

Waldorf Production UK plc  
Competent Person's Report  
As of 31 December 2024

Prepared For: Waldorf Production UK plc

By: ERCE

Date: 03 April 2025

**ERCE**

The expertise tomorrow needs

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Approved by: M Caniggia

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# Table of Contents

- 1. Executive Summary ..... 4
- 2. Introduction ..... 16
  - 2.1. Data Provided ..... 17
  - 2.2. Work Completed ..... 17
- 3. Bacchus Field ..... 20
  - 3.1. Development Plans ..... 21
  - 3.2. Estimated Ultimate Recovery ..... 21
  - 3.3. Cost Assumptions ..... 22
    - 3.3.1. CAPEX Assumptions ..... 22
    - 3.3.2. OPEX Assumptions ..... 23
    - 3.3.3. Abandonment Assumptions ..... 23
  - 3.4. Reserves ..... 23
- 4. Bittern Field ..... 24
  - 4.1. Development Plans ..... 26
  - 4.2. Estimated Ultimate Recovery ..... 26
  - 4.3. Cost Assumptions ..... 26
    - 4.3.1. CAPEX Assumptions ..... 26
    - 4.3.2. OPEX Assumptions ..... 27
    - 4.3.3. Abandonment Assumptions ..... 27
  - 4.4. Reserves ..... 27
- 5. Catcher Area ..... 29
  - 5.1. Development Plans ..... 32
  - 5.2. Estimated Ultimate Recovery ..... 34
  - 5.3. Cost Assumptions ..... 36
    - 5.3.1. CAPEX Assumptions ..... 36
    - 5.3.2. OPEX Assumptions ..... 37
    - 5.3.3. Abandonment Assumptions ..... 37
  - 5.4. Reserves ..... 37
- 6. Columbus Field ..... 39
  - 6.1. Petroleum Initially In Place ..... 41

P6921 Waldorf YE2024 Competent Person's Report

6.2. Development Plans..... 43

6.3. Estimated Ultimate Recovery ..... 43

6.4. Cost Assumptions ..... 44

6.4.1. CAPEX Assumptions..... 44

6.4.2. OPEX Assumptions..... 44

6.4.3. Abandonment Assumptions..... 45

6.5. Reserves ..... 45

7. Enoch Field ..... 47

7.1. Development Plans..... 48

7.2. Estimated Ultimate Recovery ..... 49

7.3. Cost Assumptions ..... 49

7.3.1. CAPEX Assumptions..... 49

7.3.2. OPEX Assumptions..... 49

7.3.3. Abandonment Assumptions..... 49

7.4. Reserves ..... 50

8. Kraken Field..... 51

8.1. Development Plans..... 54

8.2. Estimated Ultimate Recovery ..... 54

8.3. Cost Assumptions ..... 55

8.3.1. CAPEX Assumptions..... 55

8.3.2. OPEX Assumptions..... 56

8.3.3. Abandonment Assumptions..... 56

8.4. Reserves ..... 56

9. Scolty-Crathes Fields ..... 58

9.1. Development Plans..... 60

9.2. Estimated Ultimate Recovery ..... 60

9.3. Cost Assumptions ..... 61

9.3.1. CAPEX Assumptions..... 61

9.3.2. OPEX Assumptions..... 61

9.3.3. Abandonment Assumptions..... 62

9.4. Reserves ..... 62

10. Scott Field ..... 63

10.1. Development Plans.....	65
10.2. Estimated Ultimate Recovery.....	66
10.3. Cost Assumptions.....	67
10.3.1. CAPEX Assumptions.....	67
10.3.2. OPEX Assumptions.....	68
10.3.3. Abandonment Assumptions.....	68
10.4. Reserves.....	68
11. Telford Field.....	70
11.1. Development Plans.....	72
11.2. Estimated Ultimate Recovery.....	72
11.3. Cost Assumptions.....	72
11.3.1. CAPEX Assumptions.....	72
11.3.2. OPEX Assumptions.....	72
11.3.3. Abandonment Assumptions.....	73
11.4. Reserves.....	73
12. Economic Evaluation.....	74
12.1. Economic Assumptions.....	74
12.2. Economic Results.....	75
Appendix 1: SPE PRMS Guidelines.....	77
Appendix 2: Nomenclature.....	103
Appendix 3: Cash flow tables.....	107

## List of Tables

Table 1.1: Waldorf Licence Interest.....	4
Table 1.2: Developed Reserves as of 31 December 2024 .....	11
Table 1.3: Undeveloped Reserves as of 31 December 2024.....	12
Table 1.4: Total Reserves as of 31 December 2024 .....	13
Table 1.5: ERCE Brent Crude Oil Price Forecast as of 1 January 2025 .....	14
Table 1.6: ERCE UK NBP Natural Gas Price Forecast as of 1 January 2025 .....	14
Table 1.7: Before Tax Net Present Values of the Reserves as of 31 December 2024.....	14
Table 1.8: Cessation of Production Dates .....	15
Table 3.1: Bacchus Field Summary Data .....	20
Table 3.2: Bacchus Field EUR Estimates and Recovery Factors .....	22
Table 3.3: Bacchus Field Gross Reserves with CoP dates.....	23
Table 4.1: Bittern Field Summary Data .....	24
Table 4.2: Bittern Field Gross EUR Estimates and Recovery Factors .....	26
Table 4.3: Bittern Field Gross Reserves with CoP dates .....	28
Table 5.1: Catcher Area Summary Data.....	29
Table 5.2: Summary of Operator Depressurisation Incremental TRR.....	35
Table 5.3: Summary of ERCE's YE2024 Depressurisation Incremental TRR.....	35
Table 5.4: Catcher Area oil TRR (to end-2036) Estimates by Project.....	36
Table 5.5: Catcher Area EUR Estimates and Recovery Factors.....	36
Table 5.6: Catcher Area Assumed Production Efficiency .....	36
Table 5.7: Catcher Area Gross Reserves with CoP dates .....	38
Table 6.1: Columbus Field Summary Data.....	39
Table 6.2: Columbus Field Volumetric Input Parameters.....	43
Table 6.3: Columbus Field Volumetric GIIP Estimates .....	43
Table 6.4: Columbus Field EUR Estimates and Recovery Factors .....	44
Table 6.5: Columbus Field Gross Reserves with CoP dates .....	46
Table 7.1: Enoch Field Summary Data.....	48
Table 7.2: Enoch Field EUR Estimates and Recovery Factors.....	49
Table 7.3: Enoch Field Gross Reserves with CoP dates .....	50
Table 8.1: Kraken Field Summary Data.....	51
Table 8.2: Kraken Field Assumed Production Efficiency .....	55
Table 8.3: Kraken Field EUR Estimates and Recovery Factor .....	55
Table 8.4: Kraken Field Gross Reserves with CoP dates .....	57
Table 9.1: Scolty-Crathes Field Summary Data.....	58
Table 9.2: Scolty-Crathes Field EUR Estimates and Recovery Factors.....	61
Table 9.3: Scolty-Crathes Field Gross Reserves with CoP dates .....	62
Table 10.1: Scott Field Summary Data.....	63
Table 10.2: Scott Field EUR Estimates and Recovery Factors.....	67
Table 10.3: Scott Field Gross Reserves with CoP dates .....	69
Table 11.1: Telford Field Summary Data.....	70



Table 11.2: Telford Field EUR Estimates and Recovery Factors .....	72
Table 11.3: Telford Field Gross Reserves with CoP dates .....	73
Table 12.1: ERCE Brent Crude Oil Price Forecast as of 1 January 2025 .....	74
Table 12.2: ERCE UK NBP Natural Gas Price Forecast as of 1 January 2025.....	74
Table 12.3: Price Differentials .....	75
Table 12.4: ERCE UKA Forecast as of 1 January 2025 .....	75

# List of Figures

Figure 2.1: Waldorf Fields Location Map .....	16
Figure 3.1: Bacchus Field Structure Map .....	20
Figure 3.2: Bacchus Field Production and Injection History .....	21
Figure 4.1: Bittern Top Reservoir Depth Structure.....	25
Figure 4.2: Bittern Field Production and Injection History .....	25
Figure 5.1: Overview of Licenced Blocks, Catcher Area.....	29
Figure 5.2: Catcher Field Production and Injection History .....	30
Figure 5.3: Varadero Field Production and Injection History.....	31
Figure 5.4: Burgman Field Production and Injection History .....	31
Figure 5.5: Catcher Area Top Cromarty and Tay Depth Structure Maps .....	33
Figure 6.1: Well 23/16f-C1Z Location.....	40
Figure 6.2: Columbus Field Production History .....	41
Figure 6.3: RMS Amplitude Extraction F4 to Top Forties.....	42
Figure 7.1: Enoch Field Top Structure Map (ft TVDSS).....	47
Figure 7.2: Enoch Field Production History .....	48
Figure 8.1: Kraken Field Location Map.....	51
Figure 8.2: Kraken Stratigraphy .....	52
Figure 8.3: Kraken Field Map .....	53
Figure 8.4: Kraken Field Production and Injection History .....	54
Figure 9.1: Scolty Field Top Depth Map .....	58
Figure 9.2: Crathes Field Top Depth Map .....	59
Figure 9.3: Scolty-Crathes Field Production History .....	60
Figure 10.1: Scott Field Top Depth Map.....	63
Figure 10.2: Scott Field Production and Injection History .....	65
Figure 11.1: Telford Field Top Depth Map.....	70
Figure 11.2: Telford Field Production and Injection History .....	71



03/04/2025

The Directors  
Waldorf Production UK plc  
40 Queens Road  
Aberdeen  
AB15 4YE

Dear Board of Directors,

Re: Competent Person's Report

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a Competent Person's Report ("CPR") for the hydrocarbon Reserves associated with the assets owned by the Waldorf group of companies ultimately controlled by Waldorf Energy Partners Limited (collectively referred to as "Waldorf" or the "Company").

The effective date of this report is 31 December 2024 (the "Effective Date"). For the preparation of this CPR ERCE was provided with data and information by Waldorf up to the Effective Date. Additional information relating to the Scott and Bittern fields performance in early 2025, the Kraken field Operator Life of Field estimates and public announcement on the ruling of the Scottish Court of Session on the Jackdaw field, became available between the Effective Date and the date of this Report.

Waldorf has provided written representations that no new data or information have been acquired between the Effective Date and the publication date of the report, other than that disclosed above, that would materially affect the opinions expressed in this CPR.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1 of the CPR. The full text can be downloaded from:-

<https://www.spe.org/en/industry/petroleum-resources-management-system-2018/>

The nomenclature that may be used in this CPR is summarised in Appendix 2.

### **Use of the Report**

This CPR was prepared by ERCE for the benefit of Waldorf's Board of Directors, their financial advisors, and for possible use in discussions with lending banks and other third parties. Any third party to whom the client discloses or makes available this CPR shall not be entitled to rely on it or any part of it.

Waldorf agrees to ensure that any publication or use of this report which makes reference to ERCE shall be published or quoted in its entirety and Waldorf shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of ERCE.

### **Disclaimer**

In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after such material has been sent by ERCE to the client.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by Waldorf was not complete and accurate.

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available, which becomes known subsequent to the preparation of this CPR.

The accuracy of any Reserves and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While Reserves and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency rates, inflation, market demand and government policy, which are subject to many uncertainties and may, in future, differ materially from the forecasts utilised herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the Reserves evaluated herein.

No site visits were undertaken in the preparation of this CPR.

## Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and ERCE will receive no other benefit for the preparation of this CPR.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have, at the date of this report, any shareholding in Waldorf. Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of the Company, its directors and senior management.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The preparation of this report has been supervised by Mr Matteo Caniggia, Head of Reserves and Resources at ERCE who is the Competent Person. Mr. Caniggia has over 20 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of reserves and resources. He holds a degree in Petroleum Engineering from the Polytechnic University of Turin and an EMBA from the HEC Paris School of Management. He is a member of the Society of Petroleum Evaluation Engineers. Mr. Caniggia, therefore possesses the required competencies, being professionally qualified and a member in good standing of an appropriate recognised professional association.

Yours faithfully,

Signed by:  
  
5B1D747B5AE4470...

Mr. Matteo Caniggia,

Head of Reserves and Resources, ERCE

## 1. Executive Summary

Waldorf's portfolio of assets is located within several United Kingdom licence blocks. A summary of the assets assessed in this report is presented in Table 1.1. All the assets are non-operated and are located on the UK Continental Shelf ("UKCS").

**Table 1.1: Waldorf Licence Interest**

Asset	Field(s)	Operator	Waldorf Working Interest %	Status
Alba	Alba	Ithaca	25.68335%	Producing
Bacchus	Bacchus	Apache	30.00000%	Producing
Bittern	Bittern	Dana	2.42200%	Producing
Catcher	Catcher	Harbour	40.00000%	Producing
	Varadero			Producing
	Burgman			Producing
Columbus	Columbus	Serica	25.00000%	Producing
Enoch	Enoch	Bridge Petroleum <sup>1</sup>	9.69600%	Producing
Kraken	Kraken	EnQuest	29.50000%	Producing
Scolty and Crathes	Scolty	EnQuest	50.00000%	Producing
	Crathes			Producing
Scott and Telford	Scott	CNOOC	21.83458%	Producing
	Telford		1.58677%	Producing

<sup>1</sup> Operator from 1 January 2025

### Asset Overview and Highlights

#### Alba Field – Waldorf Interest 25.68%

The Alba field lies in Block 16/26, in the Central North Sea area of the UKCS, approximately 210 km northeast of Aberdeen. The field is an elongate mid-late Eocene turbidite channel fill, unconsolidated in nature and overlies the deeper Britannia gas field. The Alba field has been developed using an eight-leg steel jacket platform with processing, drilling and accommodation facilities. Production commenced in January 1994, initially from wells drilled from the production platform. Oil export is via a shuttle tanker from a floating storage unit with an 825,000 bbl capacity situated around 3 km west of the platform. In October 2002, a subsea development of the southern part of the structure began. Alba came off plateau production around 2004, with the overall production decline reduced by programmes of new wells and sidetracks designed to target bypassed and attic oil. Well integrity issues caused water injection to be shut in between June and December 2022, causing a severe decline in oil production. Injection was resumed at the end of December 2022, when six out of eight water injection wells were brought back into operation. Oil Production experienced a further reduction in April 2023 due to a failure of the turbine required for water injection, which was repaired in April 2024, reinstating water injection. Drilling of Well B06 was carried out in Q1 2024, but multiple failures were experienced during cement jobs while setting the casing. Drilling operations were then suspended in preparation for full abandonment. The Alba joint venture ("JV") decided that no further infill drilling will take place on Alba.

Production data for this evaluation were available up to the end of December 2024, when the average production rate was 4,900 stb/d of oil with 121,000 bbl/d of water. Cumulative production to 31 December 2024 was 442.2 MMstb of oil and 129.4 Bscf of gas.

Current plans include the conversion of the producing Well A44 into a water injector. No further infill wells are planned. The Operator, Ithaca, and the JV have also planned a Cessation of Production (“CoP”) in mid-2026, with a final date to be determined. ERCE understands that the Alba JV expects uneconomic production until the CoP, but the partners have agreed to continue to produce to generate revenue to offset losses. ERCE does not attribute any Reserves to the Alba field after testing commerciality under PRMS.

### **Bacchus Field – Waldorf Interest 30.00%**

The Bacchus field lies in Block 22/6a, in the Central North Sea area of the UKCS, approximately 190 km northeast of Aberdeen. The field contains light oil within the sands of the Jurassic Fulmar Formation. The field has been developed through three subsea wells tied back to the Forties Alpha platform, with oil export via the Forties Pipeline System (“FPS”). The field started production in 2012, initially under depletion. One of the producers was later converted to a water injector to provide pressure support to the other two producers. Since 2018, Well B2 has been the only production well online. In June 2022, a rapid fall in oil rate was observed. Subsequent investigations have not led to a definitive identification of the root cause of the drop in production. Since October 2022, the well has been producing at reduced controlled rates at the wellhead. After August 2023, an increase in the water cut (27% to 37%) was observed, and this resulted in a further decline in oil production until the field turnaround (“TAR”) in Q2 2024. Following the TAR, an improvement in performance was observed, and higher rates were measured through the end of 2024. However, the root cause of the changes in well deliverability has not yet been identified by the Operator. In December 2024, the produced at an average oil rate of 1,150 stb/d with 25% water cut. As of 31 December 2024, the cumulative field production was 17.5 MMstb of oil and 0.70 Bscf of gas.

Developed Reserves are assigned based on further production from the existing production well, and there are no further plans for development drilling. Reserves include a backout reconciliation from 2020-2022 of 118 Mstb of oil in favour of Bacchus from Forties until the end of 2025. The Operator has publicly announced the intention to stop its North Sea production by the end of 2029, and Waldorf has advised that there are no plans to produce beyond 31 December 2029. ERCE has retained this date as the latest technical CoP.

### **Bittern Field – Waldorf Interest 2.42%**

The Bittern field lies in Blocks 29/1a and 29/1b, in the Central North Sea area of the UKCS, approximately 180 km east of Aberdeen. The reservoir comprises Rogaland and Forties Member sands and contains light saturated oil with a primary gas cap. The field was initially developed with six subsea wells tied back to the Triton floating production storage and offloading vessel. Oil is sold at offload from the Triton Floating Production Storage and Offloading (“FPSO”) unit; gas is exported via the Shell Esso Gas and Associated Liquids

pipeline (“SEGAL”). Oil production commenced in April 2000 from four producing wells. Since then, two producers have been drilled and sidetracked (in 2006 and 2011), a new well was drilled in 2020 as a crestal infill, and a workover was carried out in 2022. Production was initially supported by two water injectors, but one well (Well B3) has been unable to inject water since 2021 (due to fill above the perforations). The water injection system was also offline during 2023 due to the failure of the injection pipeline to Bittern. Water injection at Well A1 was reinstated in early 2024 following an engineered wrap to the existing water injection pipeline, but poor injection was experienced in 2024 due to a reduction in the operational pressure of the repaired pipeline.

In 2024, the horizontal development Well B1Z (renamed Well B6) was drilled as a sidetrack to the watered-out B-1 well and targeted attic oil in a central area of the field. The well was brought on stream in September 2024 with an initial (choked) oil rate broadly in line with pre-drill expectations. In Q4 2024, facilities experienced outages, and production was offline from mid-October before resuming on 27th December 2024. At the time of writing, ERCE has been informed that the field produced for most of January 2025 but has been shut in since 29th January due to an integrity issue on the Triton FPSO. Production is due to restart in May. At the end of December 2024, the field was producing an average oil rate of 1,900 stb/d (six months average). Cumulative field production to 31 December 2024 was 162.7 MMstb of oil and 152.2 Bscf of gas.

Developed Reserves are assigned based on further production from the existing production wells. Undeveloped Reserves are associated with the water injection pipeline replacement project, which is on track for Q4 2025 execution.

### **Catcher Area – Waldorf Interest 40.00%**

The Catcher, Varadero and Burgman fields (collectively the “Catcher Area”) lie in Block 28/9a, and are situated to the west of the Central Graben within the UKCS around 170 km southeast of Aberdeen. The reservoirs are made up of mostly Tertiary age injectites. Production commenced in December 2017 from the Catcher field, in January 2018 from the Varadero field, and in May 2018 from the Burgman field, with all fields tied back to a newly built and leased FPSO vessel. Oil is exported via a shuttle tanker; gas is evacuated via the Fulmar Gas Line (“FGL”) to St. Fergus. To date, 21 subsea development wells (17 producers and four water injectors) have been drilled in the Catcher Area.

Drilling as part of the original plan of development was completed in 2020 and an additional two infill wells (Catcher North and Burgman Far East) were drilled in 2022.

The fields produced at a combined plateau rate of 66,000 stb/d until mid-2020, when there were injectivity issues and some facilities problems relating mainly to calcium naphthenate (CaN) deposition. Uptime was improved in 2021 but slugging issues led to vibrations and pressure spikes and the oil rate limit was reduced to ~54,000 stb/d and liquid rates were generally limited to ~110,000 bbl/d. Topside modifications between 2021 and 2023 improved these issues and the average daily liquid rate has since been stable between 125,000 and

135,000 stb/d. Production is currently constrained by gas plant throughput on the FPSO, with high gas rates triggering export gas compression alarms.

After the 2023 TAR production was affected by a failure of the electrostatic coalescer in the produced water train, with production from high water cut wells temporarily limited until January 2024. Production from Catcher was re-routed to the test separator and from Varadero and Burgman to the 1<sup>st</sup> stage separator. Repairs to the electrostatic coalescer were carried out in the 2024 TAR and it returned to service in October 2024. The average oil rate in December 2024 was 25,629 stb/d with a water cut of 79%. As of 31 December 2024, cumulative oil production from the Catcher Area was 106.2 MMstb (Catcher 56.8 MMstb; Varadero 20.8 MMstb; Burgman 28.6 MMstb) and cumulative wellhead gas production was 42.8 Bscf (Catcher 22.4 Bscf; Varadero 7.8 Bscf; Burgman 12.6 Bscf).

Gas re-injection to boost oil recovery has been limited since Q4 2022, partly due to gas export proving more commercial and partly due to a lack of suitable candidate wells. Gas export was unavailable between June and October 2024 and over this period gas was re-injected into the reservoir. Gas re-injection is likely to continue to some degree alongside gas export until the FPSO becomes fuel gas deficient, but it is no longer expected to lead to incremental production.

Alongside production from the existing wells, Reserves are also assigned to a late-life depressurisation project which was part of a field development plan addendum ("FDPA") submitted to the North Sea Transition Authority ("NSTA") in 2021. The project involves dropping the reservoir pressure below the bubble point to induce solution gas and gas cap expansion drive. The plan is to implement this by stopping or reducing water injection in a phased approach.

ERCE does not attribute Undeveloped Reserves; two infill wells that were expected to be drilled in late 2025 have been put on hold due to them currently not meeting the Operator's required economic hurdles.

### **Columbus Field – Waldorf Interest 25.00%**

The Columbus gas field is located in Blocks 23/16f and 23/21a within the Central North Sea area of the UKCS. The field is approximately 7 km northwest of the Lomond gas field and 270 km east of Aberdeen in water depths of 87 m. The field was discovered in 2006, appraised by six wells between 2007 and 2009, and developed in 2021 by drilling an approximately 1,600 m long horizontal subsea producer. The well was tied back to the Arran field pipeline which in turn is routed to the Shell-operated Shearwater platform. Gas is exported via SEGAL to St. Fergus, liquids are evacuated via FPS. The well was brought on production in November 2021.

In December 2024, the field produced an average of 10.4 MMscf/d of gas, with 235 bbl/d of condensate. Cumulative production to 31 December 2024 was 14.4 Bscf of gas and 0.41 MMstb of condensate.

Developed Reserves are assigned based on further production from the existing production well. There are no further plans for development drilling.

**Enoch Field – Waldorf Interest 9.70%**

The Enoch field lies in Block 16/13a, in the Central North Sea area of the UKCS 15 km east of the Brae field complex. The field extends into Norwegian Block 15/5, with Waldorf holding a 9.7% unitised interest. The reservoir comprises Palaeocene Flugga Member sands and contains light saturated oil with a small primary gas cap. The field was discovered in 1985 and was developed as a single well subsea tieback to the Brae Alpha platform, with oil export via FPS. The field started production in May 2007 and produced up to 10,000 stb/d of oil. The recovery mechanism is solution gas drive with gas cap expansion and some aquifer support. At the Effective Date, the Enoch well was shut in following a loss of pressure control at the topside of the Enoch choke. ERCE has been informed that production is expected to restart in or after February 2025. In September 2024 (before the well was shut in), the average oil rate was 350 stb/d, the water cut was 91%, and the gas rate was 0.64 MMscf/d. As of 31 December 2024, cumulative production was 12.1 MMstb of oil and 12.2 Bscf of gas.

Developed Reserves are assigned based on further production from the existing production well. There are no further plans for development drilling. The Brae Operator expects a CoP at the end of Q2 2026. ERCE has retained this date as the latest technical CoP.

**Kraken Field – Waldorf Interest 29.50%**

The Kraken field lies in the UK offshore Blocks 9/2b and 9/2c on the East Shetland Platform, approximately 140 km east of the Shetland Islands. The reservoir is made of Palaeocene, Heimdal Member deepwater turbidite sandstones that have been re-mobilised, leading to a phase of injectites formation. Production commenced in June 2017 with a tie-back to the Armada Kraken FPSO vessel; oil is exported via a shuttle tanker. To date, 14 production and 12 injection wells have been drilled with peak oil rates of ~50,000 stb/d in March 2019. Water production from the field has risen faster than anticipated at project sanction, In December 2024, average oil production was 16,324 stb/d, with watercut of 93.2%. Cumulative oil production to 31 December 2024 was 74.0 MMstb.

Developed Reserves are assigned based on further production from the existing production wells. The JV could not reach agreement on plans to drill Pembroke and Cumbria production sidetracks in 2025, these have been postponed and as such are not included in this evaluation.

**Scolty and Crathes Fields – Waldorf Interest 50.00%**

The Scolty and Crathes fields are located in the Central North Sea across blocks 21/8a, 21/12c and 21/13a, approximately 25 km north of the Kittiwake platform, in 93 m water depth. The oil reservoirs are good quality Cromarty sands within the Palaeocene Sele Formation.

The fields were discovered in 2007 and 2011 respectively. The fields were developed according to a Field Development Plan (“FDP”) for the Scolty Development Area with two

single horizontal producers, one in each field, tied back to the Greater Kittiwake Area (“GKA”) platform in a daisy chain (Scolty to Crathes and Crathes to Kittiwake) by means of subsea production and gas lift pipelines, with oil export via FPS and Gas export via Fulmar Gas line to St Fergus. First oil was achieved in November 2016, but within weeks, a significant reduction in production was encountered, which was subsequently identified as a wax build-up in the uninsulated pipeline. From the beginning of 2017, continuous oil production was possible only from Crathes (closer to the platform) through regular chemical treatments, and it was maintained at around 3,500 stb/d. The pipeline was replaced in 2019 when Scolty production was resumed via the common flowline. Gas lift commenced in 2021. Due to uncertainties in production allocation, Scolty and Crathes have been assessed by ERCE as a single field, referred to as the “Scolty-Crathes field” hereinafter in this CPR. In December 2024, the combined field oil rate averaged 1,250 stb/d (decreased due to the gas compression shutdown, fixed by the 18<sup>th</sup> of December) with a water cut of 85%. Cumulative production to 31 December 2024 was 13.5 MMstb of oil and 4.1 Bscf of gas.

Reserves are assigned based on further production from the two existing wells. There are no further plans for development drilling.

#### **Scott Field – Waldorf Interest 21.83%**

The Scott field straddles Blocks 15/21 and 15/22 on the southern flanks of the Witch Ground Graben in the Outer Moray Firth, approximately 170 km from Aberdeen. The oil field reservoirs are the Upper Jurassic Scott and Piper sandstones of Oxfordian to Kimmeridgian age. The field was discovered in 1983, development was sanctioned in 1990, and first oil was in 1993. Facilities include a bridge-linked platform with subsea injection and production manifolds (including Telford), with oil export via the FPS and excess gas evacuated to the Scottish Area Gas Evacuation (“SAGE”) system. In 2024 production performance was affected by lower-than-anticipated operating efficiency, particularly during H2, due to a mechanical seal failure requiring extensive inspections. In December 2024, the average production rate was circa 5,000 stb/d of oil with a water cut of 91.4% from 15 oil producers supported by five water injection wells. Water injection resumed in 2023, and was maintained in operation throughout 2024, with an annual average water injection rate of about 95 Mbb/d. Cumulative production to 31 December 2024 was 450.8 MMstb of oil and 310.3.5 Bscf of gas.

Developed Reserves are assigned based on further production from the wells online as of the Effective Date or expected to be online shortly after, including a new well drilled in 2024, until the end of 2026, the platform technical CoP date declared by the Operator. Undeveloped Reserves are attributed to a power generation unit project, which will unlock production post-2026 and four infill wells to be drilled over the next three years, starting from H2 2025. A commercial cut-off date at the end of the year 2029 (date at which zero routine flaring will be required) has been applied by ERCE, due to a current lack of commitment by the Operator to progress a Flare Gas Recovery Unit (“FGRU”) project

## Telford Field – Waldorf Interest 1.59%

The Telford field is located in Blocks 15/21a and 15/22, approximately 170 km northeast of Aberdeen and 9 km south of the Scott Platform. Like the Scott field, the oil reservoirs are the Upper Jurassic Scott and Piper sandstones of Oxfordian to Kimmeridgian age. The field came online in 1996 as a subsea tieback to Scott. In 2024 oil production was provided by two wells continuously, Wells F5 and G20, with one water injection well online. In 2024 Telford's performance was affected by the operating efficiency of the Scott facilities being lower than expected. In December 2024, production from the field was partially reinstated after a shut-down, with an average oil rate of 720 stb/d and a watercut of 87.3%. Cumulative field production to 31 December 2024 was 109.5 MMstb of oil and 230.9 Bscf of gas.

Developed Reserves are assigned based on further production from the existing wells, including production restart from Well G3 after its workover. The Operator is carrying out studies for development drilling, but these are not considered mature enough for inclusion in Reserves. Undeveloped Reserves are attributed to Telford based on the operational availability of the Scott facilities.

### Reserves

*Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).*

The Reserves are reported on a field gross and a Company net entitlement basis as of 31 December 2024. As there are no royalties payable to others, the Company net working interest Reserves are also equivalent to the Company net entitlement Reserves. Both Developed and Undeveloped Reserves are reported for each asset area and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Developed Reserves are presented in Table 1.2 and Undeveloped Reserves are presented in Table 1.3. Total Reserves (Developed plus Undeveloped) are presented in Table 1.4. Barrel of Oil Equivalent Reserves estimates were derived using a conversion of 6 Mscf/boe, however gas revenue was derived using the estimated calorific value of the gas.

Table 1.2: Developed Reserves as of 31 December 2024

Asset/Field	Field Gross on Licence			Waldorf	Company Net		
	1P	2P	3P	WI	1P	2P	3P
<b>Oil+Cond+NGLs (MMstb)</b>							
Bacchus	0.43	0.89	2.02	30.00%	0.13	0.27	0.61
Bittern	9.98	18.07	23.85	2.42%	0.24	0.44	0.58
Catcher	27.62	39.22	56.44	40.00%	11.05	15.69	22.57
Columbus	0.37	1.00	1.62	25.00%	0.09	0.25	0.40
Enoch	0.14	0.19	0.27	9.70%	0.01	0.02	0.03
Kraken	15.14	40.77	64.78	29.50%	4.47	12.03	19.11
Scolty Crathes	1.23	2.18	2.55	50.00%	0.61	1.09	1.28
Scott	4.66	6.29	8.12	21.83%	1.02	1.37	1.77
Telford	0.75	1.00	1.25	1.59%	0.01	0.02	0.02
<b>Total Oil+Cond+NGLs</b>	<b>60.30</b>	<b>109.62</b>	<b>160.90</b>		<b>17.63</b>	<b>31.17</b>	<b>46.37</b>
<b>Gas (Bscf)</b>							
Bacchus	-	-	-	30.00%	-	-	-
Bittern	5.50	9.10	14.26	2.42%	0.13	0.22	0.35
Catcher	0.37	2.64	7.27	40.00%	0.15	1.05	2.91
Columbus	5.28	14.56	23.47	25.00%	1.32	3.64	5.87
Enoch	-	-	-	9.70%	-	-	-
Kraken	-	-	-	29.50%	-	-	-
Scolty Crathes	0.10	0.18	0.22	50.00%	0.05	0.09	0.11
Scott	0.45	2.00	3.74	21.83%	0.10	0.44	0.82
Telford	0.04	0.54	1.07	1.59%	0.00	0.01	0.02
<b>Total Gas</b>	<b>11.75</b>	<b>29.02</b>	<b>50.03</b>		<b>1.75</b>	<b>5.45</b>	<b>10.06</b>
<b>BOE (MMboe)</b>							
Bacchus	0.43	0.89	2.02	30.00%	0.13	0.27	0.61
Bittern	10.90	19.59	26.23	2.42%	0.26	0.47	0.64
Catcher	27.68	39.66	57.65	40.00%	11.07	15.86	23.06
Columbus	1.25	3.43	5.53	25.00%	0.31	0.86	1.38
Enoch	0.14	0.19	0.27	9.70%	0.01	0.02	0.03
Kraken	15.14	40.77	64.78	29.50%	4.47	12.03	19.11
Scolty Crathes	1.25	2.21	2.59	50.00%	0.62	1.10	1.29
Scott	4.73	6.62	8.74	21.83%	1.03	1.45	1.91
Telford	0.76	1.09	1.43	1.59%	0.01	0.02	0.02
<b>Total BOE</b>	<b>62.26</b>	<b>114.45</b>	<b>169.24</b>		<b>17.92</b>	<b>32.08</b>	<b>48.04</b>

## Notes

1. Company Net Entitlement Reserves (Net in the table) are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. boe conversion based on 6 Mscf = 1 boe
3. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
4. The table does not include the Alba field, to which Reserves are not attributed
5. Working Interests are rounded, all decimals are reported in Table 1.1

Table 1.3: Undeveloped Reserves as of 31 December 2024

	Field Gross on Licence			Waldorf	Company Net		
	1P	2P	3P	WI %	1P	2P	3P
<b>Oil+Cond+NGLs (MMstb)</b>							
Bacchus	-	-	-	30.00%	-	-	-
Bittern	-	3.86	5.83	2.42%	-	0.09	0.14
Catcher	-	-	-	40.00%	-	-	-
Columbus	-	-	-	25.00%	-	-	-
Enoch	-	-	-	9.70%	-	-	-
Kraken	-	-	-	29.50%	-	-	-
Scolty Crathes	-	-	-	50.00%	-	-	-
Scott	-	13.33	18.71	21.83%	-	2.91	4.09
Telford	-	1.19	1.58	1.59%	-	0.02	0.03
<b>Total Oil+Cond+NGLs</b>	-	<b>18.38</b>	<b>26.11</b>		-	<b>3.02</b>	<b>4.25</b>
<b>Gas (Bscf)</b>							
Bacchus	-	-	-	30.00%	-	-	-
Bittern	-	-2.65	-4.60	2.42%	-	-0.06	-0.11
Catcher	-	-	-	40.00%	-	-	-
Columbus	-	-	-	25.00%	-	-	-
Enoch	-	-	-	9.70%	-	-	-
Kraken	-	-	-	29.50%	-	-	-
Scolty Crathes	-	-	-	50.00%	-	-	-
Scott	-	6.69	11.38	21.83%	-	1.46	2.49
Telford	-	0.14	0.72	1.59%	-	0.00	0.01
<b>Total Gas</b>	-	<b>4.18</b>	<b>7.50</b>		-	<b>1.40</b>	<b>2.39</b>
<b>BOE (MMboe)</b>							
Bacchus	-	-	-	30.00%	-	-	-
Bittern	-	3.42	5.06	2.42%	-	0.08	0.12
Catcher	-	-	-	40.00%	-	-	-
Columbus	-	-	-	25.00%	-	-	-
Enoch	-	-	-	9.70%	-	-	-
Kraken	-	-	-	29.50%	-	-	-
Scolty Crathes	-	-	-	50.00%	-	-	-
Scott	-	14.44	20.61	21.83%	-	3.15	4.50
Telford	-	1.21	1.70	1.59%	-	0.02	0.03
<b>Total BOE</b>	-	<b>19.08</b>	<b>27.36</b>		-	<b>3.26</b>	<b>4.65</b>

## Notes

1. Company Net Entitlement Reserves (Net in the table) are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. boe conversion based on 6 Mscf = 1 boe
3. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
4. The table does not include the Alba field, to which Reserves are not attributed
5. Undeveloped Reserves in Telford are linked to the Scott Undeveloped Project of facilities life extension
6. Working Interests are rounded, all decimals are reported in Table 1.1
7. In the case of Bittern, the undeveloped project to reinstate water injection causes a reduction of produced gas volumes

Table 1.4: Total Reserves as of 31 December 2024

	Field Gross on Licence			Waldorf	Company Net		
	1P	2P	3P	WI %	1P	2P	3P
<b>Oil+Cond+NGLs (MMstb)</b>							
Bacchus	0.43	0.89	2.02	30.00%	0.13	0.27	0.61
Bittern	9.98	21.93	29.68	2.42%	0.24	0.53	0.72
Catcher	27.62	39.22	56.44	40.00%	11.05	15.69	22.57
Columbus	0.37	1.00	1.62	25.00%	0.09	0.25	0.40
Enoch	0.14	0.19	0.27	9.70%	0.01	0.02	0.03
Kraken	15.14	40.77	64.78	29.50%	4.47	12.03	19.11
Scolty Crathes	1.23	2.18	2.55	50.00%	0.61	1.09	1.28
Scott	4.66	19.62	26.83	21.83%	1.02	4.28	5.86
Telford	0.75	2.19	2.83	1.59%	0.01	0.03	0.04
<b>Total Oil+Cond+NGLs</b>	<b>60.30</b>	<b>128.00</b>	<b>187.01</b>		<b>17.63</b>	<b>34.19</b>	<b>50.62</b>
<b>Gas (Bscf)</b>							
Bacchus	-	-	-	30.00%	-	-	-
Bittern	5.50	6.46	9.65	2.42%	0.13	0.16	0.23
Catcher	0.37	2.64	7.27	40.00%	0.15	1.05	2.91
Columbus	5.28	14.56	23.47	25.00%	1.32	3.64	5.87
Enoch	-	-	-	9.70%	-	-	-
Kraken	-	-	-	29.50%	-	-	-
Scolty Crathes	0.10	0.18	0.22	50.00%	0.05	0.09	0.11
Scott	0.45	8.68	15.12	21.83%	0.10	1.90	3.30
Telford	0.04	0.68	1.79	1.59%	0.00	0.01	0.03
<b>Total Gas</b>	<b>11.75</b>	<b>33.20</b>	<b>57.53</b>		<b>1.75</b>	<b>6.85</b>	<b>12.45</b>
<b>BOE (MMboe)</b>							
Bacchus	0.43	0.89	2.02	30.00%	0.13	0.27	0.61
Bittern	10.90	23.01	31.29	2.42%	0.26	0.56	0.76
Catcher	27.68	39.66	57.65	40.00%	11.07	15.86	23.06
Columbus	1.25	3.43	5.53	25.00%	0.31	0.86	1.38
Enoch	0.14	0.19	0.27	9.70%	0.01	0.02	0.03
Kraken	15.14	40.77	64.78	29.50%	4.47	12.03	19.11
Scolty Crathes	1.25	2.21	2.59	50.00%	0.62	1.10	1.29
Scott	4.73	21.06	29.35	21.83%	1.03	4.60	6.41
Telford	0.76	2.30	3.13	1.59%	0.01	0.04	0.05
<b>Total BOE</b>	<b>62.26</b>	<b>133.53</b>	<b>196.60</b>		<b>17.92</b>	<b>35.33</b>	<b>52.69</b>

## Notes

1. Company Net Entitlement Reserves (Net in the table) are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. boe conversion based on 6 Mscf = 1 boe
3. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
4. The table does not include the Alba field, to which Reserves are not attributed
5. Working Interests are rounded, all decimals are reported in Table 1.1

## Reserves Evaluation and CoP Dates

ERCE has carried out an economic evaluation of the Reserves in each field using ERCE forecast commodity prices dated 1 January 2025 (Table 1.5 and Table 1.6). Table 1.7 presents the before tax Net Present Values (“NPV”) as of 31 December 2024; the NPVs are net to Waldorf, they are presented in millions of UK £ at a 10% discount rate and are broken down by asset and Reserves category. At Waldorf’s request the NPVs have been reported on a pre-tax basis as required by the intended users of the report. It should however be noted that the commerciality of the Undeveloped Reserves was tested on an after-tax basis as required under PRMS. The CoP dates associated with the Reserves and NPVs are presented in Table 1.8.

