DeGolyer and MacNaughton
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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

June 10, 2024

The Directors of
Harbour Energy PLC
23 Lower Belgrave Street
London SW1W ONR
United Kingdom

Barclays Bank PLC
One Churchill Place
London E14 5HP
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2023, of the extent of the proved, probable, and possible oil, condensate, liquefied petroleum gas (LPG), and sales gas reserves, of the value of the proved (1P), proved-plus-probable (2P), and proved-plus-probable-plus-possible (3P) reserves, and of the extent of the 1C, 2C, and 3C contingent resources of certain properties in eight countries in which Wintershall Dea GmbH (Wintershall Dea) has represented it holds an interest: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. For the purposes of this report, the properties located in Algeria, Egypt, and Libya evaluated herein are grouped together as "North Africa" in certain instances.

Estimates of reserves and contingent 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 for listing companies in the United Kingdom. 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.

This report is compliant with the Competent Person's Report requirements as published in the United Kingdom Financial Conduct Authority Primary Market Technical Note TN/619.1 "Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers" (FCA Technical Note TN/619.1).

In addition, this report has been prepared in accordance with the requirements of the Prospectus Regulation Rules of the FCA as set forth under Section 73A of the Financial Services and Markets Act 2000 (FSMA), as amended, and the Listing Rules of the FCA as set forth under Part VI of the FSMA. For the purposes of Prospectus Regulation Rule 5.3.2 R(2)(f), we accept responsibility for the information contained in this report and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that this report makes no omission likely to affect its import.

Reserves estimated in this report are expressed as gross reserves, working interest reserves, and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2023. Working interest reserves are defined as the product of the working interest and the gross reserves. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Wintershall Dea after deducting all interests held by others.

Some fields within certain countries evaluated in this report are subject to production sharing agreements (PSA) in various forms. The terms of a PSA allow for working interest participants to be reimbursed for portions of capital costs and operating expenses and to share in the profits. In addition, the income tax paid on behalf of Wintershall Dea may also be credited to Wintershall Dea in some instances. The reimbursements, credits, and profit proceeds net to Wintershall Dea, based on its working interest share, are converted to a barrel of oil equivalent or standard cubic foot of gas equivalent by dividing by product prices to estimate the Wintershall Dea "entitlement quantities." These entitlement quantities are equivalent, in principle, to net reserves and are termed "net Wintershall Dea quantities" herein. The ratio of the net Wintershall Dea quantities to the gross quantities is termed an "entitlement interest." In this report, Wintershall Dea net reserves for certain properties subject to these agreements is the entitlement based on Wintershall Dea working interest.

Detailed explanations of the terms of the applicable PSA are included under the Valuation of Reserves heading of this report.

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 or on behalf of Wintershall Dea and forecast prices, expenses, and costs as described herein. Prices, expenses, and costs provided were expressed in European Union euros (€), Danish kroner (DKK), Norwegian kroner (NOK), and United States dollars (U.S.$). All monetary values in this report are expressed in U.S.$ unless noted otherwise. The currency exchange rates used herein are included under the Valuation of Reserves heading of this report, along with a detailed explanation of the forecast price, expense, and cost assumptions.

Values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this report are expressed in terms of 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, capital costs, abandonment costs, royalty, and taxes from future gross revenue. Operating expenses include field operating expenses, the estimated expenses of direct supervision, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and certain field maintenance costs. Abandonment costs are represented by Wintershall Dea to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. Consideration of German corporate income taxes were not included in this report; however, field-level taxes for fields in Germany are included in the evaluation herein. Present worth is defined as the future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using a discount rate of 10 percent are reported in detail and values using discount rates of 6, 8, and 12 percent are reported as totals.

The contingent resources estimated in this report are expressed as gross contingent resources, working interest 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, 2023. Working interest contingent resources are defined as the product of the working interest and the gross contingent resources. For the purposes of this report, net contingent resources are defined as being equivalent to the working interest contingent resources.

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

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

Estimates of reserves and revenue and contingent 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 was provided by Wintershall Dea on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests held by Wintershall Dea 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 Wintershall Dea. In the preparation of this report, we have relied upon information furnished by or directed to be furnished by Wintershall Dea with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, concession area 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 Wintershall Dea involved with the assessment and implementation of development of Wintershall Dea's 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 was made by us. However, existing production data, reports from third parties, and photographic evidence of the fields were considered adequate because the fields are in established producing venues.

Executive Summary

Wintershall Dea has represented that it holds certain interests in 140 fields and discoveries in 8 countries: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. These interests are evaluated herein.

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, 2023, have been considered to be valid for their stated terms, as represented by Wintershall Dea.

The estimated reserves, revenue, and contingent resources are summarized herein. The barrels of oil equivalent are based on the summation of oil, condensate, LPG, and sales gas, where sales gas is converted to oil equivalent volumes using a factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent (boe).

Estimation of Reserves

The estimated gross proved, probable, and possible reserves, as of December 31, 2023, 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 (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	26,414	19,186	2,987,893	579,152
Probable	7,374	5,270	1,000,454	191,297
Proved plus Probable	33,788	24,456	3,988,347	770,449
Possible	6,424	2,437	1,072,002	200,290
Proved plus Probable plus Possible	40,212	26,893	5,060,349	970,739
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	67,866	0	326,648	126,196
Probable	34,849	0	159,894	63,402
Proved plus Probable	102,715	0	486,542	189,598
Possible	20,850	0	119,816	42,245
Proved plus Probable plus Possible	123,565	0	606,358	231,843
Mexico				
Proved	91,518	0	50,299	100,500
Probable	24,681	0	27,095	29,519
Proved plus Probable	116,199	0	77,394	130,019
Possible	16,562	0	19,577	20,058
Proved plus Probable plus Possible	132,761	0	96,971	150,077
North Africa				
Proved	67,471	111	975,118	241,710
Probable	13,438	209	514,002	105,433
Proved plus Probable	80,909	320	1,489,120	347,143
Possible	14,431	200	483,582	100,985
Proved plus Probable plus Possible	95,340	520	1,972,702	448,128
Norway				
Proved	843,535	160,286	7,591,809	2,359,501
Probable	217,812	61,795	2,231,688	678,123
Proved plus Probable	1,061,347	222,081	9,823,497	3,037,624
Possible	224,067	54,642	2,596,081	742,295
Proved plus Probable plus Possible	1,285,414	276,723	12,419,578	3,779,919
Total Proved	**1,096,804**	**179,583**	**11,931,767**	**3,407,059**
Total Probable	**298,154**	**67,274**	**3,933,133**	**1,067,774**
Total Proved plus Probable	**1,394,958**	**246,857**	**15,864,900**	**4,474,833**
Total Possible	**282,334**	**57,279**	**4,291,058**	**1,105,873**
Total Proved plus Probable plus Possible	**1,677,292**	**304,136**	**20,155,958**	**5,580,706**

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 a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated working interest proved, probable, and possible reserves, as of December 31, 2023, 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):

	Working Interest Reserves			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	35,712	0	22,896	39,801
Probable	10,223	0	12,678	12,487
Proved plus Probable	45,935	0	35,574	52,288
Possible	6,919	0	9,168	8,556
Proved plus Probable plus Possible	52,854	0	44,742	60,844
North Africa				
Proved	9,204	111	249,044	53,787
Probable	2,804	209	138,481	27,742
Proved plus Probable	12,008	320	387,525	81,529
Possible	2,919	200	123,211	25,121
Proved plus Probable plus Possible	14,927	520	510,736	106,650
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**243,062**	**47,293**	**2,728,956**	**777,669**
Total Probable	**94,681**	**23,452**	**1,241,235**	**339,782**
Total Proved plus Probable	**337,743**	**70,745**	**3,970,191**	**1,117,451**
Total Possible	**77,272**	**16,667**	**1,246,026**	**316,444**
Total Proved plus Probable plus Possible	**415,015**	**87,412**	**5,216,217**	**1,433,895**

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 a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated net interest proved, probable, and possible reserves, as of December 31, 2023, 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 (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	22,549	0	20,018	26,124
Probable	6,317	0	11,291	8,333
Proved plus Probable	28,866	0	31,309	34,457
Possible	4,410	0	8,138	5,863
Proved plus Probable plus Possible	33,276	0	39,447	40,320
North Africa				
Proved	5,517	61	133,124	29,350
Probable	1,933	113	82,195	16,724
Proved plus Probable	7,450	174	215,319	46,074
Possible	2,089	108	79,360	16,368
Proved plus Probable plus Possible	9,539	282	294,679	62,442
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**226,212**	**47,243**	**2,610,158**	**739,555**
Total Probable	**89,904**	**23,356**	**1,183,562**	**324,610**
Total Proved plus Probable	**316,116**	**70,599**	**3,793,720**	**1,064,165**
Total Possible	**73,933**	**16,575**	**1,201,145**	**304,998**
Total Proved plus Probable plus Possible	**390,049**	**87,174**	**4,994,865**	**1,369,163**

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 a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

Valuation of Reserves

Revenue values in this report were estimated using initial prices, expenses, and costs provided by or on behalf of Wintershall Dea. 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 Prices scenario and two price sensitivities.

The two price sensitivities are labeled as Low Case Prices and High Case Prices, which represent price scenarios that are 10-percent lower and 10-percent higher than the Base Case Prices scenario, respectively. Further explanation of the Base Case Prices and two price sensitivity assumptions are included under the Valuation of Reserves heading of this report.

The estimated future net revenue and present worth of the future net revenue discounted at 6, 8, 10, and 12 percent to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of December 31, 2023, 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				
	Future Net Revenue (10^3U.S.$)	Present Worth at 6 Percent (10^3U.S.$)	Present Worth at 8 Percent (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Present Worth at 12 Percent (10^3U.S.$)
Proved					
Base Case Prices	10,414,162	8,508,852	7,983,892	7,371,082	7,087,189
Low Case Prices	8,804,685	7,289,099	6,854,990	6,336,988	6,102,659
High Case Prices	12,024,458	9,719,797	9,102,196	8,393,520	8,058,669
Proved plus Probable					
Base Case Prices	16,474,084	12,568,051	11,593,251	10,528,176	10,001,149
Low Case Prices	14,143,898	10,876,591	10,047,673	9,130,797	8,684,333
High Case Prices	18,799,670	14,243,953	13,122,214	11,908,822	11,301,044
Proved plus Probable plus Possible					
Base Case Prices	22,106,234	16,196,493	14,779,665	13,282,049	12,515,256
Low Case Prices	19,107,183	14,088,821	12,871,823	11,573,915	10,916,575
High Case Prices	25,101,048	18,289,707	16,672,921	14,976,320	14,100,595

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 Prices scenario projected to an economic limit, and quantities in the sensitivity cases are those included to the limit of projected Base Case Prices 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.

Estimation of Contingent Resources

Contingent resources were estimated for oil, condensate, LPG, and sales gas in certain fields evaluated herein. Tables summarizing the gross, working interest, and net contingent resources by country and region are presented in Tables A-6, A-7, and A-8, respectively.

