

Snøhvit
Snøhvit was out of production throughout 2021 due to a fire at the Hammerfest LNG (HLNG) facility 28th September 2020. A dedicated project (Cold Return) to re-instate production has been in effect since late 2020, and the latest forecast for re-start of HLNG is 17th May 2022. In addition to a safe re-start of HLNG (with robust regularity), the focus in 2022 will be on the Askeladd Vest project and to mature potential electrification and onshore compression projects.

Gudrun
Net production from the Gudrun field in 2021 was 4.1 mmboe, including a 17 day revision stop in August-September. Rowan Stavanger performed drilling operations throughout the year as planned. Covid-19 affected the progress on topside facility and well work for the water injection project (reduced POB). Start-up of the water injection project has thus been postponed to 2022.

Fram area
Net production from the Fram field in 2021 was 2.5 mmboe, ahich was in line with expectations.

Ivar Aasen, Draugen and Brage fields
The net production from these fields in 2021 was 1.1 mmboe and the activity was as expected.

Business Development
Neptune Energy Denmark ApS, a wholly owned subsidiary of Neptune Energy Norge AS, was divested to Danoil in 2021. The deal was completed on 1st October 2021.

On 11th November 2021 two Sales and Purchase Agreements were signed for divestment of the assets Brage, Ivar Aaasen, Draugen, Utsira high gas pipeline and Edvard Grieg oil pipeline. OKEA ASA purchased 1.2023% in the Ivar Aasen asset, while MVest Energy AS purchased the remaining shares in said assets. Both these deals were completed on 31st March 2022.

HSE & Working environment

Organisation

Most of the workforce in the Company have full-time permanent positions; temporary employees or contractors are engaged in situations where we must maintain flexibility.

Work environment

The Company has a continuous focus on the working environment to mitigate risks and to develop a safe and good place to work. Overall, the working environment is considered to be good.

Regarding health and safety, the Company had 1 recordable injury (twisted ancle) in 2021.

During 2021 absence due to illness has been 2,44%.

The Company conducts an annual global people satisfaction survey (The Pulse) with the aim to follow-up on the employee's satisfaction and wellbeing.

Employee involvement

Our Working Environment Committee, and cooperation meetings with union leaders serve as arenas for employee representation and participation. The company seeks to involve our employee representatives as early as possible before any significant changes to the organisation or operations are addressed. There are 3 unions representing our workforce.

The company has also established an annual cooperation meeting to discuss use of external resources.

The Norwegian Oil & Gas Association, where Neptune Energy is a member, has framework agreements in place with affiliated unions which ensure annual negotiations. Approximately 70 % of our employees are covered by collective bargaining agreements in one of the following unions; Tekna, Lederne 189/190 or NITO.

Condition Report 2021 – Gender equality

- Total headcount including contractors: 393
    - Contractors: 101 / permanent employees 292
- Total headcount employees: 292
    - 205 onshore / 87 offshore
- Distribution of sex:
    - Employees: 87 female / 205 male
    - Managers: 11 female / 49 male
    - Board of Directors: 1 female / 5 male
- Average age employees: 47,3
    - Distribution age: Between 23 years and 67 years
- 19 nationalities
- Turnover: 4,2%
- Part time employees: All positions in our company are 100% positions. Two employees work part-time on their own request.

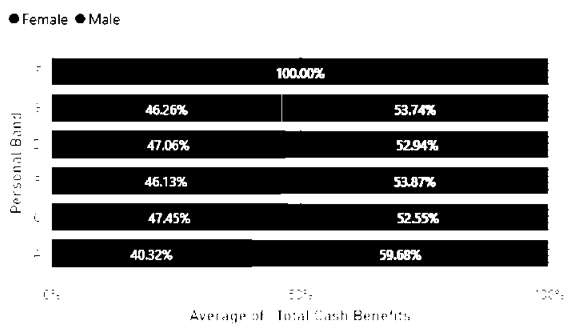
Compensation and benefits

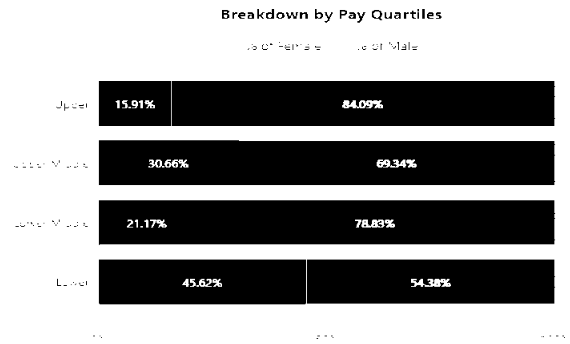
At Neptune we want to ensure that staff is rewarded competitively, fairly and in line with our values. This also means a gender-neutral pay system. To do this we aim to ensure our total reward package is market competitive, with elements of both fixed pay, and some variable elements which allows staff to share in the success of Neptune.

This is evaluated and benchmarked for new hires, promotions, and annual salary reviews. The company also conducts an annual equal pay audit to secure that our equal pay policy is followed up and that any discrepancies are corrected.

71 employees are offshore tariff workers who are paid based on a salary matrix where the only two factors impacting salary are the type of job and number of years of experience.

Onshore employees and offshore supervisors are individually evaluated based on job complexity, required know-how and accountability, as well as formal competence. Based on these factors the jobs are structured in a Band hierarchy from A to F band.





Our activities to promote and improve equality, diversity and inclusion

Neptune Energy is committed to providing equality of opportunity, valuing diversity and promoting a culture of inclusion and positive behaviours. These commitments are reflected in the fundamental principles of action set out in our Code of Ethics and Business Integrity, namely:

(a) Act in accordance with laws and regulations
(b) Consolidate a culture of integrity
(c) Behave fairly and honestly
(d) Respect others
(e) Speak up

We aim to be a workplace where staff are free to be themselves, and work without fear of discrimination, harassment or bullying. Furthermore we expect all staff to behave in a manner, and proactively develop a working environment, where everyone is treated with dignity and respect.

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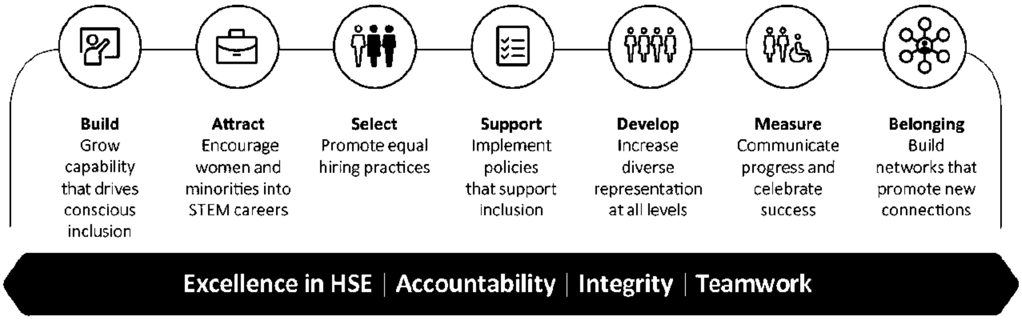
We have a zero-tolerance policy for all forms of misconduct, such as bullying, harassment and discrimination, and all types of corrupt business practices, such as bribery and fraud. We want to ensure that everyone here has the ability to speak up about injustices and bad practices they may experience or witness.

