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DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 7, 2022

IGas Energy PLC
7 Down Street
London W1J 7AJ
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2021, of the extent of the proved, probable, and possible oil, condensate, and sales gas reserves, the value of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, the extent of the 1C, 2C, and 3C contingent resources, and the extent of the prospective resources associated with certain conventional properties in and offshore the United Kingdom, in which IGas Energy PLC (IGas) has represented it holds an interest.

Estimates of reserves, contingent resources, and prospective resources presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. PRMS is a referenced standard in published guidance of the United Kingdom Listing Authority. The reserves definitions are discussed in detail under the Definition of Reserves heading of this report. The contingent resources definitions are discussed in detail under the Definition of Contingent Resources heading of this report. The prospective resources definitions are discussed in detail under the Definition of Prospective Resources heading of this report.

This report is compliant with the Competent Person's Report requirements as published in the European Securities and Markets Authority (ESMA) update of the

Committee of European Securities Regulators' recommendations for the implementation of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319). PRMS is a referenced standard therein.

Reserves estimated in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from the fields after December 31, 2021. Net reserves are defined as that portion of the gross reserves attributable to the interests held by IGas after deducting all interests held by others.

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that were estimated using initial prices, expenses, and costs provided by IGas and forecast prices, expenses, and costs as described herein. Prices, expenses, and costs were provided in United Kingdom pounds sterling (U.K.£). For the purposes of this report, U.K.£ were converted to United States dollars (U.S.$) using an exchange rate of U.S.$1.33 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. An explanation of the forecast price, expense, and cost assumptions is included under the Valuation of Reserves heading of this report.

Values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting operating expenses, abandonment costs, and capital costs from future gross revenue. Operating expenses include field operating expenses, estimated expenses of direct supervision, and an allocation of overhead that directly relates to production activities. Abandonment costs are represented by IGas to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. At the request of IGas, United Kingdom taxes were not considered in this report. Present worth is defined as the future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using a discount rate of 10 percent are reported in detail and values using discount rates of 8, 12, and 15 percent are reported as totals.

Contingent resources estimated in this report are expressed as gross contingent resources and net contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable from known accumulations after December 31, 2021. Net contingent resources are defined as that portion of the gross contingent resources attributable to the interests held by IGas after deducting all interests held by others.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves. A detailed explanation of the contingent resources estimated herein is included under the Estimation of Contingent Resources heading of this report.

Contingent resources quantities should not be confused with those quantities that are associated with reserves due to the additional risks involved. The quantities that might actually be recovered, should they be developed, may differ significantly from the estimates presented herein. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Prospective resources estimated in this report are expressed as gross prospective resources and working interest prospective resources. Gross prospective resources are defined as the total estimated petroleum that is potentially recoverable from undiscovered accumulations after December 31, 2021. Working interest prospective resources are defined as the product of the gross prospective resources and IGas' working interest in the leasehold or concession associated with a given prospect.

The prospective resources estimated herein are those quantities of petroleum that are potentially recoverable from accumulations yet to be discovered. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The prospective resources estimates in this report are not provided as a means of comparison to contingent resources or reserves.

Prospective resources quantities estimates should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates presented herein. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Estimates of reserves and revenue and contingent resources and prospective resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

In this report, key information has been provided by IGas on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests held by IGas that would require additional information for the proper evaluation of these fields. All evaluations herein are considered in the context of current agreements and regulations and do not consider uncertainties that might be associated with political conditions.

Information used in the preparation of this report was obtained from IGas. In the preparation of this report we have relied upon information furnished by or directed to be furnished by IGas with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, concession expiration dates, and various other information and data that were accepted as represented. Although we have not had independent verification, the information used in this report appears reasonable. The technical staff of IGas involved with the assessment and implementation of development of IGas' petroleum assets are represented as adherent to the generally accepted practices of the petroleum industry. The staff members appear to be experienced and technically competent in their fields of expertise. No site visit to the fields evaluated herein was made by DeGolyer and MacNaughton. However, existing production data, reports from third parties, and photographic evidence were considered adequate because the fields are in an established producing venue.

Executive Summary

IGas has represented that it holds interests in properties that include 30 discovered fields in the United Kingdom. This report includes evaluations of 8 fields that contain reserves only, 6 fields that contain contingent resources only, 11 fields that contain reserves and contingent resources, and 5 fields with no reserves or contingent resources. This evaluation also includes prospective resources for three conventional prospects.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2021, have been considered to be valid for their stated terms, as represented by IGas.

Reserves

Reserves were estimated for oil, condensate, and sales gas in 19 fields. Sales gas reserves were converted to barrels of oil equivalent (boe) using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated gross and net proved, probable, and possible reserves, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Reserves Summary

	Oil and Condensate			Sales Gas			Oil Equivalent		
	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
Gross	9,905	4,489	3,135	4,426	4,364	4,688	10,668	5,241	3,943
Net	9,803	4,471	3,118	4,426	4,364	4,688	10,566	5,223	3,926

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Revenue

Revenue values in this report were estimated using initial prices, expenses, and costs provided by IGas. Forecast price, expense, and cost assumptions used for this report are detailed herein. Estimates of future net revenue and present worth of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves estimated in this report were prepared using a Base Case and two sensitivity cases. An explanation of the economic assumptions used for the Base Case and two sensitivity cases is included under the Valuation of Reserves heading of this report.

In this report, values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable or possible reserves. Probable and possible reserves involve substantially higher risks than proved reserves. Revenue values associated with proved-plus-probable and proved-plus-probable-plus-possible reserves have not been adjusted to account for such risks; such an adjustment would be necessary in order to make the values associated with probable or possible reserves comparable to values associated with proved reserves.

The estimated future net revenue and present worth of the future net revenue discounted at 10 percent to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves and quantities, as of December 31, 2021, of the properties evaluated under the three economic scenarios described herein are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation Summary

	Proved		**Proved plus Probable**		**Proved plus Probable plus Possible**	
	Future Net Revenue (10^3U.S.$)	**Present Worth at 10 Percent (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**
Base Case	263,867	139,418	554,129	190,439	774,706	227,907
Low Case	184,338	102,683	424,229	146,282	610,749	178,701
High Case	347,536	177,090	688,132	234,816	945,714	278,393

Notes:
1. Values for probable and possible reserves and quantities have not been risk adjusted to make them comparable to values for proved reserves and quantities.
2. Reserves are those estimated using the Base Case, and quantities in the sensitivity cases should not be confused with reserves.

Reserves estimates herein were based on the Base Case projected to an economic limit, and quantities in the sensitivity cases are those included to the limit of projected Base Case production or when an annual economic limit is reached, whichever occurs first. Details regarding the annual price, expense, and cost assumptions are presented under the Valuation of Reserves heading of this report.

Contingent Resources

Contingent resources were estimated for oil, condensate, and sales gas in 17 fields and do not include any unconventional assets. Sales gas contingent resources were converted to boe using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated gross and net 1C, 2C, and 3C contingent resources, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Contingent Resources Summary

	Gross Contingent Resources			Net Contingent Resources		
	Oil and Condensate (10^3bbl)	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**
1C	11,126	9,919	12,836	10,839	9,894	12,545
2C	17,908	17,807	20,978	17,319	17,566	20,348
3C	28,068	25,513	32,467	26,424	24,005	30,563

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Prospective Resources

Estimates of prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. Prospective resources in three conventional prospects have been evaluated in three license blocks in the United Kingdom. The prospective resources estimates presented below were based on a statistical aggregation method. The estimated gross and working interest prospective resources, as of December 31, 2021, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,611
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,372

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency was applied to prospective resources in this table.
3. The prospective resources presented above were based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean oil estimate is 0.10 to 0.15.
6. The prospective resources quantities for the prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Ownership and Infrastructure

IGas has represented that it holds interests in certain licenses for exploration, production, and development in the United Kingdom. The specific properties evaluated herein are shown in the following list and on Figures 1 through 3.

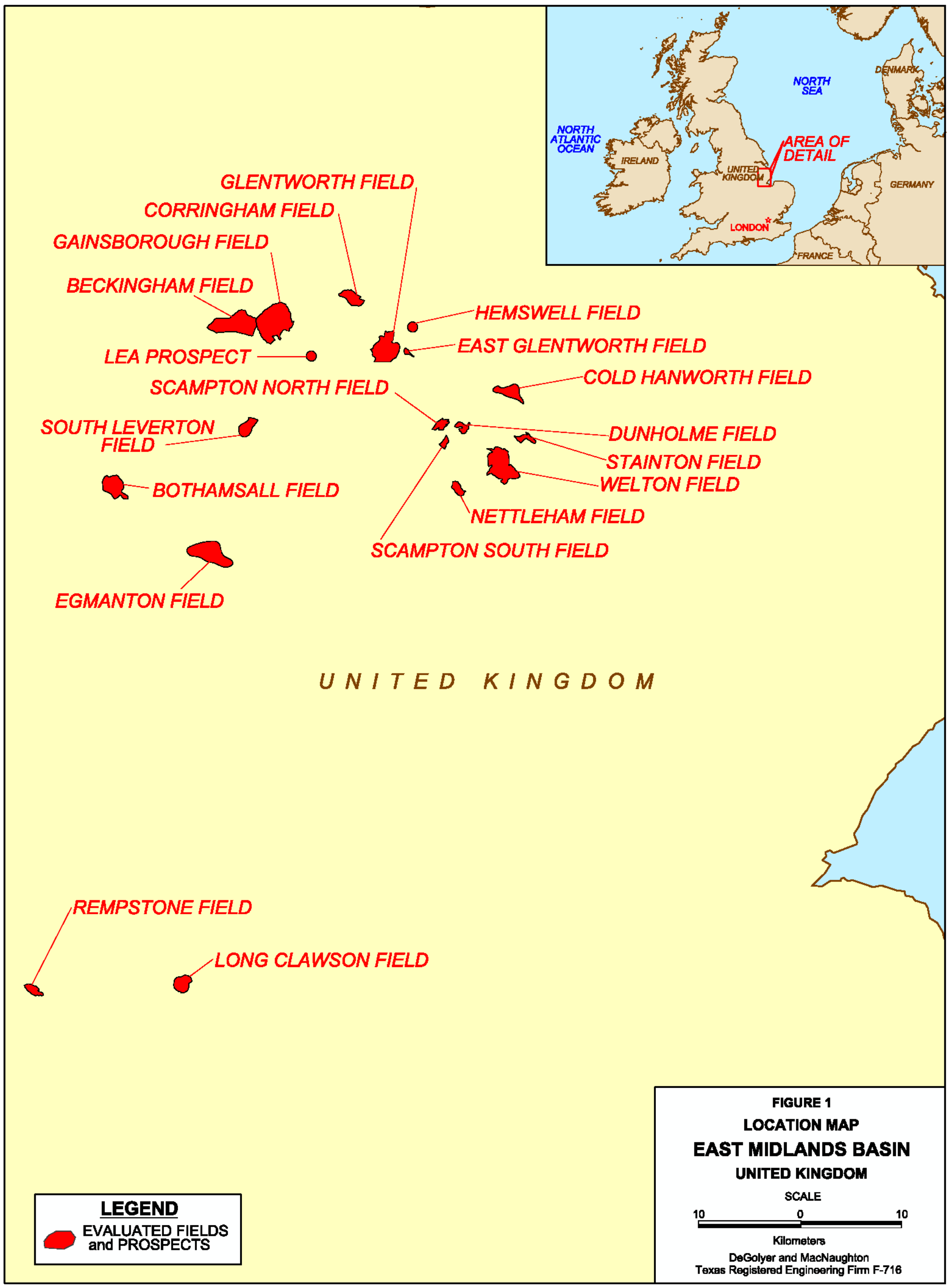
Field/Discovery/Prospect	License	Working Interest (percent)	License Expiration
Albury	DL4	100.00	11/16/2027
Avington	PEDL70	53.67	9/8/2031
Beckingham	ML4	100.00	3/31/2040
Bletchingley	ML18	100.00	1/11/2027
Bletchingley	ML21	100.00	4/1/2027
Bothamsall	ML6	100.00	3/31/2040
Cold Hanworth	PEDL6	100.00	4/4/2027
Corringham	ML4	100.00	3/31/2040
Dunholme	AL009	100.00	4/7/2025
Eartham	PEDL326	100.00	7/20/2046
East Glentworth	PL179	100.00	11/16/2034
Egmanton	ML3	100.00	12/30/2033
Gainsborough	ML4	100.00	3/31/2040
Glentworth	ML4	100.00	3/31/2040
Godley Bridge	PEDL235	100.00	6/30/2039
Goodworth	PEDL21	100.00	4/3/2027
Hemswell	PEDL6	100.00	6/30/2039
Hemswell	PEDL210	75.00	6/30/2039
Horndean	PL211	90.00	4/4/2036
Lea	PED316	35.00	7/20/2046
Lingfield	PEDL257	100.00	7/20/2046
Long Clawson	PL220	100.00	8/8/2026
Lybster	P1270	100.00	12/21/2031
Nettleham	PL179	100.00	11/16/2034
Nettleham	PL199	100.00	10/31/2045
Palmers Wood	PL182	100.00	11/16/2034
Rempstone	PL220	100.00	8/8/2026
Scampton North	PL179	100.00	11/16/2034
Scampton South	PL179	100.00	11/16/2034
Singleton	PL240	100.00	12/1/2037
South Leverton	ML7	100.00	3/31/2040
Stainton	PL179b	100.00	11/16/2034
Stockbridge	DL2	100.00	12/31/2030
Stockbridge	PL233	100.00	10/26/2030
Stockbridge	PL249	100.00	11/30/2030
Storrington	PL205	100.00	2/13/2036
Welton	PL179b	100.00	11/16/2034

Note: Eartham, Godley Bridge, and Lea are the prospects evaluated herein.

These interests are held through contractual instruments that are common in the petroleum industry. We had an opportunity to review certain segments of pertinent agreements; however, we, as engineers, cannot express an opinion as to the accounting or legal aspects of those agreements.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2021, have been considered to be valid for their stated terms, as represented by IGas.

There are 18 fields and 1 prospect evaluated herein located in the East Midlands Basin, as shown on Figure 1.



There are 11 fields and 2 prospects evaluated herein located in the Weald Basin, as shown on Figure 2.