The estimated gross, working interest, and net 1C, 2C, and 3C contingent resources, as of December 31, 2023, 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			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
1C	819,246	47,135	8,649,610	2,410,954
2C	1,725,147	96,091	17,832,473	5,005,607
3C	2,961,243	149,985	33,140,193	9,029,120

	Working Interest Contingent Resources			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

	Net Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

Notes:
1. For the purposes of this report, net contingent resources are set equal to working interest contingent resources.
2. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
3. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
4. The contingent resources reported herein have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
5. Sales gas contingent resources estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet per 1 boe.
6. The oil equivalent contingent resources reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

Ownership

Wintershall Dea has represented that it holds interests in certain licenses for production and development in eight countries: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. The properties evaluated herein are listed by country in the following table:

Country	Field/Discovery	Working Interest (percent)	License Expiration
Algeria	Azrafil Southeast	24.00	November 1, 2041
	Kahlouche	24.00	November 1, 2041
	Kahlouche South	24.00	November 1, 2041
	Reggane	24.00	November 1, 2041
	Sali	24.00	November 1, 2041
	Tiouliline	24.00	November 1, 2041
Argentina	Aguada Pichana East Residual	27.27	July 17, 2052
	Aguada Pichana East Vaca Muerta	22.50	July 17, 2052
	Aguada San Roque	24.71	November 14, 2027
	Ara South	37.50	April 30, 2031
	Aries	37.50	April 30, 2041
	Cañadón Alfa	37.50	April 30, 2031
	Carina	37.50	April 30, 2041
	Fenix	37.50	April 30, 2041
	Hidra	37.50	April 30, 2031
	Kaus	37.50	April 30, 2031

Country	Field/Discovery	Working Interest (percent)	License Expiration
Argentina – *(Continued)*	Leo	37.50	October 23, 2038
	Loma Las Yeguas	24.71	November 14, 2027
	Rincon Chico	24.71	November 14, 2027
	San Roque Vaca Muerta	24.71	November 14, 2027
	Tauro-Unicornio-Sirius	35.00	October 23, 2038
	Vega-Pleyade	37.50	April 30, 2041
Denmark	Cecilie	43.59	June 18, 2032
	Nini	42.857	June 18, 2032
Egypt	Disouq 1-3	100.00	August 11, 2034
	Disouq 1-5	100.00	August 11, 2034
	Disouq 2	100.00	August 11, 2034
	East Damanhour	40.00	September 26, 2043
	El Arish P00 Seg 1	17.25	February 5, 2039
	Fayoum	17.25	February 5, 2039
	Giza	17.25	February 5, 2039
	Hodoa Aquitan (M15 Top sand)	17.25	August 8, 2026
	Libra	17.25	March 24, 2037
	Libra DA	9.4875	March 24, 2037
	Libra P80 Seg 1a	17.25	March 24, 2037
	Maadi P80 Seg 1 (includes Seg 2 and Levee)	17.25	August 8, 2026
	Maadi Segment 3	17.25	August 8, 2026
	North Sidi Ghazy-1	100.00	August 11, 2034
	North Sidi Ghazy-2-1	100.00	August 11, 2034
	North Sidi Ghazy-2-3	100.00	August 11, 2034
	North Sidi Ghazy-4	100.00	August 11, 2034
	Northwest Khilala	100.00	September 2, 2033
	Northwest Sidi Ghazy-1	100.00	August 11, 2034
	Northwest Sidi Ghazy-7	100.00	August 11, 2034
	Polaris Pliocene P78 Ch	17.25	August 8, 2026
	Polaris Pliocene P78 Ch Splay	17.25	August 8, 2026
	Raven	17.25	February 5, 2039
	Raven West M15	17.25	February 5, 2039
	Raven West M20	17.25	February 5, 2039
	Raven West M40D2	17.25	February 5, 2039
	Raven West M40E	17.25	February 5, 2039
	Raven West Serravallian 2	17.25	February 5, 2039
	Raven West Serravallian 4	17.25	February 5, 2039
	Ruby P78 R1 Seg 1	17.25	February 5, 2039
	Sidi Salam Southeast-1	100.00	August 11, 2034
	Sidi Salam Southeast-2	100.00	August 11, 2034
	Sidi Salam Southeast-3	100.00	August 11, 2034
	Sidi Salam Southeast-6	100.00	August 11, 2034
	South Sidi Ghazy-1-1	100.00	August 11, 2034
	South Sidi Ghazy-1-2	100.00	August 11, 2034
	Taurus	17.25	March 24, 2037
	Taurus Deep Serravallian SV7	17.25	March 24, 2037
	Taurus Deep Serravallian SV8	17.25	March 24, 2037
	Taurus P80 Seg 1	17.25	March 24, 2037
	Taurus P86 Seg 2	17.25	March 24, 2037
	Viper P83 Viper Channel and Aband	17.25	August 8, 2026

Country	Field/Discovery	Working Interest (percent)	License Expiration
Germany	Aldorf	100.00	June 30, 2030
	Barrien	50.00	September 13, 2040
	Bockstedt	100.00	January 31, 2030
	Boetersen	20.8120	September 30, 2045
	Boetersen South	0.85	August 31, 2033
	Boestlingen	50.00	October 31, 2027
	Dueste Valendis	100.00	June 30, 2030
	Emlichheim	90.00	May 31, 2043
	Fehndorf	70.00	December 31, 2035
	Hemsbuende	36.279	September 30, 2045
	Mittelplate	100.00	December 31, 2041
	Preyersmuehle South	8.273	December 31, 2045
	Rehden	100.00	December 31, 2040
	Ruetenbrock	100.00	September 30, 2034
	Soehlingen	27.48	December 31, 2045
	Staffhorst HD	50.00	August 7, 2030
	Staffhorst North	50.00	April 17, 2024
	Taaken	14.28	December 5, 2040
	Voelkersen	100.00	December 31, 2028
	Weissenmoor	40.00	January 27, 2028
Libya	Al-Jurf	12.50	April 10, 2035
Mexico	Chinwol	25.00	May 7, 2053
	Hokchi	37.00	December 31, 2040
	Kan	40.00	March 31, 2024
	Naajal	50.00	March 7, 2052
	Ogarrio	50.00	March 6, 2043
	Polok	25.00	May 7, 2053
	Zama	19.83	September 4, 2045
Norway	Aasta Hansteen	24.00	February 2, 2041
	Adriana	40.00	February 2, 2032
	Ærfugl North (Snadd Outer PL212E)	25.00	February 2, 2033
	Alta	30.00	May 14, 2051
	Alve North	20.00	December 31, 2036
	Balderbrå	30.00	February 10, 2027
	Bauge	27.50	December 17, 2029
	Beaujolais	40.00	June 4, 2035
	Bergknapp	40.00	February 5, 2026
	Bergknapp Åre	40.00	February 5, 2026
	Busta	20.00	February 6, 2025
	Dvalin	55.00	October 3, 2041
	Dvalin North	55.00	October 3, 2041
	Edvard Grieg	15.00	December 17, 2029
	Gjøa	28.00	July 8, 2028
	Hamlet (Gjøa North)	28.00	July 8, 2028
	Hyme	27.50	December 17, 2029
	Idun North	40.00	December 31, 2036
	Irpa	19.00	June 18, 2041
	Iving	6.50	February 5, 2026
	Maria	50.00	February 28, 2036
	Neiden	30.00	May 14, 2051
	Newt	10.00	June 2, 2027

Country	Field/Discovery	Working Interest (percent)	License Expiration
Norway – *(Continued)*	Nidhogg	20.00	March 1, 2028
	Njord Unit	50.00	April 10, 2034
	Noatun	45.00	April 10, 2034
	Nova	39.00	February 16, 2041
	Obelix	10.00	February 19, 2027
	Ofelia	20.00	September 2, 2026
	Ofelia Kyrre	20.00	September 2, 2026
	Orion	40.00	June 4, 2035
	Oswig	20.00	February 19, 2027
	Sabina	40.00	February 2, 2032
	Skarv Unit	28.0825	March 3, 2029
	Snøhvit Unit	2.81	October 1, 2035
	Snorre Unit	8.5711	December 31, 2040
	Solveig	15.00	January 6, 2036
	Statfjord East Unit	1.40	August 10, 2026
	Storjo	30.00	May 12, 2036
	Storjo Cretaceous	30.00	May 12, 2036
	Sygna Unit	1.26	August 10, 2026
	Syrah	40.00	June 4, 2035
	Tordis	2.80	December 31, 2040
	Tornerose	2.80	December 17, 2035
	Vega Unit	56.70	June 4, 2035
	Vigdis	2.80	December 31, 2040

Note: In certain cases, the working interests shown are not representative of Wintershall Dea net reserves entitlement due to certain fields being subject to the terms of PSAs.

Wintershall Dea's interests in Denmark, Germany, and Norway are held through licenses that are routinely extended to the economic limit; therefore, reserves reported herein were not limited by license dates and were projected to the economic limit, unless business decisions by the operator or working interest holders define an earlier point of time for abandonment. In Algeria, reserves reported herein were projected to the economic limit or to the license date of November 1, 2041, whichever occurred first. In Egypt, reserves reported herein were limited to those to be recovered by the license dates with no consideration given to license extensions. In Libya, reserves reported for the Al-Jurf field include a 5-year extension to the license date of April 10, 2035, to April 10, 2040. In Argentina and Mexico, the reserves reported herein were limited to those to be recovered by the license dates with no consideration given to license extensions.

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.

Infrastructure

The infrastructure in the eight countries evaluated is well established. Both the onshore and offshore petroleum production provinces evaluated herein have access to a composite of pipelines, service structures, established platforms, and flow stations. 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, natural gas, and diesel sources, are readily available to operators in the evaluated venues.

Environmental Considerations

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, plugging any outstanding wells, and reclamation costs, if any.

Definition of Reserves

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

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *Proved Reserves* are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable

certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability (P50) that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.

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

Developed Reserves are quantities expected to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves include shut-in and behind-pipe reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves are quantities expected to be recovered through future significant investments. Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

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

Estimation of Reserves

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry, which are presented in the PRMS and Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. 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, the development plans provided by Wintershall Dea, and analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved, probable, or possible.

The undeveloped reserves estimates were based on opportunities identified in the plans of development provided by Wintershall Dea. Developed reserves consist of those quantities associated with producing wells and non-producing components that require minor remaining capital expenditure as compared to the cost of a new well, such as behind-pipe zones.

Wintershall Dea has represented that its senior management is committed to the development plans provided by Wintershall Dea and that Wintershall Dea 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 (where applicable), whichever occurs first.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

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

Except where noted, reserves estimates presented herein were generally based on data available through December 31, 2023, and were supported by 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 through December 2023. Cumulative production, as of December 31, 2023, was deducted from the gross ultimate recovery to estimate gross reserves. This report takes into account all relevant information provided by Wintershall Dea.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. LPG reserves estimated herein consist primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and LPG reserves included in this report are expressed in thousands of barrels (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 in certain instances.