**Table 1.5: ERCE Brent Crude Oil Price Forecast as of 1 January 2025**

ERCE (Base Case) Brent Assumptions (\$/bbl)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Real (Constant \$, 2025)	76	74	75	75	75	75	75	75	75	75	75
Nominal (\$ of the day)	76	76	78	80	81	83	85	86	88	90	+2.0% pa

**Table 1.6: ERCE UK NBP Natural Gas Price Forecast as of 1 January 2025**

ERCE (Base Case) NBP Gas Price Assumptions (p/therm)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Real (Constant, 2025)	102	86	79	80	80	80	80	80	80	80	80
Nominal (\$ of the day)	102	87	83	85	86	88	90	91	93	95	+2.0% pa

**Table 1.7: Before Tax Net Present Values of the Reserves as of 31 December 2024**

Asset	Before Tax Net Present Value at 10% discount rate (£MM)								
	Developed Reserves			Undeveloped Reserves			Total Reserves		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Bacchus	-7.3	-2.9	3.5	0.0	0.0	0.0	-7.3	-2.9	3.5
Bittern	1.7	8.1	13.3	0.1	1.61	3.21	1.8	9.7	16.5
Catcher	42.3	139.0	268.6	0.0	0.0	0.0	42.3	139.0	268.6
Columbus	2.6	16.1	26.6	0.0	0.0	0.0	2.6	16.1	26.6
Enoch	-1.5	-1.3	-1.2	0.0	0.0	0.0	-1.5	-1.3	-1.2
Kraken	-2.8	51.3	187.8	0.0	0.0	0.0	-2.8	51.3	187.8
Scolty Crathes	-7.7	0.5	7.8	0.0	0.0	0.0	-7.7	0.5	7.8
Scott	-105.8	-85.2	-61.1	-3.6	43.2	104.6	-109.4	-42.0	43.5
Telford	-1.9	-1.8	-1.6	0.2	0.6	0.9	-1.7	-1.1	-0.7
<b>Total</b>	<b>-80.3</b>	<b>123.7</b>	<b>443.9</b>	<b>-3.3</b>	<b>45.4</b>	<b>108.6</b>	<b>-83.6</b>	<b>169.1</b>	<b>552.5</b>

### Notes

1. The values exclude corporate overheads
2. The NPVs do not necessarily represent fair market value
3. Undeveloped NPVs include undeveloped projects in Bittern and Scott/Telford which are subeconomic in the low case, with no Reserves attributed at 1P level of confidence
4. All costs, including future Abandonment, Decommissioning, and Restoration liabilities, are included in the projects economic analysis

**Table 1.8: Cessation of Production Dates**

Asset	Date of Cessation of Production (period ending)					
	Developed			Developed + Undeveloped		
	1P	2P	3P	1P	2P	3P
Bacchus	2027	2029	2029	2027	2029	2029
Bittern	2032	2035	2035	2032	2035	2035
Catcher	2030	2032	2035	2030	2032	2035
Columbus	2028	2033	2036	2028	2033	2036
Enoch	2026	2026	2026	2026	2026	2026
Kraken	2028	2037	2042	2028	2037	2042
Scolty Crathes	2026	2027	2027	2026	2027	2027
Scott	2026	2026	2026	2026	2029	2029
Telford	2026	2026	2026	2026	2029	2029

## 2. Introduction

Waldorf has non-operated interests in several oil and gas fields within the UKCS. The interests in the Alba, Bacchus, Bittern, Columbus and Enoch fields were obtained through the acquisition of Endeavour Energy UK Limited in 2019. In 2021 Waldorf acquired Cairn Energy plc's non-operated interests in the Catcher Area and the Kraken field. In 2022 Waldorf acquired the entire UK business of MOL Group which included non-operated interests in the Catcher Area, in the Scolty and Crathes fields and the Scott and Telford licences. The location of the various fields is presented in Figure 2.1.

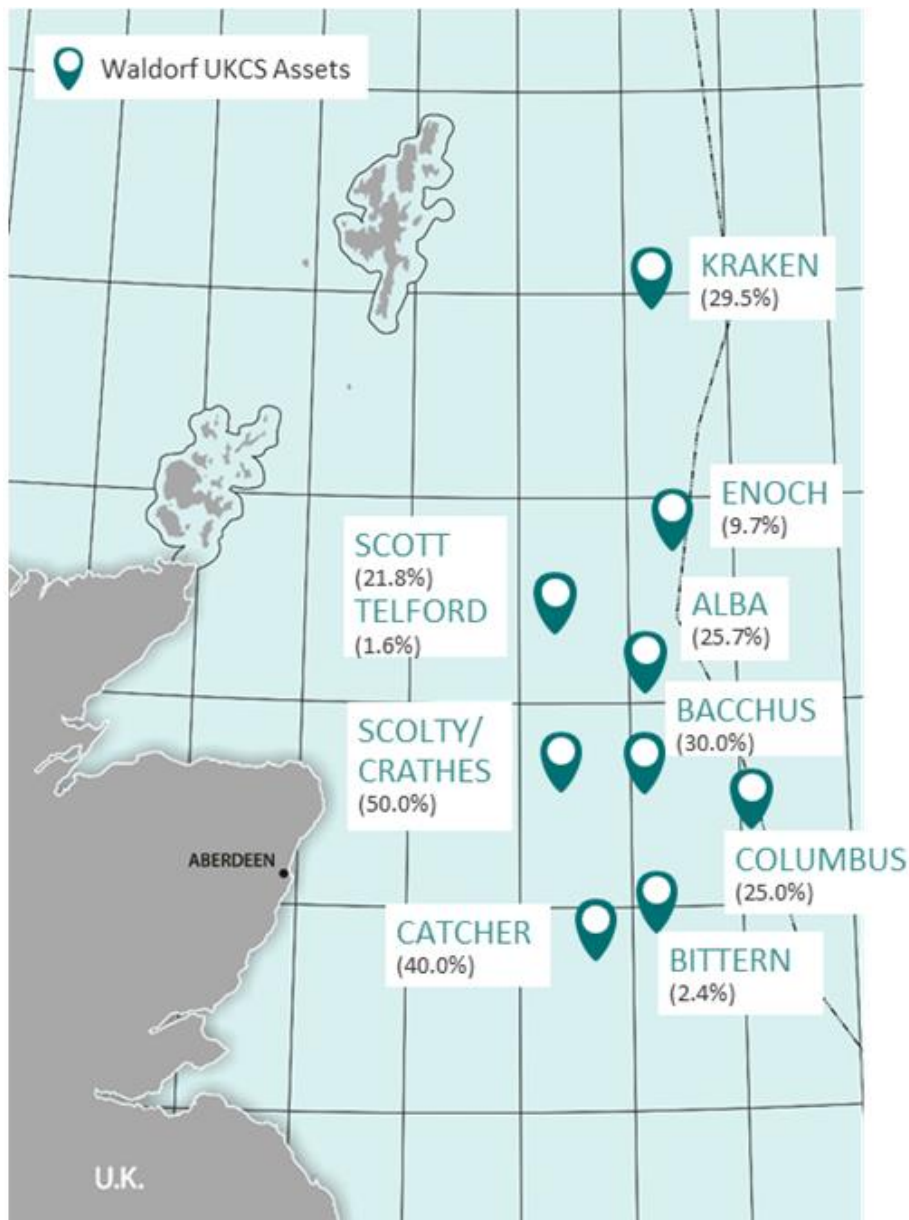


Figure 2.1: Waldorf Fields Location Map  
(Source: Waldorf)

## 2.1. Data Provided

ERCE has relied upon data and information made available by Waldorf. These data comprise details of Waldorf's licence interests, seismic data, basic exploration and engineering data (including well logs, core, PVT and test data), technical reports, interpreted data (including reservoir simulation studies), work programmes and budgets ("WP&B"), production and injection data and the field development plans. ERCE has reviewed data made available through to 31 December 2024.

For all fields production and injection data were provided allocated back to the well/reservoir level and made available up to 31 December 2024. Additional information became available after the Effective Date of this Report. This includes Scott field production performance after the January 2025 restart (three weeks of daily production data), public announcement on the ruling of the Scottish Court of Session on the Jackdaw field (future tie-back sharing facilities with the Columbus field), Kraken field Operator Life of Field estimates and Bittern field performance in Q1 2025. ERCE accounted for this information in its evaluation; for the Scott field, initial forecast rates have been adjusted to account for actuals; following the decision on the Jackdaw field, ERCE has delayed its assumed tieback date to Shearwater, with an impact on cost-sharing for the Columbus field; for the Kraken field, ERCE has aligned its assumption on the FPSO vessel purchase date to the Operator's plan; for the Bittern field, initial forecast rates have been adjusted to account for the actual January production followed by an outage reported in February and March: production is due to restart in May 2025, and this is reflected in ERCE's forecasts.

Waldorf has provided written representations that no new data or information have been acquired between the Effective Date and the publication date of the report, other than that disclosed above, that would materially affect the opinions expressed in this Report.

## 2.2. Work Completed

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data.

For the evaluation of the resources, ERCE has used the PRMS definitions of "Estimated Ultimate Recovery" and "Technically Recoverable Resources" ("EUR" and "TRR", respectively) for which the definitions can be found in Appendix 1. In this CPR, the term EUR refers to "Technical EUR" or "EUR<sub>tech</sub>" in accordance with the Guidelines for Application of the Petroleum Resources Management System, REVISED July 2022.

For most of the fields, ERCE has estimated Reserves and their associated uncertainty, by using production performance analysis, type curves from analogue wells, presentation material and where available reservoir simulation models undertaken by Waldorf and/or the

Operator. Where appropriate, the Operators' best estimates of Petroleum Initially in Place ("PIIP") have been compared to the Reserves estimates to provide relative context.

In the case of some future infill projects, ERCE has also used volumetric methods. This involved determining the range of PIIP and preparing estimates of recovery factors based on consideration of the results of production performance analysis, reservoir simulation models, classical reservoir engineering calculations and the performances of analogue fields.

Production profiles have been generated by ERCE for the Reserves cases (Developed, and Developed plus Undeveloped). The forecasts generated for Reserves have then been used as input to an economic model to undertake an Economic Limit Test ("ELT") and define the CoP date. The Reserves are the point forward volumes of oil and gas produced up to the CoP date. Reserves are presented on a property gross and net entitlement basis; as there are no royalties payable to others in the UK, the net entitlement Reserves are equivalent to the working interest share of the property gross Reserves.

The NSTA published on 27 March 2024 the OGA Plan on emissions reduction. The Plan sets out the NSTA's requirements for how relevant persons can meet certain obligations for Green House Gas ("GHG") emissions reductions from oil and gas extraction. The requirements include, amongst others, 'Zero Routine Flaring' by 2030. ERCE understands that continuing production past 31 December 2029 will require, for some fields, investments to make facilities compliant with post-2030 regulations, typically to implement flare gas recovery unit ("FGRU") projects. In the calculation of Reserves, for the fields requiring these investments, ERCE has applied a commercial cutoff at the end of 2029 where no information has been provided about facilities' life extension projects or in the absence of committed plans to achieve zero routing flaring from 2030.

ERCE has evaluated the development plans for the various assets. For each field, ERCE has reviewed forecasts of capital, operating and abandonment costs from Waldorf and/or the Operator. The costs were reviewed and benchmarked against ERCE's internal database to ensure they were reasonable. Where possible these estimates are compared to historical, actual costs. ERCE has used its own cost estimates where these differ significantly from those provided.

ERCE includes in its Reserves assessment carbon pricing, a mechanism which captures the external costs of greenhouse gas ("GHG") emissions and ties them to their sources (hydrocarbon assets) through a price. In the UK, oil and gas fields are subject to a carbon price through an emissions trading system ("ETS"), namely the UK Emissions Trading System ("UK-ETS"). These costs are included, under PRMS, in the evaluation of projects' economics and commerciality. For all assets in Waldorf's portfolio, ERCE has prepared technical forecasts of the amounts of CO<sub>2</sub> equivalent, covered under UK ETS, expected to be released during hydrocarbon exploitation operations, based on the current operational strategies, development plans, fuel forecast and historical emissions forecasts. The future costs incurred as a result of the emissions are estimated by applying a CO<sub>2</sub> price forecast (UK Allowance

“UKA”, Section 12.1) prepared by ERCE. The costs, throughout the Report, are either made explicit as ETS costs or rolled in the various estimates of future OPEX.

The economic model has been built by ERCE and, as well as determining the ELTs, was used to determine the before-tax and after-tax NPVs of the Reserves. To be considered commercial (a pre-requisite for assigning Undeveloped Reserves) ERCE uses the criteria that the best estimate (2P) after tax NPV should be positive at a discount rate of 10 percent (“NPV10”). Commodity prices were based on ERCE’s 1 January 2025 price forecasts adjusted where appropriate, in line with historical price differentials provided by Waldorf.

### 3. Bacchus Field

The Bacchus field is located in the Central North Sea area of the UKCS approximately 190 km northeast of Aberdeen, in License Block 22/6a. Waldorf holds a 30% non-operated interest. Apache North Sea Ltd is the Operator with a 50% interest, Neo Energy Central North Sea Ltd holds the balance.

The field was discovered in 2005 by Well 22/6a-14. The field contains light oil within the sands of the Jurassic, Fulmar Formation. A summary of some key field data is presented in Table 3.1.

The field has been developed through three subsea wells tied back to the Forties Alpha platform and crude is evacuated via FPS. A top structure map showing the location of the wells is shown in Figure 3.1.

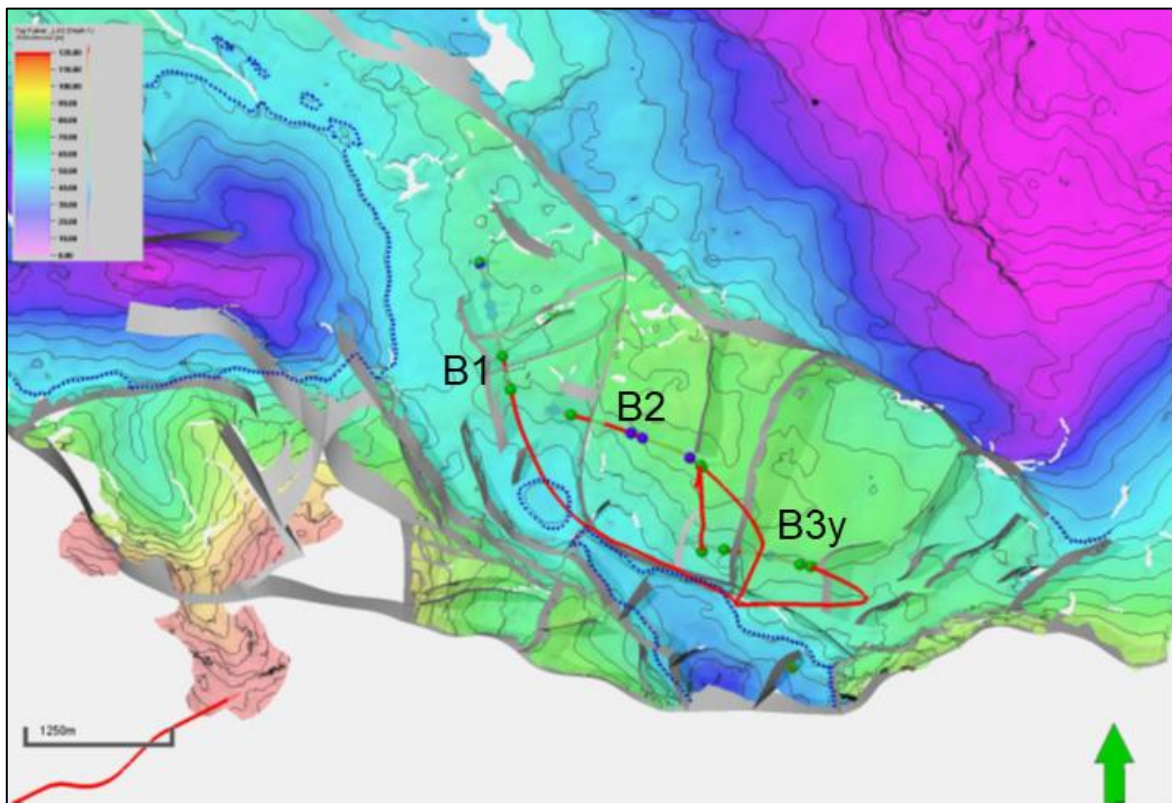


Figure 3.1: Bacchus Field Structure Map  
(Source: Waldorf)

Table 3.1: Bacchus Field Summary Data

Field	Reservoir	Depth (m TVDSS)	Trap	Fluids	Initial Res. Pressure (psia)	Solution GOR (scf/stb)	NTG	Por (%)	Perm (mD)
Bacchus	Fulmar	3,750	Strati-graphic	Oil 35°API	9,409	320	55%	25%	200

The field started production in April 2012 through Well B3Y, followed three months later by Well B2. A year later Well B1 came into production in July 2013. After producing 1.5 MMstb Well B3Y was converted into a water injector to provide pressure support to the other two producers. Well artificial lift is provided via gas lift. Since 2018 only Well B2 was continuously online until June 2022, when a rapid fall in oil rate was observed. Subsequent investigations have not led to a definitive identification of the root cause of the high-density emulsion, stabilised by asphaltene or wax, produced with light crude. Since October 2022 the well has been producing at reduced controlled rates at the wellhead. However, there has been a notable increase in water cut since August 2023, resulting in a more rapid decline. Following the 2024 TAR, an improvement in well performance was observed, with higher production rates measured through the end of year. However, the Operator has yet to identify the underlying cause of the changes in deliverability. At the end of December 2024, the well produced an average oil rate of 1,150 stb/d with a 25% water cut (Figure 3.2). As of 31 December 2024, the field produced 17.5 MMstb of oil.

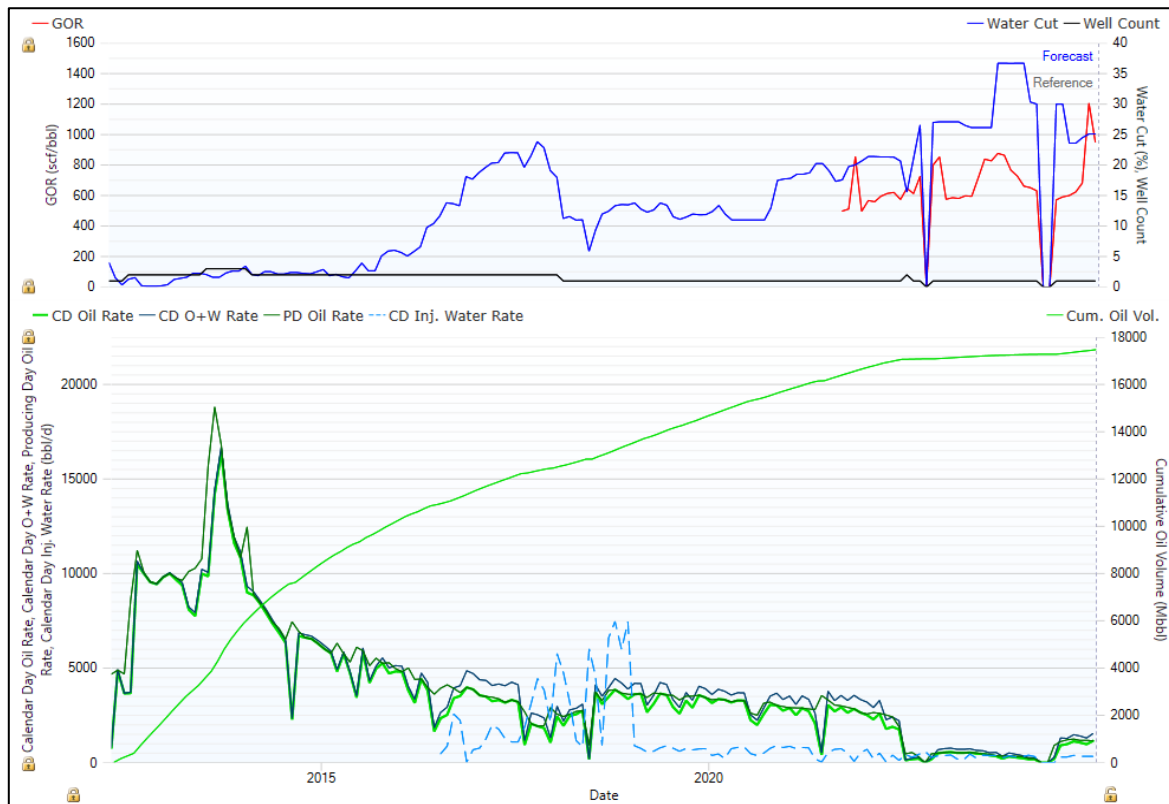


Figure 3.2: Bacchus Field Production and Injection History

### 3.1. Development Plans

There are no further plans for development drilling.

### 3.2. Estimated Ultimate Recovery

Bacchus is a relatively mature field with recovery dependent on the remaining resources associated with Well B2. ERCE has used oil rate trends to predict future production performance. Since August 2023, the water cut spiked from 27% to 37%, leading to a rapid

decline at well B2, with a similar behaviour observed in Well B1 when the main waterfront in the reservoir reached the well. Since May 2024, well productivity has increased post-TAR, reducing water cut and increasing the oil rate. In addition, there is uncertainty about the properties of the fluid (crude and emulsion) produced at the wellhead, which may impair well productivity.

ERCE production forecasts were extrapolated with a decline curve analysis (“DCA”) approach. At best level of confidence, the well is expected to decline in line with the H2 2024 trend. Uncertainty in future performance is related to the deliverability degradation/improvement observed in recent history, typically after TAR shutdowns. In the low and high cases, respectively, ERCE assumes a production degradation and improvement after the next 2025 TAR, to reflect similar water breakthrough behaviour observed in Well B1 (low case) or a return to the 2022 well performance (high case).

Production forecasts were adjusted to account for production efficiency to generate technical production forecasts and derive the EUR. Based on historical production performance and the TAR schedule, ERCE assumes an operating efficiency baseline of 83.9 %, which is decreased by an additional 21 days for TARs every second year. The total (Developed plus Undeveloped) EUR is presented in Table 3.2. EUR estimates are reported to the end of 2029, the commercial cut-off date used for CoP. Waldorf has confirmed that there are no plans to produce beyond this date, in line with the Operator’s announcement in the public domain<sup>1</sup>.

**Table 3.2: Bacchus Field EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP <sup>1</sup>	Cum. Prod. at 31 Dec. 2024	RF to date	EUR to end 2029			EUR best est. RF
					Low	Best	High	
Bacchus	Oil (MMstb)	100	17.5	17.5%	17.9	18.3	19.5	18.3%
	Gas (Bscf)	32	0.7	2.3%	1.0	1.3	2.1	4.1%

Notes

1. PIIP is uncertain but there appears to be around 100 MMstb (connected to the wells) in the Operator simulation model, which is supported by ERCE’s material balance work
2. Gas production data are reported for completeness only, as no gas is sold

### 3.3. Cost Assumptions

#### 3.3.1. CAPEX Assumptions

There are no future CAPEX costs associated with the Bacchus field.

<sup>1</sup> <https://www.energyvoice.com/oilandgas/north-sea/562622/apache-to-cease-north-sea-production-by-2030-due-to-windfall-tax/>

### 3.3.2. OPEX Assumptions

ERCE has been provided with partner meeting presentations, actual expenditures, and 2025 work programme and budgets. Based on historical cost actuals, ERCE carries a long-run fixed OPEX forecast of GBP 0.4 MM p.a., Gross Real 2025.

Variable OPEX and cost sharing with the Forties field have been calculated in line with budgeted estimates and ERCE’s independent assumptions for future throughput for life of field. Total forecast OPEX ranges from GBP 4.2 MM – GBP 7.1 MM (Gross Real 2025) at the 2P level.

### 3.3.3. Abandonment Assumptions

ERCE carries total abandonment costs for the decommissioning of facilities and plugging and abandonment of wells of GBP 43.4 MM for the Bacchus field. ERCE understands that some level of derogation is expected, allowing certain infrastructure to be cleaned and left in-situ rather than fully removed.

ERCE has reviewed the phasing of ABEX provided by Waldorf and considers it to be appropriate for the decommissioning of an asset of this type.

## 3.4. Reserves

The technical production profiles described in Section 3.1 were converted to sales profiles. The oil sales were based on the wellhead volumes exported, adjusted by a factor of 0.995 bbl/bbl (FPS blend adjustment, based on 2024 sales information provided by Waldorf). No gas is sold. A small amount of Natural Gas Liquids (“NGL”) is recovered from the stabilised crude at the Kinneil processing facility and sold separately. The average yield advised by Waldorf is 0.005 boe (of NGL) per bbl of export oil and this has been used by ERCE for estimating future NGLs. Reserves include a backout reconciliation from 2020-2022 of 118 Mstb of oil in favour of Bacchus from Forties until the end of 2025.

Reserves were estimated to the earlier of the economic cut-off date or the end of the technical profiles. The Operator has publicly announced the intention to stop its North Sea production by the end of 2029, and Waldorf has advised that there are no plans to produce beyond 31 December 2029. ERCE has retained this date as the latest technical CoP.

A summary of the gross Reserves is presented in Table 3.3 together with CoP dates.

**Table 3.3: Bacchus Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Bacchus	Developed	0.43	0.89	2.02	0.00	0.00	0.00
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvdp+Undvdp)	<b>0.43</b>	<b>0.89</b>	<b>2.02</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>
	COP (Total)	2027	2029	2029	2027	2029	2029

## 4. Bittern Field

The Bittern field lies in Blocks 29/1a and 29/1b, in the Central North Sea area of the UKCS approximately 180 km east of Aberdeen. The field lies within Licenses P233 and P361 and has been unitised. Serica has the largest unitised interest holding 64.6% but the field is operated by Dana Petroleum with a 33% interest, also operator of the Triton FPSO. Waldorf holds the remaining 2.422% unitised interest.

The field was discovered in 1996 by Well 29/1b-5 and appraised by three further wells in 1996 and 1997. The field development plan was issued in 1997 based on a six-well subsea development tied back to the Triton FPSO. Oil production commenced in April 2000 from Wells B1, B2, A2 and A3, supported by water injection in Wells A1 and B3. Well B4Z was drilled in 2006 as a crestal infill well and was side-tracked to Well B4Y in 2010. Well A3 was then side-tracked to A3Z in 2011. Well B5 was drilled as a crestal infill well in 2020 utilising Well B2 as a donor. Well B6 was drilled in 2024 utilising Well B1 as a donor.

Structurally, the field is a 4-way dip closed gas cap over an oil rim (Figure 4.1). An oil water contact (“OWC”) is observed in the wells at 2,103 ± 1.5 m TVDSS and a gas oil contact (“GOC”) at 2,052 ± 3 m TVDSS. Some key field data are summarised in Table 4.1.

**Table 4.1: Bittern Field Summary Data**

Field	Reservoir	Depth (mTVDSS)	Trap	Fluids	Initial Res. Pressure (psia)	Oil Column (m)	Solution GOR (scf/stb)	Oil in situ Visc. (cP)	NTG (%)	Por. (%)	Perm (mD)
Bittern	Rogaland & Forties	2,100	Structural	Oil (39°API) with gas cap	3,120	51	1,000	0.34	85%	33%	1,000

The production and injection history of the field is presented in Figure 4.2. In Q4 2024, facilities experienced outages, and production was offline from mid-October before resuming on 27th December 2024. At the time of writing, ERCE has been informed that the field produced for most of January 2025 but has been shut in since 29th January due to an integrity issue on the Triton FPSO. Production is due to restart in May.

At the end of December 2024, the well was producing at an average oil rate of 869 stb/d (and a six-months average of 1,900 stb/d). Cumulative production to 31 December 2024 was 162.7 MMstb of oil and 152.2 Bscf of gas.

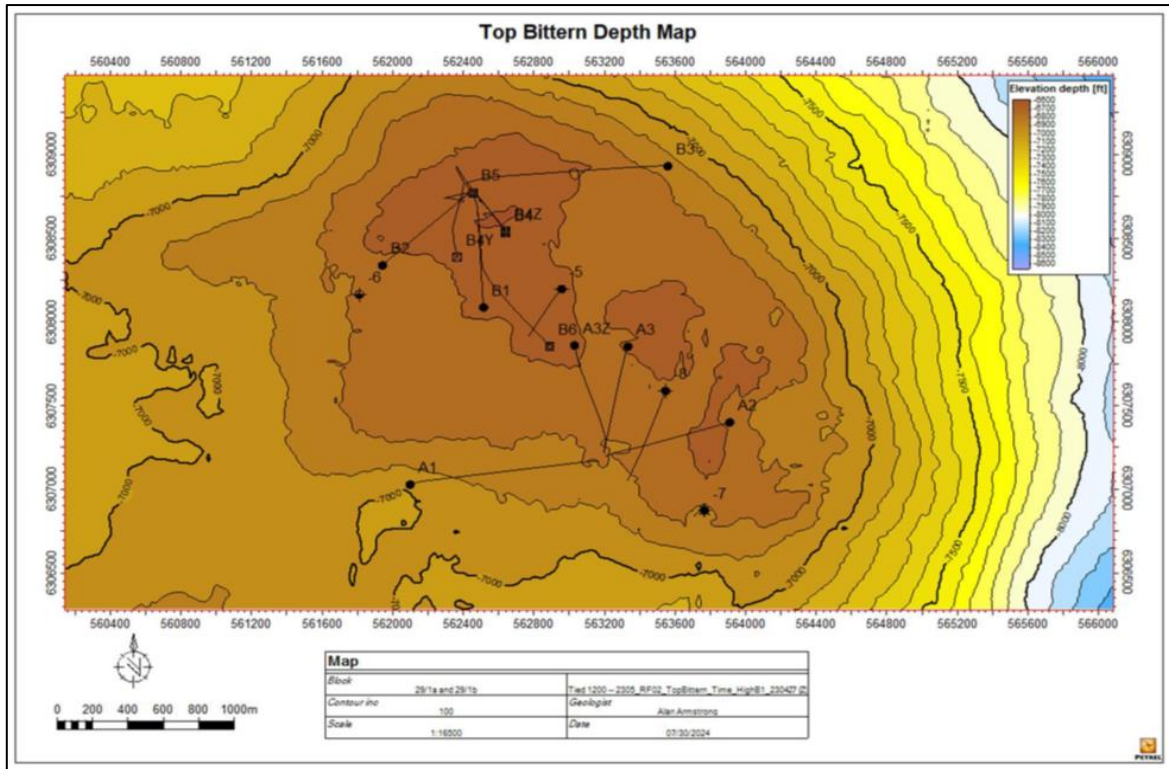


Figure 4.1: Bittern Top Reservoir Depth Structure  
(Source: Waldorf)

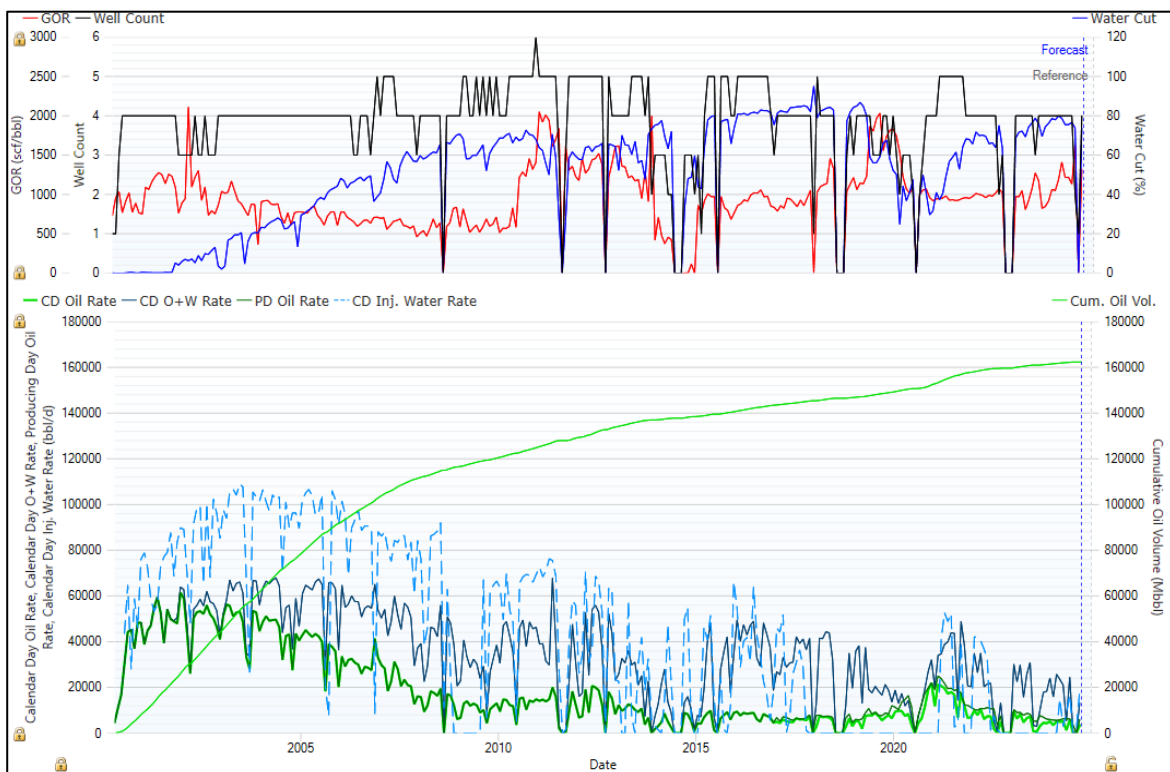


Figure 4.2: Bittern Field Production and Injection History

### 4.1. Development Plans

Bittern had minimal water injection during 2024 due to issues with topsides equipment. Water injection pipeline replacement project is due for Q4 2025 execution. The operator has used a dynamic model to determine the oil recovery increment associated to the water injection resumption. ERCE attributes Undeveloped Reserves to the incremental resources recoverable through this project.

### 4.2. Estimated Ultimate Recovery

The Developed Producing EUR has been derived using the Partners’ history-matched suite of dynamic models, along with a DCA water-oil ratio (“WOR”) trend, where ranges of outcomes were generated based on different assumptions of future liquid rates. An operating efficiency baseline of 78% (70% in 2025) has been applied to the forecasts, further reduced by an alternating 37-day and 12-day TAR shut in in every other year (resulting average production efficiency of 69.6% over 2025-2031). In 2025 there is a 71-day TAR.

In view of recent extended maintenance shutdowns involving deployment of “walk-to-work” and planned investment in the Triton FPSO, ERCE has assessed technical profiles for the Bittern field to 31 December 2035. This date is considered technically achievable and would be possible through continuous investments (subject to commerciality, as discussed in Section 4.4). There is no known technical reason why the FPSO will not stay on station based on life extension work carried out to date. ERCE has verified that the life extension scope includes, amongst several other flare reduction and emission reduction projects, a specific project to comply with zero-routine flaring. The EUR estimates are therefore reported to the end of 2035 and estimates displayed in Table 4.2.

**Table 4.2: Bittern Field Gross EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP	Cum. Prod. at 31 Dec. 2024	RF to date	EUR to end 2035			EUR best est. RF
					Low	Best	High	
Bittern	Oil (MMstb)	239	162.7	68.1%	175.3	184.2	191.8	77.1%
	Gas (Bscf)	316	152.2	48.2%	163.5	171.4	176.7	54.2%

Notes

1. Oil PIIP based on a recent JV static model.
2. Gas PIIP based on an initial gas cap of 77 Bscf and solution gas of 239 Bscf

### 4.3. Cost Assumptions

#### 4.3.1. CAPEX Assumptions

ERCE has been provided with the Operator’s 2025 work programme and budgets and life-of-field forecasts along with Technical and Operating committee meeting slides.

ERCE has reviewed the CAPEX estimate of GBP 38 MM (Gross Real 2025) for the replacement of the Bittern water injection pipeline in 2025 and found it reasonable.

ERCE has assumed CAPEX of GBP 2.2 MM (Gross, Real 2024) per annum from 2026-2028 to account for sustaining facilities maintenance work required for Bittern subsea facilities, based on historical spending.

The CAPEX sharing costs carried by ERCE are based on the Triton LoF estimates. Costs have been allocated in line with the contractual rules that govern how the CAPEX share is allocated between participating fields. ERCE has previously taken an independent view of the level of expenditure that would be required to sustain the Triton FPSO to 2035, which aligns closely with the latest LoF forecasts. The operator's LoF forecasts have therefore been accepted.

#### **4.3.2. OPEX Assumptions**

ERCE has aligned with the Operator's view of the 2025 budgeted OPEX estimates, consisting of firm and OPEX sharing costs. The firm costs include, but are not limited to, logistics, HSE, chemicals, well engineering, subsurface & subsea OPEX, engineering modifications, G&A and overheads.

The OPEX sharing is based on the Operator's LoF Triton FPSO gross OPEX estimates, to which costs have been allocated to Bittern in line with ERCE's production as a percentage throughput of the Triton FPSO in line with contractual agreements. The forecast of throughput from other fields was provided by Waldorf, and reviewed against published NSTA actuals by ERCE. ERCE has taken an independent view of the OPEX required to maintain operations to 2035, which aligns closely with the operator's latest LoF forecasts. The operator's LoF forecasts have therefore been retained. The overall OPEX ranges from GBP 31 MM – GBP 51 MM per year (Gross, Real 2025) at the 2P level of confidence.

#### **4.3.3. Abandonment Assumptions**

ERCE carries total abandonment costs for the share of decommissioning of facilities and plugging and abandonment of wells of GBP 205 MM for the Bittern field.

ERCE has reviewed the phasing of ABEX provided by Waldorf, and considers it to be appropriate for the decommissioning of an asset of this type.

#### **4.4. Reserves**

The technical production profiles described in Section 4.2 were converted to sales profiles.

The oil sales were based on the wellhead volumes exported and adjusted by a factor of 1.021 bbl/bbl (based on sales information provided by Waldorf). Wellhead gas is reduced by Bittern's share of fuel and flare consumption at the Triton FPSO, estimated by ERCE at up to 5 MMscf/d on the basis of Triton hub throughput and fuel gas allocation arrangements. Gas is then

exported via the SEGAL pipeline and sold (sales gas) with an adjustment factor of 1.081 MMscf/MMscf (advised by Waldorf).

Reserves were estimated to the earlier of the economic cut-off dates or the end of the technical profiles; for Bittern this is dictated by the estimated life of the Triton FPSO to 2035, based on the current estimated life span study of the FPSO vessel. The Developed Reserves were based on the existing well stock, the Undeveloped Reserves include the execution of the water injection pipeline replacement. ERCE attributes Undeveloped Reserves at 2P and 3P levels of confidence only, after Determination of Commerciality under PRMS.

