

Independent Evaluation of Reserves and Contingent Resources for Certain Assets Held by INEOS Energy

[CPR Summary]

As of 31 December 2025

Prepared For: INEOS UK E&P Holdings Limited

By: Sproule ERCE



Sproule
ERCE

Digital Report Notification

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Attn: Mr. Robert Mattsson, Reserves and M&A Manager, INEOS UK E&P Holdings Limited

Re: Reserves and Contingent Resources Evaluation Report

This report (the “CPR Summary”), issued on 25 September 2026, presents a summary of the Competent Person’s Report (“CPR”) that ERC Equipoise Limited (“Sproule ERCE”) prepared at the request of Mr. Robert Mattsson, Reserves and M&A Manager at INEOS UK E&P Holdings Limited (“INEOS,” the “Company,” or “Client”). The CPR’s effective date is 31 December 2025 (the “Effective Date”), and Sproule ERCE prepared the report between February 2026 and June 2026 to support INEOS’ bond offering.

Sproule ERCE’s independent evaluation covered the oil and gas Reserves and Contingent Resources for selected interests located in Denmark, the United Kingdom, and the US Gulf. The evaluation included all assets except for INEOS’ overriding royalty interest (“ORRI”) in the Shenandoah Field in the US Gulf. Due to limited data for this asset, Sproule ERCE relied on production forecasts provided by INEOS.

The preparation date of the CPR is 11 June 2026; a revision was issued on 13 August 2026. The preparation date is subsequent to the Effective Date and represented the most recent date on which information pertaining to the period ending on the Effective Date was received and considered. The report also incorporated Contingent Resources related to the Fort Sumter discovery in the US Gulf, in which INEOS acquired an interest in May 2026.

The Reserves and Contingent Resources presented in this report were prepared in accordance with the classifications and definitions of the Petroleum Resources Management System (“SPE-PRMS”), sponsored by Society of Petroleum Engineers (“SPE”), World Petroleum Council (“WPC”), American Association of Petroleum Geologists (“AAPG”), Society of Petroleum Evaluation Engineers (“SPEE”), Society of Exploration Geophysicists (“SEG”), Society of Petrophysicists and Well Log Analysts (“SPWLA”), and the European Association of Geoscientists & Engineers (“EAGE”).

Estimates of oil Reserves and Contingent Resources are presented in millions of barrels, at stock tank conditions. Estimates of natural gas Reserves and Contingent Resources are presented in billions of

cubic feet, at base conditions of 14.65 psia and 60 degrees Fahrenheit. The natural gas liquids Reserves and Contingent Resources are presented in millions of barrels, at base conditions of 60 degrees Fahrenheit and equilibrium pressure.

Disclaimer

This material is produced by Sproule ERCE based on the instructions and data from the Company to provide Sproule ERCE's professional and independent opinion to the Company and is thus prepared exclusively for the Company's sole benefit and not for the benefit of any third party.

The analysis of individual entities was conducted within the context and scope of an evaluation of a unique group of entities in aggregate. Use of this report outside of this scope may not be appropriate. The estimates of Reserves and future net revenue for individual entities or properties may not reflect the same confidence level as estimates of Reserves and future net revenue for all entities, due to the effects of aggregation.

Sproule ERCE reserves the right to review all calculations made, referred to, or included in the CPR and this CPR Summary and to revise the estimates as a result of erroneous data supplied by the Company or information that exists but was not made available to us, which becomes known subsequent to the preparation of the CPR.

The accuracy of reserves and resources estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time the CPR was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

The net present values of the reserves presented in the CPR and this CPR Summary represent discounted future cash flow values at several discount rates. Though net present values form an integral part of fair market value estimations, without consideration for other economic criteria, they are not to be construed as Sproule ERCE's opinion of fair market value.

This report contains forward-looking statements including expectations of future production revenues and capital expenditures. Information concerning reserves may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production); potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of

reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses; health, safety and environmental factors; commodity prices; and exchange rate fluctuation.

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Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 5,609 scf:1 bbl has been used across the INEOS portfolio. This is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the preparation of the CPR, field inspections of the properties were not performed. The relevant engineering and geoscience data were made available by the Company or obtained from public sources and the non-confidential files at Sproule ERCE. No material information regarding the reserves evaluation would have been obtained by an on-site visit.

Due to rounding, certain totals may not be consistent from one presentation to the next.

Qualifications

Sproule ERCE is an independent consultancy specialising in geoscience evaluation, engineering, and economic assessment. Sproule ERCE received a fee for the preparation of the CPR in accordance with normal professional consulting practices. This fee was not dependent on the findings of the CPR and Sproule ERCE received no other benefit for the preparation of the CPR. Sproule ERCE and all contributing members of the CPR consider themselves to be independent from the Company, as is defined in SPE-PRMS.

Sproule ERCE has the relevant and appropriate qualifications, experience, and technical knowledge to appraise professionally and independently the assets. The preparation of the CPR was supervised by Dr. Adam Law, Principal Strategic Advisor at Sproule ERCE. Dr. Law is a Qualified Reserves Evaluator with 30 years of experience in the evaluation of oil and gas fields and a member in good standing with SPEE, deeming him to possess the required competencies to prepare the CPR.

Yours faithfully,

Adam Law

Signed with ConsignO Cloud (2026/09/25)
Verify with verifio.com or Adobe Reader.



Dr. Adam Law

Principal Strategic Advisor, Sproule ERCE

1. Executive Summary

Sproule ERCE has carried out an independent evaluation of the oil and gas Reserves of certain interests held by INEOS and its related entities located in Denmark (the Syd Arne, Solsort West, Hejre and Lulita Fields), the United Kingdom (the Breagh and Clipper South Fields and Greater Laggan Area) and the US Gulf (the Stampede, Black Pearl, Appomattox, Vicksburg, Rydberg, Tobago, Aspen, and Longhorn Fields and Great White ORRI, Abilene ORRI and Shenandoah ORRI¹). Those interests and ORRIs included in Sproule ERCE's independent evaluation are summarised in Table 1-1. Of the 2P barrels of oil equivalent Company Net Entitlement Reserves presented in the CPR and this CPR Summary, approximately 70% is oil and 30% is gas.

