



ÅRSREGNSKAPET FOR REGNSKAPSÅRET 2021 - GENERELL INFORMASJON

Enheten

Organisasjonsnummer: 991 317 155
Organisasjonsform: Aksjeselskap
Foretaksnavn: PGNIG UPSTREAM NORWAY AS
Forretningsadresse: Moseidsletta 122
4033 STAVANGER

Regnskapsår

Årsregnskapets periode: 01.01.2021 - 31.12.2021

Konsern

Morselskap i konsern: Nei

Regnskapsregler

Regler for små foretak benyttet: Nei
Benyttet ved utarbeidelsen av årsregnskapet til selskapet: Forenklet IFRS

Årsregnskapet fastsatt av kompetent organ

Bekreftet av representant for selskapet: Eline J Haugen Pendegraft
Dato for fastsettelse av årsregnskapet: 03.02.2022

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, 05.07.2023



Resultatregnskap

Beløp i: NOK	Note	2021	2020
RESULTATREGNSKAP			
Inntekter			
Sales income		13 166 000 000	2 180 000 000
Other income		147 000 000	0
Sum inntekter	3	13 313 000 000	2 180 000 000
Kostnader			
Exploration expenses	4	310 000 000	80 000 000
Production and sales cost	6	1 238 000 000	711 000 000
Employee expenses	5	104 000 000	57 000 000
Depreciation	11	1 648 000 000	1 364 000 000
Depreciation of use to right assets	11	18 000 000	16 000 000
Nedskrivning av varige driftsmidler og immaterielle eiendeler	11	-306 000 000	831 000 000
Other operating expense	7	128 000 000	67 000 000
Sum kostnader		3 140 000 000	3 126 000 000
Driftsresultat		10 173 000 000	-946 000 000
Finansinntekter og finanskostnader			
Other financial income	8	393 000 000	176 000 000
Sum finansinntekter		393 000 000	176 000 000
Rentekostnad til foretak i samme konsern	17	150 000 000	157 000 000
Other financial expenses	9	592 000 000	14 000 000
Sum finanskostnader		742 000 000	171 000 000
Netto finans		-349 000 000	5 000 000
Ordinært resultat før skattekostnad		9 824 000 000	-941 000 000
Tax on the profit/(loss) for the year	10	7 886 000 000	-758 000 000
Ordinært resultat etter skattekostnad		1 938 000 000	-183 000 000
Årsresultat		1 938 000 000	-183 000 000



Balanse

Beløp i: NOK	Note	2021	2020
BALANSE - EIENDELER			
Anleggsmidler			
Immaterielle eiendeler			
Capitalized exploration expenses	11	909 000 000	1 503 000 000
Goodwill	11	2 896 000 000	0
Sum immaterielle eiendeler		3 805 000 000	1 503 000 000
Varige driftsmidler			
Assets in production	11	18 380 000 000	7 376 000 000
Assets in development	11	3 909 000 000	5 168 000 000
Right-of-use asset	11	190 000 000	209 000 000
Other fixtures and fittings, tools and	11	3 000 000	4 000 000
Long term receivable	20	56 000 000	0
Sum varige driftsmidler		22 538 000 000	12 757 000 000
Sum anleggsmidler		26 343 000 000	14 260 000 000
Omløpsmidler			
Varer			
Inventory	15	120 000 000	79 000 000
Sum varer		120 000 000	79 000 000
Fordringer			
Trade receivable		380 000 000	192 000 000
Trade receivables Group enterprises		2 791 000 000	129 000 000
Tax receivable	10	0	172 000 000
Other current receivables	13	601 000 000	223 000 000
Sum fordringer		3 772 000 000	716 000 000
Bankinnskudd, kontanter og lignende			
Cash and cash equivalents	14	3 355 000 000	164 000 000
Sum bankinnskudd, kontanter og lignende		3 355 000 000	164 000 000
Sum omløpsmidler		7 247 000 000	959 000 000
SUM EIENDELER		33 590 000 000	15 219 000 000



Balanse

Beløp i: NOK	Note	2021	2020
BALANSE - EGENKAPITAL OG GJELD			
Egenkapital			
Innskutt egenkapital			
Share capital	16	1 115 000 000	1 110 000 000
Share premium		1 777 000 000	1 282 000 000
Sum innskutt egenkapital		2 892 000 000	2 392 000 000
Opptjent egenkapital			
Retained earnings		1 258 000 000	-681 000 000
Sum opptjent egenkapital		1 258 000 000	-681 000 000
Sum egenkapital		4 150 000 000	1 711 000 000
Gjeld			
Langsiktig gjeld			
Utsatt skatt	10	9 800 000 000	3 331 000 000
Abandonment provision	20	2 679 000 000	1 580 000 000
Sum avsetninger for forpliktelser		12 479 000 000	4 911 000 000
Annen langsiktig gjeld			
Gjeld til kredittinstitusjoner	18	4 325 000 000	3 672 000 000
Langsiktig konserngjeld	17	1 420 000 000	4 253 000 000
Lease liabilities	12	122 000 000	147 000 000
Sum annen langsiktig gjeld		5 867 000 000	8 072 000 000
Sum langsiktig gjeld		18 346 000 000	12 983 000 000
Kortsiktig gjeld			
Debt to financial institutions payable within 1 year	18	6 000 000	2 000 000
Leverandørgjeld		123 000 000	31 000 000
Taxes payable, not assessed	10	9 821 000 000	38 000 000
Employee tax liabilities, duties		38 000 000	16 000 000
Kortsiktig konserngjeld	17, 23	12 000 000	37 000 000
Other current liabilities	21, 23	1 094 000 000	401 000 000
Sum kortsiktig gjeld		11 094 000 000	525 000 000



Balanse

Beløp i: NOK	Note	2021	2020
Sum gjeld		29 440 000 000	13 508 000 000
SUM EGENKAPITAL OG GJELD		33 590 000 000	15 219 000 000



Skattedirektoratet

Saksbehandler Torstein Kinden Helleland	Deres dato 19.09.2008	Vår dato 19.03.2009
Telefon 22 07 81 39	Deres referanse Gry Merete Mellestrand	Vår referanse 2009/170942

Deloitte AS
Postboks 287 Forus
4066 STAVANGER

Søknad om tillatelse til å utarbeide årsregnskap og årsberetning på engelsk språk for PGNiG Norway AS, org. nr. 991 317 155

Det vises til Deres brev til Finansdepartementet av 19. september 2008 oversendt Skattedirektoratet 13. mars 2009. Det vises videre til e-post av 18. mars 2009 samt telefonsamtale i sakens anledning. De søker på vegne av PGNiG Norway AS om dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk.

I søknaden er det opplyst at selskapet er stiftet og 100 % eid av polske PGNiG SA, som er børsnotert på Warsawa-børsen. Den polske stat eier ca 85 % av aksjene i PGNiG SA. Selskapet er finansiert av morselskapet og har ingen ekstern langsiktig gjeld. Selskapet er etablert som et oljeselskap. Engelsk er i stor grad etablert som forretningsspråk i oljebransjen i Norge. Selskapets regnskap utarbeides etter forenklet IFRS, og innarbeides i konsernregnskapet for det polske konsernet. Konsernregnskapet utarbeides både på polsk og engelsk. Selskapet har norsk regnskapsmedarbeider og polsk økonomisjef. Ca. 1/3 av de ansatte er polske mens resten er norske. Alle styremedlemmene er polske. Da de norske ikke snakker polsk og de polske ikke snakker norsk i særlig grad skjer kommunikasjon internt i selskapet og konsernet, samt mot revisor, i stor grad på engelsk. Avtaler med morselskap utarbeides i hovedsak på engelsk, det samme gjelder styremøtereferater. Selskapet søker på denne bakgrunn om dispensasjon fra Regnskapsloven § 3-4 tredje ledd om at årsregnskap og årsberetning skal være på norsk.

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."*

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 skjævt fordelt informasjon."

Postadresse Postboks 9200 Grøntand 0134 Oslo	Besøksadresse Fredrik Selmers vei 4 Org. nr: 974761076	Sentralbord 800 80 000 Telefaks 22 17 08 60
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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. Offentlige myndigheter må også anses som en sentral regnskapsbruker, idet ulike myndigheter, som lignings- og tilsynsmyndigheter, benytter regnskapene som sentrale verktøy i sin kontrollvirksomhet.

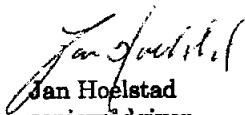
Det er etter Skattedirektoratets vurdering derfor avgjørende at spørsmål om dispensasjon fra kravet til å utarbeide årsregnskap og/eller årsberetning på norsk, ikke på vesentlige områder fraviker fra hensynet til brukere av regnskapsinformasjon. Søkeren må dessuten som et utgangspunkt for vurderingen ha en særlig interesse for kun å utarbeide årsregnskap og/eller årsberetning på et annet språk enn norsk.

Som nevnt ovenfor er det særlig hensynet til brukerne av regnskapsinformasjon som skal vurderes ved en dispensasjonssøknad. Selskapet er 100 % eid av polske PGNiG SA som er børsnotert på Warsawa-børsen. Selskapet er finansiert av morselskapet og har ingen ekstern langsiktig gjeld. Konsernregnskapet utarbeides både på polsk og engelsk. Forretningsspråket er i det vesentlige engelsk innen oljebransjen. Arbeidsspråket i selskapet er i stor grad engelsk fordi alle styremedlemmene og mange av de ansatte er polske. Avtaler med morselskap utarbeides i hovedsak på engelsk, det samme gjelder styremøtereferater

Skattedirektoratet gir på bakgrunn av en helhetsvurdering PGNiG Norway AS dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk, jf. regnskapsloven § 3-4 tredje ledd.

Dispensasjonen er gitt under den forutsetning at de ovennevnte opplysninger som vedtaket baserer seg på ikke endres vesentlig.

Med hilsen


Jan Hoelstad
seniorrådgiver
Rettsavdelingen, foretaksskatt
Skattedirektoratet


Torstein Kinden Helleland



KPMG AS
Forusparken 2
Postboks 57
4064 Stavanger

Telephone +47 45 40 40 63
Fax
Internet www.kpmg.no
Enterprise 935 174 627 MVA

To the General Meeting of PGNiG Upstream Norway AS

Independent Auditor's Report

Opinion

We have audited the financial statements of PGNiG Upstream Norway AS (the Company), which comprise the balance sheet as at 31 December 2021, the income statement, statement of comprehensive income, statement of changes in equity 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 statutory requirements, and
- the financial statements give a true and fair view of the financial position of the Company as at 31 December 2021, and its financial performance and its cash flows for the year then ended in accordance with simplified application of international accounting standards according to section 3-9 of the Norwegian Accounting Act.

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 as required by laws and regulations 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

The Board of Directors and the Managing Director (management) are responsible for the information in the Board of Directors' report. The other information comprises information in the annual report, but does not include the financial statements and our auditor's report thereon. Our opinion on the financial statements does not cover the information in the Board of Directors' report.

In connection with our audit of the financial statements, our responsibility is to read the Board of Directors' report. The purpose is to consider if there is material inconsistency between the Board of Directors' report and the financial statements or our knowledge obtained in the audit, or whether the Board of Directors' report otherwise appears to be materially misstated. We are required to report if there is a material misstatement in the Board of Directors' report. We have nothing to report in this regard.

Based on our knowledge obtained in the audit, it is our opinion that 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 of financial statements that give a true and fair view in accordance with simplified application of International Accounting Standards according to the Norwegian Accounting Act section 3-9, and for such internal control as management determines is

KPMG AS, a Norwegian limited liability company and member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity

Statsautoriserede revisorer - medlemmer av Den norske Revisorforening

Offices in:

Oslo	Elverum	Molde	Stord
Ålgård	Finnsnes	Molde	Straume
Arendal	Hartar	Skien	Tromsø
Bergen	Haugesund	Sandefjord	Trondheim
Bodo	Kolvervik	Sandnessjøen	Tynset
Drammen	Kristiansand	Stavanger	Alesund



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 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 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. We 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 a true and fair view.

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.

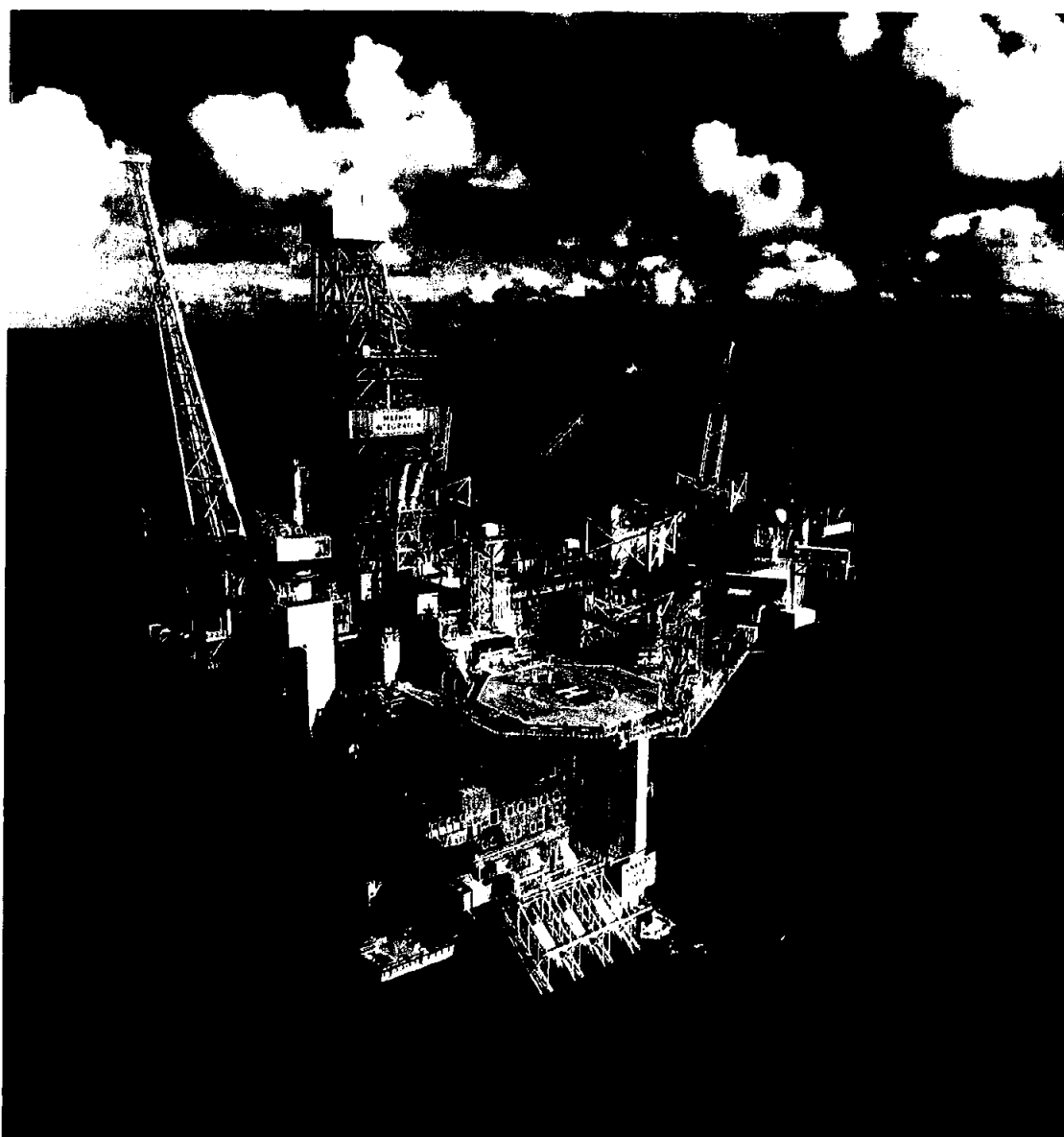
Stavanger, 8 February 2022
KPMG AS

Mads Hermansen
State Authorised Public Accountant



ANNUAL REPORT 2021

SANDNES, 3 FEBRUARY 2022





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DIRECTORS' REPORT

PGNiG Upstream Norway AS ("PGNiG Upstream" or "the Company") was established in May 2007, and its head office is located in Sandnes, Norway, with a regional office in Tromsø. The objective of the Company is to explore, develop and produce oil and gas.

PGNiG Upstream is a subsidiary company in the PGNiG Group. The sole owner of PGNiG Upstream is PGNiG SA ("PGNiG"), which is the largest oil and gas exploration and production company in Poland. It is a leader in the natural gas business in Poland, focusing on trade and distribution, as well as oil and gas exploration, production and gas storage. PGNiG has been listed on the Warsaw Stock Exchange since September 2005, with the Polish State Treasury as the main shareholder. Detailed information about the activities and business profile of PGNiG can be found at the company's internet address: www.en.pgnig.pl.

Company overview

Over the last years PGNiG Upstream has grown and gained significant experience from its operations on the Norwegian Continental Shelf ("NCS"). We have built a company that today employs 86 experienced staff from around the world and has become a successful drilling operator.

Supported by high commodity prices, the company has achieved operational revenue in 2021 of NOK 13.3 billion, with production of 14.3 mboe, accounting for 34% of the PGNiG Group's total production.

PGNiG Upstream has invested more than 26 billion NOK in Norway and participated in the drilling of multiple exploration and production wells. This has led to several discoveries on the NCS, including Ærfugl, Shrek, Warka and Egyptian Vulture. In addition, the company has participated in over ten licensing rounds and been awarded more than twenty production licenses.

PGNiG Upstream currently owns shares in fourteen producing fields on the NCS (Skarv, Morvin, Vilje, Vale, Gina Krog, Ærfugl, Ærfugl Nord, Skogul, Kvitebjørn, Valemon, Duva, Alve, Marulk, Ormen Lange) and one processing plant (Nyhamna). The company plans to develop eight other fields in the upcoming years (Alve North East, Tommeliten Alpha, King Lear, Shrek, Fogelberg, Alve North, Ormen Lange Phase 3 and Gjøk). Furthermore, there is ongoing evaluation work on the recent discoveries. As of 31st of December 2021, the total resources and reserves account for 309 million barrels of oil equivalent (unaudited information).