Gas quantities estimated herein are expressed as sales gas. Separator gas is defined as the total gas produced from the reservoir after field separation but before reduction for field use (including fuel usage), flare, and gas injection. Sales gas is defined as the quantities of separator gas available to be sold at the point of delivery after field use (including fuel usage), flare, and gas injection. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in millions of cubic feet (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 reserves estimated herein were converted to oil equivalent volumes using a factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Wintershall Dea.

Procedure and Methodology

Wintershall Dea has represented that it holds interests in certain licenses for production and development in eight countries: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. The procedures associated with the evaluation of reserves in these countries are as follows.

Generally, developed producing reserves were estimated based on performance trends of existing wells and completions where such trends exist. If performance trends did not exist, reserves were based on performance analogies for similar types of reservoirs and expected performance or based on analysis of modeling methods. Developed non-producing reserves were estimated for recompletions using a combination of analogous performance and volumetric analysis. Undeveloped reserves were estimated for scheduled drilling, improved recovery, and sidetracks based on analogy with produced reservoirs, as well as volumetric analysis where sufficient data were available. Proved reserves were estimated based on projections premised on reasonable certainty, while probable and possible reserves were based on better well performance than projected for proved reserves plus incremental volumetric recovery where appropriate.

<u>Algeria</u>

There are six fields located within Algeria evaluated herein (Figure ALG 1), which collectively are referred to as “Reggane Nord.” The larger fields, Azarafil Southeast and Reggane, are discussed below. Reserves associated with the fields in Algeria were projected to the economic limit or to the license date of November 1, 2041, whichever occurred first. A stratigraphic column of the main producing reservoirs in the Reggane Basin is shown on Figure ALG 2.

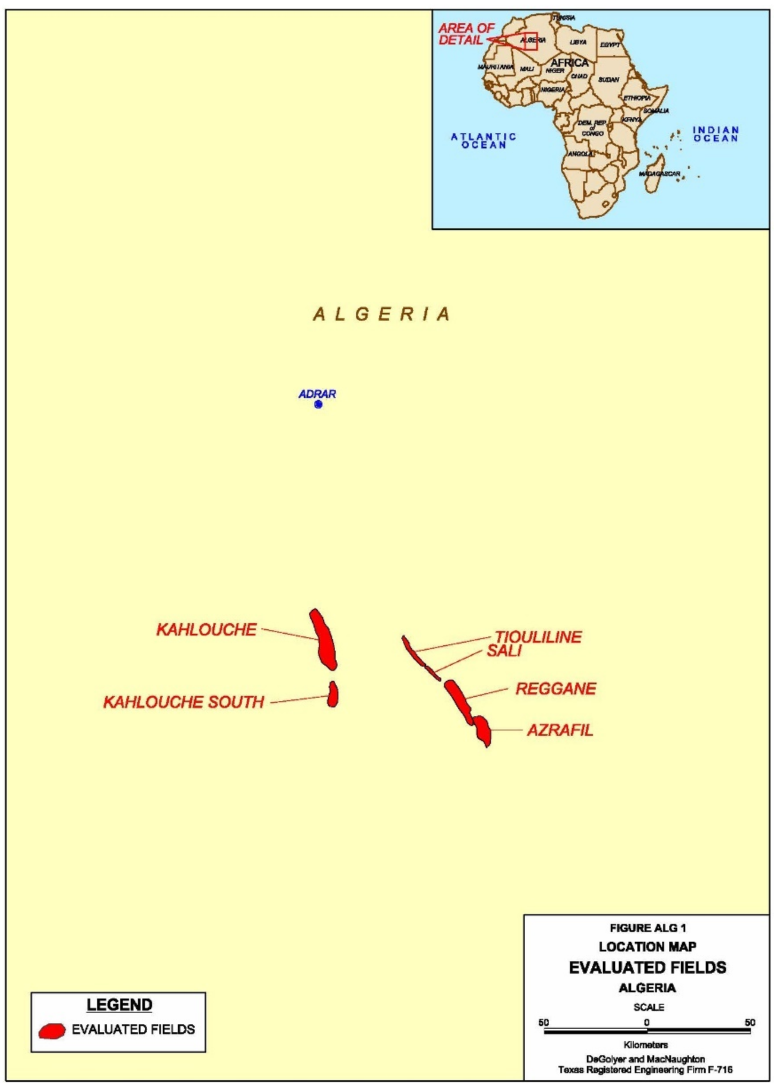
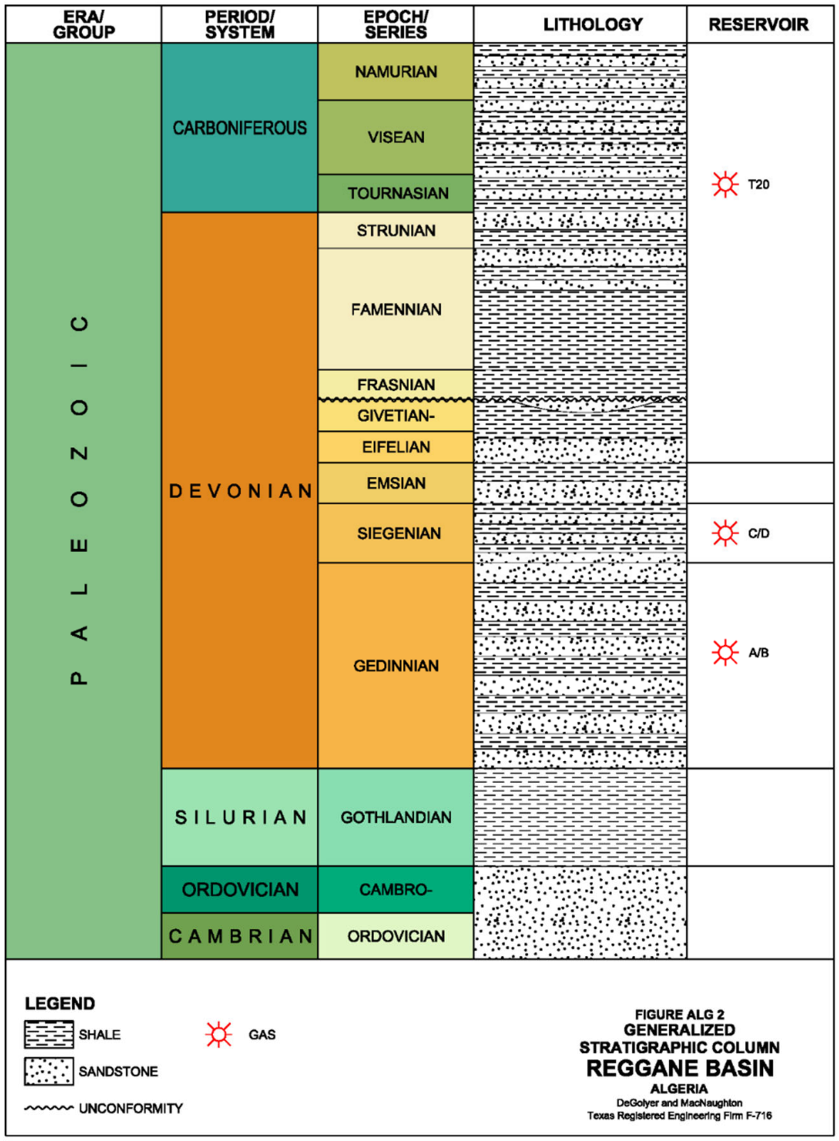


FIGURE ALG 1
LOCATION MAP
EVALUATED FIELDS
ALGERIA



Azarafil Southeast Field

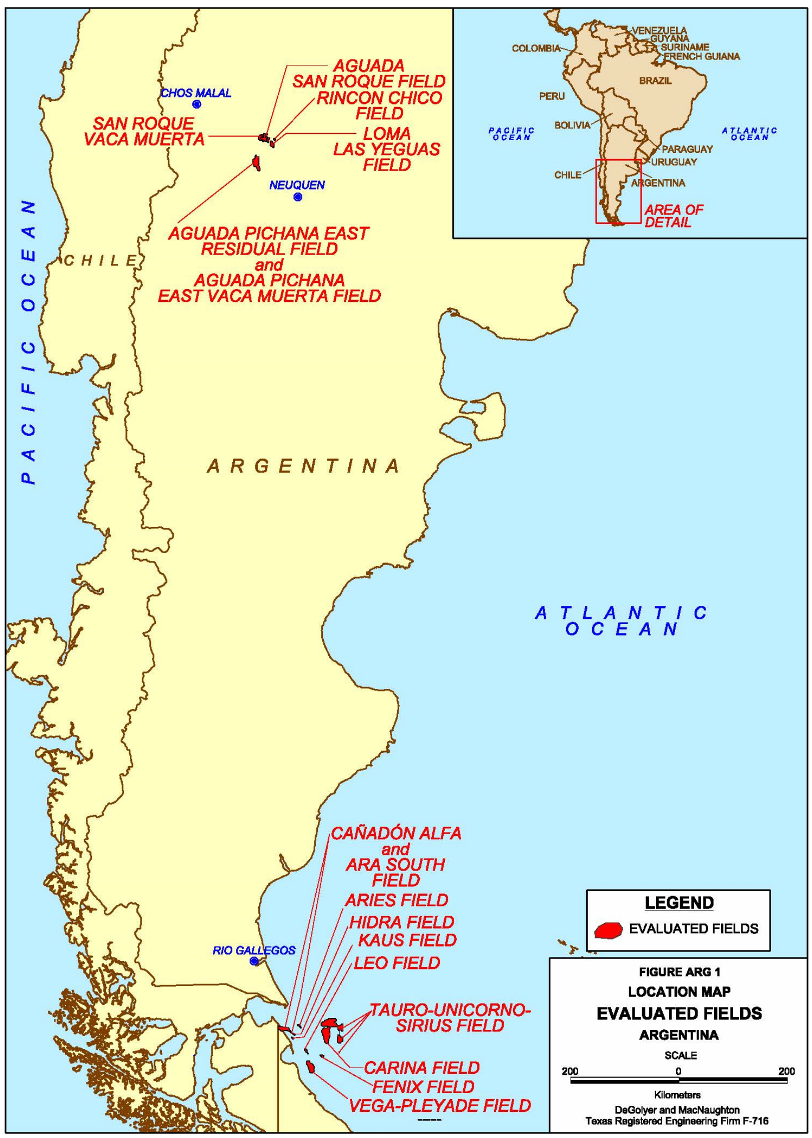
The Azrafil Southeast field commenced production in 2017. Developed reserves estimated herein were based on nine drilled wells, and the field currently produces on plateau at a rate of 140 million cubic feet per day of gas. Undeveloped reserves were estimated for four additional planned producers. Estimated total reserves were based on volumetric analysis.

Reggane Field

The Reggane field started producing in 2017. Developed reserves estimated herein were based on 11 drilled wells, and the field currently produces on plateau at 140 million cubic feet per day of gas . Undeveloped reserves were estimated for five additional planned producers. Estimated total reserves were based on volumetric analysis.

Argentina

There are 16 fields within Argentina evaluated herein (Figure ARG 1). Reserves associated with the fields in Argentina were limited to those to be recovered by the license dates with no consideration given to license extensions. Selected fields are discussed in detail as follows.