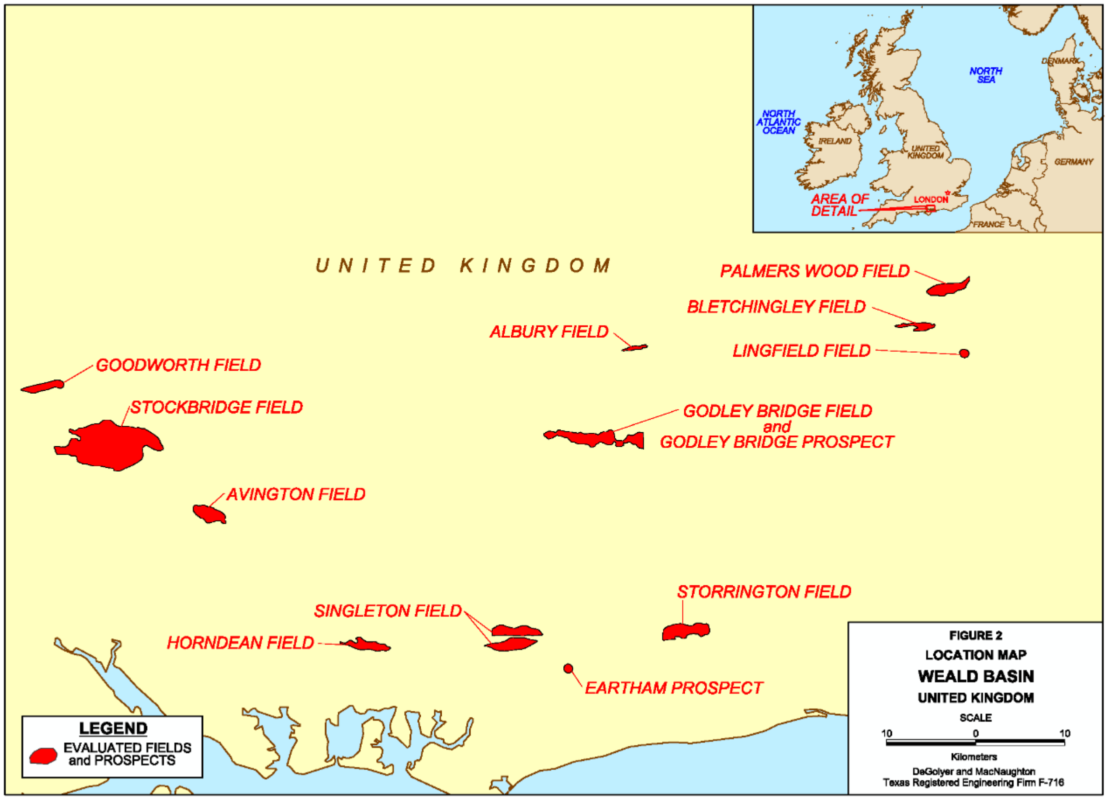


FIGURE 2
LOCATION MAP
WEALD BASIN
UNITED KINGDOM

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The Lybster field is the only offshore field evaluated herein, as shown on Figure 3.

The infrastructure in the area of these fields is well established. The United Kingdom petroleum production province has access to a composite of pipelines and service structures. There are numerous established bases in the United Kingdom, and there is an extensive established network of service companies to allow developments of all types, including complex mechanical and operational elements. Power options, including electrical, gas, and diesel sources, are available to operators in this venue.

Environmental Consideration

There are certain environmental considerations in any venue of petroleum production. We are not aware of any extraordinary environmental elements associated with the properties evaluated herein. As such, we have included abandonment costs, as appropriate, to accomplish routine and safe removal of subsurface and surface equipment. Reclamation costs, if any, are also included in the evaluation herein.

Definition of Reserves

Estimates of proved, probable, and possible reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. The petroleum reserves are defined as follows:

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 satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) 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 development and production status.

> *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 (P90) that the quantities actually recovered will equal or exceed the estimate.

> *Probable Reserves* are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. 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 [P50] that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves that analysis of geoscience and engineering data indicates 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 (P10) that the actual quantities recovered will equal or exceed the 3P estimate.

Once projects satisfy commercial maturity, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan:

Developed Reserves are quantities expected 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.

Developed Producing Reserves are 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.

Developed Non-Producing Reserves include shut-in and behind-pipe reserves. 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. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves are 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.

The extent to which probable and possible reserves ultimately may be recategorized as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable and possible reserves in this report have not been adjusted in consideration of these additional risks to make them comparable to estimates of proved reserves.

Estimation of Reserves

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, development plans provided by IGas, and analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved, probable, or possible.

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by IGas. Proved developed non-producing reserves include those quantities associated with behind-pipe zones and include minor remaining capital expenditure as compared to the cost of a new well.

IGas has represented that its senior management is committed to the development plans provided by IGas and that IGas has the financial capability to execute the development plans, including the drilling and completion of wells and the installation of equipment and facilities.

Where applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation (S_w). When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Where applicable, estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

In certain cases, the reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Except where noted herein, reserves estimates presented herein were generally based on data available through December 31, 2021, and were supported by details of drilling results, analyses of available geological data, well-test results, pressures, available core data, and production history. The reserves estimates presented herein were based on consideration of daily or monthly production data only through September 2021. Where applicable, estimated cumulative production, as of December 31, 2021, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 3 months. This report takes into account all relevant information provided to us by IGas.

Oil and condensate reserves estimated herein are to be recovered by normal field separation and are expressed in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas and fuel gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Fuel gas is defined as that portion of the gas consumed in field operations. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in 10^6ft^3.

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein consist of both associated and nonassociated gas.

At the request of IGas, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Procedure and Methodology

IGas has represented that it holds an interest in multiple fields in the United Kingdom, which have been evaluated in this report. Nineteen of the fields have reserves estimated in this report. The fields produce from various reservoirs in the East Midlands and Weald Basins (Figures 4 and 5).

The reserves estimates for the fields were based on the available performance data, incorporating volumetric analysis and analogy when appropriate.

The Albury field, located in license DL4, was discovered in 1987. The field is gas bearing in the Purbeck and Corallian Sandstones. The field previously produced from the Albury-01 well in the Purbeck Sandstone from 1994 until production was suspended in 2007. The field was redeveloped in 2018 with the restoration of the Albury-01 well. The in-place volumes for the Albury field were evaluated using material-balance methods. Porosity was estimated to range from 12 to 25 percent, S_w was estimated to range from 21 to 60 percent, and permeability was estimated to range from 0.1 to 100 millidarcys. The recovery factors were estimate to range from 61 to 79 percent. Proved developed reserves were estimated based on the producing well performance data. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Avington field, located in license PEDL70, was discovered in 1987 with oil shows in the Cornbrash and Great Oolite reservoirs. Development of the field occurred in 1987 with the Avington-1 well drilled into the upthrown side of a fault defining the field. The field stopped producing from two wells at the end of 2017 due to high operating costs. Porosity was estimated to range from 14 to 23 percent, S_w was estimated to range from 46 to 57 percent, and permeability was estimated to range from 0.08 to 0.1 millidarcys. In this fractured reservoir, the effective permeability can be much higher. The current plan is to bring the two wells back on production in 2023 by disposing the produced water offsite to the Stockbridge field and reducing operating costs. Performance analysis was completed on this field, but after economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. IGas has represented that additional analysis of this field is ongoing, but no modification or development recommendations have been finalized.

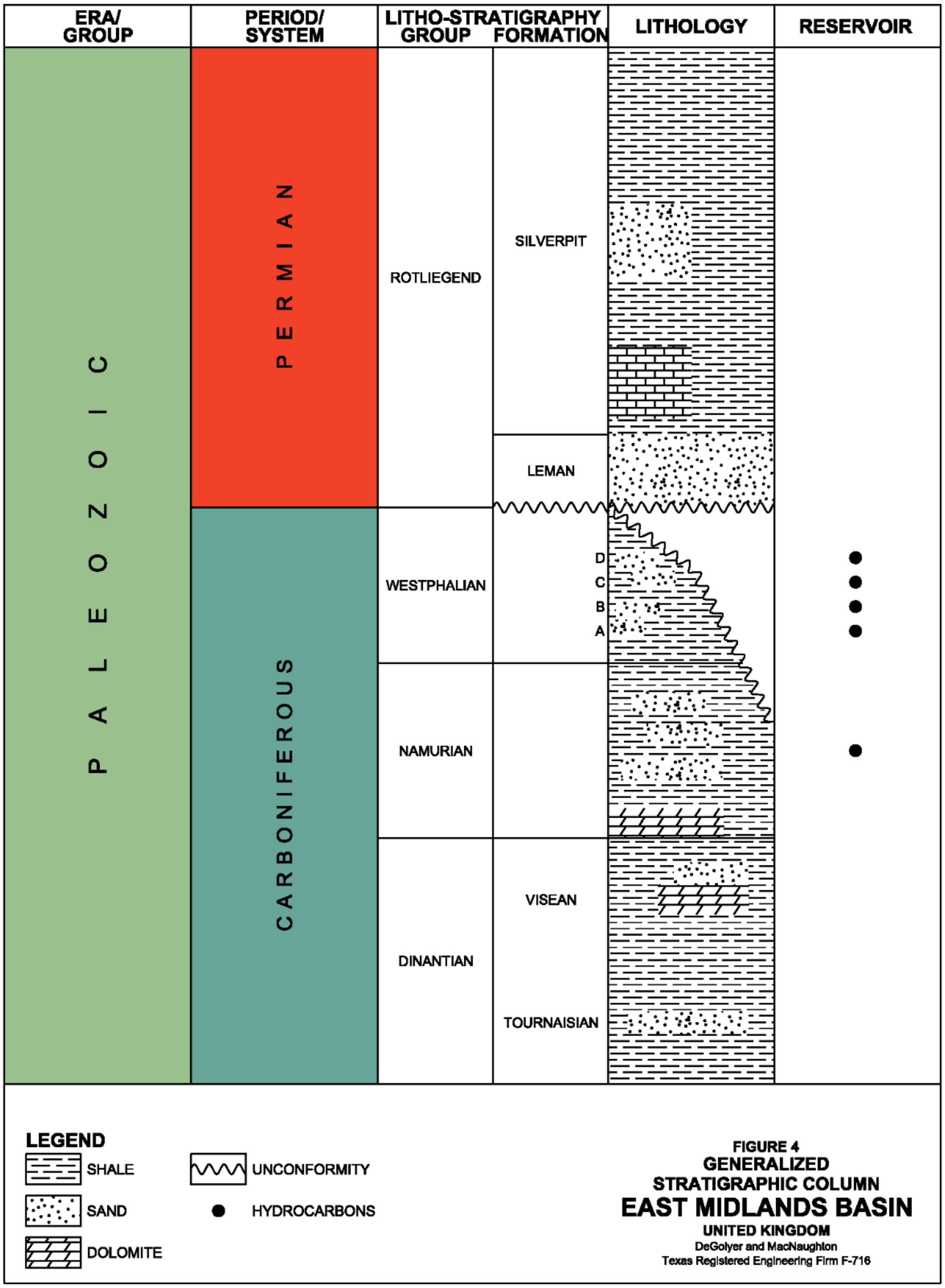
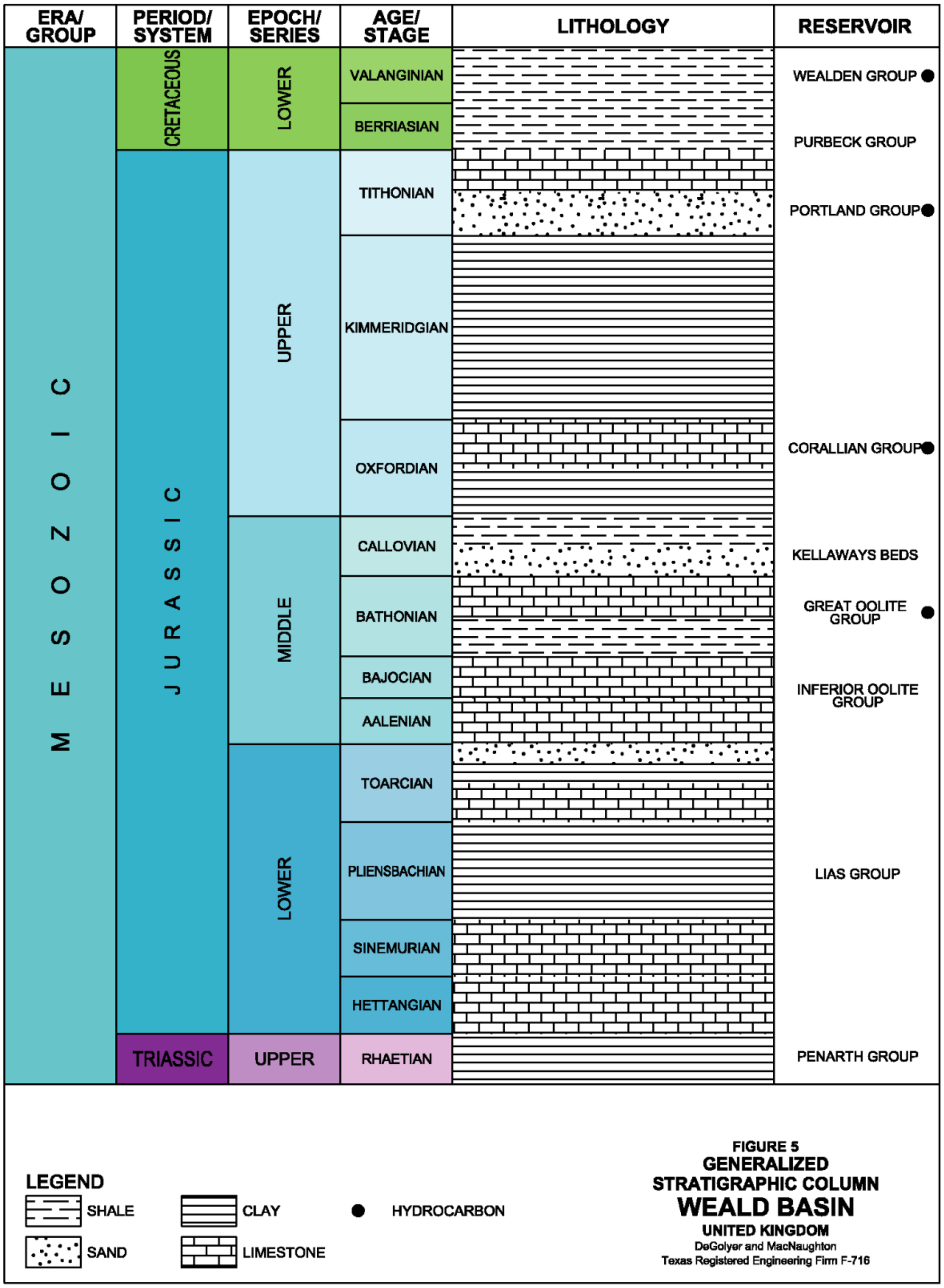


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716



The Beckingham field, located in license ML4, was discovered in 1964 and is located on the Lincolnshire-Nottingham border, 40 kilometers east of the city of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones, which produce from three separate blocks in the Beckingham field. The Beckingham field also has the potential to produce nonassociated gas from the

Mexborough/Alexander Formations; however, this development potential has not been considered in this evaluation. In the producing reservoirs, porosity was estimated to range from 8 to 20 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 degrees API (°API). Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone and the field is currently producing from two wells. Porosity was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.2 to 1,000 millidarcys. Proved reserves were estimated based on individual-well performance and proved undeveloped reserves were estimated based on volumetric analysis of one additional well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Reserves estimates for the field include a "gas-to-wire" project to support the building of a 2-megawatt generator.