In addition the Company holds a considerable exploration portfolio, which is expected to mature into future drill decisions on the NCS

PGNiG Upstream Norway Board Members



Przemysław Wacławski
(Chairman)



Magdalena Zegarska



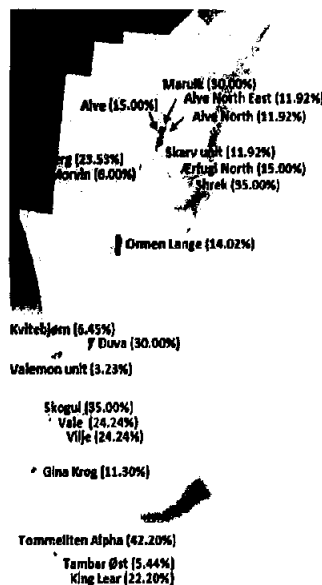
Arkadiusz Sekściński



Annual Report 2021



Field	PUN share	Operator	Partners	PUN 2P + 7C YE2021 mboe	PUN production 2021 kboe/day
Ave	16.00%	Equinor (53%)	DNO (32%)	5.0	0.4
Duva	30.00%	Neptune (30%)	Idemitsu (30%), Sval (10%)	20.4	2.0
Gina Krog	11.30%	Equinor (58%)	KUPPEC (30%)	13.3	3.5
Kvitbjørn	0.46%	Equinor (40%)	Petoro (30%), Spirit (16%), Total (9%)	10.8	4.8
Marulic	30.00%	Vår (28%)	DNO (17%), Equinor (30%)	2.9	1.1
Morvin	0.00%	Equinor (64%)	Vår (30%)	1.3	0.0
Ormen Lange	14.02%	Shell (18%)	Equinor (28%), Petoro (37%), Vår (8%), Equinor (38%), Wintershall (28%)	94.5	0.0
Skarv (incl. Erfugl Nord)	11.92%	AkerBP (24%)	Equinor (28%), Petoro (37%), Vår (8%), Equinor (38%), Wintershall (28%)	30.0	13.9
Skogul	35.00%	AkerBP (65%)		1.8	2.1
Vale	24.24%	Spirit (50%)	LOTOS (28%)	0.7	1.5
Valemon	3.23%	Equinor (87%)	Petoro (30%)	1.0	0.4
Vilje	24.24%	AkerBP (41%)	Equinor (28%)	3.3	1.4
Sum assets producing in 2021				192.3	39.2
Aha Nork	11.92%	AkerBP (84%)		3.0	-
King Lear	22.20%	AkerBP (78%)		30.7	-
Shrek	35.00%	AkerBP (34%)	Line (30%)	5.3	-
Tommeliten Alpha	42.20%	Conoco (28%)	Total (20%), Vår (8%)	68.7	-
Tambar Øst	5.44%	AkerBP (44%)	DNO (38%), Repsol (10%), KUPPEC (1%)	0.0	-
Fogelberg	25.53%	Spirit (60.82%)	Line (19.68%)	0.9	-
Sum PUN asset portfolio				309.0	39.2



*Reserves and resources recognized in the table above are based on the field operator's RNB, published annually in the various licenses. PGNiG Upstream recognize the operator's resource class 1-5, base case (P50). All figures are in million boe net to PGNiG Upstream

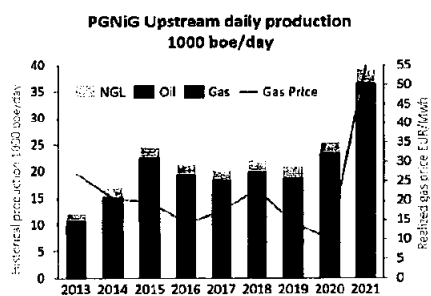
Key developments in 2021

The Company's main objective is to secure stable, reliable and cost-effective gas supplies for the PGNiG Group. This goal is expected to be materialized through diversified hydrocarbon production from the NCS. On September 31st 2021 the Company completed its acquisition of INEOS ERP Norge's assets on the NCS. With the recent transaction, PGNiG Upstream considerably increased the gas reserves and holds a well-diversified portfolio, from exploration, through developing and producing assets.

In 2021 the Company delivered strong financial results, with revenues of NOK 13.3 billion and an EBITDA of NOK 11.5 billion. These results were possible thanks to the performance of key assets including Ormen Lange and Skarv, which accounted for approximately 58% of the total revenue.

Total production in 2021 of 1.4 billion cubic metres of gas, and 732 thousand tonnes of crude oil (including NGL's), were up by 89% when comparing with 2020.

While 2020 was a challenging year with low hydrocarbon prices, 2021 proved to be the opposite. Europe is currently in a historic energy crisis resulting in record high gas prices. With a strong gas exposure, PGNiG Upstream has benefitted from the market environment.



The sections below include an overview of key achievements. All with the goal of securing own equity gas through the Baltic Pipe.

Successful business development activities

Annual Report 2021



In 2021 the company has strengthened its position on the NCS, with the successful acquisition of all assets from INEOS ERP Norge ("INEOS"). The transaction significantly increased hydrocarbon reserves and equity in gas production of PGNiG in Norway. With this acquisition, the Company will meet its production target from the PGNiG Group Strategy during 2022.

The purchase price was USD 615 million with an effective date of 1st January 2021. The transaction was completed on 30th September 2021 after fulfilment of the conditions precedent. A significant portion of the purchase price was covered with cash flows generated in the period between the effective date and the completion date.

The transaction included the producing assets Ormen Lange (14.02%), Alve (15%), Marulk (30%), gas processing facility Nyhamna (8.18%), a considerable exploration portfolio and highly competent employees.



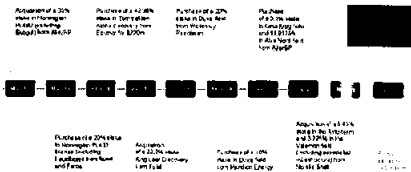
Nyhamna Facility

Ormen Lange is the 2nd largest gas field on the NCS and started its production in 2007. It is a long-life asset with production potential beyond 2040 and is developed as a subsea tie-back to the onshore gas processing facility Nyhamna, where fields such as Aasta Hansteen and Dvalin share the same processing plant via the Polarled pipeline. Ormen Lange is currently working on increasing the total recoverable reserves with an ongoing subsea compression project (Phase 3), expected to commence production in 2025.

Acquisition of assets from INEOS ERP Norge was the 9th significant M&A transaction in the last four years.

M&A track record in Norway

PGNiG 1822*



All acquired fields contain predominantly natural gas. Following the transactions, PGNiG Upstream gas production will increase to 2.6 bcm in 2022, which constitutes over 400% increase in comparison with 2017. This is particularly important for PGNiG, taking into account involvement in the Baltic Pipe project, which aims to export Norwegian gas to Poland through a new infrastructure connection ("Baltic Pipe").

Based on fields which are currently owned by PGNiG Upstream, the Company plans to reach 3.8 bcm of gas production in 2026.

The company expects to change the business development focus within the current portfolio and mature more potential exploration targets to drillable targets.

Strong development focus

PGNiG Upstream holds a well-diversified portfolio ranging from exploration, developing, producing and decommissioning. A portfolio that is expected to play an important role in securing gas deliveries to the PGNiG Group.

In 2021 the company received the first production from Gråsel, Ærfugl Nord and Duva. Gråsel was brought on-stream ahead of plan, and both Gråsel and Ærfugl Nord are a tie-ins to Skarv, which PGNiG holds equity in. Duva was acquired in 2019 and commenced production in August, with a gross rate above 25,000 boe per day.

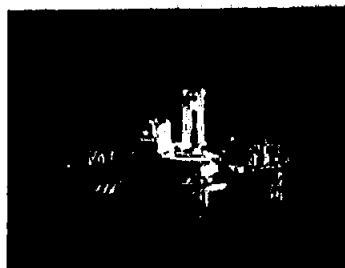
The company is currently participating in two important developments on the NCS: Ormen Lange Phase 3 and Tommeliten Alpha, which both submitted a Plan for Development and Operation (PDO) in Q4 2021. In addition to these projects the Company is currently

involved in the maturing six an additional six assets: Fogelberg, King Lear, Alve North, Alve North East, Shrek and Gjøk. Development plans (PDO's) for these assets are expected in 2022. Shrek is a result of the Company's exploration program and is expected to commence production in 2025, slightly below 30,000 boe per day (gross).

Delivering on exploration activities

In 2021, the Company participated in two exploration wells, which resulted in one discovery, on PL939 Egyptian Vulture.

PL939 well drilled by West Hercules



Egyptian Vulture (PL939) was drilled 20 kilometres from the Åsgard field and 23 km from the Kristin field. The well was drilled to a depth of 3,883 meters below the sea level and was operated by Equinor. The discovery is currently being evaluated, but preliminary results indicate light oil with potential recoverable resources ranging from 19 to 63 million barrels (gross).

The second well that was drilled in 2021 was PL937 Fat Canyon, a PGNiG operated well. The operatorship was transferred through the acquisition of INEOS ERP Norge. Unfortunately the wildcat well came in dry. PGNiG Upstream expect to finalize the remaining work and relinquish the license during Q1 2022.

Despite the Fat Canyon well, 2021 follows a good exploration track record for the Company, with discoveries at Shrek (2019) and Warka (2020). Exploration activities are expected to play an important role in enabling PGNiG Upstream to maintain high and

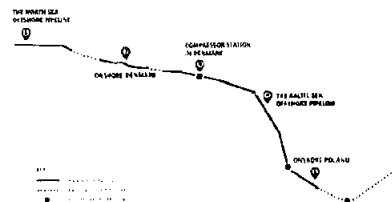
stable production on the long term. The Company is active in license rounds, and was awarded four new licenses in APA 2021, out of which three are operated. PGNiG Upstream also opened a new core region with the acquisition of INEOS, around Ormen Lange.

Involvement in the Baltic Pipe Project

The Company is actively involved in the Baltic Pipe project ("Baltic Pipe").

The Baltic Pipe is a strategic infrastructure project with the goal of creating a new gas supply corridor in the European market. The Baltic Pipe Project will allow transport of gas from Norway to the Danish and Polish markets, as well as to end-users in neighbouring countries.

The project is implemented in close cooperation with the Polish gas transmission system operator GAZ-SYSTEM and the Danish gas and electricity transmission system operator Energinet.



The gas pipeline will have the capacity to transport 10 bcm of natural gas per year. In 2021, the construction of the offshore sections were completed. Baltic Pipe is expected to be fully operational in October 2022. PGNiG Upstream plans to utilize capacity in this pipeline to send its own gas production to Poland. PGNiG Upstream's strong commitment to the Baltic Pipe project was confirmed in 2018 with the signing of the long-term capacity agreement between PGNiG and the respective transmission system operators.

The implementation of the Baltic Pipe Project will bring significant socio-economic benefits for Poland, Denmark and other countries of the Baltic Sea region,



as well as Central and Eastern Europe. The project is fully consistent with the European Union energy policy guidelines in terms of the provision of secure, affordable and sustainable energy supplies.

Key objectives of the project are:

- Strengthening security of supply in the region by providing access to Norwegian gas for the Danish-Swedish and Polish markets and for the markets in Central and Eastern Europe;
- Further increasing the capacity of Danish gas infrastructure to reduce tariffs for the benefit of the users;
- Increasing competition on regional gas markets and facilitating price convergence between markets, enabling new participants to enter the market;
- Increasing the technical reliability of gas supplies to customers through diversification of sources of gas supplies.

Research and development activities

PGNIG Upstream's R&D activities have been focused on tools and methods for exploration and production, primarily through its co-operation with universities and external experts.

The total costs of R&D activities amounted to NOK 2.5 million in 2021. The main objective of this expense is to get access to scientific studies that can be used by PGNIG Upstream to evaluate the potential for good oil and gas deposits within its licenses portfolios on the NCS.

By carrying out these studies, PGNIG Upstream is gaining access to exclusive scientific information and highly qualified personnel. The Company anticipates that the total income from research and development will offset the total costs incurred.

Company development, performance and going concern

In accordance with the Norwegian Accounting Act, the Company's Board of Directors has reviewed all available information up to the reporting date on which the Company accounts are issued and have taken into account all available information related to the future, for at least 12 months beyond the reporting date. The review includes the operational outlook and work programs, while maintaining appropriate headroom in for liquidity and financial covenant compliance throughout the assessment period.

Following its review, the Board of Directors confirms, pursuant to the Norwegian Accounting Act section 3-3a, that the requirements of the going concern assumption are met and that the financial statements have been prepared on that basis. The Board is not aware of any matters not covered in this report that could be of significance, when evaluating the Company's position.

Working environment

The Board is pleased to report that the Company has built a highly competent organisation based on experienced employees with varying backgrounds – both technical and commercial. The average number of employees in 2021 amounted to 51. All employees have been trained in HSE regulations.

The number of employees increased significantly in the last quarter, following the transaction with INEOS ERP Norge. As a consequence, PGNIG Upstream is going through an integration project aimed to ensure a good environment for collaboration between employees who have originated from two different organizations. The integration project has also created a platform for communication and the involvement of new colleagues.

Additionally in 2021, the Company maintained high focus related to the development of COVID-19. Keeping



a strong focus on the implemented measures and ensured a safe and comfortable working environment.



These measures have helped to keep the absence from work due to illness low at 2% and that no work related injuries nor accidents have occurred in 2021. At the same time the company has delivered a solid operating performance during this demanding year. Measures continue to be implemented to maintain low rates of absence.

Equal opportunities

The Company is committed to maintaining a working environment with equal opportunities for all, based on qualifications, irrespective of gender, sexual orientation or disability. PGNiG Upstream does not tolerate any form of discrimination, wherever it be trade union affiliation, social background, political opinion, medical condition and so forth. The Company has also established a Working Environment Committee and implemented several regulations that promote equality and prevent discrimination, like the "Handling bullying and harassment procedure" or "Code of Ethics".

In December 2021, women held 34% of the positions in the Company. At the same time, the Board consisted of two male and one female members. Remuneration is related to job content, competence and qualification. This ensures that men and women with corresponding positions and equal experience, and who produce equally good results, receive the same pay.

In December 2021, voluntary part time employees accounted for 4.6 per cent (all women). In addition, the Company employed eight consultants (all men). The

average number of utilized weeks for parental leave accounted for 36 for women and 13 for men.

External environment

Our aim is to prevent all incidents or accidents that cause harm to people, environment or material assets; we will conduct our business in a safe and environmentally friendly way.

We do not want to cause unnecessary strain to the environment. Our office is located in a new energy efficient building, using district heating and cooling generated by a nearby waste handling plant. PGNiG Upstream operates within an industry where there is risk of pollution to the environment. Therefore the Company places high focus on environment issues in its operated licenses. In addition, PGNiG Upstream closely follows activities of other operators. We perform our duties through audits, verifications, meetings and by reviewing daily, weekly, and monthly reports.

Results, investments

Strong performance in 2021 was supported by high commodity prices and stable and high production from the current portfolio including the recently newly acquired INEOS assets. With record high gas prices and new gas fields on stream the Company has generated revenues of NOK 13,315 million. PGNiG Upstream has managed its assets safely, reliably and in a cost effective manner, achieving an EBITDA of NOK 11,534 million

Accumulated operating costs at the end of 2021 amounted to NOK 3,141 million, of which NOK 1,360 million was classified as depreciation and impairment. The comparative figures for the preceding year were NOK 3,126 million and NOK 2,211 million, respectively. Personnel costs were NOK 104 million in 2021, compared with NOK 57 million in 2020. The increase was driven by increased number of employees following transaction with INEOS.

Annual Report 2021

Net financial costs for the period were NOK 349 million, compared to financial income of NOK 5 million for the previous year. The increase in net financial expenses was mainly due to a negative development in foreign exchange rates, an increased level of abandonment accrual and less capitalized interests.

Skarv FPSO



Fixed assets utilized in production and development are valued at NOK 22,538 million. An increase of NOK 9,782 million in comparison with the previous year is due to new assets and ongoing investments. The company's cash and cash equivalents has increased considerable from NOK 164 million to NOK 3,355 million at the end of 2021. High balance in the end of the year is related to the scheduled tax payment.

A detailed overview of the financial performance is included in the relevant sections of the Financial Statements. The Board is not aware of any circumstances of negative significance to the Group's financial position that are not described in the Financial Statements, including notes, neither during the accounting year, nor after the year end closing.

A separate country-by-country reporting of payments to authorities for 2021 is provided together with the Annual Report.

Ormen Lange unit



Liquidity and financing

The liquidity of PGNiG Upstream in 2021 has been secured through sales revenues and supported by utilization of debt. Based on an EBITDA of NOK 11,534 million, the Company generated a cash flow from operating activities at the level of NOK 10 623 million.

The details of the Company's sources of financing are presented in the notes to the Financial Statements. The Company's current liquidity, in the form of cash at hand, existing debt facilities and future operational cash flow, supports all current project commitments. The Board confirms that the Company meets the requirements of the Companies Act in ensuring a proper level of equity and liquidity relative to the risk and extent of its business. The Board also confirms that the Company complies with covenants included in its financing agreements.

In the opinion of the Board of Directors there is no risk associated with financing the operations of PGNiG Upstream. The company holds considerable un-drawn external credit facilities, cash and cash equivalents, and the income from future operational activities looks promising.



Tommeliten PDO submitted



PGNiG Upstream's production in Norway for 2022 is estimated at 920 thousand tonnes of crude oil including NGL's, and 2,6 billion cubic metres of gas. At current gas prices, PGNiG Upstream's revenue in Norway, based on the current license portfolio is expected to reach NOK 20,087 million over the next year.

Risk factors

PGNiG Upstream is operating in a macro environment with high volatility of sales prices, as experienced in 2020 and 2021. Changes in market conditions (oil and gas prices) and foreign exchange rates may impact future margins.

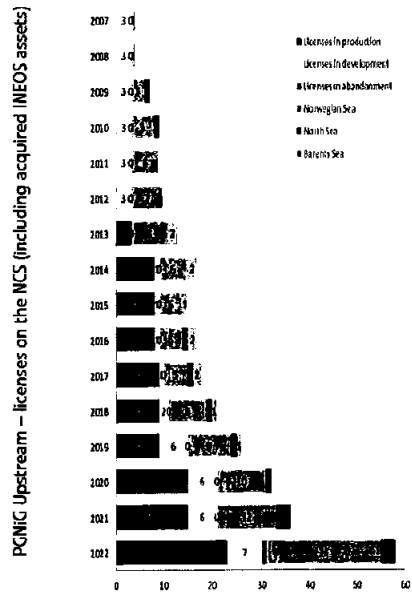
Another risk factor is related to reserves estimates, which may be inaccurate. The Company is participating in complex projects that are challenging in terms of timing and cost control (for example Ormen Lange Phase 3 and Tommeliten Alpha). However, the existing portfolio is characterized by relatively low production costs and high margins. Therefore, the risk exposure in the total investment portfolio is considered as acceptable.