¹ Due to limited data availability, Sproule ERCE has relied on INEOS' forecast for the Shenandoah ORRI.

Table 1-1: Summary of Licence Interests in Denmark and the United Kingdom

Country	Licence	Working Interest	Operator	Field	Status
Denmark	7/89	98.3%	INEOS	Syd Arne	Producing
	04/98 03/09 07/89	67.6%	INEOS	Solsort West ²	Producing
	05/98 01/06	100.0%	INEOS	Hejre ³	Under Development
	Sole Concession Area 07/86 1/90	40.0%	TotalEnergies	Lulita ⁴	Shut-in
United Kingdom	P1328 P1230	100.0%	INEOS	Breagh	Producing
	P8 P465 P1909	75.0%	INEOS	Clipper South	Producing
	P911 P1159 P1195 P1453 P1673	20.0%	Serica Energy ⁵	Laggan ⁶	Producing
				Glenlivet ⁵	Producing
				Tormore ⁵	Producing
				Edradour ⁵	Shut-in
				Glendronach ⁵	Discovery
	P2662	100.0%	INEOS	Pegasus West	Discovery
	P2663	100.0%	INEOS	Greater Pegasus	Discovery

²The Solsort West field is a two-well development drilled from the Syd Arne Wellhead Platform North.

³The Hejre field is planned to be developed with three wells and tied back to the Syd Arne facilities. The project is pending FID and first production is scheduled in November 2028. After the Effective Date of this report, Sproule ERCE was made aware that INEOS is in the process of farming down a portion of their working interest in the Hejre field. This process is ongoing but is expected to complete within months of the issuance date of this report. After completion of this process INEOS' working interest in the field will be reduced to 75.0%.

⁴The Lulita field is unitised between the Sole Concession Area and Licences 7/86 and 1/90. INEOS holds a 40% unitised interest.

⁵Serica Energy became the Operator of GLA upon completion of its acquisition of TotalEnergies interest in GLA on 26 March 2026.

⁶The Laggan, Glenlivet, Tormore and Edradour fields make up the Greater Laggan Area. Each is a subsea development producing into common multiphase flowlines that export to the onshore Shetland Gas Plant. The Edradour field was shut-in in late 2022. The Glendronach discovery is located close to the Edradour field.

Table 1-2: Summary of Licence Interests and ORRIs in the US Gulf

Country	Licence	Working Interest	Operator	Field	Status
US Gulf	GC468 / G26313 GC512 / G26315 GC511 / G34551	25.0%	Chevron	Stampede	Producing
				Flying Dutchman	Discovery
	GC468 / G26313	25.0%	Chevron	Black Pearl ⁷	Producing
	MC391 / G26252 MC392 / G26253	21.0%	Shell	Appomattox	Producing
	DC353 / G25852 MC393 / G26254	21.0%	Shell	Vicksburg ⁸	Producing
	MC524 / G33161 MC525 / G31507 MC568 / G33163 MC569 / G31513	21.0%	Shell	Rydberg ⁷	Producing
				Nashville	Discovery
	MC243 / G20051	51.8%	Walter	Aspen	Producing
	MC502 / G24084 MC546 / G25098	25.0%	ENI	Longhorn	Producing
	AC859 / G20871	10.0%	Shell	Tobago	Producing
	MC566 / G08831 N/2 MC567 / G33744	21.0%	Shell	Fort Sumter ⁹	Discovery
	AC813 / G17561 AC857 / G17565 AC900 / G17570 AC901 / G17571 AC856 / G20870 AC812 / G24593	1.5% ¹⁰	Shell	Great White (ORRI)	Producing
	MC503 / G27277 MC547 / G32334	4 – 10% ¹¹	Harbour	Abilene (ORRI)	Producing
	WR052 / G25232 WR051 / G31938	0.5%	Beacon Offshore Energy	Shenandoah (ORRI)	Producing

⁷The Black Pearl field is a single well development tied back to the Stampede facilities.

⁸The Appomattox and Vicksburg fields produce to the Appomattox host facility; the Rydberg field is tied back to the Vicksburg subsea production equipment. A third satellite field, Dover, also produces to the Appomattox host facility but INEOS does not hold any interest in the field.

⁹As of the Effective Date of this report, INEOS did not hold any interest in the Fort Sumter discovery. INEOS acquired a 21.0% working interest in the Fort Sumter discovery in May 2026 and at the request of INEOS the asset has been included in this report.

¹⁰The Great White ORRI is set on a slide scale according to cumulative production. The ORRI increased from 1.2% to 1.5% at the end of 2025 as the 400 MMboe milestone was met; this was confirmed to INEOS by Shell.

¹¹Within the Abilene field, different reservoirs have different royalty interests. The ORRI is 4% on the 4600ms sand and 10% on the 4400ms and 4200ms sands.

1.1 Asset Overview and Highlights

1.1.1 Denmark

Syd Arne (INEOS working interest 98.3%)

The Syd Arne Field is an oil field located in the Danish sector of the North Sea approximately 250 km west-northwest of Esbjerg. Oil is gathered at the Syd Arne Main platform and is exported via an offshore single anchor loading system. Gas is exported from the platform via a gas export pipeline and sold from the platform under a dedicated Gas Sales Agreement.

Hydrocarbons are contained within the Late Cretaceous Tor and Early Paleocene Ekofisk chalk reservoirs, which are naturally fractured. The fractures improve the effective permeability of the reservoir and production performance is strongly influenced by fracture distribution.