Aguada Pichana East Block

The Aguada Pichana East Block is located in the central portion of the Neuquén Basin, 50 kilometers from the city of Añelo in the Neuquén Province, Argentina. The field was discovered in 1972 and produces mainly dry gas and some condensate. The Aguada Pichana East Block was initially part of a bigger block that was divided in 2017 into the Aguada Pichana East Block, operated by Total, and the Aguada Pichana West Block, operated by Pan American Energy.

Production from the Aguada Pichana East Block is split into Aguada Pichana East Residual and Aguada Pichana East Vaca Muerta. The Aguada Pichana East Residual portion includes the production from the conventional and tight sand reservoirs of the Mulichinco Formation and the production from the wells drilled before December 31, 2016, targeting the Vaca Muerta Formation. The Aguada Pichana East Vaca Muerta includes all production and development of the Vaca Muerta Formation after December 31, 2016. A stratigraphic column of the main producing reservoirs in the Neuquén Basin is shown on Figure ARG 2.

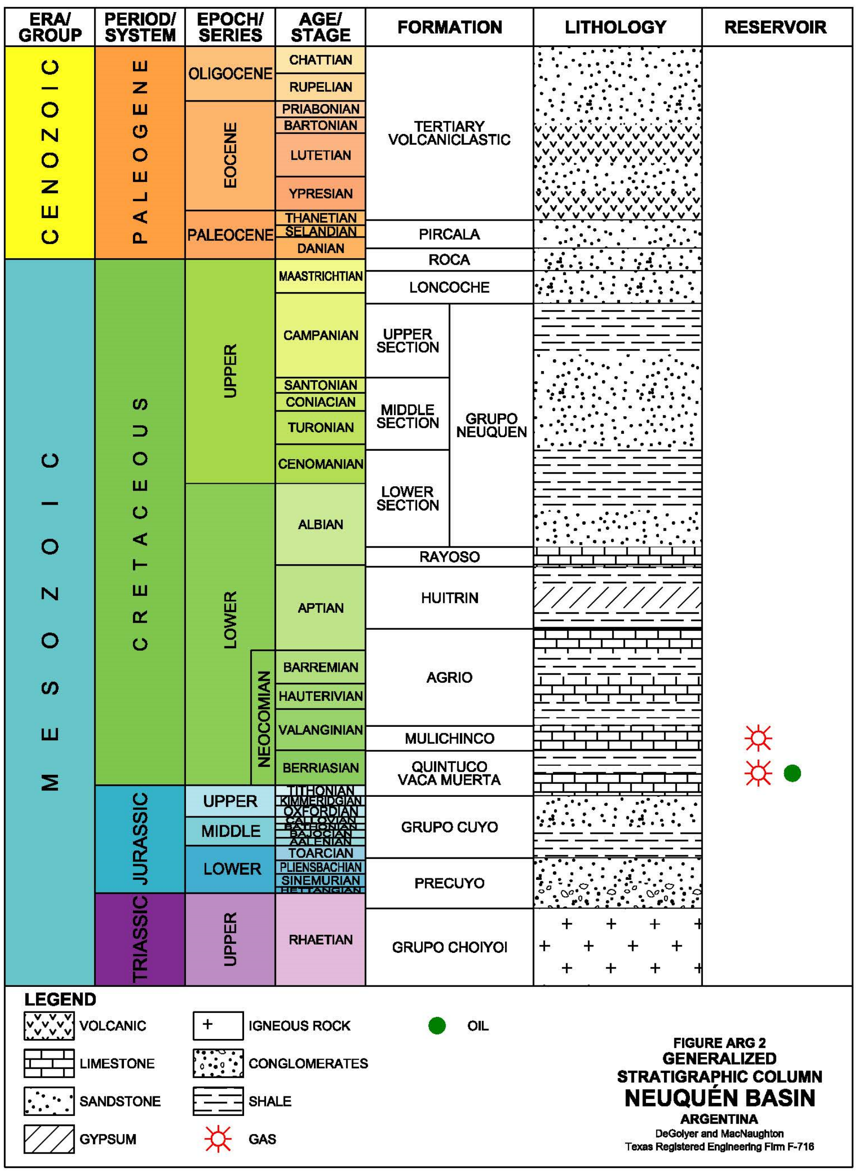
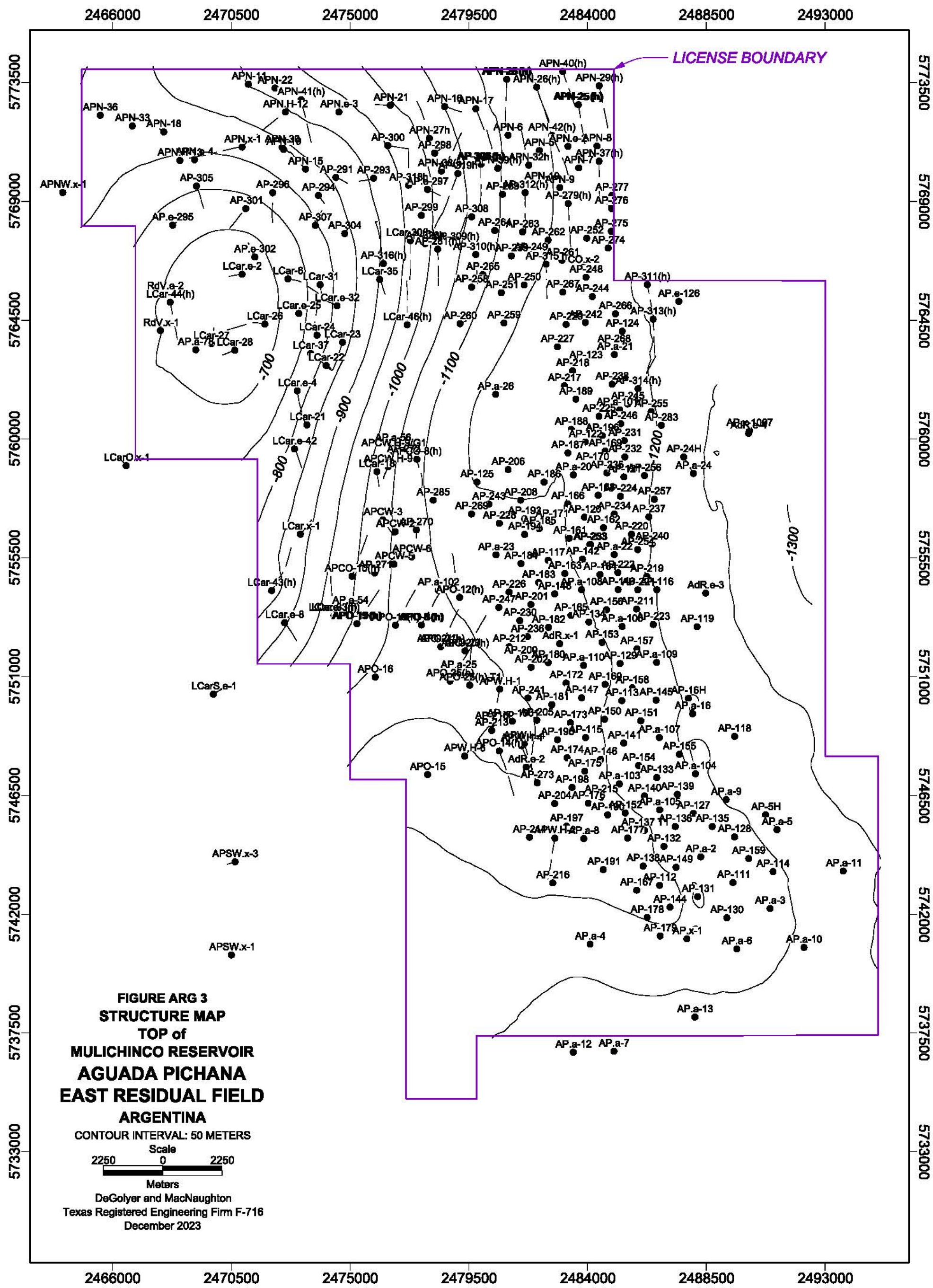


FIGURE ARG 2
GENERALIZED
STRATIGRAPHIC COLUMN
NEUQUÉN BASIN
ARGENTINA
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Aguada Pichana East Residual

The development of the Aguada Pichana East Residual is subdivided into three areas: Aguada Pichana Main, Aguada Pichana Norte, and Las Cárceles. The main reservoir of the Aguada Pichana Main area is the Middle Mulichinco; gross thickness ranges between 30 and 77 meters, net-to-gross ratio (NGR) ranges from 60 to 95 percent, porosity was estimated to range between 8 and 14 percent, and permeability was estimated to range from 0.1 to 19 millidarcys. The main reservoir of the Aguada Pichana Norte is the Upper Mulichinco; gross thickness ranges between 22 and 37 meters, NGR ranges from 40 to 60 percent, porosity was estimated to range between 10 and 17 percent, and permeability was estimated to range from 10 to 70 millidarcys. The Aguada Pichana East Residual is in a tighter area of the Middle Mulichinco reservoir; gross thickness ranges between 35 and 60 meters, NGR ranges from 40 to 75 percent, porosity was estimated to range between 5 and 10 percent, and permeability was estimated to be less than 0.01 millidarcys.

The Aguada Pichana East Block was initially developed with the Aguada Pichana Main Development Project in the east portion of the block, and production started in 1996. The objective was the Cretaceous sandstones of the Mulichinco Formation, which comprises fluvial, tidal to shallow marine deposits and represents a low-frequency lowstand wedge developed during the Early Cretaceous (Valanginian). The Mulichinco Formation was divided vertically into three zones: Lower, Middle, and Upper. The main reservoirs are the Middle and Upper Mulichinco. Toward the west, the petrophysical characteristics of the Mulichinco Formation are poor; low permeability values define it as a tight sand reservoir. From 2007 to 2009, the northern part of the block was developed by drilling vertical wells with high carbon dioxide content as part of the Aguada Pichana Norte Phase I and Aguada Pichana Norte Phase II Development Projects. In 2010, the development was focused to the south of Aguada Pichana Norte by drilling vertical wells with lower carbon dioxide content as part of the Cañadón de la Zorra Development. In 2011, Las Cárceles was developed with vertical wells of low productivity. In the following years, the Aguada Pichana Oeste and Aguada Pichana Norte tight developments were performed by drilling horizontal multi-fracture wells. A structure map on the top of the Mulichinco reservoir in the Aguada Pichana East Residual field is shown on Figure ARG 3.



All reserves estimated herein are associated with the established development. Proved developed producing reserves were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

<u>Aguada Pichana East Vaca Muerta</u>

The Aguada Pichana East Vaca Muerta produces gas and condensate from the unconventional reservoir of the Vaca Muerta Formation. The Vaca Muerta Formation is composed of Tithonian to Valanginian cycles developed in a prograding marine system. The Vaca Muerta Formation is an interbedded reservoir of mudstones and marls. The average gross thickness of the reservoir is 230 meters and the average net thickness is 150 meters; porosity was estimated to range between 8 and 12 percent, average permeability was estimated to be 0.000265 millidarcys, and average total organic carbon is 7 percent. A structural map on the top of the Vaca Muerta Sequence 9 reservoir is shown on Figure ARG 4.