PGNiG Upstream has a long-term strategy and uses conservative assumptions in its planning. At the end of the reporting period the Company had no financial hedging instruments or contracts. This policy is supported by the shareholder.

Outlook

The NCS is recognised as an important area for international upstream activities for the PGNiG Group and has significant exploration potential.

The scale of our Norwegian operations makes Norway the key destination for the PGNiG Group's international expansion, with three main factors determining our choice: diversification of Poland's gas supply sources, strong exploration potential and a stable, transparent regulatory framework.



PGNiG was founded in 2007 and has since the start been growing at a rapid pace through organic growth and targeted acquisitions, which was made possible through the strong support of the PGNiG Group, dedicated management and highly competent employees. We have invested more than NOK 26 billion and participated in numerous exploration and production wells, which has led to several discoveries. Altogether, the Company owns shares in twenty-two



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assets with a total resource and reserves estimate of 309 million boe. In addition, the Company holds a considerable exploration portfolio, which is expected to secure the long-term supply of gas to PGNiG Group.

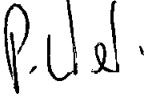
From the perspective of the Board of Directors, PGNiG Upstream will focus on two main areas:

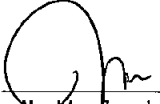
- securing natural gas supplies for the PGNiG Group, and
- developing the exploration & production business.


It is expected that business development activity will continue in the coming years. At the same time PGNiG

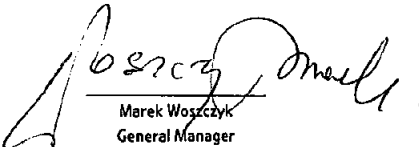
Upstream plans to further develop its operatorship capabilities. The Company is open for any opportunities and business partnerships that may arise on the NCS, as such.

To summarise, increasing production capacity on the NCS and securing new gas supplies for Poland, should allow the PGNiG Group to maintain its leading position in Central Europe. The historical activity by PGNiG Upstream should be seen as an important step on the growth path of the PGNiG Group. The next steps will be defined by new projects.


Przemysław Wacławski
Chairman of the Board


Magdalena Żegarska
Director of the Board


Arkadiusz Sekściński
Director of the Board


Marek Woźczyk
General Manager

Sandnes,
3rd February 2022



FINANCIAL STATEMENTS



Annual Report 2021



INCOME STATEMENT (NOK million)

Note	2021	2020	
	Sales income	13 167	2 180
	Other income	147	0
3	Revenue	13 315	2 180
4	Exploration expenses	(310)	(80)
5	Employee expenses	(104)	(57)
11	Depreciation	(1 648)	(1 365)
11	Depreciation of right-of-use assets	(18)	(16)
11	Impairment	306	(831)
6	Production and sales costs	(1 238)	(711)
7	Other operating expenses	(128)	(67)
	Total operating expenses	(3 141)	(3 126)
	Operating income/(loss)	10 173	(945)
17	Interest expenses to Group enterprises	(150)	(157)
8	Other financial income	393	176
9	Other financial expenses	(592)	(14)
	Net financial items	(349)	5
	Income/(loss) before tax	9 824	(941)
10	Tax on the profit/(loss) for the year	(7 886)	758
	Net income/(loss)	1 938	(183)

STATEMENT OF COMPREHENSIVE INCOME

	2021	2020
Net income/(loss)	1 938	(183)
Total comprehensive income	1 938	(183)



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BALANCE SHEET (NOK million)

ASSETS

Note		31/12/2021	31/12/2020
11	Goodwill	2 896	
11	Capitalized exploration expenses	909	1 503
	Intangible assets	3 805	1 503
11	Assets in production	18 380	7 376
11	Assets in development	3 909	5 168
11	Other fixtures and fittings, tools and equip.	3	4
11	Right-of-use asset	191	209
20	Long term receivable	56	
	Tangible fixed assets	22 538	12 757
	Non-current assets	26 343	14 260
15	Inventory	120	79
	Trade receivables	380	192
	Trade receivables Group enterprises	2 791	129
13	Other current receivables	601	223
10	Tax Receivable	0	172
	Current receivables	3 772	716
14	Cash and cash equivalents	3 355	164
	Current assets	7 246	959
	Assets	33 590	15 219

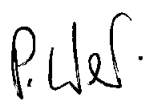


Annual Report 2021



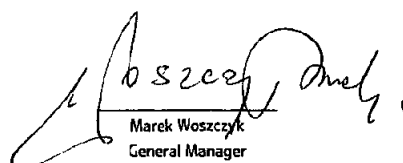
EQUITY AND LIABILITIES

Note		31/12/2021	31/12/2020
16	Share capital	1 115	1 110
	Share premium	1 777	1 282
	Paid-in capital	2 892	2 392
	Retained earnings	1 257	(681)
	Equity	4 150	1 711
10	Deferred tax	9 800	3 331
20	Abandonment provision	2 679	1 580
	Total Provisions	12 479	4 911
17	Debt to Group enterprises	1 420	4 253
18	Debt to financial institutions	4 325	3 671
12	Lease liabilities	122	147
	Long-term liabilities	5 867	8 072
	Trade payables	123	31
	Employee tax liabilities, duties	38	16
17	Interest on Debt to Group enterprises	11	36
23	Other liabilities Group enterprises	1	1
18	Debt to financial institutions payable within 1 year	6	2
21 23	Other current liabilities	1 093	402
10	Taxes payable, not assessed	9 821	38
	Current liabilities	11 094	525
	Liabilities	29 441	13 508
	Equity and liabilities	33 590	15 219


Przemysław Waclawski
Chairman of the Board


Magdalena Zegarska
Director of the Board


Arkadiusz Sekściński
Director of the Board


Marek Woszczyk
General Manager

Sandnes,
3rd February 2022



Annual Report 2021



CASH FLOW STATEMENT (NOK million)

Note	31/12/2021	31/12/2020
Cash flows from operating activities		
	Income (loss) before tax	9 824 (941)
11	Depreciation	1 666 1 381
11	Exploration drilling/capitalised seismic expenses	222 10
11	Impairment	(306) 831
9	Interest expenses	139 49
10	Taxes received/(paid)	466 756
8 9	Other financial items without cash effect	292 (26)
15	Changes in current assets – Inventory	1 (50)
	Changes in current receivables	660 264
	Changes in current receivables from Group enterprises	(2 662) (87)
	Changes in current liabilities	614 (227)
	Changes in other periodical items	(293) (73)
	Net cash from operating activities	10 623 1 889
Cash flows from investment activities		
11	Purchase of fixed assets	(4 949) (2 913)
11	Purchase of intangible assets	(583) (418)
	Divestment	84 0
	Net cash from investment activities	(5 448) (3 330)
Cash flows from financing activities		
16	Proceeds from issuance of shares and share premium	500 0
17	Proceeds/(repayment) from long-term debt raised from Group enterprises	(2 881) 1 624
18	Proceeds/(repayment) from long-term debt raised from financial institutions	654 109
17	Interests paid to Group enterprises	(173) (151)
9	Interests paid to financial institutions	(53) (86)
12	Lease payments	(31) (57)
	Net cash from financing activities	(1 984) 1 439
	Change in the balance of net cash	3 191 (3)
	Opening balance of cash and cash equivalents	164 167
14	Closing balance of cash and cash equivalents	3 355 164



STATEMENT ON CHANGES IN EQUITY (NOK million)

2021				2020			
Total	1 711	500	1 938	Total	1 894	(183)	1 711
Retained earnings	(681)		1 938	Retained earnings	(498)	(183)	(681)
Other comprehensive income	0			Other comprehensive income	0		0
Share premium	1 282	495		Share premium	1 282		1 282
Share capital	1 110	5	1 115	Share capital	1 110		1 110
	Equity at 1 st January 2021		Equity at 31 st December 2021		Equity at 1 st January 2020		Equity at 31 st December 2020
		Share capital increase	Net income/(loss) for the year			Net income/(loss) for the year	



GENERAL INFORMATION

PGNiG Upstream has its office in Sandnes, Norway and is a subsidiary, fully owned by PGNiG, whose head office is in Warsaw, Poland.

The financial statements of the Company are consolidated into PGNiG Group statements which can be found at the internet address: www.en.pgnig.pl

All amounts are in million NOK unless otherwise stated.

NOTE 1 SUMMARY OF IFRS ACCOUNTING POLICIES APPLICABLE FOR 2021

STATEMENT OF COMPLIANCE

The financial statements have been prepared in line with the simplified application of International Financial Reporting Standards ("IFRS") in accordance with the Norwegian Accounting Act § 3-9.

The financial statements were approved for issuance by the Board of Directors and the General Manager on 3rd February 2022.

The accounting policies applied in preparing these financial statements are presented below.

BASIS FOR PREPARATION

The financial statement has been prepared on a historical cost basis.

NEW OR AMENDED ACCOUNTING STANDARDS

In these financial statements, the company did not opt to early adapt any standards, interpretations or amendments to the existing standards which have been issued.

CHANGES TO THE ACCOUNTING POLICY

There have been no significant changes to the accounting policies during 2021.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

The preparation of financial statements in conformity with IFRS/simplified IFRS requires management to make judgments, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods.

Accounting estimates are employed in the financial statements to determine reported amounts, including the possibility for realisation of certain assets, income taxes and others. Although these estimates are based on management's best knowledge of historical experience, current events and actions, actual results may differ from these estimates. The estimates and the underlying assumptions are reviewed on an ongoing basis. Changes in estimates will be recognized when there are changes in the underlying assumptions or when new estimates can be determined with certainty.

The key sources of estimation uncertainty relate to:

- Fixed assets whose recoverable amount depends on the future cash flow generated by the assets. For further details refer to Note 11.
- Long term liabilities which are recognized at amortised cost using the effective interest rate method. The key uncertainty relates to the



assumption regarding drawdown and repayment of the long-term loans.

- Provisions which are based either on the expected costs related to decommissioning of facilities or relate to other obligations. For further details refer to Note 20.
- Capitalized exploration expenses which are dependent on existence of commercial oil and gas reserves. For further details refer to Note 11 and 26.

INTERESTS IN JOINT ARRANGEMENTS

A joint arrangement is a contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control (joint controlled assets). The Company accounts for the joint arrangements by recording its share of the assets, liabilities and cash flow, which is in line with industry practice in Norway. The Company combines its share of the joint ventures' individual income and expenses, assets and liabilities and cash flows on a line-by-line basis with similar items in the Company's financial statements.

ACQUISITIONS AND TRANSACTION DATE

In order to determine whether a particular transaction should be classified as a business combination in accordance with IFRS 3 (and thus accounted for using the acquisition method) or an asset acquisition in accordance with IAS 16, the reporting entity is often required to apply professional judgement.

For accounting purpose the main difference between a business combination and an asset acquisition is that ~~the business combination will result in deferred tax liabilities and goodwill that will not arise if it is an asset acquisition.~~

The transaction date is when the control is assumed, i.e. the time the related risk and reward in all material

respects are transferred to PGNiG. This date is normally dependent on approval from authorities and fulfilment of contractual obligations.

The acquirer's income statement shall incorporate the profits and losses of the acquired interest from the transaction date.

BUSINESS COMBINATIONS AND GOODWILL

In order to consider an acquisition as a business combination (as defined by IFRS 3), the acquired asset or groups of assets must constitute a business. In accordance with IFRS 3, a business is an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing goods or services to customers, generating investment income (such as dividends or interest) or generating other income from ordinary activities.

In the Exploration and Production segment, projects in the production phase are typically classified as businesses, whereas projects in the exploration phase are regarded as asset acquisitions. The acquisition of INEOS resulted in transfer of assets (mainly producing fields and infrastructure) and employees, which is an indication that the transaction should be classified as a business combination and accounted for as prescribed by IFRS 3.

The valuation is based on currently available information on fair values as of the transaction date (IFRS 13). Fair value is calculated by discounting cash flows from future operations to estimate the net present value. If new information becomes available within 12 months from the acquisition date about facts and circumstances that existed at the time of the acquisition, the company may change the fair value assessment in the purchase price allocation.

If the purchase price at the time of the acquisition exceeds the fair value of the acquired net assets goodwill arises (or vice versa negative goodwill arises).



The main part of the company's goodwill is related to the requirement to recognize deferred tax for the difference between the assigned fair values and the related tax base. Deferred tax positions are booked in accordance with IAS 12 paragraphs 15 and 24. Net deferred tax liabilities related to temporary differences on tangible assets is offset by technical goodwill. Technical goodwill is calculated as the calculated tax (78% for offshore assets in Norway) of differences between fair values of PP&E and other fixed assets and tax values.

There are no specific IFRS guidelines on the allocation of technical goodwill, and the company has therefore applied the general guidelines for allocating goodwill for the purpose of impairment testing. For the purpose of impairment testing, technical goodwill is allocated to the cash-generating units (CGUs). If ordinary goodwill is negative it will be offset against technical goodwill allocated to separate CGUs on a pro rata basis. The company's negative goodwill relates to the increase in expected prices for oil and gas in the future compared to expectations when the consideration was agreed.

Goodwill is not subject for depreciation under IFRS. Furthermore, depreciation of PP&E from the purchase price allocation will reduce recognised deferred tax liabilities. Therefore, the Company expect that goodwill will be subject for impairments if not offset by increase in other assumptions when calculating net present values in the future.

Acquisition-related costs, except costs to issue debt or equity securities, are expensed as incurred (IFRS 3, paragraph 53).

If selling a licence where the company historically has recognized deferred tax and goodwill in a business combination, both goodwill and deferred taxes from the acquisition are included when calculating gain/loss. When recording impairment of such licences as a result of impairment testing, the same assumptions are

applied when measuring the impairment. This avoids a gross up of the impairment with tax, in that the impairment charged to the Income statement will not be higher than the original post-tax amount paid in the business combination

DIVESTMENTS

When an interest in a joint arrangement is divested all assets and liabilities sold are derecognised from the balance sheet. Gain and loss from the sale is included in other income or other operating expenses. Revenues and expenses from the joint arrangement are included in the profit and loss statement until the transaction date.

FOREIGN CURRENCY TRANSLATION AND TRANSACTIONS

The financial statements are presented in Norwegian kroner (NOK). NOK is the functional currency of the Company.

Transactions, monetary assets and liabilities

Foreign currency transactions are translated into the functional currency using the exchange rates on the dates of the transactions.

Monetary items in a foreign currency are translated into NOK using the exchange rate applicable on the balance sheet date. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies are recognised as financial items in the income statement.

REVENUE RECOGNITION

Revenues associated with sale and transportation of crude oil, natural gas and other hydrocarbons are recognized when control is passed to the customer. This is typically when title passes at the point of delivery



of goods (lifting), but subject to assessment based on the contractual terms of agreements. The company applies the sales method to account for revenues from sale of hydrocarbons.

The company's volume of oil and gas sold (lifted) may differ from the volumes of which the Company is entitled to based on allocated production. If the accumulated production exceeds accumulated sales (liftings), the Company accounts for an underlift position (asset). If accumulated sales (liftings) exceed accumulated production, the Company accounts for an overlift position (liability). The Company values over-/underlift positions at fair value (market value). The periodic change in value of over-/underlift is recognized under Production and sales cost.

EXPLORATION COSTS

The Company employs the successful efforts method to account for exploration and development costs.

All exploration costs, with the exception of acquisition costs of licenses, seismic costs, field evaluation and drilling costs for exploration wells, are charged to expense as incurred.

Seismic costs (including seismic acquisitions and seismic studies), field evaluation and drilling costs for exploration wells are temporarily capitalized, pending the evaluation of potential existence of oil and gas reserves. If reserves are not found, or if discoveries are assessed not to be technically and commercially recoverable, the costs are expensed. The costs for acquiring exploration licenses are capitalized as an intangible asset and assessed for impairment.

Capitalized exploration costs are classified as intangible assets and are re-classified to tangible assets when the development concept is matured.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment include production facilities, facilities under construction, processing plants, pipelines, machinery and equipment, fixtures, etc. Items of property, plant and equipment are valued at cost, less accumulated depreciation and any impairment charges. All costs for developing commercial oil and/or gas fields are capitalized as tangible assets. Facilities under construction are not depreciated until the asset is put into operation. The Company also capitalize internal hours charged to development projects and borrowing cost allocated to the development projects.

Ordinary repairs and maintenance costs, defined as day-to-day servicing costs, are charged to the income statement during the financial period in which they are incurred. The cost of major overhauls is included in the asset's carrying amount when it is probable that the Company will derive future economic benefits in excess of the originally assessed standard.

DEPRECIATION OF OIL AND GAS PROPERTIES

Capitalized costs for oil & gas fields in production, processing plants and pipelines are depreciated individually (on a field level) using the unit-of-production method, unless another method can be shown to better reflect the expected pattern of consumption of the future benefit of the particular oil & gas field, processing plant or pipeline.

Under the unit-of-production method, annual depreciation rate is calculated based on proved and probable reserves (developed and undeveloped). The basis for depreciation is adjusted with future investments to reflect a reserve basis of proved and probable reserves. The rate of depreciation is equal to the ratio of hydrocarbon production for the period, over the estimated remaining proved reserves and contingent resources expected to be recovered at the beginning of the period.



The future development expenditures necessary to bring those resources into production are included in the basis for depreciation and are estimated by the management based on nominal price levels. Any changes in the resources and cost estimates that affect unit-of-production rates are dealt with prospectively.

The estimated residual value of each field installation is deducted when calculating the asset's depreciable amount.

The Company may also apply the reducing balance method for depreciation of oil & gas fields in special situations if the reducing balance method results in better matching between consumption of economic benefits and depreciation. Such a change from one method to another is applicable only if the reducing balance method better reflects the expected pattern of consumption of the future benefit of the particular oil & gas field.

Processing plants and pipelines are depreciated using the straight-line method over the assets' estimated useful lives.

IMPAIRMENT OF NON-CURRENT ASSETS

Property, plant and equipment and other non-current assets are subject to impairment testing when there is an indication that the assets may be impaired. At each reporting date the Company assess whether there is any indication that the assets may be impaired. If any indications exist, an impairment test is performed. Goodwill is subject for an annual impairment test regardless of indications and more often if there are impair triggers.

