



ÅRSREGNSKAPET FOR REGNSKAPSÅRET 2022 - GENERELL INFORMASJON

Enheten

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

Regnskapsår

Årsregnskapets periode: 01.01.2022 - 31.12.2022

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: 10.02.2023

Grunnlag for avgivelse

År 2022: Årsregnskapet er elektronisk innlevert
År 2021: Tall er hentet fra elektronisk innlevert årsregnskap fra 2022

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, 30.06.2024



Resultatregnskap

Beløp i: NOK	Note	2022	2021
RESULTATREGNSKAP			
Inntekter			
Sales income	3, 10	42 571 000 000	13 166 000 000
Other income		465 000 000	147 000 000
Sum inntekter		43 036 000 000	13 313 000 000
Kostnader			
Exploration expenses	4	633 000 000	310 000 000
Production and sales cost	6, 10	2 469 000 000	1 238 000 000
Employee expenses	5	81 000 000	104 000 000
Depreciation	12	4 528 000 000	1 648 000 000
Depreciation of use to right assets	12	91 000 000	18 000 000
Loss on disposals	12	182 000 000	
Nedskrivning av varige driftsmidler og immaterielle eiendeler	12	-460 000 000	-306 000 000
Other operating expense	7, 10	299 000 000	128 000 000
Sum kostnader		7 823 000 000	3 140 000 000
Driftsresultat		35 213 000 000	10 173 000 000
Finansinntekter og finanskostnader			
Renteinntekt fra foretak i samme konsern	18	58 000 000	
Other financial income	8	1 302 000 000	393 000 000
Sum finansinntekter		1 360 000 000	393 000 000
Rentekostnad til foretak i samme konsern	18	19 000 000	150 000 000
Other financial expenses	9	1 060 000 000	592 000 000
Sum finanskostnader		1 079 000 000	742 000 000
Netto finans		281 000 000	-349 000 000
Ordinært resultat før skattekostnad		35 494 000 000	9 824 000 000
Tax on the profit/(loss) for the year	11	27 621 000 000	7 886 000 000
Ordinært resultat etter skattekostnad		7 873 000 000	1 938 000 000
Årsresultat		7 873 000 000	1 938 000 000



Balanse

Beløp i: NOK	Note	2022	2021
BALANSE - EIENDELER			
Anleggsmidler			
Immaterielle eiendeler			
Capitalized exploration expenses	12	688 000 000	909 000 000
Goodwill	12	2 803 000 000	2 896 000 000
Sum immaterielle eiendeler		3 491 000 000	3 805 000 000
Varige driftsmidler			
Assets in production	12	15 452 000 000	18 380 000 000
Assets in development	12	7 643 000 000	3 909 000 000
Right-of-use asset	12	99 000 000	190 000 000
Other fixtures and fittings, tools and	12	7 000 000	3 000 000
Long Term receivable	21	207 000 000	56 000 000
Loan to Group enterprises	18	5 296 000 000	
Sum varige driftsmidler		28 704 000 000	22 538 000 000
Sum anleggsmidler		32 195 000 000	26 343 000 000
Omløpsmidler			
Varer			
Inventory	16	128 000 000	120 000 000
Sum varer		128 000 000	120 000 000
Fordringer			
Trade receivable	10	341 000 000	380 000 000
Trade receivables Group enterprises		3 673 000 000	2 791 000 000
Other current receivables	14	1 877 000 000	601 000 000
Sum fordringer		5 891 000 000	3 772 000 000
Bankinnskudd, kontanter og lignende			
Cash and cash equivalents	15	7 767 000 000	3 355 000 000
Sum bankinnskudd, kontanter og lignende		7 767 000 000	3 355 000 000
Sum omløpsmidler		13 786 000 000	7 247 000 000
SUM EIENDELER		45 981 000 000	33 590 000 000



Balanse

Beløp i: NOK	Note	2022	2021
BALANSE - EGENKAPITAL OG GJELD			
Egenkapital			
Innskutt egenkapital			
Share capital	17	1 115 000 000	1 115 000 000
Share premuim		1 777 000 000	1 777 000 000
Sum innskutt egenkapital		2 892 000 000	2 892 000 000
Opptjent egenkapital			
Retained earnings		8 645 000 000	1 258 000 000
Sum opptjent egenkapital		8 645 000 000	1 258 000 000
Sum egenkapital		11 537 000 000	4 150 000 000
Gjeld			
Langsiktig gjeld			
Utsatt skatt	11	10 431 000 000	9 800 000 000
Abandonment provision	21	3 102 000 000	2 679 000 000
Sum avsetninger for forpliktelser		13 533 000 000	12 479 000 000
Annen langsiktig gjeld			
Gjeld til kredittinstitusjoner	19		4 325 000 000
Langsiktig konserngjeld	18		1 420 000 000
Lease liabilities	13	101 000 000	122 000 000
Sum annen langsiktig gjeld		101 000 000	5 867 000 000
Sum langsiktig gjeld		13 634 000 000	18 346 000 000
Kortsiktig gjeld			
Debt to financial institutions payable	19	12 000 000	6 000 000
Leverandørgjeld	10	303 000 000	123 000 000
Taxes payable, not assessed	11	18 288 000 000	9 821 000 000
Emplo yee tax liabilities, duties		28 000 000	38 000 000
Kortsiktig konserngjeld	18, 24	0	12 000 000
Other current liabilities	22, 24	2 179 000 000	1 094 000 000
Sum kortsiktig gjeld		20 810 000 000	11 094 000 000



Balanse

Beløp i: NOK	Note	2022	2021
Sum gjeld		34 444 000 000	29 440 000 000
SUM EGENKAPITAL OG GJELD		45 981 000 000	33 590 000 000



KPMG AS
Forusparken 2
P.O. Box 57
N-4064 Stavanger

Telephone +47 45 40 40 63
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 2022, the income statement, statement of comprehensive income 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 2022, 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 relevant laws and regulations in Norway and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards) (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

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 statutory requirements.

Offices in:

© KPMG AS, a Norwegian limited liability company and a member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. All rights reserved.

Statsautoriserte revisorer - medlemmer av Den norske Revisorforening

Oslo	Elverum	Mo i Rana	Tromsø
Alta	Finnsnes	Molde	Trondheim
Arendal	Hamar	Sandefjord	Tynset
Bergen	Haugesund	Stavanger	Ulsteinvik
Bode	Knarvik	Stord	Ålesund
Drammen	Kristiansand	Strøme	

Penneco Dokument nr. 5547L-0M3TX-1XAIA-CL5A2-CYG7G-E4NYT



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 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, 13 February 2023
KPMG AS

Mads Hermansen
State Authorised Public Accountant
(This document is signed electronically)

Penneo Dokumentnøkkel: SS47L-0M3TX-1XAIA-CL5A2-CYG7G-E4NYT



PENNEO

The signatures in this document are legally binding. The document is signed using Penneo™ secure digital signature. The identity of the signers has been recorded, and are listed below.

"By my signature I confirm all dates and content in this document."

Mads Aleksander Hermansen

Statsautorisert revisor

On behalf of: KPMG AS

Serial number: 9578-5997-4-280077

IP: 80.232.xxx.xxx

2023-02-13 16:14:10 UTC



Penneo document key: 5S47L-0M3TX-1XAIA-CL5A2-CV67G-EANYT

This document is digitally signed using Penneo.com. The digital signature data within the document is secured and validated by the computed hash value of the original document. The document is locked and timestamped with a certificate from a trusted third party. All cryptographic evidence is embedded within this PDF, for future validation if necessary.

How to verify the originality of this document

This document is protected by an Adobe CDS certificate. When you open the

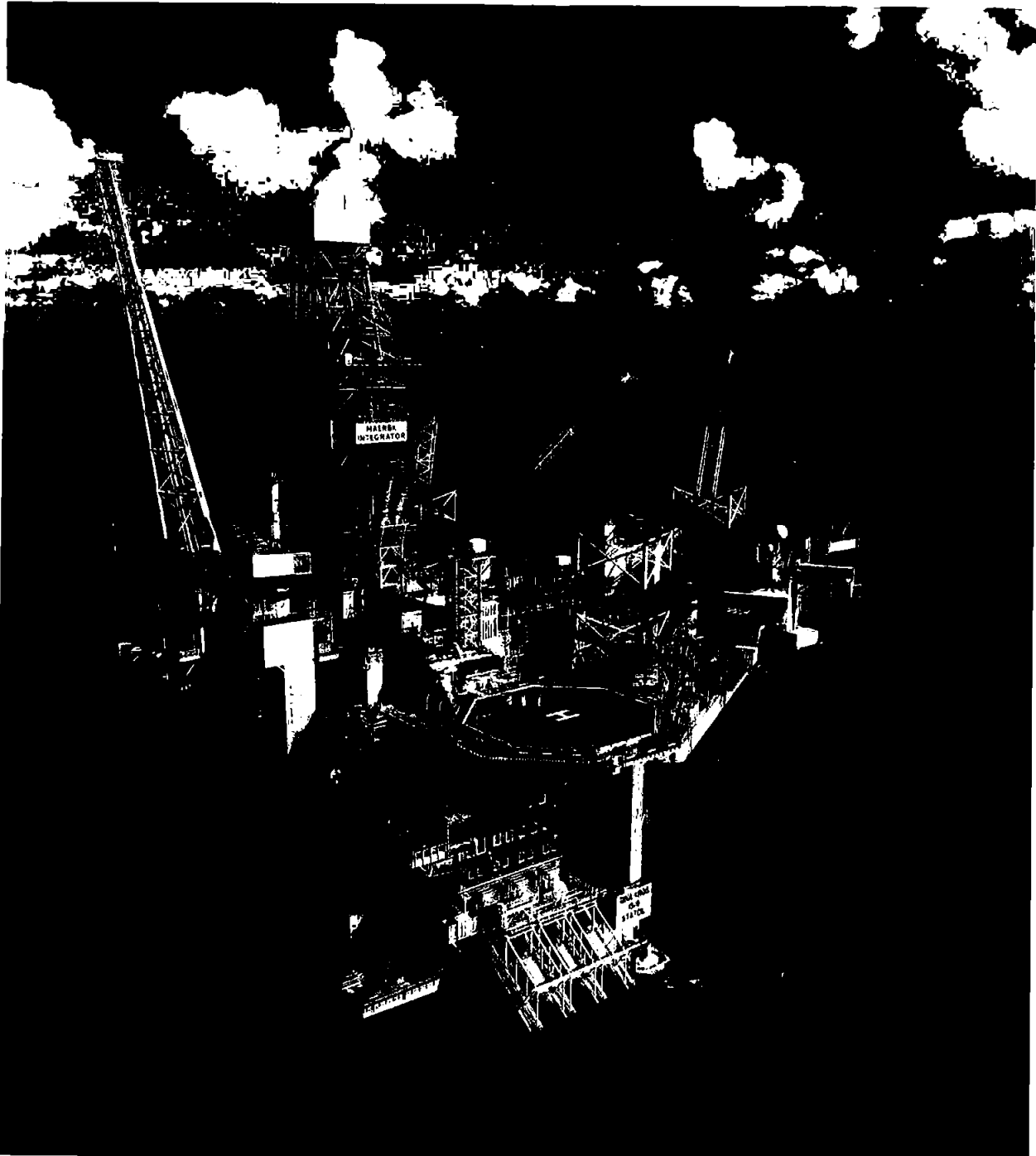
document in Adobe Reader, you should see, that the document is certified by **Penneo e-signature service <penneo@penneo.com>**. This guarantees that the contents of the document have not been changed.