The field was discovered in 1969 but was not brought onstream until 1999. Initial production relied on natural depletion before water injection was introduced in 2001 to maintain reservoir pressure. Oil production peaked at ~53,000 stb/d in 2000. As of 31 December 2025, the average oil production rate was ~3,650 stb/d from 14 active producers (with a water cut of 84%) and the average water injection rate was ~25,850 bbl/d from ten active injectors. Cumulative oil and gas production were 192 MMstb and 295 Bscf respectively.

The Developed Reserves comprise production from the existing wells, including the benefit of increased water injection and two planned interventions. A water shut-off is planned in Well SAN-02 and a stimulation is planned in Well SAN-04; both of these activities are intended to improve sweep efficiency between the wells. The Developed Reserves are estimated using a combination of decline curve analysis (“DCA”) and dynamic simulation modelling, with operational risk applied to the well interventions.

There are no Undeveloped Reserves projects in the Syd Arne Field but the Hejre Field will affect the Syd Arne Field when it is brought onstream. Firstly, some Syd Arne production will be deferred as several wells need to be shut-in to reduce gas lift demand in Syd Arne for one to two years following Hejre start-up. Secondly, for a short period after Hejre start-up, NGLs contained in the Syd Arne stream will need to be extracted and re-injected into the reservoir to avoid instability in the export stream. Finally, there will be an extension of the Syd Arne cessation of production (“CoP”) date as a result of the Hejre development.

A gas depressurisation (or “blowdown”) project is planned towards the end of field life which involves switching off water injection and gradually lowering the bottomhole pressure (“BHP”) of the wells, leading to evolution of gas in the reservoir that provides a temporary additional drive mechanism. The start date of the project is dependent on the Developed plus Undeveloped CoP dates and ranges from 2032 in the 1P scenario to 2042 in the 3P scenario. The incremental recovery, estimated using dynamic simulation modelling, is classified as Developed Reserves as the project relies on existing wells and there is no capital expenditure (“CAPEX”).

Solsort West (INEOS working interest 67.6%)

The Solsort West Field is an oil field located ~2 km northeast of the Syd Arne Field in the Danish sector of the North Sea, approximately 250 km west-northwest of Esbjerg. INEOS is the Operator. Produced fluids are commingled with the Syd Arne Field production at the Syd Arne Wellhead Platform North (“WHPN”) and then transported to the Syd Arne Main platform for processing and export.

The East Lobe of the Solsort Field was discovered in 2010 by Well Solsort-1 and the West Lobe in 2013 by Well Solsort-2. Oil is contained within the Paleocene aged Bor Member sandstone reservoir, which is within the Våle Formation. The reservoir was deposited as part of a turbidite system.

Only the West Lobe is developed and production commenced in March 2024 through a single horizontal well, supported by a horizontal water injector which began to inject in September 2024. The average monthly oil production rate peaked in 2024 at ~18,350 stb/d. Water breakthrough occurred in July 2025 and increased rapidly, reaching 68% by the end of the year. As of 31 December 2025 the oil rate was 3,500 stb/d, the water injection rate was 17,300 bbl/d and cumulative oil production was 7.0 MMstb.

The Developed Reserves comprise production from the existing well and are estimated using DCA. Undeveloped Reserves are related to the extension of the CoP after the Hejre Field is brought onstream.

Hejre (INEOS working interest 100.0%)

The Hejre Field is an oil field located approximately 300 km offshore Denmark in the Danish sector of the North Sea, close to the Danish-Norwegian border. It is located ~28 km northwest of the Syd Arne Field.

Hejre was discovered by Well Hejre-1 in 2001, which encountered 20 m of net oil pay in Gert Member shallow marine sandstones within the Upper Jurassic aged Heno Formation. The discovery is considered high pressure and high temperature (“HPHT”) with reservoir pressure ~14,750 psia at 5,300 mTVDSS and reservoir temperature ~160°C. The field is separated into three segments by faults, with evidence of compartmentalisation from pressure data and fluid properties.

In 2011 a Plan for Development and Operation (“PDO”) was approved by the Danish Energy Agency (“DEA”) with a financial investment decision (“FID”) taken in 2012. Between 2014 and 2016 five development wells (with seven wellbores) were drilled and construction work on the Hejre topsides began. However, due to technical difficulties and significant delays at the yard in South Korea, the project was stopped.

INEOS acquired its interest in Hejre in 2017 (purchase of DONG interest) and 2020 (purchase of Spirit Energy interest) and a revised PDO was submitted in 2022 which envisages development via an unmanned topside facility and utilises three of the existing pre-drilled development wells. Produced fluids will be exported multiphase via a 28 km, 10” tie-back to the South Arne facilities. Gas will be exported via the existing pipeline to the onshore receiving terminal at Nybro. This PDO was re-submitted alongside

an environmental impact assessment in Q4 2025 and the revised PDO was approved by the DEA in May 2026. FID is scheduled for mid-2026 and first oil is scheduled in November 2028¹².

Sproule ERCE attributes Undeveloped Reserves based on volumetric assessment coupled with a range of recovery factors. The total remaining CAPEX for the Hejre development is estimated to be DKK6,200 MM.

Lulita (INEOS working interest 40.0%)

The Lulita Field is an oil field located in the Danish North Sea in the northeastern part of the Danish Central Graben. Straddling two boundaries, the field is located in the Sole Concession area and Licences 7/86 and 1/90 and has been unitised. The field is operated by TotalEnergies and is a satellite of the Harald Field, which is located in the Sole Concession area. Produced hydrocarbons are transported to the Tyra facilities (located in the centre of the Sole Concession area) via the Harald facilities; oil is exported to shore via the Gorm E platform and gas is exported via the Nybro pipeline.