For the purposes of assessing impairment, assets are grouped at the level of cash-generating units (CGU). CGUs are defined as the oil and gas fields or hub of fields, processing plants and pipelines. An impairment loss is the amount by which the carrying amount of the assets exceeds the recoverable amount of the CGU

(including any allocated goodwill). The recoverable amount is the higher of the asset's net fair value less cost to sell and value in use. It is determined by reference to discounted future net cash flows expected to be generated by the asset. Cash flows are discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the recoverable amount (not however, to a higher amount than if no impairment loss had been recognised). Any reversal is recognised in the income statement. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

TRADE RECEIVABLES

Trade receivables are recognised initially at transaction price and subsequently measured at amortised cost less provision for impairment.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents comprise cash in hand, deposits held at call with banks, and other short term highly liquid investments with original maturities of three months or less. Bank overdrafts are included within borrowings in current liabilities on the balance sheet.

INTEREST-BEARING LIABILITIES

All loans and borrowings are initially recognised at cost, being the fair value of the consideration received net of issuing costs associated with the borrowing.

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest method.



Effective interest rate reflects an allocation of interest expense, transaction costs and any discount or premium on settlement, over the expected life of the financial instrument.

The measurement of effective interest rate applies to both fixed rate and variable rate instruments. For a fixed rate financial instrument, the effective interest rate is determined as a single constant rate over the life of the financial instrument and does not change as market interest rates change. For a floating rate financial instrument (for example a loan with a margin based on LIBOR plus a fixed credit spread), the effective interest rate is not a single constant interest rate, but is instead calculated through a combination of the spot curve for the benchmark interest rate (for example LIBOR) and an initial effective spread.

BORROWING COSTS

Borrowing costs are recognised as an expense in the period in which they are incurred, unless they meet criteria as explained below.

Borrowing costs which are directly attributable to the acquisition, construction or production of a qualifying asset, form part of the cost of that asset and therefore are capitalized.

FINANCIAL INSTRUMENTS

The Company may enter financial contracts for instruments related to currencies, commodities or interests. Such financial instruments may include spot and outright contracts, forward transactions, swap contracts, options etc. The Company does not apply hedge accounting as described in IFRS 9. Financial instruments held by the Company are classified and recognized at fair value at the initial measurement. Subsequent measurement will reflect the classification of the financial instrument. IFRS 9 divides financial assets into two classifications – those measured at amortised cost and those measured at fair value. For

assets measured at fair value, gains and losses are recognized entirely in profit or loss. Two measurement categories exist for financial liabilities, fair value through profit and loss ("FVTPL"), and amortized cost. Financial liabilities held for trading are measured at FVTPL, and all other financial liabilities are measured at amortised cost.

LEASES

At the conclusion of the contract, the company assesses whether the contract is a lease or contains a lease.

In the case of contracts that meet the definition of a lease, the company recognises a right-of-use of an asset and lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The right-of-use asset is subsequently depreciated using the same depreciation methods as those applied to similar underlying assets. In addition, the right-of-use asset is adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the incremental borrowing rate as the discount rate. After the commencement date, the company takes into account changes in lease payments by remeasuring the lease liability. The amount of the remeasurement of the lease liability is recognised as an adjustment to the right-of-use asset. However, if the carrying amount of the right-of-use asset is reduced to zero and there is a further reduction in the measurement of the lease liability, any remaining amount of the remeasurement is recognised in profit or loss.



INCOME TAXES

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the balance sheet date.

Deferred tax

Deferred income tax is provided using the balance sheet method on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred income tax assets are recognised for all deductible temporary differences, carried forward of unused tax credits and unused tax losses. They are recognised when it is probable that the Company will have a sufficient profit for tax purposes in subsequent periods in order to utilise the tax asset.

Companies operating on the NCS under the petroleum tax regime can claim the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash (including interest) from the tax authorities when operations cease. This mechanism, which is described in the Norwegian Petroleum Tax Act section 3c and section 5, reduces the risk related to investing in offshore assets, as the companies will in any case be able to fully recoup the tax value of the investments. Therefore, deferred tax assets that are based on offshore tax losses carried forward are normally recognised in full.

An exception will be where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

The Company recognises previously unrecognised deferred tax assets to the extent it has become probable that the Company can utilise the deferred tax asset. Similarly, the Company will reduce a deferred tax asset to the extent that the Company no longer regards it as probable that it can utilise the deferred tax asset.

Deferred tax, and deferred tax assets, are measured on the basis of the historical and enacted future tax rates applicable to the Company.

Deferred tax, and deferred tax assets, are recognised at their nominal value and classified as non-current intangible assets /long-term liabilities in the balance sheet.

The effect of uplift, a special deduction for petroleum surtax in Norway, is recognised in the current tax calculation.

EMPLOYEE BENEFITS

Pension Obligations

The Company has a defined contribution plan as of 31 December 2021.

For the defined contribution plan, the Company pays contributions to pension insurance plan and charged to the income statement in the period to which the contributions relate. The Company has no legal or constructive obligations to pay further contributions if the fund does not hold sufficient assets to pay all employees the benefits relating to employee service in the current and prior periods. Prepaid contributions are recognised as an asset to the extent that a cash refund or a reduction in the future payments is available.

Bonus Compensation

Employees participate in a bonus compensation arrangement. The expected cost of bonus payments is expensed as salary costs when the employees have



rendered the service in exchange of those benefits, and a reliable estimate of the obligation can be made.

PROVISIONS

A provision is recognised when the Company has an obligation (legal or self-imposed) as a result of a past event, it is probable (more likely than not) that a financial settlement will take place as a result of the obligation, and the size of the amount can be measured reliably. Provisions are reviewed at each balance sheet date and adjusted to reflect the current best estimate.

If the effect is considerable, the provision is calculated by discounting estimated future cash flows using a pre-tax discount rate that reflects the market's pricing of the time value of money and, if relevant, risks specifically linked to the obligation.

Assets retirement obligations

According to the license agreements on the NCS, the Company has the obligation to partly or completely remove the offshore facilities at the end of production or when the concession period expires. Consequently, the Company recognizes a provision related to future abandonment and decommissioning of offshore installation. Similarly, the Company has the obligation to participate in the costs of removal of infrastructure used to transport hydrocarbons from the fields.

The Company calculates and records the net present value of the removal liability. The discount rate used when calculating the net present value of the abandonment and decommissioning liability is calculated based on a risk free interest rate increased by risk premium and is reviewed at each balance date.

Related asset retirement costs are capitalised as part of the carrying value of the tangible fixed asset and are depreciated over the useful life of the asset, i.e. unit-of-production method. The liability is accreted for the change in its present value after each reporting period.

Accretion expense related to the time value of money is classified as part of financial expense.

SEGMENT REPORTING

The Company's business activities are reported as one segment.

CASH FLOW

The cash flow statement has been prepared using the indirect method.

CONTINGENT ASSETS AND LIABILITIES

A contingent liability is a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity; or a present obligation that arises from past events but is not recognized because it is not probable that an outflow of resources embodying economic benefits will be required to settle the obligation or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are not recognised in the annual accounts. Significant contingent liabilities are disclosed, with the exception of contingent liabilities that have a remote possibility to end up in outflow of resources.

Contingent assets are not recognised in the annual accounts but are disclosed if there is probable that a benefit will be added to the Company.

EVENTS AFTER THE BALANCE SHEET DATE

New information on the Company's financial position on the balance sheet, that are present on the balance sheet date and becomes known after the balance sheet date, is recorded in the annual accounts. Events after the balance sheet date that do not affect the Company's financial position on the balance sheet, but which will



affect the Company's financial position in the future, are disclosed if significant.

NOTE 2 SIGNIFICANT TRANSACTIONS IN 2021

TRANSACTION WITH INEOS

On the 25th March 2021 PGNiG Upstream signed an agreement to purchase all assets owned by INEOS on the Norwegian Continental Shelf, together with rights and obligations arising from agreements related to these assets. The transaction included 21 licences and an interest in the Nyhamna processing plant. The acquired licenses comprise both non-operated production licenses and operated and non-operated exploration licenses. As part of the transaction 48 employees in INEOS E&P Norge were transferred to PGNiG Upstream Norway.

The purchased licences include producing fields: Ormen Lange (14%) Marulk (30%) and Alve (15%). The key asset is Ormen Lange, the second largest gas field on the Norwegian Continental Shelf with an expected production life beyond 2045. In addition, PGNiG Upstream Norway acquired an interest in the Nyhamna gas processing plant (8.2%), which receives the output of Ormen Lange and Aasta Hansteen, among other fields. The Nyhamna terminal is a source of stable operating cash flow that does not depend on hydrocarbon price fluctuations.

The transaction significantly increased hydrocarbon reserves allocated to PGNiG Upstream Norway to 309 mboe (as of 31.12.2021). Natural gas accounts for some 94 per cent of the acquired resources. Acquisition of the assets of INEOS also increased equity gas production of PGNiG in Norway by approximately 1.5 billion cubic metres per year. As a result of this transaction, the gas production target set in the PGNiG Group's Strategy for 2017–2022 is likely to be met. Once the Baltic Pipe becomes operational, gas produced by PUN will be transported to Poland, enhancing gas supply

diversification and strengthening the country's energy security.

The acquired portfolio also includes an attractive exploration acreage, including 6 operated licences, providing longer term growth opportunities.

The purchase price was USD 615 million with an effective date of 1st January 2021. On September 24th 2021, all the conditions precedent to the Agreement and conditions for the acquisition by PUN of control over INEOS were satisfied. The consideration was paid on September 30th 2021, being the transaction date for accounting purposes within the meaning of IFRS 3.

A significant portion of the purchase price was covered with cash flows generated in the period between the effective date and the completion date. Given the achieved sales targets of hydrocarbons produced from the acquired fields in 2021 and reduced costs and capital expenditure, the ultimate cash payment for the assets amounted to approximately USD 324 million, which accounts for 53% of the purchase price. PGNiG also took over a balance of payable tax that subsequently will be paid by the company.

Pursuant to the Agreement, the final completion statement was provided by the seller within 60 working days of the acquisition date and is being reviewed by PGNiG, final settlement is expected to occur early 2022. In accordance with IFRS 3, the final accounting for the business combination might be updated within 12 months of the acquisition date if new information that would impact the measurement or recognition of assets and liabilities as of the acquisition date is obtained.

The transaction is booked as business combination in line with IFRS 3. The valuation of the identifiable assets



and liabilities is based on currently available information on fair values as of the acquisition date in line with IFRS 13. For more information on accounting principle reference is made to note 1.

The main elements from the transaction are presented below.

The table includes fair values of assets and liabilities as at the date of the acquisition, the cash consideration and goodwill identified for the acquisition (all figures are presented in million NOK).

For an overview of all licenses reference is made to note 26.

Assets		Equity and Liabilities	
Goodwill	2 896	-2 840	Purchase price
Asset in production	8 130	-5 313	Deferred tax
Inventory	42	-1 068	Abandonment provision
Other current receivables	66	-2 756	Taxes payable, not assessed
Trade receivable	1 055	-79	Trade payables
Long term receivable	53	-179	Other current liabilities
		-7	Employee tax liabilities, duties
Total assets	12 242	-12 242	Total Equity and Liabilities

NOTE 3 REVENUE

	2021	2020
Oil sales	2 620	1 422
Gas sales	10 110	569
NGL sales	437	190
Sales revenue	13 167	2 180

Sales revenues include revenue from the assets acquired from INEOS from the transaction date. PGNIG Upstream sells its share of crude oil from the Skarv and Ærfugl field to Shell under an agreement which was concluded in October 2011. The share of crude oil from Vale is sold to Shell under an agreement which was concluded in December 2014. Crude oil from Morvin is sold to Total under an agreement concluded in January 2015. Crude oil from the Gina Krog field is sold to Shell under an agreement concluded 9 January 2018. Gudrun Blend crude from the Gina Krog stream is sold to Shell

under an agreement concluded 15 August 2017. Crude oil from Skogul and Vilje is sold to Shell under an agreement concluded in March 2020. Crude oil from Alve and Marulk is sold to Equinor under an agreement concluded in February 2009 and assigned to PGNIG Upstream as part of the INEOS transaction. Condensate from Ormen Lange is sold to Equinor under an agreement concluded in November 2016 and assigned to PGNIG Upstream as part of INEOS transaction. Crude oil from Kvitebjørn and Valemon is sold to Shell under an agreement concluded December 2020. Crude oil



from Duva is sold to ENI under an agreement concluded in August 2021.

The Company's gas production is contracted to PGNiG Supply & Trading GmbH, a PGNiG subsidiary based in Munich, Germany. In addition, the company has a contract with Shell to sell gas from Vale, in a case when Vale gas cannot be exported to Germany.

Naphtha from Skarv, Morvin and Gina Krog is sold to Total under an agreement concluded in August 2015. Naphtha from Kvitebjørn and Valemon sold to Equinor under an agreement concluded December 2016. Naphtha from Alve & Marulk is sold to Equinor under an agreement concluded in September 2010 and assigned to PGNiG Upstream as part of the INEOS transaction.

Ethane from Skarv, Morvin and Gina Krog is sold to Yara Norge under an agreement concluded in March 2016. Ethane from Alve & Marulk is sold to INEOS under an agreement concluded in January 2012 and assigned to PGNiG Upstream as part of INEOS transaction.

LPG from Skarv, Morvin, Gina Krog is sold to Shell under an agreement concluded in January 2016. LPG from Kvitebjørn and Valemon is sold to Shell under an agreement concluded December 2021. LPG from Alve & Marulk is sold to ENI under an agreement concluded in June 2019 and assigned to PGNiG Upstream as part of INEOS transaction.

NGL-products (naphtha, ethane and LPG, consisting from propane, iso-butane and normal-butane), are sold at the Kårstø terminal. The same applies for Gudrun Blend crude, which is also separated and sold at the Kårstø terminal.

All sales contracts are based on the market prices of the products, and will secure a stable stream of revenues for PGNiG Upstream for years to come.

Other income

Other income mainly consists of tariff income from Nyhamna processing plant. Gain from divestment of 20 % in PL937 is also presented as other income.

NOTE 4 EXPLORATION EXPENSES

	2021	2020
Exploration expenses from production licenses	75	63
Drilling expenses from production licenses	222	14
Other exploration expenses	13	3
Direct exploration expenses	310	80
Allocated expenses included in:		
- Depreciation	0,2	0,3
- Employee expenses	43,2	29,3
- Other operating expenses	6,4	4,8
Allocated exploration expenses	49,9	34,3
Total exploration expenses	360	114



Exploration expenses are presented under different cost categories in the income statement:

- (i) **Direct exploration expenses** - reflecting expenditures from the licenses reported by the respective Operators and direct exploration expenses incurred by the Company;
- (ii) **Allocated exploration expenses** – being the result of cost allocation.

The costs in **direct exploration expenses** are connected with the following scope of work:

- Exploration expenses from production licenses which are connected with participation in, and work on, exploration licenses as further described in Note 26.
- Majority of expenses in 2021 were connected with the licenses PL937, PL939 and exploration activities on the King Lear and Duva licenses.
- Drilling cost in 2021 is connected with drilling of the Fat Canyon prospect (PL937) which was dry. In

addition, the Company drilled an Egyptian Vulture well (PL939) where discovery was made. Due to commercial potential of this discovery, the well costs were capitalized and are included in intangible assets category.

Other exploration expenses in 2021 are connected with the APA2021 applications, business development activities and purchase of various studies.

Allocated exploration expenses are linked to own exploration activities of PGNiG Upstream. In 2021 they were mostly connected with the follow-up activities on exploration licenses and the participation in the APA2021 Licensing Round, general exploration and follow-up of partner licenses.

The majority of these costs are related to Employee expenses. In addition, there are costs of securing access to G&G software and databases which are shared between different activities of PGNiG Upstream. Cost allocations are primarily based on time-writing.

NOTE 5 EMPLOYEE EXPENSES AND BENEFITS

Staff expenses comprise salaries, remuneration, pensions, social security and other expenses.

During the year the average number of employees at the Company was 50,9. On 31st December 2021, PGNiG Upstream had 86 employees.

The remuneration for the General Manager for the year amounted to NOK 6,6 million for wages and NOK 0,3 million for other compensations. In addition, contributions to the pension scheme of NOK 0,6 million have been paid for the period. These amounts are included in employee expenses above. Further, the contract with the General Manager includes a binding period with salary entitlement until 30 September 2022.

In addition, PGNiG Upstream has a bonus scheme covering all employees. The bonus amount for the General Manager shall be based on an evaluation of specific "Key Performance Indicators" agreed between the Board of Directors and the General Manager before the start of any calendar year.

PENSIONS

The Company is obliged to have an occupational pension scheme pursuant to the Act relating to Mandatory Occupational Pensions. The Company's pension scheme satisfies the requirements of this act. Ref. Note 19 for further information.



	2021	2020
Employees*		
Wages, salaries and remuneration	71	30
Social security	18	12
Pensions (Note 19)	13	12
Other staff expenses	2	2
Total	104	56

* STAFF EXPENSES ATTRIBUTABLE TO EXPLORATION ACTIVITIES ARE NOT RECLASSIFIED TO EXPLORATION COST IN THE INCOME STATEMENT, BUT PRESENTED AS EXPLORATION COST IN THE SPECIFICATION INCLUDED IN NOTE 4.

NOK thousand	2021	2020
Board of Directors		
Wages, salaries and remuneration	0	67
Total employee expenses**	104 410	56 513

** TOTAL EMPLOYEE EXPENSES ABOVE ARE PRESENTED NET OF COST, WHICH WAS RECHARGED TO OPERATED LICENCES AND BUSINESS PARTNERS, AND NET OF COST FROM INTERNAL HOURS CHARGED TO THE DEVELOPMENT PROJECTS, INCL. TOMMELITEN, DUVA, GRÅSEL, ÆRFUGL AND ÆRFUGL NORD. THE TOTAL VALUE OF COST RECHARGED TO OPERATED ACTIVITIES IN 2021 AMOUNTS TO NOK 43,4 MILLION (NOK 28,1 MILLION IN 2020), AND THE TOTAL VALUE OF COST CHARGED TO DEVELOPMENT PROJECTS AMOUNTS TO NOK 9,3 MILLION (NOK 14,2 MILLION IN 2020).

NOTE 6 PRODUCTION AND SALES COSTS

	2021	2020
Operating costs	683	402
Gas tariffs and other transportation costs	716	348
Over-/ (under)lift	(161)	(40)
Total production and sales costs	1 238	711

Operating costs are reported by the respective Operators on the production licenses: Ormen Lange, Skarv, Vilje, Vale, Morvin, Alve, Marulk, Gina Krog, Skogul, Duva, Ærfugl Nord, Nyhamna processing plant, Kvitebjørn oil pipeline and Valemon rich gas pipeline. The operating costs consist of:

- NOK 684 million from the production licenses,
- NOK (12) million related to changes in the estimated abandonment provision, and
- NOK 11 million incurred in relation to sales.

