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

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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 4, 2020

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, 2019, 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 from 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).

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, 2019. Net reserves are defined as that portion of the gross reserves attributable to the interests held by IGas evaluated herein after deducting interests held by others, as described herein.

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 of U.S.$1.30 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. 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, consideration of United Kingdom taxes has not been included 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 nominal discount rate of 10 percent are reported in detail and values using nominal discount rates of 8, 12, and 15 percent are reported as totals.

The 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, 2019. Net contingent resources are defined as that portion of the gross contingent resources that might potentially be produced from the properties attributable to the interests held by IGas evaluated herein after deducting interests attributable to 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 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. 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 or values associated with reserves due to the additional risk 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.

The 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, 2019. Working interest prospective resources are defined as the product of the gross prospective resources and IGas' working interest.

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 6 fields that contain reserves only, 5 fields that contain contingent resources only, 13 fields that contain reserves and contingent resources, and 6 fields that are uneconomic. This evaluation also includes prospective resources for two 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, 2019, 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, 2019, 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	9,884	4,665	3,281	4,504	4,964	1,914	10,661	5,521	3,611
Net	9,772	4,642	3,258	4,504	4,964	1,914	10,549	5,498	3,588

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 scenario and two price sensitivities. An explanation of the Base Case and two price sensitivity assumptions 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 and 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, 2019, 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	202,732	126,919	449,438	182,645	630,330	221,296
Low Case	106,509	68,297	301,878	112,365	447,802	142,326
High Case	304,902	182,218	602,922	249,787	818,274	296,674

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

Reserves estimates herein were based on the Base Case price scenario 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 of 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 18 fields. 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, 2019, 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	10,303	10,375	12,092	9,998	10,350	11,782
2C	16,954	18,641	20,168	16,338	18,400	19,510
3C	28,026	28,631	32,962	26,345	27,123	31,021

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 two conventional prospects have been evaluated in two 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, 2019, 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	1,409
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	1,170

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. 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	50.00	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
Dunhome	AL009	100.00	4/7/2025
Eartham	PED326	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
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

Table – (*Continued*)

Field/Discovery/Prospect	License	Working Interest (percent)	License Expiration
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: Lea and Eartham 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, 2019, 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.

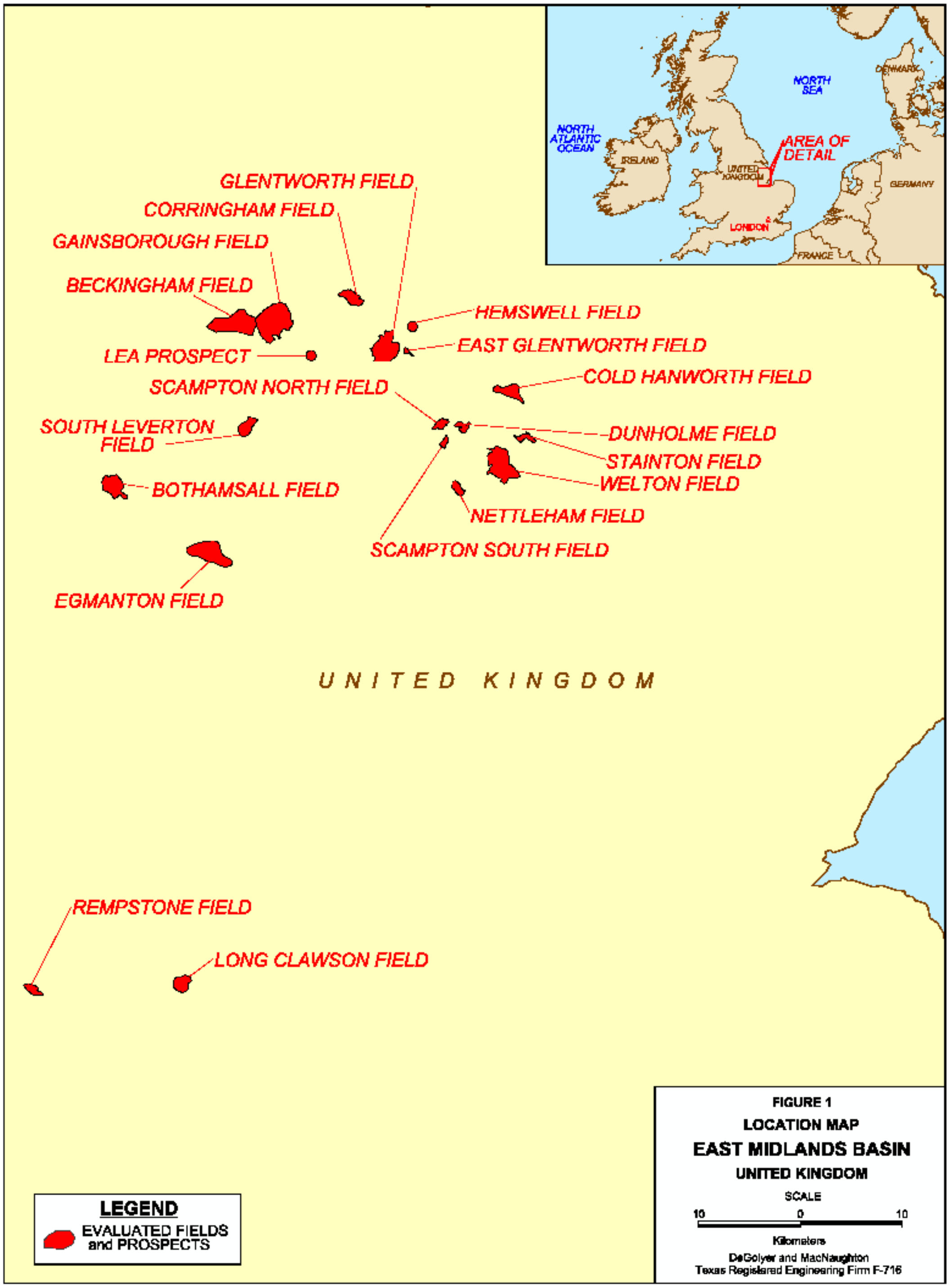

FIGURE 1
LOCATION MAP
EAST MIDLANDS BASIN
UNITED KINGDOM

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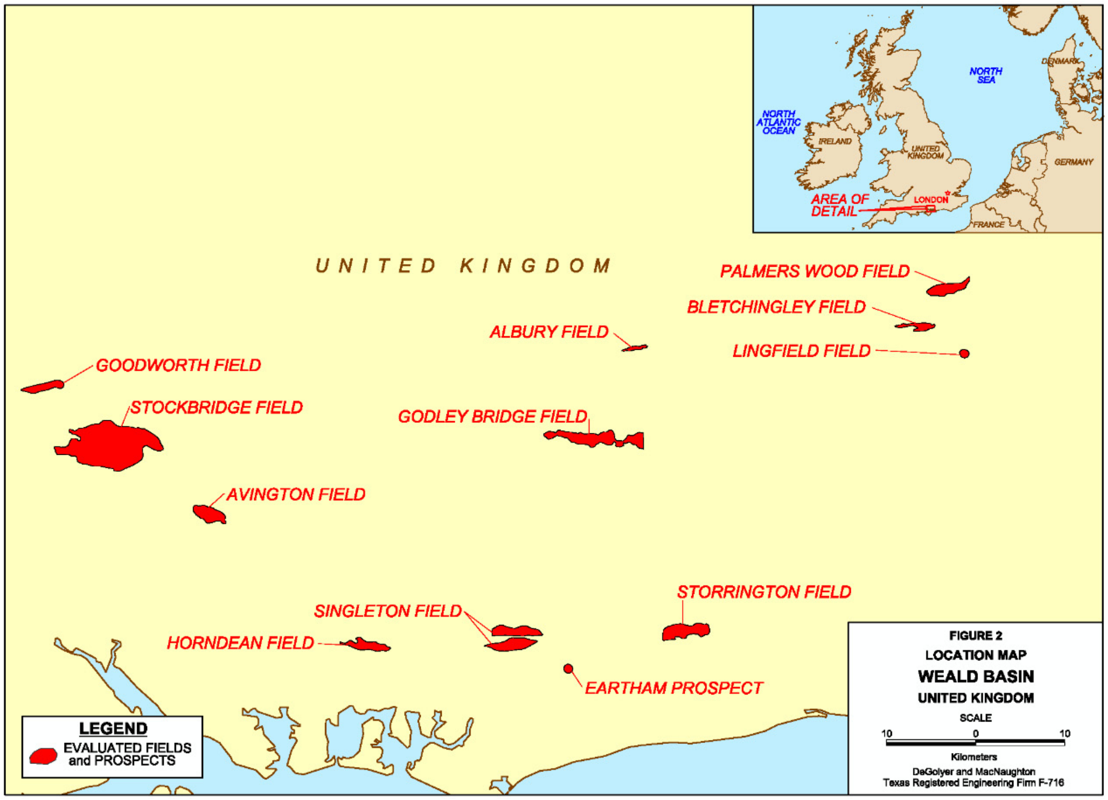
There are 11 fields and 1 prospect evaluated herein located in the Weald Basin, as shown on Figure 2.



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

FIGURE 3
LOCATION MAP
LYBSTER FIELD
OFFSHORE UNITED KINGDOM

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 at the offshore installation. 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 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 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.

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 or the license limit, whichever occurs first.

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, 2019, 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 November 2019. Where applicable, estimated cumulative production, as of December 31, 2019, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 1 month. 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 reserves estimated herein 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) and are reported in 10^6ft^3.