You can verify the cryptographic evidence within this document using the Penneo validator, which can be found at <https://penneo.com/validator>



ANNUAL REPORT 2022

STAVANGER, 10 FEBRUARY 2023





INDEX

DIRECTORS' REPORT.....	3
FINANCIAL STATEMENTS.....	13
INCOME STATEMENT (NOK million).....	14
STATEMENT OF COMPREHENSIVE INCOME.....	14
BALANCE SHEET (NOK million).....	15
CASH FLOW STATEMENT (NOK million).....	17
STATEMENT ON CHANGES IN EQUITY (NOK million).....	18
GENERAL INFORMATION.....	19
NOTE 1 SUMMARY OF IFRS ACCOUNTING POLICIES APPLICABLE FOR 2022.....	19
NOTE 2 SIGNIFICANT TRANSACTIONS IN 2022.....	27
NOTE 3 REVENUE.....	28
NOTE 4 EXPLORATION EXPENSES.....	30
NOTE 5 EMPLOYEE EXPENSES AND BENEFITS.....	31
NOTE 6 PRODUCTION AND SALES COSTS.....	32
NOTE 7 OTHER OPERATING EXPENSES.....	32
NOTE 8 OTHER FINANCIAL INCOME.....	33
NOTE 9 OTHER FINANCIAL EXPENSES.....	34
NOTE 10 RELATED PARTY ITEMS.....	34
NOTE 11 TAX ON THE INCOME/(LOSS) FOR THE YEAR.....	35
NOTE 12 INTANGIBLE ASSETS AND TANGIBLE FIXED ASSETS.....	37
NOTE 13 LEASES.....	41
NOTE 14 OTHER CURRENT RECEIVABLES.....	42
NOTE 15 CASH AND CASH EQUIVALENTS.....	42
NOTE 16 INVENTORY.....	43
NOTE 17 EQUITY.....	43
NOTE 18 INTERCOMPANY LOANS.....	44
NOTE 19 DEBT TO FINANCIAL INSTITUTIONS.....	45
NOTE 20 PENSION.....	46
NOTE 21 PROVISIONS.....	47
NOTE 22 OTHER CURRENT LIABILITIES.....	48
NOTE 23 COMMITMENTS AND CONTINGENCIES.....	48
NOTE 24 GUARANTEES.....	50
NOTE 25 FINANCIAL RISK MANAGEMENT OBJECTIVES AND POLICIES.....	51
NOTE 26 EVENTS AFTER THE BALANCE SHEET DATE.....	52
NOTE 27 LICENSES.....	53
NOTE 28 RESERVES AND CONTINGENT RESOURCES (NOT AUDITED).....	63
COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2022.....	64

© All pictures included in this report are sourced from: PGNiG Upstream, PKN Orlen, Aker BP, Equinor, Odfjell, Neptune, NPD

DIRECTORS' REPORT

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

In November 2022, PKN Orlen SA ("Orlen") completed the acquisition of the PGNiG Group ("PGNiG") and became sole owner of PGNiG Upstream. Orlen is an integrated, multi-utility company, operating mainly in Europe. The group provide energy and fuels to over 100 million Europeans and deliver products to 100 countries on 6 continents. Orlen pursues strengthening our position as a regional leader in energy transition by implementing clean and sustainable technologies, as well as power generation based on low- and zero-emission sources. Orlen's actions are driven by a strategic goal of reaching emission neutrality by 2050. The main shareholder of Orlen is the Polish State Treasury.



The merger between Orlen and PGNiG contributes to improve the energy security of Poland and the entire region, which is of crucial importance given the current geopolitical situation. Therefore, one of the most important tasks for PGNiG Upstream is to secure stable and reliable gas supplies for Orlen.

Detailed information about the activities and business profile of Orlen can be found at the company's internet address: www.orken.pl/en.

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 76 experienced staff from around the world and has become a successful drilling operator.

Supported by high commodity prices and record-high production, the company has realized operational revenue in 2022 of NOK 43.0 billion, with production of 26.2 mboe.

PGNiG Upstream has invested more than 30 billion NOK in Norway and participated in the drilling of multiple exploration and production wells. This has led to discoveries on the NCS, including Ærfugl, Lunde (Shrek), Warka and Newt. In addition, the company has participated in 19 licensing rounds and been awarded 38 production licenses (out of which 10 as operator).

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 participates in seven sanctioned development projects (Ormen Lange phase 3, Tommeliten Alpha, Fenris, Alve North, Andvare, Verdande and Ørn). Furthermore, there is ongoing evaluation work on recent discoveries. As of 31st of December 2022, the total resources and reserves are expected to be 291 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

Field	PUN share	Operator	Partners	PUN 2P + 2C 2022 mboe	PUN production 2022 kboe/d
Aive	15.00 %	Equinor (63%)	DNO (32%)	4.3	1.8
Duva	30.00 %	Nephtun (30%)	Klemitsu (30%), Sval (10%)	15.1	7.5
Gina Krog	11.30 %	Equinor (69%)	KUFPEC (30%)	8.8	7.2
Kvitebjørn	6.45 %	Equinor (40%)	Petoro (30%), Sval (10%), Total (5%)	8.0	3.0
Marulik	30.00 %	Vår (20%)	Equinor (33%), DNO (17%)	2.0	3.2
Morvin	6.00 %	Equinor (64%)	Vår (30%)	0.2	0.2
Ormen Lange	14.02 %	Shell (18%)	Petoro (30%), Equinor (25%), Vår (6%)	85.3	24.7
Skarv	11.92 %	AkerBP (24%)	Wintershall (28%), Equinor (36%)	20.5	17.2
Skogul	35.00 %	AkerBP (65%)		1.2	1.1
Vale	24.24 %	Sval (50%)	LOTOS (26%)	0.3	1.6
Valemon	3.23 %	Equinor (87%)	Petoro (30%)	1.0	0.3
Vilje	24.24 %	AkerBP (47%)	Equinor (30%)	3.0	1.1
Ærfugl Nord	15.00 %	AkerBP (30%)	Equinor (30%), Wintershall (25%)	3.0	2.0
Sum assets producing in 2022				162.6	71.7
Aive North	11.92 %	AkerBP (68%)	Wintershall (20%)	4.0	
Verdande	0.80 %	Equinor (59%)	Petoro (22%), Vår (10%), Aker BP (7%)	0.3	
Fennis	22.20 %	AkerBP (78%)		41.2	
Lunde	36.00 %	AkerBP (35%)	Line (30%)	2.3	
Ørn	40.00 %	AkerBP (30%)	Equinor (30%)	20.3	
Tommeliten Alpha	42.20 %	Conoco (28%)	Total (20%), Vår (6%)	59.0	
Tambar Øst	5.44 %	AkerBP (40%)	DNO (38%), Repsol (10%), KUFPEC (1%)	0.0	

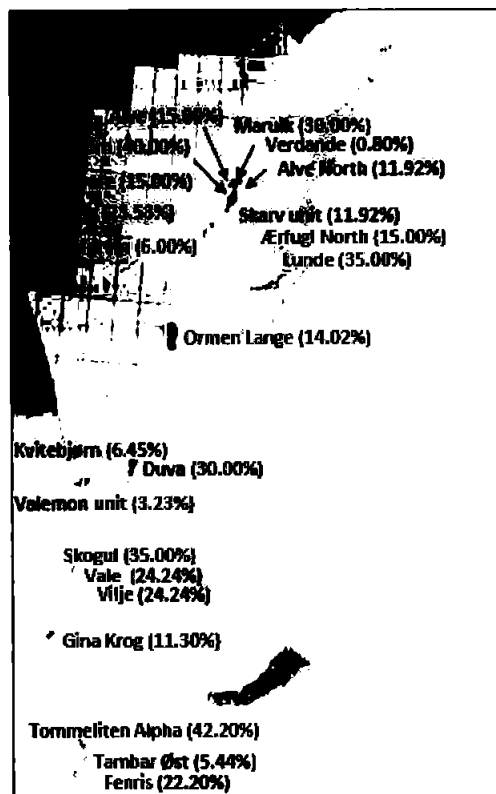
Sum PUN asset portfolio 290.6 mboe, 294.7

*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). In case of Lunde project, JV decided to resign from development concept included in its RNB2023. In this case PUN used smaller volumes associated with simplified development the JV currently focuses on.

Key developments in 2022

The Company's main objective is to secure stable, reliable and cost-effective gas supplies for Orlen. This goal is expected to be materialized through diversified hydrocarbon production from the Norwegian Continental Shelf (NCS).

In 2022 the Company delivered strong results, with revenues of NOK 43.0 billion and an EBITDA of NOK 39.4 billion. These results were possible thanks to the



performance of key assets like Ormen Lange and Skarv, which accounted for approximately 61% of the total revenue.

Total production in 2022 of 3.1 billion cubic metres of gas, and 886 thousand tonnes of crude oil (including NGL's) are up by 83 % when comparing with 2021

Russia's invasion of Ukraine has turned a rapid economic recovery from the pandemic into a full-blown energy turmoil. Russia's subsequent curtailment of natural gas supply is causing disruptive responses in the European gas markets with never-seen-before spiralling gas prices in 2022. With this global energy crisis as a backdrop, PGNiG Upstream's gas weighted production portfolio has delivered very substantial revenues during both 2021 and 2022.

Annual Report 2022

In 2022, the Company produced more than 3.1 bcm of gas and significantly exceeded the target set out in its strategy. Such an increase was possible thanks to significant investments in the previous years and change of production strategy on selected fields. In the light of the extraordinary high gas prices, PGNiG Upstream reduced gas injection on Skarv and Gina Krog and exported more gas to Europe.

Additionally, the Company has successfully integrated the assets acquired from INEOS in 2021 to its portfolio.

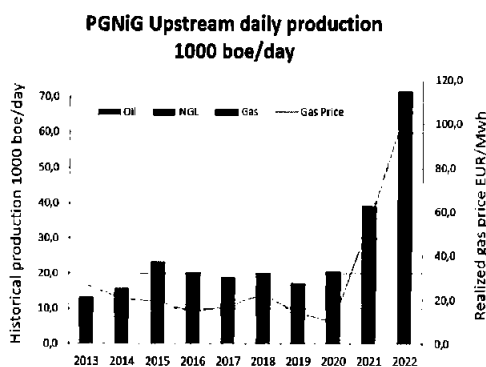


Illustration of Skarv Satellite Project, including Ørn and Alve Nord



Based on fields which are currently owned by PGNiG Upstream, the Company plans to reach 3.4 bcm of gas production in 2026.

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

Strong development focus

Successful business development activities

PGNiG Upstream holds a well-diversified portfolio ranging from exploration, development, production to decommissioning. A portfolio that is expected to play an important role in securing gas deliveries to Orlen.

In 2022 the company has continued strengthening its position on the NCS. On August 31st, the Company completed its acquisition of a 40% share in PL942, covering the Ørn gas discovery. The Ørn discovery strengthens PGNiG Upstream's position in the Skarv Area. The development of Ørn is part of a larger project labelled 'Skarv Satellite Project' which was sanctioned at the end of 2022.

The company is currently participating in seven important developments on the NCS. Two of them were sanctioned in 2021: Ormen Lange Phase 3 and Tommeliten Alpha. Additionally, five projects were matured and sanctioned in 2022: Fenris (King Lear), Alve North, Verdande (Alve North-East), Andvare (Gjøk) and Ørn. The involvement in multiple development projects will enable PGNiG Upstream to increase its hydrocarbon production in future years. As of the balance sheet date, the projects are executed according to schedule with the first oil from Tommeliten Alpha expected in the first half of 2024.

The Ørn discovery adds an expected 20.3 mboe reserves, of which 91% is gas. It fits perfectly with the Company's plans for enhancing the production potential and further cost optimization of the Skarv area. According to current data from the field operator, AkerBP, the production volume attributable to PGNiG Upstream Norway is expected to average about 0.3 billion cubic meters of natural gas per year in the period 2027-2036.

In addition, the Company is working closely with operator Aker BP to evaluate development opportunities for the Lunde (Shrek) discovery. Lunde is a result of the Company's own exploration activities.