Our ED&I charter, which is underpinned by our values, outlines our key commitments and the actions we will take to help create an inclusive organisation.



Equality, Diversity and Inclusion Policy:

This policy covers:

(a) discrimination in all aspects of employment, including recruitment, promotion, opportunities for development, compensation and benefits, discipline and selection for redundancy;

(b) harassment or bullying which occurs at work and out of the workplace, such as on business trips or at work-related events or social functions.

The policy has been agreed or implemented following consultation with local work council.

Neptune Energy will provide training in the areas of diversity and inclusion to managers and others likely to be involved in decision making where diversity and inclusion issues are likely to arise. Neptune Energy will provide training to all existing and new employees and other engaged to work at Neptune Energy to help them understand their rights and responsibilities in respect of creating a respectful work environment free of bullying and harassment.

In our work to identify any risks for discrimination and hider for equality, the Neptune Energy Group has established a Group ED&I working group. The Company has also established an ED&I subgroup in 2021, with the mandate to develop and integrate a plan for how we can improve our culture with respect to equality, diversity, and inclusion in the Company.

Environment

Gjøa field

The Gjøa facilities are designed to cause as little environmental impact as possible. Electricity from shore is the main source of power for the Gjøa installation, and there is a single fuel low Nitrous Oxide (NOx) turbine operating the gas export compressor. In addition, a waste heat recovery unit is installed. Closed flaring during regular operations also contributes to a reduction of environmental impact.

At Gjøa we have as continuous focus on reducing the concentration of oil in produced water and the status of the oil concentration is presented in the daily report. In 2021 the average oil concentration in produced water discharged to sea was 7,12 mg/l; well below the authority requirement of 30 mg/l.

The emissions and discharges to the environment from operations at Gjøa (Gjøa semi as well as drilling and RFO activities) are reported to the environmental authorities according to current regulations. 93% of chemicals discharged to sea were green chemicals and are not expected to cause any environmental impact. The company emphasizes the use of environmentally friendly chemicals. In 2021 here was a discharge of yellow chemicals of 155 tons. The discharge of 1,8 tons of red component and 1,3 kg of black component is within the existing permit given by the Norwegian Environment Agency. The discharge of red and black chemicals originates mainly from the use of wax inhibitor and lubricating oil respectively.

Gjøa has a low EIF (Environmental Impact Factor) – 2.6-3,8 (2019). The main contributor to the EIF is toluene, xylene, BETEX and Benzene.

There were two accidental spills to sea during 2021; one involving BOP-fluid (yellow environmental classification) related to the drilling activities at Gjøa P1, and one involving TEG (yellow environmental classification) related to cleaning of a MEG tank. The spills are not considered to have significant environmental impact.

The Gjøa field generated 326 tons of non-hazardous waste and 10266 tons of hazardous waste in 2021, most of which originated from the drilling operations at P1. Reducing the amount of waste to landfill is a priority. In 2021 99 % of the non-hazardous waste was recovered.

The key environmental indicators of emissions to air were:

Flaring	1,2 million standard cubic meters (Sm3)
Fuel gas consumption	43 million Sm3
Diesel consumption	7328 tons (combined from Gjøa Semi and Deepsea Yantai)
CO2 emissions	132467 tons
NOx emissions	307 tons

Duva field

Between April and August 2021, four reservoir sections on the Duva template were drilled and completed using the Semi-Submersible "Deepsea Yantai".

The emissions and discharges to the environment from drilling operations at Duva are reported to the environmental authorities according to current regulations. 88% of chemicals discharged to sea were green chemicals and there was a discharge of yellow components of 2.89 tons and red components of 0,89 kg. All the discharges were within the existing permit given by the Norwegian Environment Agency and are not expected to cause environmental impact. There were no discharges of black chemicals during the drilling operations.

The Duva drilling operations generated 86 tons of non-hazardous waste and 6569 tons of hazardous waste in 2021.

The key environmental indicators of emissions to air were:

Flaring (Well Cleanup)	3,3 million standard cubic meters (Sm3)
Diesel consumption	9780 tons
CO2 emissions	39424 tons
NOx emissions	202 tons

Fenja field

The Production Drilling with the Semi-Submersible "Deepsea Yantai" started in Q4 2021 and proceeded into 2022. Because of this, in accordance with regulations, Neptune Energy may choose to report the 2021 activity on the 2022 annual report. Therefore, The emissions and discharges to the environment from the RFO operations are reported to the environmental authorities according to current regulations on the 2021 report.

The emissions and discharges to the environment from the RFO operations are reported to the environmental authorities according to current regulations. ~100% of chemicals discharged to sea were green chemicals and there were discharges of 6 kg yellow chemicals. All the discharges were within the existing permit given by the Norwegian Environment Agency and are not expected to cause environmental impact. There were no discharges of black chemicals during the drilling operations.

No waste was reported for the RFO Operations.

According to regulation exceptions, no Diesel Consumption and emissions was reported.

Exploration
Neptune Energy drilled two exploration wells in 2021.

The emissions and discharges to the environment from the exploration drilling operations are reported to the environmental authorities according to current regulations. 94% of chemicals discharged to sea were green chemicals and there were discharges of yellow and red chemicals, respectively 74 tons and 0,79 kg. All the discharges were within the existing permit given by the Norwegian Environment Agency and are not expected to cause environmental impact. There were no discharges of black chemicals during the drilling operations.

The exploration drilling operations generated 73 tons of non-hazardous waste and 3942 tons of hazardous waste in 2021.

The key environmental indicators of emissions to air were:

Flaring (well test)	124 214 Sm3 gas
Diesel consumption	2960 tons
CO2 emissions	9699 tons
NOx emissions	96 tons

Financial market, credit and liquidity risks

As of 31 December 2021, current and other long-term liabilities amounted to NOK 6,803 million and NOK 19,055 million respectively.

The financial position of the Company will always be influenced by fluctuations in the price of crude oil and gas and in currency exchange rates. The Company has guidelines for entering into derivative contracts in order to manage the commodity price market risk exposure, utilising commodity based derivative contracts consisting of market swaps for oil and gas products. The Company's financial position means that it would be able to withstand a period of reduced oil prices and fluctuations in exchange rates.

The Company regards its credit risk as low since the majority of its sales are to other large corporations. The Company has not realised losses on receivables during the preceding years.