The Bothamsall field was discovered in 1958 and is located in license ML6, which is southwest of the town of Retford, Nottinghamshire. The field has produced from the Sub-Alton and Crawshaw Sandstones, both of which are fluvial channel deposits. Porosity was estimated to range from 6 to 16 percent, S_w was estimated to range from 26 to 60 percent, and permeability was estimated to range from 0.1 to 100 millidarcys. The field currently produces light oil from three wells. Proved developed reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Cold Hanworth field, located in license PEDL6, was discovered in April 1996 and produces from the Westphalian Basal Succession sand unit. The field is located about 25 kilometers to the southwest of the town of Gainsborough. The field is producing from two wells. Porosity was estimated to range from 7 to 16 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.05 to 10 millidarcys. The oil has a gravity of 28 °API. Proved reserves were estimated based on individual-well performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Corringham field, located in license ML4, was discovered in 1958 and consists of three main fault blocks. The Corringham field produces oil from the Silkstone and Chatsworth reservoirs. Porosity was estimated to range from 14 to 27 percent, S_w was estimated to range from 37 to 44 percent, and permeability was estimated to range from 160 to 500 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The East Glentworth field, located in license PL179, was discovered in March 1987 by the East Glentworth-1 well, which encountered oil in the Westphalian C Mexborough Rock. The field is currently producing from two wells. Porosity was estimated to range from 16 to 20 percent, S_w was estimated to range from 42 to 47 percent, and permeability was estimated to range from 1 to 20 millidarcys. Proved reserves were estimated based on individual well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Egmanton field was discovered in 1955 and produces oil from the Upper Namurian and Lower Westphalian reservoirs through two wells. The field is located in license ML3, southwest of the Gainsborough Trough. Porosity was estimated to range from 13 to 17 percent, S_w was estimated to range from 45 to 55 percent, and permeability was estimated to range from 1 to 100 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero.

The Gainsborough field, located in license ML4, was discovered in 1959 and is located on the Lincolnshire-Nottingham border, 25 miles east of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones. Porosity was estimated to range from 8 to 20 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 °API. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero.

The Glentworth field was discovered in 1961 and is located in license ML4 near Lincolnshire. The field is a four-way dip closure and produces from the Mexborough Formation. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity was estimated to range from 16 to

20 percent, S_w was estimated to range from 50 to 65 percent, and permeability was estimated to range from 0.1 to 30 millidarcys. Proved developed reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and estimates of probable undeveloped and possible undeveloped reserves account for one new well.

The Goodworth field, located in license PEDL21, was discovered in 1987. The field produces from the Great Oolite reservoir across three main blocks and is currently producing from one well. Porosity was estimated to range from 12 to 16 percent, S_w was estimated to range from 50 to 70 percent, and permeability was estimated to range from 0.1 to 5 millidarcys. Proved reserves were estimated based on performance of the existing well, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Horndean field, located in license PL211, was discovered in 1983 by well Horndean-1A. Production commenced in 1987 from the Great Oolite structure and four wells are currently producing. Porosity was estimated to range from 12 to 19 percent, S_w was estimated to range from 70 to 80 percent, and permeability was estimated to range from 0.01 to 5 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Long Clawson field was discovered in 1986. The field is located in license PL220 in Leicestershire and is currently producing from three wells. Porosity was estimated to range from 13 to 18 percent, S_w was estimated to range from 68 to 79 percent, and permeability was estimated to range from 90 to 1,100 millidarcys. The oil has a gravity of 35 °API. Proved reserves were estimated based on individual-well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Lybster field (Figure 6) was discovered in 1996 by well 11/24-1 and is located offshore the Caithness coast in license P1270. The field is gas bearing in the Beatrice Sandstone. The Lybster field was evaluated volumetrically, and reserves were estimated using analogous recovery factors based on other similar fields in the area. Recovery factors were estimated to range from 55 to 80 percent. In this field, porosity was estimated to be 12 percent, S_w was estimated to range from 35 to 45 percent, and permeability was estimated to range from 90 to 1,115 millidarcys.

Proved, probable, and possible undeveloped reserves estimated herein were based the approved redevelopment plan with recovery factors that were estimated to range from 55 to 80 percent. Well 11/24-3V2 stopped producing at the end of 2014 due to a high gas-oil ratio (GOR), and the current plan is to restore production in 2024.

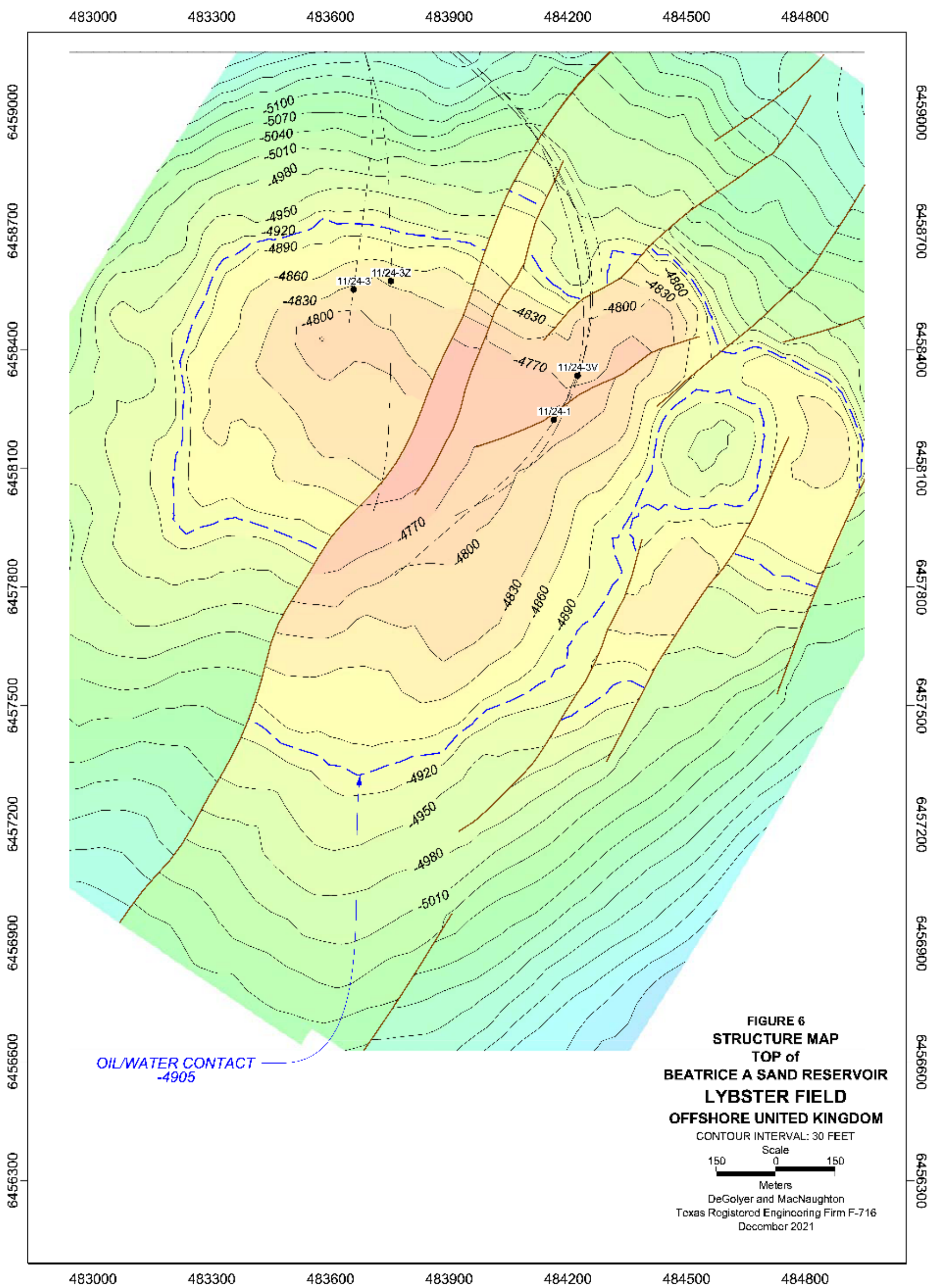


FIGURE 6
STRUCTURE MAP
TOP of
BEATRICE A SAND RESERVOIR
LYBSTER FIELD
OFFSHORE UNITED KINGDOM

The Nettleham field, located in licenses PL179 and PL199, was discovered in 1983 and is located approximately 5 kilometers northeast of the city of Lincoln. The primary reservoir is the Basal Westphalian. The field is not currently producing. Porosity ranged from 19 to 22 percent, S_w from 30 to 60 percent, and permeability from 6 to 1,000 millidarcys. Production was stopped in February 2016 due to high water cut. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero.

The Palmers Wood field was discovered in 1983 and is located 5 kilometers east of Redhill within license PL182. The Palmers Wood field currently produces through four wells from the Upper Jurassic Corallian Sandstone. In addition, there has been an active waterflood through three injectors since the beginning of production. Porosity was estimated to range from 16 to 20 percent, S_w was estimated to range from 40 to 60 percent, and permeability was estimated to range from 0.5 to 50 millidarcys. Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Rempstone field was discovered in 1985. The primary reservoir is the Lower Namurian, with gas from the H-Sandstone and oil from the C-Sandstone. The field is located in license PL220 and is currently producing from one well. Porosity was estimated to range from 16 to 19 percent, S_w was estimated to range from 40 to 50 percent, and permeability was estimated to range from 0.1 to 20 millidarcys. Proved reserves were estimated based on individual-well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity was estimated to range from 12 to 18 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.5 to 400 millidarcys. Proved reserves were estimated based on performance of existing wells, scheduled workovers, and a waterflood injector that recently came on production. Estimates of probable and possible developed reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency in the injector.

The Scampton South field is located in license PL179 in Lincolnshire, to the northwest of the Welton field. The field was discovered in 1985, but development was delayed due to consideration of high sulfur levels. The field is not currently producing and was shut in due to high water production. Porosity was estimated to range from 10 to 16 percent, S_w was estimated to range from 26 to 40 percent, and permeability was estimated to range from 5 to 500 millidarcys. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero.

The Singleton field was discovered in 1989 by the Singleton-1 well. The field is located within production license PL240 near the village of Singleton. The field currently produces light oil of approximately 39°API through six wells from the Great Oolite Formation. Porosity was estimated to range from 13 to 16 percent, S_w was estimated to range from 30 to 62 percent, and permeability was estimated to range from 0.1 to 10 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves from existing and future wells. The current plan is to install a new 1-megawatt generator by 2023, which may allow future additions of gas reserves.

The South Leverton field, located in license ML7, was discovered in 1960. The field is currently producing from a single well, the SL-7. Porosity was estimated to range from 9 to 13 percent, S_w was estimated to range from 22 to 27 percent, and permeability was estimated to range from 0.2 to 10 millidarcys. Performance analysis was completed on this field and, after economic evaluation, quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero.

The Stainton field was discovered in 1984 by well Stainton-1. The field is located within license PL179b, 10 kilometers northeast of Lincoln. The field currently produces low-shrinkage oil through one well from the Basal Sandstone Formation. Porosity was estimated to range from 12 to 16 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.4 to 50 millidarcys. Performance analysis was completed on this field and after economic evaluation, quantities were determined to be uneconomic. As such, reserves for this field were also estimated to be zero.

The Stockbridge field was discovered in 1984. This field is located within the DL2, PL233, and PL249 licenses, in the northwest portion of the Weald Basin. The field produces from the Great Oolite reservoir. Water injection began in 1998 after converting the STK-16 well to a water injector. The field is currently producing from four wells, and three wells are currently suspended due to lack of available water disposal. Porosity was estimated to range from 12 to 24 percent, S_w was estimated to range from 66 to 79 percent, and permeability was estimated to range from 0.1 to 5 millidarcys. Proved reserves were estimated based on individual-well performance and include workovers and restoration of wells closed due to current water disposal limitations. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Storrington field has been producing from the Great Oolite Formation since 1998. The field is located in license PL205 in West Sussex County. Porosity was estimated to range from 10 to 17 percent, S_w was estimated to range from 45 to 60 percent, and permeability was estimated to range from 0.01 to 50 millidarcys. Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Welton field was discovered in 1981. The field is located 7 kilometers northeast of Lincoln in license PL179b. The field has produced from several formations, including the Basal Succession and the Upper Succession. Porosity was estimated to range from 12 to 20 percent, S_w was estimated to range from 20 to 40 percent, and permeability was estimated to range from 10 to 1,000 millidarcys. Proved reserves were estimated based on individual-well performance, including planned workovers to restore several wells to production, and a waterflood injector that recently came on production. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency in the injector.

The estimated gross proved, probable, and possible reserves, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Reserves								
	Oil and Condensate			**Sales Gas**			**Oil Equivalent**		
Field	**Proved (10^3bbl)**	**Probable (10^3bbl)**	**Possible (10^3bbl)**	**Proved (10^6ft^3)**	**Probable (10^6ft^3)**	**Possible (10^6ft^3)**	**Proved (10^3boe)**	**Probable (10^3boe)**	**Possible (10^3boe)**
Albury	0	0	0	978	468	505	169	81	87
Avington	0	0	0	0	0	0	0	0	0
Beckingham	422	130	134	0	0	0	422	130	134
Bletchingley	235	78	93	1,754	3,314	3,716	537	648	734
Bothamsall	105	24	56	0	0	0	105	24	56
Cold Hanworth	178	59	61	0	0	0	178	59	61
Corringham	243	47	45	0	0	0	243	47	45
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	60	24	24	0	0	0	60	24	24
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,215	578	523	0	0	0	1,215	578	523
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	49	20	38	0	0	0	49	20	38
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	1,015	189	164	0	0	0	1,015	189	164
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	59	20	30	0	0	0	59	20	30
Lybster	110	18	31	408	68	113	180	30	50
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	40	18	2	0	0	0	40	18	2
Rempstone	10	4	1	0	0	0	10	4	1
Scampton North	602	171	419	0	0	0	602	171	419
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,750	815	376	1,286	514	354	1,972	904	437
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	904	140	102	0	0	0	904	140	102
Storrington	13	0	0	0	0	0	13	0	0
Welton	2,895	2,154	1,036	0	0	0	2,895	2,154	1,036
Total	**9,905**	**4,489**	**3,135**	**4,426**	**4,364**	**4,688**	**10,668**	**5,241**	**3,943**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated net proved, probable, and possible reserves, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Reserves								
	Oil and Condensate			Sales Gas			Oil Equivalent		
Field	**Proved (10^3bbl)**	**Probable (10^3bbl)**	**Possible (10^3bbl)**	**Proved (10^6ft^3)**	**Probable (10^6ft^3)**	**Possible (10^6ft^3)**	**Proved (10^3boe)**	**Probable (10^3boe)**	**Possible (10^3boe)**
Albury	0	0	0	978	468	505	169	81	87
Avington	0	0	0	0	0	0	0	0	0
Beckingham	422	130	134	0	0	0	422	130	134
Bletchingley	235	78	93	1,754	3,314	3,716	537	648	734
Bothamsall	105	24	56	0	0	0	105	24	56
Cold Hanworth	178	59	61	0	0	0	178	59	61
Corringham	243	47	45	0	0	0	243	47	45
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	60	24	24	0	0	0	60	24	24
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,215	578	523	0	0	0	1,215	578	523
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	49	20	38	0	0	0	49	20	38
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	913	171	147	0	0	0	913	171	147
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	59	20	30	0	0	0	59	20	30
Lybster	110	18	31	408	68	113	180	30	50
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	40	18	2	0	0	0	40	18	2
Rempstone	10	4	1	0	0	0	10	4	1
Scampton North	602	171	419	0	0	0	602	171	419
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,750	815	376	1,286	514	354	1,972	904	437
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	904	140	102	0	0	0	904	140	102
Storrington	13	0	0	0	0	0	13	0	0
Welton	2,895	2,154	1,036	0	0	0	2,895	2,154	1,036
Total	**9,803**	**4,471**	**3,118**	**4,426**	**4,364**	**4,688**	**10,566**	**5,223**	**3,926**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Valuation of Reserves

This report has been prepared using initial prices, expenses, and costs provided by IGas and certain forecast price, expense, and cost assumptions as described herein. Three economic cases were evaluated in this report: Base Case, Low Case, and High Case. The sensitivity cases were evaluated in this report to present alternative outcomes to the future revenue estimates for estimated reserves. Projections of gross and net reserves summarized herein were based on the Base Case, and quantities in the sensitivity cases are those included prior to the limit of projected production under the Base Case or when an annual economic limit for each case is reached, whichever occurs first. Only the prices were varied in each economic scenario. Unless noted otherwise, all other components of the evaluation for the sensitivity cases are the same as those stated for the Base Case herein.