The Lulita Field was brought onstream in 1998 and contains oil in a Middle Jurassic sandstone reservoir. The field was shut-in in 2019 due to the shut-in of the Tyra facility, which was no longer considered safe after subsidence of the seabed. A major redevelopment project was then undertaken by the Operator. Production through the refurbished Tyra II facility began in late November 2024 and is continuing to ramp up. As part of the ramp-up, the Lulita Field is expected to be brought back onstream in the second half of 2026.

The average production rate before the full field shut down in 2019 was 800 stb/d of oil and 3 MMscf/d of gas from one well, with cumulative oil production of 7.4 MMstb.

The Developed Reserves comprise production from the existing well. There are no Undeveloped Reserves. The CoP of the Lulita Field is determined by the Harald Hub, which INEOS is not a partner in.

Denmark Contingent Resources (various working interests)

INEOS' Contingent Resources in Denmark comprise several incremental projects in the Syd Arne Field as well as those associated with the future development of two discoveries (Solsort East and Lunde). The Syd Arne projects include an Ekofisk infill well (infill Well SAE-09), a two well development of the deeper, undeveloped Tuxen reservoir, a well intervention campaign and a further infill well campaign in the Ekofisk reservoir, involving five wells. The Solsort East discovery is located 2.5 km east of the producing Solsort West Field and is notionally planned to be developed by two oil production wells and a water injection well. The Lunde discovery lies at a shallower interval above the Hejre Field and was

¹² Since the Preparation Date of the CPR, INEOS has informed Sproule ERCE that it took FID on Hejre in September 2026.

discovered by Hejre development Well HA-4. It is notionally planned to be developed by a single oil production well.

1.1.2 United Kingdom

Breagh (INEOS working interest 100.0%)

The Breagh Field is a gas field located in the Southern North Sea approximately 100 km east of to the Teeside Gas Processing Plant ("TGPP"). INEOS is the Operator. Gas from the field is exported via a dedicated 110 km pipeline to TGPP.

Dry gas is contained in the Lower Carboniferous aged Yoredale Formation which comprises stacked fluvial sourced sandstone bodies. The reservoir is considered tight with permeability generally 0.1 – 10s mD.

The field was discovered in 1997 and brought onstream in 2013, initially through six pre-drilled, high angle development wells and two further wells drilled in 2014. Since the initial development there have been two further drilling phases, with two new wells and a sidetrack drilled in 2018 and two new wells drilled in 2021 and 2023. Seven of the wells have been hydraulically fractured and one well has a horizontal completion. In late 2024 onshore compression commenced, resulting in an increase in the field gas rate from ~32 MMscf/d to ~70-80 MMscf/d, peaking at 85 MMscf/d after opening up the well sliding sleeves.

As of 31 December 2025, the average gross wellhead gas rate was 55 MMscf/d from eleven active wells. Cumulative gas production was 239 Bscf and gas recovery factor was 24% (against the Operator's volumetric GIIP). Produced gas has a low condensate-gas ratio ("CGR") of 2.8 stb/MMscf.

The Developed Reserves comprise production from the existing wells and a planned intervention in Well A8 to improve productivity. Sproule ERCE's estimates of Developed Reserves are based on DCA. Undeveloped Reserves are assigned to an infill well (Well A13), planned to be drilled in an area of the field south of Well A7. This area of the field has been re-interpreted using the 2024 reprocessed seismic data and, due to the inclusion of a slow velocity Triassic interval, the structural relief in this area has increased.

Clipper South (INEOS working interest 75.0%)

The Clipper South Field is a gas field located in the Southern North Sea approximately 100 km to the east of the Theddlethorpe gas terminal. INEOS is the Operator. Production was originally routed via the Lincolnshire Offshore Gas Gathering System complex to the Theddlethorpe Gas Terminal but is now exported via Shell's Clipper complex to the Bacton Terminal.

Gas is contained in the Leman Formation of relatively poor quality reservoir, made of a mix of aeolian, fluvial and sandy sabkha sediments.

The field was discovered in 1983 and first gas was achieved in 2012. A total of four development wells have been drilled, all online at the Effective Date. As of 31 December 2025, the average wellhead gas production rate from the field was around 19 MMscf/d, with a current gas recovery factor in the order of 70% for the entire field.

The Developed Reserves comprise continued production from existing wells and Sproule ERCE's estimates are based on DCA. There are no Undeveloped Reserves.

Greater Laggan Area (INEOS working interest 20.0%)

The Laggan, Tormore, Edradour and Glenlivet Fields (collectively the "Greater Laggan Area" or "GLA") are gas-condensate fields located between 75 km and 125 km northwest of the Shetland Islands on the UK Continental Shelf ("UKCS"). Serica Energy is the Operator.

The fields are developed through a dedicated subsea pipeline infrastructure to the SGP. Gas is exported via the Shetland Island Regional Gas Export pipeline and the Frigg UK Association pipeline to St Fergus where natural gas liquid ("NGL") is extracted, whilst the condensate is exported to the Sullom Voe Terminal.

Gas is produced from Palaeocene aged deep marine turbidite reservoirs and Cretaceous aged deep marine mass flow deposits, with variable CGR.

Production commenced in 2016. A low-pressure compression project was completed in 2023 at the SGP. Regular pigging activities are required to liquid sweep flowlines; in the past year these have been occurring approximately every six weeks and last several days. There is a short period of flush production each time production is restarted after a pigging operation.

As of 31 December 2025, the average gross wellhead gas and condensate rates were 37 MMscf/d and 329 bbl/d from eight active wells. At the same date, cumulative gas and condensate production was 839 Bscf and 12.6 MMstb and gas recovery factors in the fields were between 41% and 83%.

In Q4 2025, the Victory Field (a single well tie back owned by a third party) was tied into the GLA infrastructure causing a back-out effect on GLA production. A compensation mechanism between the GLA and Victory partners is in place to account for this.