The total exposure related to currency, interest and price fluctuations is monitored and evaluated as part of the overall evaluation of the Company's total exposure. Possible actions are implemented in accordance with the Company's existing procedures.

The pre-tax rate of return (operating profit/average total assets) in 2021 was 30 per cent, compared with 12 per cent in 2020. The rate of return after tax was 4 per cent in 2021, compared with 7 per cent in 2020.

The differences between pre-tax income and cash flow from operations are due to differences in the timing of tax expenditures and depreciation.

Financial aspects

The Company produced 16.7 mmboe in 2021. Total sales in 2021 amounted to 15.7 mmboe, giving total revenues of NOK 10,017 million.

Out of the total 15.7 mmboe sold, 5.8 mmboe consisted of crude oil and condensate. Revenues from crude oil and condensate sales were NOK 3,476 million compared to NOK 2,425 million in 2020.

The Company sold 1.2 billion Sm3 of gas Revenues from gas amounted to NOK 6,298 million compared to NOK 1,988 million in 2020

The revenue from sale of Natural Gas Liquid (NGL) and Liquefied Petroleum Gas (LPG) mix amounted to NOK 1,148 million in 2021 compared to NOK 634 million in 2020. A total of 2.8 mmboe of these products were sold in 2021.

The Company's net income for 2021 was NOK 442 million lower than 2020. The ordinary pre-tax profit for 2021 was NOK 7,734 million, compared to NOK 2,441 million in 2020. After NOK 3,567 million for current tax expenditures and NOK 3,046 million for deferred tax expenditure, net income amounted to NOK 1,120 million, compared to NOK 1,562 million in 2020.

Net cash flow from operating activities in 2021 was NOK 5,920 million, compared to NOK 5,050 million in 2020. Capital investments in 2021 amounted to NOK 4,330 million, compared to NOK 5,062 million in 2020. The majority of the investments were made on Fenja, Gudrun, Duva and Njord. The total cash balance is considered satisfactory by the company.

The Company delivered a strong performance in 2021, both financial and operational. The company targets growing the daily production up to 100 000 boe/day during the next years contributing to the Groups target of a daily production of 200 000/boe a day. The growth in production will be enabled by production start of the current developments.

Climate change

The Company recognises that there may be potential financial implications in the future from changes in legislation and regulation implemented to address climate change risk. Whilst these changes will result in intended benefits, they are likely to increase associated costs and administration requirements and could potentially also reduce the investment capital available to the industry. Over time these changes may well have an impact across a number of areas of accounting including asset impairment, increased costs, onerous contracts and contingent liabilities. However, as at the balance sheet date, the Company believes there is no material impact on balance sheet carrying values of assets or liabilities.

Going Concern

The COVID-19 crisis increased the risk regarding the going concern assumption for most companies. In response to the pandemic, we followed applicable government and industry guidelines and best practice, also taking an active role in industry bodies to contribute to a prudent and common approach in the industry.
Through implementation of measures related to the pandemic, a continuous high activity level has been maintained across Neptune Energy's activities in Norway, both onshore and offshore. This includes drilling operations, production on Gjøa and project related operations in yards onshore and from construction vessels offshore. For our offshore personnel we successfully set up a test-clinic at the heliport in Florø and implemented mandatory testing procedures, reducing the risk of contamination at offshore facilities. A criticality assessment of main contractors and suppliers has been carried out, enabling us to identify issues that required special attention in the special circumstances.
In accordance with the Accounting Act § 3-3a, the Board of Directors confirm that the financial statements have been prepared under the assumption of going concern. The Board considers the financial position and the liquidity of the company to be sound. Cash flow from operations, combined with available funding within the Neptune Group, is expected to be more than sufficient to finance the company's commitments in 2021.

Board Members' and Managing Director's Liability

The Company maintains Directors' & Officers' Liability Insurance, which gives appropriate cover for legal action brought against its Board members and the Managing Director. The insurance does not provide cover in the event that the individual is proved to have acted fraudulently.

Allocation of net income

The Board of Directors, having no knowledge of any matters not disclosed that could be of significance when evaluating the Company's position, recommends the following allocation of net income:

Net result 2021	NOK	1,120,464,269
To Retained Earnings	NOK	1,120,464,269
Dividend	NOK	0

If the General Assembly follows the Board of Directors' recommendation above, total equity will be NOK 2,903 million, giving an equity ratio of 10,1%.

Sandnes, 1st of June 2022

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Peter Jones
Chairman of the Board

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Odin Estensen
Managing Director

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Board member

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Harald Peter Knöbl
Board member

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Rune Haukebøe
Board Member

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Income statement

	Note	2021	2020
Operating income			
Sales of oil and gas	3, 5	10 016 533 576	5 801 830 362
Tariff income		7 692 708	10 046 181
Other Income	8	1 067 825 946	429 349 821
Total operating income		11 092 052 230	6 241 226 363
Operating expenses			
Operating expenses	10	959 116 824	1 717 066 993
Exploration expenses		437 487 055	325 710 667
Payroll expenses	6, 7	120 734 728	158 867 008
Depreciation/Impairment	9	1 248 410 511	1 342 040 391
Other operating expenses	10	80 975 227	79 256 541
Total operating expenses		2 846 724 346	3 622 941 601
Operating profit		8 245 327 885	2 618 284 763
Financial income and expenses			
Interest income		7 314 366	33 047 992
Foreign currency exchange gain		210 849 383	940 749 437
Interest income from group companies	8	0	5 236 042
Other financial income	3	0	55 697 530
Impairment shares in subsidiaries		30 512 951	123 400 000
Interest expenses		14 021 781	15 784 534
Foreign currency exchange loss		237 959 048	864 720 754
Interest expenses to group companies	8	189 294 158	207 493 591
Other financial expenses	3	257 907 242	282 956
Net financial (-income)		511 531 430	176 950 834
Operating profit before tax		7 733 796 455	2 441 333 929
Tax expenses	13	6 613 332 186	879 406 615
Net income		1 120 464 269	1 561 927 314
Allocated as follows:			
Proposed dividend	14	0	1 556 500 000
Transfer (-from) other equity	14	1 120 464 269	5 427 314
Total allocations		1 120 464 269	1 561 927 314