In this report, values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable or possible reserves. Probable and possible reserves involve substantially higher risks than proved reserves. Revenue values associated with proved-plus-probable and proved-plus-probable-plus-possible reserves have not been adjusted to account for such risks; such an adjustment would be necessary in order to make the values associated with probable or possible reserves comparable to values associated with proved reserves.

Revenue values of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated utilizing methods generally accepted by the petroleum industry. Production forecasts of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on the development plan for the fields. The future net revenue and present worth of the fields' reserves were estimated using the price and cost assumptions, monetary conversion values, and the appropriate concession terms described herein.

The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and Gas Prices

Base Case Price Assumptions

Oil prices for the Base Case were anchored at the prevailing Brent oil price at the end of 2021, followed by price changes that match historical price levels. The condensate price was assumed to be 90 percent of the oil price. The oil and condensate price assumptions are shown in the table below, expressed in United States dollars per barrel (U.S.$/bbl).

Gas sales prices for the Base Case were based on the European Gas Trading Hubs (TTF) forecast at the end of 2021. IGas has represented that its produced gas is sold in two outlets: through direct sales to the United Kingdom national gas grid and "gas to power." Gas to power is a portion of produced gas that receives a net price related to the amount of electricity it produces through generation. The gas price assumptions are shown in the table below, expressed in United States dollars per thousand cubic feet (U.S.$/$10^3ft^3$).

	Base Case Prices			
Year	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Gas Export (U.S.$/$10^3ft^3$)	Gas to Power (U.S.$/$10^3ft^3$)
2022	71.58	64.42	19.67	19.43
2023	65.77	59.19	12.23	12.09
2024	62.46	56.21	10.19	10.06
2025	64.22	57.80	10.34	10.22
2026	66.03	59.43	10.50	10.37
2027	67.88	61.10	10.66	10.53
2028	69.79	62.81	10.82	10.69
2029	71.74	64.56	10.99	10.85
2030	73.74	66.37	11.16	11.02
2031	75.93	68.34	11.33	11.19
2032	78.18	70.36	11.51	11.37
2033	80.48	72.44	11.69	11.55
2034	82.85	74.57	11.87	11.73
2035	85.28	76.76	12.06	11.91
2036	87.78	79.00	12.25	12.10
2037	90.34	81.31	12.44	12.29
2038	92.97	83.67	12.64	12.49
2039	95.67	86.10	12.85	12.69
2040	98.43	88.59	13.05	12.90
2041	100.40	90.36	13.26	13.10
2042	102.41	92.17	13.48	13.32
2043	104.46	94.01	13.70	13.53
2044	106.55	95.89	14.15	13.76
2045	108.68	97.81	14.15	13.98
2046	110.85	99.77	14.38	14.21
2047	113.07	101.76	14.62	14.45
2048	115.33	103.80	14.86	14.69
2049	117.64	105.87	15.11	14.93
2050	119.99	107.99	15.36	15.18

Note: From 2050 forward, all prices were held flat.

Low Case Price Assumptions

Oil and condensate prices for the Low Case are 10 percent lower than the Base Case, and the gas price for the Low Case is 10 percent lower than the Base Case.

High Case Price Assumptions

Oil and condensate prices for the High Case are 10 percent higher than the Base Case, and the gas price for the High Case is 10 percent higher than the Base Case.

Operating Expenses, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by IGas were used in estimating future expenses required to operate the fields for all three economic scenarios. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changed operating conditions. Pipeline and processing tariffs are paid for access to markets. Future capital expenditures and abandonment costs were estimated using current forecasts provided by IGas. A 2-percent per year cost escalation was applied to any expenses or costs estimated herein. Generally, abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were assigned the year after cessation of production, except where other anticipated abandonment dates were represented by IGas. Economic limits for each field have been estimated based on annual operating expenses with no consideration of taxes.

Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the developed non-producing and undeveloped reserves estimated herein.

Royalty

No royalty is considered for these United Kingdom fields.

Exchange Rate

Where applicable, an exchange rate of U.S.$1.33 per U.K.£1.00 was used for this report.

Host Country Taxes

At the request of IGas, United Kingdom income taxes were not considered in this report.

As in any evaluation, there may be risk of unexpected cost variances and timing delays or accelerations. For this evaluation, consideration has been given to these elements to the extent possible. The resulting scheduling of production and costs is represented as a reliable estimate incorporating operational variances and timing delays where reasonable.

The estimated future revenue to be derived from the production and sale of the net proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of December 31, 2021, of the properties evaluated under the Base Case economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

	Valuation of Reserves Summary Base Case		
	Proved (10^3U.S.$)	**Proved plus Probable (10^3U.S.$)**	**Proved plus Probable plus Possible (10^3U.S.$)**
Future Gross Revenue	835,921	1,350,591	1,729,545
Operating Expenses	427,658	647,824	804,305
Abandonment and Capital Costs	144,396	148,638	150,534
Future Net Revenue	263,867	554,129	774,706
Present Worth at 10 Percent	139,418	190,439	227,907

Note: Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.

The estimated future revenue to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible quantities, as of December 31, 2021, of the properties evaluated under the Low Case and High Case economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation of Quantities Summary – Sensitivity Cases

	Low Case			High Case		
	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved plus Probable Plus Possible (10^3U.S.$)	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved plus Probable Plus Possible (10^3U.S.$)
Future Gross Revenue	730,826	1,192,849	1,546,503	940,256	1,500,949	1,923,003
Operating Expenses	403,925	622,451	786,334	446,828	663,333	825,793
Abandonment and Capital Costs	142,563	146,169	149,420	145,892	149,484	151,496
Future Net Revenue	184,338	424,229	610,749	347,536	688,132	945,714
Present Worth at 10 Percent	102,683	146,282	178,701	177,090	234,816	278,393

Notes:
1. Values for probable and possible quantities have not been risk adjusted to make them comparable to values for proved quantities.
2. Reserves are those estimated using the Base Case, and quantities in the sensitivity cases should not be confused with reserves.

The estimated future net revenue of all fields for the Base, Low, and High Cases is shown in Tables A-1 through A-12 in the appendix to this report.

Definition of Contingent Resources

Estimates of contingent resources presented in this report have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. Because of the lack of commerciality or sufficient development drilling, the contingent resources estimated herein cannot be classified as reserves. The petroleum contingent resources are classified as follows:

> *Contingent Resources* are 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.

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.

Economically Viable Contingent Resources are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecast conditions but are not Reserves because it does not meet the other commercial criteria.

Economically Not Viable Contingent Resources are 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.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is “undetermined.”

The estimation of petroleum resources is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

1C (Low), 2C (Best), and 3C (High) Estimates – Estimates of contingent resources in this report are expressed using the terms 1C (low) estimate, 2C (best) estimate, and 3C (high) estimate to reflect the range of uncertainty.

Estimation of Contingent Resources

Estimates of contingent resources were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Where applicable, the volumetric method was used to estimate the original quantities of petroleum in place. Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and S_w.

Where applicable, estimates of ultimate recovery were obtained after applying recovery factors to original quantities of petroleum in place. These recovery factors were based on consideration of the type of energy inherent in the reservoir, analyses of the fluid and rock properties, and the structural position of the properties.

In certain cases, contingent resources were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

The contingent resources estimates presented herein were generally based on consideration of drilling results, analyses of available geological data, well-test results, pressures, and other data available through December 31, 2021. The development and economic status represents the status applicable on December 31, 2021.

Oil and condensate contingent resources estimated herein are to be recovered by normal field separation and are expressed in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate contingent resources have been estimated separately and are presented herein as a summed quantity.

Gas quantities associated with contingent resources estimated herein are expressed as sales gas contingent resources. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas quantities are expressed at a temperature base of 60 °F and at a pressure base of 14.7 psia. Gas quantities included in this report are expressed in 10^6ft^3.

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein consists of both associated and nonassociated gas.

At the request of IGas, sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

After a review of the data available for the fields evaluated herein, 17 fields located in the United Kingdom were estimated to contain contingent resources: Avington, Beckingham, Bletchingley, Corringham, Dunholme, Gainsborough, Glentworth, Godley Bridge, Hemswell, Horndean, Lingfield, Long Clawson, Palmers Wood, Scampton North, Singleton, Stockbridge, and Welton.

The contingent resources estimated for the fields evaluated herein are those quantities of petroleum that are potentially recoverable from discovered accumulations but which are not currently considered to be commercially recoverable because of one or more contingencies, including lack of internal IGas approval or partner agreement for commitment to develop and produce. Because of the uncertainty of commerciality, the contingent resources estimated herein are not classified as reserves. At the request of IGas, the contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.

Procedure and Methodology

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone (Figure 7) and the field is currently producing from two wells. Porosity was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.2 to 1,000 millidarcys. Contingent resources were estimated for the drilling of one well in the western part of the reservoir and are contingent based on the lack of a firm development plan.

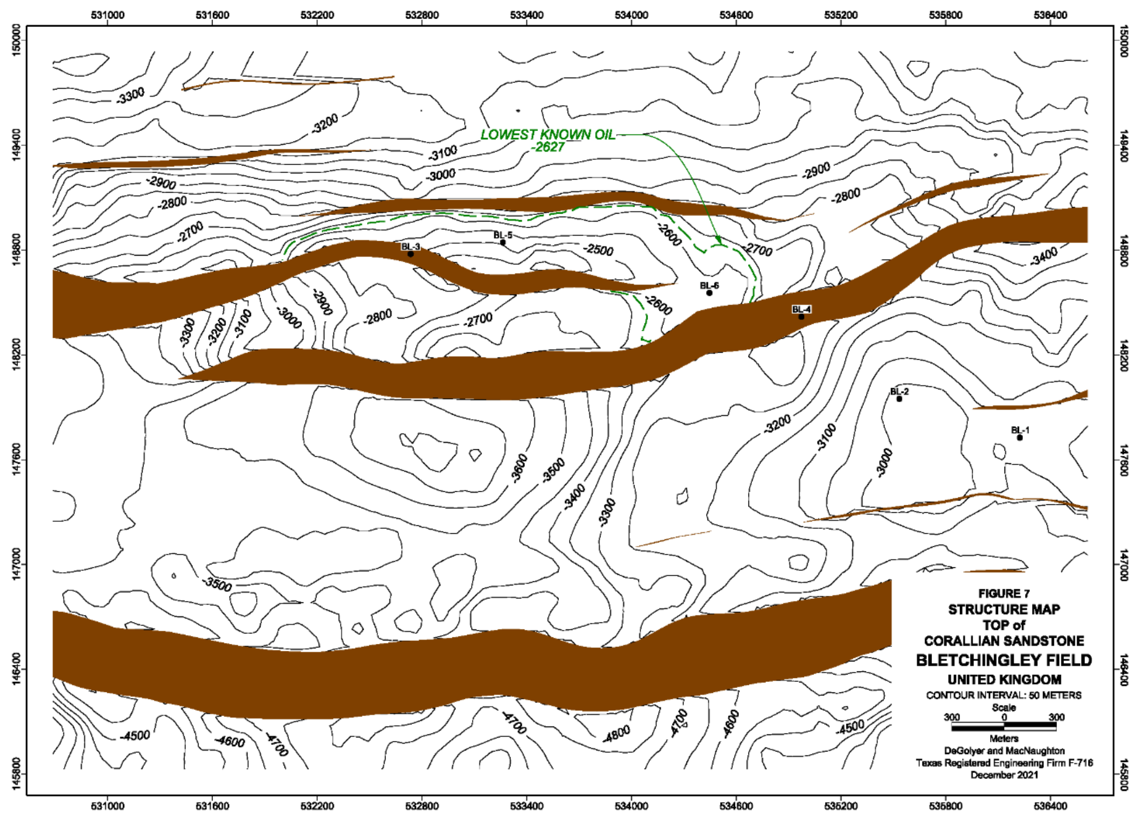
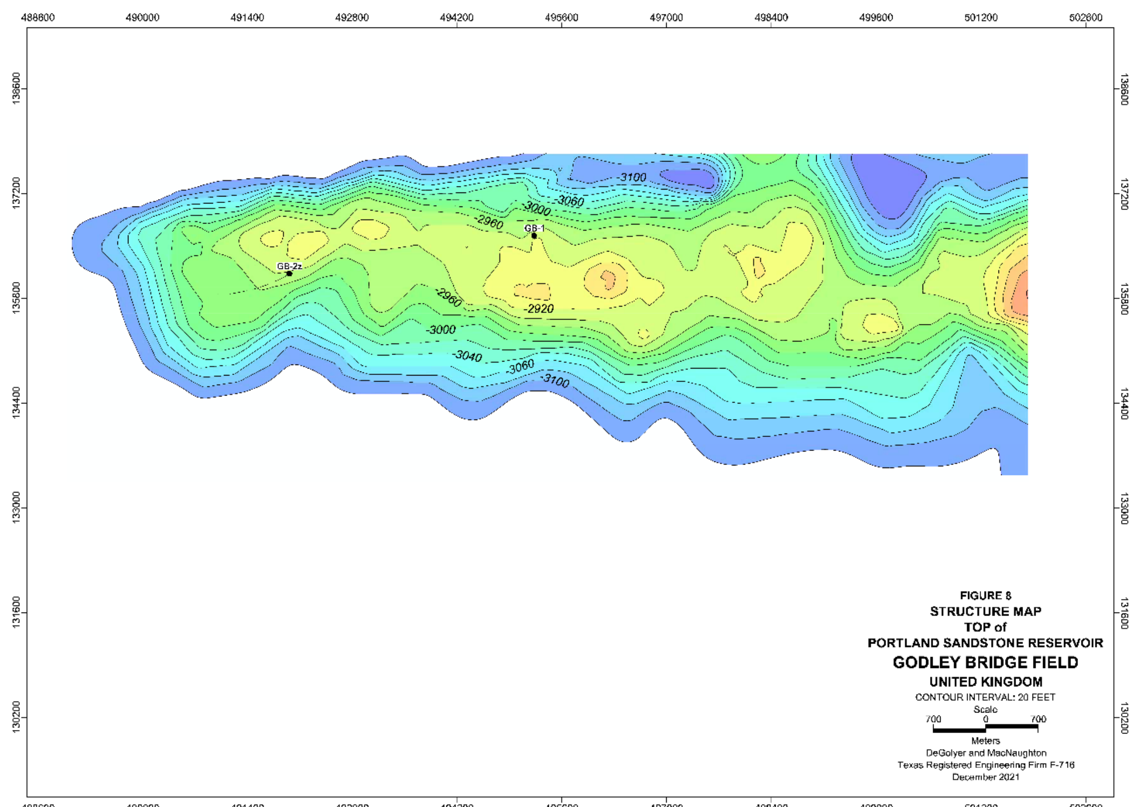