The Developed Reserves comprise continued production from existing wells and Sproule ERCE's estimates are based on DCA. There are no Undeveloped Reserves.

UK Contingent Resources (various working interests)

INEOS' Contingent Resources in the UK comprise incremental projects in the Breagh, Clipper South and Tormore (part of the GLA) Fields, as well as the development of the Glendronach gas discovery (located in the GLA), the Pegasus West gas discovery and other gas discoveries in the Greater Pegasus Area.

Incremental projects in the Breagh Field include two infill wells in the southeast area (near Well A11) and a notional two-well development of the undeveloped northwestern area of the field. Incremental projects in the Clipper South Field include two infill wells; one in the undeveloped northwestern area and one in the undeveloped southeastern area of the field.

Contingent Resources in the Tormore Field are associated with an infill well targeted north of the existing producer. The Glendronach discovery is located close to the Edradour Field, in a deeper reservoir interval, and is notionally planned to be developed by re-entering one of the appraisal wells and converting it to a gas producer.

INEOS acquired the Greater Pegasus Area licences in the UKCS 33rd round, with a strategy to build a new satellite platform with a pipeline connection to Breagh and then on to the TGPP. The first development would involve the Pegasus West discovery, with the other discoveries (Browney, Andromeda North and Pegasus East) to be potentially developed at a later date.

1.1.3 US Gulf

Stampede and Black Pearl (INEOS working interest 25.0%)

The Stampede and Black Pearl Fields are oil fields located in the Mississippi Canyon area of the Gulf of Mexico in water depths of 1,000 – 1,130 m. Chevron is the Operator. Development comprises subsea production with wells tied back to a Tension Leg Platform.

In the Stampede Field oil is contained within four Middle Miocene turbidite sandstones which have varying degrees of lateral continuity. The field is an anticline structure with internal faulting which may lead to areas of unswept oil. The field is considered high pressure, with reservoir depths ranging from ~8,200 – 9,750 mTVDSS and reservoir pressure and temperature in the order of 15,800 psia and 110°C respectively.

The field was discovered in 2005 and production began in 2018, with seven production and three injection wells drilled to date; production and injection is commingled between reservoirs. Average monthly oil production reached a peak rate of ~40,000 stb/d in late 2020. As of 31 December 2025, the field oil production rate was ~21,000 stb/d (at a water cut of 6%) and cumulative oil production was 74.6 MMstb. Water injection began in November 2018 and has achieved a cumulative voidage replacement ratio ("VRR") of ~34%. The low VRR has primarily been caused by issues with the topsides injection

equipment. The latest issues have been resolved and injection efficiency is expected to significantly improve in 2026.

The Black Pearl Field is a single well tie-back to Stampede and was brought onstream in July 2025. Oil is contained within a slightly younger turbidite reservoir than those developed in Stampede. The initial oil rate was ~3,000 stb/d and had steadily increased to ~7,000 stb/d by the end of 2025, with cumulative oil production of 0.8 MMstb. Although there is no water injection, the reservoir pressure has so far remained above the bubble point pressure. The well has not yet produced any water.

The Developed Reserves comprise continued production from existing wells and Sproule ERCE's estimates are based on volumetric assessment coupled with a range of recovery factors. A portion of the Black Pearl Field is located outside of INEOS' licence in open acreage and this is excluded from INEOS' Reserves. There are no Undeveloped Reserves.

Appomattox, Vicksburg and Rydberg (INEOS working interest 21.0%)

The Appomattox, Vicksburg, and Rydberg Fields are oil fields located in the Mississippi Canyon area of the Gulf of Mexico in water depths of ~2,200 m, approximately 265 km southeast of New Orleans. Shell is the Operator. The Appomattox and Vicksburg Fields produce to the Appomattox host facility; the Rydberg Field is tied back to the host facility via the Vicksburg subsea production system. A third satellite field, Dover, also produces via the Appomattox host facility but INEOS does not hold any interest in the field. Oil and gas are exported to shore via the Mattox Pipeline and Williams export pipeline respectively.

The fields produce oil and gas from the Jurassic-aged Norphlet reservoir and are developed through subsea wells tied back to offshore production facilities. The Norphlet reservoir is an aeolian sandstone with high net-to-gross ratio and permeability of 100-250 mD. The fields are considered HPHT, with reservoir depths range from ~7,600 mTVDSS in Appomattox and Vicksburg to ~8,200 mTVDSS in Rydberg. Reservoir pressure and temperature in the order of 18,000 psia and 165°C respectively.

Development of the fields has progressed through a phased drilling programme, with wells drilled and completed over multiple campaigns.

The Appomattox Field was discovered in 2009 and brought onstream in 2019 with ten production wells, supported by four water injection wells, drilled to date. Monthly average oil production reached ~100,000 stb/d in 2022 and, as of 31 December 2025, the average monthly oil rate was ~65,000 stb/d with a water cut of ~20%; cumulative oil production was 166 MMstb.

The Vicksburg Field was discovered in 2007 and comprises two separate areas: Vicksburg A and Vicksburg B. The Vicksburg A structure was brought onstream in 2019 and is developed by three wells. The Vicksburg-B structure was brought onstream in 2023 and is developed by a single well. A peak average monthly oil rate of ~32,000 stb/d was achieved in 2021 and, as of 31 December 2025, the average monthly oil rate was ~14,000 stb/d with a water cut of ~20%; cumulative oil production was 45.7 MMstb.

The Rydberg Field was discovered in 2014 and brought onstream in February 2024. The field is developed by two wells, the most recent of which was brought onstream in July 2025. Since the second well was brought onstream the field has been producing at an average monthly plateau oil rate of ~15,000 stb/d. The wells are currently producing relatively dry oil with water cut less than 4%. Cumulative oil production as of 31 December 2025 was 5.6 MMstb.