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Balance sheet

NOK	Note	2021	2020
Non-current assets			
Intangible fixed assets			
Goodwill		463 076 822	531 680 795
Tangible fixed assets			
Property, plant & equipment	9	21 973 395 945	18 898 100 607
Shares in subsidiary	16	0	66 289 675
Financial instruments	3	91 147 040	9 800 751
Other financial investments	16	188 000	188 000
Total tangible fixed assets		22 064 730 985	18 964 578 282
Total non-current assets		22 527 807 808	19 496 259 078
Current assets			
Drilling equipment and spare parts	12	27 323 172	21 262 972
Accounts receivable from operators		493 895 653	302 384 116
Trade accounts receivable	11	90 080 200	15 643 228
Current tax	13	0	1 051 073 702
Financial instruments	3	147 474 161	65 609 353
Other receivables	11	5 398 747 015	1 795 927 423
Total receivables		6 130 197 029	3 240 438 573
Cash and cash equivalents	4	37 010 536	4 351 305
Total current assets		6 194 530 737	3 266 052 850
Total assets		28 722 338 545	22 762 311 928
Equity and liabilities			
Equity			
Paid-in capital			
Share capital	14,15	141 500 000	141 500 000
Share premium reserve	14	1 273 500 000	1 273 500 000
Total paid-in capital		1 415 000 000	1 415 000 000
Retained earnings			
Other equity	3,14	1 487 837 719	1 444 976 248
Total equity		2 902 837 719	2 859 976 248
Liabilities			
Pension liability	7	251 221 504	227 293 630
Deferred tax	13	10 862 570 429	7 942 327 388
Financial instruments	3	154 396 903	
Other provisions	10	4 374 730 297	4 124 639 481
Long term liability	11	3 373 000 000	3 373 000 000
Total provisions		19 015 919 132	15 667 260 498
Current liabilities			
Trade accounts payable	11	300 194 546	116 496 507
Public duties payable		43 326 251	77 448 947
Accounts payable to operator		868 341 461	177 233 122
Dividend	14		1 556 500 000
Tax payable	13	3 227 651 209	137 091 424
Financial instruments	3	1 163 974 080	176 486 910
Other short term liabilities		1 200 094 148	1 993 818 274
Total current liabilities		6 803 581 694	4 235 075 183
Total liabilities		25 819 500 827	19 902 335 681
Total equity and liabilities		28 722 338 545	22 762 311 928

Cash flow statement

	2021	2020
Profit before tax	7 733 796 455	2 441 333 929
Net payment of tax	574 170 777	295 823 350
Depreciation, impairments and accretion	1 707 984 161	1 698 849 841
Changes in accounts receivable and accounts receivable operators	-265 948 509	507 572 054
Changes in accounts payable and accounts payable operators	840 683 682	-286 699 333
OCI hedging		
Difference between pension cost and amounts paid into pension scheme	8 531 319	15 494 466
Changes in other balance sheet items	-4 679 357 367	377 706 317
Net cash flow from operating activities	**5 919 860 519**	**5 050 080 624**
Acquired tangible fixed assets	-4 330 701 288	-5 062 258 494
Shares in subsidiary		
Net cash flow from investing activities	**-4 330 701 288**	**-5 062 258 494**
Dividend paid	-1 556 500 000	0
Net cash flow from financing activities	**-1 556 500 000**	**0**
Net change in cash and cash equivalents	32 659 231	-12 177 870
Cash and cash equivalents at beginning of year	4 351 305	16 529 240
Cash and cash equivalents at end of year	**37 010 536**	**4 351 305**

Note 1 - Accounting policies

The annual accounts have been prepared in accordance with the Norwegian Accounting Act of 1998 and Norwegian generally accepted accounting principles.

Revenues

Revenue is recognised when the Company satisfies a performance obligation by transferring oil and gas to a costumer. For crude oil the point of delivery is at the offshore loading point or at shipment from the terminal. The point of delivery for gas is at the gas receiving terminal onshore.
Differences may arise in a joint operation between the Company's share of production entitlement from an oil or gas field and the volume which has been lifted and sold. Such "under or over lift " entitlements are recognised in current asset or liabilities, respectively, at net realisable value, with a corresponding adjustment through production cost. As a result, the reported operating result for each period reflect the Company's share of saleable production in that period.

Expenses

Expenses are expensed as incurred in accordance with the matching principle, either along with the revenues they have generated or identified as a periodical expense.

Estimates

In accordance with Norwegian generally accepted accounting principles, the management of the company is responsible for estimates and assumptions that affect the valuation of assets and liabilities in the balance sheet and depreciation in the income statement. The final realisable values may deviate from these estimates.

Classification and assessment of items in the balance sheet

Current assets and current liabilities include items due within one year and items related to ordinary working capital. All other items are classified as fixed assets or long-term liabilities.
Current assets are valued at the lower of cost and fair value. Short-term debt is valued at the historical nominal value.
Fixed assets are valued at cost, but written down to fair value if the decline in value is not expected to be temporary. Long-term loans are stated at the historical nominal value.

Foreign currency

Monetary balance sheet items in foreign currency are converted at the exchange rate on the closing balance date.
All foreign currency transactions are converted to NOK in accordance with the Company's monthly book-keeping currency exchange rates, which approximate market rates.

Exploration costs

Geological studies and analysis are expensed as incurred. Exploration drilling costs are temporarily capitalised until potential oil and gas reserves have been evaluated (the successful efforts method). When new reserves are discovered, fully developed and put into production, the exploration drilling costs will be depreciated based on the unit-of-production method. Drilling costs related to dry or non-commercial wells are expensed.

Property, plant and equipment
All costs related to the development of commercial oil or gas fields are capitalised as a part of the installation. Capital expenditures on fields in production are capitalised based on information from the operator.
Individual assets or groups of assets, classified as cash-generating units (CGUs), are tested for impairment when indicators of impairment are identified. When assessing whether an asset is impaired, the asset's carrying value is compared to the recoverable amount. The recoverable amount is the higher of the asset's fair value less cost to sell and the asset's value in use. An impairment loss is recognised when the recoverable amount is below the carrying amount and if the decline in recoverable amount is not considered temporary. If the assets are decided to be impaired, the carrying amount is written down to the recoverable amount and the reduction in asset value is recognised as an expense.

Depreciation of production assets
The depreciation of producing assets, including site rehabilitation costs, commences when the oil or gas field is brought into production. Depreciation is calculated according to the unit of production method. According to this method, the depletion rate is equal (since 1 January 2014) to the ratio of oil and gas production for the period to proved and probable reserves. Before this date, the ratio was based on proved developed reserves. The future capex linked to the 2P reserves are included in the calculation of the depreciation rate. This change of estimate has been decided in view of the evolution of the Group's portfolio of production assets. This change aims to improve the economic vision of the production asset's consumption of benefits over its useful life.

Property, plant and equipment is capitalised and depreciated linearly over its estimated useful life. Costs for maintenance are expensed as incurred, whereas costs for improving and upgrading property, plant and equipment are added to the acquisition cost and depreciated with the related asset.

Subsidiaries and investment in associates
Subsidiaries and investments in associates are valued at cost in the Company accounts. The investment is valued as the cost of the shares in the subsidiary, less any impairment losses. Consolidated financial statements are not prepared as the Company and its subsidiaries are included in the consolidated financial statements of the parent company.