FIGURE 7
STRUCTURE MAP
TOP of
CORALLIAN SANDSTONE
BLETCHINGLEY FIELD
UNITED KINGDOM

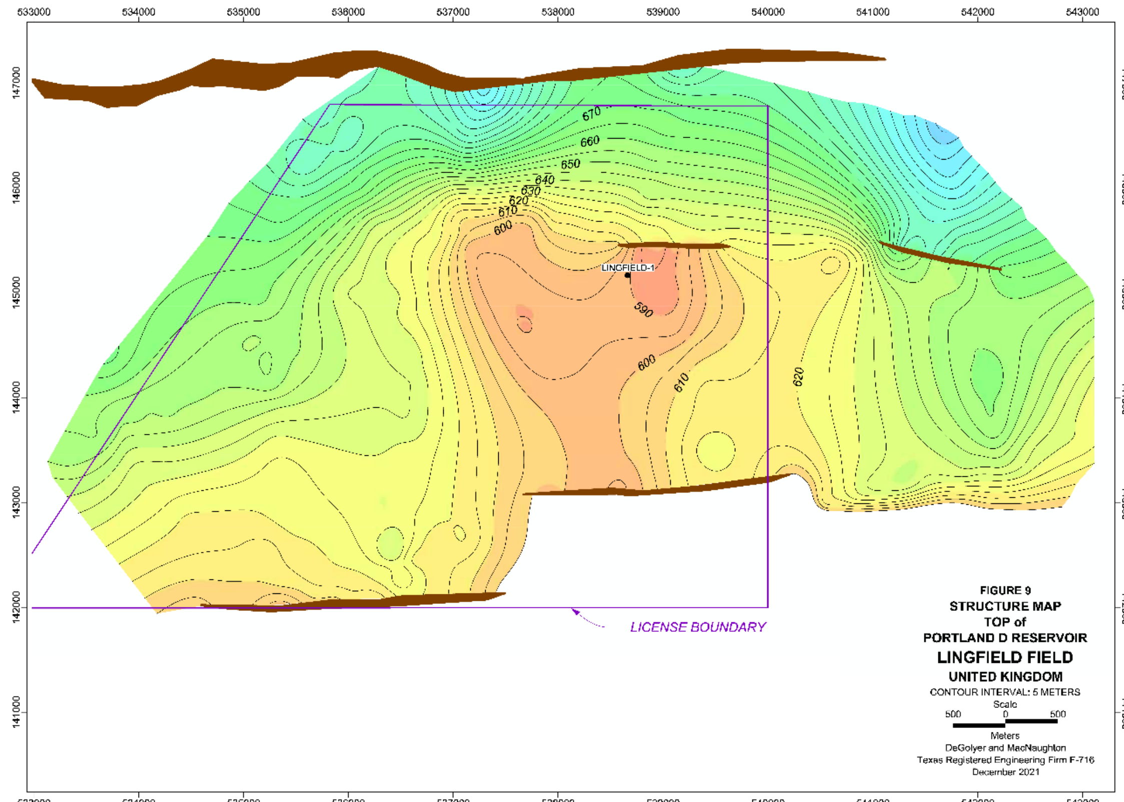
The Dunholme field was discovered in 1983 by British Petroleum with the Dunholme-1 well. The field is located in the United Kingdom in the East Midlands Platform in license AL009. The Dunholme-1 well encountered a thin oil column in the Carboniferous Westphalian-age Basal Sand reservoir. The well is interpreted to have intersected the oil column very near the oil/water contact, and additional OOIP quantities were estimated updip of the Dunholme-1 well. The porosity was estimated to be 19.8 percent, and the S_w was estimated to be 58 percent. Permeability was estimated to range from 5 to 100 millidarcys. The Dunholme field was evaluated volumetrically, and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Recovery factors were estimated to range from 5 to 15 percent. The field is considered contingent because it does not have an approved development plan.

The Glentworth field was discovered in 1961 and is located in license ML4 near Lincolnshire. The field is a four-way dip closure and produces from the Mexborough Formation. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity was estimated to range from 16 to 20 percent, S_w was estimated to range from 50 to 65 percent, and permeability was estimated to range from 0.1 to 30 millidarcys. Contingent resources were estimated for five additional infill wells and two waterflood wells and were based on a total field recovery ranging from 24 to 34 percent. The field is contingent based on a lack of firm development plans.

The Godley Bridge field (Figure 8), located in license PEDL235, was discovered in 1982. The field is gas bearing in the Portland Sandstone. The Godley Bridge field was evaluated volumetrically, and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Porosity was estimated to range from 17 to 18 percent, and S_w was estimated to be 45 percent. Permeability was estimated to range from 0.1 to 0.3 millidarcys. The recovery factors were estimated to range from 71 to 84 percent. This field is contingent based on the lack of firm development plans. The contingent resources estimated herein for the Godley Bridge field do not include the Kimmeridge Micrites reservoir.



The Lingfield field (Figure 9) was discovered in 1999 by the Lingfield-1 well. The discovery is located in the United Kingdom in license PEDL257, near the village of Lingfield in Surrey, England. The Lingfield field is located on trend and southeast of the Bletchingley gas field. The Lingfield-1 well found gas pay in the Portland D sandstone and had oil shows in the Corallian Limestone. Average porosity was estimated to be 18.2 percent and average S_w was estimated to be 59 percent. The Lingfield-1 well tested the Portland D sandstone and the well flowed at a rate of 110 thousand cubic feet per day. No development plan has been approved. The Lingfield field was evaluated volumetrically, and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. The recovery factors were estimated to range from 50 to 60 percent.



The Scampton North field was discovered in 1985 by well SNA-1. The field is located within license PL179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity was estimated to range from 12 to 18 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.5 to 400 millidarcys. Contingent resources were estimated for drilling a well to an undrained eastern target of the reservoir, and the field is contingent based on a lack of firm development plans.

Several of the producing fields also include contingent resources for certain projects that currently do not have firm development plans. These fields include Avington, Beckingham, Corringham, Gainsborough, Hemswell, Horndean, Long Clawson, Palmers Wood, Singleton, Stockbridge, and Welton.

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Contingent Resources								
	1C			2C			3C		
Field	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**
Albury	0	0	0	0	0	0	0	0	0
Avington	507	0	507	741	0	741	1,002	0	1,002
Beckingham	65	218	103	232	317	287	301	387	368
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	947	0	947	1,309	0	1,309	1,483	0	1,483
Dunholme	8	0	8	185	0	185	422	0	422
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	83	39	90	272	141	296	509	183	541
Glentworth	2,130	320	2,185	2,992	449	3,069	3,074	461	3,153
Godley Bridge	0	6,654	1,147	0	12,490	2,153	0	14,173	2,444
Goodworth	0	0	0	0	0	0	0	0	0
Hemswell (PEDL6)	0	0	0	44	64	55	2,002	2,872	2,497
Hemswell (PEDL310)	69	99	86	627	900	782	2,202	3,159	2,747
Horndean	349	0	349	798	0	798	1,296	0	1,296
Lingfield	195	2,148	565	489	2,608	939	900	2,983	1,414
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	147	324	392	188	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	0	338	491	0	491	562	0	562
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	279	1,741	3,565	627	3,674	6,206	1,016	6,382
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	589	0	589	709	0	709	858	0	858
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,516	0	4,516
Total	**11,126**	**9,919**	**12,836**	**17,908**	**17,807**	**20,978**	**28,068**	**25,513**	**32,467**

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated net 1C, 2C, and 3C contingent resources, as of December 31, 2021, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Contingent Resources								
	1C			2C			3C		
Field	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)
Albury	0	0	0	0	0	0	0	0	0
Avington	272	0	272	398	0	398	538	0	538
Beckingham	65	218	103	232	317	287	301	387	368
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	947	0	947	1,309	0	1,309	1,483	0	1,483
Dunholme	8	0	8	185	0	185	422	0	422
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	83	39	90	272	141	296	509	183	541
Glentworth	2,130	320	2,185	2,992	449	3,069	3,074	461	3,153
Godley Bridge	0	6,654	1,147	0	12,490	2,153	0	14,173	2,444
Goodworth	0	0	0	0	0	0	0	0	0
Hemswell (PEDL6)	0	0	0	33	48	41	1,502	2,154	1,873
Hemswell (PEDL310)	52	74	65	471	675	587	1,652	2,369	2,060
Horndean	314	0	314	719	0	719	1,166	0	1,166
Lingfield	195	2,148	565	489	2,608	939	900	2,983	1,414
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	147	324	392	188	425	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	0	338	491	0	492	562	0	562
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	279	1,741	3,565	627	3,673	6,206	1,016	6,381
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	589	0	589	709	0	709	858	0	858
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,516	0	4,516
Total	**10,839**	**9,894**	**12,545**	**17,319**	**17,566**	**20,348**	**26,424**	**24,005**	**30,563**

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Definition of Prospective Resources

Estimates of petroleum resources included in this report are classified as prospective resources and have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. Because of the lack of commerciality or sufficient drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The petroleum prospective resources are classified as follows:

> *Prospective Resources* – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

The estimation of petroleum resources is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

> *1U (Low), 2U (Best), 3U (High), and Median Estimates* – Estimates of prospective resources in this report are expressed using the terms 1U (low) estimate, 2U (best) estimate, 3U (high) estimate, and mean estimate to reflect the range of uncertainty.

A detailed explanation of the probabilistic terms used herein and identified with an asterisk (*) is included in the glossary bound with this report. For probabilistic estimates of petroleum resources, the low estimate reported herein is the P_{90}* quantity derived from probabilistic analysis. This means that there is at least a 90-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the low estimate. The best (median) estimate is the P_{50}* quantity derived from probabilistic analysis. This means that there is at least a 50-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the best (median) estimate. The high estimate is the P_{10}* quantity derived from probabilistic analysis. This means that there is at least a 10-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the high estimate. The expected value* (EV), an outcome of the probabilistic analysis, is the mean estimate.

Uncertainties Related to Prospective Resources – The quantity of petroleum discovered by exploration drilling depends on the number of prospects that are successful as well as the quantity that each success contains. Reliable forecasts of these quantities are, therefore, dependent on accurate predictions of the number of discoveries that are likely to be made if the entire portfolio of prospects is drilled. The accuracy of this forecast depends on the portfolio size and an accurate assessment of the P_g*.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the probability of discovering reservoirs that flow hydrocarbons at a measurable rate. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

In this report, estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation (statistical aggregate) of the quantities for the total inventory of prospects. The statistical aggregate P_g-adjusted mean estimate, or "aggregated geologic chance-adjusted mean estimate," is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially recoverable if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a "blended" quantity; it is a product of the statistically aggregated mean volume estimate and the portfolio's probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic success case" volume outcome of drilling all of the prospects in the exploration program.

Application of P_g to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. P_g-adjusted prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently made available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the study area, but also include data from similar geologic settings or technological advancements that could affect the estimation of P_g.

Predictability versus Portfolio Size – The accuracy of forecasts of the number of discoveries that are likely to be made is constrained by the number of prospects in the exploration portfolio. The size of the portfolio and P_g together are helpful in gauging the limits on the reliability of these forecasts. A high P_g, which indicates a high chance of discovering measurable petroleum, may not require a large portfolio to ensure that at least one discovery will be made (assuming the P_g does not change during drilling of some of the prospects). By contrast, a low P_g, which indicates a low chance of discovering measurable petroleum, could require a large number of prospects to ensure a high confidence level of making even a single discovery. The relationship between portfolio size, P_g, and the probability of a fully unsuccessful drilling program that results in a series of wells not encountering measurable hydrocarbons is referred to herein as the predictability versus portfolio size (PPS) relationship*. It is critical to be aware of PPS, because an unsuccessful drilling program, which results in a series of wells that do not encounter measurable hydrocarbons, can adversely affect any exploration effort, resulting in a negative present worth.

For a large prospect portfolio, the P_g-adjusted mean (statistical aggregate) estimate of the prospective resources quantity should be a reasonable estimate of the recoverable petroleum quantities found if all prospects are drilled. When the number of prospects in the portfolio is small and the P_g is low, the recoverable petroleum actually found may be considerably smaller than the statistical aggregate P_g-adjusted mean estimate would indicate. It follows that the probability that all of the prospects will be unsuccessful is smaller when a large inventory of prospects exist.

Prospect Technical Evaluation Stage – Prospective resources can often be subclassified based on their current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data as well as the quality of available data.

Prospect – A project associated with an undrilled potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources.

Lead – 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. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

Estimation of Prospective Resources

Estimates of prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of the reservoirs was tempered by experience with similar reservoirs and quality and completeness of basic data.

The probabilistic analysis of the prospective resources in this study considered the uncertainty in the amount of petroleum that may be discovered and the P_g. The uncertainty analysis addresses the range of possibilities for any given volumetric parameter. Minimum, maximum, low, best, high, and mean estimates of prospective resources were estimated to address this uncertainty. The P_g analysis addresses the probability that the identified prospect will contain petroleum that flows at a measurable rate.

Standard probabilistic methods were used in the uncertainty analysis. Probability distributions were estimated from representations of rock volume, porosity, hydrocarbon saturation, recovery efficiency, and formation volume factor for each prospect. These representations were prepared based on known data, analogy, and other standard estimation methods including experience. Statistical measures describing the probability distributions of these representations were identified and input to a Monte Carlo simulation to produce low estimate (P_{90}), best estimate (P_{50}), high estimate (P_{10}), and mean estimate prospective resources for each prospect.

Estimates of recovery efficiency presented in this report are based on analog data and global experience and reflect the potential range in recovery for the potential reservoirs considered in each prospect. Recovery efficiency estimates do not incorporate development or economic input and are subject to change upon selection of specific development options and costs, economic parameters, and product price scenarios.

It is not certain whether prospective reservoirs will be gas bearing, oil bearing, or water bearing. Hydrocarbon phase determination is based on the phase chance of occurrence per the present interpretation of the petroleum system. Therefore, prospective resources volumes in this report are identified herein as oil. In this report, three potential accumulations are referred to as prospects to reflect the current stage of technical evaluation.

Assumed recovery of the potential oil prospective resources estimated herein would be by normal separation in the field. Estimates of oil prospective resources are expressed herein in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons.

Volumetrics, Quantitative Risk Assessment, and the Application of P_g

Minimum, low, modal, best, mean, high, and maximum representations of potential productive area were interpreted from maps, available seismic data, and/or analogy. Representations for the petrophysical parameters (porosity, hydrocarbon saturation, and net hydrocarbon thickness) and engineering parameters (recovery efficiency and fluid properties) were also estimated based on available well data, regional data, analog field data, and global experience. Individual probability distributions for rock volume and petrophysical and engineering parameters were estimated from these representations.