Refinancing

High involvement in development activities was possible thanks to stable financing provided to PGNiG Upstream in the previous years.

In 2022, the Company has gone through an extensive refinancing process and secured sources of funding for the future development plans.

Firstly, the excellent results in 2022 enabled repayment of all historical intercompany loans and issuance of a new loan under which PGNiG Upstream lent EUR 500 million to its parent company.

Secondly, PGNiG Upstream signed a new six years reserve based loan facility ("RBL") with a group of international banks. RBL is a specific type of project finance where the lenders' claims are secured primarily by upstream assets. The financing parties have no recourse to parent company and therefore Norwegian operations do not limit any other investment options of Orlen.

As of the end of 2022, the available amount under the RBL amounted to USD 700 million. The drawing limit will be amortized over time, starting from 2025.

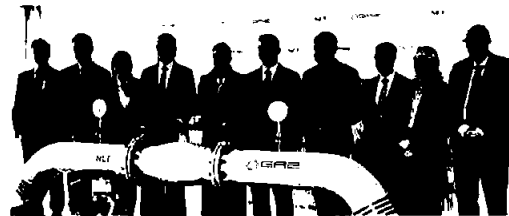
Start-up of gas deliveries through Baltic Pipe

The Company was 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. It allows transport of gas from Norway to the Danish and Polish markets, as well as to end-users in neighbouring countries. The Baltic Pipe has the capacity to transport 10 bcm of natural gas per year.

The Baltic Pipe was officially opened on 27th September 2022 and is now fully operational. PGNiG Upstream will utilize capacity in this pipeline to send its own gas production to Poland.

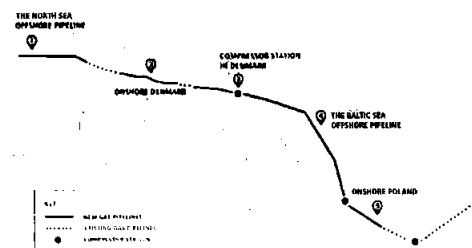
The project was implemented in close cooperation with the Polish gas transmission system operator GAZ-

SYSTEM and the Danish gas and electricity transmission system operator Energinet.



Government officials from Poland, Denmark and Norway attending the opening ceremony of Baltic Pipe

Orlen's strong commitment to the Baltic Pipe project is confirmed by the long-term capacity agreement for the gas transmission.



The implementation of the Baltic Pipe Project brings 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.

Increased exploration involvement

In 2022, the Company made one new discovery after participation in several exploration wells.

The Newt discovery (PL941) was drilled 14 kilometres northeast of the Skarv field. The well was drilled to a vertical depth of 2197 metres below sea level and was operated by Aker BP ASA. The discovery is preliminary indicated to a range between 1.7 to 5.7 million Sm³ of recoverable oil equivalents and will be considered by the licensees to be produced via the Skarv field.

Deepsea Yantai



In 2022, PGNiG Upstream also operated the drilling of the Copernicus exploration well (PL1017), utilising the Deepsea Yantai drilling facility. The well was drilled to a vertical depth of 2400 metres below sea level. Unfortunately, the well was dry. PGNiG Upstream expect to finalize the remaining work and relinquish the license during Q1 2023.

Although the Copernicus well came in dry, the year 2022 follows the good track record of the Company, with the previous discoveries such as Lunde (Shrek) in 2019 and Warka in 2020. The exploration activities are expected to play an important role in enabling PGNiG Upstream to maintain high and stable production in the long term. The Company is active in license rounds and was awarded three new licenses in APA 2022.

Research and development activities

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

Orlen R&D Centre



The total costs of RRD activities amounted to NOK 5.8 million in 2022. The main objective of this expense 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.

Company development, performance and going concern

In the accordance with Norwegian Accounting Act, the Company's Board of Directors has reviewed the going concern assumption considering all relevant information available up to the date. Company accounts are issued and all available information about the future are considered for at least 12 months from the reporting date. The review included the operational outlook and work programs, while maintaining appropriate headroom in respect of 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 these 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 2022 amounted to 79.8. All employees have been trained in Norwegian regulations.

Following the acquisition of INEOS ERP Norge AS in 2021, the Company has in 2022 initiated and completed



Annual Report 2022



a number of projects and initiatives with focus on integrating the two organisations into one team including moving into a new office, an organisational culture project and a talent development project.

Measures are taken to ensure a safe workplace and continuous improvement of the working environment amongst other efforts by also maintaining a regular dialogue with elected employee and trade union representatives.

Company Values



Driven by results

We have a clear business understanding and relate to this in our work



Collaborating

We work together as one company



Evolving

We are continuous learners, embracing change and with the ability to adapt



Absence from work due to illness has remained low at 2.65 per cent and no work-related injuries nor accidents in 2022. Measures continue to be implemented to maintain these low rates of absence and no work related injuries.

Equal opportunities

The Company is committed to maintain a working environment with equal opportunities for all based on requirements included in the Norwegian Equality and Anti-Discrimination Act, the Working Environment Act and other relevant legislation. PGNiG Upstream does not tolerate any form of discrimination in relation to employees, partners or suppliers.

In December 2022, women held 32% positions in the Company. At the same time, the Board consisted of five male and two 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.

Salary mapping for 2022 compares average women base salaries compared to men. Gender distribution in the same category is shown below in descending order of seniority as a percentage.

	Women share of men salary	Gender distribution (men/women)
Level 1	83%	62%/38%
Level 2	91%	81%/19%
Level 3	-	87,5%/12,5%
All employees	75%	68%/32%

In December 2022, a total of two employees (all women) worked voluntary part time. In addition, the Company cooperated with five consultants (all men). There was no women on parental leave during 2022. The average number of weeks of parental leave for men was 15.

External environment

Our aim is to prevent all incidents, accidents or accidental discharges that can 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 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 of the environment. Therefore, the Company places high focus on the environment 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.

The company will make available the report on transparency act on the company webpage (pgnig.no).



Annual Report 2022



Results, investments

The performance in 2022 was very strong, supported by high commodity prices and a stable and high production from the portfolio. With record high gas prices, the Company generated revenues of NOK 43 035 million. PGNiG Upstream has managed the assets safely, reliable and in a cost effective manner, materializing an EBITDA of NOK 39 372 million

Accumulated operating costs at the end of 2022 amounted to NOK 7 823 million, of which NOK 4 160 million was classified as depreciation and impairment. The comparative figures for the preceding year were NOK 3 141 million and NOK 1 360 million, respectively. Personnel costs were NOK 81 million in 2022, compared to NOK 104 million in 2021. The decrease was connected with the increased scale of operated activity and associated recharge to the operated license.

Net financial income for the period was NOK 281 million, compared to a loss of NOK 349 million in the previous year. This development is driven by a decrease in interest cost as debt has been repaid. Interest income from loans given, and a positive impact from foreign exchange rates.



Skarv FPSO

Fixed assets utilized in production and development are valued at NOK 23 095 million. This represents an increase of NOK 806 million in comparison with the previous year, and is due to new assets and ongoing investments. The company's cash and cash equivalents has increased considerable from NOK 3 355 million to

NOK 7 767 million at the end of 2022. The company's policy in 2022 was based on active cash management.

Ormen Lange unit



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 2022 is provided together with the Annual Report.

Liquidity and financing

The liquidity of PGNiG Upstream in 2022 has been secured through sales revenues. Based on the EBITDA of NOK 39 372 million, the Company generated cash flow from operating activities is at the level of NOK 20 723 million.

The details of the Company's sources of financing are presented in the notes to the Financial Statements.

In the course of 2022, the company successfully renegotiated its external debt facility. The tenor of the Loan facility was extended from 2026 to 2028, while the Facility Amount was increased from USD 500 million to USD 700 million, with the inclusion of an USD 300 million accordion mechanism on top. The conclusion of this revised financing arrangement ensures the Company can comfortably meet future commitments and also

Annual Report 2022



provide financial flexibility to pursue further development opportunities.

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 any further operations of PGNiG Upstream. The company holds considerable undrawn external credit facilities and cash and cash equivalents, and income from future operational activities look promising.

PGNiG Upstream's production in Norway for 2023 is estimated at 718 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 from the current license portfolio is expected to exceed NOK 20 billion in the next year.

Risk factors

PGNiG Upstream is operating in a macro environment with high volatility of sales prices, as experienced from price levels experienced in 2020 compared to 2021 and 2022. 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, Tommeliten Alpha and Fenris). 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.

PGNiG Upstream has signed insurance policies for the members of the Board of Directors potential liability towards the company and third parties. The limit of indemnity is NOK 50 million. The insurance policy is renewed on an annual basis.

Outlook

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

The scale of our Norwegian operations makes Norway the key destination for Orlen'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.

The expected activities in 2023 include consolidation of the Norwegian operations of PGNiG Upstream and LOTOS Exploration and Production Norge AS ("LEPN"). After ownership changes in 2022, Orlen became the ultimate owner of both PGNiG Upstream and LEPN and intends to consolidate their upstream activities within one entity. This will enable materialisation of several synergies and will also fulfil regulatory requirements in Norway. The consolidated operations of the entities is expected to rank among the eight biggest players on the NCS.





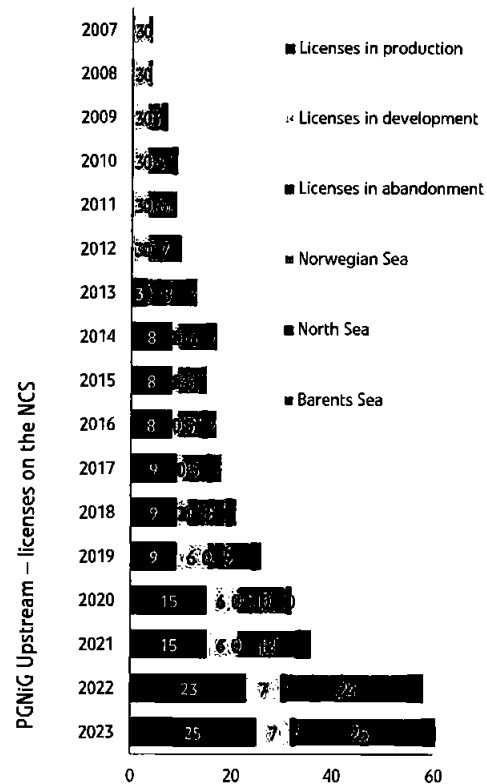
Annual Report 2022



PGNiG Upstream was founded in 2007 and has since the start been growing at a rapid pace, through organic growth and targeted acquisitions, made possible through the strong support by the parent company, dedicated management and highly competent employees. We have invested more than NOK 30 billion and participated in numerous exploration and production wells, which has led to several discoveries. Altogether, the Company owns shares in fourteen producing fields and seven developments with a total resource and reserves estimate of 290.6 million boe. In addition, the Company holds a considerable exploration portfolio, which is expected to secure the long term supply of gas to Orlen.

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

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





Annual Report 2022



To summarise, increasing production capacity on the NCS and securing new gas supplies for Poland, should allow the Natural Gas business of Orlen to maintain its leading position in Central Europe. The historical activity

by PGNiG Upstream should be seen as an initial step on the growth path of the Orlen natural gas activities. The next steps will be defined by new projects.