Assets, liabilities and expenses related to participating interests in exploration and production licences (joint venture)
The Company's participating interests in exploration and production licences on the Norwegian Continental Shelf are accounted for in the income statement and balance sheet in accordance with the proportional consolidation method.

Transfer of interest in joint arrangements
Transfers of interests in petroleum licences on The Norwegian Continental Shelf require approval from the Norwegian Government. Under such transactions the sale price is generally considered to be on an "after tax" basis (after-tax transaction) as the consideration is not taxable for the seller and not deductable for the buyer through depreciation.

When acquiring licences that yield rights to exploration for and production of oil and gas, it will be assessed if the acquisition should be classified as a business combination or an asset acquisition. Acquisitions of individual licences which do not meet the definition of business combination will be classified as the acquisition of an individual asset.

Oil and gas producing licences
For oil and gas producing ownership interests, as well as licences in the development phase, the acquisition cost will be allocated between exploration costs, licence rights, production facilities, deferred taxes and goodwill.

In connection with agreements for acquisitions or trade of interests, the parties will establish a completion date for the acquisition of the net cash flow since the effective date often set on 1 January of the calendar year. In the period between the effective date and the completion date, the seller will include the acquired interest in the seller's accounts. In accordance with the acquisition agreement, there will be a settlement with the seller of net cash flow from the ownership interest during the period from the effective date to implementation date (Pro&Contra settlement). The Pro&Contra settlement will be adjusted against the income statement and against the acquisition cost, as the settlement (after reduction for taxes) is regarded as part of the payment for the transaction. Going forward from the implementation date, revenue and costs are included in the buyer's financial statements.

As regards taxes, the buyer will include for taxation net cash flow (Pro&Contra) and any other revenue and costs as of the effective date.

Allocations will not be made for deferred taxes and goodwill in connection with acquisition of licences that are defined as acquisition of assets.

Farm-in agreements
Farm-in agreements are usually made during the exploration and development phases, and are characterised by the seller deferring future financial advantages, in the form of reserves, to reduce future financing obligations. One example can be that a licence interest is acquired and covered by the seller's share of the drilling-related costs. During the exploration phase, the company will normally enter farm-in agreements based on historical costs, as actual value often is difficult to determine. However, during the development phase, farm-in agreements are entered as acquisitions at actual cost when the company is selling shares of oil and gas interests. Fair value is determined by the costs that the buyer has agreed to carry.

Swap/Unitisation
A swap of ownership interest is measured at the fair value of the interest to be swapped, unless the transaction lacks commercial substance or if the fair value of the swapped interest is not measurable. During the exploration phase where it is often difficult to determine fair value, the Company will normally account for swaps based on historical cost.

Spare parts and drilling equipment
Spare parts and drilling equipment are valued at the lower of cost or market value. Cost is estimated using the First In First Out (FIFO) method. Capital spare parts are capitalised and presented in the financial statements together with the investment.

Over/under lift and petroleum in stock
Obligations or receivables arising as a result of lifted quantities of crude oil and NGL that are larger or lower than the Company's participating interests in a licence are valued at net realisable value / market value.

Uncertain obligations
The Company will, through its activities, be involved in conflicts and disputes. The Company will accrue for obligations in connection with such unresolved issues based on the best estimate, when it is probable that an outflow of economic benefits will be required to settle the obligation.

Accounts receivables
Trade accounts receivables and other receivables are recorded at face value less a provision for any anticipated losses.

Asset retirement obligation

When the retirement obligation is incurred, the liability is recognised as a long term provision and the corresponding amount is capitalised as part of the producing asset. The asset is expensed through depreciation over the remaining useful life of the asset. Future changes in asset retirement obligation estimates are capitalised as part of the asset and charged to profit and loss prospectively over the remaining useful life of the asset.

Tax expense

Tax expense reflects both taxes on current taxable income and changes in deferred income taxes. Deferred tax is calculated based on net temporary differences between the book and tax values at year end. The calculation has taken into account future uplift on capitalised expenditures.
Uplift on capitalised expenditures reduces the special petroleum tax. Earned uplift from capitalised expenditures has been fully reflected in the deferred tax calculation.

Pensions

Accounting for the defined benefit pension plan is based on a linear vested principle and on expected salaries at the point of retirement. Changes in pension schemes are amortised over the remaining vesting period. Estimated deviations are continuously charged to equity. Social security tax is included in the pension cost and liability. The defined contribution pension plan is booked as current costs.

Accounting for licence cost

The Company's accounts reflects the net cost after charging partners their share of licence costs for permits the Company operates.

Cash flow statement

The cash flow statement is presented using the indirect method. Cash and cash equivalents include bank deposits.

Leasing

The Company has signed only operating lease agreements, and as such the related cost is charged to the income statement as incurred.

Financial Instruments

The Company enters into commodity based derivative contracts consisting of market swaps for oil and gas products.

Hedging

The Company applies the principals of NRS18 and uses the following criteria for classifying a derivative or another financial instrument as a hedging instrument: (1) the hedging instrument is expected to be highly effective in offsetting changes in the fair value of the cash flow of an identified object – the hedging effectiveness is expected to be between 80-125%, (2) the hedging effectiveness can be measured reliably, (3) satisfactory documentation is established before entering into the hedging instrument, showing among other things that the hedging relationship is effective, (4) for cash flow hedges, that the future transaction is considered to be highly probable, and (5) the hedging relationship is evaluated regularly with quantitative analysis and is considered to be effective.

Cash flow hedges

The efficient part of changes in the fair value of a hedging instrument is recognised in equity. The inefficient part of the hedging instrument is reported in the income statement.
When a hedging instrument has matured, or is sold, exercised or terminated, or the parties discontinues the hedging relationship, even though the hedged transaction is still expected to occur, the accumulated gains and losses at this point will remain in comprehensive income, and will be recognised in the income statement when the transaction occurs.
If the hedged transaction is no longer expected to occur, the accumulated unrealised gains or losses on the hedging instrument will be recognised in the income statement immediately.

Note 2 - Financial market risk
The Company's financial result is affected by fluctuations in crude oil and gas prices and foreign currency exchange rates (mainly USD, GBP and EUR).

Note 3 - Financial Instruments
The Company enters into commodity based derivative contracts consisting of swap and option derivative contracts for oil and gas products. Swap and option derivative contracts for oil are hedged towards Brent Blend; swap and option derivative contracts for gas are hedged towards National Balancing Point (NBP) and Title Transfer Facility (TTF) prices.

The realised value on swap and derivative contracts for the year 2021 is a loss of NOK -905 428 206. The realised hedging contracts which are not fulfilling the requirements of efficiency according to NRS 18 for hedge accounting are booked as part of financial result.