The distributions for the variables were derived from (1) scenario-based interpretations, (2) the geologic, geophysical, petrophysical, and engineering data available, (3) local, regional, and global knowledge, and (4) field and case studies in the literature. The parameters used to model the recoverable quantities were potential productive area, net hydrocarbon thickness, geometric correction factor, porosity, hydrocarbon saturation, formation volume factor, and recovery efficiency. Minimum, mean, and maximum representations were used to statistically model and shape the input P_{90}, P_{50}, and P_{10} parameters. Potential productive area, net hydrocarbon thickness, and recovery efficiency were modeled using truncated lognormal distributions. Truncated normal distributions were used to model geometric correction factor, formation volume factor, porosity, and hydrocarbon saturation. Latin hypercube sampling was used to better represent the tails of the distributions.

Each individual volumetric parameter was investigated using a probabilistic approach with attention to variability. Deterministic data were used to anchor and shape the various distributions. The rock volume parameters had the greatest range of variability, and therefore had the greatest impact on the uncertainty of the simulation. The volumetric parameter variability was based on the structural and stratigraphic uncertainties due to the depositional environment and quality of the seismic data. Analog field data were statistically incorporated to derive uncertainty limits and constraints on the net hydrocarbon saturation pore volume. Uncertainties associated with the depth conversion, seismic interpretation, gross sand thickness mapping, and net hydrocarbon thickness assumptions were also derived from studies of analogous reservoirs, multiple interpretative scenarios, and sensitivity analyses.

A P_g analysis was applied to estimate the quantities that may actually result from drilling these prospects. In the P_g analysis, the P_g estimates were made for each prospect from the product of the probabilities of the four geologic chance factors: trap, reservoir, migration, and source. The P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

Estimates of gross and working interest prospective resources and the P_g estimates, as of December 31, 2021, are evaluated herein. The P_g-adjusted mean estimate of the prospective resources was then made by the probabilistic product of P_g and the resources distributions for the prospect. These results were then stochastically summed (zero dependency) to produce the statistical aggregate P_g-adjusted mean estimate prospective resources. The range in probability of the mean occurrence (P_{MEAN})* for the prospective resources volumes were estimated as defined in the glossary of this report. The range in P_{MEAN} for the statistical aggregate P_g-adjusted mean oil estimate is 0.10 to 0.15.

Application of the P_g factor to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. The P_g-adjusted estimates of prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the area of study, but also include data from similar geologic settings or from technological advancements that could affect the estimation of P_g or impact the interpretation of the petroleum system.

Estimates of prospective resources and related distributions herein are the results of probabilistic estimation. These estimates are expressed as a distribution rather than a single value. Probabilistic outcomes involve thousands of iterations using distributions. Deterministic estimations utilizing non-stochastic mathematical operations (addition, subtraction, multiplication, and division) performed on the prospective resources distributions estimated herein produce results that are not comparable.

There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Prospective resources in three prospects have been evaluated in various license blocks in United Kingdom. The prospective resources estimates presented below were based on a statistical aggregation method. The estimated gross and working interest unrisked prospective resources, as of December 31, 2021, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Gross Oil Prospective Resources Summary				**Working Interest Oil Prospective Resources Summary**			
Prospect	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**
Eartham	2,139	4,137	8,059	4,753	2,139	4,137	8,059	4,753
Godley Bridge	3,900	6,359	10,297	6,851	3,900	6,359	10,297	6,851
Lea	606	1,638	3,931	2,048	212	573	1,376	717
Statistical Aggregate	**8,571**	**13,560**	**21,093**	**13,652**	**8,063**	**12,370**	**18,674**	**12,321**

Notes:
1. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
2. P_g and the probability of economic success (P_e) have not been applied to the volumes in this table.
3. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
4. Recovery efficiency is applied to prospective resources in this table.
5. The prospective resources presented above were based on the statistical aggregation method.
6. The prospective resources quantities for the prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. Summations may vary from those shown here due to rounding.
8. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The gross and working interest statistical aggregate P_g-adjusted mean estimate oil prospective resources, as of December 31, 2021, are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,611
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,372

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency was applied to prospective resources in this table.
3. The prospective resources presented above were based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean oil estimate is 0.10 to 0.15.
6. The prospective resources quantities for the prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The prospects evaluated in this report are shown in Tables A-13 through A-16 in the appendix bound with this report.

Professional Qualifications

DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent evaluation of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. Regnald A. Boles, a Senior Vice President with DeGolyer and MacNaughton in the firm's Europe Africa Division, a Registered Professional Engineer in the State of Texas, a member of the International Society of Petroleum Engineers, and a member of the European Association of Geoscientists & Engineers. He has over 38 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
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LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

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Senior Vice President
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PROSPECTIVE RESOURCES GLOSSARY

Accumulation – An individual body of naturally occurring petroleum. A known accumulation (one determined to contain reserves or contingent resources) must have been penetrated by a well. The well must have clearly demonstrated the existence of moveable petroleum by flow to the surface or at least some recovery of a sample of petroleum through the well. However, log and/or core data from the well may establish an accumulation, provided there is a good analogy to a nearby and geologically comparable known accumulation.

Arithmetic Summation – The process of adding a set of numbers that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Statistical aggregation yields different results.

Best (Median) Estimate – The 2U (best or median) estimate is the P_{50} quantity. P_{50} means that there is a 50 percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Barrel of Oil Equivalent – Gas quantities are converted to barrels of oil equivalent (BOE) using an energy equivalent factor of 6,000 cubic feet of gas per barrel.

Contingent Resources – 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.

Geometric Correction Factor – The geometric correction factor (GCF) is a geometry adjustment correction that takes into account the relationship of the potential fluid contact to the geometry of the reservoir and trap. Input parameters used to estimate the geometric correction factor include trap shape, length-to-width ratio, potential reservoir thickness, and the height of the potential trapping closure (potential hydrocarbon column height).

High Estimate – The 3U (high) estimate is the P_{10} quantity. P_{10} means there is a 10-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Lead – 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. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Low Estimate – The 1U (low) estimate is the P_{90} quantity. P_{90} means there is a 90 percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Mean Estimate – In accordance with petroleum industry standards, the mean estimate is the probability-weighted average (expected value), which typically has a probability in the P_{45} to P_{15} range, depending on the variance of prospective resources volume or associated quantity. Therefore, the probability of a prospect or accumulation containing the probability-weighted average volume or greater is usually between 45 and 15 percent. The mean estimate is the preferred probabilistic estimate of prospective resources volumes.

Median – Median is the P_{50} quantity, where the P_{50} means there is a 50 percent chance that a given variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded. The median of a data set is a number such that half the measurements are below the median and half are above.

The median is the best estimate in probabilistic estimations of prospective resources, as required by the PRMS guidelines.

Migration Chance Factor – Migration chance factor ($P_{migration}$) is defined as the probability that a trap either predates or is coincident with hydrocarbon migration and that there exists vertical and/or lateral migration pathways linking the source to the trap.

Mode – The mode is the quantity that occurs with the greatest frequency in the data set and therefore is the quantity that has the greatest probability of occurrence. However, the mode may not be uniquely defined, as is the case in multimodal distributions.

P_g-adjusted Mean Estimate, statistical aggregate – The statistical aggregate P_g-adjusted mean estimate, or "aggregated geologic chance-adjusted mean estimate," is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially discovered if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a "blended" quantity; it is a product of the statistically aggregated mean volume estimate and the portfolio's probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic success case" volume outcome of drilling all of the prospects in the exploration portfolio. The P_g-adjusted mean volume estimate for a single prospect is calculated as follows:

P_g-adjusted mean estimate = $P_g \times$ mean estimate (mean geologic success case volume)

The probability of the statistical aggregate P_g-adjusted mean estimate is estimated by the product of the portfolio P_g and the probability of the mean volume occurrence for the entire prospect portfolio. The equation is as follows:

Statisitcal aggregate P_g-adjusted mean estimate, probability of occurrence =
Portfolio P_g x mean volume probability estimate for the portfolio

P_n Nomenclature – This report uses the convention of denoting probability with a subscript representing the greater than cumulative probability distribution. As such, the notation P_n indicates the probability that there is an n-percent chance that a specific input or output quantity will be equaled or exceeded. For example, P_{90} means that there is a 90 percent chance that a variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded.

Play – 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.

Predictability versus Portfolio Size – The number of prospects in a prospect portfolio influences the reliability of the forecast of drilling results. The relationship between predictability versus portfolio size (PPS) is also known in the petroleum industry literature as "Gambler's Ruin." The relationship of probability to portfolio size is described by the binomial probability equation given as follows:

$$P_x^n = (C_x^n)(p)^x(1 - p)^{n-x}$$

where: P_x^n = the probability of x successes in n trials
C_x^n = the number of mutually exclusive ways that x successes can be arranged in n trials
p = the probability of success for a given trial (for petroleum exploration, this is P_g)
x = the number of successes (e.g., the number of discoveries)
n = the number of trials (e.g., the number of wells to be drilled)

Note: For the case of n successive dry holes, C_x^n and p each equals 1, so the probability of failure is the quantity (1 – p) raised to the number of trials.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the probability of discovering reservoirs that flow hydrocarbons at a measurable rate. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

Probability of the Mean Occurrence – The probability of the mean occurrence (P_{MEAN}) is defined as the probability of occurrence of the mean quantity as defined by the distribution(s) in the Monte Carlo simulation. The probability associated with the mean is dependent on the variance of the distribution and type of distribution from which the mean is estimated. Typically, the range in probability of occurrence for the statistical mean estimate is 0.45 to 0.15 for lognormal (positively skewed) distributions. The statistical mean has a probability of occurrence of 0.50 for normal (symmetric) distributions.

Prospect – A project associated with an undrilled potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources. In addition, a viable drilling target requires that 70 percent of the median potential production area be located within the block or license area of interest.

Prospective Resources – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Nonassociated Gas – Nonassociated gas is the total gas produced from the reservoir prior to processing or separation and includes all nonhydrocarbon components as well as any gas equivalent of condensate.

Reservoir Chance Factor – The reservoir chance factor ($P_{reservoir}$) is defined as the probability associated with the presence of porous and permeable reservoir-quality rock.

Source Chance Factor – The source chance factor (P_{source}) is defined as the probability associated with the presence of a hydrocarbon source rock rich enough, of sufficient volume, and in the proper spatial position to charge the prospective area or areas.

Standard Deviation – Standard deviation (SD) is a measure of distribution spread. It is the positive square root of the variance. The variance is the summation of the squared distance from the mean of all possible values. Since the units of standard deviation are the same as those of the sample set, it is the most practical measure of population spread.

$$\sigma = \sqrt{\sigma^2} = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n-1}}$$

where: σ = standard deviation
σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Statistical Aggregation – The process of probabilistically aggregating distributions that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Arithmetic summation yields different results, except for the mean estimate.

Trap Chance Factor – The trap chance factor (P_{trap}) is defined as the probability associated with the presence of a structural closure and/or a stratigraphic trapping configuration with competent vertical and lateral seals, and the lack of any post migration seal integrity events or breaches.

Variance – The variance (σ^2) is a measure of how much the distribution is spread from the mean. The variance sums up the squared distance from the mean of all possible values of x. The variance has units that are the squared units of x. The use of these units limits the intuitive value of variance.

$$\sigma^2 = \frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n-1}$$

where: σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Working Interest – Working interest prospective resources are that portion of the gross prospective resources to be potentially produced from the properties attributable to the interests owned by “Company” before deduction of any associated royalty burdens, net profits payable, or government profit share. Working interest is a percentage of ownership in an oil and gas lease granting its owner the right to explore, drill, and produce oil and gas from a tract of property. Working interest owners are obligated to pay a corresponding percentage of the cost of leasing, drilling, producing, and operating a well or unit. The working interest also entitles its owner to share in production revenues with other working interest owners, based on the percentage of working interest owned.

TABLE A-1
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	691	0	256	124	56,883	25,754	3,724	27,404	25,978
2023	695	0	190	189	50,229	23,475	0	26,756	22,954
2024	633	0	92	188	42,608	22,294	0	20,313	15,776
2025	588	0	29	188	39,814	21,316	0	18,499	13,007
2026	540	0	0	179	37,517	17,738	31,583	(11,804)	(7,510)
2027	498	0	0	144	35,227	17,002	0	18,227	10,500
2028	455	0	0	98	32,798	15,923	785	16,089	8,390
2029	415	0	0	87	30,793	15,041	722	15,029	7,096
2030	385	0	0	78	29,245	14,532	0	14,712	6,285
2031	356	0	0	70	27,677	13,860	1,434	12,383	4,794
2032	328	0	0	63	26,434	13,459	0	12,978	4,543
2033	303	0	0	54	25,066	13,032	0	12,031	3,811
2034	274	0	0	49	23,297	12,027	1,832	9,443	2,710
2035	231	0	0	42	20,236	9,725	8,527	1,983	514
2036	217	0	0	36	19,432	9,509	0	9,921	2,332
2037	200	0	0	31	18,461	9,160	964	8,336	1,775
2038	186	0	0	27	17,665	8,953	0	8,713	1,679
2039	165	0	0	21	16,024	7,924	6,973	1,128	196
2040	154	0	0	18	15,420	7,780	0	7,640	1,207
2041	143	0	0	11	14,573	7,623	0	6,951	993
2042	136	0	0	0	13,728	7,485	0	6,242	807
2043	125	0	0	0	13,126	7,375	0	5,748	673
2044	110	0	0	0	11,769	6,504	20,761	(15,494)	(1,643)
2045	102	0	0	0	11,169	6,388	0	4,778	460
2046	98	0	0	0	10,700	6,321	0	4,381	380
Subtotal	**8,028**	**0**	**567**	**1,697**	**639,891**	**320,200**	**77,305**	**242,387**	**127,707**
Remaining	837	0	0	0	99,191	69,281	49,676	(19,767)	305
Total	**8,865**	**0**	**567**	**1,697**	**739,082**	**389,481**	**126,981**	**222,620**	**128,012**

Present Worth at (10^3U.S.$)	
8 Percent	142,099
12 Percent	116,259
15 Percent	102,099