Stavanger,
10th February 2023

Robert Dominik Śleszyński
Chairman of the Board

Marcin Gargas
Director of the Board

Robert Harasimiuk
Director of the Board

Urszula Monika Kowalczyk
Director of the Board

Przemysław Wacławski
Director of the Board

Iwona Waksmundzka-Olejniczak
Director of the Board

Maciej Paweł Wyszczarski
Director of the Board

Marek Woszczyk
General Manager



FINANCIAL STATEMENTS



Annual Report 2022



INCOME STATEMENT (NOK million)

Note		2022	2021
3 10	Sales income	42 571	13 167
	Other income	465	147
	Revenue	43 035	13 315
4	Exploration expenses	(633)	(310)
5	Employee expenses	(81)	(104)
12	Depreciation	(4 528)	(1 648)
12	Depreciation of right-of-use assets	(91)	(18)
12	Impairment reversals	460	306
12	Loss on disposals	(182)	0
6 10	Production and sales costs	(2 469)	(1 238)
7 10	Other operating expenses	(299)	(128)
	Total operating expenses	(7 823)	(3 141)
	Operating income/(loss)	35 212	10 173
18	Interest income from Group enterprises	58	0
18	Interest expenses to Group enterprises	(19)	(150)
8	Other financial income	1 302	393
9	Other financial expenses	(1 060)	(592)
	Net financial items	281	(349)
	Income/(loss) before tax	35 493	9 824
11	Tax on the profit/(loss) for the year	(27 621)	(7 886)
	Net income/(loss)	7 873	1 938

STATEMENT OF COMPREHENSIVE INCOME

	2022	2021
Net income/(loss)	7 873	1 938
Total comprehensive income	7 873	1 938



Annual Report 2022



BALANCE SHEET (NOK million)

ASSETS

Note		31/12/2022	31/12/2021
12	Goodwill	2 803	2 896
12	Capitalized exploration expenses	688	909
	Intangible assets	3 491	3 805
12	Assets in production	15 452	18 380
12	Assets in development	7 643	3 909
12	Other fixtures and fittings, tools and equip.	7	3
12	Right-of-use asset	99	191
21	Long term receivable	207	56
18	Loan to Group enterprises	5 296	0
	Tangible fixed assets	28 704	22 538
	Non-current assets	32 195	26 343
16	Inventory	128	120
10	Trade receivables	341	380
	Trade receivables Group enterprises	3 673	2 791
14	Other current receivables	1 877	601
	Current receivables	5 891	3 772
15	Cash and cash equivalents	7 767	3 355
	Current assets	13 786	7 246
	Assets	45 981	33 590



Annual Report 2022



EQUITY AND LIABILITIES

Note		31/12/2022	31/12/2021
17	Share capital	1 115	1 115
	Share premium	1 777	1 777
	Paid-in capital	2 892	2 892
	Retained earnings	8 645	1 257
	Equity	11 537	4 150
11	Deferred tax	10 431	9 800
21	Abandonment provision	3 102	2 679
	Total Provisions	13 534	12 479
18	Debt to Group enterprises	0	1 420
19	Debt to financial institutions	0	4 325
13	Lease liabilities	101	122
	Long-term liabilities	101	5 867
10	Trade payables	303	123
	Employee tax liabilities, duties	28	38
18	Interest on Debt to Group enterprises	0	11
24	Other liabilities Group enterprises	0	1
19	Debt to financial institutions payable within 1 year	12	6
22 24	Other current liabilities	2 179	1 093
11	Taxes payable, not assessed	18 288	9 821
	Current liabilities	20 809	11 094
	Liabilities	34 444	29 441
	Equity and liabilities	45 981	33 590

Stavanger,
10th February 2023

Robert Dominik Śleszyński
Chairman of the Board

Marcin Gargas
Director of the Board

Robert Harasimiuk
Director of the Board

Urszula Monika Kowalczyk
Director of the Board

Przemysław Waclawski
Director of the Board

Iwona Waksmundzka-Olejniczak
Director of the Board

Maciej Paweł Wyszczarski
Director of the Board

Marek Woźniak
General Manager



CASH FLOW STATEMENT (NOK million)

Note	31/12/2022	31/12/2021
Cash flows from operating activities		
	Income (loss) before tax	9 824
12	Depreciation	1 666
12	Exploration drilling/capitalised seismic expenses	222
12	Impairment/reversal of impairments/Disposals	(306)
9	Interest expenses	139
11	Taxes paid/tax refund	466
8 9	Other financial items without cash effect	292
16	Changes in current assets – Inventory	1
	Changes in current receivables	660
	Changes in current receivables from Group enterprises	(2 662)
	Changes in current liabilities	614
	Changes in other periodical items	(293)
	Net cash from operating activities	10 623
Cash flows from investment activities		
12	Purchase of fixed assets	(4 949)
12	Purchase of intangible assets	(583)
18	Other investments	0
	Divestment	84
	Net cash from investment activities	(5 448)
Cash flows from financing activities		
17	Proceeds from issuance of shares and share premium	500
18	Proceeds/(repayment) from long-term debt raised from Group enterprises	(2 881)
19	Proceeds/(repayment) from long-term debt raised from financial institutions	654
18	Interests paid to Group enterprises	(173)
9	Interests paid to financial institutions	(53)
13	Lease payments	(31)
17	Dividends paid	0
	Net cash from financing activities	(1 984)
	Change in the balance of net cash	3 191
	Opening balance of cash and cash equivalents	164
15	Closing balance of cash and cash equivalents	3 355



STATEMENT ON CHANGES IN EQUITY (NOK million)

2022		2021	
Total	4 150	1 711	500
Retained earnings	1 257	(681)	1 938
Other comprehensive income	0	0	0
Share premium	1 777	1 282	495
Share capital	1 115	1 110	5
	Equity at 1 st January 2022		Equity at 1 st January 2021
	Dividend		Share capital increase
	Net income/(loss) for the year		Net income/(loss) for the year
	Equity at 31 st December 2022		Equity at 31 st December 2021



GENERAL INFORMATION

PGNiG Upstream has its office in Stavanger, Norway and is a subsidiary, fully owned by PKN Orlen S.A, whose head office is in Plock, Poland.

The financial statements of the Company are consolidated into PKN Orlen Group statements which can be found at the internet address: www.ornen.pl/en

All amounts are in million NOK unless otherwise stated.

NOTE 1 SUMMARY OF IFRS ACCOUNTING POLICIES APPLICABLE FOR 2022

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 10th February 2023.

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 2022.

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 12.
- 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 21.
- Capitalized exploration expenses which are dependent on existence of commercial oil and gas reserves. For further details refer to Note 12 and 27.

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. Amendments to IFRS 3 effective in January 2020 introduce an optional 'concentration test' which may result in a business combination being accounted for as an asset acquisition if substantially all of the fair value of the assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

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 million 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.

NET PROFIT INTEREST

The Gina Krog field is subject to a net profit interest ("NPI"), as this field was awarded in the second licensing round.

The net profit interest is calculated on the basis of quarterly cash flows. Losses in a quarter can be offset against profits in subsequent quarters. NPI related to abandonment costs incurred after the production has ceased will be refunded by Petoro.

NPI payments are classified as production and sales costs.

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. In 2022 the company changed the input used in the calculation to better reflect the expected pattern of consumption of the future benefit. In 2022 annual depreciation rate is based on proved reserves (developed). The rate of depreciation is equal to the ratio of hydrocarbon production for the period, over the proven 1P developed reserves. In 2021 annual depreciation rate was based on proved and probable reserves (developed and undeveloped). The basis for depreciation was adjusted with future investments to reflect a reserve basis of proved and probable reserves. The rate of depreciation was 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.

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.

Processing plants, pipelines and right-of-use asset 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 impairment 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 recognised at nominal value



after a deduction for the provision for credit losses. Historically there have been no significant credit losses.

LONG TERM LOANS

Long term loans are initially recognised at fair value plus any directly attributable transaction costs and subsequently measured at amortised cost adjusted for expected credit losses.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents comprise cash in hand, deposits held at call with banks, and cash equivalents. Cash equivalents are short-term (generally with original maturity of three months or less), highly liquid investments that are readily convertible to a known amount of cash and which are subject to an insignificant risk of changes in value. 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 EURIBOR 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 EURIBOR) 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, and it 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.

New regulation

Amendment of the Petroleum tax act was enacted in June 2022 with effect from 1 January 2022. The special petroleum tax is converted into a cash based tax system and companies can make immediate deductions for expenses. Corporate tax (22%) is deductible within the special tax (71.8%), in effect total tax rate is unchanged (78%). Uplift on offshore investments is removed in the new amendment, but the temporary 2020 rules are maintained for the development fields that are qualified with uplift of 17.69% in special tax.

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 most of the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash from the tax authorities. 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 2022.

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 and is reviewed at each balance sheet 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 it 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 2022

TRANSACTION WITH INEOS (2021)

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 transaction significantly increased hydrocarbon reserves allocated to PGNiG Upstream. The income statement in 2021 include revenues and costs from the assets acquired from INEOS from the transaction date which was September 30th 2021. As a result, there is a difference in asset base underlying financial data in 2021 and 2022.

ACQUISITION OF THE ØRN FIELD

On 31st August 2022, the Company completed acquisition of a 40% share in PL942 from Wellesley Petroleum AS, covering the Ørn gas field. The purchase price for transaction, together with the associated investment expenditures are reported as part of investment cash flow in 2022,

The Ørn field is located approx. 20 km from the Skarv field, in which PGNiG Upstream Norway also holds an interest. This will make it possible to use the existing production infrastructure, including the Skarv FPSO, to reduce time and costs of production start-up.

Ørn adds an expected 20.3 mboe reserves, of which 91% is gas. It fits perfectly with Company's plans for enhancing the production potential and further cost optimization of the Skarv area. According to current data from the field operator, AkerBP, the production volume attributable to PGNiG Upstream Norway is

expected to average about 0.3 billion cubic meters of natural gas per year in the period 2026-2035.

FIVE DEVELOPMENT PLANS



In 2022, the Company, together with its license partners sanctioned five development projects. The planned investments include the following fields on the NCS: Fenris (King Lear), Alve North, Verdande (Alve North-East), Andvare (Gjøk), and Ørn.

The first production from the abovementioned investments is expected in 2025. All projects are expected to benefit from the tax incentive scheme which was launched by the Norwegian government in 2020.

REFINANCING

In 2022, the Company has gone through extensive refinancing process.

In September 2022 PGNiG Upstream signed amendment to the reserve based loan facility ("RBL") which extended the loan maturity from 2026 to 2028. The new RBL includes three years grace period which allows funding of the Company's development projects. As a part of the process, PGNiG Upstream increased size of the RBL agreement from USD 500 million to USD 700 million (ref Note 19).

In addition, the Company repaid in 2022 all outstanding amounts under intercompany loans (ref Note 18) and also lent EUR 500 million to PGNiG SA.

Refinancing process in 2022 was aimed at repaying outstanding intercompany balances and securing necessary funds for ambitious development plans. As of the end of 2022, PGNiG Upstream had 700 million USD and 9100 million NOK available for drawing under the existing loan agreements. Financial stability of PGNiG Upstream can be additionally confirmed by a lack of scheduled loan repayments until 2025.