NOK	2021	2020
Total Gas hedging revenue (-loss)	-580 841 258	358 074 067
Total Liquids hedging revenue (-loss)	-324 586 948	396 465 485
Total hedging revenues (-loss)	-905 428 206	754 539 552
Financial income from hedging (-loss)	-257 621 496	55 697 530
Total hedging income (-loss)	-1 163 049 702	810 237 081

NOK	Booked	31.12.2021	Due	2022	2023	2024
Cash flow hedge commodities liabilities	Liability	-1 318 370 982		-1 163 974 083	-154 396 900	0
Cash flow hedge commodities reserves equity	Equity	1 323 603 099		1 116 905 176	206 697 923	0
Market to Market	P&L Loss	-257 621 496				

Note 4 - Bank deposits
Restricted funds relating to withholding taxes
The Company has issued a bank guarantee towards the tax authorities of NOK 35 000 000, replacing the cash deposit for withholding taxes.

Note 5 - Operating revenues
Sales of the Company's production has derived the following revenues:

NOK	Norway	France	UK	Switzerland	Hungary	Netherlands	USA	TOTAL	2020 TOTAL
Crude oil	306 433 800		3 169 308 299					3 475 742 099	2 382 407 548
NGL	73 931 639		396 116 159	545 469 706	132 493 021			1 148 010 524	634 441 977
Gas	1 160 508 123		5 136 405 856	1 295 181				6 298 209 159	1 325 016 859
LNG								0	662 912 416
Condensate								0	42 511 950
Hedging of oil and gas	-113 228 371	-15 130 283	-586 464 627	0	0	-21 602 568	-169 002 356	-905 428 206	754 539 552
Total	1 427 645 191	-15 130 283	8 115 365 686	546 764 886	132 493 021	-21 602 568	-169 002 356	10 016 533 577	5 801 830 302

Note 6 - Salaries and fees

NOK	2021	2020
Salaries	511 195 887	528 766 938
Social security tax	84 805 572	77 875 218
Pension costs	61 546 309	92 037 292
Other employee benefits	(35 540 132)	37 596 296
Total salary	622 007 636	736 275 743
Salaries recharged to licences	501 272 908	577 408 735
Total net salary	120 734 728	158 867 008
Number of full-time equivalent employees in fiscal year	298,0	329,0

Remuneration for Managing Director
The Managing Director position is held by Odin Estensen. The total salary, bonus and other fringe benefits paid to the Managing Director for 2021 is NOK 5 195 240 of which NOK 5 166 739 is salary and NOK 28 501 is other benefits.

Remuneration of the Board
No remuneration to the Board were paid in 2021.

Audit fees
The fees paid to Ernst & Young during the year 2021, excluding VAT, are comprised of the following amounts:

NOK	2021
Audit decreed by law	1 414 291
Other attestation services	391 678
Technical VAT and tax services	
Total	1 805 969

Note 7 - Pensions

The Company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("lov om obligatorisk tjenestepensjon"). The Company's pension scheme meets the requirements of that law.

The Company has a retirement benefit plan for all permanent staff. This benefit plan gives the employees the right to receive defined future pensions. The Company decided to change the pension scheme for the employees from a defined benefit plan to a defined contribution plan, as of 01.01.2016. The new pension scheme will be mandatory for all employees having more than 15 years remaining until retirement age, hence the employees having less than 15 years left until retirement will still be members of the old defined benefit pension plan. 284 employees are part of the defined contribution pension scheme and 46 employees are part of the defined benefit pension scheme. The Company's actuarial report is provided by Storebrand Pensjonstjenester AS. The value of these is mainly dependent on the number of years in service and the level of compensation at retirement. The obligation up to 12G is financed through an insurance company, the remainder is financed through normal operation.

NOK	2021	2020
Pension rights earned during the year, including a new retroactive pension scheme (2016-2018)	24 625 056	53 555 184
Defined contribution pension scheme	34 970 994	36 143 627
VNG pension cost	1 176 940	1 804 670
Interest expense on earned pension rights		
Other pension cost (admin	773 318	533 811
Net pension cost	61 546 309	92 037 292
Assets/obligations		
Pension benefit obligations	365 251 136	361 429 629
Plan assets	-111 675 177	-131 907 526
Yield assets	-2 353 708	-2 228 474
Defined contribution pension schemes	0	0
Net pension liability	251 222 251	227 293 629
Financial assumptions		
Discount rate	1,70%	1,70%
Expected increase in salaries	2,00%	2,00%
Expected increase in pensions	0,00%	0,00%
Expected increase of social security base amount (G)	1,75%	1,75%
Expected return on plan assets	1,70%	1,50%

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Note 8 - Related Party Transactions

Related Party	Relationship to the Company	Value of Transactions 2021	Value of Transactions 2020	Nature of transactions	Other Comments
Neptune Energy Deutschland GmbH	Associated company	55 017 081	2 068 444	Operating and support income	Income statement
Neptune Energy Deutschland GmbH	Associated company	507 506	1 324 480	Operating and support expenses	Income statement
Neptune Energy Touat B.V	Associated company	5 284 964	4 437 273	Operating and support income	Income statement
Neptune Energy Touat B.V	Associated company	-	-	Operating and support expenses	Income statement
Neptune Energy Germany BV	Associated company	48 256	-	Operating and support income	Income statement
Neptune Energy Holding Germany GmbH	Associated company	688 676	-	Operating and support expenses	Income statement
Neptune Energy Netherlands B.V.	Associated company	59 354 302	72 707 381	Operating and support income	Income statement
Neptune Energy Netherlands B.V.	Associated company	46 822 437	60 359 654	Operating and support expenses	Income statement
Noordgastransport B.V	Associated company	-	1 982	Operating and support income	Income statement
NOGAT B.V	Associated company	-	5 737	Operating and support income	Income statement
Neptune Energy North Ganal B.V.	Associated company	30 734	-	Operating and support income	Income statement
Neptune Energy East Ganal BV	Associated company	3 740	-	Operating and support income	Income statement
Neptune Energy West Ganal BV	Associated company	55 239	-	Operating and support income	Income statement
Neptune Energy East Sepinggan BV	Associated company	72 667	-	Operating and support income	Income statement
Neptune Energy North West El Amal B.V.	Associated company	2 625 720	-	Operating and support income	Income statement
Neptune E&P UK Ltd	Associated company	25 267 544	16 818 144	Operating and support income	Income statement
Neptune E&P UK Ltd	Associated company	24 134 873	36 189 991	Operating and support expenses	Income statement
Neptune Energy International SA (Paris)	Associated company	50 997	14 057 795	Operating and support income	Income statement
Neptune Energy International SA (Paris)	Associated company	-	28 521 806	Operating and support expenses	Income statement
Neptune Energy Group Holdings Ltd. (UK)	Parent company	18 638 987	10 772 707	Operating and support income	Income statement
Neptune Energy Group Holdings Ltd. (UK)	Parent company	226 405 296	213 231 309	Operating and support expenses	Income statement
Neptune Energy Egypt B.V	Associated company	474 861	451 805	Operating and support income	Income statement
Neptune Energy Muara Bakau B.V.	Associated company	8 793 583	2 563 733	Operating and support income	Income statement
Neptune Energy Bonaparte PTY Ltd.	Associated company	1 789 751	110 376	Operating and support income	Income statement
Neptune Energy Participation Netherlands	Associated company	1 707	5 583	Operating and support income	Income statement
Neptune Energy Danmark ApS	Subsidiary	372 801	2 065 310	Operating and support income	Income statement
Neptune Energy Capital Ltd (UK)	Associated company	187 455 412	207 385 157	Accrued interest intercompany loan	Income statement
Neptune Energy Finance Ltd (UK)	Associated company	-	5 236 042	Interest & financial revenue group account	Income statement
Neptune Energy Finance Ltd (UK)	Associated company	1 838 746	108 433	Interest & financial cost group account	Income statement

Some of the intercompany transactions are direct recharges and do not have a P&L effect.