The Company covered gas tariffs in the Gassled network and other transportation costs of NOK 431 million. Other transportation costs included balancing, dispatching, contract handling etc. In addition, the Company incurred NOK 159 million related to cost of sales of dry gas to the affiliated company PGNIG Supply & Trading GmbH, fully owned by PGNIG Group.



In the end of 2021, the Company moved from overlift to underlift position, which means that accumulated production exceeded the accumulated sales. As a consequence, the Company incurred a reduction of cost related to change in over-/underlift position for

2021. According to accounting policy change in over-/underlift positions is to be adjusted towards production and sales cost. Please refer to note 13 for further information about underlift position.

NOTE 7 OTHER OPERATING EXPENSES

	2021	2020
External fees	55	13
Rent premises	2	2
Insurance premium	45	33
Expensed purchases	12	11
Travel costs	1	1
Other	13	8
Other operating expenses	128	67
Remuneration to auditor (thousand NOK):		
Audit fee (excl. VAT)	512	375
Other services (excl. VAT)	15	87
	527	462

INDIRECT EXPLORATION COSTS PRESENTED IN NOTE 4 (WITH THE AMOUNT OF NOK 6,4 MILLION) ARE NOT RECLASSIFIED AND ARE INCLUDED IN DIFFERENT COST CATEGORIES (FOR EXAMPLE RENT PREMISES ETC.)

Other operating expenses comprise external fees, rent premises, insurance, expensed purchases, travel costs etc.

External fees were connected with running the Company accounts, legal support and various advisory services. They also include advisory costs related to the INEOS transaction. Moreover, the Company incurred costs connected with the maintenance of IT solutions, telephones and internet access.

Other agreements affecting the cost level are those concerning the rental and maintenance of the offices and offshore insurance cost according to legal requirements in Norway.

RESEARCH AND DEVELOPMENT EXPENSES

PGNIG Upstream's R&D activities have been focused on tools and methods for exploration and production, primarily through its co-operation with universities and external experts.

The total costs of R&D activities amounted to NOK 2,5 million in 2021. The main objective of these expenses is to get access to scientific studies that can be used by PGNIG Upstream on its licenses on the NCS.

By carrying out these studies, PGNIG Upstream is gaining access to exclusive scientific information and highly qualified personnel. The Company anticipates that the total income from research and development will offset the total costs incurred.



NOTE 8 OTHER FINANCIAL INCOME

	2021	2020
Interest received bank	1	1
Exchange rate differences	392	175
Other financial income	393	176

NOTE 9 OTHER FINANCIAL EXPENSES

	2021	2020
Interest costs to financial institutions*	67	90
Exchange rate differences	422	66
Accretion	131	47
Other interest cost	51	8
Capitalized borrowing cost	(78)	(197)
Other financial expenses	592	14

* INTEREST COSTS TO FINANCIAL INSTITUTIONS ARE PRESENTED USING THE EFFECTIVE INTEREST RATE METHOD

Interest costs are recognised as an expense in the period in which they are incurred. The Company has capitalized the share of borrowing cost allocated to the Duva, Tommeliten Alpha, Ærfugl and Ærfugl Nord

development projects until production start. The part of borrowing cost capitalized is included under Additions to Assets in development in Note 11.

NOTE 10 TAX ON THE INCOME/(LOSS) FOR THE YEAR

Calculation of taxable income for the year	2021	2020
Net income before taxes	9 824	(941)
Permanent differences	3 884	505
Changes in temporary differences	(332)	185
Basis for corporate taxes payable, not assessed	13 376	(251)
Net financial costs only allowed against CT	162	231
Net other 22%, only allowed against CT	251	0
Uplift allowable only against SPT	(704)	(548)
Expense of capex addition in SPT	(1 936)	(1 263)
Taxable income, special petroleum tax ("SPT")	11 149	(1 832)
Covered from loss carry forward SPT	0	0
Basis for taxes payable, not assessed	11 149	(1 832)



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Tax payable	2021	2020
Tax payable	9 461	0
Other	360	38
Tax payable in balance sheet*	9 821	38

Tax receivable	2021	2020
Tax receivable	0	1 081
Tax refund received	0	(909)
Tax receivable in balance sheet	0	172

Calculation of deferred taxes	2021	2020
<i>Temporary differences:</i>		
Over-/underlift	(114)	(15)
Long-term liabilities	(46)	(193)
ARO provision	2 428	1 573
Fixed Assets	(12 485)	(4 432)
Intangible Assets	(659)	(608)
Lease	(68)	(61)
Other	187	(15)
Net temporary differences	(10 756)	(3 752)

	2021	2020
Deferred tax liability on temporary differences	(9 800)	(3 331)
Deferred tax asset on loss carry forward CT	0	0
Deferred tax asset/(liability) in the balance sheet*	(9 800)	(3 331)

Income taxes charged to income statement consist of:	2021	2020
Changes in deferred taxes	1 157	439
Taxes booked to balance sheet (related to acquisitions)	(2 759)	(89)
Taxes payable/(receivable), not assessed	9 232	(1 081)
Correction previous year	256	(27)
Total Tax charge/(credit) to income statement	7 886	(758)



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Effective tax rate reconciliation	2021	2020
Income before taxes	9 824	(941)
Expected tax charge - 78%	7 663	(734)
Permanent differences	179	267
Prior year items	301	(2)
Financial items	102	1
Uplift	(394)	(307)
Other	35	18
Total Tax charge/(credit)	7 886	758
Effective tax rate	80 %	81 %

*DEFERRED AND PAYABLE TAX FROM TRANSACTION WITH INEOS ERP NORGE AS IS INCLUDED IN THE DEFERRED AND PAYABLE TAX BALANCES.

NOTE 11 INTANGIBLE ASSETS AND TANGIBLE FIXED ASSETS

RIGHT OF USE ASSET

2021	FPSO/FSO	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2021*	231	13	244
Additions	0	0	0
Investments at 31/12/21	231	13	244
Accum. depreciation at 1/1/21	(33)	(2)	(35)
Depreciation in 2021**	(17)	(1)	(18)
Accum. depreciation at 31/12/21	(50)	(3)	(53)
Net book value at 31/12/21	181	10	191
Depreciation method**	unit of production	unit of production	

* REFERENCE IS MADE TO NOTE 1 AND NOTE 12 FOR ACCOUNTING PRINCIPLES USED TO MEASURE THE VALUE OF THE RIGHT-OF-USE ASSET.

** DEPRECIATION OF RIGHT-OF-USE ASSETS IS BASED ON THE UOP METHODOLOGY USING THE SAME DEPRECIATION METHODS AS THOSE APPLIED TO SIMILAR UNDERLYING ASSETS



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2020	FPSO/FSO	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2020*	171	13	184
Additions	60	0	60
Investments at 31/12/20	231	13	244
Accum. depreciation at 1/1/20	(18)	(1)	(19)
Depreciation in 2020**	(15)	(1)	(16)
Accum. depreciation at 31/12/20	(33)	(2)	(35)
Net book value at 31/12/20	198	11	209
Depreciation method**	unit of production	unit of production	

* REFERENCE IS MADE TO NOTE 1 AND NOTE 12 FOR ACCOUNTING PRINCIPLES USED TO MEASURE THE VALUE OF THE RIGHT-OF-USE ASSET.

** DEPRECIATION OF RIGHT-OF-USE ASSETS IS BASED ON THE UOP METHODOLOGY USING THE SAME DEPRECIATION METHODS AS THOSE APPLIED TO SIMILAR UNDERLYING ASSETS



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2021	Capitalized exploration expenses	Goodwill	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/21	1 503	0	5 323	15 645	43	22 515
Additions *	583	2 896	1 525	8 669	1	13 675
Transfer to Assets in development/production**	(890)	0	(2841)	3 731	0	0
Disposals/Expensed previously capitalised exploration	(287)	0	0	0	0	(287)
Investments at 31/12/21	909	2 896	4 007	28 046	44	35 903
Acc. depreciation 1/1/21	0	0	0	(7 475)	(36)	(7 511)
Acc. impairment 1/1/21	0	0	(155)	(795)	(3)	(953)
Accum. depreciation and impairment at 1/1/21	0	0	0	(8 270)	(39)	(8 464)
Depreciation in 2021***	0	0	0	(1 646)	(2)	(1 648)
Reversal of impairment****	0	0	57	249	0	306
Impairment in 2021 ****	0	0	0	0	0	0
Accum. depreciation and impairment at 31/12/21	0	0	(98)	(9 666)	(42)	(9 806)
Net book value at 31/12/2	909	2 896	3 909	18 380	3	26 097
Depreciation method***	N/A	N/A	N/A	unit of production	straight line	
Useful life			-	-	3-6 years	

* ADDITIONS UNDER "CAPITALIZED EXPLORATION EXPENSES" INCLUDE CAPITALIZED EXPLORATION WELL ON THE LICENSES PL939 (EGYPTIAN VULTURE) AND PL937 (FAT CANYON). THE FIRST ONE WAS CONCLUDED TO BE GEOLOGICAL DISCOVERY, POSSIBILITY OF ITS COMMERCIAL DEVELOPMENT. THE FAT CANYON WELL WAS DRY THEREFORE WAS EXPENSED AT THE YEAR END. OTHER CAPITALIZED EXPENSES ARE RELATED TO SEISMIC AND FIELD EVALUATION. PGNIG DIVESTED 20% OF THE FAT CANYON LICENSE WITH TRANSACTION DATE 31.12.21.

**ADDITIONS UNDER "GOODWILL" CATEGORY IS CONNECTED WITH AN ACQUISITION OF INEOS ERP NORGE AS. THE TRANSACTION WAS CLASSIFIED AS BUSINESS COMBINATION UNDER IFRS, THE BUYER ACQUIRES THE SELLERS TAX BALANCES, CREATING A TEMPORARY DIFFERENCE BETWEEN ACCOUNTING AND TAX VALUES. SINCE ALL TRANSACTIONS WAS POST-TAX, THE DEFERRED TAX IS OFFSET BY A CORRESPONDING TECHNICAL GOODWILL ENTRY. NEGATIVE ORDINARY GOODWILL OF NOK (3 210) MILLION WAS OFFSET AGAINST TECHNICAL GOODWILL OF NOK 6 107 MILLION.

* ADDITIONS UNDER "ASSETS IN DEVELOPMENT" RELATES TO DEVELOPMENT CAPEX, CAPITALIZED HOURS AND CAPITALIZED BORROWING COST ON ÆRFUGL, ÆRFUGL NORD, TOMMELITEN ALPHA, KING LEAR, DUVA AND ORMEN LANGE PHASE III PROJECTS.

* ADDITIONS UNDER "ASSETS IN PRODUCTION" RELATES MAINLY TO THE PURCHASE OF PRODUCING ASSETS WITHIN INEOS ERP NORGE AS ACQUISITION, INCLUDING ORMEN LANGE, NYHAMNA, ALVE, MARULK AND TAMBAR EAST. IN ADDITION IT INCLUDES CAPEX TO THE PRODUCING ASSETS SKARV, GINA KROG, MORVIN, VILJE, SKOGUL, KVITEBJØRN, VALEMON, DUVA AND VALE. THE AMOUNT ALSO INCLUDES THE RECOGNIZED ABANDONMENT REMOVAL OBLIGATION ACQUIRED WITH ORMEN



LANGE, ALVE, MARULK, TAMBAR ØST (ASSETS ACQUIRED IN INEOS TRANSACTION) AND THE CHANGE IN THE ESTIMATE OF THE ASSET RETIREMENT OBLIGATIONS ALL PRODUCING ASSETS AS AT THE END OF THE YEAR OF NOK (120) MILLION, WHICH HAS NO CASH EFFECT IN 2021. FOR FURTHER DETAILS REFER TO NOTE 20.

** TRANSFER TO ASSETS IN DEVELOPMENT FROM CAPITALIZED EXPLORATION EXPENSES RELATES TO RECLASSIFICATION OF CAPITALIZED EXPLORATION EXPENSES FOR KING LEAR AND FOGELBERG PROSPECTS. TRANSFER TO ASSET IN PRODUCTION FROM ASSET IN DEVELOPMENT RELATES TO RECLASSIFICATION OF CAPITALIZED DEVELOPMENT CAPEX FOR DUVA, GRÅSEL, ÆRFUGL AND ÆRFUGL NORD WHEN THESE STARTED PRODUCTION.

*** DEPRECIATION OF ASSETS IN PRODUCTION IS BASED ON THE UOP METHODOLOGY AND TAKES INTO ACCOUNT CONSISTENT ASSUMPTIONS OVER THE WHOLE YEAR. THESE ASSUMPTIONS WERE PROVIDED BY FIELD OPERATORS AT THE END OF 2020. ANY CHANGES IN ESTIMATES WILL BE RECOGNIZED PROSPECTIVELY FROM THE FOLLOWING YEAR. THE COMPANY MAY IN SPECIAL CASES ALSO APPLY THE REDUCING BALANCE METHOD OF DEPRECIATION IN ACCORDANCE WITH ACCOUNTING PRINCIPLES, REFER NOTE 1. THE VIJJE FIELD WAS DEPRECIATED UNDER THE REDUCING BALANCE METHOD FROM 2016.

**** THE COMPANY HAS REVERSED IMPAIRMENT FROM PRIOR YEARS OF NOK 129 MILLION FOR THE GINA KROG FIELD, NOK 150 MILLION FOR THE DUVA FIELD AND NOK 26 MILLION FOR VALE FIELD IN 2021. THE REVERSAL WAS MAINLY DRIVEN BY SUBSTANTIAL IMPROVEMENT OF MACROECONOMIC ENVIRONMENT, ESPECIALLY LEVEL OF GAS PRICES. FOR FURTHER DETAILS ON IMPAIRMENT TESTING, PLEASE SEE BELOW.

2020	Capitalized exploration expenses	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/20	1 056	4 963	12 373	39	18 430
Additions *	479	2 025	1 587	4	4 095
Transfer to Assets in development/production**	(21)	(1 664)	1 685	0	0
Expensed previously capitalised exploration	(10)	0	0	0	(10)
Investments at 31/12/20	1 503	5 323	15 645	43	22 515
Acc. depreciation 1/1/20	0	0	(6 112)	(34)	(6 146)
Acc. Impairment 1/1/20	0	0	(119)	(3)	(122)
Accum. depreciation and impairment at 1/1/20	0	0	(6 231)	(37)	(6 268)
Depreciation in 2020***	0	0	(1 363)	(2)	(1 365)
Reversal of impairment****	0	0	33	0	33
Impairment in 2020 ****	0	(155)	(709)	0	(863)
Accum. depreciation and impairment at 31/12/20	0	(155)	(8 270)	(39)	(8 464)
Net book value at 31/12/20	1 503	5 168	7 376	4	14 051
Depreciation method***	N/A	N/A	unit of production	straight line	
Useful life				3-7 years	



* ADDITIONS UNDER "CAPITALIZED EXPLORATION EXPENSES" INCLUDE THE ACQUIRED ÅLVE NORD FIELD (PL127C), CAPITALIZED EXPLORATION WELL ON THE LICENSE AND CAPITALIZED DRILLING EXPENSES ON THE WARKA PROSPECT DRILLED IN 2020 ON THE PL1009 LICENSE IN THE NORWEGIAN SEA RESULTING IN SIGNIFICANT GAS DISCOVERY. OTHER CAPITALIZED EXPENSES ARE RELATED TO SEISMIC AND FIELD EVALUATION.

* ADDITIONS UNDER "ASSETS IN DEVELOPMENT" RELATES TO THE ACQUISITION OF THE DUVA FIELD. IN ADDITION THERE WAS DEVELOPMENT CAPEX, CAPITALIZED HOURS AND CAPITALIZED BORROWING COST ON THE SKOGUL (BEFORE SKOGUL STARTED PRODUCTION), ÆRFUGL, ÆRFUGL NORD, TOMMELITEN ALPHA, GRÅSEL AND DUVA PROJECTS. THE AMOUNT ALSO INCLUDES THE CHANGE IN THE ESTIMATE OF THE ASSET RETIREMENT OBLIGATIONS RELATED TO ÆRFUGL, ÆRFUGL NORD AND DUVA FIELDS IN THE AMOUNT OF NOK 72 MILLION, WHICH HAS NO CASH EFFECT IN 2020. FOR FURTHER DETAILS REFER TO NOTE 20.

* ADDITIONS UNDER "ASSETS IN PRODUCTION" RELATES TO THE ACQUISITION OF ADDITIONAL 3,3% IN THE GINA KROG FIELD AND THE ACQUIRED INTEREST IN KVITEBJØRN AND VALEMØN FIELDS. IN ADDITION IT INCLUDES CAPEX TO THE PRODUCING ASSETS SKARV, GINA KROG, MORVIN, VILJE, SKOGUL AND VALE. THE AMOUNT ALSO INCLUDES THE RECOGNIZED ABANDONMENT REMOVAL OBLIGATION ACQUIRED WITH KVITEBJØRN AND VALEMØN AND THE CHANGE IN THE ESTIMATE OF THE ASSET RETIREMENT OBLIGATIONS RELATED TO SKARV, GINA KROG, MORVIN, VILJE, SKOGUL AND VALE IN THE AMOUNT OF NOK 276 MILLION, WHICH HAS NO CASH EFFECT IN 2020. FOR FURTHER DETAILS REFER TO NOTE 20.

** TRANSFER TO ASSETS IN DEVELOPMENT FROM CAPITALIZED EXPLORATION EXPENSES RELATES TO RECLASSIFICATION OF CAPITALIZED EXPLORATION EXPENSES FOR GRÅSEL PROSPECT WITHIN SKARV LICENSE. TRANSFER TO ASSET IN PRODUCTION FROM ASSET IN DEVELOPMENT RELATES TO RECLASSIFICATION OF CAPITALIZED DEVELOPMENT CAPEX FOR SKOGUL AND ÆRFUGL PHASE 1 WHEN THESE STARTED PRODUCTION.

*** DEPRECIATION OF ASSETS IN PRODUCTION IS BASED ON THE UOP METHODOLOGY AND TAKES INTO ACCOUNT CONSISTENT ASSUMPTIONS OVER THE WHOLE YEAR. THESE ASSUMPTIONS WERE PROVIDED BY FIELD OPERATORS AT THE END OF 2019. ANY CHANGES IN ESTIMATES WILL BE RECOGNIZED PROSPECTIVELY FROM THE FOLLOWING YEAR. THE COMPANY MAY IN SPECIAL CASES ALSO APPLY THE REDUCING BALANCE METHOD OF DEPRECIATION IN ACCORDANCE WITH ACCOUNTING PRINCIPLES, REFER NOTE 1. THE VILJE FIELD WAS DEPRECIATED UNDER THE REDUCING BALANCE METHOD FROM 2016.