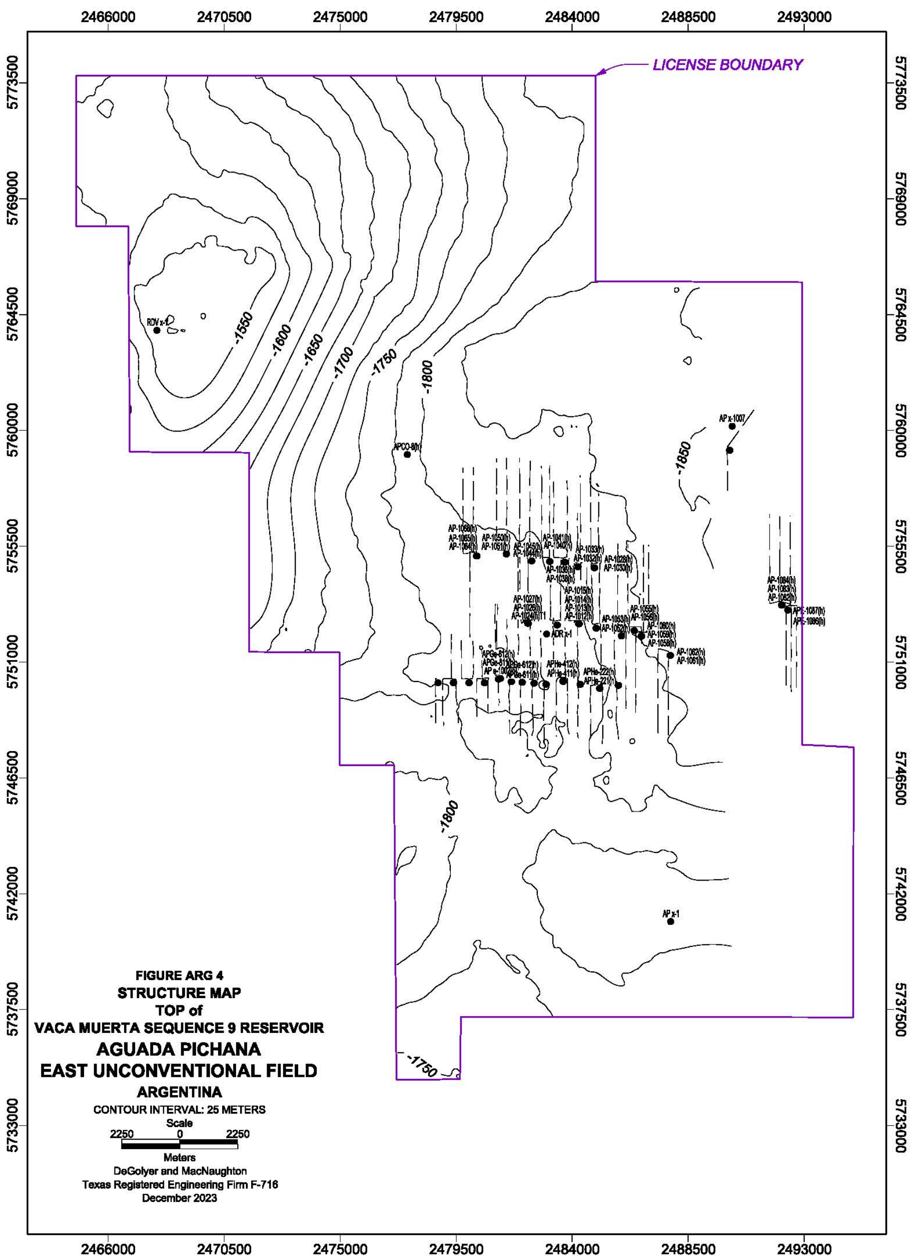


FIGURE ARG 4
STRUCTURE MAP
TOP of
VACA MUERTA SEQUENCE 9 RESERVOIR
AGUADA PICHANA
EAST UNCONVENTIONAL FIELD
ARGENTINA
CONTOUR INTERVAL: 25 METERS
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2023

The AP.xp-1001 well discovered gas in the Vaca Muerta Formation in 2011, and production started in 2012. During the Technology Phase, an additional vertical well was drilled in 2012. From 2013 to 2015, 12 horizontal wells were drilled for a pilot project. The first development project, Development 1A, consisted of approximately 20 horizontal wells that were drilled between 2016 and 2018. The Development 1B Project consisted of approximately 36 horizontal wells. The Development 2A Project is underway, and as of December 31, 2023, a total of five of these wells have been drilled.

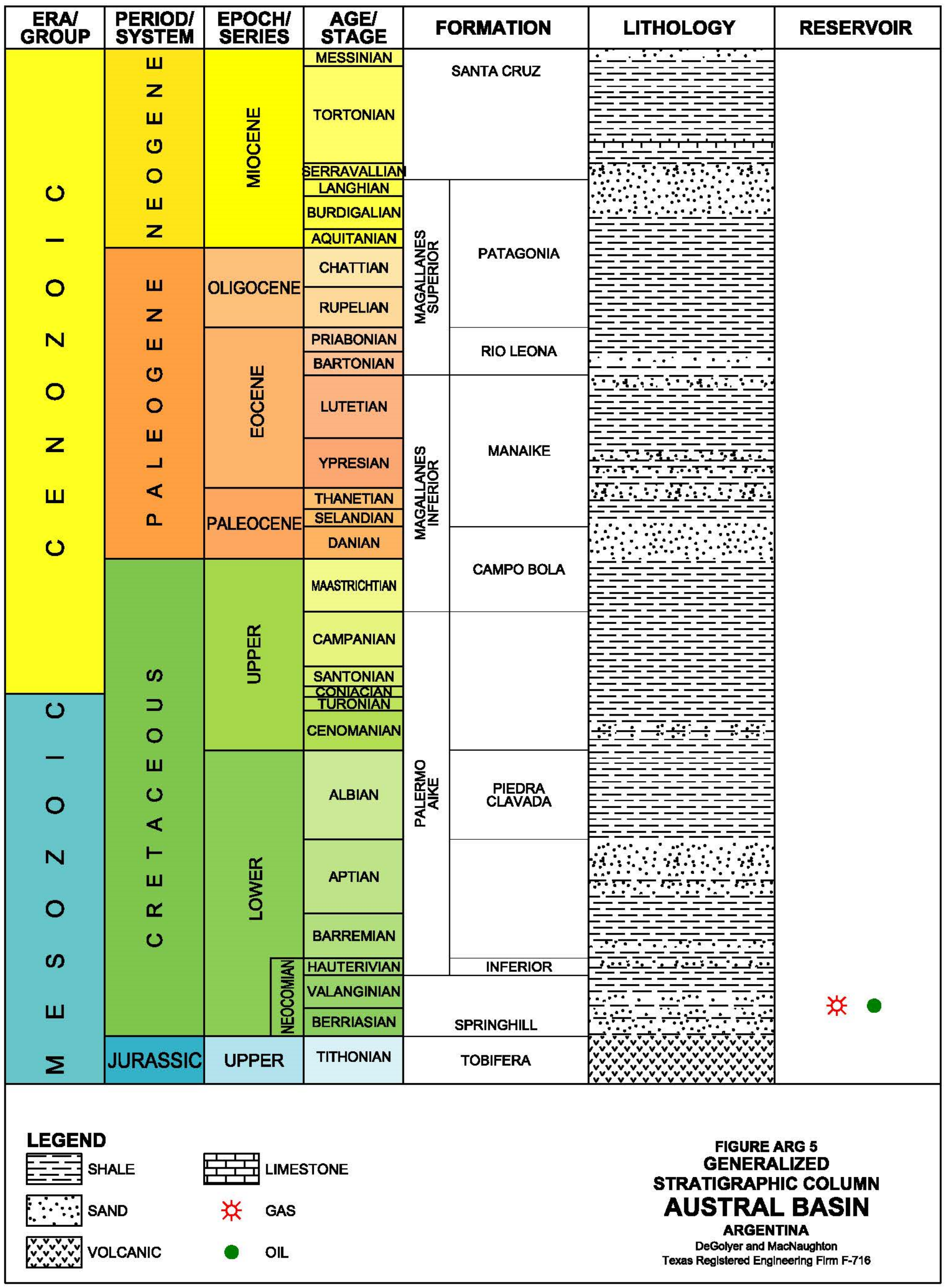
A performance-based methodology was used for estimated reserves associated with unconventional reservoirs. Performance-based methodology primarily includes production diagnostics and decline-curve analysis. Production diagnostics include data quality control, identification of flow regimes and characteristic flow behavior. Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Proved developed producing reserves were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous wells in the Vaca Muerta reservoir for which more complete historical performance data were available. Proved undeveloped reserves were estimated for the remaining horizontal wells of the Development 2A project. Probable and possible undeveloped incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Ara South Field

The Ara South field is located in the Austral Basin, 7 to 12 kilometers offshore Tierra del Fuego in water depths ranging from 20 to 40 meters. The field was discovered in 1982 and started production in 1996. The field has one oil well on production as of December 31, 2023.

The reservoir in the Ara South field is the Hidra sequence of the Springhill Formation (Figure ARG 5). The Springhill Formation is a lithostratigraphic unit that presents a second-order transgressive pattern. The Springhill Formation was deposited during the Cretaceous above the volcaniclastic deposits of the Serie Tobífera Formation and filled the paleotopography. The first deposits of the Springhill Formation were fluvial, evolving to coastal, deltaic estuarine, and proximal marine deposits. The marine deposits evolved to offshore shales, represented by the Inoceramus Inferior Formation, which act as the seal and source rock of the Springhill Formation reservoirs. The different sequences that comprise the Springhill Formation have a retrogradational stacking pattern that backsteps from the west of the basin to the west, toward the Rio Chico High. The Springhill Formation was divided into several depositional sequences: Hidra, Argo, Paloma, and Carina. The RH-5 sands are the main reservoir and have a net thickness of 9.2 meters; porosity was estimated to be 24 percent and permeability was estimated to range from 500 to 1,000 millidarcys.



Proved developed reserves for the Ara South field are associated with its one active well producing as of December 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Ara South field.

Aries Field

The Aries field is located in the Austral Basin, 25 to 35 kilometers offshore Tierra del Fuego in water depths ranging from 55 to 80 meters. The field was discovered in 1982 and started production in 2006. The Aries field consists of a gas cap with an associated oil rim of 11 meters in thickness; however, the field produces from only the gas cap. The trap is structural (four-way dip closure). There are currently one deviated and two horizontal production wells.

The reservoirs in the Aries field are the Argo sequence and the Hidra sequence of the Springhill Formation. The Argo sequence has a gross thickness ranging from 8 to 12 meters; net sand porosity was estimated to range from 20 to 30 percent and permeability was estimated to range from 80 to 1,000 millidarcys. The Hidra sequence has a gross thickness ranging from 4 to 14 meters; net sand porosity was estimated to range from 20 to 25 percent and permeability was estimated to range from 1 to 550 millidarcys.