NOTE 3 REVENUE

	2022	2021
Oil sales	4 794	2 620
Gas sales	37 131	10 110
NGL sales	645	437
Sales revenue	42 571	13 167

All sales contracts are based on the market prices of the products, and will secure stable stream of revenues

from PGNiG Upstream for years to come. The below provides an overview over the sales contracts



Crude oil sales agreements	Description
Skarv & Ærfugl Nord	Is sold to Shell under an agreement concluded in October 2011
Vale	Is sold to Shell under an agreement concluded in December 2014
Morvin	Is sold to Total under an agreement concluded in January 2015
Gina Krog	Is sold to Shell under an agreement concluded in January 2018
Gudrun blend - Gina Krog	Is sold to Shell under an agreement concluded in August 2017
Skogul and Vilje	Is sold to Shell under an agreement concluded in March 2020
Ormen Lang	Is sold to Equinor under an agreement concluded in November 2016
Kvitebjørn & Valemon	Is sold to Shell under an agreement concluded in December 2020
Duva	Is sold to ENI under an agreement concluded in August 2021
Alve & Marulk	Is sold to Equinor under an agreement concluded in January 2009
Gas sales agreements:	
PGNiG Supply & Trading GmbH	The Company's gas production is contracted to PGNiG Supply & Trading GmbH, a PGNiG subsidiary based in Munich, Germany (ref. note 10)
Shell	In addition, the company has a stand-by contract with Shell for volumes which cannot be delivered to PGNiG Supply & Trading GmbH
NGL	
Naphtha	
Skarv, Morvin, Gina Krog & Ærfugl Nord	Is sold to Total under an agreement concluded in August 2015
Kvitebjørn & Valemon	Is sold to Equinor under agreements concluded in December 2016 and December 2014
Alve & Marulk	Is sold to Equinor under an agreement concluded in September 2010
Ethane	
Skarv, Morvin, Gina Krog and Ærfugl Nord	Is sold to Yara Norge under an agreement concluded in March 2016
Alve & Marulk	Is sold to INEOS under an agreement concluded in November 2018
Duva	Is sold to Shell and Esso under an agreement concluded in October 2020
LPG	
Skarv, Morvin, Gina Krog & Ærfugl Nord	Is sold to Shell under an agreement concluded in January 2016
Kvitebjørn & Valemon	Is sold to Shell under an agreement concluded in January 2021



NOTE 4 EXPLORATION EXPENSES

	2022	2021
Exploration expenses from production licenses	293	75
Drilling expenses from production licenses	333	222
Other exploration expenses	7	13
Direct exploration expenses	633	310
Allocated expenses included in:		
- Depreciation	0.6	0.2
- Employee expenses	48.1	43.2
- Other operating expenses	12.2	6.4
Allocated exploration expenses	60.8	49.9
Total exploration expenses	693.6	359.9

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. Majority of expenses in 2022 were connected with drilling of the licenses PL941, PL1017 and PL1064, write-off of Gina Krog capitalized exploration expenses, seismic acquisition and exploration activities on the other licenses.
- Drilling cost in 2022 is connected with drilling of the of Newt and Balindåsen prospect on PL941, PL209,

PL1017 and PL1064. Discovery was made for the Newt prospect, due to commercial potential of this discovery, the well costs were capitalized and are included in intangible assets category. Cost associated with the remaining wells were expensed.

Other exploration expenses in 2022 are connected with the APA2022 applications, business development activities and purchase of various studies.

Allocated exploration expenses are linked to own exploration activities of PGNiG Upstream. In 2022 they were mostly connected with the follow-up activities on exploration licenses and the participation in the APA2022 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 79.8. On 31st December 2022, PGNiG Upstream had 76 employees.

The remuneration for the General Manager for the year amounted to NOK 5 821 133 for wages and NOK 134 356 for other compensations. In addition, contributions to the pension scheme of NOK 623 192 have been paid for the period. These amounts are included in employee expenses above. 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 20 for further information.

	2022	2021
Employees*		
Wages, salaries and remuneration	28	71
Social security	21	18
Pensions (Note 20)	27	13
Other staff expenses	3	2
Total	80	104

* 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.

	2022	2021
Board of Directors		
Wages, salaries and remuneration	1	0
Total employee expenses**	81	104

** 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, ORMEN LANGE PHASE 3, ALVA NORD AND FENRIS. THE TOTAL VALUE OF COST RECHARGED TO OPERATED LICENCES IN 2022 AMOUNTS TO NOK 81.6 MILLION (NOK 43.4 MILLION IN 2021), AND THE TOTAL VALUE OF COST CHARGED TO DEVELOPMENT PROJECTS AMOUNTS TO NOK 33.4 MILLION (NOK 9.3 MILLION IN 2021).



NOTE 6 PRODUCTION AND SALES COSTS

	2022	2021
Operating costs	1 269	683
Gas tariffs and other transportation costs	1 630	716
Net Profit (NPI)	290	0
Over-/underlift	(721)	(161)
Total production and sales costs	2 469	1 238

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 1 183 million from the production licenses,
- NOK 58 million related to changes in the estimated abandonment provision, and
- NOK 28 million incurred in relation to sales.

The Company covered gas tariffs in the Gassled network and other transportation costs of NOK 1 142

million. Other transportation costs included balancing, dispatching, contract handling etc. Reference is made to note 10 for sales costs towards affiliated company PGNiG Supply & Trading GmbH.

In the end of 2022, the Company increased its 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 2022. According to accounting policy change in over-/underlift positions is to be adjusted towards production and sales cost. Please refer to note 14 for further information about underlift position.

NOTE 7 OTHER OPERATING EXPENSES

	2022	2021
External fees	206	55
Rent premises	5	2
Insurance premium	48	45
Expensed purchases	17	12
Travel costs	1	1
Other	23	13
Other operating expenses	299	128



	2022	2021
Remuneration to auditor (thousand NOK):		
Audit fee (excl. VAT)	800	512
Other services (excl. VAT)	0	15
	800	527

INDIRECT EXPLORATION COSTS PRESENTED IN NOTE 4 (WITH THE AMOUNT OF NOK 12.2 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.

Majority of external fees are connected with the support provided to the company by the central upstream unit under the SLA agreement. Thanks to this agreement PGNiG Upstream has direct access to geologists, geophysicists and engineers who are involved in exploration and production activities in Norway.

Remaining part of external fees were connected with running the Company accounts, legal support and various advisory services. 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, external experts and joint projects with Orlen.

The total costs of R&D activities amounted to NOK 5.8 million in 2022. The main objective of this 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

	2022	2021
Interest received bank	38	1
Other income from bank deposits	9	0
Other interest earnings	21	0
Exchange rate differences	1 235	392
Other financial income	1 302	393

Realized gain from exchange rate differences on sales due to timing difference between the date when income is earned and when payment is received

constitutes approximately 50 % of other financial income.



NOTE 9 OTHER FINANCIAL EXPENSES

	2022	2021
Interest costs to financial institutions*	113	67
Exchange rate differences	810	422
Accretion	97	131
Other interest cost	91	51
Capitalized borrowing cost	(51)	(78)
Other financial expenses	1 060	592

* 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 Tommeliten Alpha, Ormen Lange Phase 3, Alve Nord and Fenris development projects. When production start borrowing costs are no longer allocated to these projects. The part of borrowing cost capitalized is

included under Additions to Assets in development in Note 12.

Realized loss from exchange rate differences on sales due to timing difference between the date when income is earned and when payment is received constitutes approximately 42 % of other financial expenses.

NOTE 10 RELATED PARTY ITEMS

Transaction type	P&L line	Counterpart	Relationship	2022	2021
Gas sales	Sales revenue	PGNiG Supply & Trading GmbH	Affiliated company	37 131	10 159
Costs related to gas sales	Production and sales costs	PGNiG Supply & Trading GmbH	Affiliated company	(370)	(159)
Insurance	Other operating expenses	POLSKI GAZ	Affiliated company	(8)	(43)
Technical services	Other operating expenses	PKN Orlen	Parent	(185)	0
Other services	Other			(11)	(4)
Total				36 554	9 953



Annual Report 2022



Balance sheet items		Accounts receivables		Accounts payable	
Counterpart	Relationship	2022	2021	2022	2021
PGNiG Supply & Trading GmbH	Affiliated company	3 661	2 828	0	0
PKN Orlen	Parent	0	0	(8)	0
Total		3 661	0	(8)	0

Related party transactions and associated balance sheet items are displayed in above table. Substantially all transactions with related parties in above table are priced on an arm's length basis and are to be settled within two months of the reporting date. No expense has been recognised in the current year or previous

years for bad or doubtful debt in respect of amounts owed by related parties.

For information on intercompany loans and guarantees not disclosed in this note reference is made to note 18 and 24.

NOTE 11 TAX ON THE INCOME/(LOSS) FOR THE YEAR

Calculation of taxable income for the year	2022	2021
Net income before taxes	35 493	9 824
Permanent differences	683	3 884
Changes in temporary differences	1 226	(332)
Basis for corporate taxes payable, not assessed	37 402	13 376
Tax base corporate tax deductible in special tax	(8 285)	0
Net financial costs only allowed against CT	(388)	162
Net other 22%, only allowed against CT	645	251
Uplift allowable only against SPT	(538)	(704)
Expense of capex addition in SPT	(2 765)	(1 936)
Taxable income, special petroleum tax ("SPT")	26 071	11 149
Covered from loss carry forward SPT	0	0
Basis for taxes payable, not assessed	26 071	11 149
Tax payable	2022	2021
Tax payable	17 985	9 461
Other	304	360
Tax payable in balance sheet*	18 288	9 821



Calculation of deferred taxes	2022	2021
<i>Temporary differences:</i>		
Over-/underlift	(646)	(114)
Long-term liabilities	(105)	(46)
ARO provision	2 771	2 428
Fixed Assets	(11 127)	(12 485)
Intangible Assets	(688)	(659)
Lease	2	(68)
Other	245	187
Net temporary differences	(9 548)	(10 756)
	2022	2021
Deferred tax liability on temporary differences	(10 431)	(9 800)
Deferred tax asset on loss carry forward CT	0	0
Deferred tax asset/(liability) in the balance sheet*	(10 431)	(9 800)
Income taxes charged to income statement consist of:		
	2022	2021
Changes in deferred taxes	631	1 157
Taxes booked to balance sheet (related to acquisitions)	140	(2 759)
Taxes payable/(receivable), not assessed	26 947	9 232
Correction previous year	(98)	256
Total Tax charge/(credit) to income statement	27 621	7 886
Effective tax rate reconciliation		
	2022	2021
Income before taxes	35 493	9 824
Expected tax charge - 78%	27 686	7 663
Permanent differences	563	179
Prior year items	(12)	301
Financial items	(231)	102
Uplift	(386)	(394)
Other	1	35
Total Tax charge/(credit)	27 621	7 886
Effective tax rate	78 %	80 %



NOTE 12 INTANGIBLE ASSETS AND TANGIBLE FIXED ASSETS

RIGHT OF USE ASSET

2022	FPSO/FSO	Land & buildings	Total
Right-of-use asset at initial recognition 01/01/2022*	231	13	244
Additions	0	0	0
Investments at 31/12/22	231	13	244
Accum. depreciation at 1/1/22	(50)	(3)	(53)
Depreciation in 2022	(91)	(1)	(91)
Accum. depreciation at 31/12/22	(141)	(4)	(145)
Net book value at 31/12/22	90	9	99
Depreciation method	Straight line	Straight line	
Useful life	Until 2024	Until 2032	

* REFERENCE IS MADE TO NOTE 1 FOR ACCOUNTING PRINCIPLES FOR DEPRECIATION AND FOR PRINCIPLE USED TO MEASURE THE VALUE OF THE RIGHT-OF-USE ASSET AND NOTE 13.

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 13 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



Annual Report 2022



2022	Capitalized exploration expenses	Goodwill	Assets in Development	Assets in Production	Other tools and equipment	Total
Investments at 1/1/22	909	2 896	4 007	28 046	44	35 903
Additions *	448	0	3 729	1 047	7	5 231
Transfer to Assets in development/production**	(276)	0	213	63	0	0
Disposals/expensed previously capitalised cost *****	(393)	(93)	(182)	0	0	(668)
Investments at 31/12/22	688	2 804	7 669	29 156	52	40 466
Acc. depreciation 1/1/22	0	0	0	(9 120)	(39)	(9 159)
Acc. impairment 1/1/22	0	0	0	(644)	(3)	(647)
Accum. depreciation and impairment at 1/1/22	0	0	0	(9 764)	(42)	(9 806)
Depreciation in 2022***	0	0	0	(4 525)	(3)	(4 528)
Reversal of impairment****	0	0	0	489	0	489
Impairment in 2022	0	(1)	(26)	(2)	0	(29)
Accum. depreciation and impairment at 31/12/22	0	(1)	(26)	(13 803)	(45)	(13 874)
Net book value at 31/12/22	688	2 803	7 643	15 452	7	26 592
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 PL1064 (PEDER), PL1017 (COPERNICUS) AND PL941 (NEWT&BALINDÅSEN). NEWT WAS CONCLUDED TO BE GEOLOGICAL DISCOVERY, POSSIBILITY OF ITS COMMERCIAL DEVELOPMENT. THE OTHER DID LEAD TO COMMERCIAL DISCOVERIES AND WERE THEREFORE EXPENSED AT YEAR END. OTHER CAPITALIZED EXPENSES ARE RELATED TO SEISMIC AND FIELD EVALUATION.