Note 9 - Tangible fixed assets

NOK	Assets in Production	Assets under development	Equipment etc.	Capitalised exploration cost	TOTAL
Acquisition cost at 01.01.2021	39 485 168 047	5 425 765 319	667 215 903	623 585 429	46 201 734 698
Acquisitions during the year	2 656 778 939	1 106 628 990	27 934 015	735 952 601	4 527 294 545
Disposal	0	0	0		0
Impairment/Reversal impairment during the year		0	0	-272 192 669	-272 192 669
Reclassification	1 938 681 526	-1 938 875 255	0	193 730	0
Acquisition cost at 31.12.2021	44 080 628 511	4 593 519 054	695 149 918	1 087 539 091	50 456 836 574
Less accumulated depreciation at 31.12.2021	-27 617 989 876	-254 494 118	-610 956 635	0	-28 483 440 629
Book value as at 31.12.2021	16 462 638 635	4 339 024 936	84 193 283	1 087 539 091	21 973 395 945
Current year depreciation	-1 102 274 830	-47 297 911	-30 233 798		-1 179 806 538

Note 10 - Other provisions and obligation

NOK	2021	2020
Asset retirement obligation	4 185 118 418	3 874 287 286
Other long-term provisions	189 611 879	250 352 196
Other provisions	4 374 730 297	4 124 639 481

Other long-term provisions

Other long term provisions are mainly related to the Company's net liability related to the Gjøa liability to the Vega licences. This long term debt relates to capex pre-payments from the Vega licences to the Gjøa development project. The Gjøa liability is reduced according to units of production, based on the throughput of hydrocarbons from the Vega licences in the Gjøa processing facility.

Asset retirement obligation

In accordance with the concession terms of the Production licences which the Company holds, the Norwegian State can assume ownership of licence installations without charge when the production ends or when the licence expires. Alternatively the State can require the installations to be removed. In addition to provisions for future abandonment cost, provisions have been made for future costs of plugging and securing production wells. The accretion expense is classified as an operating expense.

	2021	2020
Asset retirement obligations at January 1	3 874 287 285	3 480 855 749
Liabilities incurred / revision in estimates	192 838 103	274 713 377
Liabilities incurred VNG acquisition	0	0
Accretion expense	121 091 306	118 718 159
Disposal	-3 098 276	-
Asset retirement obligations at December 31	4 185 118 418	3 874 287 285

Financial assumptions						
Years until removal	1-3 years	4-5 years	6-10 years	11-15 years	16-20 years	21-25 years
Discount rate	1,10%	1,80%	2,40%	2,70%	2,90%	3,20%

Assets related to removal and abandonment are also included within tangible fixed assets described in note 9.

Drilling commitments

The Company, together with its licence partners, is committed to taking part in the drilling of wells in accordance with its licence agreements.

Contractual obligations

	2021	Thereafter	Total
Obligations committed NOK	1 656 411 224	343 030 083	1 999 441 307

The contractual obligations are related to the acquisition and construction of assets in licences where the Company has ownership interests.

Operating lease

	2021	2020
Operating lease NOK	28 332 680	27 760 666

Operating lease includes rental of offices and other facilities

Note 11 - Inter-company balances

Receivables	31.12.2021	31.12.2020
Trade accounts receivable from inter-company	18 009 675	12 583 968
Short-term receivables from inter-company	2 743 969 572	501 272 173

Liability	31.12.2021	31.12.2021
Long term loan from inter-company	3 373 000 000	3 373 000 000
Margin Call		
Trade accounts payables from inter-company	1 753 615	8 128 069

Note 12 - Drilling equipment

Spare parts and drilling equipment are valued at the lower of cost or market value. Cost is estimated using the First In First Out (FIFO) method. Capital spare parts are capitalised and presented in the financial statements together with the investment.

	2021	2020
Drilling and well equipment	27 323 173	21 262 972
Total Inventories	27 323 173	21 262 972

Note 13 - Taxes

Specification of the tax expense for the year:

	2021	2020
Change in deferred tax before adjustment in tax rates	3 045 900 563	3 207 763 865
Current tax payable	3 437 344 028	-2 299 225 888
Adjustment for tax provision in prior years	130 087 594	-29 131 363
Total tax expense	6 613 332 186	879 406 615

Specification of the tax basis for the year:

Ordinary profit before tax	7 733 796 455	2 441 333 929
Permanent differences	143 500 712	29 028 493
Use of loss carried forward 22%	686 742 824	-202 424 861
Change in temporary differences	-3 057 463 628	-1 589 209 565
Basis ordinary income tax	5 506 576 363	678 727 997
Net financial expenses/income (-) not subject to special petroleum tax	136 393 964	-5 644 453
Income/Loss (-) from onshore activities	1 373 485 648	-819 923 242
Use of tax loss carry forward 22%	-686 742 824	202 424 861
Extra depreciation temporary tax regime	-1 467 410 819	-3 180 270 288
Uplift on capitalised expenditures	-887 485 851	-1 250 535 729
Basis special petroleum tax	3 974 816 481	-4 375 220 855

Tax Payable:

Tax payable - ordinary income tax 22%	1 211 446 800	149 320 159
Tax payable - special petroleum tax 56%	2 225 897 229	-2 450 123 679
Total tax payable	3 437 344 029	-2 300 803 519

Specification of basis for deferred tax:
Net differences :

Fixed assets	14 703 652 456	12 100 347 838
Pension liability	-251 221 504	-227 293 630
Crude oil inventory	0	0
Gain and loss account	11 917 661	14 897 076
Hedging Asset / Liability	-539 874 891	-101 076 805
Restructuring cost	-1 975 992	-18 898 723
Over/underlift	849 996 605	287 936 760
Leasing commitment	0	0
Asset retirement obligations	-4 178 666 747	-3 867 835 615
Basis ordinary income tax	10 593 827 587	8 188 076 901
Limited capitalisation of interest on development projects	-45 684 171	-47 757 120
Gain and loss account	-9 915 645	-12 394 556
Hedging Asset / Liability	539 874 891	101 076 805
Fixed assets tax values in 56% tax regime	4 415 756 815	3 180 270 288
Unused uplift	-258 273 120	-443 289 338
Basis special petroleum tax	15 235 586 356	10 965 982 980