Proved developed reserves for the Aries field are associated with its three active wells on production as of December 31, 2023, and were estimated using a material-balance model in the integrated production system model for the CMA-1 complex. Probable and possible developed incremental reserves were also estimated with the integrated production system model associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves or contingent resources were estimated for the Aries field.

Cañadon Alfa Complex

The Cañadon Alfa complex (consisting of the Antares and Ara-Cañadon Alfa fields) is located both onshore and offshore in the Austral Basin. The offshore part of the field extends up to 17 kilometers from the shore of Tierra del Fuego in water depth up to 50 meters. The field was discovered in 1972 and started production the same year. The field has 29 gas and 7 oil wells on production as of December 31, 2023.

The reservoirs in the Cañadon Alfa complex are the Argo sequence and the Hidra sequence of the Springhill Formation. The main reservoirs are the marine sandstones of the Argo sequence with an average gross thickness of 25 meters and an average net sand thickness of 18 meters; average porosity was estimated to be 22 percent and average permeability was estimated to be 500 millidarcys.

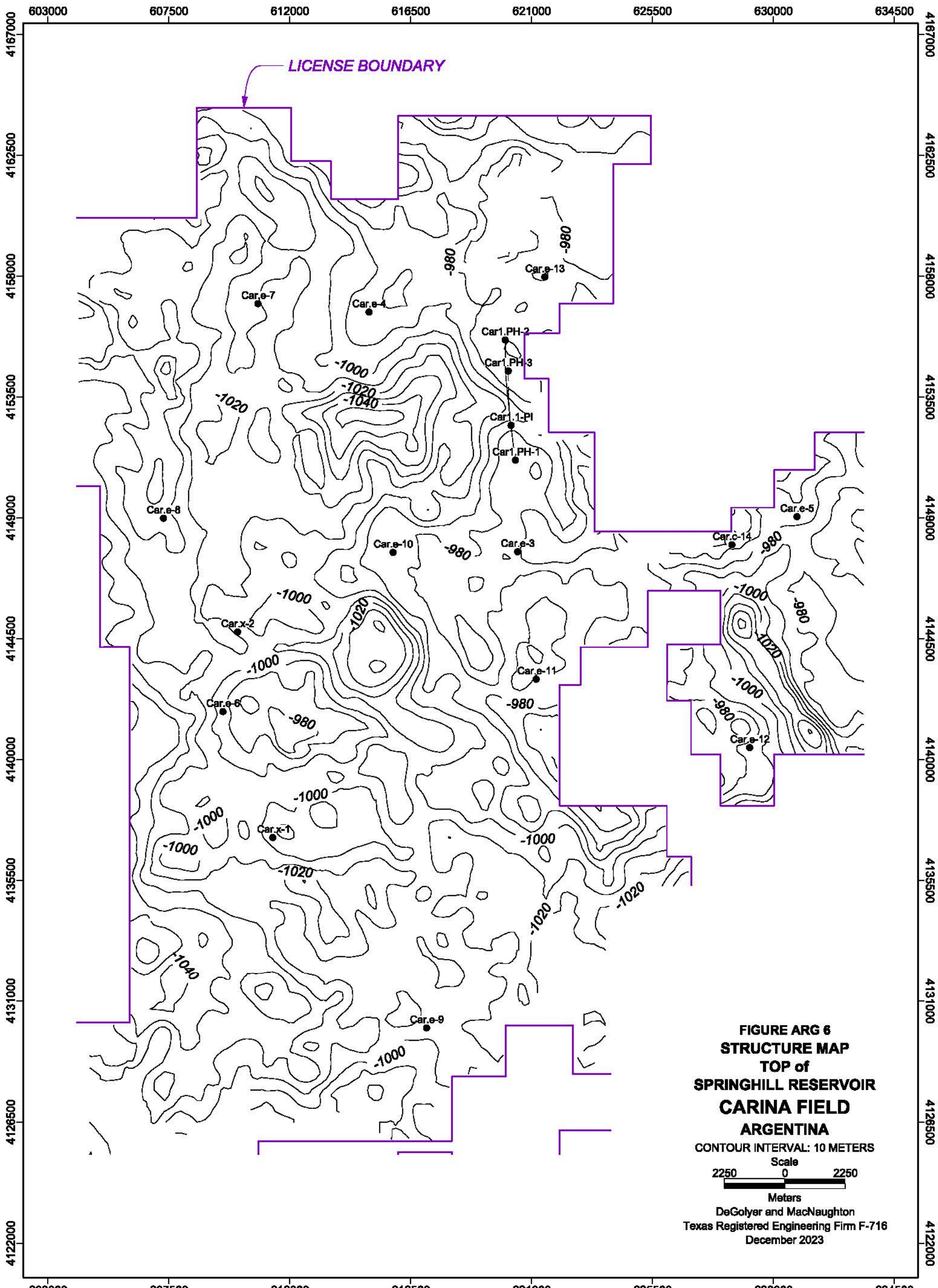
Proved developed reserves for the Cañadon Alfa complex are associated with the active wells on production as of December 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Cañadon Alfa complex.

Carina Field

The Carina field is located in the Austral Basin, 65 kilometers offshore Tierra del Fuego in an average water depth of 80 meters. The field was discovered in 1983 and started production in 2005.

The Carina field consists of a gas cap with an associated oil rim and produces gas from the Springhill Formation. The Springhill Formation is a lithostratigraphic unit that presents a second-order transgressive pattern. The Springhill Formation was deposited during the Cretaceous above the volcaniclastic deposits of the Serie Tobífera Formation and filled the paleotopography. The first deposits of the Spinghill Formation were fluvial, evolving to coastal, deltaic estuarine, and proximal marine deposits. The marine deposits evolved to offshore shales represented by the Inoceramus Inferior Formation, which act as the seal and source rock of the Springhill Formation reservoirs. The different sequences that comprise the Springhill Formation have a retrogradational stacking pattern that backsteps from the west of the basin to the west, toward the Rio Chico High. The Springhill Formation was divided into several depositional sequences: Hidra, Argo, Paloma, and Carina.

The producing sequences within the Springhill reservoir in the Carina field are the Paloma and Carina sequences. The Paloma sequence has a gross thickness of up to 60 meters and an average NGR of 60 percent. The Carina field sequence has a gross thickness of up to 35 meters and an average NGR of 90 percent. The Springhill Formation net sand porosity was estimated to range from 15 to 35 percent, average permeability was estimated to range between 100 and 300 millidarcys, with values of up to 5,000 millidarcys, and average S_w was estimated to be 33 percent. The trap is structural (four-way dip closure) and stratigraphic (pinchout at the basement highs) (Figure ARG 6).



Proved developed reserves for the Carina field are associated with its four active producing wells as of December 31, 2023, and were estimated using a three-dimensional (3–D) integrated reservoir simulation model. Probable and possible developed incremental reserves were also estimated with the simulation model associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Carina field.

Fenix Field

The Fenix field is located in the Austral Basin, to the south of the Carina field, 80 kilometers offshore Tierra del Fuego in water depths ranging from 70 to 90 meters over an area of 425 square kilometers. The field was discovered in 1983 with the drilling of the Fenix-1 exploration well that proved oil in the Springhill Formation. The field was subsequently appraised by three additional wells between 1987 and 2015. In 1987, the Fenix.e-2 delineation well tested gas in the Springhill Formation. The field has one vertical exploratory well and four vertical delineation wells.

The reservoirs in the Fenix field are the Carina sequence and the Paloma sequence of the Springhill Formation. The fluvial and marine reservoirs have an average net sand thickness of 15 meters and a NGR of nearly 100 percent; net sand porosity was estimated to range from 15 to 35 percent with an average of 24 percent. Permeability was estimated to range between 100 and 1,000 millidarcys.

The Fenix field will be developed as a gas field. Undeveloped reserves estimated for the Fenix Phase 1 project are associated with the drilling of three development wells from a new platform, which will be connected via pipeline to the existing CMA-1 complex.

Hidra Field

The Hidra field is located in the Austral Basin, 11 to 14 kilometers offshore Tierra del Fuego in water depths ranging from 25 to 40 meters. The field was discovered in 1982 and started production in 1989. The field has five active oil wells on production as of December 31, 2023.

The reservoir in the Hidra field is the Hidra sequence of the Springhill Formation. The Hidra sequence has an average gross thickness of 70 meters and an average NGR of 45 percent; porosity was estimated to range from 13 to 25 percent and permeability was estimated to range from 50 to 5,000 millidarcys.

Proved developed reserves for the Hidra field are associated with the five active wells producing as of December 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Hidra field.

Kaus Field

The Kaus field is located in the Austral Basin, 3 to 8 kilometers offshore Tierra del Fuego in a water depth of over 20 meters. The field was discovered in 1982 and started production in 1998. The field has one active oil well on production as of December 31, 2023.

The reservoir in the Kaus field is within the Hidra sequence of the Springhill Formation. The Hidra sequence has a gross thickness of 25 meters and an average net sand thickness of 11.2 meters; average porosity was estimated to be 21 percent and average permeability was estimated to be 500 millidarcys.

Proved developed reserves for the Kaus field are associated with one active well on production as of August 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Kaus field.

San Roque Vaca Muerta

The San Roque Vaca Muerta field is located in the center of the Neuquén Province to the northeast of the Aguada Pichana Block, 130 kilometers from the city of Neuquén, Argentina. The San Roque Vaca Muerta field covers an area of 1,040 square kilometers, and the main source rock is the Vaca Muerta Formation. The Vaca Muerta Formation, which is composed of marls and bituminous claystones with type II kerogen of marine origin, extends throughout the field with an average thickness of 200 meters and total organic content (TOC) of 4.5 percent. The field is located in a transitional fluid-type region, from volatile oil in the west to black oil in the east.