* ADDITIONS UNDER "ASSETS IN DEVELOPMENT" RELATES TO DEVELOPMENT CAPEX, CAPITALIZED HOURS AND CAPITALIZED BORROWING COST ON TOMMELITEN ALPHA, FENRIS, ORMEN LANGE PHASE III, ALVE NORD, VERDANDE AND ANDVARE PROJECTS.

* ADDITIONS UNDER "ASSETS IN PRODUCTION" INCLUDES CAPEX TO THE PRODUCING ASSETS ORMEN LANGE, SKARV, GINA KROG, ALVE, MARULK, MORVIN, VILJE, SKOGUL, KVITEBJØRN, VALEMON, DUVA AND VALE. THE AMOUNT ALSO INCLUDES THE CHANGE IN THE ESTIMATE OF THE ASSET RETIREMENT OBLIGATIONS ALL PRODUCING ASSETS AS AT THE END OF THE YEAR OF NOK 311 MILLION, WHICH HAS NO CASH EFFECT IN 2022. FOR FURTHER DETAILS REFER TO NOTE 21.

** TRANSFER TO ASSETS IN DEVELOPMENT FROM CAPITALIZED EXPLORATION EXPENSES RELATES TO RECLASSIFICATION OF CAPITALIZED EXPLORATION EXPENSES FOR ALVE NORD AND VERDANDE. TRANSFER TO ASSET IN PRODUCTION FROM ASSET IN DEVELOPMENT RELATES TO RECLASSIFICATION OF CAPITALIZED DEVELOPMENT CAPEX FOR IDUN TUNGE WHEN THIS 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 2021. ANY CHANGES IN ESTIMATES WILL BE RECOGNIZED PROSPECTIVELY FROM THE FOLLOWING YEAR. REFERENCE IS MADE TO NOTE 1 FOR DETAILS ON ACCOUNTING PRINCIPLES.

**** THE COMPANY HAS REVERSED IMPAIRMENT FROM PRIOR YEARS OF NOK 489 MILLION FOR THE GINA KROG FIELD. 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.

***** CHANGES UNDER "GOODWILL" CATEGORY IS CONNECTED WITH 2021 ACQUISITION OF INEOS ERP NORGE AS AND ADJUSTMENT IN THE MEASUREMENT WITHIN 12 MONTHS AFTER THE ACQUISITION. IN ADDITION TYRVING (PREVIOUSLY FOGELBERG) WAS DISPOSED WITH VALUE OF NOK 182 MILLION UNDER CATEGORY "ASSETS IN DEVELOPMENT".

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	(2 939)	3 829	0	0
Disposals/Expensed previously capitalised exploration	(287)	0	0	0	0	(287)
Investments at 31/12/21	909	2 896	3 909	28 144	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	155	151	0	306
Impairment in 2021 *****	0	0	0	0	0	0
Accum. depreciation and impairment at 31/12/21	0	0	0	(9 764)	(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, FENRIS, 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, VIJJE, SKOGUL, KVITEBJØRN, VALEMON, DUVA AND VALE. THE AMOUNT ALSO INCLUDES THE RECOGNIZED ABANDONMENT REMOVAL OBLIGATION ACQUIRED WITH ORMEN LANGE, ALVE, MARULK, TAMBAR OST (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 21.

** 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.

IMPAIRMENT TEST

In the end of 2022, 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 Upstream portfolio (Tommeliten Alpha, Duva, Fenris, 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 no impairment has been performed.

In calculating the net present value, the company applied the oil price scenario based on the latest reports received from parent company (Orlen SA). According to assumptions, the average oil price in the next five years accounts for 721 NOK/bbl (in real terms), and the average gas price in this period accounts for 6.06 NOK/Sm³ (in real terms).



In addition, a discount rate of 8.33% (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 10.67%.

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 Morvin, Gina Krog and Duva projects. For Morvin the carrying amount it is slightly lower than recoverable amount (below materiality threshold) while for Gina Krog and Duva the headroom between carrying amount and recoverable amount is equal to respectively 302 million and 381 million.

It was concluded that Gina Krog and Duva field are the most sensitive to gas prices. A 10% gas price decrease

would not result in revaluation decrease for any of these assets.

The technical goodwill is included in the carrying value of the CGU/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 13 LEASES

	2022	2021
Lease debt 01.01	122	147
New leases	0	0
Payments of lease debt	(34)	(31)
Interest expense on lease debt	0	2
Currency exchange differences	13	4
Lease debt 31.12	101	122

Nominal lease debt maturity breakdown:

Within one year	53	42
Two to five years	47	79
After five years	6	7
Total	106	128



Annual Report 2022



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 14 OTHER CURRENT RECEIVABLES

	2022	2021
Accounts receivable, JV	24	127
Prepayments, JV	23	84
Underlift (oil, NGL)	839	118
VAT	70	4
Other current receivables	138	181
Overcall, JV	782	86
Other current receivables	1 877	601

PGNiG Upstream have invoice mechanisms under some sales contracts where the invoice values are not directly linked to physical liftings.

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 31.12.2022.

The periodical change to underlift position at the end of 2022 of NOK 721 million is recognized under the Production and sales cost in the Income Statement, see also Note 6.

NOTE 15 CASH AND CASH EQUIVALENTS

	2022	2021
Cash, non-restricted	5 300	3 342
Cash, restricted	8	13
Cash	5 308	3 355
Cash equivalents	2 458	0
Total cash and cash equivalents	7 767	3 355

RESTRICTED CASH IS RELATED TO:

* TAXES WITHHELD FROM EMPLOYEES OF NOK 8 MILLION (NOK 13 MILLION IN 2021)



During 2022 PGNiG Upstream entered into short-term bank deposits with an original maturity of three months or less, net of outstanding bank overdrafts. Cash and

cash equivalents at the end of the reporting period as shown in the statement of cash flows can be reconciled to the position as shown above.

NOTE 16 INVENTORY

The inventory in 2022 (NOK 128 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,

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

NOTE 17 EQUITY

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

In 2022, the Company paid dividend to its shareholders with the value of 485 million NOK.

As of the balance sheet date, all the shares are held by the parent company, Orlen. 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.

Please note the change in ownership that occurred on 2 November 2022 when Orlen completed the acquisition of the PGNiG Group and became sole owner of PGNiG Upstream. This transaction created multi-

utility group with diversified and complementary revenue structure.

The combination of Orlen and PGNiG is a natural next step in creating an integrated and diversified Polish multi energy corporation of significant transformation potential and enhanced energy security to face the current macroeconomic conditions.

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 19). 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 18 INTERCOMPANY LOANS

	2022	2021
Principal Loan to Group enterprises	5 257	0
Interest receivable from Group enterprises	39	0
Total Loan to Group enterprises	5 296	0
Principal debt to Group enterprises	0	1 420
Interests to Group enterprises	0	11
Total debt to Group enterprises	0	1 431
Hereof short-term – interest payable within 1 year	0	11
Long term liabilities to Group enterprises	0	1 420

LOAN TO GROUP ENTERPRISES

The intercompany loan to sole shareholder was signed in June 2022. The available limit under this loan accounts for EUR 500 million.

The purpose of the loan is to fund corporate needs.

The loan to shareholder can be disbursed in several tranches. Each tranche shall be disbursed on the basis of a duly prepared Drawdown Request. The tranche is to be paid within 5 working days from receipt of the Drawdown Request. Each tranche can be drawn in NOK, EUR or USD. The availability period for the loan extends to December 2025.

As of 31 December 2022, Orlen has drawn the entire available limit of EUR 500 million. Any outstanding balance under the Loan Agreement bears interest based on the relevant reference rate applicable to the currency drawn, plus margin.

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

The Loan Agreement includes covenants for borrower to disclose information to lender on events that may impact its capacity to repay the loan.

DEBT TO GROUP ENTERPRISES

As of 31 December 2022 PGNiG Upstream had funding available through two intercompany loans:

- Loan no 3: From 27 August 2010 with the maximum available amount of NOK 4 100 million - not utilised as of 31.12.2022
- Loan no 8: From 14 April 2021 with the maximum available amount of NOK 5 000 million - not utilised as of 31.12.2022

The Intercompany Loans 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 2022, PGNiG Upstream paid interest related to intercompany loans for previous periods in the total amount of USD 1.8 million for loan no 8.

In the event of any outstanding balance of Intercompany loans, this 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 2 993 million. 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 19). Additionally, loan receivables under this loan are secured for the benefit of Societe Generale, as a part of the security package under the Facility

NOTE 19 DEBT TO FINANCIAL INSTITUTIONS

	2022	2021
Principal debt	0	4 374
Commitment fee	12	0
Arrangement fees paid	0	(47)
Effective interest rate amortization	0	4
Debt to financial institutions	12	4 331
Hereof short-term - payable within 1 year	12	6
Long term Debt to financial institutions	0	4 325

The credit facility ("Facility") was first signed in August 2015 with a group of eight banks. During 2022, PGNiG Upstream signed a six year extension of this loan. As per 31.12.2022, the bank consortium consists of the following banks:

- Société Générale
- ING Belgium NV/SA
- BNP Paribas
- DNB Bank ASA
- SMBC Bank EU AG
- Bank Handlowy w Warszawie S.A.
- Bank Gospodarstwa Krajowego
- Powszechna Kasa Oszczędności Bank Polski S.A.

- Crédit Agricole Corporate and Investment Bank

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 2022 the available amount under the Facility was limited by overall limit of USD 700 million. The Company had not utilised the Facility at 31st December 2022.



The drawing limit will be amortizing over time in accordance with the reduction schedule, starting from 1st July 2025 until 1st September 2028. The Facility is to be repaid in full by 1st September 2028.

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 in respect of 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 PKN Orlen S.A and PGNiG Upstream;
- (iii) the registered pledge over shares in Production Licenses 029C, 029B, 036, 036D, 044, 122, 134B, 134C, 159B, 193, 193B, 193D, 208, 212, 212B, 249, 250, 262, 460, 636 and the pledge over the Company's accounts, refund claims, trade receivables and insurance proceeds.

All pledge agreements have been concluded with Societe Generale, 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 18 996 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.

NOTE 20 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 2022, the plan had

76 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 21 PROVISIONS

ABANDONMENT PROVISION

Provisions recognized in 2022 consist of (numbers presented below are PGNiG share in NOK million):

Field	Abandonment provision	Expected abandonment
Skarv	423	2037-2040
Morvin	51	2034
Vilje	125	2042-2044
Vale	145	2023-2028
Gina Krog	365	2032-2034
Ærfugl	106	2037-2038
Skogul	81	2043-2044
Duva	209	2031-2032
Ærfugl Nord	30	2036-2037
Valemon	102	2032
VRGP	4	2023-2025
Kvitebjørn (incl. KOR)	158	2036
Ormen Lange	548	2037-2044
Alve	107	2036
Marulk	179	2025-2027
Tambar East	10	2029
Gyda	31	2023-2026
Gassled	332	2060
Nyhamna	98	2060
Total	3 102	

The Company has recognized provisions for future abandonment for all its oil & gas fields as per year-end 2022. 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 2022. The value of the abandonment costs was based on the study performed by the field operators. 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 Skarv satellite projects 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 12).

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 3.22 per cent with a mid-year discounting.