The estimated gross fuel gas quantities associated with gas reserves attributable to certain IGas interests evaluated herein are summarized as follows, expressed in millions of cubic feet (10^6ft^3):

	Fuel Gas Associated with Gas Reserves		
Field	**Proved (10^6ft^3)**	**Probable (10^6ft^3)**	**Possible (10^6ft^3)**
Albury	37	8	8
Gainsborough	839	289	228
Glentworth	100	23	6
Singleton	936	78	78
Welton	730	769	415
Total	**2,641**	**1,168**	**735**

Notes:
1. Probable and possible quantities have not been risk adjusted to make them comparable to proved quantities.
2. Net fuel gas was estimated by applying IGas' working interest to the gross fuel gas. IGas working interest is 100 percent; therefore, net fuel gas equals gross fuel gas.

In this report, gas quantities are identified by the type of reservoir from which the gas is or will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. 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. Solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Gas quantities estimated herein include both associated and nonassociated gas.

For the purposes of this report, 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. This conversion factor was provided by IGas.

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 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 ranged from 12 to 25 percent, S_w from 21 to 60 percent, and permeability from 0.1 to 100 millidarcys. The recovery factors range from 61 to 79 percent. Proved developed reserves were estimated based on the producing well. 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 ranged from 14 to 23 percent, S_w from 46 to 57 percent, and permeability from 0.08 to 0.1 millidarcy. In this fractured reservoir, the effective permeability can be much higher. The current plan is to bring the two wells back on production in 2021 by disposing the produced water offsite to the Stockbridge field. Reserves for the Avington field were categorized as proved developed non-producing.

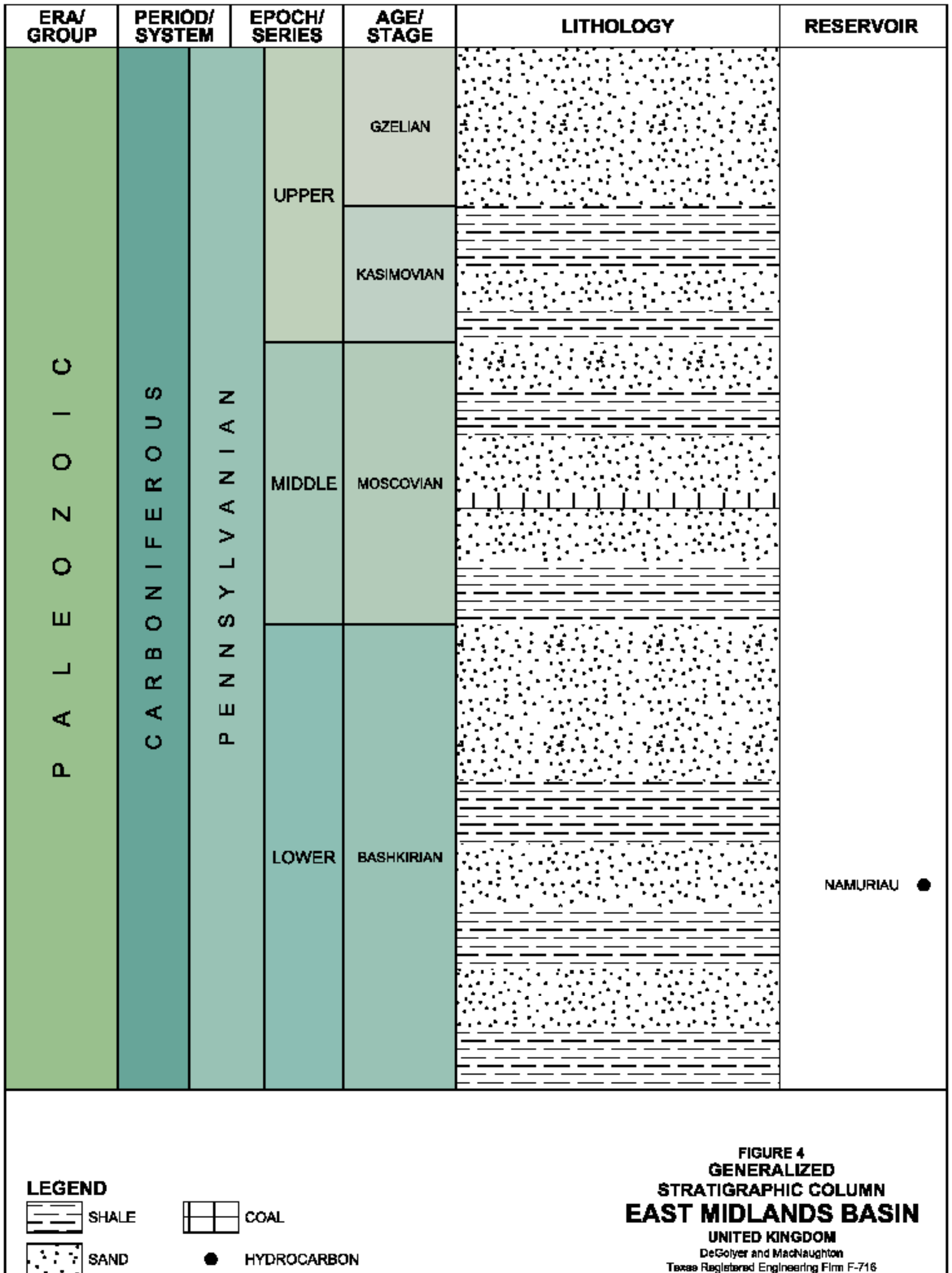
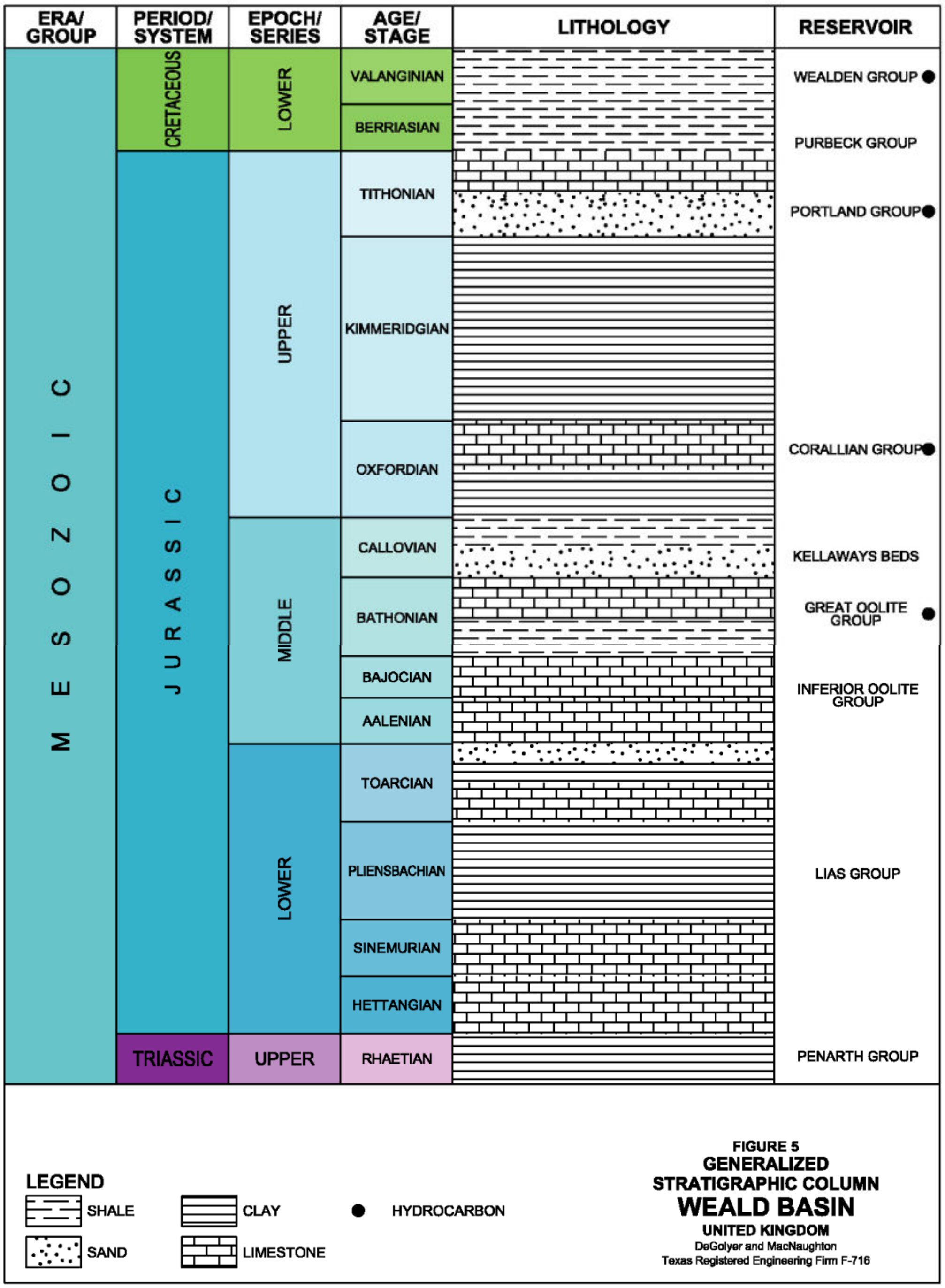


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716



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 Beckhingham field also has the development potential to produce nonassociated gas from the Mexborough/Alexander Formations; however, this potential has not been considered in this evaluation. In the producing reservoirs, porosity ranged from 8 to 20 percent, S_w from 40 to 70 percent, and permeability 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 ranged from 5 to 25 percent, S_w from 40 to 70 percent, and permeability from 0.2 to 1000 millidarcys. Proved reserves were estimated based on individual well performance and proved undeveloped reserves were estimated based on volumetrics for one new 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 build 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 ranged from 6 to 16 percent, S_w from 26 to 60 percent, and permeability 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 ranged from 7 to 16 percent, S_w from 40 to 70 percent, and permeability 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 ranged from 14 to 27 percent, S_w from 37 to 44 percent, and permeability 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 ranged from 16 to 20 percent, S_w from 42 to 47 percent, and permeability 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 ranged from 13 to 17 percent, S_w from 45 to 55 percent, and permeability from 1 to 100 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 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 ranged from 8 to 20 percent, S_w from 40 to 70 percent, and permeability from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 °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.