A summary of the gross Reserves is presented in Table 4.3 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

**Table 4.3: Bittern Field Gross Reserves with CoP dates**

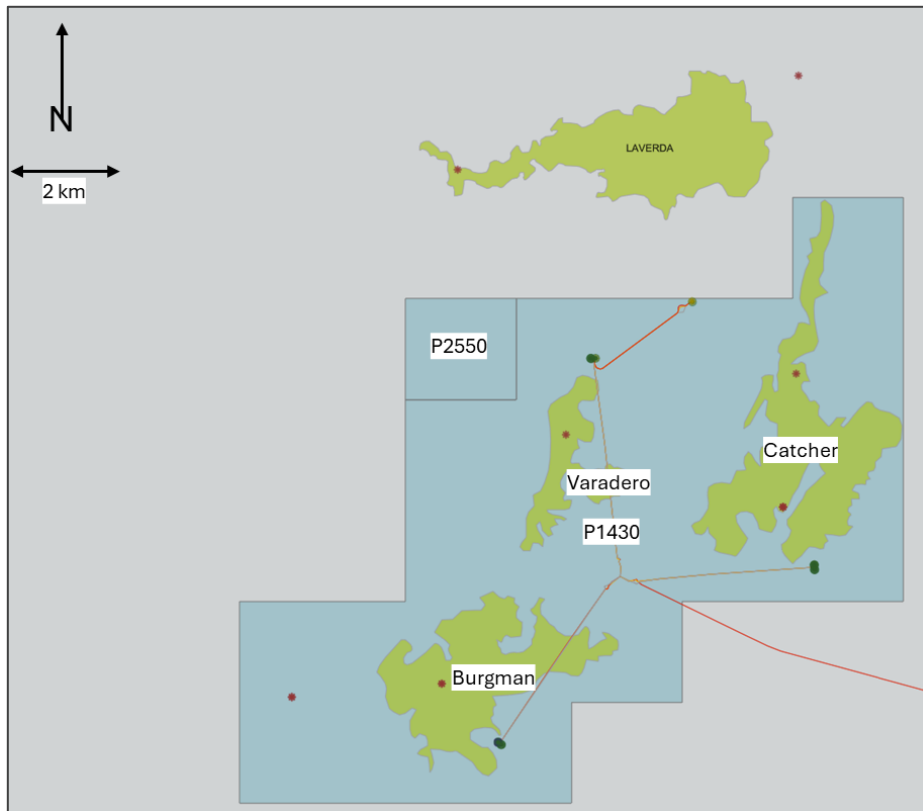
Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Bittern	Developed	9.98	18.07	23.85	5.50	9.10	14.26
	Undeveloped	0.00	3.86	5.83	0.00	-2.65	-4.60
	Total (Dvdp+Undvdp)	<b>9.98</b>	<b>21.93</b>	<b>29.68</b>	<b>5.50</b>	<b>6.46</b>	<b>9.65</b>
	COP (Total)	2032	2035	2035	2032	2035	2035

Notes

1. The undeveloped project to reinstate water injection causes a reduction of produced gas volumes

## 5. Catcher Area

The Catcher, Varadero and Burgman fields (collectively the Catcher Area) lie within Licence P1430 (Block 28/9a) and were discovered in 2010. The licence is situated to the west of the Central Graben within the UKCS (Figure 5.1) around 170 km southeast of Aberdeen. Water depths are less than 100 m. Waldorf holds a 40% non-operated interest. Harbour Energy operates the licence with a 50% interest, One-Dyas UK Ltd. holds the balance (10%) of the ownership in the JV.



**Figure 5.1: Overview of Licenced Blocks, Catcher Area**

Catcher JV holds P1430 (Catcher, Varadero and Burgman fields) and P2550 (Rapide prospect)

Source: NSTA Offshore Activities

A summary of some key field data is presented in Table 5.1.

**Table 5.1: Catcher Area Summary Data**

Field	Reservoir	Depth (m TVDSS)	Trap	Fluids	Initial Reservoir Pressure (psia)	Bubble Pt. Pressure (psia)	Initial GOR (scf/stb)	Insitu Oil Viscosity (cP)	Avg. Por.	Perm. (mD)
Catcher	Cromarty, Tay	1,360	Struc. / Strat.	Oil - 31 API	2,069	2,028	294	2	35%	1,000 - 2,000
Varadero	Cromarty, Tay	1,250		Oil - 27 API	1,889	1,865	211	6		
Burgman	Tay	1,150		Oil - 25 API	1,742	1,668	187	12		

The discovered hydrocarbons in the Catcher area lie in structural/stratigraphic traps within Tertiary age Cromarty and Tay Member sandstones of deep marine origin.

Originally deep marine channels and fans were remobilised as fluidised injectites into the shale host rock early in burial history, due to catastrophic dewatering. The injectites form complex reservoir architectures. The large seismically resolvable injectite sills or in-situ sands (“geobodies”) form the main reservoir targets around which networks of smaller seismically unresolvable sands exist. High quality 3D seismic data is available over the licence and rock physics work relating seismic attribute extractions to net pay thickness has been calibrated to the drilling results.

The Catcher development comprises an FPSO production hub with a 60,000 stb/d nominal oil production capacity, processing oil from subsea wells on each field. Oil production is supported by water injection and gas re-injection. Production commenced in December 2017 from the Catcher field. The Varadero and Burgman fields were brought onstream in January and May 2018 respectively. As of 31 December 2024, cumulative oil production from the Catcher Area was 106.2 MMstb (Catcher 56.8 MMstb; Varadero 20.8 MMstb; Burgman 28.6 MMstb) and cumulative wellhead gas production was 42.8 Bscf (Catcher 22.4 Bscf; Varadero 7.8 Bscf; Burgman 12.6 Bscf). Production and injection histories (monthly data) for each field are presented in Figure 5.2, Figure 5.3 and Figure 5.4.

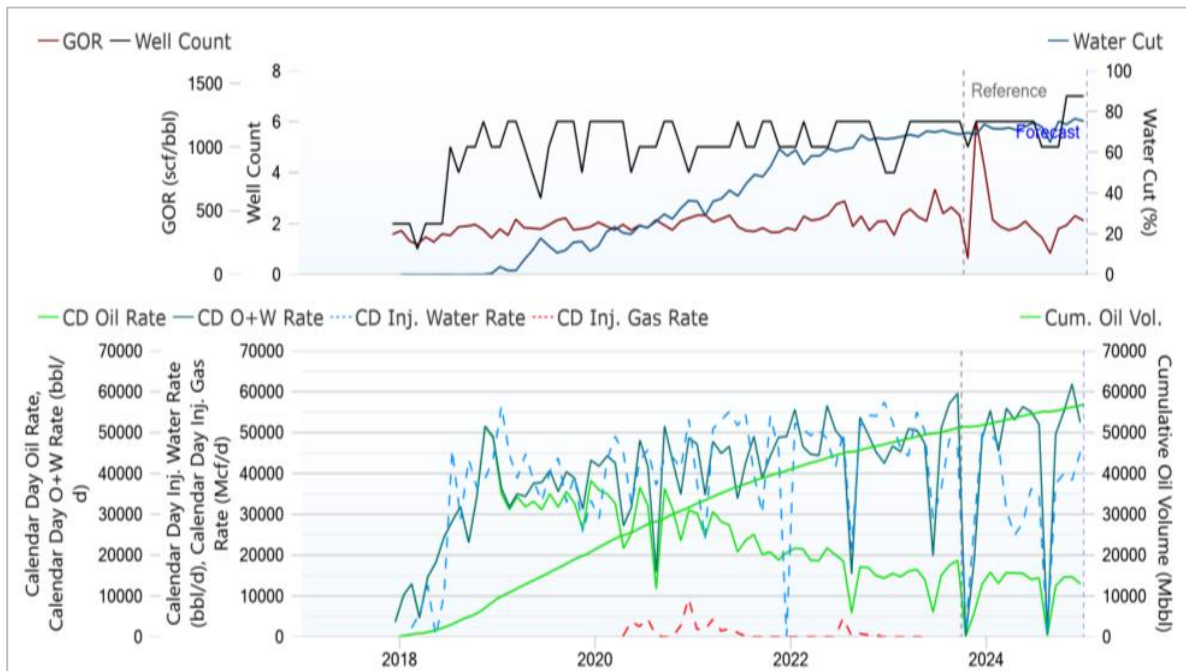


Figure 5.2: Catcher Field Production and Injection History

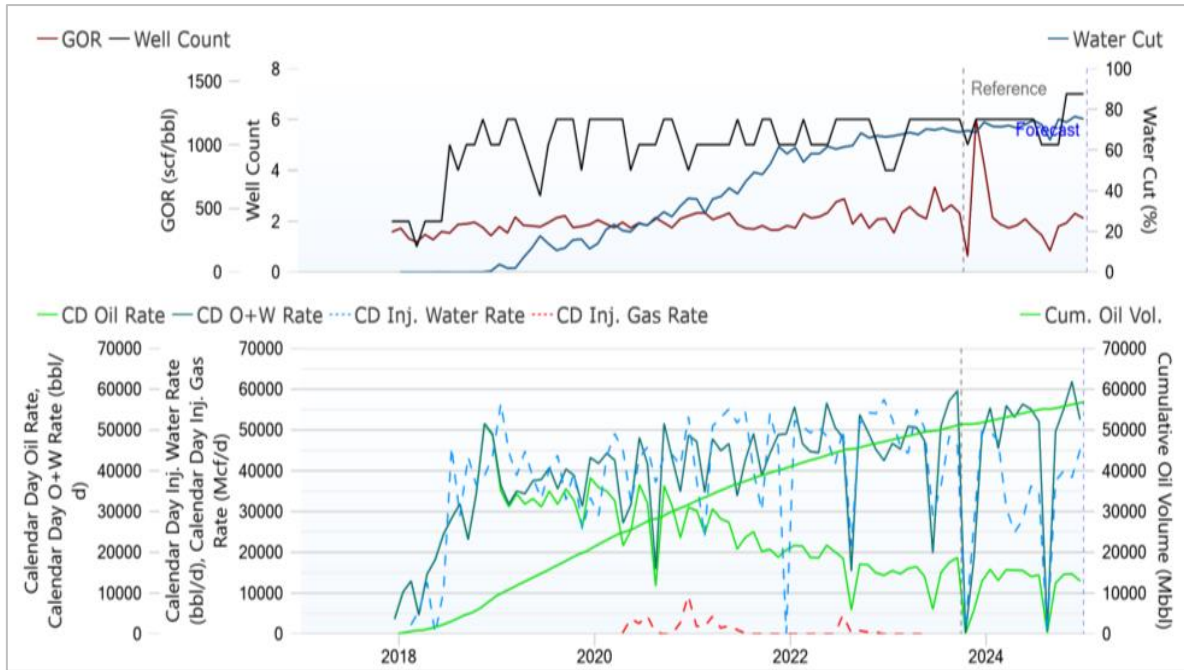


Figure 5.3: Varadero Field Production and Injection History

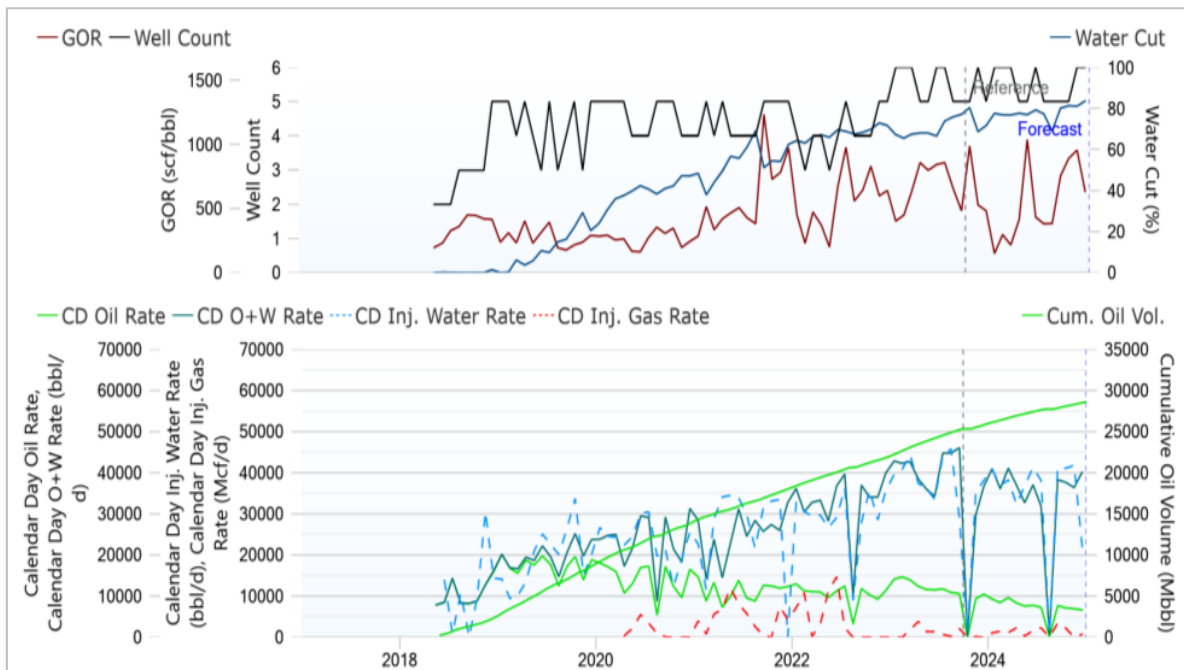


Figure 5.4: Burgman Field Production and Injection History

Prior to 2021 gross liquids handling was 125,000 bbl/d but the FPSO has had some production problems limiting capacity. These include; calcium naphthanate (CaN) deposition experienced between end 2020 and early 2021, and now managed by injection of acetic acid and dispersants; vibrations within the topsides pipework and pressure spikes due to slugging water cut which caused limitation of liquid handling to 110,000 bbl/d during 2021, and were solved in 2022 with topsides works.

Since the start of 2023, the average daily liquid rate has been relatively stable at 125,000 – 135,000 bbl/d, although on occasion rates of around 140,000 bbl/d have been achieved. The primary constraint on production is the gas plant throughput, with too much gas causing export gas compressor alarms and trips.

In 2023 two new wells came on stream, Burgman Far East well (Well BP6) and Catcher North (Well CP7), in January and February 2023 respectively. Well BP6 is less well connected than anticipated and has produced under natural depletion with no water production. Well CP7 initially produced gas but with an increasing oil-gas ratio (“OGR”). The well now appears to be producing as an oil well (a similar behaviour to that observed in Well CP5).

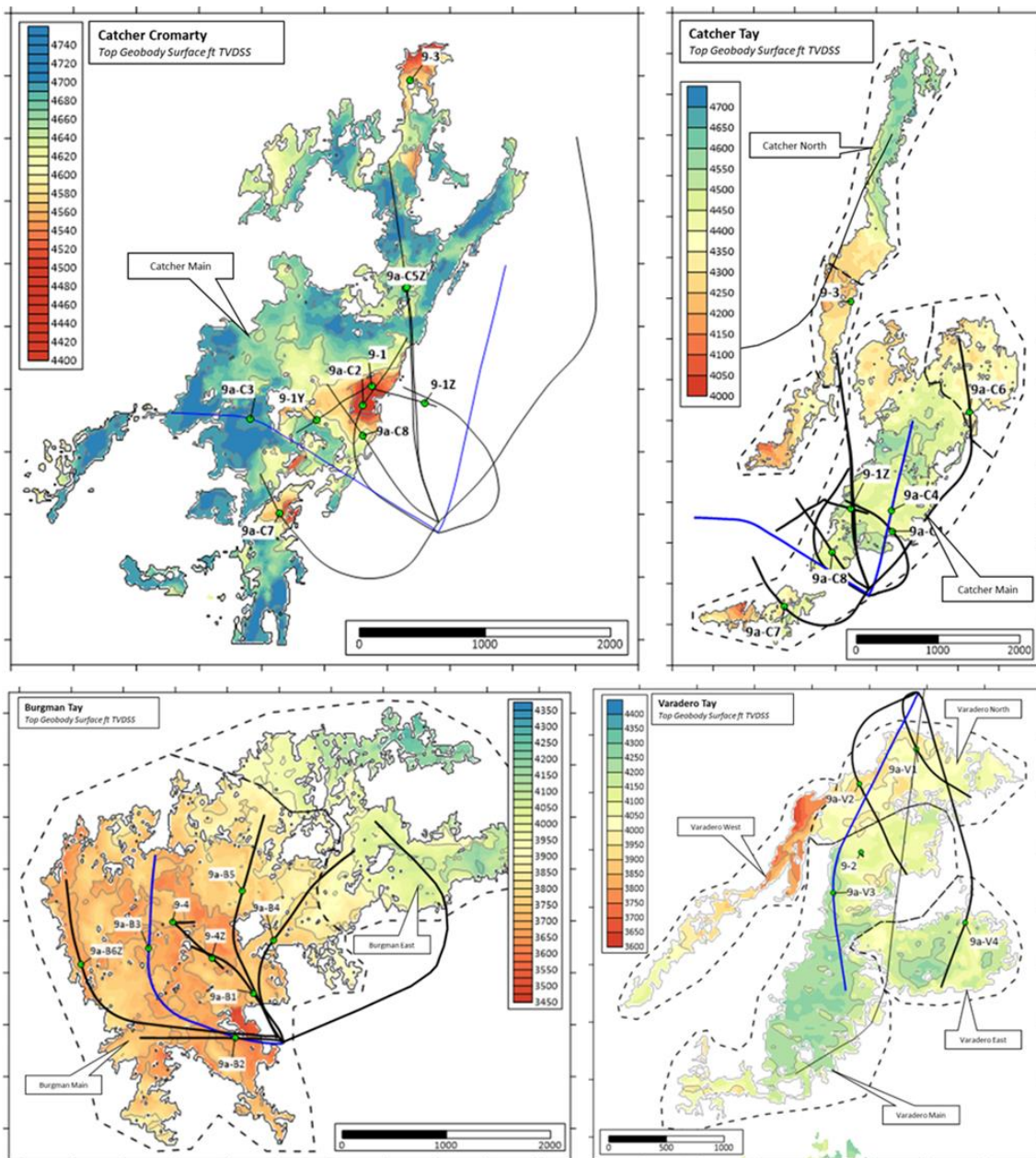
After the 2023 TAR production was affected by a failure of the electrostatic coalescer in the produced water train, with production from high water cut wells temporarily limited until January 2024. Production from Catcher was re-routed to the test separator and from Varadero and Burgman to the 1<sup>st</sup> stage separator. Repairs to the electrostatic coalescer were carried out in the 2024 TAR and it returned to service in October 2024.

## 5.1. Development Plans

As of the Effective Date, 21 development wells have been drilled in the Catcher Area. The locations of exploration and development wells on the Catcher, Varadero and Burgman fields are shown in Figure 5.5. Drilling as part of the original plan of development was completed in 2020 and an additional two development wells (Catcher North and Burgman Far East) were drilled in 2022.

In November 2021, an FDPA received approval from the NSTA. The FDPA outlines improved oil recovery (“IOR”) schemes for the Catcher Area, including relaxing well constraints (“RWC”), gas re-injection and field depressurisation. The implementation of the RWC project has been partially achieved. A maximum daily liquid throughput of 70,677 bbl/d was achieved through the Catcher riser in November 2024, although the average daily liquid rate in 2024 was approximately 54,000 bbl/d.

Gas re-injection has been significantly reduced since Q4 2022, partly due to gas export proving more commercial and partly due to a lack of suitable candidate injection wells. Gas export was unavailable between June and October 2024 due to an issue with one of the gas treatment trains. Over this period, gas was consistently re-injected into the reservoir. Gas re-injection is likely to continue to some degree alongside gas export until the facility becomes fuel gas deficient but is no longer expected to lead to incremental oil production.



**Figure 5.5: Catcher Area Top Cromarty and Tay Depth Structure Maps**

*Blue, black and green lines indicate injector, exploration and production well trajectories respectively*

The field depressurisation project involves dropping the reservoir pressure below bubble point to induce solution gas and gas cap expansion drive. The plan is to implement this by stopping or reducing water injection in a phased approach. Depressurisation is expected to start with the Burgman field, although the timing of the project is dependent on the forecast CoP date, which itself is dependent on production performance and execution of future projects (e.g. further infill wells).

The JV partners approved long-lead item Authorisation for Expenditure (“AFE”)s for two additional wells (targeting the Varadero West and Burgman North areas) in January 2024, and these were expected to be drilled in 2025. However, in March 2024 the Operator

communicated to partners that it had not committed to a rig contract, and in April 2024 that the wells did not meet the required internal economic hurdles. In the absence of a firm plan, no Reserves are attributed to these wells.

## **5.2. Estimated Ultimate Recovery**

EUR estimates in the Catcher Area fields have been derived with a DCA approach, based on a combination of WOR trend extrapolation and oil decline on a well-by-well basis. The DCA also captures uncertainty in the liquid rate of each well and the WOR. A maximum water cut limit of 97.5% is used for each well.

ERCE has assumed a range in liquid handling capacities of 130,000 – 135,000 – 140,000 bbl/d in the Low, Best and High Cases respectively. Individual wells use their potential liquid rate (based on recent performance) for forecasting and the total production forecasts are then constrained to the handling capacities.

Wells BP4 and BP6 are forecast using oil decline. Well CP7 behaved historically as a gas well until 2024, when water breakthrough occurred in January and the GOR of the well continued to decrease (average GOR in November 2024 was 694 scf/stb). The water cut has risen to ~68% by the end of 2024 and the well is now forecast using WOR extrapolations, in line with other wells.

ERCE has assumed that the benefit of the RWC project is now captured in the DCA forecasts for each well. The Operator has not outlined any plans to increase liquid rates further or increase the drawdown of certain wells.

The Operator has communicated that any future gas injection cycles are likely to continue to use only Wells BP2, BP4 and VP2, which are not expected to benefit from gas re-injection. As such, there is no incremental oil TRR associated with future re-injection.

However, a portion of the gas stored by re-injection into these wells is expected to be re-produced at a later date as the FPSO becomes fuel gas deficient. ERCE has assumed that up to July 2025, 50% of available gas will be re-injected and 50% will be exported, and from July 2025 all available gas will be re-injected until the FPSO becomes fuel gas deficient. Once fuel deficiency is reached, ERCE assumes the stored gas is steadily re-produced to delay the need to import fuel gas.

Through the last couple of years, the Operator updated its simulation models (constructed in 2020) to newer static and dynamic historical models (the “2024 vintage” models). As a result of the update the incremental production forecasts associated with the depressurisation project have been reduced (Table 5.2).

**Table 5.2: Summary of Operator Depressurisation Incremental TRR**

		Operator 2020 Models	Operator 2024 Models	Difference (2024 vs 2020)
3 yrs after start	Incremental Oil (MMstb)	2.8	1.3	-56%
	Incremental Gas (Bscf)	11.4	5.6	-51%
End-2036	Incremental Oil (MMstb)	2.8	-4.5	-264%
	Incremental Gas (Bscf)	15.7	13.3	-16%

The Operator’s latest modelling work suggests the depressurisation project will start to have a negative impact on oil production after three years, which highlights the sensitivity of the economic value of the project to its timing relative to the asset’s CoP date. The main value of the project is to increase gas production and therefore avoid or limit fuel gas deficiency.

The 2020 and 2024 modelling works also demonstrate the uncertainty of the outcome of the depressurisation project. ERCE has updated its production forecasts for the project to account for the results of both sets of dynamic models, with more weight given to the 2024 vintage models as these are based on recent production performance and have an improved history match compared to the 2020 models. The start of ERCE’s depressurisation is linked to ERCE’s estimates of the CoP dates without the project. The start dates, incremental production three years after start and at end-2036 are shown in Table 5.3.

**Table 5.3: Summary of ERCE’s YE2024 Depressurisation Incremental TRR**

		ERCE YE2024		
		Low	Best	High
Start Date		Jan-26	Jan-28	Jan-30
3 yrs after start	Incremental Oil (MMstb)	0.8	1.2	2.2
	Incremental Gas (Bscf)	2.1	4.9	9.0
End-2036	Incremental Oil (MMstb)	-2.9	-0.1	2.3
	Incremental Gas (Bscf)	5.3	8.5	12.2

A summary of the oil TRR by project is presented in Table 5.4. ERCE’s gross Developed plus Undeveloped EUR estimates until the end of 2036 (the predicted life of the FPSO) for the Catcher, Varadero and Burgman fields are presented in Table 5.5.

**Table 5.4: Catcher Area oil TRR (to end-2036) Estimates by Project**

Project	Oil TRR (MMstb)		
	Low	Best	High
Catcher NFA	20.1	26.8	31.2
Varadero NFA	7.9	9.4	11.1
Burgman NFA	8.4	11.1	14.1
<b>NFA Sub-Total</b>	<b>36.5</b>	<b>47.3</b>	<b>56.4</b>
De-pressurisation	-2.9	-0.1	2.3
<b>Total</b>	<b>33.5</b>	<b>47.2</b>	<b>58.7</b>

**Table 5.5: Catcher Area EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP (Op. Models)	Cum. Prod. at 31 Dec. 2024	RF to date	EUR Estimate to end 2036			EUR RF (vs Op Model STOIP)
					Low	Best	High	
Catcher	Oil (MMstb)	160	56.8	36%	76.9	83.6	88.1	52%
Varadero	Oil (MMstb)	68	20.8	31%	27.3	30.1	33.0	44%
Burgman	Oil (MMstb)	145	28.6	20%	35.5	39.7	43.8	27%
<b>Total</b>	<b>Oil (MMstb)</b>	<b>373</b>	<b>106.2</b>	<b>28%</b>	<b>139.8</b>	<b>153.4</b>	<b>164.9</b>	<b>41%</b>

The field production forecasts are based on an operating efficiency of 90.7% in 2025, declining to 86% in 2031 (and held at this level in perpetuity), reflecting both the historical average (2022-2024) and the increasing age of the facilities. TARs are assumed to occur every two years starting from 2025, lasting 29 days. The Catcher PE estimates as determined by ERCE are presented in Table 5.6.

**Table 5.6: Catcher Area Assumed Production Efficiency**

Field(s)	Production Efficiency							
	2025	2026	2027	2028	2029	2030	2031	2032
Catcher Area	83.5%	89.5%	82.8%	88.0%	81.0%	86.0%	79.2%	86.0%

Note

1. PE estimates from 2031-2032 repeat on the same two-year cycle in perpetuity.

### 5.3. Cost Assumptions

#### 5.3.1. CAPEX Assumptions

ERCE has reviewed and included relevant CAPEX projects from the 2025 WP&B in all forecasts, excluding those activities related to non-reserves workscopes such as exploration.

ERCE also assumes maintenance CAPEX of GBP 0.5 MM (Gross, Real 2025) in 2026 and 2027, based on historical expenditure rates and the remaining asset lifetime.

### 5.3.2. OPEX Assumptions

ERCE has reviewed historical expenditures, the 2025 WP&B, and the FPSO lease contract to determine the Catcher OPEX forecast.

ERCE has accepted the fixed OPEX allocation in the 2025 WP&B, and for 2026 onwards forecasts that fixed OPEX would remain at the 2022-2024 historical average spend of GBP 94.7 MM p.a. (Gross, Real 2025). The fixed OPEX makes allowances for the FPSO Contractor's operating and maintenance ("O&M") cost, logistics, General and Administrative ("G&A"), chemicals, subsea maintenance and insurance.

Elements of variable OPEX include the shuttle tanker tariff rate which is set at GBP 1.23/stb (Gross Real 2025), and fuel gas imports which are charged at the UK NBP gas price plus 40%.

FPSO lease costs are forecast in accordance with the terms specified in Appendix B to the lease agreement. An exchange rate of 1.28 USD/GBP has been assumed in all forecast years.

### 5.3.3. Abandonment Assumptions

Total costs allocated for the decommissioning of facilities and plugging and abandonment of wells are GBP 317 MM, based on ERCE's independent benchmarking.

ERCE has reviewed the phasing of ABEX provided by Waldorf and considers it to be appropriate for the decommissioning of an asset of this type.

## 5.4. Reserves

The technical production profiles described in Section 5.2 were converted to sales profiles. The oil sales were based on the exported wellhead volumes multiplied by a factor of 1.0107 based on sales information provided by Waldorf. Gas sales were based on the wellhead gas less fuel and flare consumption, estimated at 6.72 MMscf/d flat, and gas re-injection. The Catcher area will be fuel gas deficient in the future and the cost of purchasing fuel gas has been included.

Reserves were estimated to the earlier of the economic cut-off date and the end of the technical profiles. For the Catcher area the Low case technical profiles were used as input into the economic model to determine the 1P CoP date. Similarly, the Best -case profiles and the High case profiles were used to determine the 2P and 3P CoP dates respectively.

The Developed Reserves were based on the existing well stock. Opportunities for infills have been cancelled or delayed and no Undeveloped Reserves are attributed by ERCE.

A summary of the gross Reserves is presented in Table 5.7 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.



**Table 5.7: Catcher Area Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Catcher	Developed	27.62	39.22	56.44	0.37	2.64	7.27
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	<b>Total (Dvdp+Undvdp)</b>	<b>27.62</b>	<b>39.22</b>	<b>56.44</b>	<b>0.37</b>	<b>2.64</b>	<b>7.27</b>
	COP (Total)	2030	2032	2035	2030	2032	2035

## 6. Columbus Field

The Columbus gas field is located in Blocks 23/16f and 23/21a within the Central North Sea area of the UKCS. The field is approximately 7 km northwest of the Lomond field and 270 km east of Aberdeen in water depths of 87 m. Waldorf holds a 25% non-operated interest. Serica operates the licence, with a 75% interest.

The field is interpreted to be in partial communication with the adjacent Lomond field. Columbus was discovered in 2006 by Well 23/16f-11 which targeted a seismic amplitude versus offset (“AVO”) anomaly which was interpreted as a gas accumulation in a structural low in the Palaeocene Sele Formation. The well was tested and flowed at a stabilised average rate of 17.5 MMscf/d of gas and 1,060 bbl/d of condensate from the Forties sandstones. The subsequent appraisal included six wells drilled between 2007 and 2009. The wells found varying levels of depletion, caused by Lomond production, and varying fluid contacts. A summary of some key field data is presented in Table 6.1.

**Table 6.1: Columbus Field Summary Data**

Field	Reservoir	Depth (m TVDSS)	Trap	Fluids	Initial Res. Pressure (psia)	CGR (stb/MMscf)	NTG (%)	Por. (%)	Perm (mD)
Columbus	Forties Sandstone	3,000	Stratigraphic	Gas-Cond.	4,693	56	46%	20%	1 - 50

The field was developed in 2021 by drilling an approximately 1,600 m long horizontal producer Well 23/16f-C1Z. The subsea well was drilled from updip of Well 23/16f-11 in the north towards Well 23/21-7x in the south. The well is tied back to the Arran field pipeline which in turn is routed to the Shell operated Shearwater platform. Condensate is exported via FPS and gas is exported via the SEGAL system. In December 2024, the field produced an average of 10.4 MMscf/d of gas, with 235 bbl/d of condensate (Figure 6.2). Cumulative production to 31 December 2024 was 14.4 Bscf of gas and 0.41 MMstb of condensate.

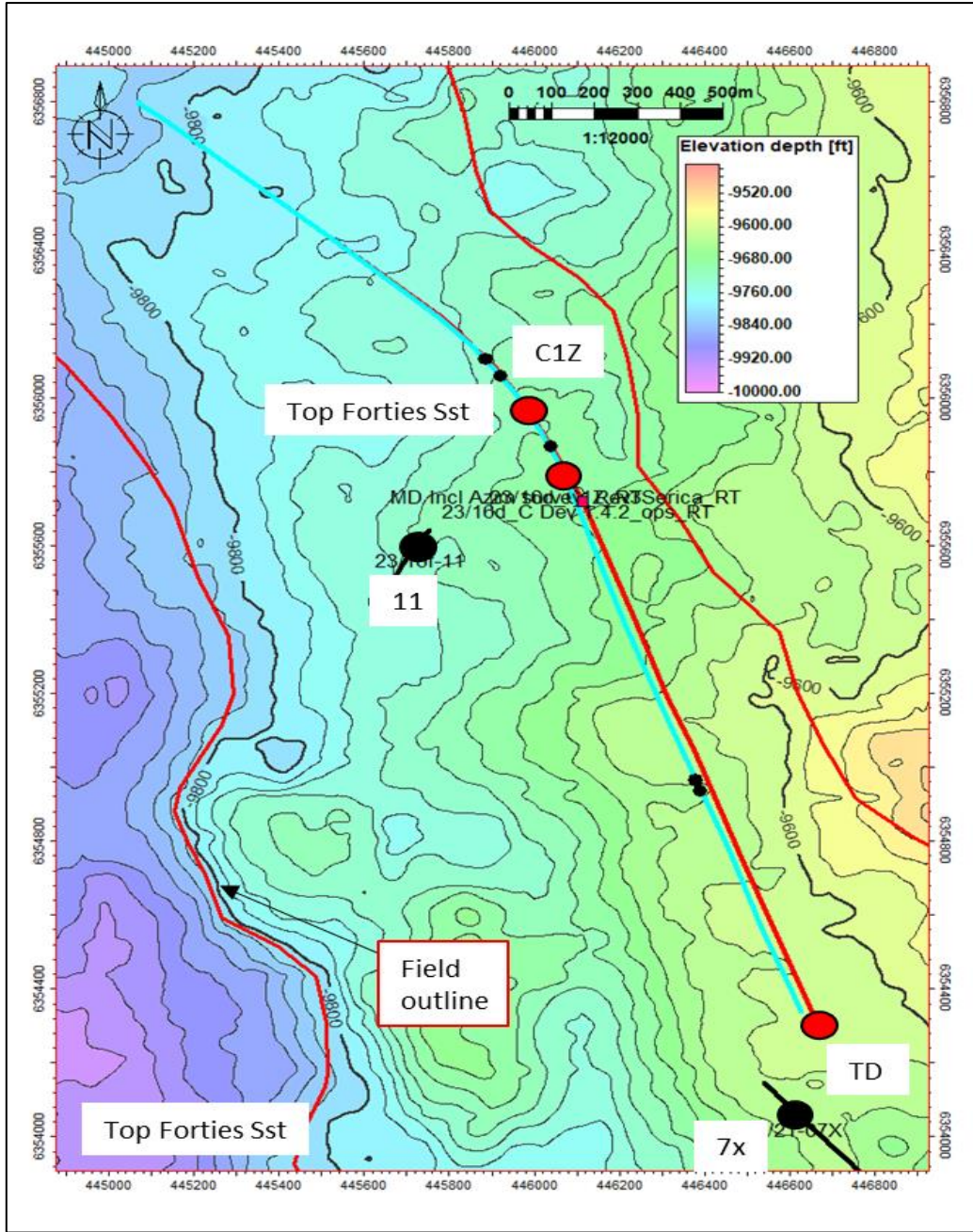


Figure 6.1: Well 23/16f-C1Z Location  
(Source: Operator)

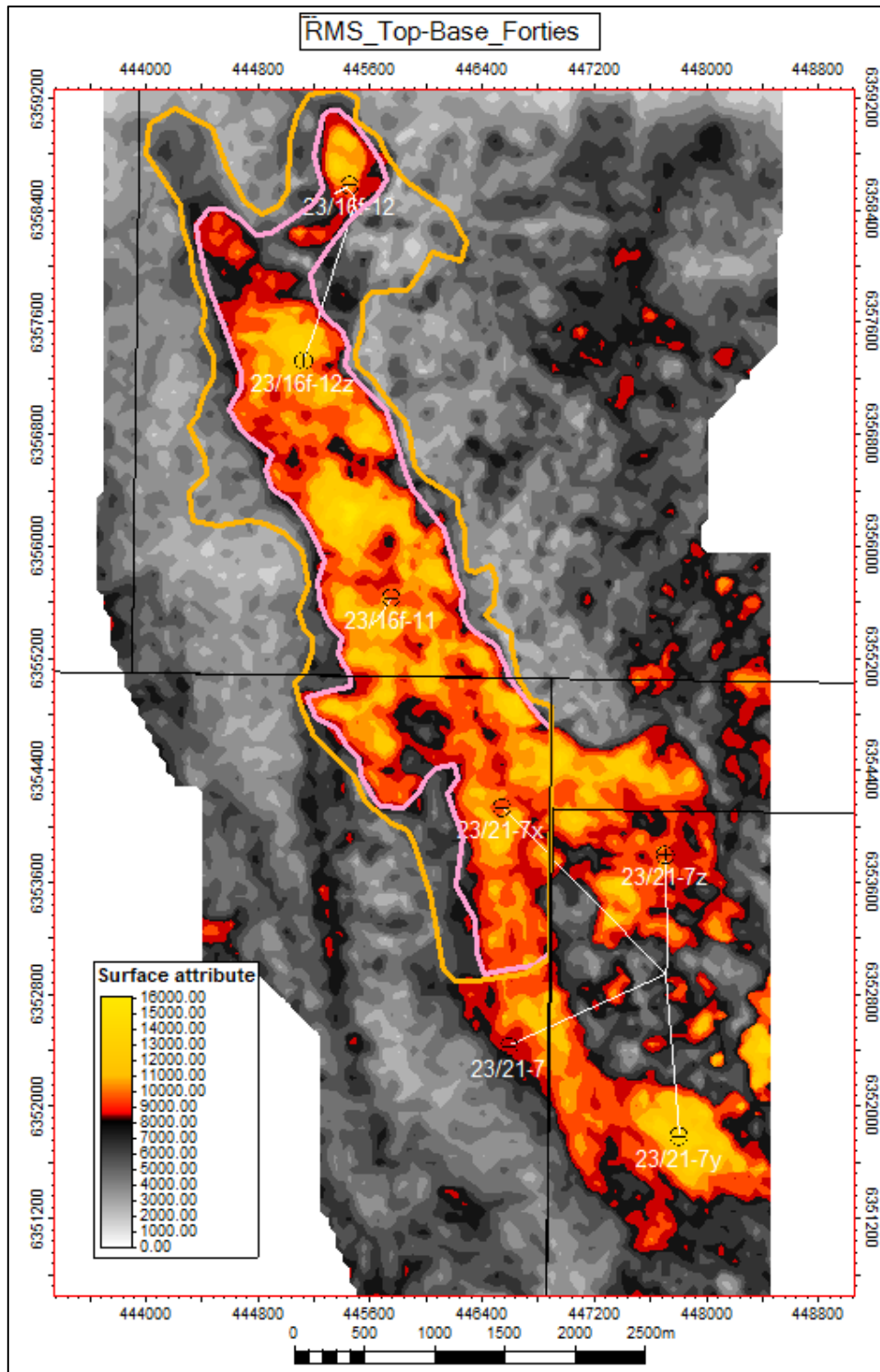


Figure 6.2: Columbus Field Production History

### 6.1. Petroleum Initially In Place

The Columbus field lies along the eastern edge of a Forties sand distribution system that transported turbidite sands in a northwest-southeast direction. The Forties sand is a Member of the Sele Formation. The reservoir consists of medial to distal submarine fan channel sandstones which decrease in thickness from west to east as the Forties onlaps onto the Jaeren High. Reservoir quality is variable in the Columbus field.

Columbus displays stratigraphic trapping to the north, south and east. There is higher uncertainty in the interpretation of the southern extent of the pinch-out. An amplitude anomaly (on Root mean square “RMS” extraction) can be observed in the section between the Top Forties and the F4 horizons in the 3D seismic volumes (Figure 6.3).



**Figure 6.3: RMS Amplitude Extraction F4 to Top Forties**

*(Pink and Orange polygons show ERCE's low and high case polygons respectively, Source: Operator)*

ERCE has reviewed the Operator's petrophysical analysis of the Columbus field exploration and appraisal wells and carried out an independent assessment, which led to an interpretation in line with the Operator's estimates. Petrophysical analysis also suggests that the fluid distribution across the Columbus field is complex and that GWCs vary significantly. There is

therefore uncertainty in reservoir continuity and the degree to which different parts of the field are in communication.