**** THE COMPANY HAS RECOGNISED IMPAIRMENT OF NOK 709 MILLION FOR THE GINA KROG FIELD AND NOK 155 MILLION FOR THE DUVA FIELD IN 2020. THE IMPAIRMENT IS BASED ON A LOWER RECOVERABLE AMOUNT CALCULATED COMPARED TO THE ACTUAL BOOK VALUE PRIOR TO IMPAIRMENT. FOR FURTHER DETAILS ON IMPAIRMENT TESTING, PLEASE SEE BELOW. IN CONTRAST, THE COMPANY HAS REVERSED PARTS OF IMPAIRMENT FROM PRIOR YEARS RELATED TO THE MORVIN AND VALE FIELD, IN GROSS NOK 32,5 MILLION.

IMPAIRMENT TEST

In the end of 2021, the Company conducted an impairment tests for all its Cash Generating Units (CGUs), which combine assets using the same infrastructure (like the same host platform) or infrastructure assets with fields they are critical to (like Nyhamna in case of Ormen Lange field). Following CGUs have been created: Skarv CGU, Norne CGU, Alvheim CGU, Ormen Lange CGU, Aasgard CGU, Kvitebjørn CGU. Single assets, in case there is lack of commercial/technical basis to combine them with other assets in PGNIG portfolio (Tommeliten Alpha, Duva, King Lear, Gina Krog, Tambar East and Vale), are tested on the asset-level. The main aim of these tests was to ensure that all assets are carried at no more than its recoverable amount. The recoverable amount was calculated as the asset's net fair value, less cost to sell. It was determined by reference to discounted future net cash flows expected to be generated by the asset.

The projected cash flow for assets has been determined based on production and cost profiles provided by respective field Operators. The Company has used its own assumptions regarding gas tariffs.

As a result of the tests, impairment reversal was done on Gina Krog, Duva and Vale projects.

In calculating the net present value, the company applied the oil price scenario based on the latest reports received from parent company (PGNIG SA), which are based on WoodMackenzie and Pöyry forecasts. According to assumptions, the average oil price in the next five years accounts for 608 NOK/bbl (in real terms), and the average gas price in this period accounts for 3,19 NOK/Sm³ (in real terms).

In addition, a discount rate of 8,46% (after tax, nominal) was used that reflects current market assessments of the time value of money and the specific risks. The pre tax equivalent is 10,45%.



A sensitivity analysis has been carried out in relation to the impairment of all CGUs/Assets owned by the Company. All results of the sensitivity analysis are presented on a net basis (post tax). Gas price, oil price and discount rate have been used in sensitivity analysis.

According to sensitivity analysis, future impairment risk is highest on Gina Krog and Duva projects. For Gina Krog the carrying amount is equal to the recoverable amount, on Duva project it is slightly lower than recoverable amount.

It was concluded that Gina Krog field is the most sensitive to gas prices. A 10% gas price decrease would result in a value decrease of NOK 58,4 million, while a 10% decrease of oil price would decrease the value by NOK 53,5 million NOK.

For the Duva project, the highest sensitivity was observed on gas price as well. A 10% gas price decrease would result in decrease of field's value of NOK 97,5

million, while a 10% decrease of oil price would decrease value by NOK 92,0 million NOK.

The technical goodwill is included in the carrying value of the CCU/Asset which it was allocated to. Depreciation of PP&E from the acquired assets from INEOS will reduce the deferred tax and it is expected that the goodwill will be subject for impairment if not offset by increase in other assumptions increasing the calculated net present value.

IMPAIRMENT TEST FOR CAPITALIZED EXPLORATION EXPENSES

Exploration assets are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset exceeds its recoverable amount.

PGNiG Upstream has assessed capitalized exploration cost for all the exploration licences, and has written off all capitalized cost for licences which are not likely to be the subject of future drilling campaigns

NOTE 12 LEASES

	2021	2020
Lease debt 01.01	147	148
New leases	0	60
Payments of lease debt	(31)	(57)
Interest expense on lease debt	2	5
Currency exchange differences	4	(9)
Lease debt 31.12	122	147

Nominal lease debt maturity breakdown (NOK):

Within one year	42	38
Two to five years	79	110
After five years	7	8
Total	128	156



The company has used the effective interest rate as the incremental borrowing rate applied in discounting of the nominal lease debt.

The identified leases have no significant impact on the Company's financing or loan covenants.

NOTE 13 OTHER CURRENT RECEIVABLES

	2021	2020
Accounts receivable, JV	127	15
Prepayments, JV	84	64
Underlift (oil, NGL)	118	0
VAT	4	2
Other current receivables	181	97
Overcall, JV	86	45
Other current receivables	601	223

PGNIG Upstream have invoice mechanisms under some sales contracts where the invoice values are not directly linked to physical liftings. Other current receivables include the value of revenue which is incurred on the basis of liftings, but not invoiced, of NOK 139 million at the end of 2021.

Lifting arrangements for oil and NGL produced in some of PGNIG Upstream's assets are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production less stock, is underlift or overlift.

The Company accounts for fair value of under and overlift position of hydrocarbons based on market prices as per 31.12.2021.

The periodical change from overlift position at the end of 2020 (NOK -52 million, reference is made to notes 7 and 21) to underlift position at the end of 2021 was NOK 170 million. Out of the periodical change NOK 161 million is recognized under the Production and sales cost in the Income Statement, see also Note 6. Remaining part is the part that was acquired as part of the acquisition of INEOS and through final settlement of Kvitebjørn and Valemon acquisition from 2020.

NOTE 14 CASH AND CASH EQUIVALENTS

	2021	2020
Cash and cash equivalents, non-restricted	3 342	158
Cash and cash equivalents, restricted	13	6
Total cash and cash equivalents *	3 355	164

RESTRICTED CASH IS RELATED TO:

* TAXES WITHHELD FROM EMPLOYEES OF NOK 13 MILLION (NOK 6 MILLION IN 2020)



NOTE 15 INVENTORY

The inventory in 2021 (NOK 120 million) is substantially connected with the spare parts and drilling equipment kept within the joint ventures. The majority of reported spare parts are related to the Skarv Unit, Gina Krog Unit,

Skogul, Kvitebjørn, Valemon, Ormen Lange and Nyhamna JV. The Company did not account for any hydrocarbons left in inventor.

NOTE 16 EQUITY

The share capital consists of 1 115 000 shares each with a nominal value of NOK 1 000.

All the shares are held by the parent company, PGNiG, with its office in Warsaw. The parent company represents 100% of votes at the shareholders meeting of PGNiG Upstream. In addition, the parent company produces consolidated statements which include PGNiG Upstream.

All the shares are pledged for the benefit of Societe Generale, London Branch, which acts as the Facility Agent and the Security Agent under the external loan facility (ref Note 18). The execution of the pledge was a pre-condition for PGNiG Upstream raising financing under the reserve based loan formula. There are certain restrictions on enforcement of this pledge. They are described in the Shareholder Register.

NOTE 17 DEBT TO GROUP ENTERPRISES

	2021	2020
Principal debt to Group enterprises	1 420	4 253
Interests to Group enterprises	11	36
Total debt to Group enterprises	1 431	4 289
Hereof short-term – interest payable within 1 year	11	36
Long term liabilities to Group enterprises	1 420	4 253

As of 31 December 2021 PGNiG Upstream was funded through two intercompany loans:

- Loan no 3: From 27 August 2010 with the maximum available amount of NOK 4 100 million (out of which the Company has drawn NOK 0). Loan no 8: From 14 April 2021 with the maximum available amount of NOK 5 000 million (out of which the Company has drawn USD 161 million).

The Intercompany Loan can be used to fund corporate needs, including current capital expenditure and exploration-related expenses.

The abovementioned loans can be disbursed in several tranches. Each tranche shall be disbursed on the basis of a duly prepared Drawdown Request at least 7 days prior to the requested date of disbursement. Each tranche can be drawn in NOK, EUR or USD.



During 2021, PGNIG Upstream paid interest related to Intercompany loans for previous periods in the total amount of NOK 147 million for loan no 3 and USD 3 million for loan no 8.

The outstanding balance of loan number 8 (USD 161 million) is to be repaid in 5 equal instalments starting from 31st December 2027, and it bears interest based on 3M NIBOR + margin. The last principal instalment is due on the 31st December 2031.

The margin level was based on a benchmarking study and comparable transactions in the oil and gas industry.

The repayment of the Loan is secured through;

- (a) the Norwegian law promissory note; and
- (b) the registered pledge over the shares in Production Licenses 212, 212B, 262 on the NCS. The pledge over the Skarv licenses has second priority. The carrying amount of the Company assets pledged as security amounts to NOK 3 949. The value of all pledges is limited to the value of PGNIG Upstream's liabilities under this loan.

Intercompany loan is subordinated to the Facility (ref Note 18). Additionally, loan receivables under this loan are secured for the benefit of Societe Generale, London Branch, as a part of the security package under the Facility

NOTE 18 DEBT TO FINANCIAL INSTITUTIONS

	2021	2020
Principal debt	4 374	3 730
Arrangement fees paid	(47)	(58)
Effective interest rate amortization	4	1
Debt to financial institutions	4 331	3 673
Hereof short-term - payable within 1 year	6	2
Long term Debt to financial institutions	4 325	3 671

The credit facility ("Facility") was initially signed in August 2015 with eight banks. As per 31.12.2021, the bank consortium consists of the following banks (BNP Paribas, Societe Generale, ING, SEB, HSBC, Citibank, BGK S.A, PKB S.A, SMBC and Bank Handlowy w Warszawie S.A).

The Facility provides a revolving credit for seven years and therefore the Facility is classified as a long-term debt. Under this agreement, the Company may select an interest period of one, three or six months. Under the Facility the Company can draw loans in EUR and USD. The Facility is based on the reserve-based loan formula and is governed by English law.

As of 31st December 2021 the available amount under the Facility was limited by overall limit of USD 500 million. The Company borrowed USD 495 million under the Facility at 31st December 2021.

The drawing limit will be amortizing over time in accordance with the reduction schedule, starting from 1st July 2023 until 1st July 2026. The Facility is to be repaid in full by 1st July 2026.

The Facility will be one of the key sources of financing for the Company in the years to come. It provides PGNIG Upstream with flexibility with respect to its planned exploration and production activities. The Facility allows the Company to freely acquire further upstream assets in the area of the Norwegian Continental Shelf



(without any restrictions imposed by the banks). It also provides for the possibility of including new upstream assets under the RBL. In the balance sheet the loan is presented using the effective interest method.

SECURITY UNDER FACILITY

The repayment of the Facility is secured through;

- (i) the pledge over shares of PGNiG Upstream;
- (ii) the registered pledge over loan receivables under a loan agreement between PGNiG and PGNiG Upstream;
- (iii) the registered pledge over shares in Production Licenses 029C, 029B, 036, 036D, 134B, 134C, 212, 212B, 249, 262, 460, 044 TA, 044, 636, 193, 193B,

193D and the pledge over the Company's accounts, refund claims, trade receivables and insurance proceeds.

All pledge agreements have been concluded with Societe Generale, London Branch, which acts as the Facility Agent and the Security Agent under the Facility. The carrying amount of the Company assets pledged as security amounts to NOK 20 228 million.

The effective value of the pledge created under the Pledge Agreements is capped by the value of PGNiG Upstream's liabilities to banks under the Facility, i.e. USD 495 million.

NOTE 19 PENSION

The company maintains a defined contribution pension scheme in compliance with the Act related to Mandatory Occupational Pensions. The scheme covers pensions for salary amounts both below and above 12G. In addition, the company has signed an agreement with Storebrand which regulates employees' rights connected with transition from the old pension scheme.

The pension scheme covers all employees from the date of employment. By 31st December 2021, the plan had

86 active members. The plan is organised through the insurance company Storebrand Livsforsikring AS. The plan is purely a savings scheme in which the enterprise saves a percentage of the employee's salary in a separate pension account for each employee. The employee's pension is thus determined by the amount saved up during his/her working life and the return added along the way.

NOTE 20 PROVISIONS

ABANDONMENT PROVISION

Provisions recognized in 2021 consist of (numbers presented below are PGNIG share in NOK million):

Field	Abandonment provision	Expected abandonment
Skarv	364	2035-2038
Morvin	38	2039
Vilje	100	2041-2043
Vale	97	2022-2028
Gina Krog	316	2033-2035
Ærfugl	91	2035-2037
Skogul	64	2042-2043
Duva	198	2032
Ærfugl Nord	24	2036-2037
Valemon	97	2030
VRGP	4	2022-2025
Kvitebjørn (incl. KOR)	137	2036
Ormen Lange	397	2041-2049
Alve	72	2036
Marulk	177	2025-2027
Tambar East	9	2029
Gyda	187	2022-2025
Gassled	250	2050
Nyhamna	56	2050
Total	2 679	

The Company has recognized provisions for future abandonment for all its oil & gas fields as per year-end 2021. These provisions are related to removal expenditures for the offshore installations.

Decommissioning cost related to Nyhamna processing plant and the pipeline assets (VRGP and KOR) are paid and passed on to the Shippers through the shipper agreement through Gassco/Equinor as operators for the pipelines and processing plant.

The value of abandonment provision is related to the expected costs for plugging of wells and removal of

well heads, pipelines and platforms. The abandonment provision covers only installations that existed at the end of 2021. The value of the abandonment costs was based on the study performed by the field operators and verified through comparison to the other development projects. The Company has assumed a time of abandonment which is in line with the operator's official data. There is a considerable risk associated with assessing both value and time of abandonment liability. For example, the future development of new reserves like Ærfugl may defer the abandonment date for the Skarv field.

The removal liability is viewed to be a part of the total cost of the relevant property, plant and equipment (ref Note 11).

When calculating the net present value of the long term portion of the liability, PGNIG Upstream used an inflation rate of 2 per cent and a nominal discount rate of 4,42 per cent with a mid-year discounting.

An increase of abandonment removal obligation was observed on Duva (+38 million), Vale (+7 million), Vilje (+9 million), Ærfugl Nord (+20 million) and VRGP (+1 million). A decrease was observed on Skarv including Ærfugl (-24 million), Gina Krog (-65 million), Morvin (-8 million), Vilje (-7 million), Skogul (-8 million), Valemon (-12 million) and Kvitebjørn (-43 million). In addition, the Company accounted for abandonment removal obligation on Ormen Lange (+397 million), Alve (+72 million), Marulk (+177 million), Tambar East (+9 million), Gyda (+187 million) and Nyhamna (+56 million). Unwinding of the discount in 2021 accounted for NOK +131 million (ref Note 9).

PGNIG Upstream is also obliged to cover its relative share of removal cost for Gassled installations based on the share of transportation capacity used by the



Company relative to the total transportation capacity for the Gassled installations. The Company has received an estimate of expected cost to be covered from PGNiG Upstream for future removal from the Gassled operator. This estimate was inflated using a rate of 2 per cent and discounted at the rate of 4,42 per cent. PGNiG Upstream has assumed removal in 2050, resulting in a value of the liability of NOK 250 million at the end of 2021. As such, the Company has accrued for the liability at the end of 2021.

Decommissioning cost related to the pipeline assets (VRGP and KOR) are paid and passed on to the Shippers because it is only the JV license partners themselves that have volumes in these pipelines no decommissioning receivable has been recognized and the company has recognized abandonment removal obligation according to participant interest. Decommissioning cost related to the Nyhamna processing plant is passed on to the Shippers and a decommissioning receivable of NOK 53 million has been recognized.

NOTE 21 OTHER CURRENT LIABILITIES

	2021	2020
Working capital, JV	739	216
Overlift (oil, NGL)	0	52
Other current liabilities	330	133
Undercall, JV	24	1
Other current liabilities	1 093	402

At the end of 2021 the company was in a underlift position, reference is made to note 13.

NOTE 22 COMMITMENTS AND CONTINGENCIES

PGNiG Upstream has two loan agreements from PGNiG with the value of NOK 9,1 billion, out of which a total of NOK 1,4 billion is drawn by the end of 2021 (USD 161 million). The loan is secured by respective promissory notes. By the end of 2021, the outstanding value of promissory notes amounted to USD 161 million.

PGNiG Upstream's activities on the NCS are secured by the parent company guarantee issued on 22nd October 2007 (see Note 23). In return, PGNiG Upstream issued a Recourse Note which covers the whole principal sum of the parent company guarantee (EUR 627 555 648,36).

In addition, PGNiG Upstream has a loan agreement with external lenders with the outstanding liability of USD 218,5 million and EUR 245 million. This agreement is secured by a comprehensive security package, described in Note 18.

For the time being PGNiG Upstream has not booked any liability connected with the agreements mentioned above. According to the Company accounting policy, liability should be booked in the balance sheet of PGNiG Upstream if it is obliged to make a payment.



At 31st December 2021, PGNiG Upstream is not subject to any legal disputes other than tax dispute with the tax authorities concerning the price (deduction elements) under the intercompany agreement for sales of dry gas. In 2021 the tax authorities have also issued a draft reassessment for thin capitalisation for the income years 2010-2016.

EXPECTED LICENSE COMMITMENTS

As a partner in various oil and gas assets, PGNiG Upstream is committed to participate in the expenses within the approved budgets. The budgets for all assets and the Company's shares are presented below. Inside these amounts there are both expenses which are already committed by the license partners as well as other payments.

Field	PGNiG share	Net budget 2022 (NOK million) *
Tommeliten Alpha	42,38 %	1887.90
Ormen Lange	14,02 %	846.96
Gina Krog	11,30 %	393.17
King Lear	22,20 %	353.79
Skarv	11,92 %	334.71
Duva	30,00 %	238.08
Sjrek	35,00 %	202.22
Nyhamna	8,19 %	127.72
Kvitebjørn	6,45 %	127.41
Alve	30,00 %	114.80
Maruk	15,00 %	83.86
Valemon	3,23 %	80.15
Vale	24,24 %	66.11
Skogul	35,00 %	50.06
Vilje	24,24 %	49.76
Alve Nord	11,92 %	8.79
Ærfugl Nord	15,00 %	8.78
Morvin	6,00 %	4.14

* Planned license expenses (opex and capex) are based on the approved Business Plan 2022 for PGNiG Upstream

As presented above, the largest commitment is connected with the three ongoing development projects with the PDO approved in 2021: Tommeliten Alpha, Ormen Lange and Gina Krog (PDO related to the

oil export pipeline). PGNiG Upstream is committed to execute the investments.