For both the Appomattox and Vicksburg Fields, the Developed Reserves comprise continued production from existing wells and Sproule ERCE's estimates are based on volumetric assessment coupled with a range of recovery factors.

In the Appomattox Field, Undeveloped Reserves are assigned to two infill wells, one of which is a short sidetrack of an existing well. The wells are planned to be drilled and onstream in 2027 and will complete the original FDP commitment for the Appomattox area. In the Vicksburg Field, Undeveloped Reserves are assigned to one infill well. Drilling commenced in January 2026 and planned to be brought onstream in July 2026¹³. Undeveloped Reserves are estimated considering the results of INEOS' dynamic simulation model, benchmarked against the performance of existing wells.

Other US interests

Sproule ERCE has evaluated INEOS' working interest in three additional fields in the US Gulf (Tobago, Longhorn and Aspen) as well as ORRIs in three fields (Abilene¹⁴, Great White and Shenandoah). Production data for these assets was made available to 31 August 2025.

The Tobago Field, operated by Shell, was brought onstream in 2011 and, as of 31 August 2025, produces from one oil well at oil and gas rates of 1,136 stb/d and 1.8 MMscf/d respectively. Developed Reserves comprise production from the existing well and are evaluated using a DCA approach.

The Longhorn Field, operated by ENI, was brought onstream in 2009 and, as of 31 August 2025, produces from two wells at oil and gas rates of 354 stb/d and 15.5 MMscf/d respectively. Production is uneconomic based on current price forecasts and there are no Reserves.

The Aspen Field, operated by Walter Oil & Gas Corporation, was brought onstream in 2011 and, as of 31 August 2025, produces from one oil well at oil and gas rates of 281 stb/d and 0.3 MMscf/d respectively. Developed Reserves comprise production from the existing well and are evaluated using a DCA approach.

¹³ INEOS informed Sproule ERCE that the well was brought onstream ahead of schedule in April 2026. This has not been accounted for in this evaluation.

¹⁴ INEOS holds a working interest in the West Abilene field which produces intermittently from a single well. INEOS does not book Reserves for the field and it is outside of Sproule ERCE's scope of work for this evaluation.

The Abilene Field is operated by Harbour Energy following its acquisition of LLOG Exploration Offshore's interest in February 2026. The field contains hydrocarbons in multiple reservoirs and, as of 31 August 2025, the oil and gas production rates from wells in which INEOS holds an ORRI were 4,749 stb/d and 25.4 MMscf/d, respectively (six active oil wells and one active gas well). INEOS holds a 4% ORRI on the 4600ms sands and a 10% ORRI on the 4200ms and 4400ms sands.

The Great White Field, operated by Shell, was brought onstream in 2010 and, as of 31 August 2025, produces from 19 wells at oil and gas rates of 59,150 stb/d and 79 MMscf/d respectively. Production is supported by eight water injection wells. Production forecasts are based on DCA, truncated at the notional end of facilities life in 2035. Shell has a history of continuously drilling infill wells in the field to reduce the decline rate. INEOS' ORRI is set on a sliding scale according to cumulative production. The ORRI increased from 1.2% to 1.5% at the end of 2025 as the 400 MMboe milestone was met; this was confirmed to INEOS by Shell.

The Shenandoah Field, operated by Beacon Offshore Energy, was brought onstream in July 2025 with four wells. The field is expected to continue its ramp up with further phases of activity. Production data were not available and INEOS and Sproule ERCE have relied on forecasts presented in a publicly available third party Reserves report effective 30 November 2024. Oil production is expected to reach an annual average rate of 100,000 stb/d in 2026. INEOS holds a 0.5% ORRI on Shenandoah production.

US Gulf Contingent Resources (various working interests)

INEOS' Contingent Resources in the US Gulf comprise incremental projects in the Stampede, Appomattox and Vicksburg Fields, as well as the future development of the Nashville, Flying Dutchman and Fort Sumter discoveries.

The Contingent Resources are associated with a range of potential development opportunities, including recompletions, infill drilling, production enhancement initiatives and future development concepts associated with discovered resources. These opportunities remain subject to further technical, commercial, regulatory and economic evaluation, as well as any required approvals, before development decisions are made.

1.2 Reserves

Under PRMS 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 country gross, Company working interest and Company net entitlement basis as of 31 December 2025. Under PRMS, it is the Company's net entitlement that should be reported

as the entity's Reserves. Developed plus Undeveloped Reserves are reported for each country and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves using a conversion of 5,609 scf per boe, as advised by INEOS.

A summary of the Total Reserves (Developed plus Undeveloped) is presented in Table 1-3.

Table 1-3: Total Reserves as of 31 December 2025

Total Reserves as of 31 December 2025									
Country	Gross on Licence			Company Working Interest			Company Net Entitlement		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Oil + Condensate + NGL (MMstb)									
Denmark	37.0	73.5	106.9	35.8	71.7	104.4	35.8	71.7	104.4
United Kingdom	1.1	1.7	2.5	0.4	0.7	1.1	0.4	0.7	1.1
US Gulf	192.0	348.9	515.8	43.8	78.4	114.7	39.4	70.0	102.3
Total	230.0	424.1	625.2	80.1	150.8	220.2	75.6	142.4	207.8
Gas (Bscf)									
Denmark	81.2	154.9	225.0	77.9	149.8	218.2	77.9	149.8	218.2
United Kingdom	135.4	243.0	384.2	103.5	195.4	316.1	103.5	195.4	316.1
US Gulf	29.0	64.2	116.7	6.3	14.1	25.6	7.4	15.9	28.4
Total	245.5	462.1	725.9	187.7	359.2	559.8	188.8	361.0	562.6
Oil Equivalent (MMboe)									
Denmark	51.4	101.1	147.0	49.7	98.4	143.3	49.7	98.4	143.3
United Kingdom	25.2	45.0	71.0	18.9	35.6	57.5	18.9	35.6	57.5
US Gulf	197.2	360.3	536.6	45.0	80.9	119.3	40.7	72.8	107.3
Total	273.8	506.5	754.7	113.5	214.9	320.0	109.3	206.8	308.1