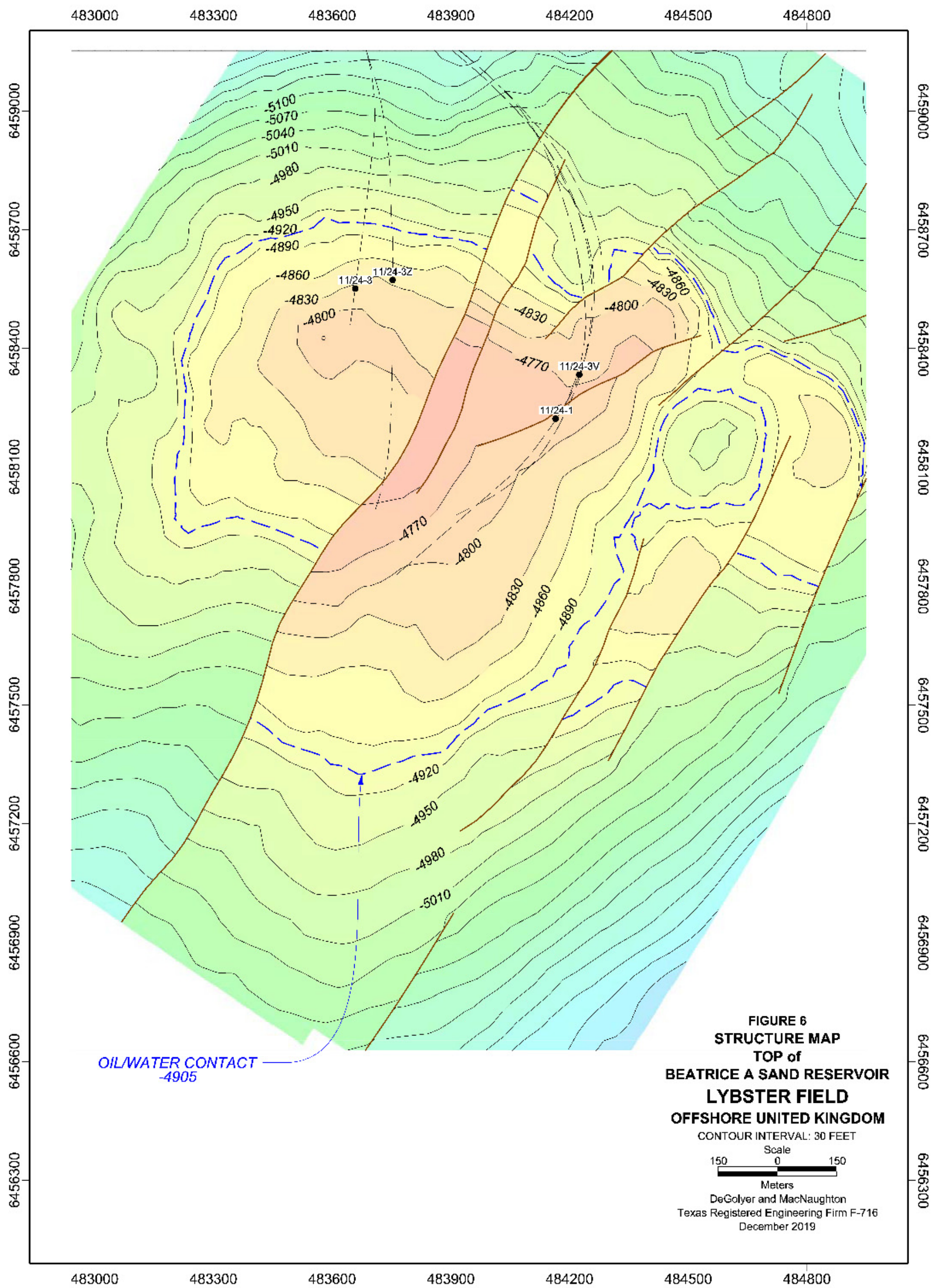
The Glentworth field was discovered in 1961 and is located in license ML4 near Lincolnshire. The field is a four-way dip closure and produces from the Mexborough rock. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity ranged from 16 to 20 percent, S_w from 50 to 65 percent, and permeability 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 ranged from 12 to 16 percent, S_w from 50 to 70 percent, and permeability from 0.1 to 5 millidarcys. Proved developed 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 ranged from 12 to 19 percent, S_w from 70 to 80 percent, and permeability 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 ranged from 13 to 18 percent, S_w from 68 to 79 percent, and permeability 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 ranged from 55 to 80 percent. The following ranges were also used in volumetrics: porosity of 12 percent, S_w from 35 to 45 percent, and permeability from 90 to 1,115 millidarcys. Proved, probable, and possible undeveloped reserves estimated herein were based on the volumetric method. 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 bring the well back on production in 2022.



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. No reserves were estimated for this field because production stopped in February 2016, and the projections that might have allowed the field to come back on line were determined to be uneconomic.

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 from the Upper Jurassic Corallian Sandstone through four wells. In addition, there has been an active waterflood through three injectors since the beginning of production. Porosity ranged from 16 to 20 percent, S_w from 40 to 60 percent, and permeability 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 ranged from 16 to 19 percent, S_w from 40 to 50 percent, and permeability from 0.1 to 20 millidarcys. Performance analysis was completed on this field and after economic evaluation, proved and proved-plus-probable quantities were estimated to be uneconomic; therefore, only possible reserves are reported for this field.

The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL 179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity ranged from 12 to 18 percent, S_w from 30 to 50 percent, and permeability from 0.5 to 400 mllidarcys. Proved developed 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 and estimates of proved, probable, and possible undeveloped include conversion of a shut-in well to water injection, which will support production.

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 high sulfur levels. The field is not currently producing. Porosity ranged from 10 to 16 percent, S_w from 26 to 40 percent, and permeability from 5 to 500 millidarcys. Reserves for this field were estimated to be zero, as the field has watered out.

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 ranged from 13 to 16 percent, S_w from 30 to 62 percent, and permeability 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, and also include undeveloped reserves. The current plan is to install a new 1-megawatt generator by 2022, which may allow future estimation 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 ranged from 9 to 13 percent, S_w from 22 to 27 percent, and permeability 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 ranged from 12 to 16 percent, S_w from 30 to 50 percent, and permeability 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 estimated to be zero.

The Stockbridge field was discovered in 1984. This field is located within the DL2, PL233, and PL249 licenses and is 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, with three wells currently suspended due to lack of available water disposal. Porosity ranged from 12 to 24 percent, S_w from 66 to 79 percent, and permeability 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 ranged from 10 to 17 percent, S_w from 45 to 60 percent, and permeability 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 ranged from 12 to 20 percent, S_w from 20 to 40 percent, and permeability 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 include the conversion of an existing suspended producer to a water injector. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency of the planned injector.

The estimated gross proved, probable, and possible reserves, as of December 31, 2019, 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	1,459	490	448	252	84	77
Avington	39	13	15	0	0	0	39	13	15
Beckingham	555	153	155	0	0	0	555	153	155
Bletchingley	264	102	103	1,753	3,259	908	566	664	260
Bothamsall	83	35	64	0	0	0	83	35	64
Cold Hanworth	251	110	66	0	0	0	251	110	66
Corringham	269	30	31	0	0	0	269	30	31
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	73	21	28	0	0	0	73	21	28
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	875	417	469	0	0	0	875	417	469
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	24	2	16	0	0	0	24	2	16
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL317)	0	0	0	0	0	0	0	0	0
Horndean	923	162	166	0	0	0	923	162	166
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	53	13	8	0	0	0	53	13	8
Lybster	112	24	30	418	88	113	184	39	49
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	91	44	95	0	0	0	91	44	95
Rempstone	0	0	5	0	0	0	0	0	5
Scampton North	583	117	191	0	0	0	583	117	191
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,774	899	385	874	1,127	445	1,925	1,087	459
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	845	190	58	0	0	0	845	190	58
Storrington	130	83	50	0	0	0	130	83	50
Welton	2,940	2,250	1,346	0	0	0	2,940	2,250	1,346
Total	**9,884**	**4,665**	**3,281**	**4,504**	**4,964**	**1,914**	**10,661**	**5,521**	**3,611**

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, 2019, 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	1,459	490	448	252	84	77
Avington	19	7	8	0	0	0	19	7	8
Beckingham	555	153	155	0	0	0	555	153	155
Bletchingley	264	102	103	1,753	3,259	908	566	664	260
Bothamsall	83	35	64	0	0	0	83	35	64
Cold Hanworth	251	110	66	0	0	0	251	110	66
Corringham	269	30	31	0	0	0	269	30	31
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	73	21	28	0	0	0	73	21	28
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	875	417	469	0	0	0	875	417	469
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	24	2	16	0	0	0	24	2	16
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL317)	0	0	0	0	0	0	0	0	0
Horndean	831	145	150	0	0	0	831	145	150
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	53	13	8	0	0	0	53	13	8
Lybster	112	24	30	418	88	113	184	39	49
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	91	44	95	0	0	0	91	44	95
Rempstone	0	0	5	0	0	0	0	0	5
Scampton North	583	117	191	0	0	0	583	117	191
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,774	899	385	874	1,127	445	1,925	1,093	462
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	845	190	58	0	0	0	845	190	58
Storrington	130	83	50	0	0	0	130	83	50
Welton	2,940	2,250	1,346	0	0	0	2,940	2,250	1,346
Total	**9,772**	**4,642**	**3,258**	**4,504**	**4,964**	**1,914**	**10,549**	**5,498**	**3,588**

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 below. Three economic scenario cases (Base Case, Low Case, High Case) were evaluated. Gross and net reserves estimated herein were based on the Base Case price, expense, and cost estimations. The Low Case and High Case sensitivity cases were projected to the Base Case projected limit or the economic limit, whichever occurs first. Only the prices are varied in each economic scenario.