ERCE has assessed the petroleum initially in place for a reconciliation with the production performance. PIIP estimates were carried out using probabilistic volumetric methods. ERCE has followed an area/net approach for the estimation of GIIP; by using the average of the net pay observed in the wells it implicitly takes account of the variation in GWC across the field. The extent of the Top Forties and lateral intra-Forties seal (F4) horizons define the field area High case. The Low case polygon is based on the extent of the RMS amplitude extraction between Top Forties and F4 horizon (Figure 6.3), which ERCE views as qualitatively demonstrating the presence of gas-bearing Forties sandstone. The Best case is then estimated from a normal distribution. The polygons exclude the off-block area to the southeast which includes Well 23/21a-7Z. Net thicknesses and reservoir parameters are assigned based on ERCE’s petrophysical analysis. Table 6.2 shows ERCE’s volumetric input parameters used for the probabilistic GIIP calculations and Table 6.3 presents the GIIP estimates.

**Table 6.2: Columbus Field Volumetric Input Parameters**

Area (km <sup>2</sup> )			Net (m)			Porosity (frac)			Sg (frac)			GEF (scf/rcf)		
Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
5.3	6.79	8.27	11	21	31	0.17	0.19	0.21	0.4	0.45	0.5	223	228	232

**Table 6.3: Columbus Field Volumetric GIIP Estimates**

GIIP (Bscf)		
Low	Best	High
46.7	84.1	151.1

## 6.2. Development Plans

Columbus is considered to be a single well development and as such there are no plans for further development.

## 6.3. Estimated Ultimate Recovery

The JV Partners use a material balance model (“MBAL”) to forecast Columbus’ future production. ERCE has been provided with the model prepared by the Operator and used by Waldorf to generate its forecast.

ERCE has reviewed the model: history match parameters and recent well performance suggest that not all the GIIP calculated volumetrically (Table 6.3) may be accessed by the well. As such, determining EUR volumetrically by applying a range of recovery factors to the GIIP volumetric estimate is not appropriate. ERCE assesses a range of connected GIIP between 30 Bscf and 90 Bscf, after the review of dynamic GIIP analysis provided by Waldorf (P/Z, flowing material balance, Blasingame plots, Deconvolution) and historic static GIIPs generated by the Partners.

ERCE assumptions on production are informed by recent production data and by the latest available information regarding planned outages of host infrastructure. The baseline operating efficiency (excluding planned shutdowns) is assumed to be 85.7%. After various planned shutdowns of host infrastructure are incorporated, the average production efficiency is assumed to be 79.8%, varying between 70%-86% in any given year.

The total (Developed plus Undeveloped) EUR are presented in Table 6.4. EUR are reported to a minimum well cut-off rate in the order of 3 MMscf/d, in line with the Operator’s model assumption. ERCE has considered that production beyond 2030 will be possible in compliance with zero-flaring requirements as there is a reasonable expectation the host facility (Shearwater) will be equipped with an FGRU unit. This expectation is based on the Emissions Reduction Action Plan (“ERAP”) prepared by the Shearwater Operator, provided to ERCE, and on the Operator’s public commitment to meeting the requirements of the North Sea Transition Deal.<sup>2</sup>

**Table 6.4: Columbus Field EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP (ERCE Best Estimate)	Cum. Prod. at 31 Dec. 2024	RF to date	EUR			EUR best est. RF
					Low	Best	High	
Columbus	Gas (Bscf)	84	14.4	17.12%	21.2	32.3	43.1	38.4%
	Cond. (MMstb)	5	0.4	8.72%	0.6	0.9	1.1	18.3%

Notes

1. PIIP based on best case volumetric estimates
2. EUR refers to wellhead volumes

## 6.4. Cost Assumptions

### 6.4.1. CAPEX Assumptions

There are no further capital activities forecast for the Columbus field. Continuing production via host facilities past 2030 requires investment related to flare recovery. ERCE has included an allowance of GBP 50 MM (Gross Real 2025) to the host’s inferred cost sharing base in 2029 to reflect the implementation of flare gas recovery based on reference cost estimates applicable to fixed platforms of comparable scale and age to Shearwater.

### 6.4.2. OPEX Assumptions

ERCE has prepared its OPEX forecast based on the data provided, which includes the Operator’s 2025 work programme and budget, JV Partner committee meetings, and excerpts of the terms of tariff arrangements provided by Waldorf.

<sup>2</sup> <https://www.shell.com/what-we-do/oil-and-natural-gas/flaring.html>

ERCE has included fixed OPEX of GBP 2.0 MM in 2025 in line with the WP&B, and GBP 1.0 MM per annum (Gross, Real 2025) for the remainder of field life in line with average historical costs in 2022-2024.

ERCE has independently calculated the tariff payments due under the production forecasts at each level of confidence, taking into account the terms of tariff agreements and in particular the send-or-pay contractual terms that set the minimum payment levels. ERCE has also taken an independent view on the likely profile of OPEX sharing from Shearwater that would be attributable to Columbus on the basis of production profiles provided by Waldorf that have been reviewed against public domain data.

ERCE understands that one remaining backout payment is due once Columbus has reached a cumulative production level of 3.8 MMboe. ERCE has calculated the timing and amount of this payment in line with the terms and reference prices of the Back-Out Compensation Agreement, ERCE's production forecasts for each case, and ERCE's oil and gas forward price forecasts. The timing and magnitude of the payments are outlined below:

- Second backout payment
  - 1P/2P NFA: GBP 5.2 MM (gross, real 2025) due in 2026
  - 3P NFA: GBP 5.2 MM (gross, real 2025) due in 2025

#### **6.4.3. Abandonment Assumptions**

ERCE carries abandonment estimates of approximately GBP 11.0 MM for the plugging and abandonment of the Columbus well and tie-in spool.

ERCE has reviewed the phasing of ABEX provided by Waldorf and considers it to be appropriate for the decommissioning of an asset of this type.

### **6.5. Reserves**

The technical production profiles described in Section 6.2 were converted to sales profiles. Gas produced at wellhead is adjusted by a factor of 0.95 (based on sales information provided by Waldorf) when comingled fluids of Columbus and Arran (both wells have subsea metering) arrive at Shearwater platform and are re-measured by an import meter. Columbus gas is then reduced by fuel and flare consumption (estimated for Columbus to be reducing from an initial value of 0.5 MMscf/d in 2024) before export. Export gas is further reduced with a shrinkage of 0.89 (advised by Waldorf) for liquid extraction, before being sold.

Condensate quantities produced at wellhead are derived with two adjustment factors of 1 and 0.99 (provided by Waldorf) to determine export quantities first and sales quantities after.

NGL quantities are also recovered and sold, calculated with a yield of 36.3 boe/MMscf applied to export gas quantities.

Reserves were estimated to the earlier of the economic cut-off date and the end of the technical profiles. A summary of the gross Reserves is presented in Table 6.5 together with the CoP dates.

**Table 6.5: Columbus Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Columbus	Developed	0.37	1.00	1.62	5.28	14.56	23.47
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	<b>Total (Dvdp+Undvdp)</b>	<b>0.37</b>	<b>1.00</b>	<b>1.62</b>	<b>5.28</b>	<b>14.56</b>	<b>23.47</b>
	COP (Total)	2028	2033	2036	2028	2033	2036

## 7. Enoch Field

The Enoch field is located in the Central North Sea area of the UKCS 15 km east of the Brae field complex and extends into Norwegian Block 15/5. A unitisation agreement for 2005 determined that 80% of the field lies with UK Block 16/13a (Licence P219). As Waldorf has a 12.125% interest in Licence P219, their unitised interest in the field is 9.696%. The field is operated by Bridge Petroleum since 1 January 2025.

A summary of some key field data is presented in Table 7.1. The main reservoir is the Flugga Sandstone Member of the Sele Formation. Hydrocarbons have been trapped by a combination of compaction-related dip closure and sand pinch-out. The field was discovered in 1985 and was developed as a single well subsea tieback to the Brae Alpha platform. Oil production is exported from Brae via FPS.

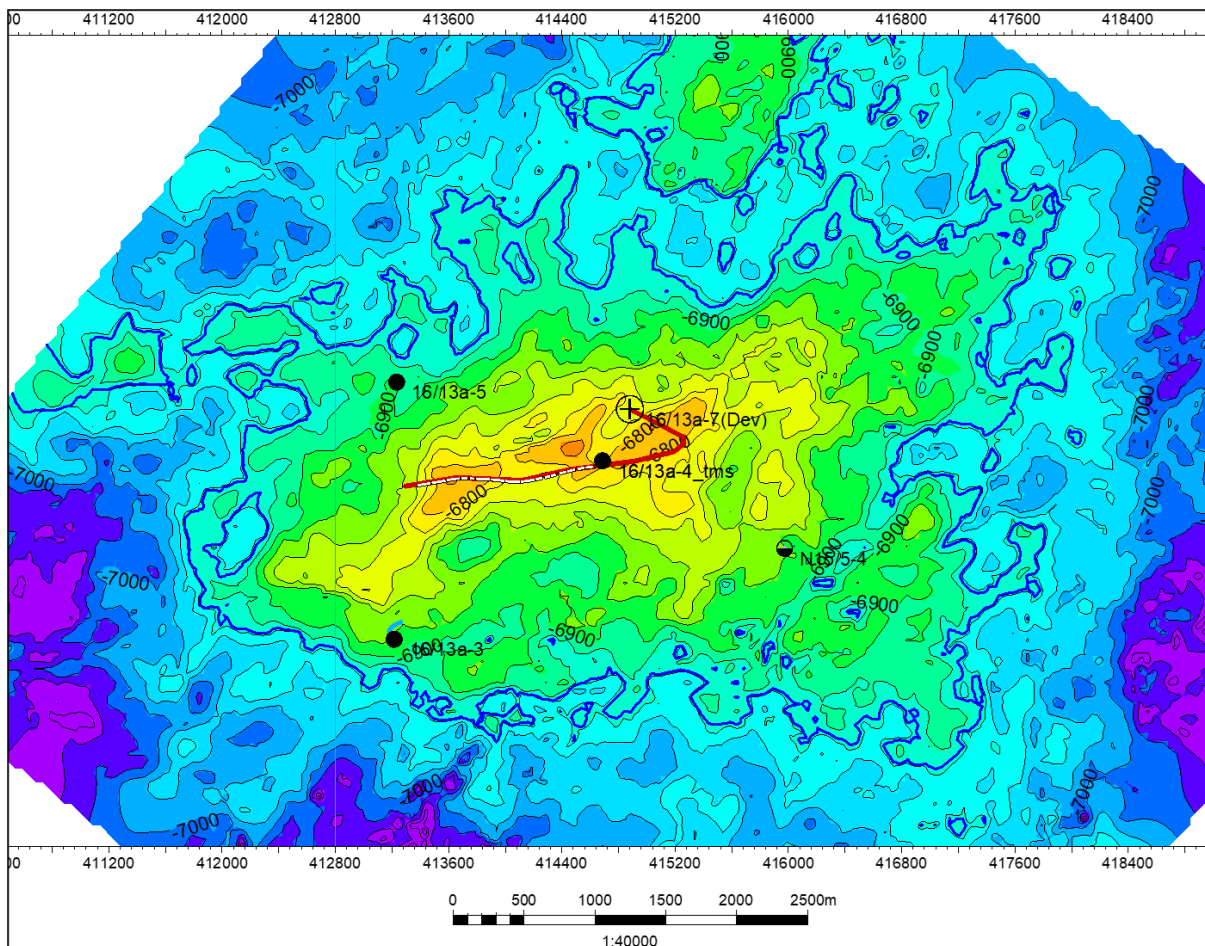


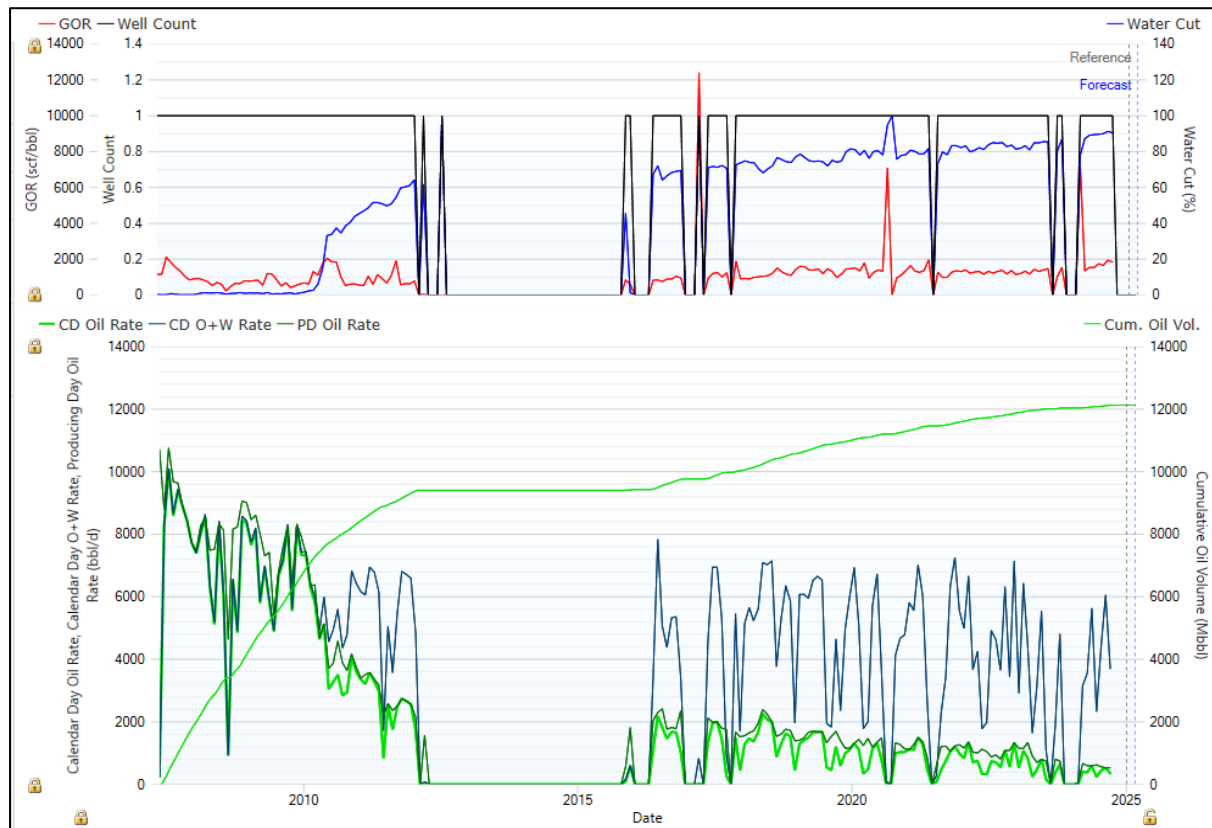
Figure 7.1: Enoch Field Top Structure Map (ft TVDSS)

(Source: Waldorf)

**Table 7.1: Enoch Field Summary Data**

Field	Reservoir	Depth (mTVDSS)	Trap	Fluids	Oil Column (m)	Oil Viscosity (cP)	Solution GOR (scf/stb)	NTG	Por.	Perm (mD)
Enoch	Flugga SS	2,100	Stratigraphic	Oil (37°API) with gas cap	33	0.5	840	92%	27%	100-1,000

The field started production in May 2007, and the oil rate peaked at 10,000 stb/d after the first oil. The recovery mechanism is solution gas drive with gas cap expansion and some aquifer support. At the end of 2024 (September), the single development well was producing at an average oil rate of 350 stb/d, with a water cut of 91% and a gas rate of 0.64 MMscf/d. ERCE understands that the well is shut in following a loss of pressure control at the topside of the field. Cumulative production to 31 December 2024 was 12.1 MMstb of oil and 12.2 Bscf of gas.



**Figure 7.2: Enoch Field Production History**

### 7.1. Development Plans

Enoch is considered to be a single well development, and as such, there are no plans for further development.

## 7.2. Estimated Ultimate Recovery

EUR was estimated based on performance analysis with DCA carried out using extrapolation of 1+WOR trends. Gross liquid rates were varied from 5,000 bbl/d in the Low case to 7,500 bbl/d in the High case. Based on the information made available, ERCE has assumed production will be reinstated in March 2025 at high and best levels of confidence (low and best cases respectively) and in February 2025 at low level of confidence (high case).

Production forecasts extrapolated with a DCA approach were adjusted by production efficiency to generate technical forecast profiles and derive EUR. Based on historical production performance and TAR schedule, ERCE assumes a production efficiency baseline of 68%, which has decreased by an additional 2 months of annual TAR (in 2025 only).

The total (Developed plus Undeveloped) EUR are presented in Table 7.2. EUR is reported to the end of June 2026, when the Brae Operator expects to decommission the host facility.

**Table 7.2: Enoch Field EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP <sup>1</sup>	Cum. Prod. at 31 Dec. 2024	RF to date	EUR to mid-2026			EUR Best Est RF
					1P	2P	3P	
Enoch	Oil (MMstb)	42	12.1	28.9%	12.3	12.3	12.4	29.3%
	Gas (Bscf)	41	12.2	30.0%	12.5	12.6	12.7	30.8%

Notes

1. Operator’s best estimate is reported for the oil, estimate of gas is from public data

## 7.3. Cost Assumptions

### 7.3.1. CAPEX Assumptions

There are no forward capital activities forecast for the Enoch field.

### 7.3.2. OPEX Assumptions

ERCE has estimated the OPEX forecast based on the data provided, which includes the Operator’s 2025 work programme and budget and Technical and Operator committee meetings.

ERCE aligns with the Operator’s budgeted fixed cost for 2025 of GBP 0.34 MM and assumes fixed cost of GBP 0.17 MM in 2026, in line with actual expenditures during 2020-2024. Variable and tariff rates have been held in line with the 2025 budget, through field life.

### 7.3.3. Abandonment Assumptions

ERCE carries total abandonment costs for the decommissioning of facilities and plugging and abandonment of the well amounting to GBP 20.5 MM for the Enoch field.

### 7.4. Reserves

The technical production profiles described in Section 7.2 were converted to sales profiles. The oil sales were based on the wellhead volumes exported and adjusted by a factor of 0.982 bbl/bbl (based on 2024 sales information provided by Waldorf). There are no sales gas volumes, as all produced gas contributes to Brae Alpha platform fuel requirements. A small amount of NGLs is recovered from the stabilised crude at the Kinneil processing facility. The average yield advised by Waldorf is 0.051 boe (NGL) per bbl of export oil and this has been used by ERCE for estimating future NGL quantities. Reserves were estimated to the earlier of the economic cut-off date and the end of the technical profiles in year 2026.

A summary of the gross Reserves is presented in Table 7.3 together with CoP dates applicable to Reserves cases.

**Table 7.3: Enoch Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Enoch	Developed	0.14	0.19	0.27	0.00	0.00	0.00
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvdp+Undvdp)	<b>0.14</b>	<b>0.19</b>	<b>0.27</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>
	COP (Total)	2026	2026	2026	2026	2026	2026

## 8. Kraken Field

The Kraken field lies in UK offshore Blocks 9/2b and 9/2c, which comprise Licence P1077 (Figure 8.1). The field is located on the East Shetland Platform, just west of the Viking Graben and northwest of the Beryl Embayment, approximately 140 km east of the Shetland Islands. Waldorf acquired their 29.5% interest from Cairn Energy plc in November 2021. The licence is operated by EnQuest Heather Ltd., which holds the remaining 70.5% interest. The Kraken field development plan was approved by the UK Government in November 2013. The drilling activity originally sanctioned included 25 development wells drilled in two phases, Phase 1 and Phase 2. In the approved FDP 14 oil producers and 11 water injectors were to be drilled from 4 drill centre (“DC”) templates. During subsequent revisions to the drilling plan, one water injector, planned from the DC4 template, was removed from the drilling schedule.

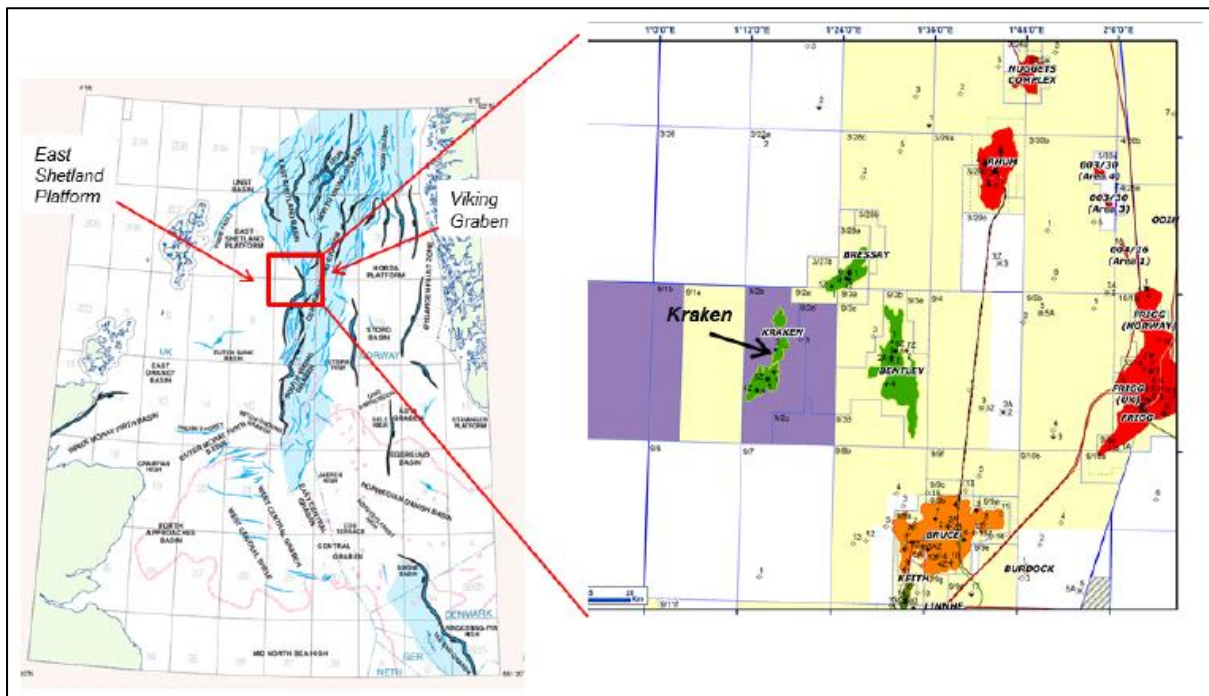


Figure 8.1: Kraken Field Location Map

(Source: Operator)

A summary of some key field data is presented in Table 8.1.

Table 8.1: Kraken Field Summary Data

Field	Reservoir	Depth (mTVDSS)	Trap	Fluids	Initial Res. Pressure (psia)	Solution GOR (scf/stb)	NTG (%)	Por. (%)	Perm (mD)
Kraken	Heimdal SS	1,153	Strati-graphic	Oil (15.4°API)	1,694	150	96%	37%	4,000

The Kraken accumulation was discovered by Well 9/2-1 in 1985. Heavy oil was encountered in the Palaeocene age Heimdal Unit III sandstone (Figure 8.2) at a depth of 1,154.5 m TVDSS.

Well 9/2-2 was drilled in 2007 and discovered oil bearing reservoir in Heimdal Unit III and in the deeper Heimdal Unit I sandstone. Well 9/2b-6 was drilled into an untested geobody (Head) in the northern part of the field in 2013. This well encountered an OWC at 1,217.4 m TVDSS, indicating the northern geobody has a shallower contact than the rest of the field. Hydrocarbon sands were also encountered within the Western Area by Well 9/2b-7 & 7Y.

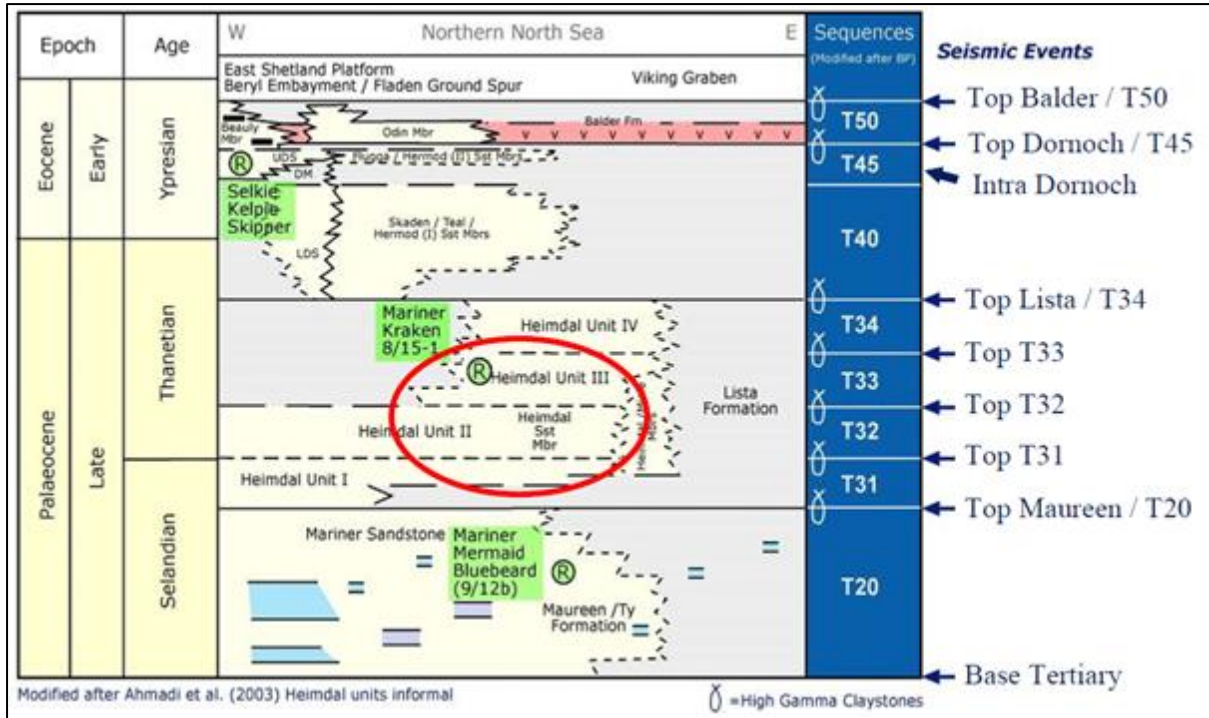
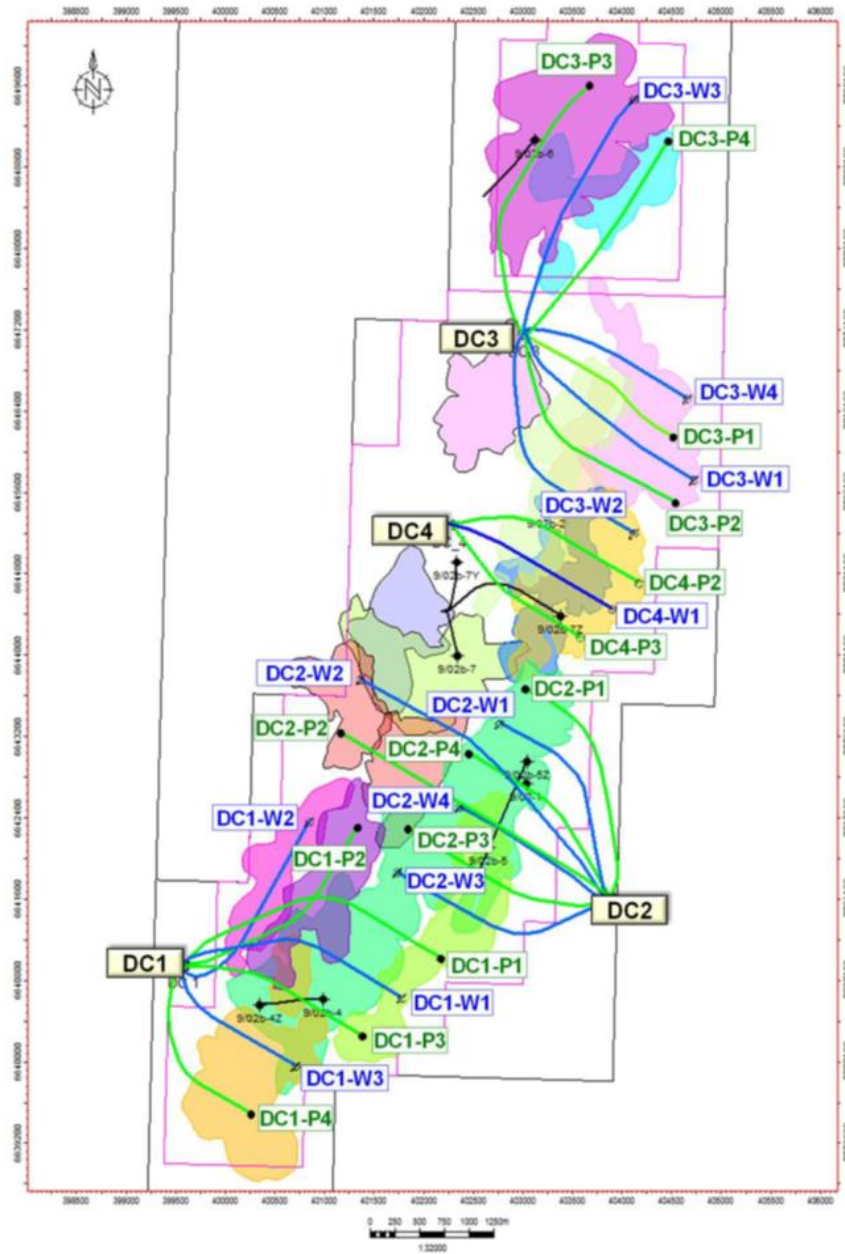


Figure 8.2: Kraken Stratigraphy

(Source: Operator, Kraken is highlighted in red oval)

The FDP was approved in 2013, and development drilling started in the second half of 2015. The wells were drilled as horizontal wells with a spacing between 450 and 600 m drilled in batch sequences (Figure 8.3).



**Figure 8.3: Kraken Field Map**

(Source: Operator)

*The map shows interpreted geobodies with development well locations and support paths from injectors to producers*

The field currently has 14 active production and 12 active injection wells, including the Worcester producer / injector pair, drilled and brought onstream in July 2020. Production and injection history for the field is shown in Figure 8.4. DC4 production wells were brought onstream early 2019, which is the cause of the decrease in field watercut seen. As of 31 December 2024, the field was producing 16,800 stb/d of oil with an average water cut of 93%; the cumulative oil production is 74.0 MMstb.

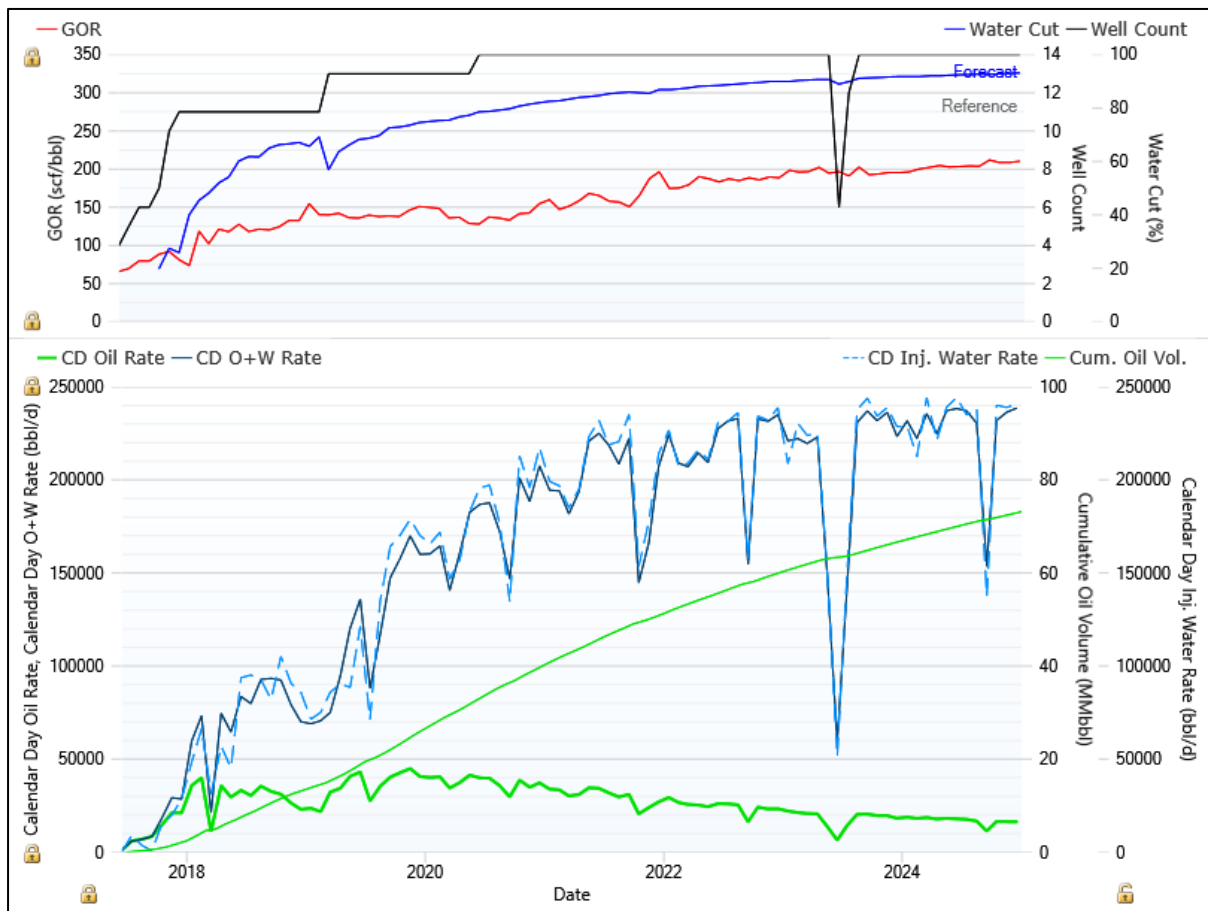


Figure 8.4: Kraken Field Production and Injection History

### 8.1. Development Plans

New seismic was acquired across Kraken in 2022, and updated static and dynamic models have been built using this latest information. The Operator has used the models to assess further drilling in the field, and in 2023 two opportunities were high-ranked: Pembroke and Cumbria. As of YE2024, the JV has failed to reach agreement on drilling of these targets and plans have been postponed. The Operator is continuing to assess further infill well targets, however these are not sufficiently matured at this time for reserves inclusion.

### 8.2. Estimated Ultimate Recovery

ERCE has estimated the EUR for Kraken using DCA on a well-by-well basis, forecasting the 1+WOR and allowing for heavy oil “roll-over” behaviour, where the 1+WOR curve should flatten as the field watercut increases.

During 2024, the total liquid rate of Well DC3-P1 has declined, with analysis indicating likely damage to the HSP pump from sand production in early field life. ERCE’s forecasts have been generated allowing for a range in well liquid rate behaviour. Operating efficiency has been applied on a monthly basis with the yearly average values presented in Table 8.2. In 2024 operating efficiency for the field has been high, which is reflected in the 2025 forecast of

93.3%. This is reduced to 91.5% in 2026 (a 10-day TAR reduces this to a production efficiency of 89.0%). Operating efficiency is forecast to decline from 90% in 2027 to 86% in 2031, reflecting the increasing age of the Kraken FPSO. 10-day TARs are assumed to occur every two years, with the next occurring in 2026.

The total Developed EUR is presented in Table 8.3. ERCE has considered that production beyond 2030 will be possible in compliance with zero-flaring requirements as there is a reasonable expectation the vessel will be equipped with an FGRU unit. This expectation is based on a study prepared for Bumi Armada (FPSO owner), and provided to ERCE, which outlines scope, system description, and considered operating conditions for flare gas recovery. ERCE has reasonable expectations on the Operator’s intention to produce beyond 2030 with a potential combination of infill drilling of the existing field (yet to be matured) and development of the nearby Bressay field (which will contribute to Kraken gas import). EUR is therefore reported to the end of 2042, aligned with the design life of the FPSO facility.

**Table 8.2: Kraken Field Assumed Production Efficiency**

Field	Production Efficiency								
	2025	2026	2027	2028	2029	2030	2031	2032	2033
Kraken	93.3%	89.0%	90.0%	86.6%	88.0%	84.6%	86.0%	83.7%	86.0%

Notes

1. PE estimates after 2033 repeats on the same two-year cycle.

**Table 8.3: Kraken Field EUR Estimates and Recovery Factor**

Asset/ Field	Hydrocarbon	PIIP (Operator Best Estimate) MMstb	Cum. Prod. at 31 Dec. 2024 MMstb	RF to date	EUR to end 2042 (MMstb)			EUR best est. RF
					Low	Best	High	
Kraken	Oil (MMstb)	592	74.0	12.5%	111.2	124.3	138.8	21.0%

Notes

1. PIIP is from the Operator YE2024 dynamic model.
2. Cumulative based on actual production to 31 December 2024.

### 8.3. Cost Assumptions

#### 8.3.1. CAPEX Assumptions

The Operator’s CAPEX forecasts have been reviewed and near-term budgetary information, including the latest 2025 WP&B, has been incorporated into ERCE’s cost forecasts.

ERCE has adopted the Operator’s 2025 WP&B CAPEX estimate of GBP 4.6 MM, excluding the costs which are not associated with the Reserves cases. Sustaining CAPEX for facilities of GBP 8.3 MM (Gross, Real 2025) are included in 2026, and CAPEX associated with flare gas recovery of GBP 15.7 MM (Gross, Real 2025) is included in 2027.

ERCE has assumed that hydraulic submersible pumps will require replacement as they reach end of serviceable life, with 12 workovers assumed to be needed between 2029-2033 at a cost of GBP 12.3 MM (Gross, Real 2025) per workover. In the 1P case, ERCE tested whether

greater value or reserves could be obtained by foregoing some workovers and instead allowing wells to fail, however this was found to be decremental to both value and reserves.

At the 2P/3P levels of confidence, the contractual option to purchase the FPSO is assumed to be exercised in 2029, at the price determined by contractual terms, assuming an exchange rate of 1.28 USD/GBP.

### **8.3.2. OPEX Assumptions**

ERCE has reviewed the fixed OPEX profile proposed by the Operator in the latest 2024 WP&B and considers it to be reasonable based on historical costs, broadly aligning with budgeted estimates through the field life.

The annual FPSO lease cost is based on the contract signed with the FPSO contractor. In the 1P case this continues in perpetuity, whilst in the 2P/3P cases is terminated in 2029. ERCE has reviewed the vessel O&M contract and assumes the duty holders and Operator of the vessel will remain the same upon ownership transfer, thus assumes the majority of vessel related operating costs will remain in line with previous figures prior to purchase, except for minor additional insurance/contract related costs of GBP 6.5 MM p.a. (Gross, Nominal) which are assumed to transfer to the operator upon vessel purchase.

ERCE profiles include an allowance for diesel and fuel gas import. The other component of variable OPEX is for transportation of crude, which ERCE assumes to be GBP 1.2/bbl.

### **8.3.3. Abandonment Assumptions**

Total abandonment costs for the decommissioning of facilities and plugging and abandonment of wells amounts to approximately GBP 291 MM (Gross, Real 2025) for the Kraken field. ERCE considers this to be a reasonable estimate based on independent benchmarking exercises.

ERCE has reviewed the phasing of ABEX provided by Waldorf and considers it to be appropriate for the decommissioning of an asset of this type.

## **8.4. Reserves**

The technical production profiles described in Section 8.2 were converted to sales profiles. The oil sales were based on the wellhead volumes as supported by the data provided. Any associated gas was assumed to be used for fuel requirements, which is supplemented with diesel and as such there are no gas sales.

Developed Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profiles. ERCE does not assign any Undeveloped Reserves.