An increase of abandonment removal obligation was observed on Skarv including Ærfugl (+73 million), Morvin (+13 million), Vilje (+25 million), Duva (+11 million), Vale (+48 million), Gina Krog (+49 million), Skogul (+17 million), Ærfugl Nord (+6 million), Valemon (+5 million), Kvitebjørn (+21 million), Ormen Lange (+151 million), Alve (+35 million), Marulk (+2 million), Tambar East (+1 million) and Nyhamna (+42 million). A decrease was observed on Gyda (-156 million) due to ongoing decommission project.

Unwinding of the discount in 2022 accounted for NOK +97 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 long term rate of 2.6396 per cent. PGNiG Upstream has assumed removal in 2060, resulting in a value of the liability of NOK 332 million at the end of 2022. As such, the Company has accrued for the liability at the end of 2022.

Decommissioning cost related to the Nyhamna processing plant and VRGP pipeline are passed on to the Shippers and a decommissioning receivable of NOK 102 million has been recognized. Decommissioning cost related to the KOR pipeline is paid and passed on to the Shippers, but because it is only the JV license partners themselves that have volumes in this pipeline no decommissioning receivable has been recognized and the company has recognized abandonment removal obligation according to participant interest.

NOTE 22 OTHER CURRENT LIABILITIES

	2022	2021
Working capital, JV	721	739
Other current liabilities	936	330
Undercall, JV	0	24
Accruals billings	521	0
Other current liabilities	2 179	1 093

Other current liabilities include the value of prepayments from customers of NOK 579 million, in

addition it includes other accrued costs of NOK 336 million and other items of NOK 21 million.

NOTE 23 COMMITMENTS AND CONTINGENCIES

PGNiG Upstream has two loan agreements from Orlen with the value of NOK 9.1 billion. As of 31.12.2022 these were not utilised. In the event of utilisation, the loans are secured by respective promissory notes.

PGNiG Upstream's activities on the NCS are secured by the parent company guarantee issued on 22nd October 2007 (see Note 24). 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, As of 31.12.2022 this loan was not

utilised. The agreement is secured by a comprehensive security package, described in Note 19.

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 2022, 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



and tax dispute with the tax authorities concerning the 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 2023 (NOK million) *
Skarv	11.92 %	339.11
Ærfugl Nord	15.00 %	22.90
Morvin	6.00 %	24.86
Vale	24.24 %	91.12
Vilje	24.24 %	58.03
Skogul	35.00 %	37.32
Kvitebjørn	6.45 %	144.68
Valemon	3.23 %	39.18
Kvitebjørn Oil Pipeline	6.45 %	0.54
Valemon Rich Gas Pipeline	3.23 %	0.05
Duva	30.00 %	176.43
Fogelberg	23.52 %	7.79
Tommeliten Alpha	42.20 %	2 204.45
Tommeliten Gamma	42.38 %	2.36
Fenris	22.20 %	1 011.18
Alve North	11.92 %	231.02
Alve North East	0.83 %	5.14
Lunde	35.00 %	458.63
Ormen Lange	14.02 %	257.64
Ormen Lange LLR	14.02 %	538.51
Nyhamna	8.19 %	169.09
Alve	15.00 %	75.79
Gyda	34.00 %	3.44
Marulk	30.00 %	76.22
Andvare	15.00 %	3.48
Tambar Øst	5.44 %	2.20
Gina Krog	11.30 %	1 053.61
Ørn	40.00 %	750.86

* Planned license expenses (opex and capex) are based on the approved Business Plan 2023 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:

- Gina Krog Dougal well (operated by Equinor)
- PL636 (operated by Neptune)
- PL1009 (operated by Conoco Phillips)

The Company has financial commitments related to bookings in the gas transportation system operated by Gassco. Such commitment in the next two years is secured through the intercompany guarantee with the nominal value of NOK 1500 million. See also Note 21 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. The rental agreement is valid until 31st December 2025 and has a yearly value of approximately NOK 3 million.

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 24 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, Orlen has a valid guarantee to PGNiG Upstream to the amount of EUR 628 million. The guarantee is effective until 1st January 2050.

The Guarantee Agreement concerns the provision of security by Orlen 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 2022, the Company has booked NOK 3 million 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 31.12.2022. In 2022, the Company has booked NOK 0.2 million as a liability connected with this agreement.

In 2021, PGNiG Upstream received a parent company guarantee requested by INEOS in association with purchase of INEOS ERP Norge AS assets and operations on the NCS. As of 31.12.2022, the Guarantee covers liabilities up to NOK 1000 million.

In 2022 the Company has booked NOK 5 million as liabilities associated with this agreement.

OTHER GUARANTEES

The Company secured a Letter of Credit from DNB Bank ASA 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 DNB Bank ASA 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 130.2 million. The Company has accrued for the expected future decommissioning liabilities for the assets as presented in Note 21.



NOTE 25 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 ERP 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 utilising loans over several currencies - 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 2025 and 2028 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 Orlen 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 Orlen;

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 19). In addition, the potential risk of liquidity loss is covered by available amount under intercompany loan (see Note 18)



NOTE 26 EVENTS AFTER THE BALANCE SHEET DATE

AWARDS IN APA2022

In January 2023, PGNiG Upstream was awarded three new exploration licenses as a result of the APA2022 licensing round. As a result, the number of licenses will increase to 65 in the beginning of 2022.

Two of the newly awarded licenses are located in the Norwegian Sea and one in the North Sea.

In case of PL1172, PGNiG Upstream Norway will acquire 30%, the operator's role with 40% of shares will be taken by AkerBP and the remaining partner is DNO with 30%. The license is located near the Fenris development where PGNiG is a partner with 22.2%.

In case of PL1190, PGNiG Upstream Norway will acquire 20%, the operator's role with 50% of shares will be

taken by Habour and the remaining partner is Lime with 30%. The license is located south of the Heidrun field.

In case of PL1193, PGNiG Upstream Norway will acquire 20%, the operator's role with 80% of shares will be taken by AkerBP. The license is located near the Skarv field where PGNiG is a partner with 11.9175% and the 2022 Newt discovery where PGNiG is a partner with 20% .

For PL1111, PL1103 and PL1064 the operators have completed their voting in preparation to relinquish the license and to notify the authorities, for PL1124 the operator has sent their relinquishment notification to the authorities. The company did not have any capitalized exploration expenses made on these licenses at 31.12.2022.



NOTE 27 LICENSES

PGNiG Upstream's licenses at 31/12/2022

PL019G	(Gyda/Tambar East)	34%/5.44%	PL262	(Skarv Unit)	11.9175%
PL029B	(Gina Krog Unit)	11.3%	PL333	(Fennis)	22.2%
PL029C	(Gina Krog Unit)	11.3%	PL433	(Tyrving)	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	(Lunde)	35%
PL122D	(Marulk)	30%	PL838B		40%
PL249	(Vale)	24.243%	PL939		30%
PL044	(Tommeliten Unit)	42.1978%	PL941		20%
PL127C	(Alve N)	11.9175%	PL941B		20%
PL127DS	(Verdande Unit)	0.827%	PL942	(Ørn)	40%
PL134B	(Morvin)	6%	PL997		30%
PL134C	(Morvin)	6%	PL1009	(Warka)	35%
PL146	(Fennis)	22.2%	PL1009B	(Warka)	35%
PL146B	(Fennis)	22.2%	PL1013		40%
PL159B	(Alve/Andvare)	15%	PL1013B		40%
PL159F	(Osprey)	7.5%	PL1017		50%
PL159G	(Alve)	15%	PL1055		60%
PL193	(Kvitebjørn)	6.45%	PL1055B		60%
PL193C	(Kvitebjørn)	6.45%	PL1055C		60%
PL193B	(Valemon)	3.25%	PL1064		30%
PL193D	(Valemon)	3.25%	PL1088		22.2%
PL208	(Ormen Lange Unit)	14.0208%	PL1101		30%
PL209BS	(Ormen Lange Unit)	14.0208%	PL1103		30%
PL212	(Skarv Unit)	11.9175%	PL1111		60%
PL212B	(Skarv Unit)	11.9175%	PL1123		30%
PL212E	(Ærfugl Nord)	15%	PL1124		11.9175%
PL250	(Ormen Lange Unit)	14.0208%	PL1135		70%
261 C	(Skarv Unit)	11.9175%	PL1136		50%

THE SKARV FIELD

The licenses PL212, PL212B and PL262 contain the Skarv oil and gas field. The Skarv Field was discovered in 1998, and started production 2013. 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 Unit.

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.

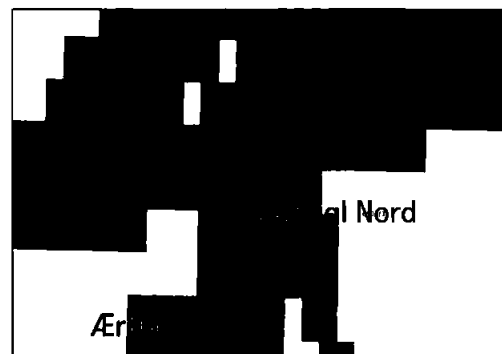


Ærfugl field

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 ØRN FIELD

The Ørn field is located ca 20 km northwest of Skarv FPSO. Its development plan (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on 16 December 2022.

First production is scheduled in 2027, and the field will be developed as a subsea tie-back to Skarv FPSO.



The licence is operated by Aker BP (30%), with Equinor (30%), and PGNiG Upstream (40%) as partners.



The Alve Nord field is located ca 30 km north of Skarv FPSO. Its development plan (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on 16 December 2022.

First production is scheduled Q2 2027, and the field will be developed as a subsea tie-back to Skarv FPSO.

The licence is operated by Aker BP (68.1%), with Winthershall DEA (20%), and PGNiG Upstream (11.9%) as partners.

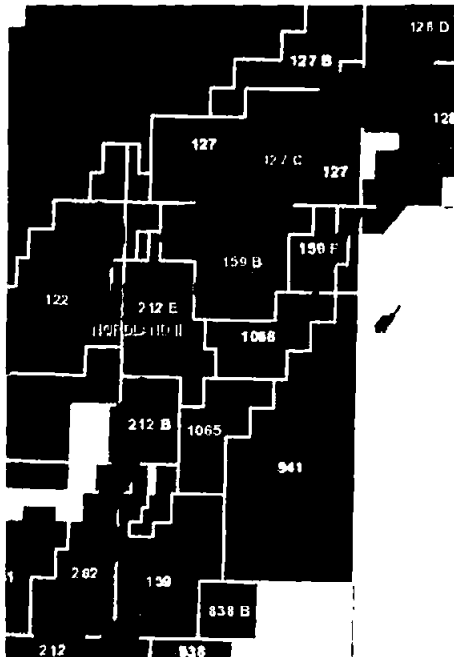
THE VERDANDE FIELD

The Verdande field is located ca 5 km northeast of Alve Nord. Its development plan (PDO) was submitted to the Ministry of Petroleum and Energy (MPE) on 5 December 2022 after 5 licenses were unitized.

First production is scheduled Q4 2025, and the field will be developed as a subsea tie-back to Norne FPSO.

The licence is operated by Equinor (59.3%) with Petoro (22.4%), Vår (10.5%), Aker BP (7.0%) and PGNiG Upstream (0.8%) as partners.

THE ALVE NORD FIELD



THE GINA KROG FIELD

Gina Krog 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 %

The field has been developed with a fixed platform for wells and processing. Oil is exported via a floating storage unit (FSO) that is connected to the platform. Produced gas is transported to Sleipner for further treatment.



Production started in 2017 and Gina Krog currently has 9 oil producers, 4 gas injectors and two gas producers. Gas injection has been the main recovery strategy and gas has been imported for that purpose.

A second drilling campaign with one in-fill well and one exploration well (Dougal) is being planned for. The drilling has been delayed due to the rig being busy elsewhere and drilling is now estimated to start in the second quarter of 2023.