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 based on the futures market forward curve at the end of 2019, namely, the Intercontinental Exchange (ICE) forward curve averaged for the month of December 2019. After the forward curve ends in 4 years, a 2-percent escalation was applied to subsequent years but capped at U.S.$100 per barrel. The condensate price was assumed to be 90 percent of the oil price. The oil and condensate price assumptions are shown in the table below, expressed in United States dollars per barrel (U.S.$/bbl).

Gas sales prices for the Base Case were based on the prevailing United Kingdom national balancing point gas price at the end of 2019 and a 1-percent escalation was applied to subsequent years. 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.$/$10^3$ft^3).

	Base Case Prices			
Year	**Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**Gas Export (U.S.$/$10^3$ft^3)**	**Gas to Power (U.S.$/$10^3$ft^3)**
2020	61.78	55.60	7.44	7.11
2021	58.39	52.55	7.51	7.18
2022	56.97	51.27	7.59	7.25
2023	56.54	50.89	7.67	7.33
2024	57.67	51.90	7.74	7.40
2025	58.82	52.94	7.82	7.47

Note: From 2025 forward, oil and condensate prices were escalated at 2 percent per year and gas prices were escalated at 1 percent per year.

Low Case Price Assumptions

Oil and condensate prices for the Low Case are U.S.$10.00 per barrel lower than the Base Case, and the Low Case gas price is U.S.$1.00 per 10^3ft^3 lower than the Base Case. Reserves estimates herein were based on the Base Case scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case limit of projected production or when an annual economic limit is reached, whichever comes first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case herein.

High Case Price Assumptions

Oil and condensate prices for the High Case are U.S.$10.00 per barrel higher than the Base Case, and the High Case gas price is U.S.$1.00 per 10^3ft^3 higher than the Base Case. Reserves estimates herein were based on the Base Case scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case limit of projected production or when an annual economic limit is reached, whichever comes first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case herein.

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 cost escalation per year was applied for fixed operating expenses, capital costs, and abandonment costs for 2020 and beyond. 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.

Royalty

No royalty is applicable for these United Kingdom fields.

Exchange Rate

Where applicable, an exchange rate of U.S.$1.30 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, 2019, 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	676,068	1,089,820	1,367,974
Operating Expenses	341,760	498,146	589,122
Abandonment and Capital Costs	131,576	142,236	148,522
Future Net Revenue	202,732	449,438	630,330
Present Worth at 10 Percent	126,919	182,645	221,296

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, 2019, 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	536,298	895,659	1,136,361	778,238	1,243,304	1,555,918
Operating Expenses	304,508	458,002	546,486	341,760	498,146	589,122
Abandonment and Capital Costs	125,281	135,779	142,073	131,576	142,236	148,522
Future Net Revenue	106,509	301,878	447,802	304,902	602,922	818,274
Present Worth at 10 Percent	68,297	112,365	142,326	182,218	249,787	296,674

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

The estimated future net revenue of all fields for the Base, Low, and High Cases is shown in Tables A-1 through A-9 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.

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.

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, 2019. The development and economic status represents the status applicable on December 31, 2019.

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 quantitiesassociated 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 contingent resources estimated herein are expressed at a temperature base of 60 °F and at a pressure base of 14.7 psia and are reported in 10^6ft^3.

In this report, gas quantities are identified by the type of reservoir from which the gas is or will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. 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. Solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Gas quantities estimated herein include both associated and nonassociated gas.

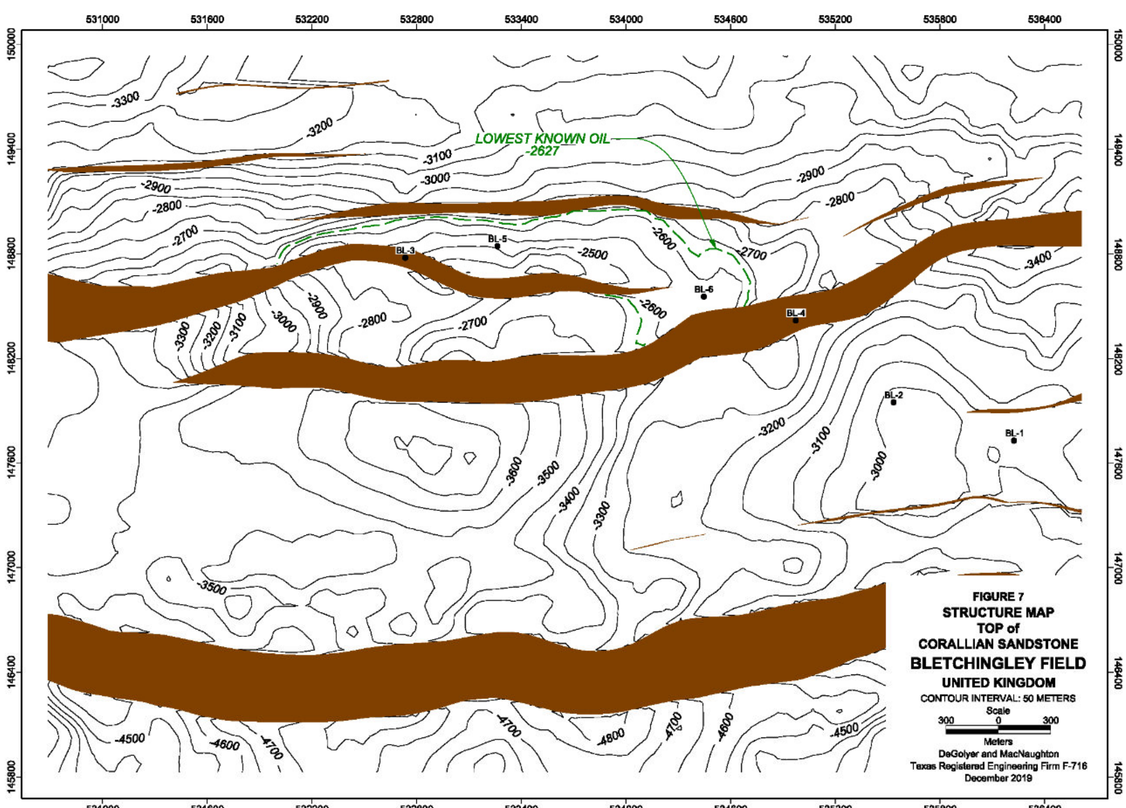
For the purposes of this report, sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe. This conversion factor was provided by IGas.

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

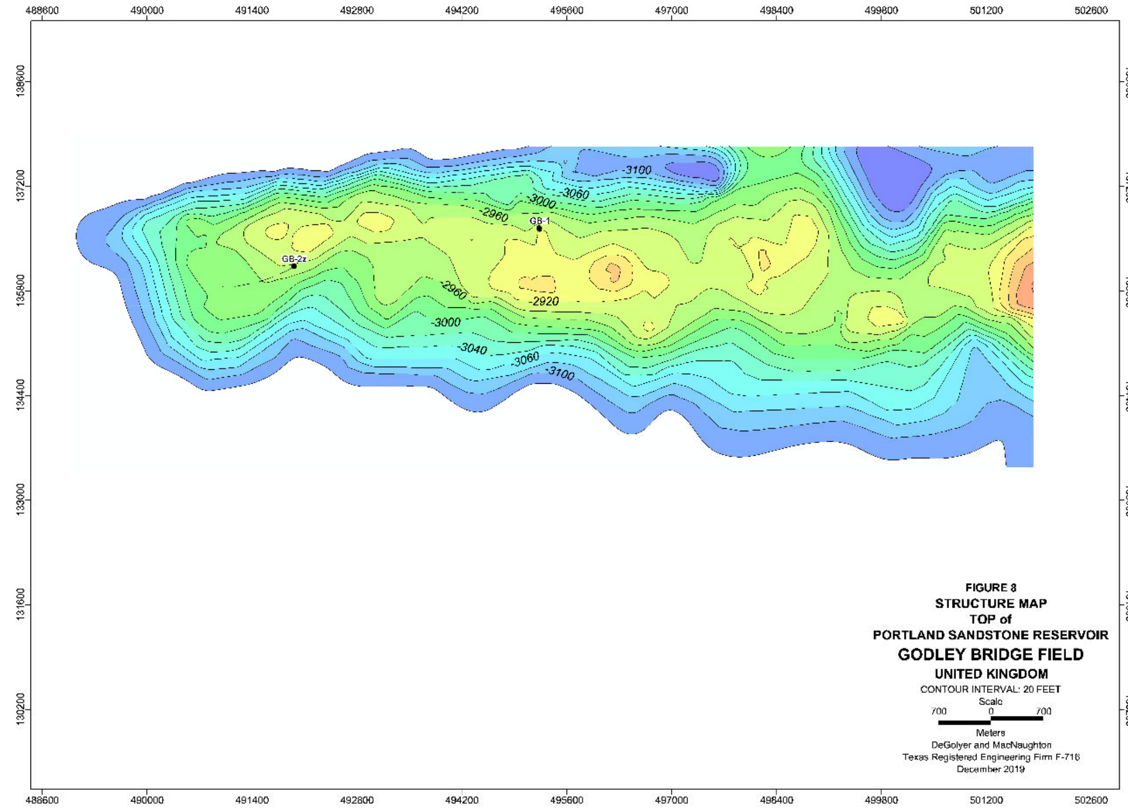
The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone (Figure 7) and the field is currently producing from two wells. Porosity ranged from 5 to 25 percent, S_w from 40 to 70 percent, and permeability from 0.2 to 1,000 millidarcys.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