OTHER COMMITMENTS

PGNiG Upstream has also commitments to drill exploration wells in the following licenses:

- PL941 (operated by Aker BP)
- PL1009 (operated by Conoco Phillips)
- PL1017 (operated by PGNiG Upstream)
- PL1064 (operated by Conoco Phillips)

The Company has financial commitments related to bookings in the gas transportation system operated by Gassco. The estimated value of such commitments in 2022 amounts to approximately NOK 958 million. See also Note 20 for information regarding commitment for PGNiG Upstream to share future removal cost related to Gassled transportation system.

PGNiG Upstream is committed to cover the costs from the office rental agreement with C5 Eiendom AS. The rental agreement is valid until 31st December 2025 and has a yearly value of approximately NOK 3 million. The total value of the remaining commitment under this

CONTINGENCIES

The contracts of top managers of PGNiG Upstream include a non-competition clause. This clause is applicable for not more than a one-year period, starting at the end of the employment.

The managers will receive a compensation based on their monthly salary (without benefits) in return for the application of the non-competition clause.



LIABILITY FOR DAMAGES/INSURANCE

PGNiG Upstream's operations involve risk for damages, including pollution. Installations and operations are insured through the OEE insurance and drilling Insurance including Third Party Liability.

In addition, PGNiG Upstream holds an insurance policy that covers all risks of physical loss or physical damage to its fields.

NOTE 23 GUARANTEES

PARENT COMPANY GUARANTEES

In 2007, PGNiG Upstream received a parent company guarantee as requested by the Ministry of Petroleum and Energy pursuant to the Norwegian Petroleum Act.

Pursuant to the provisions of the Guarantee Agreement, PGNiG has issued a guarantee to PGNiG Upstream to the amount of EUR 627 555 thousand. The guarantee is effective until 1st January 2050.

The Guarantee Agreement concerns the provision of security by PGNiG with regard to the fulfilment of certain obligations of PGNiG Upstream arising under the licenses or by operation of the law with respect to, inter alia, the Norwegian government and certain Norwegian entities. The provision of the guarantee is required under Article 10-7 of the Norwegian Oil Operations Act of 1996. Such a guarantee is a standard document used customarily in production operations in Norway.

The guarantee is secured with a Recourse Note issued by PGNiG Upstream.

In 2011, PGNiG Upstream received a parent company guarantee requested by Gassco as operator of the gas transportation system. In 2021, the Company has booked NOK 1 450 thousand as a liability connected with this agreement. This value is included in other current liabilities on the basis of invoices received.

In 2020, PGNiG Upstream received a parent company guarantee requested by Aker BP in relation of purchase of interest in Gina Krog. The guarantee covers liability of up to NOK 25 million as of 31.12.2020. In 2021, the Company has booked NOK 177 thousand as a liability connected with this agreement.

In 2021, PGNiG Upstream received two parent company guarantees requested by INEOS in association with purchase of INEOS ERP Norge AS assets and operations on the NCS:

- Buyers guarantee for the benefit of INEOS for the fulfilment of PGNiG Upstream's obligations to complete the transaction. This guarantee has been fully settled upon the completion of the transaction 30th September 2021.
- Decommissioning Security Guarantee for the benefit of INEOS for abandonment obligations associated with the assigned interests.

In 2021 the Company has booked USD 1 236 thousand and NOK 1 278 thousand, respectively, as liabilities associated with these agreements.

OTHER GUARANTEES

The Company secured a Letter of Credit from SEB (Svenska Enskilda Banken) towards Total ERP Norge AS to cover the decommissioning liabilities transferred from Total ERP Norge AS to the Company as a part of the asset acquisition in 2014.



Similarly, the Company secured a Letter of Credit from SEB (Svenska Enskilda Banken) towards A/S Norske Shell in relation to purchase of assets in 2020.

As of the balance sheet date, the maximum liability covered under these two guarantees were NOK 127,3 million. The Company has accrued for the expected future decommissioning liabilities for the assets as presented in Note 20.

NOTE 24 FINANCIAL RISK MANAGEMENT OBJECTIVES AND POLICIES

PGNiG Upstream has identified the major risks associated with the nature of the Company's business and the appropriate measures to manage those risks have been determined.

As an E&P company, PGNiG Upstream is exposed to a variety of financial risks. These include the following risk categories;

- market risk;
- liquidity risk;
- credit risk.

PGNiG Upstream seeks to minimise the impact of adverse fluctuations in financial markets on its financial performance. Risk management is an integral part of the Company's activities.

The market risk is related to oil and gas commodity price and exchange rate uncertainties. For the time being PGNiG Upstream does not have any derivative forward sales of oil and gas or currencies or other agreements designed to reduce the future risk exposure. The lack of oil price hedging is among other things connected with the adverse tax treatment of crude oil hedging in Norway and the uncertainty regarding production volumes.

PGNiG Upstream minimised exchange rate exposure by using loans both in Norwegian kroner, euro and US dollars.

The debt from financial institutions is denominated in US dollars but allows funds to be drawn under multiple

loans in both euro and US dollars. The currency of this loan is a part of the risk management.

The external loan is supposed to be repaid between 2023 and 2026 based on the revenues generated by PGNiG Upstream in these periods. As the revenues are denominated in US dollars and euro, the Company will be able to repay external debt without additional currency risk. Further to that, in 2015 the Company has entered into a Market Risk Management Services Framework Agreement in PGNiG (Centralized Model), which is a master agreement setting general rules for future operational and strategic risk management.

The following was undertaken by PGNiG Upstream to mitigate credit risk:

- cooperation with leading commercial banks;
- cooperation with credible customers;
- conclusion of framework agreements with business partners, that expressly define the rights and obligations of the parties.

The measures undertaken by the PGNiG Group to mitigate the liquidity risk included:

- on-going control of credit/debit operations on bank accounts;
- availability of a revolving credit facility agreement;
- projections of cash flows at the Company/the PGNiG Group;

The main objective of the PGNiG Upstream financial risk management policy is to limit the volatility of cash flows

related to the Company's operations to acceptable levels in the short and midterm while building the Company's value in the long term.

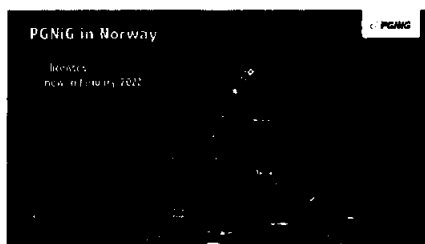
In connection with future spending on fields, the Company is able to finance its operations through

operating cash flow and external loan (see Note 18). In addition, the potential risk of liquidity loss is covered by available amount under intercompany loan (see Note 17)

NOTE 25 EVENTS AFTER THE BALANCE SHEET DATE

AWARDS IN APA2021

In January 2021, PGNiG Upstream was awarded four new exploration licenses as a result of the APA2021 licensing round. As a result, the number of licenses will increase to 62 in the beginning of 2022.



Two of the newly awarded licenses are located in the North Sea. PGNiG Upstream will act as the operator for

both of them. In case of license PL1135, it will cover 70% of shares and the remaining shares will belong to Lotos. In case of the PL1136 license, PGNiG Upstream Norway will have the similar shares as its partner - Equinor (50%).

The other two licenses are located in the Norwegian Sea. In case of the PL1055C license, PGNiG Upstream Norway will take up 60% of the shares and the role of operator, and the remaining shares will belong to Shell. The license is located near the Ormen Lange field, which is the largest field owned by PGNiG Upstream. In case of PL941B, PGNiG Upstream Norway will acquire 20%, and the operator's role with 80% of shares will be taken over by AkerBP. The license is located near the Skarv field, from which PGNiG's operations in Norway began.



NOTE 26 LICENSES

PGNiG Upstream's licenses at 31/12/2021

PL019G	(Gyda/Tambar East)	34%/5,44%	PL262	(Skarv Unit)	11,9175%
PL029B	(Gina Krog Unit)	11,3%	PL333	(King Lear)	22,2%
PL029C	(Gina Krog Unit)	11,3%	PL433	(Fogelberg)	20%
PL036D	(Vilje)	24,243%	PL460	(Skogul)	35%
PL036	(Vale)	24,243%	PL636	(Duva)	30%
PL122	(Marulk)	30%	PL636B	(Duva)	30%
PL122B	(Marulk)	30%	PL636C	(Duva)	30%
PL122C	(Marulk)	30%	PL838	(Shrek)	35%
PL122D	(Marulk)	30%	PL838B		40%
PL249	(Vale)	24,243%	PL937		65%
PL044	(Tommeliten Unit)	42,1978%	PL937B		65%
PL127C	(Alve N)	11,9175%	PL939		30%
PL134B	(Morvin)	6%	PL941		20%
PL134C	(Morvin)	6%	PL997		30%
PL146	(King Lear)	22,2%	PL1009	(Warka)	35%
PL146B	(King Lear)	22,2%	PL1009B	(Warka)	35%
PL159B	(Alve)	15%	PL1013		40%
PL159F		7,5%	PL1013B		40%
PL159G	(Alve)	15%	PL1017		50%
PL193	(Kvitebjørn)	6,45%	PL1055		60%
PL193C	(Kvitebjørn)	6,45%	PL1055B		60%
PL193B	(Valemon)	3,25%	PL1064		30%
PL193D	(Valemon)	3,25%	PL1065		30%
PL208	(Ormen Lange)	45%	PL1088		22,2%
PL212	(Skarv Unit)	11,9175%	PL1101		30%
PL212B	(Skarv Unit)	11,9175%	PL1103		30%
PL212E	(Ærfugl Nord)	15%	PL1111		60%
PL250	(Ormen Lange)	9,44%	PL1123		30%
261 C	(Skarv Unit)	11,9175%	PL1124		11,9175%

THE SKARV FIELD

The licenses PL212, PL212B and PL262 contain the Skarv oil and gas field. The Skarv Field was discovered in 1998, and it has taken 13 years to mature the field to its current stage. The Skarv field was developed together with the Idun field located nearby. During 2007 the Skarv and Idun licenses were unitized and both are now only referred to as Skarv.

The Skarv Unit:	
Aker BP (operator)	23,8350 %
Equinor	36,1650 %
Wintershall DEA	28,0825 %
PGNiG Upstream	11,9175 %

The Skarv Field is approximately 210 km west of the Norwegian coast in water depths of around 350-450 meters.



Skarv FPSO

The field was developed using a highly-advanced FPSO (floating production, storage and offloading vessel), purpose-built for harsh waters and connected to a gas pipeline, allowing the export of natural gas to markets in Europe.

THE ÆRFUGL FIELD

The Ærfugl field is located within the Skarv Unit. Its development plan (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on behalf of the Skarv Unit and PL212 E partnerships on 15 December 2017. The PDO was approved in April 2018.

The PDO covered the full-field development and includes the resources in both the Ærfugl and Ærfugl Nord fields. The PDO outlines a two-phased

development. Phase 1 started production in November 2020. Phase 2 started production from first well in April 2020, and the last 2 remaining wells came onstream in November 2021.

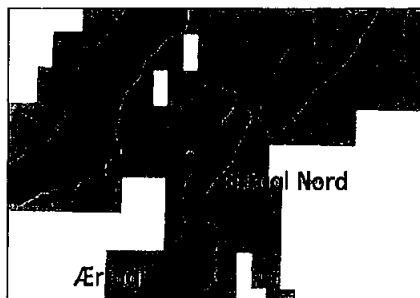


Ærfugl field

LICENSE PL212E

PL212E was carved out of the Skarv Unit after the unitization agreement in 2007. The licence is operated by Aker BP (30%), with Equinor (30%), Wintershall DEA (25%) and PGNiG Upstream (15%) as partners.

The license includes the Ærfugl Nord, which lies close to the Ærfugl gas field. Ærfugl Nord was included in the second phase of the Ærfugl development.



THE GINA KROG FIELD

Gina Krog, previously known as Dagny, was first discovered by Esso in 1974. It is an oil and gas discovery located in the Central North Sea, 250 kilometres west of Stavanger and 30 kilometres northwest of Sleipner.

The Gina Krog Unit:

Equinor (operator)	58,7000 %
KUFPEC	30,0000 %
PGNiG Upstream	11,3000 %

It has been developed through a new build oil processing platform and attendant FSO. It includes 20 well slots and full oil processing for up to 10000 Sm³/d, gas injection/export of 9 mmSm³/d and produced water treatment of 4000 Sm³/d.



The Gina Krog field started production in 2017 and is now in stable operation, with 9 oil producers, 4 gas injectors and two gas producers on stream.

Gina Krog Oil production is constrained by the 9 MSm³/d gas processing capacity. The oil processing capacity is not fully utilized and a second drilling campaign is being planned for 2022.

In the long term phase (2020+), it is important to develop Gina Krog further in accordance with the Sleipner Region 2040 ambitions. This includes infill IOR drilling, evaluating an alternative oil export solution and establish a basis for low pressure production. Possible third-party tie-ins will also still be an option. Cost efficiency is important to maximize the tail end production period.

Produced gas is transported to the Sleipner hub centre where the gas is processed and routed into the Gassled pipeline. The produced condensate is routed via Sleipner to Kårstø in an existing condensate pipeline.

Oil export is organized through Atea shuttle tankers. Oil recovery is increased by gas injection.

ORMEN LANGE UNIT

The Ormen Lange field is located in the Norwegian Sea, 120 kilometers west-northwest of the Nyhamna processing plant. It was discovered in 1997 in water depth from 800 to more than 1,100 meters. The reservoir lies at a depth of 2,700-2,900 meters below sea level and has excellent quality.

The production from the Ormen Lange Field started in 2007 from two 8-slots subsea templates in the central part of the field. Two new templates were installed in 2009 and 2011 in the southern and northern parts of the field increasing the well stock to 19 production wells. The subsequent phase in the development was the installation of onshore compression with production start in 2017. The license has recently taken FID on the Ormen Lange Phase 3 (OLP3) offshore compression which has a P50 RFSU in 2025. The field is produced through two 120 km long multiflow pipelines up to the Nyhamna processing plant.



The Ormen Lange Unit:

Shell (operator)	17,8134 %
Equinor	23,3452 %
Petoro	36,4850
Vår Energi AS	6,3356 %
PGNiG Upstream	14,0208 %

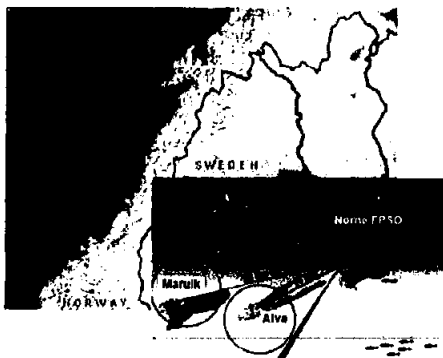


MARULK

The Marulk field is a gas and condensate producer located in PL122 in the Norwegian Sea. It is located some 215 kms offshore with a distance to the production host of c. 25 kms. The Marulk field was discovered in 1992 and it started production in 2012. The water depth in the area is approximately 370 m and the development is completed as a three well subsea tie-back to the Norne FPSO.

Gas and condensate from the Marulk field was initially produced from two wells draining the Lysing reservoir that was drilled and put on stream in 2012. A third well was drilled in 2019, draining the Lange Formation. Marulk produces gas from Cretaceous sandstone in the Lysing- and Lange Formation. The reservoirs are located at a depth of 2,800 – 2,850 meters. Both reservoirs are in turbidite fans and have moderate to good quality.

Marulk is produced via a multiphase pipeline to Norne, with subsequent wet Gas export from Norne via Gassled to Kårstø. Oil and condensate is exported from Norne via Transport tanker.



Marulk

Vår Energi AS (operator)	20,00 %
Equinor	33,00 %
DNO Norge	17,00 %
PGNIG Upstream	30,00 %

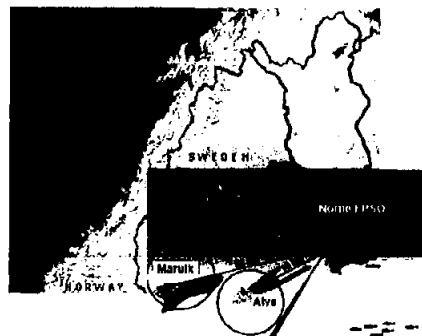
ALVE

The Alve field is a gas, oil and condensate producer located in PL159B in the Norwegian Sea. It is located some 215 kms offshore with a distance to the production host of c. 16 kms. The Alve field was discovered in 1990 and it started production in 2009. The water depth in the area is approximately 370 m and the development is completed as a three well subsea tie-back to the Norne FPSO.

The Alve field was initially produced from two wells that was drilled and put on stream in 2009/2010. A third well was drilled in 2016, draining the Ile Formation. Alve produces oil and gas from sandstone of Early and Middle Jurassic age in the Tilje, Not and Garn Formations. The reservoir lies at a depth of 3,600 meters and has moderate to good quality.

The license has committed to drilling a fourth well in the Alve Field, targeting the Tilje Gas Cap. The well will be utilizing the fourth slot in the subsea template and is expected to be drilled in the summer of 2022.

Alve is produced via a multiphase pipeline to Norne, with subsequent wet Gas export from Norne via Gassled to Kårstø. Oil and condensate is exported from Norne via Transport tanker.



Alve	
Equinor (operator)	53,00 %
DNO Norge	32,00 %
PGNIG Upstream	15,00 %

TAMBAR EAST

Tambar East is a field in the southern part of the Norwegian sector in the North Sea, two kilometers east of the Tambar field, 16 km south of the Ula field and 12 km north of Gyda. The Tambar East field was discovered in 2007 (K-5T2). In the same year authorities granted an exemption for the plan for development and operation (PDO) and the field started production. The field was developed with one production well (K-5A) drilled from the unmanned Tambar facility remotely controlled from the Ula field. Production from Tambar East was shut in in 2017 and the well was temporarily plugged in 2019.



Tambar East Unit	
Aker BP (operator)	46,20 %
DNO Norge	37,80 %
Repsol	9,76 %
Kufpec	0,80 %
PGNIG Upstream	5,44 %

GYDA

The Gyda field is located in the southern North Sea in PL019B about 280km southwest of Stavanger and between the Ula and Ekofisk fields. The field is operated by Repsol. Production from Gyda ended 29 Feb 2020 after almost 30 years of producing oil and gas. The PL019B license was not extended after its expiration 1 Sept 2020.

The Gyda Decommissioning Plan was approved by the Norwegian Authorities in June 2017 with a deadline to remove the Gyda facilities (topside, jacket and subsea equipment) to shore within 2023. The Decommissioning project is divided into two main sub-projects; Plug and Abandonment of wells (P&A) and removal and disposal of installations (Facility Removal). The P&A sub project commenced in Jan 2019 where a total of 32 wells has now been plugged.