Notes:

1. Gross Reserves represent 100% of the Reserves to be recovered from the licence.
2. Company Working Interest Reserves are based on the INEOS Working Interest share of the field gross Reserves.
3. Company Net Entitlement Reserves take into account royalties. For the Danish and UK assets, as there are no royalties to be deducted, Company Working Interest Reserves are equal to Company Net Entitlement Reserves. For the US assets in which INEOS has a Working Interest share, royalties are deducted and Company Net Entitlement Reserves are less than Company Working Interest Reserves. For the US assets in which INEOS holds an ORRI, there are no Company Gross or Company working Interest Reserves and royalty volumes are included as Net Entitlement Reserves only.
4. Gas Reserves are based on sales volumes and exclude fuel and flare.
5. Barrels of oil equivalent are calculated using a conversion of 5,609 scf/boe.

Reserves evaluation

Sproule ERCE has carried out an economic evaluation of the Reserves at an asset level using commodity price forecasts provided by INEOS (Table 1-4). European Union and United Kingdom Carbon price allowance forecasts are based on Sproule ERCE's price decks as of 31 December 2025. Sproule ERCE has applied discounts and premiums to the price forecasts based on guidance from INEOS.

Table 1-4: Hydrocarbon and CO₂ allowance price forecasts as of 31 December 2025

	Brent Crude Oil Price	WTI Crude Oil Price	NBP Gas Price	HH Gas Price	EU Allowances Price	UK Allowances Price
Year	USD/bbl	USD/bbl	p/therm	USD/MMbtu	EUR/tonne	GBP/tonne
2026	85.00	80.00	115.00	3.50	72.35	56.78
2027	73.53	68.63	98.04	3.43	73.51	58.14
2028	70.00	67.12	70.00	3.50	74.60	61.12
2029	70.00	67.17	70.00	3.50	75.94	63.61
2030	70.00	67.23	70.00	3.50	77.05	66.42
2031	70.00	67.28	70.00	3.50	78.19	69.26
2032	70.00	67.34	70.00	3.50	79.49	70.55
2033	70.00	67.39	70.00	3.50	80.93	72.00
2034	70.00	67.44	70.00	3.50	82.50	73.57
2035+	70.00	67.49	70.00	3.50	84.18	75.27

Notes:

1. Brent crude oil price, WTI crude oil price, National Balancing Point ("NBP") gas price and Henry Hub ("HH") gas price forecasts are presented in real (2026) terms and have been provided by INEOS. Sproule ERCE has been instructed by INEOS to use these price forecasts in its evaluation.
2. EUA and UKA price forecasts are based on the Sproule ERCE 31 December 2025 price forecast and are presented in real (2026) terms.
3. Discounts and premiums have been applied based on guidance from INEOS.

Sproule ERCE has calculated before and after tax NPVs at the country level at discount factors of 0%, 5%, 10%, 15% and 20%; these are presented in Table 1-5 to Table 1-7. The after tax NPVs take into account INEOS' historical tax balances in each country, which were provided by INEOS.

Table 1-5 Denmark – Before and After tax Net Present Values of the Reserves

(attributable to INEOS as of 31 December 2025)

	Category	Denmark - Corporate Level Net NPVs				
		0%	5%	10%	15%	20%
		(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)
Before Tax	1P	-477	-92	-91	-90	-89
	2P	1,705	1,056	1,043	1,031	1,018
	3P	4,893	2,234	2,206	2,179	2,153
After Tax	1P	-477	-92	-91	-90	-89
	2P	1,201	893	882	871	861
	3P	3,594	1,791	1,769	1,747	1,726

Table 1-6: UK – Before and After tax Net Present Values of the Reserves

(attributable to INEOS as of 31 December 2025)

	Category	UK - Corporate Level Net NPVs				
		0%	5%	10%	15%	20%
		(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)
Before Tax	1P	316	368	363	359	355
	2P	830	732	723	714	706
	3P	1,748	1,188	1,174	1,159	1,145
After Tax	1P	57	166	164	162	160
	2P	480	467	461	455	450
	3P	1,298	856	845	835	825

Table 1-7: US Gulf – Before and after tax Net Present Values of the Reserves

(attributable to INEOS as of 31 December 2025)

	Category	US Gulf - Corporate Level Net NPVs				
		0%	5%	10%	15%	20%
		(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)
Before Tax	1P	1,166	1,157	1,143	1,129	1,116
	2P	2,860	2,078	2,052	2,027	2,002
	3P	5,107	3,006	2,968	2,932	2,897
After Tax	1P	1,037	1,068	1,055	1,042	1,029
	2P	2,334	1,791	1,769	1,747	1,726
	3P	4,119	2,519	2,488	2,458	2,428

1.3 Contingent Resources

Under PRMS, Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates as 1C, 2C and 3C.

The projects associated with Contingent Resources are, by definition, commercially less mature than the Reserves projects. Summaries of the oil, gas and oil equivalent Contingent Resources at a country level, presented on a gross and Company Working Interest basis, are presented in Table 1-8.

No economic analyses have been performed on the Contingent Resources and, therefore, their economic status is undetermined.