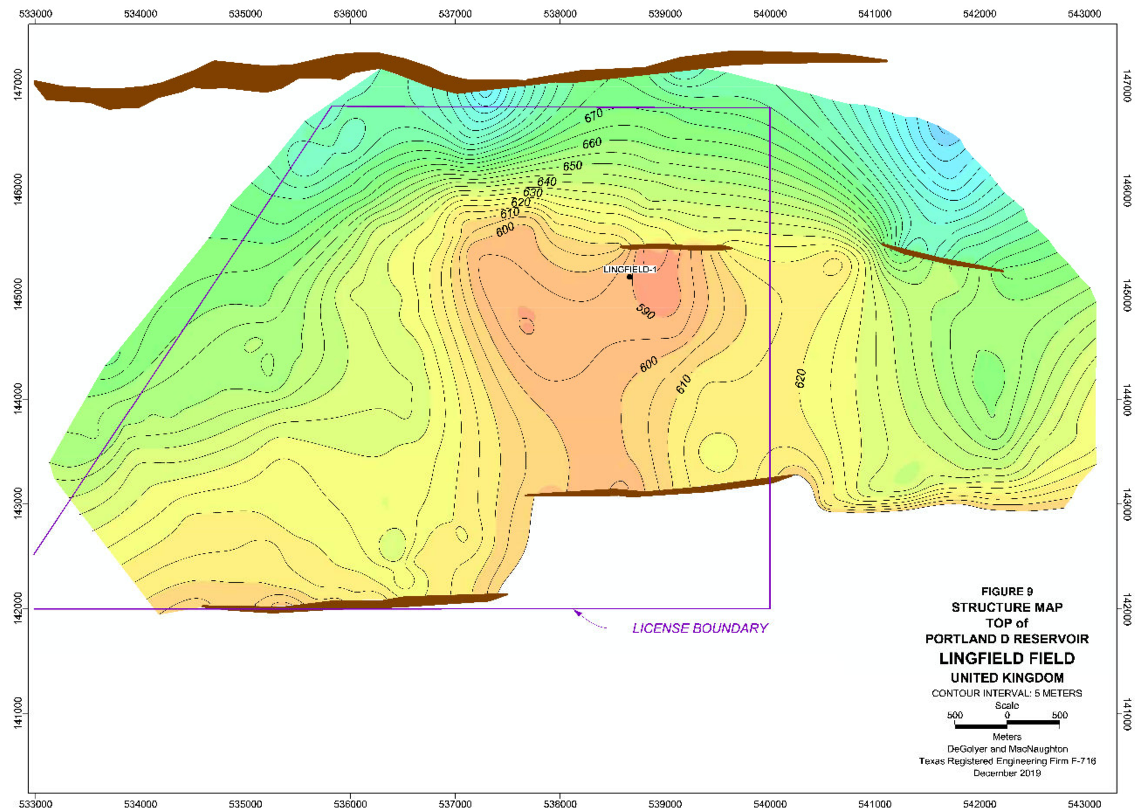
The Dunholme field was discovered in 1983 by British Petroleum with the Dunholme-1 well. The field is located in the United Kingdom in the East Midlands Platform in license AL009. The Dunholme-1 well encountered a thin oil column in the Carboniferous Westphalian-age Basal Sand reservoir. The well is 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 estimated porosity is 19.8 percent, and the estimated S_w is 58 percent. Permeability ranged 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. Estimated recovery factors used a 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 rock. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity ranged from 16 to 20 percent, S_w from 50 to 65 percent, and permeability 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. The estimated porosity ranges from 17 to 18 percent, and the estimated S_w is 45 percent. Permeability ranged from 0.1 to 0.3 millidarcy. The recovery factors used ranged 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 is 18.2 percent and average S_w is 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 used ranged from 50 to 60 percent.



The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL 179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity ranged from 12 to 18 percent, S_w from 30 to 50 percent, and permeability 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.

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2019, 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	115	447	192	274	1,067	458	480	1,871	803
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	319	2,185	2,992	449	3,069	3,074	461	3,153
Godley Bridge	0	6,750	1,164	0	12,240	2,110	0	13,999	2,414
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
Hemswell (PEDL317)	0	0	0	55	78	68	909	1,304	1,134
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	495	0	495	566	0	566
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	193	1,726	3,565	566	3,663	6,206	1,133	6,401
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	598	0	598	731	0	731	904	0	904
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,518	0	4,518
Total	**10,303**	**10,375**	**12,092**	**16,954**	**18,641**	**20,168**	**28,026**	**28,631**	**32,962**

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, 2019, 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	254	0	254	371	0	371	501	0	501
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	115	447	192	274	1,067	458	480	1,871	803
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	319	2,185	2,992	449	3,069	3,074	461	3,153
Godley Bridge	0	6,750	1,164	0	12,240	2,110	0	13,999	2,414
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
Hemswell (PEDL317)	0	0	0	55	78	68	909	1,304	1,134
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	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	0	338	495	0	495	566	0	566
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	193	1,726	3,565	566	3,663	6,206	1,133	6,401
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	598	0	598	731	0	731	904	0	904
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,518	0	4,518
Total	**9,998**	**10,350**	**11,782**	**16,338**	**18,400**	**19,510**	**26,345**	**27,123**	**31,021**

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 – A prospect can often be subclassified based on its 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.

Threshold Economic Field Size – The threshold economic field size (TEFS) is the minimum amount of the producible petroleum required to recover the total capital and operating expenditure used to establish the potential accumulation as having a potential present worth at 10 percent equal to zero using the most likely price scenario.

Probability of Development – The probability of development (P_d) is defined as the probability that a given discovery will be a viable development project. It takes into account the chance that the discovered target zone will flow the predicted hydrocarbon phase(s) at a commercial rate. It also considers the chance that the target zone can be mechanically completed and appraised in a reasonable time and in compliance with the projected cost schedule. The P_d is estimated by the quantification and product of these two chance factors.

Probability of Threshold Economic Field Size – The probability of threshold economic field size (P_{TEFS}) is defined as the probability of discovering an accumulation that is large enough to be economically viable. P_{TEFS} is estimated by using the prospective resources potential recoverable quantities distribution in conjunction with the TEFS.

The probability associated with the TEFS is estimated from the potential gross recoverable quantities distribution.

> *Probability of Economic Success* – The probability of economic success (P_e) is defined as the probability that a given discovery will be economically viable for commercial development. It takes into account P_g, TEFS, P_{TEFS}, P_d, capital costs, operating expenses, the proposed development plan, the economic model (discounted cash flow analysis), and other business and economic factors. P_e is calculated as follows:

$$P_e = P_g \times P_{TEFS} \times P_d$$

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, 35 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 prospective resources and the P_g estimates, as of December 31, 2018, 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 0.15 to 0.23.

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 two 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 prospective resources, as of December 31, 2019, 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	587	1,837	5,710	2,601	587	1,837	5,710	2,601
Lea	606	1,638	3,931	2,048	212	573	1,376	717
Statistical Aggregate	**1,539**	**3,883**	**9,124**	**4,650**	**1,031**	**2,694**	**6,706**	**3,318**

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. 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 and solution gas prospective resources, as of December 31, 2019, are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	1,409
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	1,170

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. 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.

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 36 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton

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.