A summary of the gross Reserves is presented in Table 8.4 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

**Table 8.4: Kraken Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Kraken	Developed	15.14	40.77	64.78	0.00	0.00	0.00
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvdp+Undvdp)	<b>15.14</b>	<b>40.77</b>	<b>64.78</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>
	COP (Total)	2028	2037	2042	2028	2037	2042

## 9. Scolty-Crathes Fields

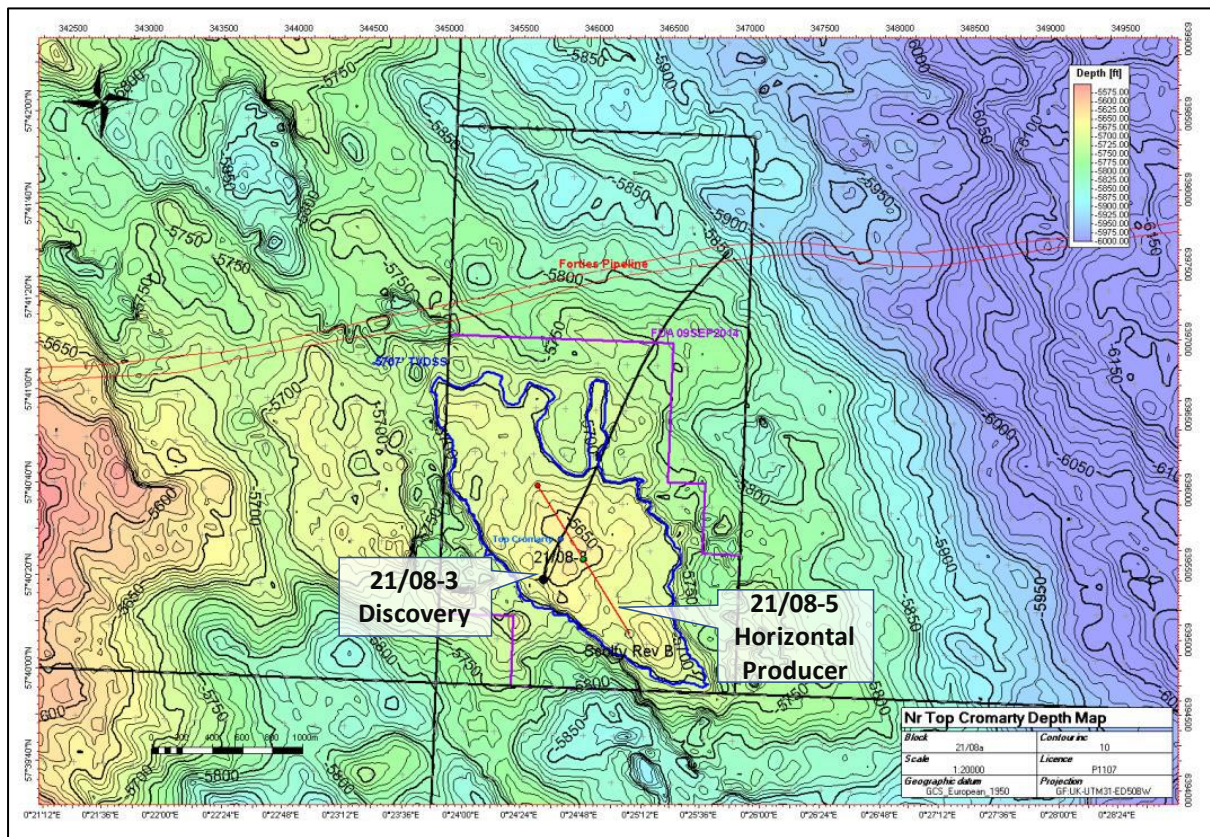
The Scolty-Crathes oil fields are located in blocks 21/8a, 21/12c and 21/13a in the central North Sea sector of the UK Continental Shelf. Waldorf holds a 50% interest, EnQuest is the Operator and holds the balance.

A summary of some of the relevant field data is presented in Table 9.1.

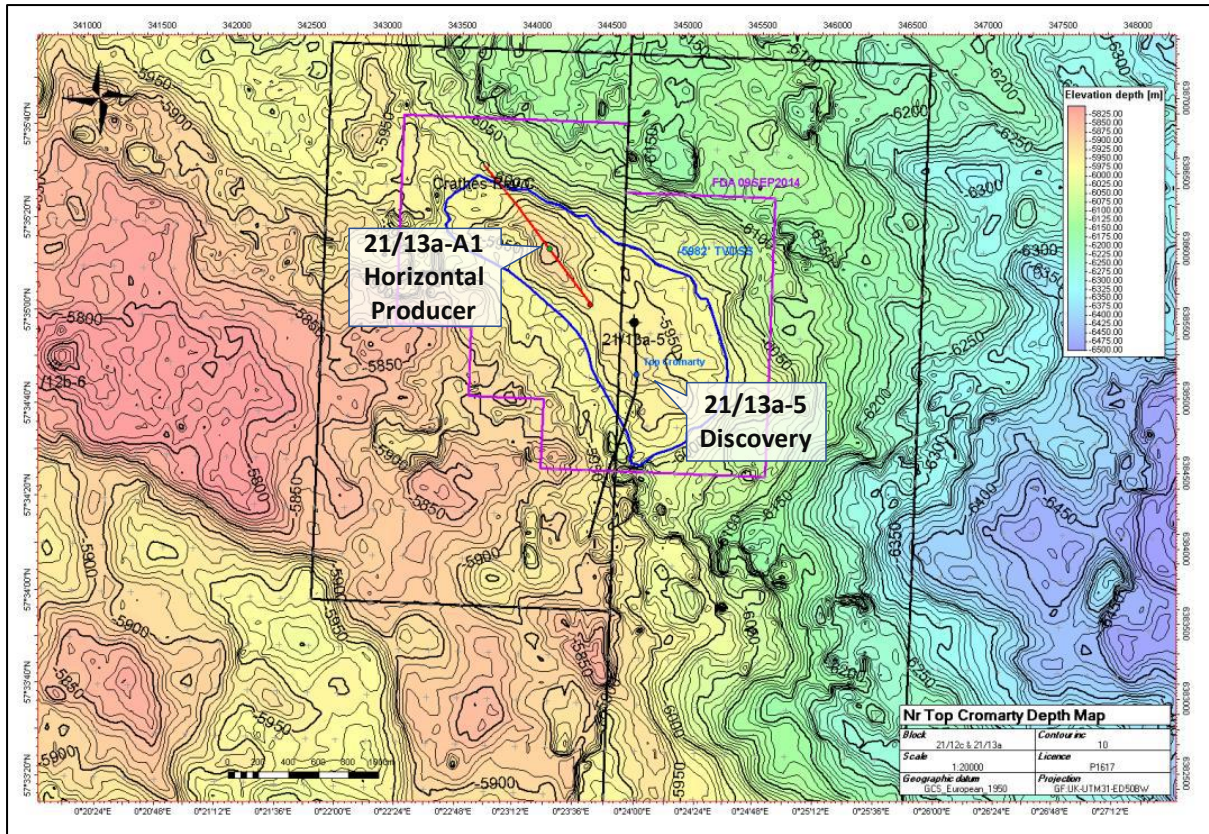
**Table 9.1: Scolty-Crathes Field Summary Data**

Field	Reservoir	Depth to crest (m TVDSS)	Trap	Fluids	In situ Visc. (cP)	Initial Res. Pressure (psia)	Solution GOR (scf/stb)	NTG	Por.	Perm (mD)
Scolty	Cromarty sands	1,718	Four-way-dip-closure	Oil - 40 API	0.77	2,545	323	100%	32.2%	2,000
Crathes	Cromarty sands	1,796	Four-way-dip-closure	Oil - 40 API	0.8	2,645	307	94.40%	31.4%	2,000

The Scolty accumulation is a four-way dip closure at the top of a Tertiary turbidite fan system. The Crathes accumulation is similar to Scolty in size, depth and seismic character (Figure 9.1 and Figure 9.2). The reservoirs in both fields comprise good quality sands of the Late Palaeocene/Early Eocene Cromarty Formation.



**Figure 9.1: Scolty Field Top Depth Map**  
(Source: Operator)



**Figure 9.2: Crathes Field Top Depth Map**  
(Source: Operator)

The Scolty field was discovered in 2007 by EnQuest upon the drilling of Well 21/8-3 in production license PL107. The Crathes field was also discovered by EnQuest in 2011 by the drilling of Well 21/13a-5 in production licence PL617. Well results exceeded expectations and each field was developed with a long development well with a high angle gravel pack completion, and shared infrastructures between the two wells. Installation and commissioning of the pipeline, subsea infrastructure and umbilicals were concluded in the fourth quarter of 2016. The two fields are linked with the GKA platform in a daisy chain (Scolty to Crathes and Crathes to GKA) by means of subsea production and gas lift pipelines. First oil was achieved in November 2016 but within weeks a significant reduction in production was encountered which was subsequently identified as a wax build up in the uninsulated pipeline between Scolty and Crathes. Scolty production was resumed in 2019, with the replacement of the pipeline, whilst Crathes was maintained on production by using frequent injection of wax inhibitor chemicals. Since the pipeline replacement, the Scolty-Crathes production has been optimised for watercut development (to help minimise wax deposition issues). Gas lift became operational in early 2021 which has helped maintain higher fluid rates alleviating possible wax deposition.

ERCE has been informed that no reliable production allocation exists between the fields and therefore Scolty-Crathes production is reported on a combined basis. Production forecasts are also generated on a combined basis, as reported in Section 9.2. In December 2024, the oil

rate averaged 1,250 stb/d with a water cut of 85%, with an operating efficiency of 51%. By the end of 2024, Scolty-Crathes had produced 13.5 MMstb of oil and 4.1 Bscf of gas. A plot of historical production is presented in Figure 9.3.

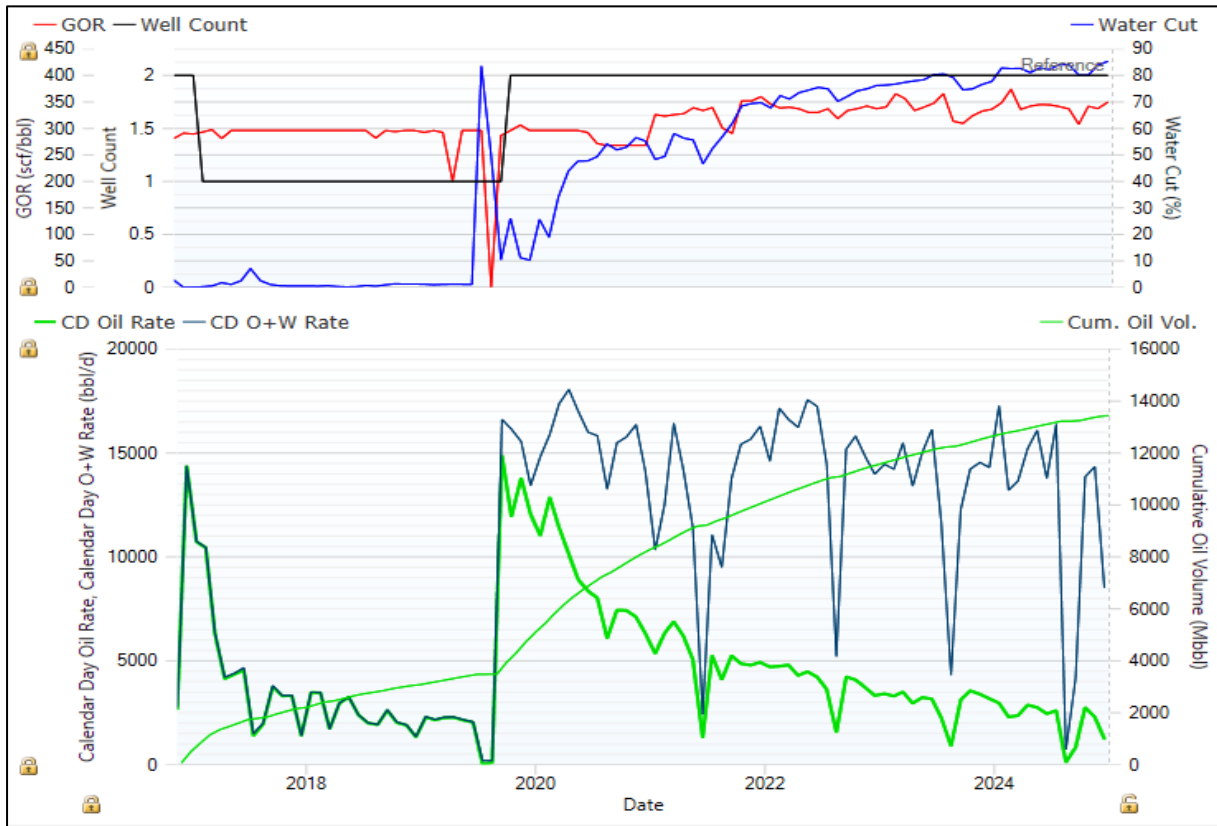


Figure 9.3: Scolty-Crathes Field Production History

Produced oil is directed to the GKA platform via a 12” insulated pipeline (16 km) before export via pipeline to the FPS Unity Platform entry point (33 km away) and then to the FPS. Produced gas is processed for use by GKA owners (fuel and gas lift), and any surplus is exported via the Fulmar Gas Line to St Fergus.

**9.1. Development Plans**

There are no plans for further development of the fields.

**9.2. Estimated Ultimate Recovery**

ERCE’s EUR was estimated based on performance analysis with DCA, carried out using extrapolation of 1+WOR trends. The Operator also uses DCA forecasts as reservoir modelling is difficult because of the uncertain production split between Scolty and Crathes. Operator PIIP estimates were available from the 2016 post-drill reservoir characterisation studies and ERCE understands that no further modelling has been carried out. ERCE has not prepared an independent PIIP calculation and uses the Operator’s estimate to provide indicative RFs.

ERCE prepared the DCA forecasts in aggregate for the two fields. Forecast gross liquid rates were varied from 14,500 bbl/d in the Low case to 17,500 bbl/d in the High case and the 1+WOR trends were cut off at a 98% water cut. A constant GOR of 333 scf/bbl, from analysis of historical data, was used to derive the wellhead gas profiles.

An average baseline operating efficiency of 87.4% was derived from actual production data covering 2021-2024. A 25-day TAR shutdown was assumed yearly (except CoP year 2027), bringing the resulting average production efficiency over 2025-2027 to 81.6%.

The total (Developed plus Undeveloped) EUR are presented in Table 9.2 through to the end of 2027, technical CoP date anticipated by the Operator.

**Table 9.2: Scolty-Crathes Field EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP1	Cum. Prod. at 31 Dec. 2024	RF to date	EUR to end 2027			EUR best est. RF
					Low	Best	High	
Scolty-Crathes	Oil (MMstb)	38	13.4	35.4%	15.1	15.6	15.9	41.0%
	Gas (Bscf)	12	4.1	35.5%	4.7	4.8	5.0	41.6%

Notes

1. PIIP estimates are from 2016 post-drill Operator evaluation

### 9.3. Cost Assumptions

ERCE has reviewed the Operator’s WP&B for 2025, JV Partner committee meeting presentations (which report actual expenditure), the Asset Retirement Obligation (“ARO”) decommissioning estimate and information provided by Waldorf regarding cost sharing arrangements.

#### 9.3.1. CAPEX Assumptions

There is no further CAPEX forecast for the Scolty-Crathes fields.

#### 9.3.2. OPEX Assumptions

ERCE has reviewed and accepts the 2025 WP&B as being reasonable and in line with historical expenditures.

ERCE assumes a fixed OPEX element of GBP 4.5 MM p.a. will continue in 2026 onwards. The product tariff rate has been recalibrated to actuals of GBP 3.79 / stb is also projected to remain constant in real terms.

The majority of OPEX relates to cost sharing with the Kittiwake/GKA cluster. For the cost share calculation, ERCE has relied on data including third party field production forecasts made available by Waldorf and NSTA published production data. The total facility cost share base has also been reviewed by ERCE against actuals and representative benchmark analogues.

### 9.3.3. Abandonment Assumptions

ERCE has reviewed and accepted the updated operator ABEX estimate of GBP 30.3 MM (Gross, Real 2025) for the decommissioning of the Scolty-Crathes wells and subsea infrastructure.

ERCE has reviewed the phasing of ABEX provided by Waldorf and considers it to be appropriate for the decommissioning of an asset of this type.

### 9.4. Reserves

The technical production profiles described in Section 9.2 were converted to sales profiles. The oil sales were based on the wellhead volumes exported and adjusted by a factor of 1.048 bbl/bbl (based on 2024 sales information provided by Waldorf).

Gas wellhead volumes were reduced by their share of fuel and flare consumption at the GKA facility, by a fraction of 73.3% based on historical GKA hub throughput and fuel and flare allocation. ERCE understands that gas export quantities are then sold via the SEGAL system (sales gas) with no further shrinkage and that no NGL is sold.

Reserves were estimated to the earlier of the economic cut-off dates or the end of the technical profiles, provided by Waldorf. Only Developed Reserves were attributed, on the basis of the existing two producing wells.

A summary of the gross Reserves is presented in Table 9.3 together with CoP dates.

**Table 9.3: Scolty-Crathes Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Scolty Crathes	Developed	1.23	2.18	2.55	0.10	0.18	0.22
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvdp+Undvdp)	<b>1.23</b>	<b>2.18</b>	<b>2.55</b>	<b>0.10</b>	<b>0.18</b>	<b>0.22</b>
	COP (Total)	2026	2027	2027	2026	2027	2027

## 10. Scott Field

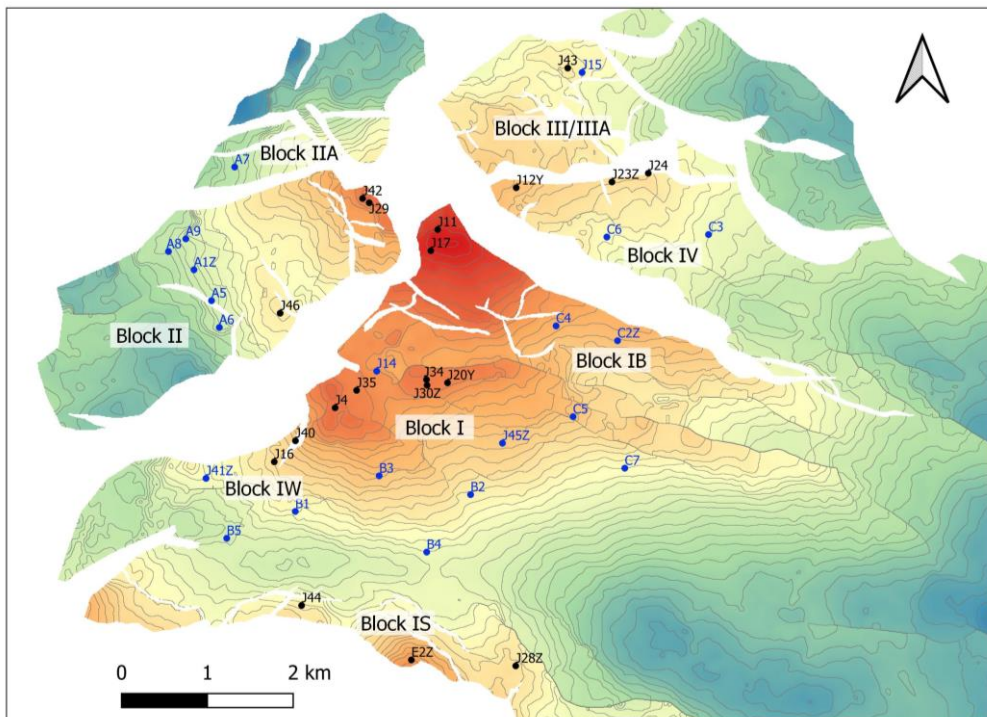
The Scott field straddles Blocks 15/21 and 15/22 on the southern flanks of the Witch Ground Graben in the Outer Moray Firth, approximately 170 km from Aberdeen. Waldorf holds a 21.83458% interest, CNOOC operates the licence with a 41.88872% interest. The other Scott JV Partners are Dana Petroleum E&P Limited (20.64361%), Energean UK Limited (10.47219%) and NEO Energy Production UK Limited (5.1609%).

A summary of some of the relevant field data is presented in Table 10.1.

**Table 10.1: Scott Field Summary Data**

Field	Reservoir	Depth to crest (m tvdss)	Trap	Fluids	Insitu Visc.(cP)	Initial Res. Pressure (psia)	Solution GOR (scf/stb)	NTG	Por.	Perm (mD)
Scott	Jurassic Piper and Scott	3,170	Structural	Oil - 36 API	0.2-0.6 @8,500 psi	8,650	578-1398	80%	10-22%	<0.1-c 6,500

The field structure is a large, tilted fault block, which is compartmentalised into a series of four main pressure-isolated fault blocks (I, II, III and IV), as shown in Figure 10.1. The Kimmeridge Clay Formation provides both the top seal and is the source of the trapped hydrocarbons.



**Figure 10.1: Scott Field Top Depth Map**  
(Source: Waldorf)

The Scott and the Piper Member reservoirs are both bound by marine flooding surfaces. The Scott reservoir consists of a westward prograding marine shoreface sandstone overlain by back-barrier deposits. Above this, the Mid Shale is a regionally extensive flooding event separating the Scott from the overlying Piper reservoir. The Piper consists of stacked mass flow sandstones, overlain by a shoreface/back-barrier system. Lateral facies changes and thickness variations significantly affect reservoir distribution in both the Scott and Piper intervals. Reservoir erosion is also evident towards the crests of specific fault blocks. The best reservoir quality occurs within the coarsest grained, highest energy facies, particularly the upper shoreface deposits. At the crest of the field, multi-Darcy permeabilities and porosities of 20% are common. However, reservoir quality declines progressively down-flank due to increased quartz cementation and compaction.

Scott is developed with two steel jackets linked by two bridges, and there are 28 well slots. It has been further developed by the installation of three clusters of subsea facilities to optimise development of the western, eastern and southern margins of the field. Production began in September 1993 and reached a plateau oil rate of around 180,000 stb/d and 97 MMscf/d in 1995. The field has low levels of aquifer support and water has been injected into the distinct fault blocks since the commencement of production. In general, a significant improvement in historical off-take rates can be observed with increased water injection.

During 2024 infill drilling activity was carried out. A first well, Well J47 (ST35), drilled in Block II, was spudded in July 2022 and came online in January 2024 at rates in line with pre-drill expectations with dry oil production until April, when water started to break through. Later on, a production decline steeper than anticipated was observed to current water cut levels in the order of 93%. A second well, Well J48 (ST-31) was drilled in H2 2024 and encountered Upper and Lower Scott developed as predicted and containing hydrocarbons. The well was completed as per plan and was expected to come online in January 2025. Daily data for January 2025, received after the Effective Date, confirmed that the well, when routed to the test separator and with choke at 10%, showed initial production at a stable rate of 5,100 stb/d, with negligible water and in line with pre-drill expectations from reservoir model.

In 2024 production performance was affected by lower than anticipated operating efficiency, in particular during H2 2024. In December 2024, the average calendar production rate was around 5,000 stb/d of oil with a water cut of 91.4% from 15 oil producers supported by 5 water injection wells. Water injection resumed in 2023 and was maintained in operation throughout 2024, with an annual average injection rate of around 95 Mbb/d of water. Cumulative production to 31 December 2024 was 450.8 MMstb of oil and 310.3.5 Bscf of gas.

The Scott field historical production is shown in Figure 10.2.

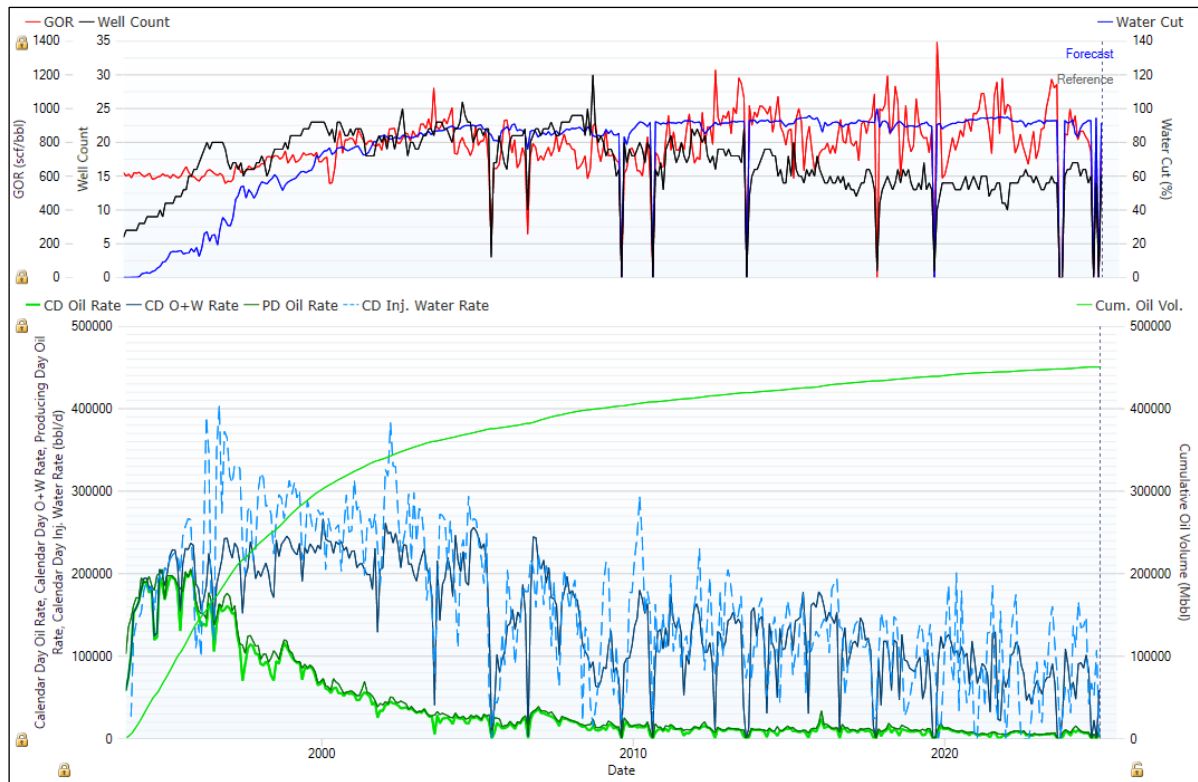


Figure 10.2: Scott Field Production and Injection History

Scott pipeline liquids are exported via a 24" spur pipeline to the Forties Unity Platform and forms part of the Forties Blend prior to processing at Kinneil Terminal at Grangemouth. Scott excess gas is exported via the SAGE pipeline for further processing at the St Fergus onshore terminal where NGLs are then exported to Mosmorran via the FLAGS pipeline. The Scott platform is expected to become fuel gas deficient within a few years. A project to import fuel gas is in progress and ERCE understands the gas will be provided from the SAGE pipeline via the existing gas export route.

### 10.1. Development Plans

Future plans at Scott include investment in the facilities and additional infill drilling.

The main facilities project relates to Power Generation Upgrades. A project to replace one Power Generation Unit (PGU#1) is already sanctioned by the JV to extend technical CoP to 2026 and will be online in Q3 2025. A project to upgrade a second Power Generation Unit ("PGU#2") will provide increased power stability to the Scott platform. The project is expected to extend the life of the facilities beyond end 2026 (date beyond which a single unit would not suffice due to remaining expected life) and therefore underpin additional infill drilling. The project is included by ERCE in the Undeveloped basis.

Scott's near-term drilling targets are selected by the Operator from a panel of opportunities (hopper) developed by the Operator and then matured with further studies. The hopper includes a variety of targets such as 'attic' and bypassed oil (between well-developed areas,

and at the margins of the field), new water injection targets or twinning of wells abandoned/side-tracked early due to moderate watercut.

ERCE understands that there are currently four projects at an advanced stage of maturity, either being sanctioned or about to be sanctioned.

The first infill activity will be water injection Well ST76 in Block II. The well is planned as the fallback option of the initial Well ST-04 (a producer in the undeveloped east half of Block IIa) which is considered prospective by ERCE. Therefore injection Well ST-76 (fall back option) is retained for Reserves calculation. Well ST121 location is an optimisation of the previous ST27, targeting the un-swept Lower Scott B reservoir in Block 1. There is currently no offtake in the area, which could be connected to another well (Well E2Z), and therefore an opportunity exists to drain oil attic to E2Z Lower Terrace top perforations. Well ST68 targets unswept oil from the Well E2Z within the Piper Formation in Block S. This reservoir has not been developed in the south of Block I. Well ST115 will target potential unswept oil in the Scott sands to the east of J14, based on possible extension of fault forming a local permeability baffle. ERCE has reviewed the petroleum initially in place estimates associated with the locations. Checks were also made on other pertinent information including:

- earlier activity within the relevant fault blocks;
- planning information provided in the TCMs;
- the quality of the simulation model history match; and
- benchmarking the forecasts against the recently drilled producers on a plot of “start-up date vs technical EUR” (a creaming curve).

The four proposed infill wells have been included in ERCE’s forecast of Undeveloped EUR.

## 10.2. Estimated Ultimate Recovery

Scott is a mature field with recovery dependent on production maintenance through routine interventions, new successful infills and capacity to maintain voidage replacement across different blocks. Given the current high RF factor of around 50% (in almost all blocks for the Piper and Scott reservoirs in aggregate), ERCE has used a combination of WOR and oil rate trends to predict the future production performance for the entire online well stock.

There are key uncertainties relating to the future water injection system capacity and reliability. The Operator’s 2025 forecast accounts for reduced water injection with a single low-pressure (“LP”) pump that is currently available until a return to dual LP pump operations. Failure rates of the water injection system however are difficult to predict and as such ERCE has considered this in its range of uncertainty. In order to define the EUR the current decline was continued in the Best estimate case, whilst a more rapid oil decline was adopted in the Low case, to account for uncertainty in full water injection reinstatement. The High case was based on the Operator’s simulation modelling results. A constant GOR of 850 scf/bbl, from analysis of historical data, was used to derive wellhead gas profiles.

An average baseline operating efficiency of 64% was assumed for 2025 in alignment with the Operator’s budget, with an expected improvement to 75.3%, following installation of the second upgraded power generation unit. A 24-day TAR shut-down was assumed for August 2025, and average 21-day annual TARs assumed to 2028 included.

The total (Developed plus Undeveloped) EUR estimates are presented in Table 10.2 and include RFs based on the Operator’s best estimate PIIP.

In alignment with the NSTA expectations, the Scott Operator has declared a Company CoP (the likely CoP date of an asset) in 2030 for the Scott field. During 2024 the Operator has also assessed a FGRU installation project at the Scott platform and concluded this would not be economically viable. In the absence of a project, as of the Effective Date, to guarantee production in compliance with future zero routine flaring requirements, ERCE has applied a commercial cutoff at the end of 2029. The EUR estimates reported in Table 10.2 are reported to the end of year 2029.

**Table 10.2: Scott Field EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP <sup>1</sup>	Cum. Prod. at 31 Dec. 2024	RF to date	EUR to end 2029			EUR best est. RF
					Low	Best	High	
Scott	Oil (MMstb)	851	450.8	53.0%	463.6	469.1	478.0	55.1%
	Gas (Bscf)	680	310.3	45.6%	321.1	325.8	333.3	47.9%

Notes

1. PIIP is the Operator’s best estimate

### 10.3. Cost Assumptions

ERCE has reviewed the Operator’s WP&B for 2025, the actual expenditures reported by Waldorf for 2022-2024, JV Partner committee meeting presentations, relevant AFEs and life-of-field economics forecasts.

#### 10.3.1. CAPEX Assumptions

ERCE accepts the planned facilities CAPEX, development G&G, and workover costs outlined in the 2025 WP&B. An ongoing GBP 15.2 MM p.a. (Gross, Real 2025) of sustaining facilities CAPEX covering facilities, workovers and development G&G has also been assumed beyond 2026, based on 2022-2024 historical costs.

ERCE accepts the projected cost for PGU#2 of GBP 22.5 MM (Gross, Real 2025). A cost of GBP 42.5 MM (Gross, Real 2025) has been allocated for future infill wells in alignment with actual outturn costs of recent wells.

### 10.3.2. OPEX Assumptions

ERCE has accepted the fixed OPEX of GBP 89 MM provided in the 2025 WP&B, and forecasts an average of GBP 88 MM p.a. (Gross, Real 2025) from 2026 onwards. The majority of the OPEX comprises these fixed costs, with a small variable element of GBP 2.7 / stb.

Scott and Telford have a cost sharing arrangement, whereby a portion of the Scott cluster's costs are paid by the Telford field. On this basis, the OPEX paid by Scott (net of the cost share payments) ranges from GBP 80 MM to GBP 90MM per year (Gross, Real 2025).

### 10.3.3. Abandonment Assumptions

ERCE carries an independent ABEX estimate of GBP 766 MM (Gross, Real 2025). ERCE has reviewed the phasing of ABEX provided by Waldorf and considers it to be appropriate for the decommissioning of an asset of this type.

## 10.4. Reserves

The technical production profiles described in Section 10.2 were converted to sales profiles. Wellhead oil volumes are exported as stabilised crude oil ("SCO") to the Kinneil Terminal, where quantities require an adjustment of 1.022 bbl/bbl (based on sales information provided by Waldorf) to determine sales quantities.

Sales gas quantities are calculated from excess gas (after fuel and flare reduction) exported to the SAGE Terminal with an adjustment of 1.043, with the addition of dry gas recovered at Kinneil from the crude oil stream, calculated with a yield of 0.048 Mscf/bbl from sales (SCO) oil. Fuel and flare consumption is estimated, for the Scott field, at around 4.5 MMscf/d, from data provided by the Operator.

NGL quantities are also sold, extracted at both the Kinneil and the Sage Terminals. ERCE has used yields of 0.018 boe/bbl (on SCO) and of 0.045 boe/Mscf respectively.

Reserves were estimated to the earlier of the economic cut-off date or the end of the technical profiles. The Developed Reserves were based on the existing well stock at the Effective Date and expected to be brought on stream in January 2025, until the technical life of the field (end 2026) with one power generation unit only. Undeveloped Reserves are based on the implementation of the PGU#2 project and four proposed infill wells until end of 2029.

A summary of the gross Reserves is presented in Table 10.3 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases. ERCE attributes Undeveloped Reserves at 2P and 3P levels of confidence only, after Determination of Commerciality under PRMS.

**Table 10.3: Scott Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Scott	Developed	4.66	6.29	8.12	0.45	2.00	3.74
	Undeveloped	0.00	13.33	18.71	0.00	6.69	11.38
	Total (Dvdp+Undvdp)	<b>4.66</b>	<b>19.62</b>	<b>26.83</b>	<b>0.45</b>	<b>8.68</b>	<b>15.12</b>
	COP (Total)	2026	2029	2029	2026	2029	2029

## 11. Telford Field

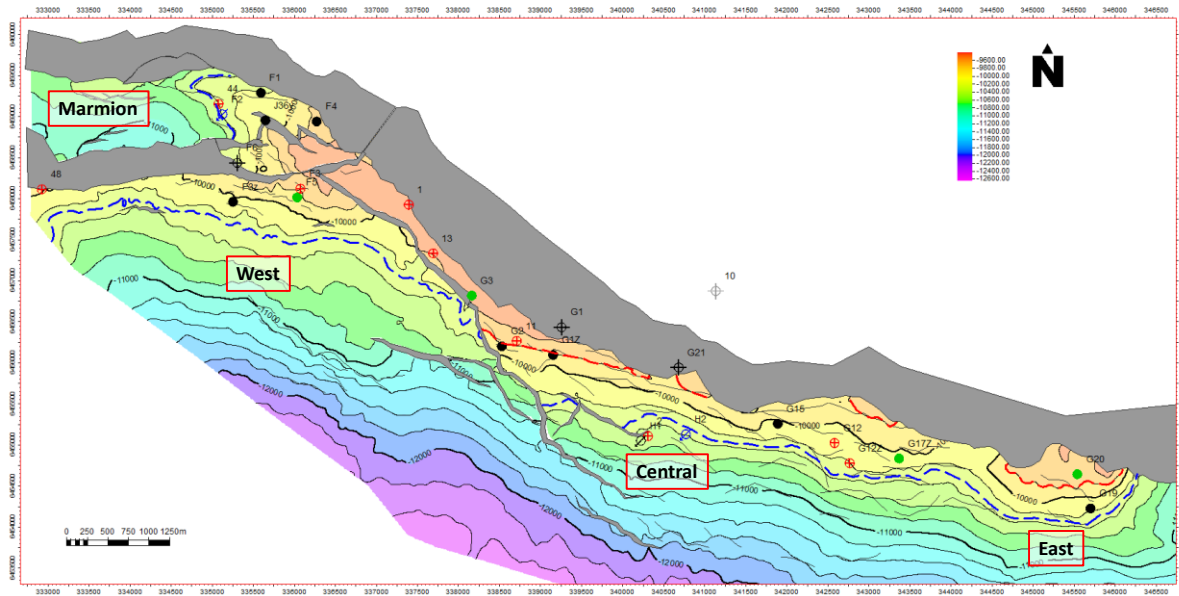
The Telford field is located in Blocks 15/21a and 15/22 of the UKCS. The field is located approximately 170 km northeast of Aberdeen, 9 km south of the Scott Platform. Waldorf holds a 1.58677% interest, CNOOC operates the licence with a 80.40698% interest. The other Telford JV Partners are Energean UK Limited (15.65%) and NEO Energy Production UK Limited (2.35625%).

A summary of some of the relevant field data is presented in Table 11.1.

**Table 11.1: Telford Field Summary Data**

Field	Reservoir	Depth (m tvdss)	Trap	Fluids	Insitu Visc.(cP)	Initial Res. Pressure (psia)	Solution GOR (scf/stb)	NTG	Por.	Perm (mD)
Telford	Jurassic Piper and Scott	2,896	Structural	Oil - 37.4 API	0.15-1 @8,500 psi	4,700	275-1,984	11-99%	17-22%	<0.1-c 9,000

The Telford field is an elongate structure measuring 11 km by 1 km. It comprises four separate accumulations within structural compartments of late Jurassic Piper and Scott Member reservoir sandstones. Like the Scott field, the reservoir is sealed and sourced by the overlying Kimmeridge Clay Formation. The various accumulations along the NW-SE fault have been named Central, West and East Telford and Marmion (Figure 11.1).



**Figure 11.1: Telford Field Top Depth Map**  
(Source: Waldorf)

Exploitation of the field was by phased development through a sub-sea tie back to the Scott platform. Phase 1 of the development involved production from the Central Telford and Marmion accumulations. This came on stream in October 1996 following the drilling of eight development and appraisal wells, including two side-tracks. Of these eight wells, five were

producers and three were water injectors. Phase 2 involved further appraisal and development of the West and East Telford areas and began in 2001 with the drilling of Well 15/22-G15 in the East which targeted the shallow marine sands in the Upper Piper. West Telford is a rich gas condensate accumulation, initially developed under natural depletion and by a later updip well. East Telford had an initial small gas cap at the top of the structure; the area is believed to receive pressure support from Central Telford water injectors and was successfully redeveloped in 2009-2010.

Production began in October 1996 and reached a short plateau oil rate of around 23,000 stb/d in early 2000s. There are currently two oil producing wells (Well G20 in East Telford and Well F5 in West Telford) producing via a flexible flowline. A third well, Well G3, produced discontinuously from Central Telford until 2020 and was offline due to an inability to open the downhole safety valve (“DHSV”). The well has been successfully worked over in Q4 2024 but has not yet been put on production. Water injection (provided by Well H2) supports East and Central Telford.