Table 1-8: Contingent Resources as of 31 December 2025

Country	Gross on Licence			Company Working Interest		
	1C	2C	3C	1C	2C	3C
Oil + Condensate + NGL (MMstb)						
Denmark	31.1	53.5	89.8	23.8	42.9	74.1
UK	2.3	3.9	7.0	1.4	2.4	4.4
US Gulf	56.8	115.2	213.2	12.3	24.9	46.0
Total	90.3	172.7	310.0	37.6	70.2	124.5
Gas (Bscf)						
Denmark	37.6	64.3	103.3	29.9	52.8	86.0
UK	196.7	346.2	586.1	161.4	285.0	482.6
US Gulf	34.8	70.0	128.9	7.6	15.3	28.0
Total	269.1	480.5	818.3	199.0	353.1	596.7
Oil Equivalent (MMboe)						
Denmark	37.8	65.0	108.3	29.2	52.3	89.5
UK	37.4	65.7	111.5	30.2	53.3	90.4
US Gulf	63.0	127.7	236.1	13.7	27.7	51.0
Total	138.2	258.4	455.9	73.0	133.2	230.9

Notes:

1. Gross Contingent Resources represent 100% of the Contingent Resources to be recovered from the licence.
2. Company Working Interest Contingent Resources are based on the INEOS Working Interest share of the field gross Contingent Resources. Net entitlement Contingent Resources are not reported, but these would be equal to Company Working Interest for the Danish and UK assets as there are no royalties to be deducted. In the US, Net entitlement Contingent Resources will be less than Company Working Interest as royalties must be deducted.
3. Gas Contingent Resources are based on wellhead volumes prior to shrinkage.
4. Conversion of gas to boe equivalent is based on 5,609 scf/boe.
5. These are unrisks Contingent Resources that have not been risked for Chance of Development.
6. These Contingent Resources contain a mixture of the following PRMS sub-classifications: Development Pending ("DP"), Development On Hold ("DOH") and Development Unclassified ("DUC").
7. The Greater Pegasus Area discoveries in the UK comprise Browney, Andromeda North and Pegasus East.
8. INEOS did not hold a working interest in the Fort Sumter discovery in the US Gulf as of the Effective Date of this report; it acquired its interest in May 2026. The associated volumes are included in the estimates presented.

Appendix 1: Hejre Working Interest Sensitivity

After the Effective Date of the CPR, Sproule ERCE was made aware that INEOS is in the process of farming down a portion of their working interest in the Hejre field. This process is ongoing but is expected to complete within months of the issuance date of the CPR. After completion of this process INEOS' working interest in the field will be reduced to 75.0% in Hejre.

The reduction in working interest also impacts the Contingent Resources of the Lunde discovery, which is located in the same licence.

On INEOS' request, Sproule ERCE has performed a sensitivity analysis of this scenario and the impact on Company Working Interest and Company Net Entitlement Reserves, NPVs and Contingent Resources. The results of this analysis are presented in Table A - 1, Table A - 2 and Table A - 3.

Table A - 1: Total Reserves as of 31 December 2025, Hejre WI sensitivity

Country	Gross on Licence			Company Working Interest			Company Net Entitlement		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Oil + Condensate + NGL (MMstb)									
Denmark	37.0	73.5	106.9	29.6	59.8	86.7	29.6	59.8	86.7
United Kingdom	1.1	1.7	2.5	0.4	0.7	1.1	0.4	0.7	1.1
US Gulf	192.0	348.9	515.8	43.8	78.4	114.7	39.4	70.0	102.3
Total	230.0	424.1	625.2	73.8	138.9	202.6	69.4	130.5	190.1
Gas (Bscf)									
Denmark	81.2	154.9	225.0	68.9	132.3	191.4	68.9	132.3	191.4
United Kingdom	135.4	243.0	384.2	103.5	195.4	316.1	103.5	195.4	316.1
US Gulf	29.0	64.2	116.7	6.3	14.1	25.6	7.4	15.9	28.4
Total	245.5	462.1	725.9	178.8	341.8	533.0	179.8	343.6	535.8
Oil Equivalent (MMboe)									
Denmark	51.4	101.1	147.0	41.8	83.4	120.8	41.8	83.4	120.8
United Kingdom	25.2	45.0	71.0	18.9	35.6	57.5	18.9	35.6	57.5
US Gulf	197.2	360.3	536.6	45.0	80.9	119.3	40.7	72.8	107.3
Total	273.8	506.5	754.7	105.7	199.8	297.6	101.4	191.8	285.6

Table A - 2: Denmark – Before and After tax Net Present Values of the Reserves, Hejre WI sensitivity

Before / After Tax	Category	Denmark - Corporate Level Net NPVs				
		0%	5%	10%	15%	20%
		(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)	(US\$MM)
Before Tax	1P	-501	-74	-73	-72	-71
	2P	1,279	895	884	873	862
	3P	3,923	1,866	1,843	1,820	1,798
After Tax	1P	-501	-74	-73	-72	-71
	2P	910	784	774	765	756
	3P	2,894	1,529	1,510	1,492	1,474

Table A - 3: Contingent Resources as of 31 December 2025, Hejre WI sensitivity

Country	Gross on Licence			Company Working Interest		
	1C	2C	3C	1C	2C	3C
Oil + Condensate + NGL (MMstb)						
Denmark	31.1	53.5	89.8	23.5	41.7	70.3
UK	2.3	3.9	7.0	1.4	2.4	4.4
US Gulf	56.8	115.2	213.2	12.3	24.9	46.0
Total	90.3	172.7	310.0	37.2	69.1	120.7
Gas (Bscf)						
Denmark	37.6	64.3	103.3	29.7	52.1	83.7
UK	196.7	346.2	586.1	161.4	285.0	482.6
US Gulf	34.8	70.0	128.9	7.6	15.3	28.0
Total	269.1	480.5	818.3	198.8	352.4	594.4
Oil Equivalent (MMboe)						
Denmark	37.8	65.0	108.3	28.8	51.0	85.3
UK	37.4	65.7	111.5	30.2	53.3	90.4
US Gulf	63.0	127.7	236.1	13.7	27.7	51.0
Total	138.2	258.4	455.9	72.7	131.9	226.7