A performance-based methodology was used for estimating reserves associated with unconventional reservoirs in this field. Proved developed reserves were estimated for three wells by decline-curve analysis. Probable and possible developed reserves were estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Vega Pleyade Field

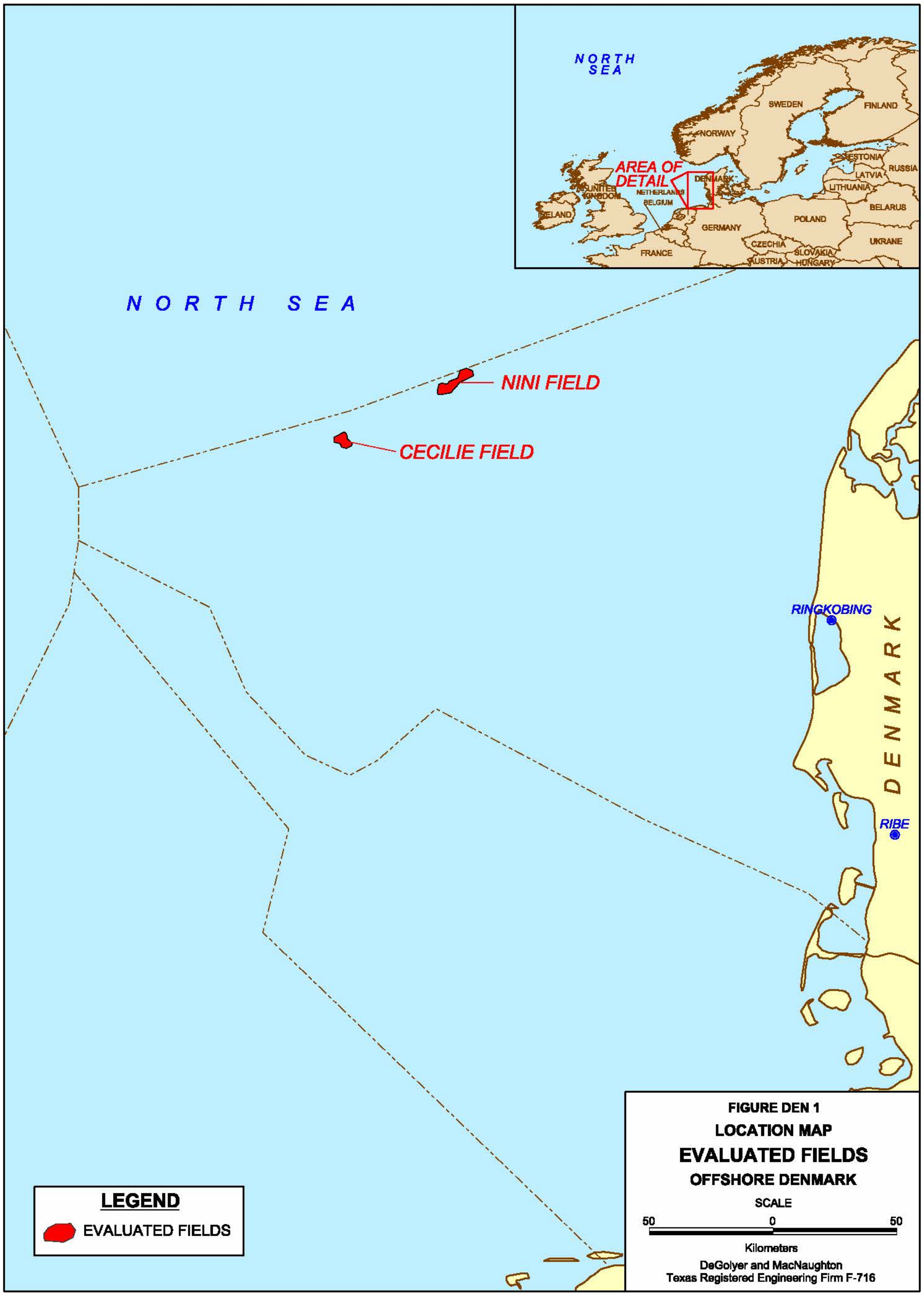
The Vega Pleyade field is located 20 kilometers offshore Tierra del Fuego, in water depths ranging from 40 to 60 meters. The field was discovered in 1981 and started production in 2016. The Vega Pleyade field consists of a gas cap with an associated oil rim and produces gas from the Springhill Formation. There are two horizontal production wells. The trap is structural (four-way dip closure) and stratigraphic (pinchout at the basement highs).

The reservoirs in the Vega Pleyade field are the Hidra sequence, Argo sequence, and Paloma sequence of the Springhill Formation. The Paloma sequence is the main reservoir. The gross thickness of the Springhill Formation ranges from 40 to 75 meters. The sandstones of the Paloma sequence have an average NGR of 69 percent, porosity was estimated to be 19 percent, permeability was estimated to be 200 millidarcys, and S_w was estimated to be 45 percent.

Proved developed reserves for the Vega Pleyade field are associated with two active wells on production as of December 31, 2023, and were estimated using a 3–D integrated reservoir simulation model. Probable and possible developed incremental reserves were also estimated with the simulation model associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Vega Pleyade field.

Denmark

There are two fields located in Denmark evaluated herein: Cecilie and Nini (Figure DEN 1). The reserves in these fields were estimated to be zero, as any further production or development is not economically viable.



Egypt

There are 42 fields located within Egypt evaluated herein (Figure EGY 1). Reserves associated with the fields in Egypt were limited to those expected to be recovered prior to the license dates with no consideration given to license extensions.

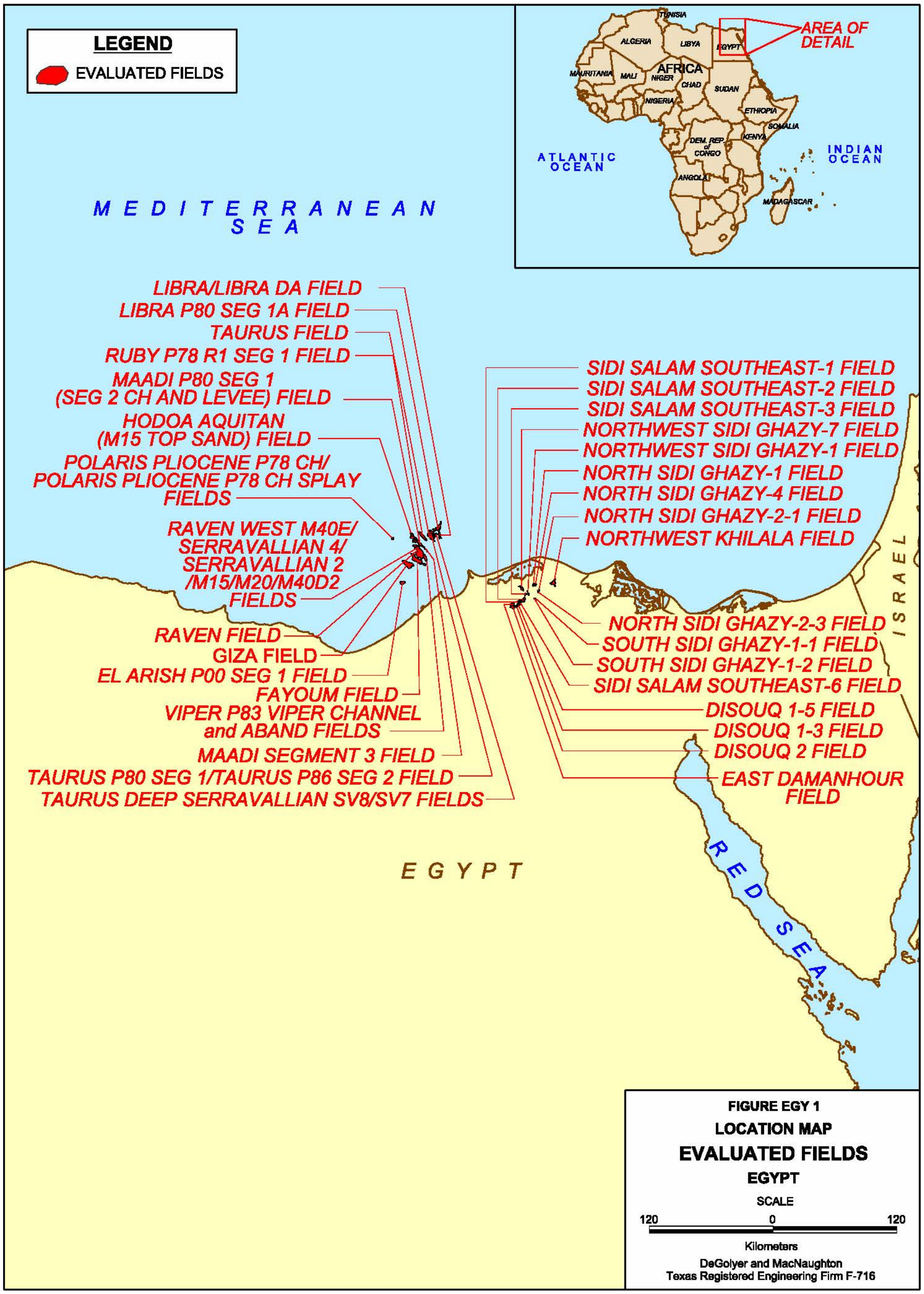


FIGURE EGY 1
LOCATION MAP
EVALUATED FIELDS
EGYPT

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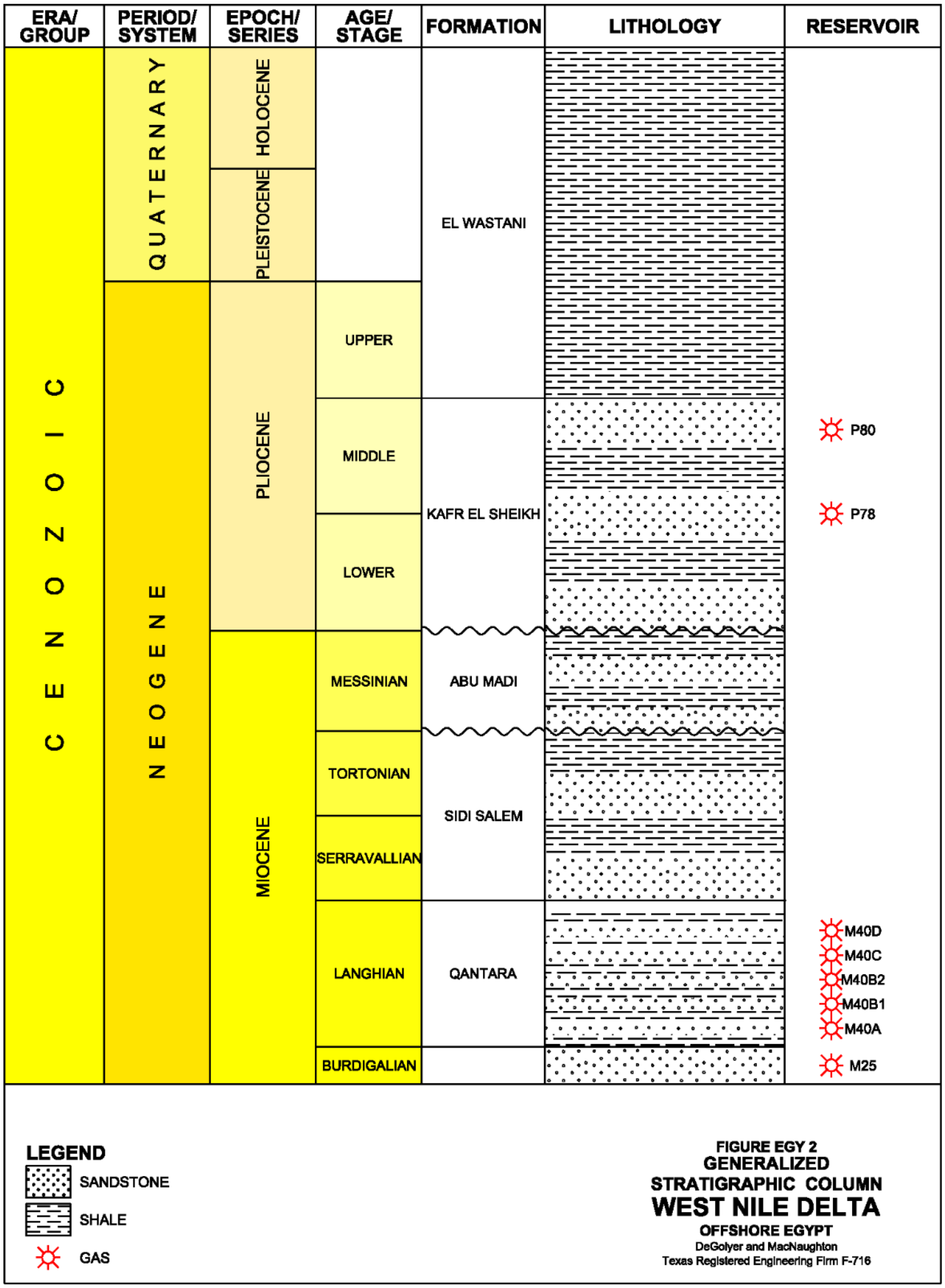
Texas Registered Engineering Firm F-716

The Fayoum, Giza, Libra, Raven, and Taurus fields in the West Nile Delta area and the onshore Disouq area are discussed in detail herein. A stratigraphic column of the main producing reservoirs in the West Nile Delta area is shown on Figure EGY 2.