In 2024 production performance was affected by lower than anticipated operating efficiency, particularly during H2 2024. In December 2024 the Telford field was mostly offline, the average H2 calendar production rate was around 635 stb/d of oil with a water cut of around 90%. Cumulative production to 31 December 2024 was 109.5 MMstb of oil and 230.9 Bscf of gas. ERCE has been informed that Telford was offline in January 2025, expected to restart in February after intelligent pigging operations. A plot of the Telford historical production is shown in Figure 11.2.

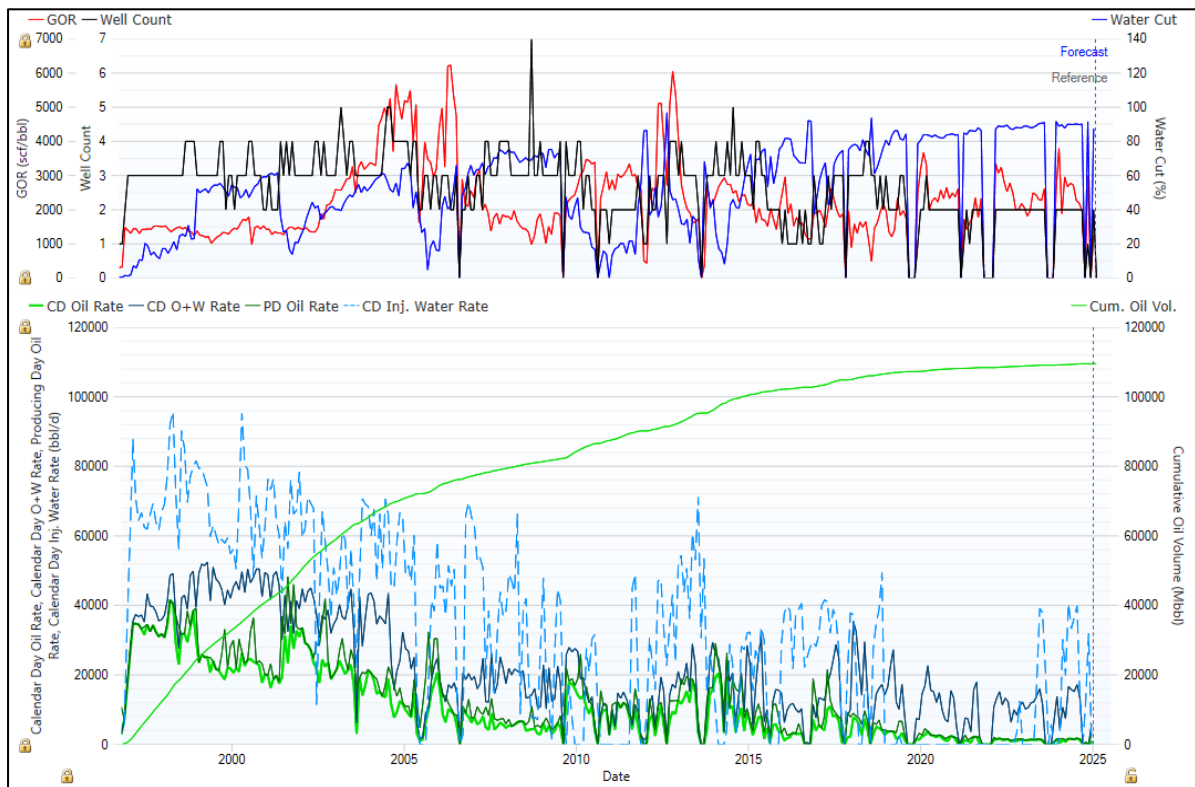


Figure 11.2: Telford Field Production and Injection History

The oil produced from Telford is sent to the Scott platform and exported via the FPS to the Kinneil Terminal in Scotland. Natural gas is used to contribute to Scott fuel gas requirement and excess is exported, with the same export routes described for Scott in Section 9.

### 11.1. Development Plans

The 2025 Budget prepared by the Operator displays no interventions or infill drilling planned for 2025. The Partners are investigating infill opportunities in Telford, but these are considered by ERCE not mature enough for inclusion in Reserves.

### 11.2. Estimated Ultimate Recovery

The Developed EUR were determined by using extrapolation of producing day rates using DCA; historical production efficiency assumptions were added at a later stage to derive technical profiles and determine EUR.

An average baseline injection efficiency of 64% was assumed for 2025 in alignment with the Operator’s budget, with an expected improvement to 75.3%, following installation of second power generation unit at the Scott platform. A 24-day TAR shut-down was assumed for August 2025, and average 21-day annual TARs assumed to 2028 included.

The total (Developed plus Undeveloped) EUR are presented in Table 11.2. EUR are reported to end of year 2029, in line with the assumption for the shared Scott facilities. ERCE attributes Undeveloped Reserves at 2P and 3P levels of confidence only, after Determination of Commerciality.

**Table 11.2: Telford Field EUR Estimates and Recovery Factors**

Asset/ Field	Hydrocarbon	PIIP <sup>1</sup>	Cum. Prod. at 31 Dec. 2024	RF to date	EUR to end 2029			EUR best est. RF
					Low	Best	High	
Telford	Oil (MMstb)	222	109.5	49.3%	111.4	112.0	112.6	50.4%
	Gas (Bscf)	565	230.9	40.9%	232.4	234.0	235.8	41.4%

Notes

1. PIIP is the Operator’s best estimate

### 11.3. Cost Assumptions

#### 11.3.1. CAPEX Assumptions

ERCE has accepted GBP 2.2 MM of reservoir development CAPEX in 2025, with no further CAPEX beyond this.

#### 11.3.2. OPEX Assumptions

ERCE accepts the field OPEX of GBP 6.7 MM in the 2025 WP&B. An annual field OPEX of GBP 5.4 MM (Gross, Real 2025) from 2026 onwards is assumed based on average of the 2024 actual spend and 2025 WP&B. A tariff rate of GBP 3.3/stb is also assumed.

Scott and Telford have a cost sharing arrangement, whereby a portion of the Scott cluster’s costs are paid by the Telford field. This represents a significant majority of the OPEX for Telford. On this basis, Telford OPEX (including cost share payments) would range between GBP 15 MM – GBP 28 MM per year (Gross, Real 2025).

**11.3.3. Abandonment Assumptions**

ERCE carries an independent ABEX estimate of GBP 153 MM (Gross, Real 2025).

ERCE has reviewed the phasing of ABEX provided by Waldorf, and considers it to be appropriate for the decommissioning of an asset of this type.

**11.4. Reserves**

The technical production profiles described in Section 11.2 were converted to sales profiles using the same methodology used for the Scott field, described in Section 10.4. Wellhead oil volumes were converted to sales quantities with an adjustment of 0.971 bbl/bbl. Sales gas quantities are calculated from excess gas (after fuel and flare reduction) with an adjustment of 0.807 for export to the SAGE terminal, and dry gas calculated with a yield of 0.104 Mscf/bbl from sales (SCO) oil. For NGL ERCE has used yields of 0.029 boe/Mscf and of 0.065 boe/bbl the quantities sold at the SAGE and Kinneil terminals respectively.

Fuel and flare gas consumption allocated to the Telford field was estimated to be in the order of 1 MMscf/d, from Operator’s data. Reserves were estimated to the earlier of the economic cut-off date or the end of the technical profiles in alignment with the Scott facilities. Developed Reserves were based on the well stock, including Well G3 recently worked over, available as of the Effective Date, assuming production re-start in February 2025 and production to the end of year 2026. Undeveloped Reserves are based on production continuation beyond 2026, based on the availability of the Scott facilities, until end of year 2029.

A summary of the gross Reserves is presented in Table 11.3 together with CoP dates.

**Table 11.3: Telford Field Gross Reserves with CoP dates**

Asset	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Telford	Developed	0.75	1.00	1.25	0.04	0.54	1.07
	Undeveloped	0.00	1.19	1.58	0.00	0.14	0.72
	Total (Dvdp+Undvdp)	<b>0.75</b>	<b>2.19</b>	<b>2.83</b>	<b>0.04</b>	<b>0.68</b>	<b>1.79</b>
	COP (Total)	2026	2029	2029	2026	2029	2029

## 12. Economic Evaluation

ERCE has built independently an economic model to evaluate the Reserves associated with Waldorf’s assets. Economic Limit (ELT), before and after-tax Net Present Value (NPV10) were determined at the 1P/2P/3P Developed and 1P/2P/3P Undeveloped levels of uncertainty. These were based on the UK fiscal regime, production and cost profiles generated by ERCE and several economic assumptions listed below. At Waldorf’s request, the NPVs have been reported on a pre-tax basis as required by the intended users of the report. It should however be noted that the commerciality of the Undeveloped Reserves for each field was tested on an after-tax basis as required under PRMS. The results are presented in this CPR both on a 100% gross basis and a net entitlement basis for all Reserves and cost cases.

The ELT was carried out at the field level. Forecasts were prepared on an annual basis and the CoP dates coincide with the time when the maximum cumulative net cash flow occurs for the field. For some assets, the NPV estimates are negative due to future abandonment liabilities; Reserves are still assigned as long as their associated production adds incremental value. ERCE has not considered whether Waldorf will be able to fund future abandonment liabilities as this was beyond the scope of work. In line with PRMS, Undeveloped Reserves are included if the incremental value associated with the project is NPV10 positive at a 2P level on an after-tax basis; however, if the project 1P is NPV0 negative, only 2P and 3P Undeveloped Reserves are assigned.

### 12.1. Economic Assumptions

ERCE’s 1 January 2025 price forecasts of Brent crude oil and UK NBP natural gas were used for the evaluation and are presented in Table 12.1 and Table 12.2 respectively. Prices are escalated at 2.0% per annum inflation. Percentage crude oil and natural price differentials for the various assets are presented in Table 12.3. The differentials were based on current differentials provided by Waldorf in \$/bbl and pence per therm.

**Table 12.1: ERCE Brent Crude Oil Price Forecast as of 1 January 2025**

ERCE (Base Case) Brent Assumptions (\$/bbl)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Real (Constant \$, 2025)	76	74	75	75	75	75	75	75	75	75	75
Nominal (\$ of the day)	76	76	78	80	81	83	85	86	88	90	+2.0% pa

**Table 12.2: ERCE UK NBP Natural Gas Price Forecast as of 1 January 2025**

ERCE (Base Case) NBP Gas Price Assumptions (p/therm)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Real (Constant, 2025)	102	86	79	80	80	80	80	80	80	80	80
Nominal (\$ of the day)	102	87	83	85	86	88	90	91	93	95	+2.0% pa

**Table 12.3: Price Differentials**

Field	% Discount (-ve) / Premium (+ve)	
	to Brent Oil	to NBP Gas
Bacchus	0.79%	-39.42%
Bittern	3.39%	-31.30%
Catcher	1.08%	-33.48%
Columbus	0.79%	-5.57%
Enoch	0.79%	-71.40%
Kraken	-9.99%	
Scolty-Crathes	0.79%	
Scott and Telford	0.79%	-43.61%

Carbon cost estimates are based on UKA price forecasts prepared by ERCE, shown in Table 12.4.

**Table 12.4: ERCE UKA Forecast as of 1 January 2025**

ERCE (Base Case) UKA Assumptions (£/tCO <sub>2</sub> )	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036+
UKA Price (Nominal)	35	37	39	41	43	45	47	49	51	53	55	+2.0% p.a.
UKA Price (Real 2025)	35	36	37	38	40	41	42	43	44	45	45	

**Other Assumptions**

- For NGLs, ERCE applied a 34.81% discount to Brent for Scott and a 32.88% discount to Brent for Columbus, based on Waldorf’s guidance on historical realised prices.
- Capital and operating costs have been determined in 2025 real terms and inflated at a 2.0 per cent annual inflation rate.
- An exchange rate of GBP 1.00 /USD of 1.2782 has been applied in all years.
- To check commerciality, ERCE performed after-tax calculations applying the latest UK fiscal terms: Corporate Tax Rate of 30%, Supplementary Charge Tax Rate of 20%, Energy Profits Levy of 38%, all investment allowances and carry back/forward mechanisms as applicable.

**12.2. Economic Results**

Though NPVs form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as ERCE’s opinion of fair market value. There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company’s oil and natural gas Reserves are estimates only and there is no guarantee that the estimated Reserves will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report.

The Reserves estimates associated with the economic results are presented in the Executive Summary in Table 1.2, Table 1.3 and Table 1.4. The before-tax NPV10 estimates as of 31 December 2024 are presented in Table 1.7.

Cash flow tables for each field are presented in Appendix 3.

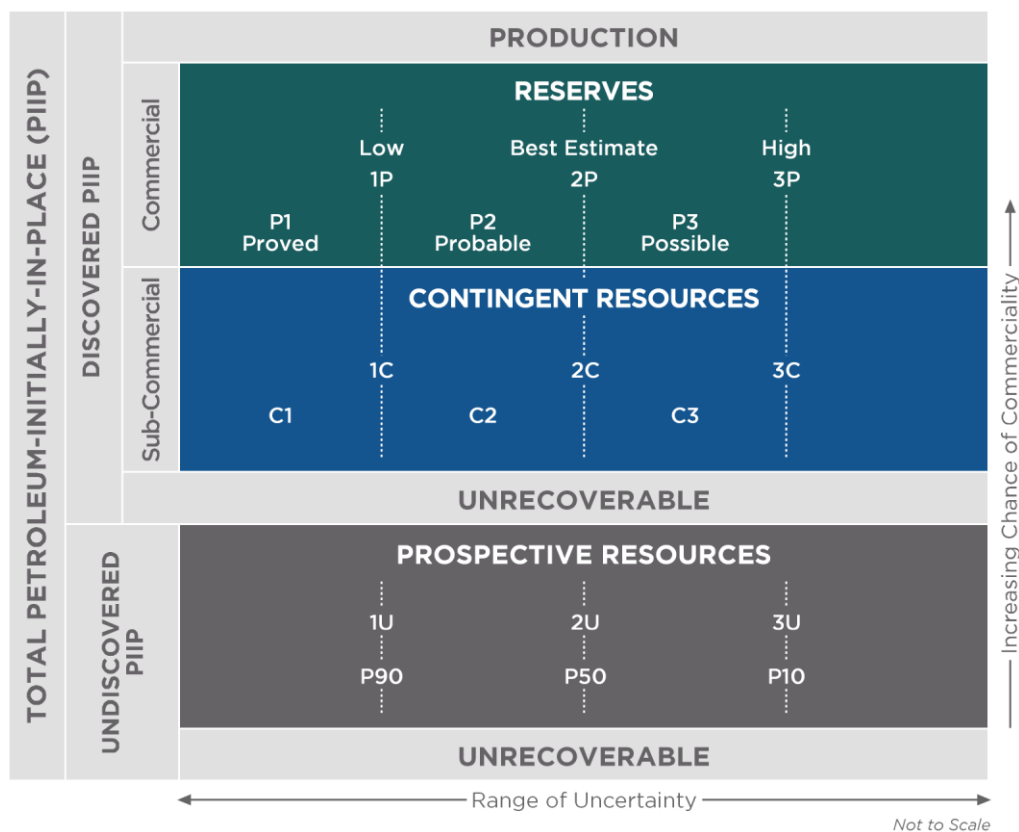
The CoP dates for each asset are presented in the Executive Summary in Table 1.8.

## Appendix 1: SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

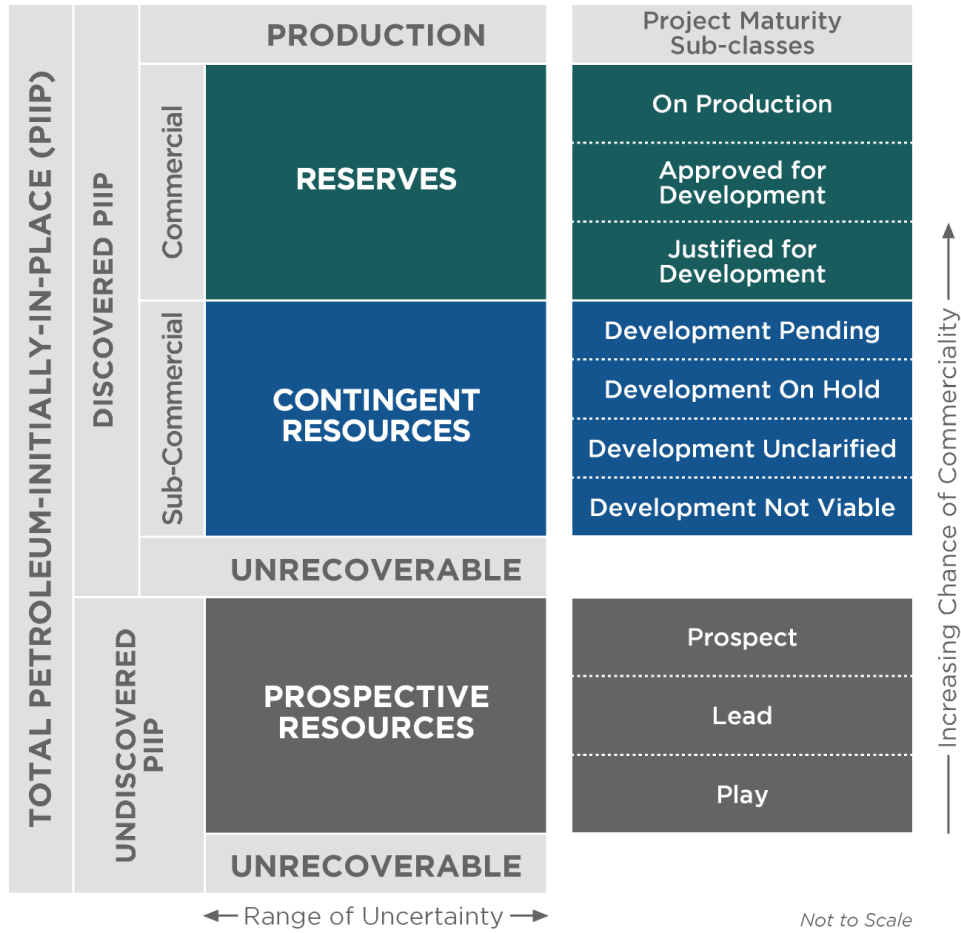
<https://www.spe.org/en/industry/petroleum-resources-management-system-2018/>

Definitions of the key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.



**Figure A: PRMS Resources classification framework**

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)



**Figure B: PRMS Resources sub-classes**

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

**Table 1: PRMS Recoverable Resources Classes and Sub-Classes**

Classes/Sub-classes	Definition	Guidelines
<b>Reserves</b>	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	<p>Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status.</p> <p>To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame.</p> <p>A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.</p> <p>To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.</p>
<b>On Production</b>	The development project is currently producing or capable of producing and selling petroleum to market.	<p>The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves.</p> <p>The project decision gate is the decision to initiate or continue economic production from the project.</p>

Classes/Sub-classes	Definition	Guidelines
<b>Approved for Development</b>	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	<p>At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget.</p> <p>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.</p>
<b>Justified for Development</b>	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	<p>To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class).</p> <p>The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.</p>
<b>Contingent Resources</b>	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	<p>Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist.</p> <p>Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.</p>

<b>Classes/Sub-classes</b>	<b>Definition</b>	<b>Guidelines</b>
<b>Development Pending</b>	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	<p>The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status.</p> <p>The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.</p>
<b>Development on Hold</b>	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	<p>The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.</p> <p>The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.</p>
<b>Development Unclarified</b>	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	<p>The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.</p> <p>This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.</p>

<b>Classes/Sub-classes</b>	<b>Definition</b>	<b>Guidelines</b>
<b>Development Not Viable</b>	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	<p>The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.</p> <p>The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.</p>
<b>Prospective Resources</b>	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
<b>Prospect</b>	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
<b>Lead</b>	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
<b>Play</b>	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

**Table 2: PRMS Reserves Status Definitions and Guidelines**

Status	Definition	Guidelines
<b>Developed Reserves</b>	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
<b>Developed Producing Reserves</b>	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
<b>Developed Non-Producing Reserves</b>	Shut-in and behind-pipe Reserves.	<p>Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.</p> <p>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.</p>
<b>Undeveloped Reserves</b>	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

**Table 3: PRMS Reserves Category Definitions and Guidelines**

Category	Definition	Guidelines
<b>Proved Reserves</b>	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	<p>If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.</p> <p>The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and</p> <p>2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.</p> <p>In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved.</p> <p>Reserves in undeveloped locations may be classified as Proved provided that:</p> <ul style="list-style-type: none"> <li>A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.</li> <li>B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.</li> </ul> <p>For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.</p>
<b>Probable Reserves</b>	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	<p>It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.</p> <p>Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.</p> <p>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.</p>

<p><b>Possible Reserves</b></p>	<p>Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.</p>	<p>The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario.</p> <p>When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.</p> <p>Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project.</p> <p>Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.</p>
<p><b>Probable and Possible Reserves</b></p>	<p>See above for separate criteria for Probable Reserves and Possible Reserves.</p>	<p>The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.</p> <p>In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.</p> <p>Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.</p> <p>In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.</p>

**Table 4: Glossary of Terms Used in PRMS**

<b>Term</b>	<b>Definition</b>
<b>1C</b>	Denotes low estimate of Contingent Resources.
<b>2C</b>	Denotes best estimate of Contingent Resources.
<b>3C</b>	Denotes high estimate of Contingent Resources.
<b>1P</b>	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
<b>2P</b>	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
<b>3P</b>	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
<b>1U</b>	Denotes the unrisks low estimate qualifying as Prospective Resources.
<b>2U</b>	Denotes the unrisks best estimate qualifying as Prospective Resources.
<b>3U</b>	Denotes the unrisks high estimate qualifying as Prospective Resources.
<b>Abandonment, Decommissioning, and Restoration (ADR)</b>	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as “ADR net of salvage.”
<b>Accumulation</b>	An individual body of naturally occurring petroleum in a reservoir.
<b>Aggregation</b>	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
<b>Appraisal</b>	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
<b>Approved for Development</b>	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
<b>Analog</b>	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator’s assessment of similarities of the analogous reservoir(s) together with the development plan.
<b>Analogous Reservoir</b>	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.

<b>Assessment</b>	See Evaluation.
<b>Associated Gas</b>	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
<b>Basin-Centered Gas</b>	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
<b>Barrel of Oil Equivalent (BOE)</b>	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
<b>Basis for Estimate</b>	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
<b>Behind-Pipe Reserves</b>	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
<b>Best Estimate</b>	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
<b>C1</b>	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
<b>C2</b>	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
<b>C3</b>	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
<b>Chance</b>	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
<b>Chance of Commerciality</b>	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
<b>Chance of Development</b>	The estimated probability that a known accumulation, once discovered, will be commercially developed.
<b>Chance of Geologic Discovery</b>	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
<b>Coalbed Methane (CBM)</b>	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]

<b>Commercial</b>	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met. .
<b>Committed Project</b>	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)
<b>Completion</b>	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
<b>Completion Interval</b>	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
<b>Concession</b>	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
<b>Condensate</b>	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
<b>Confidence Level</b>	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
<b>Constant Case</b>	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
<b>Consumed in Operations (CiO)</b>	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)

<b>Contingency</b>	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
<b>Contingent Project</b>	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
<b>Contingent Resources</b>	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
<b>Continuous-Type Deposit</b>	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include "basin-centered" gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.
<b>Conventional Resources</b>	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
<b>Cost Recovery</b>	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
<b>Crude Oil</b>	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
<b>Cumulative Production</b>	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
<b>Current Economic Conditions</b>	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
<b>Defined Conditions</b>	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
<b>Deposit</b>	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)

<b>Deterministic Incremental Method</b>	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
<b>Deterministic Method</b>	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
<b>Deterministic Scenario Method</b>	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
<b>Developed Reserves</b>	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non- Producing.
<b>Developed Producing Reserves</b>	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
<b>Developed Non-Producing Reserves</b>	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
<b>Development On Hold</b>	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
<b>Development Not Viable</b>	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
<b>Development Pending</b>	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
<b>Development Plan</b>	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
<b>Development Unclarified</b>	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.

<b>Discovered</b>	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
<b>Discovered Petroleum Initially-In-Place</b>	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
<b>Discovered Unrecoverable</b>	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
<b>Dry Gas</b>	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
<b>Economic</b>	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
<b>Economic Interest</b>	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
<b>Economic Limit</b>	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.
<b>Economically Not Viable Contingent Resources</b>	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
<b>Economically Viable Contingent Resources</b>	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
<b>Economically Producing</b>	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity’s interest. The ADR costs are excluded from the determination.
<b>Effective Date</b>	Resource estimates of remaining quantities are “as of the given date” (effective date) of the evaluation. The evaluation must take into account all data related to the period before the “as of date.”
<b>Entitlement</b>	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
<b>Entity</b>	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
<b>Established Technology</b>	Methods of recovery or processing that have proved to be successful in commercial applications.

<b>Estimated Ultimate Recovery (EUR)</b>	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
<b>Evaluation</b>	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
<b>Evaluator</b>	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
<b>Exploration</b>	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
<b>Field</b>	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
<b>Final Investment Decision (FID)</b>	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
<b>Flare Gas</b>	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).
<b>Flow Test</b>	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
<b>Fluid Contacts</b>	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
<b>Forecast Case</b>	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
<b>Gas Balance</b>	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
<b>Gas Cap Gas</b>	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.

<b>Gas Hydrates</b>	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
<b>Gas/Oil Ratio</b>	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, $R_s$ ; produced gas/oil ratio, $R_p$ ; or another suitably defined ratio of gas production to oil production.
<b>Geostatistical Methods</b>	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
<b>High Estimate</b>	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
<b>Hydrates</b>	See Gas Hydrates.
<b>Hydrocarbons</b>	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
<b>Improved Recovery</b>	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
<b>Injection</b>	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
<b>Justified for Development</b>	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/contracts will be obtained. A project maturity sub-class of Reserves.
<b>Kerogen</b>	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
<b>Known Accumulation</b>	An accumulation that has been discovered.
<b>Lead</b>	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources.

<b>Learning Curve</b>	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
<b>Likelihood</b>	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
<b>Low/Best/High Estimates</b>	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
<b>Low Estimate</b>	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
<b>Lowest Known Hydrocarbons (LKH)</b>	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
<b>Market</b>	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.
<b>Marketable Quantities</b>	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
<b>Mean</b>	The sum of a set of numerical values divided by the number of values in the set.
<b>Measurement</b>	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
<b>Mineral Lease</b>	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
<b>Monte Carlo Simulation</b>	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).
<b>Multi-Scenario Method</b>	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.

<b>Natural Bitumen</b>	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non- hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa-s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
<b>Natural Gas</b>	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non- hydrocarbons.
<b>Natural Gas Liquids (NGLs)</b>	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
<b>Net Entitlement</b>	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest” is estimated using a formula based on the contract terms incorporating costs and profits.
<b>Net Pay</b>	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
<b>Net Revenue Interest</b>	An entity’s revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
<b>Netback Calculation</b>	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.
<b>Non-Hydrocarbon Gas</b>	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
<b>Non-Sales</b>	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non- hydrocarbons.
<b>Oil Sands</b>	Sand deposits highly saturated with natural bitumen. Also called “tar sands.” Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
<b>Oil Shales</b>	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called kerogen shale.)

<b>On Production</b>	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
<b>Overlift/Underlift</b>	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year- end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
<b>P1</b>	Denotes Proved Reserves. P1 is equal to 1P.
<b>P2</b>	Denotes Probable Reserves.
<b>P3</b>	Denotes Possible Reserves.
<b>Penetration</b>	The intersection of a wellbore with a reservoir.
<b>Petroleum</b>	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
<b>Petroleum Initially-in-Place (PIIP)</b>	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
<b>Pilot Project</b>	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
<b>Play</b>	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
<b>Pool</b>	An individual and separate accumulation of petroleum in a reservoir within a field.
<b>Possible Reserves</b>	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
<b>Primary Recovery</b>	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
<b>Probability</b>	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)

<b>Probabilistic Method</b>	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
<b>Probable Reserves</b>	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
<b>Production</b>	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
<b>Production Forecast</b>	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
<b>Production-Sharing Contract (PSC)</b>	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).
<b>Project</b>	<p>A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove.</p> <p>There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)</p>
<b>Property</b>	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.

<b>Prospect</b>	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
<b>Prospective Resources</b>	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
<b>Proved Reserves</b>	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
<b>Pure Service Contract</b>	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor’s reimbursement is fixed by the contract’s terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
<b>Qualified Reserves Auditor</b>	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
<b>Qualified Reserves Evaluator</b>	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
<b>Range of Uncertainty</b>	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
<b>Raw Production</b>	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).

<b>Reasonable Certainty</b>	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
<b>Reasonable Expectation</b>	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.)
<b>Recoverable Resources</b>	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
<b>Recovery Efficiency</b>	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
<b>Reference Point</b>	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
<b>Report</b>	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
<b>Reserves</b>	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
<b>Reservoir</b>	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
<b>Resources</b>	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
<b>Resources Categories</b>	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.

<b>Resources Classes</b>	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
<b>Resources Type</b>	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
<b>Revenue-Sharing Contract</b>	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
<b>Risk</b>	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
<b>Risk and Reward</b>	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
<b>Risk Service Contract (RSC)</b>	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
<b>Royalty</b>	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
<b>Sales</b>	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
<b>Shale Gas</b>	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
<b>Shale Oil</b>	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
<b>Shut-In Resources</b>	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.

<b>Split Classification</b>	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as “split classification.” If there are differing commercial conditions, separate sub-classes should be defined.
<b>Split Conditions</b>	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as “split conditions.”
<b>Stochastic</b>	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.
<b>Sub-Commercial</b>	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.
<b>Sunk Cost</b>	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
<b>Synthetic Crude Oil</b>	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
<b>Taxes</b>	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
<b>Technical Forecast</b>	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cut-off. (See also Technically Recoverable Resources).
<b>Technical Uncertainty</b>	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
<b>Technically Recoverable Resources</b>	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
<b>Technology Under Development</b>	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.

<b>Tight Gas</b>	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
<b>Tight Oil</b>	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
<b>Total Petroleum Initially-in-Place</b>	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
<b>Uncertainty</b>	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
<b>Unconventional Resources</b>	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called “continuous-type deposits”). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
<b>Undeveloped Reserves</b>	Those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.
<b>Undiscovered Petroleum Initially-in-Place</b>	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
<b>Unrecoverable Resources</b>	Those quantities of discovered or undiscovered PIIP that are assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
<b>Upgrader</b>	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
<b>Wet Gas</b>	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
<b>Working Interest</b>	An entity’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

## Appendix 2: Nomenclature

<b>3D</b>	three dimensional
<b>ABEX</b>	abandonment cost
<b>AFE</b>	authorisation for expenditure
<b>API</b>	American Petroleum Institute
<b>ARO</b>	asset retirement obligations
<b>AVO</b>	amplitude versus offset
<b>AXS</b>	Alba Extreme South
<b>bbl</b>	barrel (42 US gallons)
<b>Bg</b>	gas formation volume factor, in scf/rcf
<b>BH</b>	bottom hole
<b>Bo</b>	oil formation volume factor, in rb/stb
<b>Bscf</b>	thousands of millions of standard cubic feet
<b>CGR</b>	condensate gas ratio
<b>CO<sub>2</sub></b>	carbon dioxide
<b>CoP</b>	cessation of production
<b>CPR</b>	Competent Person's Report
<b>d</b>	day
<b>DC</b>	drill centre
<b>DCA</b>	decline curve analysis
<b>DHSV</b>	downhole safety valve
<b>Eg</b>	gas expansion factor
<b>ELT</b>	economic limit test
<b>FDP</b>	field development plan
<b>ERAP</b>	Emissions Reduction Action Plan
<b>FPD</b>	field development plan
<b>FDPA</b>	field development plan addendum
<b>FGL</b>	Fulmar Gas Line
<b>FPS</b>	Forties Pipeline System
<b>FPSO</b>	floating production storage and offloading vessel
<b>ft</b>	feet
<b>GDT</b>	gas down to

<b>G&amp;A</b>	general and administrative
<b>GEF</b>	gas expansion factor
<b>GIIP</b>	gas initially in place
<b>GKA</b>	Greater Kittiwake Area
<b>GOC</b>	gas oil contact
<b>GOR</b>	gas oil ratio
<b>GWC</b>	gas water contact
<b>HIIP</b>	hydrocarbons initially in place
<b>ICV</b>	interval control valve
<b>IOR</b>	Improved oil recovery
<b>IRM</b>	inspection, repair and maintenance
<b>JV</b>	Joint Venture
<b>kh</b>	permeability thickness
<b>km</b>	kilometres
<b>LoF</b>	Life of Field
<b>LP</b>	low pressure (ref pumps)
<b>LPG</b>	liquefied petroleum gas
<b>m</b>	metre
<b>M MM</b>	thousands and millions respectively
<b>MD</b>	measured depth
<b>md or mD</b>	millidarcy
<b>MDRKB</b>	measured depth below Kelly Bushing
<b>MDT</b>	modular dynamic tester
<b>MSL</b>	mean sea level
<b>mss</b>	metres subsea
<b>NBP</b>	National Balancing Point
<b>NGL</b>	natural gas liquids
<b>NPV xx</b>	net present value at xx discount rate
<b>NSTA</b>	North Sea Transition Authority
<b>NTG</b>	net to gross ratio
<b>NUI</b>	normally unmanned installation
<b>ODT</b>	oil down to
<b>O&amp;M</b>	operating and maintenance
<b>OGR</b>	oil gas ratio

<b>OPEX</b>	operating cost
<b>OWC</b>	oil water contact
<b>P90</b>	low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate)
<b>P50</b>	mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this estimate)
<b>P10</b>	high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate)
<b>Pb</b>	saturation, or bubble point, pressure
<b>PBU</b>	pressure-build-up
<b>PE</b>	production efficiency
<b>Phi</b>	porosity
<b>Phie</b>	effective porosity
<b>Phit</b>	total porosity
<b>PI</b>	productivity index, in stb/d/psi for oil or MMscf/d/psi or Mscf/d/psi for gas
<b>PIIP</b>	petroleum initially in place
<b>psi</b>	pressure, measured in pounds per square inch
<b>psia</b>	absolute pressure, measured in pounds per square inch
<b>psig</b>	gauge pressure which is the pressure above atmospheric pressure, measured in pounds per square inch
<b>PVT</b>	pressure volume temperature experiment
<b>rb</b>	reservoir barrels
<b>RCA</b>	routine core analysis
<b>rcf</b>	cubic feet at reservoir conditions
<b>RMS</b>	root mean square
<b>Rs</b>	solution gas oil ratio
<b>RWC</b>	relaxed well constraints
<b>SAGE</b>	Scottish Area Gas Evacuation
<b>scf</b>	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
<b>SCO</b>	stabilised crude oil
<b>SEGAL</b>	Shell Esso Gas and Associated Liquids (pipeline)
<b>ss</b>	sub-sea
<b>SSSV</b>	subsurface safety valve
<b>stb</b>	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
<b>STOIP</b>	stock tank oil initially in place
<b>Sw</b>	water saturation
<b>Swc</b>	connate water saturation

<b>TAR</b>	turn around (relates to planned facility related shutdowns)
<b>TD</b>	total depth
<b>THP</b>	tubing head pressure
<b>TVD</b>	true vertical depth
<b>TVDSS</b>	true vertical depth sub-sea
<b>UKCS</b>	UK Continental Shelf
<b>WGR</b>	water gas ratio
<b>WOR</b>	water oil ratio
<b>WP&amp;B</b>	work programme and budget
<b>WUT</b>	water up to

## Appendix 3: Cash flow tables



**Waldorf Production UK Limited**  
**Total UK Assets**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Net Oil stb/d	Field Net Production Rate			Pricing			Net Sales Revenue				Net Costs			Net Values	
		Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM	Aband. Costs £MM	Pre-Tax Revenues £MM	NPV10 £MM
2025	14,374	74.0	1,519	14,734	74.6	51.2	13.0	306.0	1.1	5.7	312.7	(186.5)	(19.7)	(4.6)	101.9	101.9
2026	11,861	71.2	1,380	12,193	74.3	50.5	11.4	251.6	1.0	4.5	257.1	(178.1)	(0.8)	(5.6)	72.5	69.2
2027	7,656	32.2	894	7,857	76.2	52.8	10.6	166.5	0.5	2.7	169.7	(143.5)	(2.4)	(21.9)	1.9	1.7
2028	6,721	24.0	662	6,870	77.7	53.6	10.9	149.5	0.4	2.1	152.0	(138.1)	(0.5)	(43.6)	(30.2)	(23.8)
2029	3,665	-	28	3,671	82.3	-	8.7	86.2	-	0.1	86.2	(88.1)	(0.4)	(88.5)	(90.7)	(65.0)
2030	3,724	-	292	3,777	84.0	-	7.8	89.3	-	0.7	89.9	(86.1)	(0.7)	(70.4)	(67.2)	(43.8)
2031	49	-	15	52	87.6	-	9.0	1.2	-	0.0	1.3	(0.8)	(0.2)	(59.6)	(59.4)	(35.1)
2032	37	-	13	40	89.3	-	9.2	0.9	-	0.0	1.0	(0.7)	(0.2)	(68.4)	(68.4)	(36.8)
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	(56.2)	(56.2)	(27.5)
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	(17.5)	(17.5)	(7.8)
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	(32.5)	(32.5)	(13.1)
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.0)	(0.0)	(0.0)
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.4)	(0.4)	(0.1)
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.1)	(0.1)	(0.0)
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>17.56</b>	<b>0.07</b>	<b>1.75</b>	<b>17.96</b>				<b>1,051.3</b>	<b>3.0</b>	<b>15.7</b>	<b>1,070.0</b>	<b>(821.8)</b>	<b>(25.0)</b>	<b>(469.3)</b>	<b>(246.1)</b>	<b>(80.3)</b>



**Waldorf Production UK Limited**  
**Total UK Assets**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Net Oil stb/d	Field Net Production Rate			Pricing			Net Sales Revenue				Net Costs			Net Values	
		Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM	Aband. Costs £MM	Pre-Tax Revenues £MM	NPV10 £MM
2025	16,156	122.4	2,652	16,776	74.7	50.9	13.1	344.5	1.8	9.9	356.3	(191.0)	(21.0)	(3.3)	140.9	140.9
2026	14,128	125.6	2,539	14,732	74.4	50.4	11.5	300.1	1.8	8.4	310.2	(183.3)	(3.3)	(4.5)	119.1	113.5
2027	10,251	55.1	1,592	10,607	76.5	52.9	10.7	223.8	0.8	4.9	229.5	(164.1)	(5.6)	(11.2)	48.5	42.1
2028	8,374	48.2	1,297	8,666	77.7	53.8	11.0	186.2	0.7	4.1	191.0	(149.0)	(0.5)	(26.7)	14.7	11.6
2029	7,149	39.1	1,059	7,387	78.9	54.6	11.2	161.1	0.6	3.4	165.1	(142.0)	(43.2)	(26.3)	(46.4)	(33.2)
2030	6,680	38.0	1,005	6,907	80.6	55.7	11.5	153.8	0.6	3.3	157.7	(133.5)	(12.7)	(53.1)	(41.6)	(27.1)
2031	6,447	28.4	1,661	6,780	82.3	56.8	9.6	151.5	0.5	4.6	156.5	(127.2)	(8.4)	(37.1)	(16.2)	(9.6)
2032	6,124	29.3	2,506	6,609	84.0	58.0	9.3	147.3	0.5	6.7	154.5	(127.5)	(8.6)	(56.9)	(38.5)	(20.7)
2033	2,152	22.0	582	2,283	79.8	59.1	12.2	49.0	0.4	2.0	51.4	(39.0)	(8.7)	(68.7)	(65.0)	(31.8)
2034	1,969	-	16	1,972	81.2	-	9.5	45.7	-	0.0	45.7	(37.8)	(0.3)	(21.9)	(14.2)	(6.3)
2035	1,931	-	18	1,935	82.8	-	9.7	45.7	-	0.0	45.7	(38.3)	-	(20.7)	(13.3)	(5.4)
2036	1,750	-	-	1,750	84.2	-	-	42.2	-	-	42.2	(41.6)	-	(21.6)	(21.1)	(7.8)
2037	1,727	-	-	1,727	85.8	-	-	42.3	-	-	42.3	(42.1)	-	(35.9)	(35.7)	(11.9)
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	(60.4)	(60.4)	(18.3)
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	(33.8)	(33.8)	(9.3)
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.9)	(4.9)	(1.2)
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.1)	(4.1)	(0.9)
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	(3.5)	(3.5)	(0.7)
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	(0.2)	(0.0)
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>30.98</b>	<b>0.19</b>	<b>5.45</b>	<b>32.19</b>				<b>1,893.2</b>	<b>7.7</b>	<b>47.3</b>	<b>1,948.2</b>	<b>(1,416.4)</b>	<b>(112.4)</b>	<b>(495.0)</b>	<b>(75.6)</b>	<b>123.7</b>