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

Base Case

	Net								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	720	0	256	124	58,955	26,581	4,123	28,249	26,780
2023	720	0	190	189	51,866	24,201	6,783	20,884	17,914
2024	706	0	92	188	47,184	23,720	8,026	15,437	11,990
2025	659	24	136	332	48,300	24,965	0	23,337	16,409
2026	601	19	84	323	45,168	21,033	31,583	(7,448)	(4,737)
2027	555	15	66	288	42,177	20,006	0	22,173	12,771
2028	506	12	52	242	39,164	18,689	785	19,688	10,268
2029	460	9	41	231	36,641	17,606	722	18,313	8,646
2030	426	7	33	222	34,666	16,935	0	17,729	7,574
2031	392	6	25	214	32,737	16,130	1,434	15,175	5,874
2032	360	0	0	207	30,573	14,947	674	14,956	5,235
2033	332	0	0	198	29,052	14,476	0	14,571	4,616
2034	300	0	0	193	27,148	13,436	1,832	11,886	3,412
2035	277	0	0	186	25,860	13,055	0	12,804	3,325
2036	258	0	0	145	24,416	12,568	0	11,845	2,785
2037	217	0	0	88	20,645	9,835	9,835	973	207
2038	201	0	0	31	19,110	9,279	0	9,831	1,894
2039	179	0	0	21	17,340	8,206	7,314	1,823	317
2040	166	0	0	18	16,663	8,044	0	8,619	1,362
2041	156	0	0	11	15,730	7,868	0	7,863	1,123
2042	145	0	0	0	14,810	7,715	0	7,094	917
2043	135	0	0	0	14,135	7,589	0	6,543	767
2044	119	0	0	0	12,715	6,704	20,761	(14,748)	(1,564)
2045	110	0	0	0	12,050	6,575	0	5,471	526
2046	106	0	0	0	11,522	6,496	0	5,029	436
Subtotal	**8,806**	**92**	**975**	**3,451**	**728,627**	**356,659**	**93,872**	**278,097**	**138,847**
Remaining	905	0	0	0	107,294	70,999	50,524	(14,230)	571
Total	**9,711**	**92**	**975**	**3,451**	**835,921**	**427,658**	**144,396**	**263,867**	**139,418**

Present Worth at (10^3U.S.$)	
8 Percent	156,629
12 Percent	125,203
15 Percent	108,246

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGOLYER AND MacNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	742	0	256	124	60,652	27,162	4,123	29,366	27,836
2023	743	0	256	189	54,193	24,859	6,783	22,549	19,350
2024	781	0	257	188	53,308	25,699	8,026	19,590	15,210
2025	708	24	278	332	53,128	26,371	0	26,757	18,816
2026	668	20	142	333	50,129	22,545	31,583	(3,999)	(2,543)
2027	626	17	73	324	47,847	21,732	0	26,114	15,043
2028	595	13	59	255	45,720	20,832	785	24,104	12,572
2029	562	11	49	256	44,193	20,242	0	23,948	11,303
2030	527	9	39	254	42,867	19,747	0	23,118	9,881
2031	502	7	33	246	41,630	19,307	0	22,328	8,632
2032	469	6	26	239	40,247	18,601	766	20,878	7,313
2033	444	0	0	232	38,379	17,500	687	20,194	6,399
2034	417	0	0	226	37,250	16,979	1,522	18,748	5,380
2035	394	0	0	219	36,261	16,678	0	19,582	5,088
2036	375	0	0	214	35,558	16,477	0	19,078	4,485
2037	356	0	0	208	34,693	16,247	0	18,449	3,925
2038	333	0	0	202	33,262	15,332	1,983	15,948	3,074
2039	292	0	0	198	30,559	13,090	9,229	8,241	1,435
2040	281	0	0	193	30,145	13,003	0	17,137	2,705
2041	267	0	0	189	29,343	12,887	0	16,461	2,354
2042	256	0	0	184	28,667	12,799	0	15,865	2,050
2043	242	0	0	177	27,602	12,361	6,413	8,830	1,035
2044	229	0	0	149	26,573	12,166	1,107	13,299	1,409
2045	221	0	0	146	25,924	12,080	0	13,842	1,329
2046	211	0	0	145	25,365	12,025	0	13,341	1,158
Subtotal	**11,241**	**107**	**1,468**	**5,422**	**973,495**	**446,721**	**73,007**	**453,768**	**185,239**
Remaining	2,926	0	0	1,900	377,096	201,103	75,631	100,361	5,200
Total	**14,167**	**107**	**1,468**	**7,322**	**1,350,591**	**647,824**	**148,638**	**554,129**	**190,439**

Note: Probable reserves and values for probable reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	223,764
12 Percent	165,180
15 Percent	137,345

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	755	0	256	124	61,544	27,437	4,123	29,984	28,424
2023	760	0	256	189	55,490	25,298	6,783	23,409	20,086
2024	840	0	257	188	56,764	26,710	8,026	22,028	17,105
2025	763	25	367	332	57,821	27,789	0	30,036	21,115
2026	730	21	350	333	56,568	24,439	31,583	543	349
2027	696	18	212	332	54,057	23,600	0	30,457	17,546
2028	666	15	68	330	51,629	22,817	0	28,809	15,023
2029	632	13	57	256	49,618	22,002	801	26,815	12,660
2030	605	11	49	255	48,617	21,613	0	27,007	11,537
2031	573	9	41	255	47,754	21,259	0	26,496	10,251
2032	555	8	35	256	47,063	20,974	0	26,090	9,135
2033	528	7	30	250	46,121	20,641	0	25,478	8,079
2034	504	6	25	244	45,325	20,371	0	24,951	7,158
2035	477	0	0	238	43,699	19,343	715	23,641	6,139
2036	462	0	0	233	43,193	19,197	0	24,002	5,643
2037	439	0	0	227	42,479	18,992	0	23,483	4,997
2038	414	0	0	221	41,288	18,226	2,510	20,554	3,960
2039	396	0	0	216	40,763	18,096	0	22,667	3,953
2040	384	0	0	212	40,352	18,007	0	22,344	3,526
2041	346	0	0	207	37,341	15,736	9,602	12,000	1,713
2042	323	0	0	202	35,918	14,885	2,146	18,887	2,447
2043	313	0	0	198	35,330	14,835	0	20,499	2,398
2044	301	0	0	195	34,852	14,814	0	20,039	2,124
2045	291	0	0	186	34,145	14,747	0	19,395	1,862
2046	280	0	0	154	33,200	14,714	0	18,488	1,606
Subtotal	**13,033**	**133**	**2,003**	**5,833**	**1,140,931**	**506,542**	**66,289**	**568,102**	**218,836**
Remaining	4,226	0	0	5,642	588,614	297,763	84,245	206,604	9,071
Total	**17,259**	**133**	**2,003**	**11,475**	**1,729,545**	**804,305**	**150,534**	**774,706**	**227,907**

Note: Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	272,464
12 Percent	194,918
15 Percent	159,363

TABLE A-5
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

	Net								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	691	0	256	124	51,290	25,804	3,724	21,759	20,625
2023	695	0	190	189	45,296	23,475	0	21,822	18,725
2024	633	0	92	188	38,414	22,294	0	16,122	12,522
2025	588	0	29	188	35,889	21,317	0	14,572	10,243
2026	540	0	0	179	33,810	17,738	31,583	(15,511)	(9,870)
2027	492	0	0	144	31,407	16,661	694	14,052	8,095
2028	450	0	0	98	29,228	15,591	785	12,851	6,703
2029	411	0	0	87	27,474	14,782	1,378	11,317	5,341
2030	381	0	0	78	26,111	14,284	0	11,824	5,055
2031	356	0	0	70	24,928	13,860	0	11,072	4,280
2032	319	0	0	63	23,137	12,763	1,761	8,612	3,015
2033	267	0	0	54	20,005	10,305	8,195	1,504	477
2034	250	0	0	49	19,164	10,036	0	9,130	2,621
2035	224	0	0	42	17,764	9,262	6,401	2,101	545
2036	212	0	0	36	17,057	9,049	0	8,005	1,882
2037	190	0	0	31	15,838	8,335	1,008	6,495	1,382
2038	178	0	0	27	15,168	8,141	0	7,025	1,353
2039	165	0	0	21	14,426	7,924	0	6,505	1,134
2040	154	0	0	18	13,884	7,780	0	6,104	964
2041	143	0	0	11	13,116	7,623	0	5,496	786
2042	127	0	0	0	11,593	6,703	19,955	(15,066)	(1,949)
2043	118	0	0	0	11,090	6,603	0	4,487	526
2044	110	0	0	0	10,593	6,504	0	4,088	433
2045	102	0	0	0	10,050	6,388	0	3,662	352
2046	98	0	0	0	9,632	6,321	0	3,311	286
Subtotal	**7,894**	**0**	**567**	**1,697**	**566,364**	**309,543**	**75,484**	**181,339**	**95,526**
Remaining	724	0	0	0	77,133	56,580	49,676	(29,125)	(473)
Total	**8,618**	**0**	**567**	**1,697**	**643,497**	**366,123**	**125,160**	**152,214**	**95,053**

Present Worth at (10^3U.S.$)	
8 Percent	104,796
12 Percent	86,794
15 Percent	76,728

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	720	0	256	124	53,168	26,636	4,123	22,406	21,239
2023	721	0	190	189	46,801	24,213	6,783	15,804	13,563
2024	706	0	92	188	42,532	23,720	8,026	10,788	8,376
2025	659	24	136	332	43,587	24,966	0	18,625	13,093
2026	601	19	84	323	40,754	21,033	31,583	(11,863)	(7,549)
2027	549	15	66	288	37,712	19,665	694	17,356	10,000
2028	501	12	52	242	35,008	18,357	785	15,862	8,273
2029	456	9	41	231	32,784	17,347	1,378	14,062	6,637
2030	422	7	33	222	31,034	16,687	0	14,343	6,131
2031	391	0	0	214	28,827	15,394	661	12,777	4,941
2032	351	0	0	207	26,897	14,251	1,761	10,884	3,810
2033	323	0	0	198	25,566	13,785	0	11,779	3,732
2034	300	0	0	193	24,484	13,436	0	11,050	3,173
2035	244	0	0	186	20,846	10,491	14,928	(4,571)	(1,189)
2036	229	0	0	145	19,691	10,059	0	9,629	2,264
2037	213	0	0	88	18,288	9,502	0	8,786	1,869
2038	193	0	0	27	16,426	8,442	1,362	6,618	1,276
2039	179	0	0	21	15,610	8,206	0	7,407	1,291
2040	166	0	0	18	15,003	8,044	0	6,960	1,099
2041	156	0	0	11	14,158	7,868	0	6,291	899
2042	136	0	0	0	12,566	6,933	19,955	(14,321)	(1,852)
2043	128	0	0	0	11,999	6,817	0	5,181	607
2044	119	0	0	0	11,444	6,704	0	4,738	502
2045	110	0	0	0	10,842	6,575	0	4,269	410
2046	106	0	0	0	10,372	6,496	0	3,876	335
Subtotal	**8,679**	**86**	**950**	**3,447**	**646,399**	**345,627**	**92,039**	**208,736**	**102,930**
Remaining	792	0	0	0	84,427	58,298	50,524	(24,398)	(247)
Total	**9,471**	**86**	**950**	**3,447**	**730,826**	**403,925**	**142,563**	**184,338**	**102,683**

Present Worth at (10^3U.S.$)	
8 Percent	114,943
12 Percent	92,451
15 Percent	80,160

TABLE A-7
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	742	0	256	124	54,676	27,162	4,123	23,392	22,175
2023	743	0	256	189	48,887	24,859	6,783	17,240	14,791
2024	760	0	257	188	46,857	25,093	8,026	13,743	10,673
2025	708	24	278	332	47,968	26,370	0	21,599	15,187
2026	668	20	142	333	45,239	22,545	31,583	(8,891)	(5,657)
2027	626	17	73	324	43,162	21,732	0	21,431	12,344
2028	595	13	59	255	41,226	20,832	785	19,611	10,228
2029	556	11	49	256	39,496	19,890	722	18,881	8,913
2030	522	9	39	254	38,319	19,401	0	18,919	8,084
2031	498	7	33	246	37,225	18,968	0	18,257	7,064
2032	465	0	0	239	35,296	17,577	2,136	15,582	5,455
2033	441	0	0	232	34,373	17,250	0	17,123	5,427
2034	417	0	0	226	33,580	16,979	0	16,604	4,764
2035	385	0	0	219	31,975	15,942	1,868	14,162	3,680
2036	366	0	0	214	31,362	15,744	0	15,617	3,671
2037	322	0	0	208	28,490	13,334	8,871	6,287	1,337
2038	309	0	0	202	28,015	13,209	0	14,807	2,853
2039	288	0	0	198	27,201	12,736	5,925	8,540	1,491
2040	277	0	0	193	26,830	12,649	0	14,179	2,235
2041	264	0	0	189	26,128	12,532	0	13,595	1,943
2042	251	0	0	184	25,381	12,300	1,064	12,020	1,558
2043	240	0	0	177	24,760	12,219	0	12,539	1,467
2044	229	0	0	149	23,949	12,166	0	11,785	1,250
2045	221	0	0	146	23,368	12,080	0	11,286	1,081
2046	211	0	0	145	22,865	12,025	0	10,841	943
Subtotal	**11,104**	**101**	**1,442**	**5,422**	**866,628**	**435,594**	**71,886**	**359,149**	**142,957**
Remaining	2,800	0	0	1,900	326,221	186,857	74,283	65,080	3,325
Total	**13,904**	**101**	**1,442**	**7,322**	**1,192,849**	**622,451**	**146,169**	**424,229**	**146,282**

Note: Probable reserves and values for probable reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	172,173
12 Percent	126,663
15 Percent	105,085

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

Low Case

	Net								
Year	**Oil (10^3bbl)**	**Condensate (10^3bbl)**	**Sales Gas Export (10^6ft^3)**	**Sales Gas to Power (10^6ft^3)**	**Future Gross Revenue (10^3U.S.$)**	**Operating Expenses (10^3U.S.$)**	**Abandonment and Capital Costs (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**
2022	755	0	256	124	55,480	27,437	4,123	23,921	22,674
2023	760	0	256	189	50,051	25,298	6,783	17,973	15,421
2024	816	0	257	188	49,910	26,101	8,026	15,780	12,253
2025	763	25	367	332	52,216	27,790	0	24,426	17,176
2026	730	21	350	333	51,082	24,439	31,583	(4,939)	(3,141)
2027	696	18	212	332	48,789	23,600	0	25,188	14,510
2028	666	15	68	330	46,563	22,817	0	23,745	12,385
2029	632	13	57	256	44,735	22,002	801	21,931	10,352
2030	605	11	49	255	43,833	21,613	0	22,222	9,493
2031	573	9	41	255	43,055	21,259	0	21,795	8,433
2032	555	8	35	256	42,427	20,974	0	21,455	7,513
2033	528	7	30	250	41,582	20,641	0	20,942	6,636
2034	498	0	0	244	39,756	19,227	1,498	19,029	5,460
2035	472	0	0	238	39,043	18,978	0	20,065	5,212
2036	455	0	0	233	38,327	18,559	1,583	18,183	4,276
2037	432	0	0	227	37,708	18,364	0	19,345	4,116
2038	414	0	0	221	37,215	18,226	0	18,990	3,659
2039	362	0	0	216	33,787	15,078	11,251	7,459	1,300
2040	352	0	0	212	33,572	15,032	0	18,536	2,927
2041	338	0	0	207	32,920	14,944	0	17,976	2,568
2042	323	0	0	202	32,376	14,885	0	17,493	2,264
2043	313	0	0	198	31,847	14,835	0	17,012	1,992
2044	301	0	0	195	31,412	14,814	0	16,600	1,758
2045	291	0	0	186	30,776	14,747	0	16,026	1,537
2046	280	0	0	154	29,924	14,714	0	15,209	1,322
Subtotal	**12,910**	**127**	**1,978**	**5,833**	**1,018,386**	**496,374**	**65,648**	**456,362**	**172,096**
Remaining	4,156	0	0	5,642	528,117	289,960	83,772	154,387	6,605
Total	**17,066**	**127**	**1,978**	**11,475**	**1,546,503**	**786,334**	**149,420**	**610,749**	**178,701**