Raw Natural Gas – Raw natural 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 TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	774	0	184	128	61.78	55.60	7.44	7.11	50,059	26,011	10,189	13,859	13,134
2021	805	0	183	262	58.39	52.55	7.51	7.18	50,322	22,719	10,182	17,421	16,511
2022	762	11	231	260	56.97	51.27	7.59	7.25	47,652	22,429	8,043	17,180	14,742
2023	695	22	245	293	56.54	50.89	7.67	7.33	44,401	21,293	6,309	16,799	13,047
2024	618	17	170	318	57.67	51.90	7.74	7.40	40,193	18,825	8,367	13,001	9,139
2025	562	13	110	305	58.82	52.94	7.82	7.47	36,934	17,502	3,755	15,677	9,977
2026	515	11	66	294	60.00	54.00	7.90	7.55	34,082	16,293	448	17,341	9,987
2027	468	8	37	280	61.20	55.08	7.98	7.62	31,745	15,390	0	16,355	8,527
2028	431	7	29	253	62.42	56.18	8.06	7.70	29,506	14,407	1,682	13,417	6,333
2029	400	5	24	198	63.67	57.30	8.14	7.78	27,295	13,403	981	12,911	5,518
2030	364	0	0	190	64.95	-	-	7.85	25,238	12,392	526	12,320	4,767
2031	331	0	0	184	66.25	-	-	7.93	23,371	11,476	1,787	10,108	3,539
2032	302	0	0	134	67.57	-	-	8.01	21,527	10,661	5,378	5,488	1,738
2033	254	0	0	68	68.92	-	-	8.09	18,079	8,338	7,118	2,623	754
2034	237	0	0	37	70.30	-	-	8.17	16,936	8,015	0	8,921	2,316
2035	211	0	0	17	71.71	-	-	8.25	15,271	7,141	1,337	6,793	1,597
2036	192	0	0	4	73.14	-	-	8.34	14,213	6,895	0	7,318	1,556
2037	173	0	0	0	74.60	-	-	-	12,878	6,163	3,019	3,696	713
2038	161	0	0	0	76.10	-	-	-	12,257	6,039	0	6,218	1,084
2039	150	0	0	0	77.62	-	-	-	11,669	5,929	0	5,740	906
2040	143	0	0	0	79.17	-	-	-	11,124	5,834	0	5,290	756
2041	130	0	0	0	80.75	-	-	-	10,562	5,744	0	4,818	625
2042	121	0	0	0	82.37	-	-	-	10,047	5,671	0	4,376	513
2043	114	0	0	0	84.02	-	-	-	9,579	5,612	0	3,967	420
2044	107	0	0	0	85.70	-	-	-	9,107	5,557	0	3,550	341
Subtotal	**9,020**	**94**	**1,279**	**3,225**					**614,047**	**299,739**	**69,121**	**245,187**	**128,540**
Remaining	658	0	0	0					62,021	42,021	62,455	(42,455)	(1,621)
Total	**9,678**	**94**	**1,279**	**3,225**					**676,068**	**341,760**	**131,576**	**202,732**	**126,919**

Present Worth at (10^3U.S.$)	
8 Percent	139,719
12 Percent	115,942
15 Percent	102,330

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

Base Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	802	0	184	128	61.78	55.60	7.44	7.11	51,950	26,606	10,189	15,155	14,365
2021	855	0	183	262	58.39	52.55	7.51	7.18	53,143	23,654	10,182	19,307	18,299
2022	828	11	231	260	56.97	51.27	7.59	7.25	51,470	23,675	8,043	19,752	16,947
2023	775	22	283	293	56.54	50.89	7.67	7.33	49,067	22,843	6,309	19,915	15,468
2024	725	19	266	326	57.67	51.90	7.74	7.40	47,196	21,801	4,091	21,304	14,977
2025	677	15	213	324	58.82	52.94	7.82	7.47	44,767	20,669	3,755	20,343	12,946
2026	620	12	145	325	60.00	54.00	7.90	7.55	41,504	18,669	4,448	18,387	10,591
2027	587	10	92	325	61.20	55.08	7.98	7.62	39,543	17,835	0	21,708	11,325
2028	549	8	53	324	62.42	56.18	8.06	7.70	37,794	17,027	466	20,301	9,583
2029	522	7	30	316	63.67	57.30	8.14	7.78	36,141	16,361	0	19,780	8,450
2030	486	5	24	290	64.95	58.46	8.22	7.85	34,482	15,577	1,750	17,155	6,635
2031	462	5	20	240	66.25	59.63	8.30	7.93	32,912	14,768	1,020	17,124	5,999
2032	436	0	0	233	67.57	-	-	8.01	31,444	13,931	547	16,966	5,378
2033	415	0	0	226	68.92	-	-	8.09	30,345	13,550	0	16,795	4,821
2034	391	0	0	221	70.30	-	-	8.17	29,392	13,228	0	16,164	4,199
2035	374	0	0	215	71.71	-	-	8.25	28,382	12,906	0	15,476	3,639
2036	328	0	0	211	73.14	-	-	8.34	25,834	10,883	7,554	7,397	1,573
2037	314	0	0	205	74.60	-	-	8.42	25,081	10,684	0	14,397	2,772
2038	292	0	0	199	76.10	-	-	8.50	24,133	10,222	6,056	7,855	1,369
2039	275	0	0	196	77.62	-	-	8.59	23,074	9,622	2,094	11,358	1,793
2040	266	0	0	191	79.17	-	-	8.68	22,559	9,508	0	13,051	1,864
2041	252	0	0	187	80.75	-	-	8.76	21,936	9,378	0	12,558	1,624
2042	239	0	0	184	82.37	-	-	8.85	21,290	9,155	1,105	11,030	1,292
2043	228	0	0	179	84.02	-	-	8.94	20,786	9,065	0	11,721	1,243
2044	219	0	0	176	85.70	-	-	9.03	20,351	8,996	0	11,355	1,090
Subtotal	**11,917**	**114**	**1,724**	**6,036**					**844,576**	**380,613**	**67,609**	**396,354**	**178,242**
Remaining	2,383	0	0	1,708					245,244	117,533	74,627	53,084	4,403
Total	**14,300**	**114**	**1,724**	**7,744**					**1,089,820**	**498,146**	**142,236**	**449,438**	**182,645**

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	210,342
12 Percent	161,075
15 Percent	136,659

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Product Prices								
Year	Oil (10^{3}bbl)	Condensate (10^{3}bbl)	Sales Gas Export (10^{6}ft^3)	Sales Gas to Power (10^{6}ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/10^{3}ft^3)	Sales Gas to Power (U.S.$/10^{3}ft^3)	Future Gross Revenue (10^{3}U.S.$)	Operating Expenses (10^{3}U.S.$)	Abandonment and Capital Costs (10^{3}U.S.$)	Future Net Revenue (10^{3}U.S.$)	Present Worth at 10 Percent (10^{3}U.S.$)
2020	832	0	184	128	61.78	55.60	7.44	7.11	53,613	27,042	10,189	16,382	15,528
2021	899	0	183	262	58.39	52.55	7.51	7.18	55,896	24,534	10,182	21,180	20,078
2022	891	11	232	260	56.97	51.27	7.59	7.25	54,895	24,773	8,043	22,079	18,945
2023	846	23	286	293	56.54	50.89	7.67	7.33	53,170	24,481	5,508	23,181	18,002
2024	797	20	272	326	57.67	51.90	7.74	7.40	51,614	23,537	4,091	23,986	16,866
2025	746	17	256	324	58.82	52.94	7.82	7.47	49,317	22,138	4,588	22,591	14,378
2026	711	14	246	325	60.00	54.00	7.90	7.55	47,776	21,313	0	26,463	15,245
2027	675	12	201	325	61.20	55.08	7.98	7.62	46,061	20,498	0	25,563	13,333
2028	644	10	133	324	62.42	56.18	8.06	7.70	44,370	19,738	0	24,632	11,626
2029	615	9	84	325	63.67	57.30	8.14	7.78	42,672	19,004	0	23,668	10,116
2030	581	7	47	324	64.95	58.46	8.22	7.85	41,173	18,281	485	22,407	8,667
2031	540	7	27	312	66.25	59.63	8.30	7.93	38,814	16,638	6,696	15,480	5,418
2032	517	5	24	248	67.57	60.81	8.38	8.01	37,462	15,884	1,041	20,537	6,510
2033	494	4	20	241	68.92	62.03	8.47	8.09	36,432	15,480	0	20,952	6,011
2034	472	0	0	236	70.30	-	-	8.17	35,122	14,690	569	19,863	5,160
2035	450	0	0	230	71.71	-	-	8.25	34,244	14,375	0	19,869	4,672
2036	435	0	0	227	73.14	-	-	8.34	33,609	14,140	0	19,469	4,142
2037	392	0	0	220	74.60	-	-	8.42	31,047	12,093	7,705	11,249	2,168
2038	375	0	0	216	76.10	-	-	8.50	30,517	11,932	0	18,585	3,241
2039	364	0	0	211	77.62	-	-	8.59	30,004	11,783	0	18,221	2,876
2040	350	0	0	208	79.17	-	-	8.68	29,588	11,666	0	17,922	2,560
2041	338	0	0	203	80.75	-	-	8.76	29,024	11,523	0	17,501	2,262
2042	326	0	0	199	82.37	-	-	8.85	28,567	11,411	0	17,156	2,010
2043	314	0	0	195	84.02	-	-	8.94	28,118	11,309	0	16,809	1,783
2044	299	0	0	192	85.70	-	-	9.03	27,299	10,762	2,312	14,225	1,365
Subtotal	**13,903**	**139**	**2,195**	**6,354**					**990,404**	**429,025**	**61,409**	**499,970**	**212,962**
Remaining	3,630	0	0	2,833					377,570	160,097	87,113	130,360	8,334
Total	**17,533**	**139**	**2,195**	**9,187**					**1,367,974**	**589,122**	**148,522**	**630,330**	**221,296**

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^{3}U.S.$)	
8 Percent	259,088
12 Percent	192,656
15 Percent	161,111