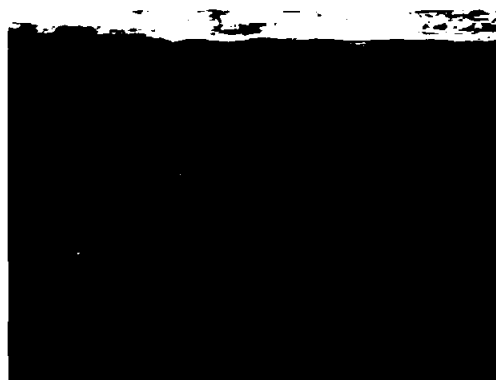
As a part of the CO2 reduction efforts it was planned to have the platform hooked up to power from shore via the Johan Sverdrup field during 2022. The project is almost complete but start-up is delayed and estimated to end 2023.

At the end of 2021 import of gas for gas injection was halted due to a combination of high demand for gas in Europe and very high gas prices. Injection has not been restarted. The effect on production is closely monitored and the reservoir development will determine if injection will be restarted in the future.

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. The subsequent phase in the development was the installation of onshore compression with production start in 2017. The current well stock is now 21 production wells after two new wells were drilled in 2022. The Ormen Lange Phase 3 (OLP3) offshore compression is in execution mode with a P50 RFSU in Q4 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 %

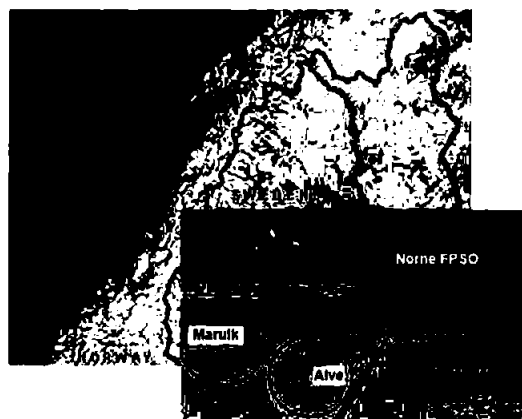
MARULK

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 %

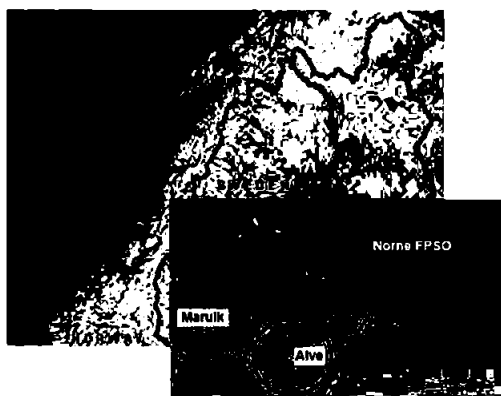


ALVE

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 with a third well drilled in 2016, draining the Ile Formation. During 2022 a fourth well was put on production in the gas zone in the Tilje 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.

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. The well will be back in production in 2023.

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 P&A sub project commenced in Jan 2019 and a total of 32 wells have been plugged.

The Gyda topside, steel jacket, 32 well conductors and the subsea drilling template were removed during summer 2022, utilizing the Allseas Pioneering Spirit heavy lift vessel. Platform demolition is currently ongoing at Aker Stord.



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. 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.

Vilje	
Aker BP ASA (operator)	46.904 %
DNO Norge AS	28.853%
PGNiG Upstream	24.243 %

Since the start-up of production the field has consistently delivered production above the annual plans. Currently Vilje is being produced through the Vilje V11 well with intermittent production from V12. V13 is currently shut in.

THE VALE FIELD

The Vale field is a gas and condensate field 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.

Vale	
Sval Energi AS (operator)	50.000 %
LOTOS Exploration and Production Norge AS	25.757%
PGNiG Upstream	24.243 %

The development 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 licence approved the decommissioning project in 2022. When Heimdal ceases its operation in the summer of 2023 Vale will be decommissioned. Disconnection of the flowline will take place shortly after Heimdal cease of production. Plugging of the well and removal of subsea equipment will take place within 3 years after that.

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. A coiled tubing well clean out operations for two wells is planned for in Q2/Q3 2023.

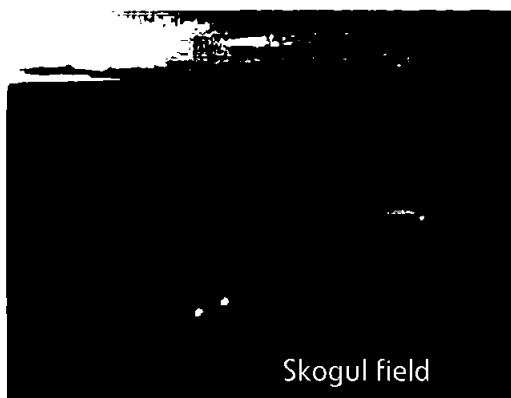
THE SKOGUL FIELD

The Skogul oil field, in PL460, is located approximately 30 km North of Alvheim in blocks 24/3 in the Norwegian sector of the North Sea. The water depth is 107 meters.

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 with one multi-lateral subsea well tied back to the existing Alvheim facilities via the Vilje subsea field.

Skogul	
Aker BP ASA (operator)	65.00 %
PGNiG Upstream	35.00 %

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 on a steel jacket. Production started in 2004.



Kvitebjørn	
Equinor (operator)	39.55 %
Petoro AS	30.00 %
Sval Energi AS	19.00 %
TotalEnergies	5.00%
PGNiG Upstream	6.45 %

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

PGNiG purchased its license share from Shell in 2020 and officially became partner from 31.12.2020.

Short term and long-term focus is to continue to mature infill targets and on the planned lifetime extension project for Kvitebjørn in order to maintain production beyond 2027.

Kvitebjørn receives condensate from Valemon for further processing and will from summer of 2023 also receive rich gas from Valemon.

THE VALEMÓN FIELD

Valemon is a 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 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 is a tie-back to the existing infrastructure on Ekofisk.

THE FENRIS FIELD (PL146/333)

Fenris 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, and initial discovery was made in 1988.

A Plan for Development and Operation was submitted to the authorities on Dec 16th 2022, based on an Unmanned Wellhead Platform with 4 production wells, 50 km tie-back and cost sharing on a new Production and Wellhed Platform on Valhall. Production start-up is expected in 2027.

The partnership in PL146/333 consists of Aker BP (78.8% and operator) and PGNiG Upstream (22.2%).



PGNiG Upstream's pipelines at 31/12/2021

VRGP (Valemon rich gas pipeline)	3.25%
KOR (Kvitebjørn Oljerør)	6.45%
Nyhamna Processing Plant	8.188%

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. A new Mercury Filter will become operational during 2023 giving removal capability to the Polarled inlet.

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 %

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 with Equinor as the technical service provider.

The pipeline will be decommissioned in the summer of 2023 (see Valemon).

Valemon rich gas pipeline	
Equinor	66.775 %
Petoro AS	30.000 %
PGNiG Upstream	3.225 %



KVITEBJØRN OLJERØR (KOR)

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

Kvitebjørn oljerør	
Equinor (operator)	39.55 %
Petoro AS	30.00 %
Sval Energi AS	19.00 %
TotalEnergies	5.00 %
PGNiG Upstream	6.45 %

NOTE 28 RESERVES AND CONTINGENT RESOURCES (NOT AUDITED)

For all assets, with exception of Lunde/Shrek project, the Company's reserves and Contingent Resources are based on the operator's official data reported in the Revised National Budget (RNB2023) prepared by field Operators at the end of 2022. PGNiG Upstream follows defend 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. In case of Lunde/Shrek project, JV decided to resign from development concept included in its RNB2023. In this case PUN used smaller volumes associated with simplified development the JV currently focuses on. 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	3.3	21.3	4.8	29.5
Ærfugl Nord	0.2	2.3	0.5	3.0
Morvin	0.1	0.1	0.0	0.2
Gina Krog	1.7	6.5	0.6	8.7
Vilje	3.0	0.0	0.0	3.0
Vale	0.1	0.1	0.0	0.3
Skogul	1.2	0.1	0.0	1.2
Tommeliten Alpha	15.4	41.8	1.9	59.0
Fenris	15.5	23.6	2.1	41.2
Duva	3.4	9.5	2.2	15.1
Alve Nord	1.1	2.9	0.8	4.9
Lunde	0.3	1.7	0.3	2.3
Kvitebjørn	1.4	7.3	0.3	8.9
Valemon	0.1	0.8	0.1	1.0
Ørn	0.8	18.2	1.2	20.3
Ormen Lange	2.5	82.8	0.0	85.3
Marulk	0.1	1.7	0.3	2.0
Alve	0.3	3.3	0.7	4.3
Tambar Ost	0.0	0.0	0.0	0.0
Vedande	0.2	0.0	0.0	0.3
Total	50.9	223.9	15.8	290.6



**COUNTRY-BY-COUNTRY REPORTING OF
PAYMENTS TO AUTHORITIES IN 2022**



INFORMATION ON COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2022

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 2022. This report is issued together with the Annual Report for 2022. 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 2022 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 2022 and, to the best extent possible, reflect the actual amounts paid in 2022.

COUNTRY-BY-COUNTRY REPORTING OF PAYMENTS TO AUTHORITIES IN 2022

Payments made in 2022	Profit oil in-kind (1)	Taxes and fees (2)	Royalty	Dividends	Bonuses	Licence fees (3)	Infrastruc ture (4)	Ownership rights (5)
Paid, in million NOK	0	18 518.5	0	0	0	2.6	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 2022 is related to tax instalments to the Norwegian state of 18 382 347 thousand, payment of net profit interest (NPI) of NOK 135 304 thousand to SDFI (State's Direct Financial Interest) and net custom tariffs paid (+)/refunded (-) to Skatteetaten for CO2 fuel and flare and NOx of NOK 876 thousand. VOC is not included, as the payment is done to a third party (Altera Norway). For further details, please refer to the Annual Report.

(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, during 2022 area fee was paid for PL159F of NOK 2 295 thousand. Reported amounts in 2022 include NOK 147 thousand for the sector fees from Petroleum Safety Authority in Norway and 123 thousand for fees related to the APA2022 licencing 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 2022



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.

Other information	Investments (1)	Revenues (2)	Production (3) million boe	Purchase of goods and services (4)	Interest to/from associated companies (5)
Million NOK (except production)	9 616	43 035	26,2	3 135	11

- (1) Investments include the acquisition loan to parent company. It also includes purchase of Ørn license, investments on Ormen Lange Phase 3, Tommeliten Alpha, Fenris, King Lear, Alve North, Verdande and Andvare development projects, investments on the producing fields 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 2022 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, Valemon, Kvitebjørn, 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) Net of Interest cost/income paid to (+) /received from (-) associated companies (loan from/to parent Company). For further details, please refer to the Annual Report.

Stavanger,
10th February 2023

Robert Dominik Śleszyński
Chairman of the Board

Marcin Gargas
Director of the Board

Robert Harasimiuk
Director of the Board

Urszula Monika Kowalczyk
Director of the Board

Przemysław Waclawski
Director of the Board

Iwona Waksmundzka-Olejniczak
Director of the Board

Maciej Pawel Wyszczarski
Director of the Board

Marek Woszczyk
General Manager



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 forretningspråk 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 skattedirektoratet@skatteetaten.no	Besøksadresse Fredrik Selmers vei 4 Org. nr: 974761076	Sentralbord 800 80 000 Telefaks 22 17 08 60
--	--	--



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.

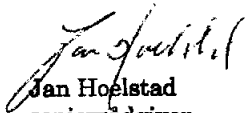
Det er etter Skattedirektoratets vurdering derfor avgjørende at spørsmål om dispensasjon fra kravet til å utarbeide årsregnskap og/eller årsberetning på norsk, ikke på vesentlige områder fraviker fra hensynet til brukere av regnskapsinformasjon. Søkeren må dessuten som et utgangspunkt for vurderingen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