**Waldorf Production UK Limited**  
**Total UK Assets**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Net Oil stb/d	Field Net Production Rate			Pricing			Net Sales Revenue				Net Costs			Net Values	
		Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM	Aband. Costs £MM	Pre-Tax Revenues £MM	NPV10 £MM
2025	17,959	164.2	3,570	18,793	74.8	50.8	13.1	383.6	2.4	13.4	399.4	(196.0)	(19.7)	(3.3)	180.4	180.4
2026	16,594	172.6	3,438	17,415	74.5	50.4	11.6	353.0	2.5	11.4	366.8	(188.1)	(0.8)	(4.5)	173.3	165.3
2027	12,266	67.2	1,926	12,698	76.5	53.4	10.7	268.0	1.0	5.9	274.9	(170.5)	(2.4)	(11.2)	90.8	78.7
2028	10,334	62.0	1,660	10,709	77.7	54.3	11.0	229.9	1.0	5.2	236.1	(159.1)	(0.5)	(26.7)	49.7	39.2
2029	9,060	54.8	1,464	9,390	78.9	55.3	11.2	204.2	0.9	4.7	209.7	(151.4)	(43.2)	(26.3)	(11.2)	(8.0)
2030	8,291	54.8	1,474	8,623	80.5	55.7	11.4	190.6	0.9	4.8	196.3	(141.1)	(12.7)	(44.2)	(1.7)	(1.1)
2031	7,369	46.1	1,248	7,649	81.8	56.8	11.6	172.1	0.7	4.1	177.0	(140.1)	(8.4)	(27.0)	1.5	0.9
2032	7,478	47.1	1,800	7,859	83.7	58.0	10.8	179.3	0.8	5.5	185.6	(141.5)	(8.6)	(42.0)	(6.5)	(3.5)
2033	7,743	39.6	4,340	8,570	85.6	59.1	9.2	189.2	0.7	11.4	201.2	(139.8)	(8.7)	(45.8)	6.9	3.4
2034	7,047	40.1	4,048	7,822	87.2	60.3	9.5	175.4	0.7	10.9	187.0	(135.1)	(0.3)	(11.6)	40.0	17.8
2035	5,951	33.8	1,717	6,300	88.2	61.5	10.7	149.9	0.6	5.3	155.8	(128.7)	-	(18.3)	8.7	3.5
2036	2,486	33.9	877	2,684	84.3	62.8	13.0	60.0	0.6	3.3	63.9	(45.3)	-	(37.3)	(18.7)	(6.9)
2037	2,452	-	-	2,452	85.8	-	-	60.1	-	-	60.1	(42.5)	-	(20.8)	(3.2)	(1.1)
2038	2,317	-	-	2,317	87.6	-	-	57.9	-	-	57.9	(43.0)	-	(18.8)	(3.8)	(1.2)
2039	2,318	-	-	2,318	89.3	-	-	59.1	-	-	59.1	(43.6)	-	(20.2)	(4.7)	(1.3)
2040	2,196	-	-	2,196	91.1	-	-	57.3	-	-	57.3	(44.2)	-	(36.5)	(23.3)	(5.9)
2041	2,202	-	-	2,202	92.9	-	-	58.4	-	-	58.4	(44.7)	-	(1.7)	12.0	2.7
2042	2,091	-	-	2,091	94.8	-	-	56.6	-	-	56.6	(45.3)	-	(2.6)	8.7	1.8
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	(66.6)	(66.6)	(12.6)
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	(36.9)	(36.9)	(6.3)
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(0.8)
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.5)	(4.5)	(0.6)
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	(3.9)	(3.9)	(0.5)
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	(0.2)	(0.0)
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>46.07</b>	<b>0.30</b>	<b>10.06</b>	<b>48.24</b>				<b>2,904.5</b>	<b>12.7</b>	<b>85.9</b>	<b>3,003.1</b>	<b>(2,000.2)</b>	<b>(105.3)</b>	<b>(516.2)</b>	<b>381.5</b>	<b>443.9</b>



**Waldorf Production UK Limited**  
**Total UK Assets**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Net Oil stb/d	Field Net Production Rate			Pricing			Net Sales Revenue				Net Costs			Net Values	
		Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM	Aband. Costs £MM	Pre-Tax Revenues £MM	NPV10 £MM
2025	14,381	74.4	1,526	14,743	74.6	51.2	13.0	306.2	1.1	5.7	312.9	(186.5)	(34.3)	(4.7)	87.4	87.4
2026	12,294	95.8	1,764	12,722	74.4	50.2	11.6	261.0	1.4	5.8	268.2	(179.7)	(34.4)	(1.2)	53.0	50.5
2027	9,538	93.8	1,544	9,922	76.7	51.6	11.1	209.0	1.4	4.9	215.2	(162.8)	(22.2)	(16.5)	13.7	11.9
2028	8,328	69.7	1,075	8,599	78.2	52.5	11.4	186.6	1.0	3.5	191.1	(155.2)	(12.1)	(27.9)	(4.0)	(3.2)
2029	5,084	34.8	275	5,170	82.2	53.0	12.0	119.4	0.5	0.9	120.9	(107.4)	(0.4)	(99.6)	(86.5)	(61.9)
2030	3,735	-	280	3,785	84.0	-	7.8	89.5	-	0.6	90.2	(86.2)	(0.7)	(58.1)	(54.9)	(35.7)
2031	61	-	-	61	87.6	-	-	1.5	-	-	1.5	(0.9)	(0.2)	(60.9)	(60.5)	(35.8)
2032	49	-	-	49	89.3	-	-	1.2	-	-	1.2	(0.8)	(0.2)	(51.8)	(51.6)	(27.8)
2033	47	-	-	47	91.1	-	-	1.2	-	-	1.2	(0.9)	(0.3)	(62.3)	(62.3)	(30.5)
2034	40	-	-	40	92.9	-	-	1.1	-	-	1.1	(0.9)	(0.3)	(51.5)	(51.5)	(22.9)
2035	40	-	-	40	94.8	-	-	1.1	-	-	1.1	(0.9)	-	(35.4)	(35.3)	(14.3)
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	(2.8)	(2.8)	(1.0)
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	(0.5)	(0.2)
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.1)	(0.1)	(0.0)
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.0)	(0.0)	(0.0)
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.0)	(0.0)	(0.0)
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.1)	(0.1)	(0.0)
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>19.57</b>	<b>0.13</b>	<b>2.36</b>	<b>20.15</b>				<b>1,177.8</b>	<b>5.4</b>	<b>21.5</b>	<b>1,204.7</b>	<b>(882.2)</b>	<b>(105.1)</b>	<b>(473.4)</b>	<b>(256.0)</b>	<b>(83.6)</b>



**Waldorf Production UK Limited**  
**Total UK Assets**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Net Oil stb/d	Field Net Production Rate			Pricing			Net Sales Revenue				Net Costs			Net Values	
		Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM	Aband. Costs £MM	Pre-Tax Revenues £MM	NPV10 £MM
2025	16,169	123.1	2,663	16,792	74.7	50.9	13.1	344.8	1.8	10.0	356.6	(191.0)	(35.6)	(3.3)	126.6	126.6
2026	14,825	165.3	3,169	15,587	74.5	50.2	11.6	315.3	2.4	10.5	328.2	(185.0)	(36.9)	(0.0)	106.3	101.3
2027	12,873	159.8	2,949	13,587	77.0	51.7	11.1	283.0	2.4	9.3	294.7	(185.2)	(25.5)	(5.8)	78.2	67.8
2028	10,658	132.3	2,323	11,226	78.3	52.6	11.4	238.8	2.0	7.6	248.4	(168.2)	(12.1)	(10.9)	57.1	45.0
2029	9,311	115.4	1,961	9,794	79.6	53.5	11.6	211.7	1.8	6.5	220.0	(163.6)	(43.2)	(36.8)	(23.7)	(16.9)
2030	6,709	38.0	987	6,932	80.7	55.7	11.5	154.5	0.6	3.2	158.4	(133.6)	(12.7)	(40.5)	(28.4)	(18.5)
2031	6,481	28.4	1,645	6,810	82.3	56.8	9.6	152.3	0.5	4.5	157.3	(127.4)	(8.4)	(38.9)	(17.3)	(10.3)
2032	6,156	29.3	2,490	6,638	84.0	58.0	9.3	148.2	0.5	6.6	155.3	(127.7)	(8.6)	(42.8)	(23.7)	(12.8)
2033	2,186	22.0	566	2,314	79.9	59.1	12.2	49.9	0.4	2.0	52.2	(39.2)	(8.7)	(78.0)	(73.7)	(36.1)
2034	2,000	-	-	2,000	81.4	-	-	46.5	-	-	46.5	(38.1)	(0.3)	(56.2)	(48.0)	(21.4)
2035	1,964	-	-	1,964	83.0	-	-	46.6	-	-	46.6	(38.6)	-	(21.2)	(13.2)	(5.3)
2036	1,750	-	-	1,750	84.2	-	-	42.2	-	-	42.2	(41.6)	-	(21.6)	(21.1)	(7.8)
2037	1,727	-	-	1,727	85.8	-	-	42.3	-	-	42.3	(42.1)	-	(35.9)	(35.7)	(11.9)
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	(60.4)	(60.4)	(18.3)
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	(33.8)	(33.8)	(9.3)
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.9)	(4.9)	(1.2)
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.1)	(4.1)	(0.9)
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	(3.5)	(3.5)	(0.7)
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	(0.2)	(0.0)
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>33.89</b>	<b>0.30</b>	<b>6.85</b>	<b>35.47</b>				<b>2,076.1</b>	<b>12.2</b>	<b>60.3</b>	<b>2,148.5</b>	<b>(1,481.3)</b>	<b>(192.0)</b>	<b>(498.9)</b>	<b>(23.6)</b>	<b>169.1</b>



**Waldorf Production UK Limited**  
**Total UK Assets**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Net Oil stb/d	Field Net Production Rate			Pricing			Net Sales Revenue				Net Costs			Net Values	
		Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM	Aband. Costs £MM	Pre-Tax Revenues £MM	NPV10 £MM
2025	17,977	165.2	3,586	18,814	74.8	50.8	13.1	384.0	2.4	13.5	399.9	(196.1)	(34.3)	(3.3)	166.2	166.2
2026	17,490	223.6	4,243	18,512	74.6	50.2	11.7	372.5	3.2	14.2	389.9	(189.8)	(34.4)	(0.0)	165.7	157.9
2027	15,876	229.3	4,180	16,890	77.1	51.7	11.1	349.4	3.4	13.3	366.1	(193.4)	(22.2)	(5.8)	144.8	125.5
2028	13,560	200.3	3,529	14,421	78.4	52.6	11.4	304.2	3.0	11.5	318.8	(180.1)	(12.1)	(10.9)	115.7	91.1
2029	12,168	184.8	3,204	12,953	79.7	53.6	11.6	277.0	2.8	10.6	290.5	(174.9)	(43.2)	(36.8)	35.6	25.5
2030	8,333	54.8	1,437	8,657	80.5	55.7	11.5	191.6	0.9	4.7	197.2	(141.2)	(12.7)	(31.6)	11.7	7.6
2031	7,417	46.1	1,218	7,692	81.8	56.8	11.7	173.3	0.7	4.1	178.1	(140.3)	(8.4)	(28.7)	0.7	0.4
2032	7,526	47.1	1,775	7,902	83.8	58.0	10.8	180.5	0.8	5.5	186.8	(141.7)	(8.6)	(27.9)	8.6	4.6
2033	7,796	39.6	4,322	8,619	85.6	59.1	9.2	190.5	0.7	11.4	202.6	(140.1)	(8.7)	(55.0)	(1.3)	(0.6)
2034	7,098	40.1	4,028	7,869	87.2	60.3	9.5	176.7	0.7	10.9	188.3	(135.4)	(0.3)	(45.9)	6.7	3.0
2035	6,007	33.8	1,695	6,352	88.3	61.5	10.7	151.5	0.6	5.2	157.2	(129.0)	-	(18.8)	9.4	3.8
2036	2,486	33.9	877	2,684	84.3	62.8	13.0	60.0	0.6	3.3	63.9	(45.3)	-	(37.3)	(18.7)	(6.9)
2037	2,452	-	-	2,452	85.8	-	-	60.1	-	-	60.1	(42.5)	-	(20.8)	(3.2)	(1.1)
2038	2,317	-	-	2,317	87.6	-	-	57.9	-	-	57.9	(43.0)	-	(18.8)	(3.8)	(1.2)
2039	2,318	-	-	2,318	89.3	-	-	59.1	-	-	59.1	(43.6)	-	(20.2)	(4.7)	(1.3)
2040	2,196	-	-	2,196	91.1	-	-	57.3	-	-	57.3	(44.2)	-	(36.5)	(23.3)	(5.9)
2041	2,202	-	-	2,202	92.9	-	-	58.4	-	-	58.4	(44.7)	-	(1.7)	12.0	2.7
2042	2,091	-	-	2,091	94.8	-	-	56.6	-	-	56.6	(45.3)	-	(2.6)	8.7	1.8
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	(66.6)	(66.6)	(12.6)
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	(36.9)	(36.9)	(6.3)
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(0.8)
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	(4.5)	(4.5)	(0.6)
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	(3.9)	(3.9)	(0.5)
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	(0.2)	(0.0)
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>50.14</b>	<b>0.47</b>	<b>12.45</b>	<b>52.93</b>				<b>3,160.7</b>	<b>19.8</b>	<b>108.1</b>	<b>3,288.6</b>	<b>(2,070.5)</b>	<b>(184.9)</b>	<b>(520.0)</b>	<b>513.3</b>	<b>552.5</b>



**Waldorf Production UK Limited  
Bacchus Field, UK  
Production and Revenue Forecasts  
Proved Developed Reserves  
Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	755	4	-	759	227	1.1	-	228	77	76	-	5.0	0.0	-	5.0	(1.7)	-
2026	293	2	-	294	88	0.5	-	88	76	76	-	1.9	0.0	-	1.9	(1.1)	-
2027	123	1	-	124	37	0.2	-	37	79	78	-	0.8	0.0	-	0.8	(0.7)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.43</b>	<b>0.00</b>	<b>0.00</b>	<b>0.43</b>	<b>0.128</b>	<b>0.001</b>	<b>-</b>	<b>0.129</b>				<b>7.7</b>	<b>0.0</b>	<b>-</b>	<b>7.8</b>	<b>(3.4)</b>	<b>-</b>



**Waldorf Production UK Limited  
Bacchus Field, UK  
Production and Revenue Forecasts  
Proved + Probable Developed Reserves  
Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	928	4	-	933	278	1.3	-	280	77	76	-	6.1	0.0	-	6.1	(2.1)	-
2026	568	3	-	572	171	0.9	-	171	76	76	-	3.7	0.0	-	3.7	(1.9)	-
2027	424	2	-	426	127	0.7	-	128	79	78	-	2.9	0.0	-	2.9	(2.0)	-
2028	294	2	-	295	88	0.5	-	89	80	80	-	2.0	0.0	-	2.0	(1.6)	-
2029	219	-	-	219	66	-	-	66	82	-	-	1.5	-	-	1.5	(1.4)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.89</b>	<b>0.00</b>	<b>0.00</b>	<b>0.89</b>	<b>0.267</b>	<b>0.001</b>	<b>-</b>	<b>0.268</b>				<b>16.3</b>	<b>0.1</b>	<b>-</b>	<b>16.3</b>	<b>(9.0)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Bacchus Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,103	5	-	1,109	331	1.6	-	333	77	76	-	7.3	0.0	-	7.3	(2.5)	-
2026	1,222	7	-	1,229	367	2.0	-	369	76	76	-	8.0	0.0	-	8.0	(4.0)	-
2027	1,299	7	-	1,306	390	2.1	-	392	79	78	-	8.8	0.0	-	8.8	(5.8)	-
2028	1,018	6	-	1,024	306	1.7	-	307	80	80	-	7.0	0.0	-	7.1	(5.2)	-
2029	860	5	-	865	258	1.4	-	259	82	81	-	6.0	0.0	-	6.1	(4.9)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.01</b>	<b>0.01</b>	<b>0.00</b>	<b>2.02</b>	<b>0.603</b>	<b>0.003</b>	<b>-</b>	<b>0.606</b>				<b>37.1</b>	<b>0.2</b>	<b>-</b>	<b>37.3</b>	<b>(22.6)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Bacchus Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	755	4	-	759	227	1.1	-	228	77	76	-	5.0	0.0	-	5.0	(1.7)	-
2026	293	2	-	294	88	0.5	-	88	76	76	-	1.9	0.0	-	1.9	(1.1)	-
2027	123	1	-	124	37	0.2	-	37	79	78	-	0.8	0.0	-	0.8	(0.7)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.43</b>	<b>0.00</b>	<b>0.00</b>	<b>0.43</b>	<b>0.128</b>	<b>0.001</b>	<b>-</b>	<b>0.129</b>				<b>7.7</b>	<b>0.0</b>	<b>-</b>	<b>7.8</b>	<b>(3.4)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Bacchus Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	928	4	-	933	278	1.3	-	280	77	76	-	6.1	0.0	-	6.1	(2.1)	-
2026	568	3	-	572	171	0.9	-	171	76	76	-	3.7	0.0	-	3.7	(1.9)	-
2027	424	2	-	426	127	0.7	-	128	79	78	-	2.9	0.0	-	2.9	(2.0)	-
2028	294	2	-	295	88	0.5	-	89	80	80	-	2.0	0.0	-	2.0	(1.6)	-
2029	219	-	-	219	66	-	-	66	82	-	-	1.5	-	-	1.5	(1.4)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.89</b>	<b>0.00</b>	<b>0.00</b>	<b>0.89</b>	<b>0.267</b>	<b>0.001</b>	<b>-</b>	<b>0.268</b>				<b>16.3</b>	<b>0.1</b>	<b>-</b>	<b>16.3</b>	<b>(9.0)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Bacchus Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,103	5	-	1,109	331	1.6	-	333	77	76	-	7.3	0.0	-	7.3	(2.5)	-
2026	1,222	7	-	1,229	367	2.0	-	369	76	76	-	8.0	0.0	-	8.0	(4.0)	-
2027	1,299	7	-	1,306	390	2.1	-	392	79	78	-	8.8	0.0	-	8.8	(5.8)	-
2028	1,018	6	-	1,024	306	1.7	-	307	80	80	-	7.0	0.0	-	7.1	(5.2)	-
2029	860	5	-	865	258	1.4	-	259	82	81	-	6.0	0.0	-	6.1	(4.9)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.01</b>	<b>0.01</b>	<b>0.00</b>	<b>2.02</b>	<b>0.603</b>	<b>0.003</b>	<b>-</b>	<b>0.606</b>				<b>37.1</b>	<b>0.2</b>	<b>-</b>	<b>37.3</b>	<b>(22.6)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Bittern Field, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	3,598	-	3,222	4,233	87	-	78	103	79	-	10	2.0	-	0.2	2.2	(0.9)	(0.6)
2026	6,172	-	4,414	7,042	149	-	107	171	78	-	9	3.3	-	0.3	3.6	(1.1)	(0.6)
2027	4,967	-	2,839	5,526	120	-	69	134	81	-	8	2.8	-	0.2	2.9	(1.1)	(0.6)
2028	3,655	-	1,784	4,006	89	-	43	97	83	-	8	2.1	-	0.1	2.2	(0.9)	(0.5)
2029	3,090	-	1,175	3,322	75	-	28	80	84	-	9	1.8	-	0.1	1.9	(0.9)	(0.4)
2030	2,287	-	500	2,385	55	-	12	58	86	-	9	1.4	-	0.0	1.4	(0.8)	(0.7)
2031	2,028	-	600	2,147	49	-	15	52	88	-	9	1.2	-	0.0	1.3	(0.8)	(0.2)
2032	1,532	-	520	1,635	37	-	13	40	89	-	9	0.9	-	0.0	1.0	(0.7)	(0.2)
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>9.98</b>	<b>0.00</b>	<b>5.50</b>	<b>11.06</b>	<b>0.242</b>	<b>-</b>	<b>0.133</b>	<b>0.268</b>				<b>15.5</b>	<b>-</b>	<b>0.9</b>	<b>16.4</b>	<b>(7.1)</b>	<b>(4.0)</b>



**Waldorf Production UK Limited**  
**Bittern Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	4,198	-	3,899	4,966	102	-	94	120	79	-	10	2.3	-	0.3	2.6	(1.0)	(0.6)
2026	8,183	-	6,356	9,435	198	-	154	229	78	-	9	4.4	-	0.4	4.8	(1.2)	(0.6)
2027	7,525	-	4,606	8,432	182	-	112	204	81	-	8	4.2	-	0.3	4.5	(1.3)	(0.6)
2028	5,711	-	2,852	6,273	138	-	69	152	83	-	8	3.3	-	0.2	3.4	(1.2)	(0.5)
2029	5,251	-	2,174	5,679	127	-	53	138	84	-	9	3.1	-	0.1	3.2	(1.2)	(0.4)
2030	4,190	-	1,074	4,401	101	-	26	107	86	-	9	2.5	-	0.1	2.6	(1.2)	(0.7)
2031	3,882	-	1,148	4,108	94	-	28	100	88	-	9	2.4	-	0.1	2.4	(1.1)	(0.2)
2032	3,106	-	744	3,253	75	-	18	79	89	-	9	1.9	-	0.0	2.0	(1.1)	(0.2)
2033	2,896	-	663	3,027	70	-	16	73	91	-	9	1.8	-	0.0	1.9	(1.1)	(0.3)
2034	2,341	-	679	2,474	57	-	16	60	93	-	10	1.5	-	0.0	1.5	(1.0)	(0.3)
2035	2,205	-	731	2,349	53	-	18	57	95	-	10	1.4	-	0.0	1.5	(1.1)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>18.07</b>	<b>0.00</b>	<b>9.10</b>	<b>19.86</b>	<b>0.438</b>	<b>-</b>	<b>0.220</b>	<b>0.481</b>				<b>28.8</b>	<b>-</b>	<b>1.5</b>	<b>30.3</b>	<b>(12.5)</b>	<b>(4.5)</b>



**Waldorf Production UK Limited**  
**Bittern Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	4,750	-	4,552	5,647	115	-	110	137	79	-	10	2.6	-	0.3	2.9	(1.0)	(0.6)
2026	9,498	-	7,896	11,054	230	-	191	268	78	-	9	5.1	-	0.5	5.6	(1.3)	(0.6)
2027	8,806	-	6,418	10,070	213	-	155	244	81	-	8	4.9	-	0.4	5.3	(1.4)	(0.6)
2028	7,168	-	4,449	8,044	174	-	108	195	83	-	8	4.1	-	0.3	4.4	(1.3)	(0.5)
2029	6,787	-	3,784	7,532	164	-	92	182	84	-	9	4.0	-	0.2	4.2	(1.3)	(0.4)
2030	5,678	-	2,619	6,194	138	-	63	150	86	-	9	3.4	-	0.2	3.5	(1.4)	(0.7)
2031	5,568	-	2,613	6,082	135	-	63	147	88	-	9	3.4	-	0.2	3.5	(1.4)	(0.2)
2032	4,664	-	1,830	5,024	113	-	44	122	89	-	9	2.9	-	0.1	3.0	(1.3)	(0.2)
2033	4,596	-	1,591	4,910	111	-	39	119	91	-	9	2.9	-	0.1	3.0	(1.4)	(0.3)
2034	3,934	-	1,515	4,232	95	-	37	103	93	-	10	2.5	-	0.1	2.6	(1.4)	(0.3)
2035	3,872	-	1,779	4,222	94	-	43	102	95	-	10	2.5	-	0.1	2.7	(1.5)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>23.85</b>	<b>0.00</b>	<b>14.26</b>	<b>26.66</b>	<b>0.578</b>	<b>-</b>	<b>0.345</b>	<b>0.646</b>				<b>38.3</b>	<b>-</b>	<b>2.4</b>	<b>40.7</b>	<b>(14.8)</b>	<b>(4.5)</b>



**Waldorf Production UK Limited  
Bittern Field, UK  
Production and Revenue Forecasts  
Total Proved Reserves (1P)**

Total Proved Reserves (1P) - the 1P Reserves are less than the volumes shown, as the PUDs are assessed as being uneconomic

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	3,598	-	3,222	4,233	87	-	78	103	79	-	10	2.0	-	0.2	2.2	(0.9)	(1.7)
2026	6,294	-	4,016	7,085	152	-	97	172	78	-	9	3.4	-	0.2	3.7	(1.1)	(0.6)
2027	5,296	-	1,282	5,549	128	-	31	134	81	-	8	3.0	-	0.1	3.0	(1.1)	(0.6)
2028	3,983	-	263	4,035	96	-	6	98	83	-	8	2.3	-	0.0	2.3	(0.9)	(0.5)
2029	3,526	-	-	3,526	85	-	-	85	84	-	-	2.1	-	-	2.1	(0.9)	(0.4)
2030	2,725	-	-	2,725	66	-	-	66	86	-	-	1.6	-	-	1.6	(1.0)	(0.7)
2031	2,507	-	-	2,507	61	-	-	61	88	-	-	1.5	-	-	1.5	(0.9)	(0.2)
2032	2,012	-	-	2,012	49	-	-	49	89	-	-	1.2	-	-	1.2	(0.8)	(0.2)
2033	1,927	-	-	1,927	47	-	-	47	91	-	-	1.2	-	-	1.2	(0.9)	(0.3)
2034	1,647	-	-	1,647	40	-	-	40	93	-	-	1.1	-	-	1.1	(0.9)	(0.3)
2035	1,659	-	-	1,659	40	-	-	40	95	-	-	1.1	-	-	1.1	(0.9)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>12.84</b>	<b>0.00</b>	<b>3.21</b>	<b>13.48</b>	<b>0.311</b>	<b>-</b>	<b>0.078</b>	<b>0.326</b>				<b>20.4</b>	<b>-</b>	<b>0.6</b>	<b>21.0</b>	<b>(10.3)</b>	<b>(5.6)</b>

Note: Production rates include the rates from the sub-economic Undeveloped project related to the water injection pipeline replacement



**Waldorf Production UK Limited**  
**Bittern Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	4,198	-	3,899	4,966	102	-	94	120	79	-	10	2.3	-	0.3	2.6	(1.0)	(1.7)
2026	8,318	-	6,162	9,532	201	-	149	231	78	-	9	4.5	-	0.4	4.9	(1.3)	(0.6)
2027	8,035	-	3,541	8,733	195	-	86	212	81	-	8	4.5	-	0.2	4.7	(1.3)	(0.6)
2028	6,546	-	1,790	6,899	159	-	43	167	83	-	8	3.7	-	0.1	3.9	(1.2)	(0.5)
2029	6,391	-	1,354	6,658	155	-	33	161	84	-	9	3.7	-	0.1	3.8	(1.3)	(0.4)
2030	5,383	-	360	5,454	130	-	9	132	86	-	9	3.2	-	0.0	3.2	(1.3)	(0.7)
2031	5,257	-	508	5,357	127	-	12	130	88	-	9	3.2	-	0.0	3.2	(1.3)	(0.2)
2032	4,409	-	69	4,422	107	-	2	107	89	-	9	2.7	-	0.0	2.7	(1.2)	(0.2)
2033	4,302	-	-	4,302	104	-	-	104	91	-	-	2.7	-	-	2.7	(1.4)	(0.3)
2034	3,646	-	-	3,646	88	-	-	88	93	-	-	2.3	-	-	2.3	(1.3)	(0.3)
2035	3,569	-	-	3,569	86	-	-	86	95	-	-	2.3	-	-	2.3	(1.4)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>21.93</b>	<b>0.00</b>	<b>6.46</b>	<b>23.20</b>	<b>0.531</b>	<b>-</b>	<b>0.156</b>	<b>0.562</b>				<b>35.3</b>	<b>-</b>	<b>1.1</b>	<b>36.4</b>	<b>(14.0)</b>	<b>(5.6)</b>



**Waldorf Production UK Limited**  
**Bittern Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	4,750	-	4,552	5,647	115	-	110	137	79	-	10	2.6	-	0.3	2.9	(1.0)	(1.7)
2026	9,687	-	7,466	11,158	235	-	181	270	78	-	9	5.2	-	0.5	5.7	(1.3)	(0.6)
2027	9,526	-	4,275	10,368	231	-	104	251	81	-	8	5.3	-	0.2	5.6	(1.4)	(0.6)
2028	8,285	-	2,395	8,757	201	-	58	212	83	-	8	4.7	-	0.1	4.9	(1.4)	(0.5)
2029	8,387	-	2,127	8,806	203	-	52	213	84	-	9	4.9	-	0.1	5.0	(1.4)	(0.4)
2030	7,383	-	1,097	7,599	179	-	27	184	86	-	9	4.4	-	0.1	4.5	(1.5)	(0.7)
2031	7,569	-	1,356	7,836	183	-	33	190	88	-	9	4.6	-	0.1	4.7	(1.5)	(0.2)
2032	6,647	-	796	6,804	161	-	19	165	89	-	9	4.1	-	0.1	4.2	(1.5)	(0.2)
2033	6,795	-	814	6,955	165	-	20	168	91	-	9	4.3	-	0.1	4.3	(1.7)	(0.3)
2034	6,038	-	690	6,174	146	-	17	150	93	-	10	3.9	-	0.0	3.9	(1.6)	(0.3)
2035	6,206	-	873	6,378	150	-	21	154	95	-	10	4.1	-	0.1	4.1	(1.8)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>29.68</b>	<b>0.00</b>	<b>9.65</b>	<b>31.58</b>	<b>0.719</b>	<b>-</b>	<b>0.234</b>	<b>0.765</b>				<b>48.1</b>	<b>-</b>	<b>1.6</b>	<b>49.8</b>	<b>(16.3)</b>	<b>(5.6)</b>



**Waldorf Production UK Limited**  
**Catcher Field, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	18,993	-	315	19,050	7,597	-	126	7,620	77	-	9	167.0	-	0.3	167.3	(96.4)	(1.3)
2026	15,749	-	-	15,749	6,300	-	-	6,300	77	-	-	137.7	-	-	137.7	(97.3)	(0.2)
2027	11,888	-	-	11,888	4,755	-	-	4,755	79	-	-	107.6	-	-	107.6	(97.5)	(0.2)
2028	10,862	-	-	10,862	4,345	-	-	4,345	81	-	-	100.4	-	-	100.4	(94.8)	-
2029	8,976	-	-	8,976	3,590	-	-	3,590	82	-	-	84.4	-	-	84.4	(87.2)	-
2030	9,172	-	699	9,298	3,669	-	280	3,719	84	-	8	87.9	-	0.6	88.5	(85.2)	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>27.62</b>	<b>0.00</b>	<b>0.37</b>	<b>27.69</b>	<b>11.048</b>	<b>-</b>	<b>0.148</b>	<b>11.075</b>				<b>684.9</b>	<b>-</b>	<b>0.9</b>	<b>685.8</b>	<b>(558.3)</b>	<b>(1.7)</b>



**Waldorf Production UK Limited**  
**Catcher Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	21,082	-	619	21,193	8,433	-	248	8,477	77	-	9	185.3	-	0.6	186.0	(96.8)	(1.3)
2026	18,200	-	-	18,200	7,280	-	-	7,280	77	-	-	159.1	-	-	159.1	(96.7)	(0.2)
2027	14,256	-	-	14,256	5,702	-	-	5,702	79	-	-	129.0	-	-	129.0	(96.9)	(0.2)
2028	13,093	-	-	13,093	5,237	-	-	5,237	81	-	-	121.0	-	-	121.0	(102.9)	-
2029	10,580	-	-	10,580	4,232	-	-	4,232	82	-	-	99.4	-	-	99.4	(97.3)	-
2030	10,339	-	-	10,339	4,136	-	-	4,136	84	-	-	99.1	-	-	99.1	(95.4)	-
2031	10,068	-	2,257	10,472	4,027	-	903	4,189	86	-	8	98.4	-	2.0	100.5	(89.0)	-
2032	9,773	-	4,334	10,550	3,909	-	1,733	4,220	87	-	8	97.7	-	4.0	101.7	(88.9)	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>39.22</b>	<b>0.00</b>	<b>2.64</b>	<b>39.69</b>	<b>15.688</b>	<b>-</b>	<b>1.054</b>	<b>15.877</b>				<b>989.1</b>	<b>-</b>	<b>6.7</b>	<b>995.8</b>	<b>(763.9)</b>	<b>(1.7)</b>



**Waldorf Production UK Limited**  
**Catcher Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	23,243	-	906	23,405	9,297	-	362	9,362	77	-	9	204.3	-	0.9	205.3	(97.2)	(1.3)
2026	20,886	-	-	20,886	8,354	-	-	8,354	77	-	-	182.6	-	-	182.6	(97.2)	(0.2)
2027	16,700	-	-	16,700	6,680	-	-	6,680	79	-	-	151.1	-	-	151.1	(97.4)	(0.2)
2028	15,781	-	-	15,781	6,312	-	-	6,312	81	-	-	145.8	-	-	145.8	(108.5)	-
2029	13,004	-	-	13,004	5,201	-	-	5,201	82	-	-	122.2	-	-	122.2	(102.2)	-
2030	12,475	-	-	12,475	4,990	-	-	4,990	84	-	-	119.6	-	-	119.6	(102.1)	-
2031	10,415	-	-	10,415	4,166	-	-	4,166	86	-	-	101.8	-	-	101.8	(100.9)	-
2032	11,248	-	1,357	11,492	4,499	-	543	4,597	87	-	8	112.5	-	1.3	113.7	(101.7)	-
2033	12,005	-	8,208	13,477	4,802	-	3,283	5,391	89	-	8	122.1	-	7.7	129.9	(99.4)	-
2034	10,736	-	7,446	12,071	4,294	-	2,978	4,828	91	-	8	111.4	-	7.2	118.5	(93.9)	-
2035	8,051	-	2,006	8,411	3,220	-	803	3,364	93	-	9	85.2	-	2.0	87.2	(86.8)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>56.44</b>	<b>0.00</b>	<b>7.27</b>	<b>57.74</b>	<b>22.574</b>	<b>-</b>	<b>2.909</b>	<b>23.096</b>				<b>1,458.7</b>	<b>-</b>	<b>19.1</b>	<b>1,477.7</b>	<b>(1,087.2)</b>	<b>(1.7)</b>



**Waldorf Production UK Limited**  
**Catcher Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	18,993	-	315	19,050	7,597	-	126	7,620	77	-	9	167.0	-	0.3	167.3	(96.4)	(1.3)
2026	15,749	-	-	15,749	6,300	-	-	6,300	77	-	-	137.7	-	-	137.7	(97.3)	(0.2)
2027	11,888	-	-	11,888	4,755	-	-	4,755	79	-	-	107.6	-	-	107.6	(97.5)	(0.2)
2028	10,862	-	-	10,862	4,345	-	-	4,345	81	-	-	100.4	-	-	100.4	(94.8)	-
2029	8,976	-	-	8,976	3,590	-	-	3,590	82	-	-	84.4	-	-	84.4	(87.2)	-
2030	9,172	-	699	9,298	3,669	-	280	3,719	84	-	8	87.9	-	0.6	88.5	(85.2)	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>27.62</b>	<b>0.00</b>	<b>0.37</b>	<b>27.69</b>	<b>11.048</b>	<b>-</b>	<b>0.148</b>	<b>11.075</b>				<b>684.9</b>	<b>-</b>	<b>0.9</b>	<b>685.8</b>	<b>(558.3)</b>	<b>(1.7)</b>



**Waldorf Production UK Limited**  
**Catcher Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	21,082	-	619	21,193	8,433	-	248	8,477	77	-	9	185.3	-	0.6	186.0	(96.8)	(1.3)
2026	18,200	-	-	18,200	7,280	-	-	7,280	77	-	-	159.1	-	-	159.1	(96.7)	(0.2)
2027	14,256	-	-	14,256	5,702	-	-	5,702	79	-	-	129.0	-	-	129.0	(96.9)	(0.2)
2028	13,093	-	-	13,093	5,237	-	-	5,237	81	-	-	121.0	-	-	121.0	(102.9)	-
2029	10,580	-	-	10,580	4,232	-	-	4,232	82	-	-	99.4	-	-	99.4	(97.3)	-
2030	10,339	-	-	10,339	4,136	-	-	4,136	84	-	-	99.1	-	-	99.1	(95.4)	-
2031	10,068	-	2,257	10,472	4,027	-	903	4,189	86	-	8	98.4	-	2.0	100.5	(89.0)	-
2032	9,773	-	4,334	10,550	3,909	-	1,733	4,220	87	-	8	97.7	-	4.0	101.7	(88.9)	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>39.22</b>	<b>0.00</b>	<b>2.64</b>	<b>39.69</b>	<b>15.688</b>	<b>-</b>	<b>1.054</b>	<b>15.877</b>				<b>989.1</b>	<b>-</b>	<b>6.7</b>	<b>995.8</b>	<b>(763.9)</b>	<b>(1.7)</b>



**Waldorf Production UK Limited**  
**Catcher Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	23,243	-	906	23,405	9,297	-	362	9,362	77	-	9	204.3	-	0.9	205.3	(97.2)	(1.3)
2026	20,886	-	-	20,886	8,354	-	-	8,354	77	-	-	182.6	-	-	182.6	(97.2)	(0.2)
2027	16,700	-	-	16,700	6,680	-	-	6,680	79	-	-	151.1	-	-	151.1	(97.4)	(0.2)
2028	15,781	-	-	15,781	6,312	-	-	6,312	81	-	-	145.8	-	-	145.8	(108.5)	-
2029	13,004	-	-	13,004	5,201	-	-	5,201	82	-	-	122.2	-	-	122.2	(102.2)	-
2030	12,475	-	-	12,475	4,990	-	-	4,990	84	-	-	119.6	-	-	119.6	(102.1)	-
2031	10,415	-	-	10,415	4,166	-	-	4,166	86	-	-	101.8	-	-	101.8	(100.9)	-
2032	11,248	-	1,357	11,492	4,499	-	543	4,597	87	-	8	112.5	-	1.3	113.7	(101.7)	-
2033	12,005	-	8,208	13,477	4,802	-	3,283	5,391	89	-	8	122.1	-	7.7	129.9	(99.4)	-
2034	10,736	-	7,446	12,071	4,294	-	2,978	4,828	91	-	8	111.4	-	7.2	118.5	(93.9)	-
2035	8,051	-	2,006	8,411	3,220	-	803	3,364	93	-	9	85.2	-	2.0	87.2	(86.8)	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>56.44</b>	<b>0.00</b>	<b>7.27</b>	<b>57.74</b>	<b>22.574</b>	<b>-</b>	<b>2.909</b>	<b>23.096</b>				<b>1,458.7</b>	<b>-</b>	<b>19.1</b>	<b>1,477.7</b>	<b>(1,087.2)</b>	<b>(1.7)</b>