Note: Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	214,123
12 Percent	152,485
15 Percent	124,269

TABLE A-9
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton F-716 TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	691	0	256	124	62,477	25,804	3,724	32,949	31,233
2023	706	0	190	189	56,004	24,093	0	31,910	27,379
2024	654	0	92	188	48,233	22,874	0	25,363	19,698
2025	606	0	29	188	45,050	21,854	0	23,193	16,307
2026	540	0	0	179	41,223	17,738	31,583	(8,098)	(5,153)
2027	498	0	0	144	38,719	17,002	0	21,718	12,510
2028	455	0	0	98	36,053	15,923	785	19,343	10,090
2029	419	0	0	87	34,199	15,362	0	18,838	8,895
2030	389	0	0	78	32,479	14,845	0	17,629	7,532
2031	359	0	0	70	30,682	14,097	751	15,838	6,125
2032	330	0	0	63	29,292	13,687	0	15,604	5,465
2033	303	0	0	54	27,556	13,032	1,492	13,033	4,131
2034	282	0	0	49	26,352	12,713	0	13,640	3,912
2035	261	0	0	42	25,026	12,359	0	12,668	3,290
2036	237	0	0	36	23,321	11,425	1,906	9,987	2,350
2037	202	0	0	31	20,437	9,287	8,871	2,280	483
2038	187	0	0	27	19,557	9,078	0	10,478	2,019
2039	174	0	0	21	18,470	8,724	1,003	8,743	1,525
2040	157	0	0	18	17,306	8,113	1,069	8,123	1,283
2041	143	0	0	11	16,027	7,623	6,164	2,243	321
2042	136	0	0	0	15,099	7,485	0	7,612	984
2043	125	0	0	0	14,439	7,375	0	7,063	826
2044	117	0	0	0	13,776	7,268	0	6,509	691
2045	109	0	0	0	13,070	7,144	0	5,926	569
2046	98	0	0	0	11,772	6,321	21,600	(16,149)	(1,403)
Subtotal	**8,178**	**0**	**567**	**1,697**	**716,619**	**331,226**	**78,948**	**306,443**	**161,062**
Remaining	912	0	0	0	119,031	78,676	49,676	(9,319)	979
Total	**9,090**	**0**	**567**	**1,697**	**835,650**	**409,902**	**128,624**	**297,124**	**162,041**

Present Worth at (10^3U.S.$)	
8 Percent	180,637
12 Percent	146,682
15 Percent	128,319

TABLE A-10
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	720	0	256	124	64,756	26,631	4,123	34,002	32,231
2023	731	0	190	189	57,805	24,819	6,783	26,201	22,482
2024	727	0	92	188	53,267	24,300	8,026	20,945	16,265
2025	677	24	136	332	54,320	25,503	0	28,816	20,261
2026	601	19	84	323	49,583	21,033	31,583	(3,034)	(1,930)
2027	555	15	66	288	46,310	20,006	0	26,308	15,154
2028	506	12	52	242	43,008	18,689	785	23,530	12,274
2029	464	9	41	231	40,587	17,927	0	22,661	10,697
2030	430	7	33	222	38,399	17,248	0	21,146	9,037
2031	395	6	25	214	36,206	16,367	751	19,093	7,384
2032	363	5	21	207	34,490	15,849	0	18,637	6,527
2033	332	0	0	198	31,902	14,476	2,179	15,249	4,834
2034	308	0	0	193	30,554	14,122	0	16,432	4,712
2035	285	0	0	186	29,096	13,739	0	15,360	3,989
2036	258	0	0	145	26,819	12,568	1,906	12,343	2,904
2037	239	0	0	88	24,803	11,903	0	12,899	2,744
2038	202	0	0	31	21,149	9,404	9,048	2,694	520
2039	188	0	0	21	19,917	9,006	1,003	9,908	1,726
2040	169	0	0	18	18,673	8,377	1,417	8,879	1,404
2041	156	0	0	11	17,300	7,868	6,164	3,270	468
2042	145	0	0	0	16,289	7,715	0	8,573	1,108
2043	135	0	0	0	15,549	7,589	0	7,959	931
2044	126	0	0	0	14,816	7,468	0	7,349	780
2045	117	0	0	0	14,039	7,331	0	6,708	644
2046	106	0	0	0	12,676	6,496	21,600	(15,419)	(1,339)
Subtotal	**8,935**	**97**	**996**	**3,451**	**812,313**	**366,434**	**95,368**	**350,509**	**175,807**
Remaining	980	0	0	0	127,943	80,394	50,524	(2,973)	1,283
Total	**9,915**	**97**	**996**	**3,451**	**940,256**	**446,828**	**145,892**	**347,536**	**177,090**

Present Worth at (10^3U.S.$)	
8 Percent	199,393
12 Percent	158,808
15 Percent	137,110

TABLE A-11
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	742	0	256	124	66,620	27,162	4,123	35,337	33,499
2023	756	0	256	189	60,417	25,525	6,783	28,103	24,113
2024	793	0	257	188	59,348	26,338	8,026	24,987	19,406
2025	728	24	278	332	59,685	26,945	0	32,740	23,016
2026	671	20	142	333	55,248	22,773	30,566	1,916	1,221
2027	626	17	73	324	52,536	21,732	1,037	29,763	17,147
2028	595	13	59	255	50,217	20,832	785	28,599	14,916
2029	562	11	49	256	48,530	20,242	0	28,291	13,353
2030	527	9	39	254	47,083	19,747	0	27,332	11,679
2031	502	7	33	246	45,725	19,307	0	26,422	10,221
2032	473	6	26	239	44,571	18,934	0	25,638	8,975
2033	449	5	22	232	43,252	18,537	0	24,712	7,835
2034	424	0	0	226	41,504	17,546	701	23,257	6,674
2035	394	0	0	219	39,834	16,678	2,365	20,790	5,399
2036	375	0	0	214	39,059	16,477	0	22,581	5,311
2037	356	0	0	208	38,115	16,247	0	21,869	4,653
2038	341	0	0	202	37,314	16,062	0	21,253	4,092
2039	320	0	0	198	36,541	15,890	0	20,649	3,602
2040	300	0	0	193	35,178	15,031	2,063	18,085	2,856
2041	267	0	0	189	32,238	12,887	9,602	9,749	1,392
2042	256	0	0	184	31,481	12,799	0	18,682	2,418
2043	245	0	0	177	30,702	12,718	0	17,985	2,106
2044	233	0	0	149	29,711	12,666	0	17,046	1,807
2045	221	0	0	146	28,479	12,080	7,802	8,594	824
2046	211	0	0	145	27,870	12,025	0	15,844	1,375
Subtotal	**11,367**	**112**	**1,490**	**5,422**	**1,081,258**	**457,180**	**73,853**	**550,224**	**227,890**
Remaining	2,966	0	0	1,900	419,691	206,153	75,631	137,908	6,926
Total	**14,333**	**112**	**1,490**	**7,322**	**1,500,949**	**663,333**	**149,484**	**688,132**	**234,816**

Note: Probable reserves and values for probable reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	275,658
12 Percent	203,887
15 Percent	169,793

TABLE A-12
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2022	755	0	256	124	67,604	27,437	4,123	36,042	34,167
2023	773	0	256	189	61,856	25,974	6,783	29,104	24,969
2024	852	0	257	188	63,170	27,367	8,026	27,773	21,569
2025	796	25	367	332	65,728	28,994	0	36,737	25,828
2026	760	21	350	333	64,265	26,578	24,687	12,996	8,274
2027	724	18	212	332	61,450	25,709	0	35,744	20,592
2028	666	15	68	330	56,693	22,817	7,171	26,702	13,924
2029	632	13	57	256	54,502	22,002	801	31,699	14,965
2030	605	11	49	255	53,399	21,613	0	31,788	13,585
2031	573	9	41	255	52,458	21,259	0	31,200	12,068
2032	555	8	35	256	51,701	20,974	0	30,725	10,757
2033	528	7	30	250	50,663	20,641	0	30,022	9,516
2034	504	6	25	244	49,794	20,371	0	29,417	8,439
2035	478	5	22	238	48,784	20,078	0	28,712	7,457
2036	462	0	0	233	47,457	19,197	729	27,533	6,474
2037	439	0	0	227	46,666	18,992	0	27,674	5,890
2038	421	0	0	221	46,044	18,847	0	27,194	5,238
2039	402	0	0	216	45,426	18,710	0	26,716	4,659
2040	390	0	0	212	44,959	18,617	0	26,340	4,159
2041	367	0	0	207	43,324	17,876	2,664	22,786	3,256
2042	348	0	0	202	42,464	17,781	0	24,681	3,193
2043	321	0	0	198	39,652	15,632	9,990	14,032	1,645
2044	308	0	0	195	39,100	15,616	0	23,485	2,486
2045	291	0	0	186	37,515	14,747	2,277	20,489	1,965
2046	280	0	0	154	36,483	14,714	0	21,773	1,892
Subtotal	**13,230**	**138**	**2,025**	**5,833**	**1,271,157**	**522,543**	**67,251**	**681,364**	**266,967**
Remaining	4,269	0	0	5,642	651,846	303,250	84,245	264,350	11,426
Total	**17,499**	**138**	**2,025**	**11,475**	**1,923,003**	**825,793**	**151,496**	**945,714**	**278,393**

Note: Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	332,141
12 Percent	238,623
15 Percent	195,732

DEGOLYER AND MACNAUGHTON
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TEXAS REGISTERED ENGINEERING FIRM

TABLE A-13
PROSPECT PORTFOLIO SUMMARY
as of
DECEMBER 31, 2021
with interests attributable to
IGAS ENERGY PLC
VARIOUS PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

Prospect	Country	Area/Basin	License/Block	Working Interest (decimal)	Potential Hydrocarbon Phase
Eartham	United Kingdom	Weald	PEDL326	1.00	Oil
Godley Bridge	United Kingdom	Weald	PEDL235	1.00	Oil
Lea	United Kingdom	East Midlands	PEDL316	0.35	Oil

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-14
ESTIMATE of the GROSS PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2021
with interests attributable to
IGAS ENERGY PLC
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

				Gross Prospective Oil Resources Summary					
Prospect	**Country**	**Area/Basin**	**License/Block**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Eartham	United Kingdom	Weald	PEDL326	2,139	4,137	8,059	4,753	0.270	1,283
Godley Bridge	United Kingdom	Weald	PEDL235	3,900	6,359	10,297	6,851	0.432	2,959
Lea	United Kingdom	East Midlands	PEDL316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate				**8,571**	**13,560**	**21,093**	**13,651**	**0.338**	**4,611**
Arithmetic Summation				6,645	12,134	22,287	13,651	0.338	4,611

Notes:
1. 1U (Low), 2U (Best), 3U (High), and mean estimates follow the PRMS guidelines for prospective resources.
2. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.10 to 0.15.

TABLE A-15
ESTIMATE of the WORKING INTEREST PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2021
attributable to
IGAS ENERGY PLC
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Working Interest Prospective Oil Resources Summary					
Prospect	**Country**	**Area/Basin**	**License/Block**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Eartham	United Kingdom	Weald	PEDL326	2,139	4,137	8,059	4,753	0.270	1,283
Godley Bridge	United Kingdom	Weald	PEDL235	3,900	6,359	10,297	6,851	0.432	2,959
Lea	United Kingdom	East Midlands	PEDL316	212	573	1,376	717	0.180	129
Statistical Aggregate				**8,063**	**12,370**	**18,674**	**12,320**	**0.355**	**4,372**
Arithmetic Summation				6,251	11,069	19,732	12,320	0.355	4,372

Notes:

1. 1U (Low), 2U (Best), 3U (High), and mean estimates follow the PRMS guidelines for prospective resources.
2. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.10 to 0.15.

TABLE A-16
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
DECEMBER 31, 2021
with interests attributable to
IGAS ENERGY PLC
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

DeGolyer and MacNaughton F-716 TEXAS REGISTERED ENGINEERING FIRM

Prospect	Potential Target	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Eartham	Upper Great Oolite	Productive area, acres	525	1,027	1,741	2,916	4,553	1,875
		Productive area, sq km	2.12	4.16	7.05	11.80	18.43	7.59
		Porosity, decimal	0.091	0.107	0.120	0.133	0.148	0.120
		Oil saturation, decimal	0.501	0.586	0.650	0.714	0.791	0.650
		Formation volume factor, Bo	1.195	1.164	1.140	1.116	1.085	1.140
		Recovery efficiency, decimal	0.050	0.069	0.100	0.145	0.200	0.104
		Prospective OOIP, barrels	4,198,030	11,254,843	23,878,046	49,338,028	108,528,232	27,957,271
		Prospective gross ultimate recovery, barrels	308,008	1,028,155	2,364,997	5,229,463	16,798,812	2,905,918
Eartham	Lower Great Oolite	Productive area, acres	123	399	945	2,192	4,532	1,151
		Net hydrocarbon thickness, feet	8.28	13.26	22.90	39.48	63.64	24.93
		Porosity, decimal	0.112	0.127	0.140	0.153	0.169	0.140
		Oil saturation, decimal	0.504	0.586	0.650	0.714	0.793	0.650
		Formation volume factor, Bo	1.194	1.164	1.140	1.116	1.085	1.140
		Recovery efficiency, decimal	0.050	0.069	0.100	0.144	0.198	0.104
		Prospective OOIP, barrels	1,542,391	4,764,496	13,157,897	36,406,065	99,928,542	17,768,100
		Prospective gross ultimate recovery, barrels	125,217	467,993	1,319,451	3,763,701	14,452,831	1,846,841
Godley Bridge	Kimmeradge Micrites	Productive area, acres	1,647	2,337	3,048	3,953	4,965	3,103
		Net hydrocarbon thickness, feet	74.90	97.19	131.04	176.53	228.76	134.43
		Porosity, decimal	0.085	0.094	0.100	0.106	0.114	0.100
		Oil saturation, decimal	0.351	0.436	0.500	0.564	0.645	0.500
		Formation volume factor, Bo	1.258	1.225	1.200	1.174	1.142	1.200
		Recovery efficiency, decimal	0.030	0.038	0.050	0.064	0.080	0.051
		Prospective OOIP, barrels	45,211,295	85,486,483	127,338,938	193,815,175	304,102,993	134,851,495
		Prospective gross ultimate recovery, barrels	1,870,336	3,900,317	6,358,598	10,297,080	18,301,803	6,850,524
Lea	Westphalian Eagle Sandstone	Productive area, acres	107	193	301	464	671	316
		Net hydrocarbon thickness, feet	16.42	31.00	56.28	101.84	181.38	62.30
		Porosity, decimal	0.090	0.110	0.140	0.170	0.190	0.140
		Oil saturation, decimal	0.401	0.461	0.550	0.639	0.699	0.550
		Formation volume factor, Bo	1.315	1.223	1.150	1.076	0.986	1.150
		Recovery efficiency, decimal	0.050	0.109	0.191	0.306	0.393	0.200
		Prospective OOIP, barrels	1,135,875	3,768,624	8,652,833	19,613,361	50,696,615	10,240,423
		Prospective gross ultimate recovery, barrels	144,919	606,284	1,637,952	3,931,267	14,711,688	2,048,085