Deferred Tax Liability:

Ordinary income tax (22%)	2 330 642 069	1 801 376 918
Special petroleum tax (56%)	8 531 928 360	6 140 950 469
Total deferred tax	10 862 570 429	7 942 327 387

Tax Payable/ Receivable:

Ordinary income tax	3 437 344 029	-2 300 803 519
Prior year adjustments	-22 846 214	14 891 010
Tax paid in advance	-186 846 606	1 371 930 237
Total tax payable in balance sheet	3 227 651 209	137 091 428
Total tax receivable in balance sheet	0	-1 051 073 701

Reconciliation of tax expense and calculated tax expense:

Ordinary profit before tax	7 733 796 455	2 441 333 929
Marginal tax at 78%	6 032 361 235	1 904 240 465
Uplift on capitalised expenditures	-393 382 994	-521 867 168
Hedging	613 365 520	-453 732 766
Permanent differences depreciation §10	4 998 574	9 167 521
Permanent differences goodwill depreciation	53 511 099	53 511 099
Other permanent differences	170 384 583	-88 413 140
Financial items not subject to special petroleum tax	90 847 386	5 631 966
Adjustments from prior years	41 246 784	-29 131 362
Tax expense	6 613 332 186	879 406 615

Note 14 - Equity

	Share capital	Share premium reserve	Other equity	TOTAL
Equity at 31.12.2020	141 500 000	1 273 500 000	1 444 976 248	2 859 976 248
Current year net income			1 120 464 269	1 120 464 269
Hedging MTM			-1 075 034 850	-1 075 034 850
Pension actuarial valuation			-2 567 947	-2 567 947
Dividend 2021			0	0
Equity at 31.12.2021	141 500 000	1 273 500 000	1 487 837 720	2 902 837 719

Note 15 - Share capital and shareholder information

The share capital of the Company consists of 141 500 shares with a nominal value of NOK 1 000 per share.
All shares are held by the parent company, Neptune Energy Group Holdings Ltd.

The ultimate parent company (Neptune Energy Group Ltd) issues consolidated statements which include Neptune Energy Norge AS. This can be found on www.neptuneenergy.com.

Note 16 - Investment in subsidiaries and associates

The Company has ownership of 8,356% of the shares in Aksello AS, booked value of NOK 188 000

Note 17 - Reserves (not audited)

According to the reserves information published by the Norwegian Oil Directorate, the Company`s share of remaining reserves at 31.12.2021 are:

	Licence duration	Oil (million Sm3)	Gas (billion Sm3)	NGL (million tonnes)	Condensate (million Sm3)
BAUGE	17.12.2029	0,70	0,14	0,07	0,00
BRAGE	06.04.2030	0,10	0,01	0,00	0,00
BYRDING	09.03.2024	0,03	0,06	0,01	0,00
DRAUGEN	09.03.2024	0,62	0,10	0,02	0,00
DUVA	22.02.2044	0,93	1,88	0,23	0,00
FENJA	04.02.2039	2,06	0,64	0,11	0,00
FRAM	09.03.2024	0,50	1,28	0,13	0,00
FRAM H-NORD	09.03.2024	0,01	0,00	0,00	0,00
GJØA	08.07.2028	0,21	1,89	0,43	0,00
GUDRUN	10.09.2032	2,27	1,86	0,22	0,00
HYME	17.12.2029	0,16	0,07	0,03	0,00
IVAR AASEN	31.12.2036	0,28	0,06	0,01	0,00
NJORD	10.04.2034	1,13	3,05	0,87	0,00
SNØHVIT	01.10.2035	0,00	17,77	0,62	1,79
VEGA	04.06.2035	0,09	0,35	0,09	0,00

Note 18 - Events after the balance sheet date

The Sales and purchase agreements with OKEA ASA and M VEST ENERGY AS signed on November 11th 2021 where Neptune Energy Norge AS is selling it's equity shares in Draugen, Brage, Ivar Aasen, Utsira High Gas Pipeline and Edvard Grieg Oil Pipeline where completed on March 31st 2022.

31st of December 2021
1st of June 2022

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Peter Jones
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Peter Jones
Chairman of the Board

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Harald Peter Knöbl
Board member

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Daniel Hektoen
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Board member

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Eick Sterkman
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Hendrikus Thomas Sterkman
Board member

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Rune Haukebøe
Board member

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Trond Myklebust
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Board member

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Sidsel Margrethe Asheim
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Sidsel Margrethe Asheim
Board member

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Odin Estensen
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Odin Estensen
Managing Director

Building a better working world

Statsautoriserte revisorer
Ernst & Young AS

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INDEPENDENT AUDITOR'S REPORT

To the Annual Shareholders' Meeting of Neptune Energy Norge AS

Opinion

We have audited the financial statements of Neptune Energy Norge AS (the Company), which comprise the balance sheet as at 31 December 2021, the income statement and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion the financial statements comply with applicable legal requirements and give a true and fair view of the financial position of the Company as at 31 December 2021 and its financial performance and cash flows for the year then ended in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Company in accordance with the requirements of the relevant laws and regulations in Norway and the International Ethics Standards Board for Accountants' *International Code of Ethics for Professional Accountants (including International Independence Standards)* (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other information

Other information consists of the information included in the annual report other than the financial statements and our auditor's report thereon. Management (the board of directors and chief executive officer) is responsible for the other information. Our opinion on the financial statements does not cover the other information, and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information, and, in doing so, consider whether the board of directors' report contains the information required by legal requirements and whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated. If, based on the work we have performed, we conclude that there is a material misstatement of this other information or that the information required by legal requirements is not included, we are required to report that fact.

We have nothing to report in this regard, and in our opinion, the board of directors' report is consistent with the financial statements and contains the information required by applicable legal requirements.

Responsibilities of management for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the

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going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the board of directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Stavanger, 1 June 2022
ERNST & YOUNG AS

The auditor's report is signed electronically

Tor Inge Skjellevik
State Authorised Public Accountant (Norway)

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Signaturene i dette dokumentet er juridisk bindende. Dokument signert med "Penneo™ - sikker digital signatur". De signerende parter sin identitet er registrert, og er listet nedenfor.

"Med min signatur bekrefter jeg alle datoer og innholdet i dette dokument."

Tor Inge Skjellevik
Statsautorisert revisor
På vegne av: Ernst & Young AS
Serienummer: 9578-5997-4-259359
IP: 145.62.xxx.xxx
2022-06-01 11:23:33 UTC

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