**Waldorf Production UK Limited**  
**Columbus Field, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	138	179	4,609	1,181	34	44.8	1,152	295	76	51	13	0.7	0.7	4.4	5.8	(2.8)	-
2026	125	159	4,086	1,050	31	39.6	1,021	262	76	51	11	0.7	0.6	3.3	4.6	(4.0)	-
2027	102	128	3,299	848	25	32.0	825	212	78	53	11	0.6	0.5	2.6	3.6	(2.5)	-
2028	74	96	2,476	634	19	24.0	619	159	80	54	11	0.4	0.4	2.0	2.8	(2.3)	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.16</b>	<b>0.21</b>	<b>5.28</b>	<b>1.36</b>	<b>0.040</b>	<b>0.051</b>	<b>1.321</b>	<b>0.339</b>				<b>2.4</b>	<b>2.1</b>	<b>12.3</b>	<b>16.8</b>	<b>(11.6)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Columbus Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	201	260	6,706	1,718	50	65.1	1,676	430	76	51	13	1.1	1.0	6.4	8.5	(3.4)	-
2026	199	252	6,499	1,670	50	63.0	1,625	417	76	51	11	1.1	0.9	5.3	7.3	(4.8)	-
2027	173	218	5,612	1,443	43	54.4	1,403	361	78	53	11	1.0	0.8	4.3	6.1	(3.2)	-
2028	147	191	4,913	1,259	37	47.7	1,228	315	80	54	11	0.8	0.7	3.9	5.5	(3.0)	-
2029	118	156	4,025	1,029	30	39.1	1,006	257	81	55	11	0.7	0.6	3.3	4.5	(2.4)	-
2030	116	152	3,915	1,002	29	38.0	979	250	83	56	12	0.7	0.6	3.2	4.5	(2.1)	-
2031	86	114	2,922	747	21	28.4	730	187	85	57	12	0.5	0.5	2.5	3.4	(1.7)	-
2032	90	117	3,018	773	22	29.3	754	193	86	58	12	0.6	0.5	2.6	3.6	(1.7)	-
2033	67	88	2,265	580	17	22.0	566	145	88	59	12	0.4	0.4	2.0	2.8	(1.5)	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.44</b>	<b>0.57</b>	<b>14.56</b>	<b>3.73</b>	<b>0.109</b>	<b>0.141</b>	<b>3.640</b>	<b>0.933</b>				<b>6.8</b>	<b>5.9</b>	<b>33.5</b>	<b>46.3</b>	<b>(23.9)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Columbus Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	233	302	7,779	1,993	58	75.5	1,945	498	76	51	13	1.3	1.1	7.4	9.8	(5.1)	-
2026	235	297	7,655	1,967	59	74.2	1,914	492	76	51	11	1.3	1.1	6.3	8.6	(3.9)	-
2027	207	260	6,710	1,725	52	65.1	1,677	431	78	53	11	1.2	1.0	5.2	7.3	(3.6)	-
2028	186	241	6,209	1,591	46	60.3	1,552	398	80	54	11	1.1	0.9	4.9	6.9	(3.4)	-
2029	161	213	5,487	1,403	40	53.3	1,372	351	81	55	11	0.9	0.8	4.4	6.2	(2.8)	-
2030	167	219	5,642	1,444	42	54.8	1,411	361	83	56	12	1.0	0.9	4.7	6.5	(2.5)	-
2031	139	184	4,739	1,212	35	46.1	1,185	303	85	57	12	0.8	0.7	4.0	5.6	(2.1)	-
2032	144	189	4,852	1,243	36	47.1	1,213	311	86	58	12	0.9	0.8	4.2	5.8	(2.3)	-
2033	121	158	4,075	1,044	30	39.6	1,019	261	88	59	12	0.8	0.7	3.6	5.0	(2.3)	-
2034	126	160	4,132	1,061	32	40.1	1,033	265	90	60	12	0.8	0.7	3.7	5.2	(2.8)	-
2035	107	135	3,484	895	27	33.8	871	224	92	62	13	0.7	0.6	3.2	4.5	(2.8)	-
2036	111	136	3,507	905	28	33.9	877	226	93	63	13	0.7	0.6	3.3	4.6	(3.3)	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.71</b>	<b>0.91</b>	<b>23.47</b>	<b>6.02</b>	<b>0.177</b>	<b>0.228</b>	<b>5.869</b>	<b>1.505</b>				<b>11.4</b>	<b>9.9</b>	<b>54.8</b>	<b>76.1</b>	<b>(36.8)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Columbus Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	138	179	4,609	1,181	34	44.8	1,152	295	76	51	13	0.7	0.7	4.4	5.8	(2.8)	-
2026	125	159	4,086	1,050	31	39.6	1,021	262	76	51	11	0.7	0.6	3.3	4.6	(4.0)	-
2027	102	128	3,299	848	25	32.0	825	212	78	53	11	0.6	0.5	2.6	3.6	(2.5)	-
2028	74	96	2,476	634	19	24.0	619	159	80	54	11	0.4	0.4	2.0	2.8	(2.3)	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.16</b>	<b>0.21</b>	<b>5.28</b>	<b>1.36</b>	<b>0.040</b>	<b>0.051</b>	<b>1.321</b>	<b>0.339</b>				<b>2.4</b>	<b>2.1</b>	<b>12.3</b>	<b>16.8</b>	<b>(11.6)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Columbus Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	201	260	6,706	1,718	50	65.1	1,676	430	76	51	13	1.1	1.0	6.4	8.5	(3.4)	-
2026	199	252	6,499	1,670	50	63.0	1,625	417	76	51	11	1.1	0.9	5.3	7.3	(4.8)	-
2027	173	218	5,612	1,443	43	54.4	1,403	361	78	53	11	1.0	0.8	4.3	6.1	(3.2)	-
2028	147	191	4,913	1,259	37	47.7	1,228	315	80	54	11	0.8	0.7	3.9	5.5	(3.0)	-
2029	118	156	4,025	1,029	30	39.1	1,006	257	81	55	11	0.7	0.6	3.3	4.5	(2.4)	-
2030	116	152	3,915	1,002	29	38.0	979	250	83	56	12	0.7	0.6	3.2	4.5	(2.1)	-
2031	86	114	2,922	747	21	28.4	730	187	85	57	12	0.5	0.5	2.5	3.4	(1.7)	-
2032	90	117	3,018	773	22	29.3	754	193	86	58	12	0.6	0.5	2.6	3.6	(1.7)	-
2033	67	88	2,265	580	17	22.0	566	145	88	59	12	0.4	0.4	2.0	2.8	(1.5)	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.44</b>	<b>0.57</b>	<b>14.56</b>	<b>3.73</b>	<b>0.109</b>	<b>0.141</b>	<b>3.640</b>	<b>0.933</b>				<b>6.8</b>	<b>5.9</b>	<b>33.5</b>	<b>46.3</b>	<b>(23.9)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Columbus Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	233	302	7,779	1,993	58	75.5	1,945	498	76	51	13	1.3	1.1	7.4	9.8	(5.1)	-
2026	235	297	7,655	1,967	59	74.2	1,914	492	76	51	11	1.3	1.1	6.3	8.6	(3.9)	-
2027	207	260	6,710	1,725	52	65.1	1,677	431	78	53	11	1.2	1.0	5.2	7.3	(3.6)	-
2028	186	241	6,209	1,591	46	60.3	1,552	398	80	54	11	1.1	0.9	4.9	6.9	(3.4)	-
2029	161	213	5,487	1,403	40	53.3	1,372	351	81	55	11	0.9	0.8	4.4	6.2	(2.8)	-
2030	167	219	5,642	1,444	42	54.8	1,411	361	83	56	12	1.0	0.9	4.7	6.5	(2.5)	-
2031	139	184	4,739	1,212	35	46.1	1,185	303	85	57	12	0.8	0.7	4.0	5.6	(2.1)	-
2032	144	189	4,852	1,243	36	47.1	1,213	311	86	58	12	0.9	0.8	4.2	5.8	(2.3)	-
2033	121	158	4,075	1,044	30	39.6	1,019	261	88	59	12	0.8	0.7	3.6	5.0	(2.3)	-
2034	126	160	4,132	1,061	32	40.1	1,033	265	90	60	12	0.8	0.7	3.7	5.2	(2.8)	-
2035	107	135	3,484	895	27	33.8	871	224	92	62	13	0.7	0.6	3.2	4.5	(2.8)	-
2036	111	136	3,507	905	28	33.9	877	226	93	63	13	0.7	0.6	3.3	4.6	(3.3)	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.71</b>	<b>0.91</b>	<b>23.47</b>	<b>6.02</b>	<b>0.177</b>	<b>0.228</b>	<b>5.869</b>	<b>1.505</b>				<b>11.4</b>	<b>9.9</b>	<b>54.8</b>	<b>76.1</b>	<b>(36.8)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Enoch Field, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	209	11	-	220	20	1.0	-	21	77	76	-	0.4	0.0	-	0.5	(0.3)	-
2026	145	7	-	152	14	0.7	-	15	76	76	-	0.3	0.0	-	0.3	(0.2)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.13</b>	<b>0.01</b>	<b>0.00</b>	<b>0.14</b>	<b>0.013</b>	<b>0.001</b>	<b>-</b>	<b>0.013</b>				<b>0.8</b>	<b>0.0</b>	<b>-</b>	<b>0.8</b>	<b>(0.5)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Enoch Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	295	15	-	310	29	1.5	-	30	77	76	-	0.6	0.0	-	0.7	(0.4)	-
2026	208	11	-	219	20	1.0	-	21	76	76	-	0.4	0.0	-	0.5	(0.3)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.18</b>	<b>0.01</b>	<b>0.00</b>	<b>0.19</b>	<b>0.018</b>	<b>0.001</b>	<b>-</b>	<b>0.019</b>				<b>1.1</b>	<b>0.1</b>	<b>-</b>	<b>1.1</b>	<b>(0.8)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Enoch Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	438	22	-	461	43	2.2	-	45	77	76	-	0.9	0.0	-	1.0	(0.6)	-
2026	277	14	-	292	27	1.4	-	28	76	76	-	0.6	0.0	-	0.6	(0.4)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.26</b>	<b>0.01</b>	<b>0.00</b>	<b>0.27</b>	<b>0.025</b>	<b>0.001</b>	<b>-</b>	<b>0.027</b>				<b>1.5</b>	<b>0.1</b>	<b>-</b>	<b>1.6</b>	<b>(1.0)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Enoch Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	209	11	-	220	20	1.0	-	21	77	76	-	0.4	0.0	-	0.5	(0.3)	-
2026	145	7	-	152	14	0.7	-	15	76	76	-	0.3	0.0	-	0.3	(0.2)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.13</b>	<b>0.01</b>	<b>0.00</b>	<b>0.14</b>	<b>0.013</b>	<b>0.001</b>	<b>-</b>	<b>0.013</b>				<b>0.8</b>	<b>0.0</b>	<b>-</b>	<b>0.8</b>	<b>(0.5)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Enoch Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	295	15	-	310	29	1.5	-	30	77	76	-	0.6	0.0	-	0.7	(0.4)	-
2026	208	11	-	219	20	1.0	-	21	76	76	-	0.4	0.0	-	0.5	(0.3)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.18</b>	<b>0.01</b>	<b>0.00</b>	<b>0.19</b>	<b>0.018</b>	<b>0.001</b>	<b>-</b>	<b>0.019</b>				<b>1.1</b>	<b>0.1</b>	<b>-</b>	<b>1.1</b>	<b>(0.8)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Enoch Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	438	22	-	461	43	2.2	-	45	77	76	-	0.9	0.0	-	1.0	(0.6)	-
2026	277	14	-	292	27	1.4	-	28	76	76	-	0.6	0.0	-	0.6	(0.4)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.26</b>	<b>0.01</b>	<b>0.00</b>	<b>0.27</b>	<b>0.025</b>	<b>0.001</b>	<b>-</b>	<b>0.027</b>				<b>1.5</b>	<b>0.1</b>	<b>-</b>	<b>1.6</b>	<b>(1.0)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Kraken Field, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	13,794	-	-	13,794	4,069	-	-	4,069	69	-	-	79.6	-	-	79.6	(50.6)	-
2026	10,752	-	-	10,752	3,172	-	-	3,172	68	-	-	61.7	-	-	61.7	(43.4)	-
2027	9,214	-	-	9,214	2,718	-	-	2,718	71	-	-	54.8	-	-	54.8	(41.8)	(1.6)
2028	7,692	-	-	7,692	2,269	-	-	2,269	72	-	-	46.7	-	-	46.7	(40.1)	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>15.14</b>	<b>0.00</b>	<b>0.00</b>	<b>15.14</b>	<b>4.466</b>	<b>-</b>	<b>-</b>	<b>4.466</b>				<b>242.8</b>	<b>-</b>	<b>-</b>	<b>242.8</b>	<b>(176.0)</b>	<b>(1.6)</b>



**Waldorf Production UK Limited**  
**Kraken Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	14,614	-	-	14,614	4,311	-	-	4,311	69	-	-	84.4	-	-	84.4	(50.8)	(1.4)
2026	12,233	-	-	12,233	3,609	-	-	3,609	68	-	-	70.2	-	-	70.2	(43.6)	(2.5)
2027	11,109	-	-	11,109	3,277	-	-	3,277	71	-	-	66.0	-	-	66.0	(42.1)	(4.8)
2028	9,742	-	-	9,742	2,874	-	-	2,874	72	-	-	59.1	-	-	59.1	(40.4)	-
2029	9,135	-	-	9,135	2,695	-	-	2,695	73	-	-	56.4	-	-	56.4	(39.8)	(42.9)
2030	8,183	-	-	8,183	2,414	-	-	2,414	75	-	-	51.5	-	-	51.5	(34.7)	(12.0)
2031	7,813	-	-	7,813	2,305	-	-	2,305	76	-	-	50.2	-	-	50.2	(35.4)	(8.1)
2032	7,177	-	-	7,177	2,117	-	-	2,117	78	-	-	47.1	-	-	47.1	(35.9)	(8.3)
2033	6,999	-	-	6,999	2,065	-	-	2,065	79	-	-	46.8	-	-	46.8	(36.3)	(8.5)
2034	6,482	-	-	6,482	1,912	-	-	1,912	81	-	-	44.2	-	-	44.2	(36.8)	-
2035	6,366	-	-	6,366	1,878	-	-	1,878	83	-	-	44.2	-	-	44.2	(37.2)	-
2036	5,931	-	-	5,931	1,750	-	-	1,750	84	-	-	42.2	-	-	42.2	(41.6)	-
2037	5,855	-	-	5,855	1,727	-	-	1,727	86	-	-	42.3	-	-	42.3	(42.1)	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>40.77</b>	<b>0.00</b>	<b>0.00</b>	<b>40.77</b>	<b>12.027</b>	<b>-</b>	<b>-</b>	<b>12.027</b>				<b>704.6</b>	<b>-</b>	<b>-</b>	<b>704.6</b>	<b>(516.5)</b>	<b>(88.4)</b>



**Waldorf Production UK Limited**  
**Kraken Field, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	15,348	-	-	15,348	4,528	-	-	4,528	69	-	-	88.6	-	-	88.6	(50.8)	-
2026	13,627	-	-	13,627	4,020	-	-	4,020	68	-	-	78.2	-	-	78.2	(43.7)	-
2027	12,978	-	-	12,978	3,829	-	-	3,829	71	-	-	77.1	-	-	77.1	(42.3)	(1.6)
2028	11,852	-	-	11,852	3,496	-	-	3,496	72	-	-	71.9	-	-	71.9	(40.7)	-
2029	11,512	-	-	11,512	3,396	-	-	3,396	73	-	-	71.1	-	-	71.1	(40.1)	(42.9)
2030	10,583	-	-	10,583	3,122	-	-	3,122	75	-	-	66.6	-	-	66.6	(35.1)	(12.0)
2031	10,281	-	-	10,281	3,033	-	-	3,033	76	-	-	66.0	-	-	66.0	(35.7)	(8.1)
2032	9,593	-	-	9,593	2,830	-	-	2,830	78	-	-	63.0	-	-	63.0	(36.2)	(8.3)
2033	9,488	-	-	9,488	2,799	-	-	2,799	79	-	-	63.4	-	-	63.4	(36.7)	(8.5)
2034	8,901	-	-	8,901	2,626	-	-	2,626	81	-	-	60.7	-	-	60.7	(37.1)	-
2035	8,846	-	-	8,846	2,610	-	-	2,610	83	-	-	61.5	-	-	61.5	(37.6)	-
2036	8,333	-	-	8,333	2,458	-	-	2,458	84	-	-	59.2	-	-	59.2	(42.0)	-
2037	8,311	-	-	8,311	2,452	-	-	2,452	86	-	-	60.1	-	-	60.1	(42.5)	-
2038	7,854	-	-	7,854	2,317	-	-	2,317	88	-	-	57.9	-	-	57.9	(43.0)	-
2039	7,858	-	-	7,858	2,318	-	-	2,318	89	-	-	59.1	-	-	59.1	(43.6)	-
2040	7,446	-	-	7,446	2,196	-	-	2,196	91	-	-	57.3	-	-	57.3	(44.2)	-
2041	7,466	-	-	7,466	2,202	-	-	2,202	93	-	-	58.4	-	-	58.4	(44.7)	-
2042	7,089	-	-	7,089	2,091	-	-	2,091	95	-	-	56.6	-	-	56.6	(45.3)	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>64.78</b>	<b>0.00</b>	<b>0.00</b>	<b>64.78</b>	<b>19.109</b>	<b>-</b>	<b>-</b>	<b>19.109</b>				<b>1,176.8</b>	<b>-</b>	<b>-</b>	<b>1,176.8</b>	<b>(741.5)</b>	<b>(81.3)</b>



**Waldorf Production UK Limited**  
**Kraken Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	13,794	-	-	13,794	4,069	-	-	4,069	69	-	-	79.6	-	-	79.6	(50.6)	-
2026	10,752	-	-	10,752	3,172	-	-	3,172	68	-	-	61.7	-	-	61.7	(43.4)	-
2027	9,214	-	-	9,214	2,718	-	-	2,718	71	-	-	54.8	-	-	54.8	(41.8)	(1.6)
2028	7,692	-	-	7,692	2,269	-	-	2,269	72	-	-	46.7	-	-	46.7	(40.1)	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>15.14</b>	<b>0.00</b>	<b>0.00</b>	<b>15.14</b>	<b>4.466</b>	<b>-</b>	<b>-</b>	<b>4.466</b>				<b>242.8</b>	<b>-</b>	<b>-</b>	<b>242.8</b>	<b>(176.0)</b>	<b>(1.6)</b>



**Waldorf Production UK Limited**  
**Kraken Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	14,614	-	-	14,614	4,311	-	-	4,311	69	-	-	84.4	-	-	84.4	(50.8)	(1.4)
2026	12,233	-	-	12,233	3,609	-	-	3,609	68	-	-	70.2	-	-	70.2	(43.6)	(2.5)
2027	11,109	-	-	11,109	3,277	-	-	3,277	71	-	-	66.0	-	-	66.0	(42.1)	(4.8)
2028	9,742	-	-	9,742	2,874	-	-	2,874	72	-	-	59.1	-	-	59.1	(40.4)	-
2029	9,135	-	-	9,135	2,695	-	-	2,695	73	-	-	56.4	-	-	56.4	(39.8)	(42.9)
2030	8,183	-	-	8,183	2,414	-	-	2,414	75	-	-	51.5	-	-	51.5	(34.7)	(12.0)
2031	7,813	-	-	7,813	2,305	-	-	2,305	76	-	-	50.2	-	-	50.2	(35.4)	(8.1)
2032	7,177	-	-	7,177	2,117	-	-	2,117	78	-	-	47.1	-	-	47.1	(35.9)	(8.3)
2033	6,999	-	-	6,999	2,065	-	-	2,065	79	-	-	46.8	-	-	46.8	(36.3)	(8.5)
2034	6,482	-	-	6,482	1,912	-	-	1,912	81	-	-	44.2	-	-	44.2	(36.8)	-
2035	6,366	-	-	6,366	1,878	-	-	1,878	83	-	-	44.2	-	-	44.2	(37.2)	-
2036	5,931	-	-	5,931	1,750	-	-	1,750	84	-	-	42.2	-	-	42.2	(41.6)	-
2037	5,855	-	-	5,855	1,727	-	-	1,727	86	-	-	42.3	-	-	42.3	(42.1)	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>40.77</b>	<b>0.00</b>	<b>0.00</b>	<b>40.77</b>	<b>12.027</b>	<b>-</b>	<b>-</b>	<b>12.027</b>				<b>704.6</b>	<b>-</b>	<b>-</b>	<b>704.6</b>	<b>(516.5)</b>	<b>(88.4)</b>



**Waldorf Production UK Limited**  
**Kraken Field, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	15,348	-	-	15,348	4,528	-	-	4,528	69	-	-	88.6	-	-	88.6	(50.8)	-
2026	13,627	-	-	13,627	4,020	-	-	4,020	68	-	-	78.2	-	-	78.2	(43.7)	-
2027	12,978	-	-	12,978	3,829	-	-	3,829	71	-	-	77.1	-	-	77.1	(42.3)	(1.6)
2028	11,852	-	-	11,852	3,496	-	-	3,496	72	-	-	71.9	-	-	71.9	(40.7)	-
2029	11,512	-	-	11,512	3,396	-	-	3,396	73	-	-	71.1	-	-	71.1	(40.1)	(42.9)
2030	10,583	-	-	10,583	3,122	-	-	3,122	75	-	-	66.6	-	-	66.6	(35.1)	(12.0)
2031	10,281	-	-	10,281	3,033	-	-	3,033	76	-	-	66.0	-	-	66.0	(35.7)	(8.1)
2032	9,593	-	-	9,593	2,830	-	-	2,830	78	-	-	63.0	-	-	63.0	(36.2)	(8.3)
2033	9,488	-	-	9,488	2,799	-	-	2,799	79	-	-	63.4	-	-	63.4	(36.7)	(8.5)
2034	8,901	-	-	8,901	2,626	-	-	2,626	81	-	-	60.7	-	-	60.7	(37.1)	-
2035	8,846	-	-	8,846	2,610	-	-	2,610	83	-	-	61.5	-	-	61.5	(37.6)	-
2036	8,333	-	-	8,333	2,458	-	-	2,458	84	-	-	59.2	-	-	59.2	(42.0)	-
2037	8,311	-	-	8,311	2,452	-	-	2,452	86	-	-	60.1	-	-	60.1	(42.5)	-
2038	7,854	-	-	7,854	2,317	-	-	2,317	88	-	-	57.9	-	-	57.9	(43.0)	-
2039	7,858	-	-	7,858	2,318	-	-	2,318	89	-	-	59.1	-	-	59.1	(43.6)	-
2040	7,446	-	-	7,446	2,196	-	-	2,196	91	-	-	57.3	-	-	57.3	(44.2)	-
2041	7,466	-	-	7,466	2,202	-	-	2,202	93	-	-	58.4	-	-	58.4	(44.7)	-
2042	7,089	-	-	7,089	2,091	-	-	2,091	95	-	-	56.6	-	-	56.6	(45.3)	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>64.78</b>	<b>0.00</b>	<b>0.00</b>	<b>64.78</b>	<b>19.109</b>	<b>-</b>	<b>-</b>	<b>19.109</b>				<b>1,176.8</b>	<b>-</b>	<b>-</b>	<b>1,176.8</b>	<b>(741.5)</b>	<b>(81.3)</b>



**Waldorf Production UK Limited**  
**Scolty-Crathes, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,822	-	154	1,854	911	-	77	927	77	-	16	20.0	-	0.3	20.3	(17.1)	-
2026	1,547	-	131	1,574	773	-	66	787	76	-	13	16.9	-	0.3	17.1	(16.6)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>1.23</b>	<b>0.00</b>	<b>0.10</b>	<b>1.25</b>	<b>0.615</b>	<b>-</b>	<b>0.052</b>	<b>0.626</b>				<b>36.8</b>	<b>-</b>	<b>0.6</b>	<b>37.4</b>	<b>(33.7)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Scolty-Crathes, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	2,198	-	187	2,237	1,099	-	93	1,118	77	-	16	24.1	-	0.4	24.5	(18.5)	-
2026	1,932	-	163	1,966	966	-	81	983	76	-	13	21.1	-	0.3	21.4	(18.3)	-
2027	1,838	-	155	1,870	919	-	77	935	79	-	13	20.7	-	0.3	21.0	(18.6)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.18</b>	<b>0.00</b>	<b>0.18</b>	<b>2.22</b>	<b>1.089</b>	<b>-</b>	<b>0.092</b>	<b>1.108</b>				<b>65.9</b>	<b>-</b>	<b>1.0</b>	<b>66.9</b>	<b>(55.4)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Scolty-Crathes, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	2,520	-	214	2,564	1,260	-	107	1,282	77	-	16	27.6	-	0.5	28.1	(19.5)	-
2026	2,270	-	192	2,310	1,135	-	96	1,155	76	-	13	24.7	-	0.4	25.1	(19.5)	-
2027	2,205	-	187	2,244	1,103	-	93	1,122	79	-	13	24.9	-	0.3	25.2	(20.0)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.55</b>	<b>0.00</b>	<b>0.22</b>	<b>2.60</b>	<b>1.277</b>	<b>-</b>	<b>0.108</b>	<b>1.299</b>				<b>77.2</b>	<b>-</b>	<b>1.2</b>	<b>78.4</b>	<b>(59.0)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Scolty-Crathes, UK**  
**Production and Revenue Forecasts**  
**Total Proved Reserves (1P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,822	-	154	1,854	911	-	77	927	77	-	16	20.0	-	0.3	20.3	(17.1)	-
2026	1,547	-	131	1,574	773	-	66	787	76	-	13	16.9	-	0.3	17.1	(16.6)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>1.23</b>	<b>0.00</b>	<b>0.10</b>	<b>1.25</b>	<b>0.615</b>	<b>-</b>	<b>0.052</b>	<b>0.626</b>				<b>36.8</b>	<b>-</b>	<b>0.6</b>	<b>37.4</b>	<b>(33.7)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Scolty-Crathes, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	2,198	-	187	2,237	1,099	-	93	1,118	77	-	16	24.1	-	0.4	24.5	(18.5)	-
2026	1,932	-	163	1,966	966	-	81	983	76	-	13	21.1	-	0.3	21.4	(18.3)	-
2027	1,838	-	155	1,870	919	-	77	935	79	-	13	20.7	-	0.3	21.0	(18.6)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.18</b>	<b>0.00</b>	<b>0.18</b>	<b>2.22</b>	<b>1.089</b>	<b>-</b>	<b>0.092</b>	<b>1.108</b>				<b>65.9</b>	<b>-</b>	<b>1.0</b>	<b>66.9</b>	<b>(55.4)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Scolty-Crathes, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	2,520	-	214	2,564	1,260	-	107	1,282	77	-	16	27.6	-	0.5	28.1	(19.5)	-
2026	2,270	-	192	2,310	1,135	-	96	1,155	76	-	13	24.7	-	0.4	25.1	(19.5)	-
2027	2,205	-	187	2,244	1,103	-	93	1,122	79	-	13	24.9	-	0.3	25.2	(20.0)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.55</b>	<b>0.00</b>	<b>0.22</b>	<b>2.60</b>	<b>1.277</b>	<b>-</b>	<b>0.108</b>	<b>1.299</b>				<b>77.2</b>	<b>-</b>	<b>1.2</b>	<b>78.4</b>	<b>(59.0)</b>	<b>-</b>



**Waldorf Production UK Limited**  
**Scott, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	6,475	120	382	6,666	1,414	26.2	83	1,456	77	50	14	31.0	0.4	0.3	31.7	(16.4)	(17.7)
2026	6,032	134	856	6,326	1,317	29.3	187	1,381	76	49	12	28.7	0.4	0.6	29.8	(14.1)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>4.56</b>	<b>0.09</b>	<b>0.45</b>	<b>4.74</b>	<b>0.997</b>	<b>0.020</b>	<b>0.099</b>	<b>1.035</b>				<b>59.7</b>	<b>0.8</b>	<b>1.0</b>	<b>61.5</b>	<b>(30.5)</b>	<b>(17.7)</b>



**Waldorf Production UK Limited**  
**Scott, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	8,411	243	2,415	9,105	1,836	53.0	527	1,988	77	50	14	40.2	0.8	2.1	43.1	(17.7)	(17.7)
2026	8,300	270	3,056	9,141	1,812	58.9	667	1,996	76	49	12	39.5	0.8	2.3	42.6	(16.0)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>6.10</b>	<b>0.19</b>	<b>2.00</b>	<b>6.66</b>	<b>1.332</b>	<b>0.041</b>	<b>0.436</b>	<b>1.454</b>				<b>79.7</b>	<b>1.6</b>	<b>4.4</b>	<b>85.8</b>	<b>(33.7)</b>	<b>(17.7)</b>



**Waldorf Production UK Limited**  
**Scott, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	10,561	379	4,685	11,816	2,306	82.8	1,023	2,580	77	50	14	50.5	1.2	4.1	55.8	(18.8)	(17.7)
2026	10,875	424	5,555	12,338	2,375	92.5	1,213	2,694	76	49	12	51.8	1.3	4.2	57.3	(17.5)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>7.82</b>	<b>0.29</b>	<b>3.74</b>	<b>8.82</b>	<b>1.708</b>	<b>0.064</b>	<b>0.816</b>	<b>1.925</b>				<b>102.3</b>	<b>2.5</b>	<b>8.3</b>	<b>113.1</b>	<b>(36.3)</b>	<b>(17.7)</b>



**Waldorf Production UK Limited  
Scott, UK  
Production and Revenue Forecasts  
Total Proved Reserves (1P)**

Total Proved Reserves (1P) - the 1P Reserves are less than the volumes shown, as the PUDs are assessed as being uneconomic

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	6,508	122	413	6,707	1,421	26.6	90	1,465	77	50	14	31.1	0.4	0.4	31.9	(16.4)	(31.3)
2026	8,000	247	2,657	8,744	1,747	53.9	580	1,909	76	49	12	38.1	0.8	2.0	40.8	(15.8)	(33.6)
2027	8,522	278	3,168	9,393	1,861	60.8	692	2,051	79	51	11	42.0	0.9	2.3	45.1	(19.1)	(19.8)
2028	7,325	209	2,059	7,919	1,599	45.7	450	1,729	80	52	12	36.8	0.7	1.5	39.0	(17.1)	(11.5)
2029	6,447	159	1,260	6,842	1,408	34.8	275	1,494	82	53	12	33.0	0.5	0.9	34.4	(19.3)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>13.44</b>	<b>0.37</b>	<b>3.49</b>	<b>14.46</b>	<b>2.935</b>	<b>0.081</b>	<b>0.762</b>	<b>3.158</b>				<b>181.0</b>	<b>3.2</b>	<b>7.1</b>	<b>191.3</b>	<b>(87.6)</b>	<b>(96.2)</b>

Note: Production rates include the rates from the sub-economic Undeveloped project related to the PGU #2 and infill campaign projects



**Waldorf Production UK Limited**  
**Scott, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	8,468	246	2,468	9,175	1,849	53.7	539	2,003	77	50	14	40.5	0.8	2.2	43.5	(17.7)	(31.3)
2026	11,478	452	5,964	13,045	2,506	98.6	1,302	2,848	76	49	12	54.6	1.4	4.5	60.5	(17.8)	(33.6)
2027	11,868	474	6,308	13,521	2,591	103.4	1,377	2,952	79	51	11	58.5	1.5	4.5	64.5	(20.8)	(19.8)
2028	10,294	381	4,810	11,575	2,248	83.1	1,050	2,527	80	52	12	51.8	1.2	3.5	56.5	(18.8)	(11.5)
2029	9,709	345	4,227	10,845	2,120	75.4	923	2,368	82	53	12	49.7	1.1	3.2	54.0	(21.2)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>18.92</b>	<b>0.69</b>	<b>8.68</b>	<b>21.24</b>	<b>4.132</b>	<b>0.151</b>	<b>1.896</b>	<b>4.638</b>				<b>255.0</b>	<b>6.0</b>	<b>17.9</b>	<b>278.9</b>	<b>(96.3)</b>	<b>(96.2)</b>



**Waldorf Production UK Limited**  
**Scott, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	10,641	384	4,759	11,915	2,324	83.8	1,039	2,602	77	50	14	50.9	1.2	4.2	56.3	(18.8)	(31.3)
2026	14,956	657	9,289	17,351	3,266	143.5	2,028	3,789	76	49	12	71.2	2.0	7.0	80.2	(19.2)	(33.6)
2027	16,343	733	10,486	19,038	3,568	160.1	2,289	4,157	79	51	11	80.5	2.3	7.5	90.3	(22.4)	(19.8)
2028	14,555	626	8,743	16,816	3,178	136.7	1,909	3,672	80	52	12	73.2	2.0	6.4	81.6	(20.6)	(11.5)
2029	13,969	589	8,130	16,079	3,050	128.7	1,775	3,511	82	53	12	71.5	1.9	6.1	79.5	(23.0)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>25.73</b>	<b>1.09</b>	<b>15.12</b>	<b>29.65</b>	<b>5.619</b>	<b>0.238</b>	<b>3.302</b>	<b>6.475</b>				<b>347.3</b>	<b>9.5</b>	<b>31.2</b>	<b>388.0</b>	<b>(104.1)</b>	<b>(96.2)</b>



**Waldorf Production UK Limited**  
**Telford, UK**  
**Production and Revenue Forecasts**  
**Proved Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	881	59	153	968	14	0.9	2	15	77	43	14	0.3	0.0	0.0	0.3	(0.3)	(0.0)
2026	1,043	67	(35)	1,104	17	1.1	(1)	18	76	43	-	0.4	0.0	(0.0)	0.4	(0.4)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.70</b>	<b>0.05</b>	<b>0.04</b>	<b>0.76</b>	<b>0.011</b>	<b>0.001</b>	<b>0.001</b>	<b>0.012</b>				<b>0.7</b>	<b>0.0</b>	<b>0.0</b>	<b>0.7</b>	<b>(0.7)</b>	<b>(0.0)</b>



**Waldorf Production UK Limited**  
**Telford, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,134	92	776	1,371	18	1.5	12	22	77	43	14	0.4	0.0	0.0	0.5	(0.4)	(0.0)
2026	1,407	107	710	1,646	22	1.7	11	26	76	43	12	0.5	0.0	0.0	0.5	(0.4)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>0.93</b>	<b>0.07</b>	<b>0.54</b>	<b>1.10</b>	<b>0.015</b>	<b>0.001</b>	<b>0.009</b>	<b>0.017</b>				<b>0.9</b>	<b>0.0</b>	<b>0.1</b>	<b>1.0</b>	<b>(0.8)</b>	<b>(0.0)</b>



**Waldorf Production UK Limited**  
**Telford, UK**  
**Production and Revenue Forecasts**  
**Proved + Probable + Possible Developed Reserves**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,383	127	1,422	1,774	22	2.0	23	28	77	43	14	0.5	0.0	0.1	0.6	(0.4)	(0.0)
2026	1,762	153	1,523	2,198	28	2.4	24	35	76	43	12	0.6	0.0	0.1	0.7	(0.5)	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>1.15</b>	<b>0.10</b>	<b>1.07</b>	<b>1.45</b>	<b>0.018</b>	<b>0.002</b>	<b>0.017</b>	<b>0.023</b>				<b>1.1</b>	<b>0.1</b>	<b>0.2</b>	<b>1.3</b>	<b>(1.0)</b>	<b>(0.0)</b>



**Waldorf Production UK Limited  
Telford, UK  
Production and Revenue Forecasts  
Total Proved Reserves (1P)**

**Total Proved Reserves (1P) - the 1P Reserves are less than the volumes shown, as the PUDs are assessed as being uneconomic**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	881	59	153	968	14	0.9	2	15	77	43	14	0.3	0.0	0.0	0.3	(0.3)	(0.0)
2026	1,043	67	(35)	1,104	17	1.1	(1)	18	76	43	-	0.4	0.0	(0.0)	0.4	(0.3)	-
2027	830	54	(219)	843	13	0.9	(3)	13	79	44	-	0.3	0.0	(0.0)	0.3	(0.2)	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>1.01</b>	<b>0.07</b>	<b>-0.04</b>	<b>1.06</b>	<b>0.016</b>	<b>0.001</b>	<b>-0.001</b>	<b>0.017</b>				<b>1.0</b>	<b>0.0</b>	<b>(0.0)</b>	<b>1.0</b>	<b>(0.9)</b>	<b>(0.0)</b>

Note: Production rates include the rates from the sub-economic Undeveloped project related to the PGU #2 and infill campaign projects in Scott



**Waldorf Production UK Limited**  
**Telford, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable Reserves (2P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,134	92	776	1,371	18	1.5	12	22	77	43	14	0.4	0.0	0.0	0.5	(0.4)	(0.0)
2026	1,407	107	710	1,646	22	1.7	11	26	76	43	12	0.5	0.0	0.0	0.5	(0.4)	-
2027	1,168	82	342	1,314	19	1.3	5	21	79	44	11	0.4	0.0	0.0	0.5	(0.3)	-
2028	989	64	107	1,072	16	1.0	2	17	80	45	12	0.4	0.0	0.0	0.4	(0.3)	-
2029	898	58	(77)	942	14	0.9	(1)	15	82	46	-	0.3	0.0	(0.0)	0.3	(0.3)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.04</b>	<b>0.15</b>	<b>0.68</b>	<b>2.32</b>	<b>0.032</b>	<b>0.002</b>	<b>0.011</b>	<b>0.037</b>				<b>2.0</b>	<b>0.1</b>	<b>0.1</b>	<b>2.2</b>	<b>(1.7)</b>	<b>(0.0)</b>



**Waldorf Production UK Limited**  
**Telford, UK**  
**Production and Revenue Forecasts**  
**Total Proved + Probable + Possible Reserves (3P)**  
**Effective 31 December 2024**

Year	Field Gross Production Rate				Field Net Production Rate				Pricing			Net Sales Revenue				Net Costs	
	Gross Oil stb/d	Gross NGL bbl/d	Gross Gas Mscf/d	Gross BOE boe/d	Net Oil stb/d	Net NGL bbl/d	Net Gas Mscf/d	Net BOE boe/d	Oil Price US\$/bbl	NGL Price US\$/bbl	Gas Price \$/Mscf	Oil Revenue £MM	NGL Revenue £MM	Gas Revenue £MM	Total Revenue £MM	Operating Costs £MM	Capital Costs £MM
2025	1,383	127	1,422	1,774	22	2.0	23	28	77	43	14	0.5	0.0	0.1	0.6	(0.4)	(0.0)
2026	1,762	153	1,523	2,198	28	2.4	24	35	76	43	12	0.6	0.0	0.1	0.7	(0.4)	-
2027	1,505	122	993	1,811	24	1.9	16	29	79	44	11	0.5	0.0	0.1	0.6	(0.4)	-
2028	1,303	98	613	1,515	21	1.6	10	24	80	45	12	0.5	0.0	0.0	0.5	(0.4)	-
2029	1,208	85	355	1,358	19	1.3	6	22	82	46	12	0.4	0.0	0.0	0.5	(0.4)	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>2.62</b>	<b>0.21</b>	<b>1.79</b>	<b>3.16</b>	<b>0.041</b>	<b>0.003</b>	<b>0.028</b>	<b>0.050</b>				<b>2.6</b>	<b>0.1</b>	<b>0.3</b>	<b>2.9</b>	<b>(2.0)</b>	<b>(0.0)</b>