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	749	0	184	128	51.78	-	6.44	6.11	40,739	26,011	14,658	70	66
2021	773	0	183	262	48.39	-	6.51	6.18	40,237	20,971	10,952	8,314	7,880
2022	731	0	183	260	46.97	-	6.59	6.25	37,188	20,062	5,608	11,518	9,883
2023	658	0	149	293	46.54	-	6.67	6.33	33,415	18,230	7,033	8,152	6,332
2024	595	0	93	318	47.67	-	6.74	6.40	31,056	16,825	5,645	8,586	6,036
2025	541	0	50	305	48.82	-	6.82	6.47	28,696	15,617	4,194	8,885	5,658
2026	497	0	19	294	50.00	-	6.90	6.55	26,839	14,733	0	12,106	6,973
2027	448	0	0	280	51.20	-	-	6.62	24,899	13,662	4,871	6,366	3,319
2028	415	0	0	206	52.42	-	-	6.70	23,181	12,699	961	9,521	4,495
2029	344	0	0	198	53.67	-	-	6.78	19,707	9,945	6,576	3,186	1,361
2030	317	0	0	190	54.95	-	-	6.85	18,754	9,588	0	9,166	3,545
2031	295	0	0	184	56.25	-	-	6.93	17,864	9,267	0	8,597	3,012
2032	275	0	0	134	57.57	-	-	7.01	16,762	8,836	0	7,926	2,513
2033	252	0	0	68	58.92	-	-	7.09	15,354	8,221	925	6,208	1,781
2034	228	0	0	22	60.30	-	-	7.17	13,855	7,270	1,311	5,274	1,371
2035	201	0	0	17	61.71	-	-	7.25	12,592	6,557	1,940	4,095	962
2036	185	0	0	4	63.14	-	-	7.34	11,755	6,321	0	5,434	1,156
2037	173	0	0	0	64.60	-	-	-	11,150	6,163	0	4,987	961
2038	161	0	0	0	66.10	-	-	-	10,651	6,039	0	4,612	804
2039	150	0	0	0	67.62	-	-	-	10,164	5,929	0	4,235	670
2040	143	0	0	0	69.17	-	-	-	9,717	5,834	0	3,883	555
2041	130	0	0	0	70.75	-	-	-	9,255	5,744	0	3,511	455
2042	121	0	0	0	72.37	-	-	-	8,828	5,671	0	3,157	369
2043	114	0	0	0	74.02	-	-	-	8,438	5,612	0	2,826	300
2044	107	0	0	0	75.70	-	-	-	8,045	5,557	0	2,488	239
Subtotal	**8,603**	**0**	**861**	**3,163**					**489,141**	**271,364**	**64,674**	**153,103**	**70,696**
Remaining	561	0	0	0					47,157	33,144	60,607	(46,594)	(2,399)
Total	**9,164**	**0**	**861**	**3,163**					**536,298**	**304,508**	**125,281**	**106,509**	**68,297**

Present Worth at (10^3U.S.$)	
8 Percent	76,140
12 Percent	61,455
15 Percent	52,956

TABLE A-5
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

	Net				Product Prices								
Year	**Oil (10^3bbl)**	**Condensate (10^3bbl)**	**Sales Gas Export (10^6ft^3)**	**Sales Gas to Power (10^6ft^3)**	**Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**Sales Gas Export (U.S.$/$10^3$ft^3)**	**Sales Gas to Power (U.S.$/$10^3$ft^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.$)**
2020	777	0	184	128	51.78	-	6.44	6.11	42,282	26,572	14,658	1,052	998
2021	820	0	183	262	48.39	-	6.51	6.18	42,482	21,826	10,952	9,704	9,196
2022	794	0	183	260	46.97	-	6.59	6.25	40,219	21,211	5,608	13,400	11,498
2023	748	0	183	293	46.54	-	6.67	6.33	37,754	20,306	5,508	11,940	9,273
2024	702	0	184	326	47.67	-	6.74	6.40	36,733	19,539	4,091	13,103	9,212
2025	656	0	147	324	48.82	-	6.82	6.47	35,172	18,645	3,755	12,772	8,130
2026	609	0	90	325	50.00	-	6.90	6.55	33,268	17,415	2,065	13,788	7,943
2027	578	0	48	325	51.20	-	6.98	6.62	31,974	16,726	0	15,248	7,954
2028	544	0	16	324	52.42	-	7.06	6.70	30,886	16,145	0	14,741	6,960
2029	506	0	0	316	53.67	-	-	6.78	29,178	14,995	1,718	12,465	5,326
2030	474	0	0	245	54.95	-	-	6.85	27,884	14,176	1,000	12,708	4,915
2031	448	0	0	240	56.25	-	-	6.93	26,735	13,448	5,273	8,014	2,807
2032	422	0	0	233	57.57	-	-	7.01	26,021	13,096	0	12,925	4,097
2033	369	0	0	226	58.92	-	-	7.09	23,262	10,724	7,118	5,420	1,556
2034	349	0	0	221	60.30	-	-	7.17	22,705	10,506	0	12,199	3,169
2035	335	0	0	215	61.71	-	-	7.25	22,082	10,274	0	11,808	2,776
2036	317	0	0	211	63.14	-	-	7.34	21,625	10,105	0	11,520	2,452
2037	303	0	0	205	64.60	-	-	7.42	21,065	9,918	0	11,147	2,147
2038	286	0	0	199	66.10	-	-	7.50	20,583	9,762	0	10,821	1,887
2039	274	0	0	196	67.62	-	-	7.59	20,000	9,499	1,042	9,459	1,494
2040	264	0	0	191	69.17	-	-	7.68	19,615	9,386	0	10,229	1,460
2041	243	0	0	187	70.75	-	-	7.76	18,626	8,752	2,184	7,690	996
2042	232	0	0	184	72.37	-	-	7.85	18,233	8,652	0	9,581	1,122
2043	222	0	0	179	74.02	-	-	7.94	17,857	8,563	0	9,294	985
2044	213	0	0	176	75.70	-	-	8.03	17,539	8,495	0	9,044	869
Subtotal	**11,485**	**0**	**1,218**	**5,991**					**683,780**	**348,736**	**64,972**	**270,072**	**109,222**
Remaining	2,295	0	0	1,708					211,879	109,266	70,807	31,806	3,143
Total	**13,780**	**0**	**1,218**	**7,699**					**895,659**	**458,002**	**135,779**	**301,878**	**112,365**

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

Present Worth at (10^3U.S.$)	
8 Percent	132,042
12 Percent	97,164
15 Percent	80,186

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

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	801	0	184	128	51.78	-	6.44	6.11	43,400	26,971	14,658	1,771	1,677
2021	863	0	183	262	48.39	-	6.51	6.18	44,662	22,621	10,952	11,089	10,511
2022	854	0	183	260	46.97	-	6.59	6.25	42,918	22,200	5,608	15,110	12,966
2023	809	0	183	293	46.54	-	6.67	6.33	40,597	21,371	5,508	13,718	10,655
2024	764	0	184	326	47.67	-	6.74	6.40	39,805	20,676	4,091	15,038	10,576
2025	722	0	182	324	48.82	-	6.82	6.47	38,698	19,918	3,755	15,025	9,559
2026	689	0	183	325	50.00	-	6.90	6.55	37,800	19,274	0	18,526	10,672
2027	648	0	147	325	51.20	-	6.98	6.62	36,300	18,196	2,106	15,998	8,342
2028	618	0	88	324	52.42	-	7.06	6.70	35,231	17,600	0	17,631	8,323
2029	592	0	45	325	53.67	-	7.14	6.78	34,135	17,011	0	17,124	7,317
2030	561	0	14	324	54.95	-	7.22	6.85	33,251	16,524	0	16,727	6,470
2031	539	0	0	312	56.25	-	-	6.93	32,436	16,081	0	16,355	5,727
2032	515	0	0	248	57.57	-	-	7.01	31,457	15,369	1,041	15,047	4,770
2033	458	0	0	241	58.92	-	-	7.09	28,671	12,914	7,118	8,639	2,479
2034	440	0	0	236	60.30	-	-	7.17	28,234	12,693	0	15,541	4,036
2035	421	0	0	230	61.71	-	-	7.25	27,716	12,457	0	15,259	3,588
2036	401	0	0	227	63.14	-	-	7.34	26,870	11,769	1,973	13,128	2,794
2037	384	0	0	220	64.60	-	-	7.42	26,412	11,581	0	14,831	2,857
2038	368	0	0	216	66.10	-	-	7.50	26,043	11,428	0	14,615	2,549
2039	357	0	0	211	67.62	-	-	7.59	25,688	11,287	0	14,401	2,272
2040	343	0	0	208	69.17	-	-	7.68	25,412	11,176	0	14,236	2,033
2041	332	0	0	203	70.75	-	-	7.76	25,000	11,039	0	13,961	1,808
2042	316	0	0	199	72.37	-	-	7.85	24,352	10,602	6,556	7,194	840
2043	303	0	0	195	74.02	-	-	7.94	24,039	10,505	0	13,534	1,436
2044	295	0	0	192	75.70	-	-	8.03	23,804	10,432	0	13,372	1,282
Subtotal	**13,393**	**0**	**1,576**	**6,354**					**802,931**	**391,695**	**63,366**	**347,870**	**135,539**
Remaining	3,571	0	0	2,833					333,430	154,791	78,707	99,932	6,787
Total	**16,964**	**0**	**1,576**	**9,187**					**1,136,361**	**546,486**	**142,073**	**447,802**	**142,326**

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

Present Worth at (10^3U.S.$)	
8 Percent	170,256
12 Percent	121,387
15 Percent	98,630

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-7
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

High Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	774	0	184	128	71.78	64.60	8.44	8.11	58,106	26,011	10,189	21,906	20,761
2021	805	0	183	262	68.39	61.55	8.51	8.18	58,827	22,719	10,182	25,926	24,573
2022	762	11	231	260	66.97	60.27	8.59	8.25	55,869	22,429	8,043	25,397	21,795
2023	695	22	245	293	66.54	59.89	8.67	8.33	52,083	21,293	6,309	24,481	19,010
2024	618	17	170	318	67.67	60.90	8.74	8.40	47,010	18,825	8,367	19,818	13,939
2025	562	13	110	305	68.82	61.94	8.82	8.47	43,096	17,502	3,755	21,839	13,901
2026	515	11	66	294	70.00	63.00	8.90	8.55	39,662	16,293	448	22,921	13,205
2027	468	8	37	280	71.20	64.08	8.98	8.62	36,854	15,390	0	21,464	11,193
2028	431	7	29	253	72.42	65.18	9.06	8.70	34,165	14,407	1,682	18,076	8,534
2029	400	5	24	198	73.67	66.30	9.14	8.78	31,533	13,403	981	17,149	7,326
2030	364	0	0	190	74.95	-	-	8.85	29,082	12,392	526	16,164	6,252
2031	331	0	0	184	76.25	-	-	8.93	26,866	11,476	1,787	13,603	4,764
2032	302	0	0	134	77.57	-	-	9.01	24,684	10,661	5,378	8,645	2,741
2033	254	0	0	68	78.92	-	-	9.09	20,692	8,338	7,118	5,236	1,504
2034	237	0	0	37	80.30	-	-	9.17	19,343	8,015	0	11,328	2,942
2035	211	0	0	17	81.71	-	-	9.25	17,396	7,141	1,337	8,918	2,098
2036	192	0	0	4	83.14	-	-	9.34	16,156	6,895	0	9,261	1,970
2037	173	0	0	0	84.60	-	-	-	14,603	6,163	3,019	5,421	1,043
2038	161	0	0	0	86.10	-	-	-	13,869	6,039	0	7,830	1,365
2039	150	0	0	0	87.62	-	-	-	13,173	5,929	0	7,244	1,142
2040	143	0	0	0	89.17	-	-	-	12,527	5,834	0	6,693	956
2041	130	0	0	0	90.75	-	-	-	11,869	5,744	0	6,125	793
2042	121	0	0	0	92.37	-	-	-	11,269	5,671	0	5,598	656
2043	114	0	0	0	94.02	-	-	-	10,718	5,612	0	5,106	541
2044	107	0	0	0	95.70	-	-	-	10,168	5,557	0	4,611	443
Subtotal	**9,020**	**94**	**1,279**	**3,225**					**709,620**	**299,739**	**69,121**	**340,760**	**183,447**
Remaining	658	0	0	0					68,618	42,021	62,455	(35,858)	(1,229)
Total	**9,678**	**94**	**1,279**	**3,225**					**778,238**	**341,760**	**131,576**	**304,902**	**182,218**

Present Worth at (10^3U.S.$)	
8 Percent	200,452
12 Percent	166,755
15 Percent	147,746

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

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)	Product Prices Oil (U.S.$/bbl)	Product Prices Condensate (U.S.$/bbl)	Product Prices Sales Gas Export (U.S.$/$10^3$ft^3)	Product Prices Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	802	0	184	128	71.78	64.60	8.44	8.11	60,303	26,606	10,189	23,508	22,282
2021	855	0	183	262	68.39	61.55	8.51	8.18	62,134	23,654	10,182	28,298	26,819
2022	828	11	231	260	66.97	60.27	8.59	8.25	60,354	23,675	8,043	28,636	24,570
2023	775	22	283	293	66.54	59.89	8.67	8.33	57,558	22,843	6,309	28,406	22,064
2024	725	19	266	326	67.67	60.90	8.74	8.40	55,194	21,801	4,091	29,302	20,604
2025	677	15	213	324	68.82	61.94	8.82	8.47	52,222	20,669	3,755	27,798	17,693
2026	620	12	145	325	70.00	63.00	8.90	8.55	48,292	18,669	4,448	25,175	14,504
2027	587	10	92	325	71.20	64.08	8.98	8.62	45,899	17,835	0	28,064	14,636
2028	549	8	53	324	72.42	65.18	9.06	8.70	43,754	17,027	466	26,261	12,399
2029	522	7	30	316	73.67	66.30	9.14	8.78	41,741	16,361	0	25,380	10,844
2030	486	5	24	290	74.95	67.46	9.22	8.85	39,721	15,577	1,750	22,394	8,663
2031	462	5	20	240	76.25	68.63	9.30	8.93	37,830	14,768	1,020	22,042	7,718
2032	436	0	0	233	77.57	-	-	9.01	36,051	13,931	547	21,573	6,839
2033	415	0	0	226	78.92	-	-	9.09	34,710	13,550	0	21,160	6,070
2034	391	0	0	221	80.30	-	-	9.17	33,539	13,228	0	20,311	5,276
2035	374	0	0	215	81.71	-	-	9.25	32,306	12,906	0	19,400	4,562
2036	328	0	0	211	83.14	-	-	9.34	29,340	10,883	7,554	10,903	2,318
2037	314	0	0	205	84.60	-	-	9.42	28,415	10,684	0	17,731	3,416
2038	292	0	0	199	86.10	-	-	9.50	27,279	10,222	6,056	11,001	1,919
2039	275	0	0	196	87.62	-	-	9.59	26,026	9,622	2,094	14,310	2,258
2040	266	0	0	191	89.17	-	-	9.68	25,388	9,508	0	15,880	2,269
2041	252	0	0	187	90.75	-	-	9.76	24,640	9,378	0	15,262	1,974
2042	239	0	0	184	92.37	-	-	9.85	23,861	9,155	1,105	13,601	1,592
2043	228	0	0	179	94.02	-	-	9.94	23,245	9,065	0	14,180	1,504
2044	219	0	0	176	95.70	-	-	10.03	22,717	8,996	0	13,721	1,318
Subtotal	**11,917**	**114**	**1,724**	**6,036**					**972,519**	**380,613**	**67,609**	**524,297**	**244,111**
Remaining	2,383	0	0	1,708					270,785	117,533	74,627	78,625	5,676
Total	**14,300**	**114**	**1,724**	**7,744**					**1,243,304**	**498,146**	**142,236**	**602,922**	**249,787**

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

Present Worth at (10^3U.S.$)	
8 Percent	285,866
12 Percent	221,631
15 Percent	189,633

TABLE A-9
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2019
with interests attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2020	832	0	184	128	71.78	64.60	8.44	8.11	62,233	27,042	10,189	25,002	23,701
2021	899	0	183	262	68.39	61.55	8.51	8.18	65,359	24,534	10,182	30,643	29,045
2022	891	11	232	260	66.97	60.27	8.59	8.25	64,385	24,773	8,043	31,569	27,086
2023	846	23	286	293	66.54	59.89	8.67	8.33	62,382	24,481	5,508	32,393	25,158
2024	797	20	272	326	67.67	60.90	8.74	8.40	60,379	23,537	4,091	32,751	23,027
2025	746	17	256	324	68.82	61.94	8.82	8.47	57,530	22,138	4,588	30,804	19,606
2026	711	14	246	325	70.00	63.00	8.90	8.55	55,572	21,313	0	34,259	19,739
2027	675	12	201	325	71.20	64.08	8.98	8.62	53,450	20,498	0	32,952	17,181
2028	644	10	133	324	72.42	65.18	9.06	8.70	51,360	19,738	0	31,622	14,927
2029	615	9	84	325	73.67	66.30	9.14	8.78	49,281	19,004	0	30,277	12,938
2030	581	7	47	324	74.95	67.46	9.22	8.85	47,435	18,281	485	28,669	11,087
2031	540	7	27	312	76.25	68.63	9.30	8.93	44,603	16,638	6,696	21,269	7,450
2032	517	5	24	248	77.57	69.81	9.38	9.01	42,954	15,884	1,041	26,029	8,249
2033	494	4	20	241	78.92	71.03	9.47	9.09	41,671	15,480	0	26,191	7,514
2034	472	0	0	236	80.30	-	-	9.17	40,080	14,690	569	24,821	6,446
2035	450	0	0	230	81.71	-	-	9.25	38,984	14,375	0	24,609	5,784
2036	435	0	0	227	83.14	-	-	9.34	38,172	14,140	0	24,032	5,116
2037	392	0	0	220	84.60	-	-	9.42	35,180	12,093	7,705	15,382	2,963
2038	375	0	0	216	86.10	-	-	9.50	34,502	11,932	0	22,570	3,937
2039	364	0	0	211	87.62	-	-	9.59	33,846	11,783	0	22,063	3,483
2040	350	0	0	208	89.17	-	-	9.68	33,306	11,666	0	21,640	3,092
2041	338	0	0	203	90.75	-	-	9.76	32,604	11,523	0	21,081	2,727
2042	326	0	0	199	92.37	-	-	9.85	32,019	11,411	0	20,608	2,412
2043	314	0	0	195	94.02	-	-	9.94	31,454	11,309	0	20,145	2,134
2044	299	0	0	192	95.70	-	-	10.03	30,471	10,762	2,312	17,397	1,668
Subtotal	**13,903**	**139**	**2,195**	**6,354**					**1,139,212**	**429,025**	**61,409**	**648,778**	**286,470**
Remaining	3,630	0	0	2,833					416,706	160,097	87,113	169,496	10,204
Total	**17,533**	**139**	**2,195**	**9,187**					**1,555,918**	**589,122**	**148,522**	**818,274**	**296,674**

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

Present Worth at (10^3U.S.$)	
8 Percent	344,749
12 Percent	260,107
15 Percent	219,557