The Gyda topside, steel jacket, 32 well conductors and the subsea drilling template are planned to be removed in summer 2022. The removal of the facilities in 2022 will be done by Allseas employing the Pioneering Spirit heavy lift vessel to carry out the removal and transportation to Kværner Stord for further demolition.



Gyda	
Repsol (operator)	61,00 %
Kufpec	5,00 %
PGNIG Upstream	34,00 %

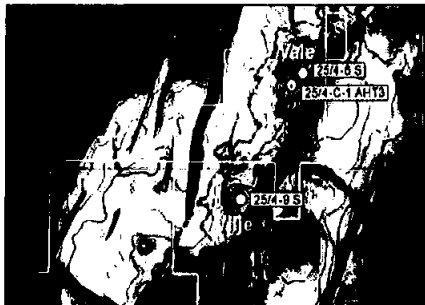
THE VILJE FIELD

The Vilje field is located in block 25/4 of the Norwegian North Sea, about 20 kilometres northeast of Alvheim and just north of Heimdal, in 120 metres of water. The Vilje reservoir is Middle to Late Paleocene Heimdal Formation turbidite sandstone, at a depth of approximately 2,100 metres. The Heimdal Formation is a high porosity, high net-to-gross, unconsolidated, high permeability, normally pressured sandstone, with an active water drive.



Vilje is a subsea development with three horizontal subsea wells connected to the Alvheim FPSO. The field started production in August 2008. The subsea wells are tied back 19 km via a 12" production flow line, 6" gas lift line and an umbilical to the Alvheim FPSO for processing. The oil is exported from the Alvheim FPSO via tankers.

Since the start-up of production the field has consistently delivered production above the annual plans. Currently Vilje is being produced through the Vilje VI1 well, VI2 and VI3 is shut in.



THE VALE FIELD

The Vale field is a gas and condensate producer located 16 km north of the Heimdal Gas Centre (HGC). The Vale field was discovered in 1991 and started production in 2002. The water depth in the area is approximately 114-120 metres.

The development concept is a single well subsea tie-back via 8" flowline to the Heimdal platform. No pressure support is employed for the field. The base model for field life is therefore natural depletion. There is a regional aquifer to the south and west of the field, which provides the drive necessary for production. The License has approved to extend gas processing at Heimdal and to continue production beyond 24th October 2021.

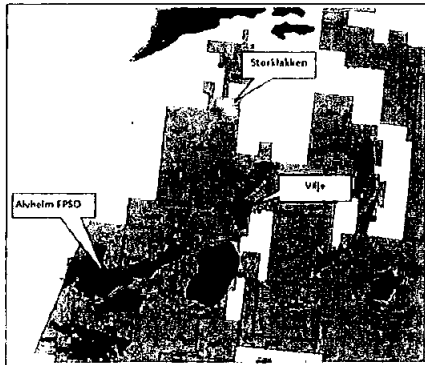
THE MORVIN FIELD

Morvin is located in the Norwegian Sea. The field is classified as a HPHT field, with an initial reservoir pressure of 818 bar and a temperature of 162 degrees Celsius. The field is located close to other projects, approximately 20km north of the existing Kristin field and 15km west of Åsgard B. The reservoir depth is from 4500 – 4800 meters. The water depth in the area is 360 meters.

The reservoir contains oil and gas and is developed with four horizontal production wells and two subsea templates tied back to Åsgard B. Åsgard B is a semi-submersible floating production vessel, containing process facilities for treating gas and stabilisation of gas and condensate. Three infill drilling targets and three coiled tubing well clean out operations is planned for execution by 2025 to extend and maintain production.

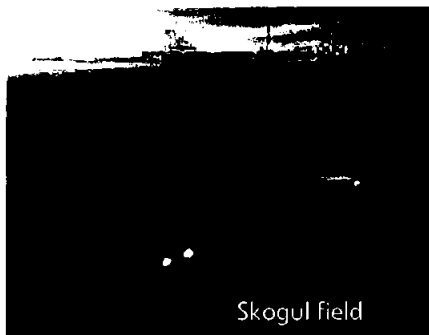
THE SKOGUL FIELD

The Skogul oil field, in PL460, is located approximately 40 km North of Alvheim in blocks 24/3, 25/1 and 25/2 in the Norwegian sector of the North Sea. The water depth is 107 meters. An area map and overview is shown below.



The field was discovered in April 2010 by Det Norske and a PDO was submitted to the authorities in December 2017. The field is developed as a one multi-lateral subsea well tied back to the existing Alvheim facilities via the Vilje subsea flowbase. The Vilje subsea flowbase is located approximately 16 km from Skogul.

The Skogul development project was completed and production started 14th March 2020.



THE KVITEBJØRN FIELD



Kvitebjørn is an HPHT field in the Tampen area in the northern part of the North Sea, 15 kilometres southeast of the Gullfaks field. The water depth is 190 metres. Kvitebjørn was discovered in 1994, and the plan for development and operations (PDO) was approved in 2000. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket. Production started in 2004.

Production is routed through first stage separation facilities where rich gas is transported via Kvitebjørn gas pipeline to Kollsnes. Condensate is transported via Kvitebjørn oljerør and TOR 2 pipeline to Mongstad.

The license partners are Equinor (operator), Petoro, Spirit Energy and Total. PGNiG purchased license share from Shell in 2020 and officially became partner from 31.12.2020.

There is an ongoing infill drilling campaign that will continue in 2022 and likely into 2023. Short term and long term focus is therefore to continue to mature infill targets and on various aspects related to lifetime extension for Kvitebjørn in order to maintain production beyond 2027

THE VALEMON UNIT



Valemon is an HPHT field in the northern part of the North Sea, just west of the Kvitebjørn field. The water depth is 135 metres. Valemon was discovered in 1985, and the plan for development and operation (PDO) was approved in 2011. The field is developed with a fixed production platform with a simplified separation process design. The facility is the first Not Normally Manned platform on the NCS and is controlled from shore. Power is supplied from Kvitebjørn. Temporary living quarters for 40 people. Drilling is performed by jack-up rig. Production started in 2015.

The condensate is transported by pipeline to the Kvitebjørn field, and via the Kvitebjørn oljerør to Mongstad. The rich gas is exported via the previous Huldra pipeline to Heimdal for further export to the UK or continental Europe.

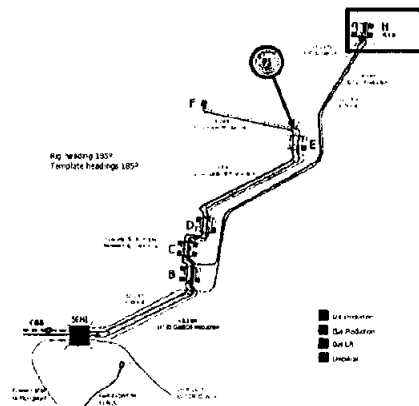
The license partners are Equinor (operator) and Petoro.

THE DUVA FIELD

Duva is an oil & gas discovery located in PL 636, 636 B & 636 C in the Norwegian sector of the North Sea, approximately 12 km northeast of the Gjølå semi-submersible. Closest distance to shore is only 35 km.

The Duva License partnership is: Neptune 30% (Operator), Idemitsu 30%, SVAL 10% and PGNiG Upstream 30%.

The Duva discovery was made in well 36/7-4 in August 2016. The Water depth in the Duva area ranges from 345 to 361 meters. Expected lifetime for Duva is 13 years. Duva was developed as a Subsea tieback to Gjølå with 3 oil producers and 1 gas producer. Production commenced in August 2021, but there is outstanding project work for 2022. Initial 2 years, production profile is limited by available oil and gas processing capacity at host, Gjølå.



THE TOMMELITEN ALPHA FIELD

The Tommeliten Alpha field is located in PL044, in the Central Graben in the Norwegian North Sea, about 25 km southwest of the Ekofisk field. The discovery was made by Equinor in 1976 with subsequent appraisal wells drilled between 1976-2003. The reservoir is in chalk and there are two main reservoir layers, the Ekofisk Formation and the Tor Formation.

The partnership in the AMI (PL044 unitized with UK license P2220) currently consists of: ConocoPhillips (28,35% and operator), PGNiG Upstream (42,20%), Total (20,29%), Vår Energi (9,09%) and ENI UK (0,07%).

Additionally, PGNiG have a 30% share in the PL044 exploration area which lies outside the Sole Risk Area (covering Tommeliten Alpha and Tommeliten Gamma).

The field is located in the direct vicinity of large, already developed fields, including the giant Ekofisk field.

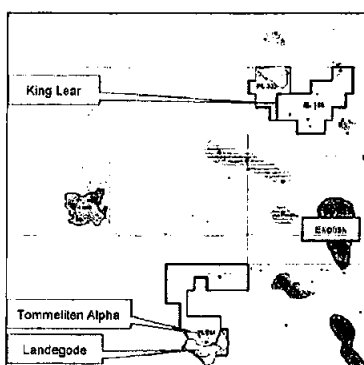
According to current plans, production is expected to commence in 2024, and the development concept will be a tie-back to the existing infrastructure on Ekofisk. This will allow for a cost-effective development, further decrease of future production cost, and will accelerate the field's start-up.

THE KING LEAR FIELD (PL146/333)

King Lear is an HP/HT discovery located way south in the Norwegian Sector of the North Sea, 49 km north of Valhall the Water depth is 67 meters.

Reservoir depth of 5344 meters with pressure above 900 bars and temp. Approx. 165oC. A total of 8 wildcats have been drilled, and initial discovery was made in 1988. Exploration well in 2012 proved 48 m gas/condensate column, and 70m in sidestep.

The partnership in PL146/333 currently consists of Aker BP (78,8% and operator) and PGNiG Upstream (22,2%).



THE FOGELBERG DISCOVERY (PL433)

Fogelberg is located in blocks 6506/9 and 6506/12 in the Haltenbanken area of the Norwegian Sea.

The partnership in PL433 currently consists of: Spirit Energy (60,82% and Operator), PGNiG Upstream (23,53%) and Lime (15,65%).

Gas/condensate was found in the Garn and Ile formations in 2010. The discovery is located 17 km north of Åsgard and 30 km south west of Heidrun.

An appraisal well was drilled H1 2018 to reduce volume uncertainty, verify reservoir quality and well productivity in Garn and Ile, and collect representative fluid samples.

Following the appraisal well campaign the definition of the in place volume range has been improved. Recoverable volumes and associated profiles are currently being evaluated. The reserve estimate related to Fogelberg may be changed as a result of further evaluation of the discovery.

PGNiG Upstream's pipelines at 31/12/2021

KOR (Kvitebjørn Oljerør)	6,45%
VRGP (Valemon rich gas pipeline)	3,25%
Nyhamna Processing Plant	8,188%

KVITEBJØRN OLJERØR (KOR)

Kvitebjørn oljerør is a 90 km pipeline transporting condensate from Kvitebjørn platform to Mongstad process facilities.

The operator is Equinor, holding 39.55% share. Petoro AS has 30%, Spirit Energy Norway AS has 19% and Total ERP Norge AS has 5%. PGNiG Upstream purchased 6,45% of the license shares from Shell in 2020.



VALEMON RICH GAS PIPELINE (VRGP)

Valemon Rich Gas Pipeline is a 177 km pipeline transporting rich gas from Valemon platform to Heimdal process facilities.

The operator is Gassco AS. Equinor, holding 39.55% share is the Technical Service Provider (TSP). Petoro AS has 30% share. PGNIG Upstream purchased 3,225% of the license shares from Shell in 2020.

NYHAMNA

Nyhamna gas processing plant became operational in 2007. It was originally built to process gas from the

Ormen Lange field in the Norwegian Sea. The plant was expanded in 2017 to receive gas through Polarled and became a separate joint venture on 1 October that year. Gassco is the operator with Shell as the Technical Service Provider.

Nyhamna	
Petoro	26,138 %
Equinor	30,056 %
CapeOmega	18,209 %
Shell	2,027 %
North Sea Infrastructure	13,700 %
ConocoPhillips	1,681 %
PGNIG Upstream	8,188 %

NOTE 27 RESERVES AND CONTINGENT RESOURCES (NOT AUDITED)

For all assets the Company's reserves and Contingent Resources are based on the operator's official data reported in the Revised National Budget (RNB) for 2021. PGNIG Upstream follows defined by Operators base cases of proven reserves in Resource Class 1-3 and Contingent Resources in Resource Class 4-5 as per the NPD resource classification. All figures are in million boe and net to PGNIG Upstream*:

* Please note that all data regarding reserves in this Annual Report are unaudited and are based on the information from the respective license Operators.

Field	Oil	Gas	NGL	Total
Skarv & Ærfugl	5,0	23,6	5,3	33,9
Ærfugl Nord	0,2	2,2	0,3	2,7
Morvin	0,7	0,5	0,2	1,3
Gina Krog	3,8	8,2	1,4	13,3
Vilje	3,3	0,0	0,0	3,3
Vale	0,2	0,4	0,0	0,7
Skogul	1,8	0,1	0,0	1,8
Tommeliten	15,3	41,6	1,9	58,7
Alpha				
King Lear	14,8	21,4	3,5	39,7
Duva	5,8	11,8	2,7	20,4
Alve Nord	0,5	2,1	0,5	3,0
Shrek	3,0	1,9	0,4	5,3
Kvitebjørn	1,8	8,6	0,4	10,8
Valemon	0,2	1,3	0,0	1,6
Fogelberg	0,8	7,7	1,5	9,9
Ormen Lange	3,0	91,4	0,0	94,5
Maruik	0,2	2,4	0,4	2,9
Alve	0,4	3,5	1,1	5,0
Tambar East	0,0	0,0	0,0	0,0
Total	60,8	228,6	19,6	309,0



COUNTRY-BY-COUNTRY REPORTING OF
PAYMENTS TO AUTHORITIES IN 2021



INFORMATION ON COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2021

Background

PGNiG Upstream Norway AS ("PGNiG Upstream" or "the Company") is subject to the country-by-country reporting of payments to authorities as stated in the Norwegian Accounting Act § 3-3d. The Company is as such obliged to report and publish an annual overview of payments to the authorities for the year. The reporting is based on actual payments done in the year 2021. This report is issued together with the Annual Report for 2021. The report is not subject to external audit.

Country-by-country reporting of payments to authorities

The overview of payments made to the authorities in 2021 consists of profit oil in-kind, taxes and fees, royalty, dividends, bonuses, licencing fees and

infrastructure and ownership rights in accordance with the Norwegian Accounting Act § 3-3d and the Regulations to country-by-country reporting §2. As the Company only operates in Norway, all amounts refer to payments to Norwegian authorities. All amounts are presented in Norwegian kroner (unless otherwise stated).

Reporting of other data

In addition, the Company has provided an overview of investments, sales revenues, production, purchase of goods and services and interest costs to associated companies in accordance with the Regulations on country-by-country reporting §3. Information on payments on project level is given where this is available. The amounts included are based on the financial statements for 2021 and, to the best extent possible, reflect the actual amounts paid in 2021.

COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2021

Payments made in 2021	Profit oil in-kind (1)	Taxes and fees (2)	Royalty	Dividends	Bonuses (3)	Licence fees (4)	Infrastruc ture (5)	Ownership rights (6)
Paid, in thousand NOK	0	(469 759)	0	0	0	398	0	0

(1) Profit oil in-kind: Part of production emitted to authorities.

(2) Taxes and fees: Taxes and fees to the Company's income, production or net result, excluding taxes and fees on consuming goods such as VAT, tax withholding for employees e.g. The amount included for 2021 is related to negative tax instalments from the Norwegian state of -469 759 thousand, and net custom tariffs refunded from Skatteetaten for CO2 fuel and flare and NOx of NOK -29 thousand. VOC is not included, as the payment is done to a third party (Teekay).

(3) Bonuses related to signatures, discoveries and production.

(4) Fees related to licences, access to licences, concessions e.g. typically this includes area fee in Norway. As area fee is paid by the operators, the Company will only include area fees paid from operated licences for the year. Reported amounts in 2021 include NOK 29 thousand for the sector fees from Petroleum Safety Authority in Norway and 369 thousand for fees related to the APA2021 licensing round.

(5) Contributions to improved infrastructure. Ordinary tariff cost from the Gassled transportation system paid to Gassco is not included.

(6) Distribution of shares or other ownership interests in the Company to the authorities.



Annual Report 2021



REPORTING OF ADDITIONAL DATA

The Company is also obliged to provide certain additional data under the regulations on country-by-country reporting § 3. Such data is presented in the table below. For further details to these numbers, please refer to the financial statement and notes to the Annual Report.

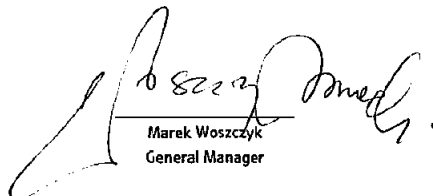
<u>Other information</u>	<u>Investments (1)</u>	<u>Revenues (2)</u>	<u>Production (3) million boe</u>	<u>Purchase of goods and services (4)</u>	<u>Interest cost to associated companies (5)</u>
Million NOK (except production)	5 446	13 315	14,3	1 527	173

- (1) Investments include the acquisition of Ormen Lange, Alve, Marulk, Nyhamna processing plant and Tambar East. It also includes the Ærfugl phase 2 (incl. Ærfugl Nord), Gråsel and Duva projects that went into production during 2021 and Tommeliten Alpha, Gråsel and Fogelberg development projects, investments on the producing fields Skarv, Gina Krog, Vilje, Skogul, Vale, Morvin, Kvitebjørn and Valemon and investments on exploration licences and investment in onshore assets (office machines e.g.). For further details, please refer to the Annual Report.
- (2) Total revenues for the year 2021 from sales of hydrocarbons and other income. For further details, please refer to the Annual Report.
- (3) Production of hydrocarbons in million boe for the year from Skarv, Ærfugl Nord, Vilje, Skogul, Vale, Morvin, Gina Krog, Alve, Marulk and Ormen Lange fields presented in million barrels of oil equivalent.
- (4) Purchase of goods and services in relation to operating activities. Includes also operating cost from joint ventures.
- (5) Interest cost paid to associated companies (loan from parent Company).


Przemysław Waclawski
Chairman of the Board


Magdalena Zegarska
Director of the Board


Arkadiusz Sekściński
Director of the Board


Marek Woszczyk
General Manager

Sandnes,
3rd February 2022