Disouq Area

The Disouq area consists of 16 fields, including the Disouq fields, North Sidi Ghazy fields, Northwest Khilala field, Northwest Sidi Ghazy fields, Sidi Salam Southeast fields, and South Sidi Ghazy fields. There are a total of 31 wells in the Disouq area, and most of the fields have 1 or 2 wells. The area produces gas with low condensate yields. Reserves were estimated based on performance analysis of the wells.

Fayoum Field

The Fayoum field is a gas field located in the Mediterranean Sea approximately 10 kilometers south-southeast of the Giza field, approximately 55 kilometers northwest of the city of Alexandria, Egypt. The field was discovered by the FN-1 well in 2001 and is part of the West Nile Delta Concession area.

The geologic structure of the Fayoum field consists of a faulted anticline. A 3--D seismic survey shot over the Fayoum field in 2005 helped define the stratigraphic limits of the reservoirs.

There are two main sandstone reservoir intervals in the field, the P79 and P78, which are of Pliocene age. The reservoirs were deposited in a mid-slope setting as a turbidite channel and splay system composed of thinly bedded sandstones. Figure EGY 3 presents a structure map on the top of the P79 reservoir in the Fayoum field. Average net thickness is less than 15 meters. Porosity was estimated to range from 24 to 31 percent, initial S_w was estimated to range from 30 to 33 percent, and permeability was estimated up to 2.5 darcys in the P79 reservoir and up to 2.9 darcys in the P78 reservoir.

Production from the field began in 2019. The field produces lean gas from four wells with a low condensate-gas ratio (CGR) of less than 1 barrel per million cubic feet ($bbl/10^6ft^3$). The P79 and P78 reservoirs are normally pressured, and the drive mechanism is a combination of gas expansion and aquifer drive. The produced gas is transported via pipeline to the existing Rosetta and Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Rosetta facility and then exported via the Burullus condensate export system into the Petroleum Pipelines Company (PPC) pipeline.

Proved, probable, and possible developed reserves were estimated based on volumetric analysis and performance of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration on February 5, 2039.

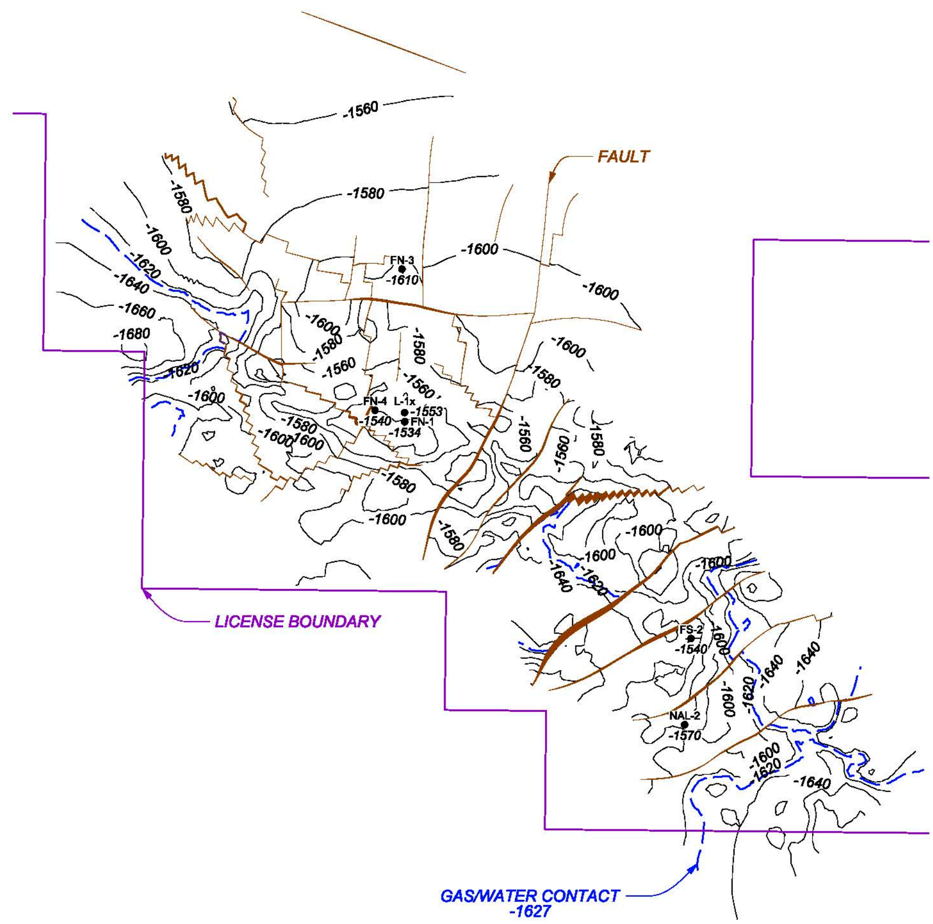


FIGURE EGY 3
STRUCTURE MAP
TOP of
P79 RESERVOIR
FAYOUM FIELD
EGYPT
CONTOUR INTERVAL: 20 METERS
Scale
1000 0 1000
Meters
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Texas Registered Engineering Firm F-716
December 2023

Giza Field

The Giza field is a gas field located in the Mediterranean Sea approximately 65 kilometers northwest of Alexandria, Egypt. The field was discovered by the Giza North-1 well in 2007 and is part of the West Nile Delta Concession area. The structure consists of a faulted anticline; however, a stratigraphic pinchout is the hydrocarbon trapping mechanism (Figure EGY 4). A 3–D seismic survey shot over the Giza field in 2005 was crucial in defining the stratigraphic limits of the reservoirs.

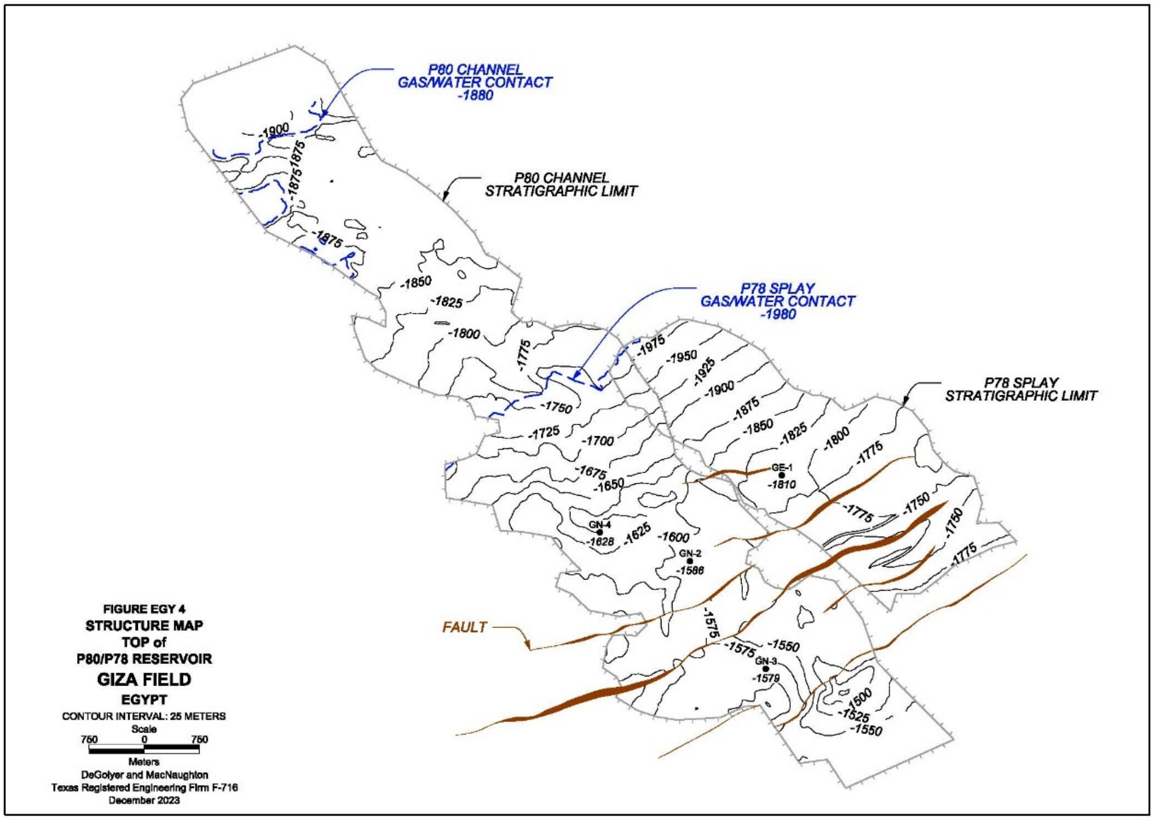

FIGURE EGY 4
STRUCTURE MAP
TOP of
P80/P78 RESERVOIR
GIZA FIELD
EGYPT

There are two main sandstone reservoir intervals in the field, the P80 and P78, which are of Pliocene age. The reservoirs were deposited as marine channels, channel-levees, and crevasse splays in a slope channel complex. The reservoir sections are highly heterogeneous, ranging from aggradational massive sands to heteroliths and thin beds. Average net thickness is less than 25 meters. Porosity was estimated to be greater than 27 percent, initial S_w was estimated to be less than 41 percent, and permeability was estimated to be up to 90 millidarcys in the splays and levees and greater than 400 millidarcys in the channel facies.

Production from the field began in 2019. The field currently produces lean gas from four wells with a low CGR of less than 1 bbl/10^6ft^3. The produced gas is transported via pipeline to the existing Rosetta and Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Rosetta facility and then exported via the Burullus condensate export system into the PPC pipeline.

Proved, probable, and possible developed reserves were estimated based on volumetric analysis and performance of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration of February 5, 2039.

Libra Field

The Libra field is a gas field located in the Mediterranean Sea approximately 5 kilometers northeast of the Taurus field and approximately 85 kilometers north-northwest of Alexandria, Egypt. The field was discovered by the K-1X exploration well in 2003 and is part of the West Nile Delta Concession area.

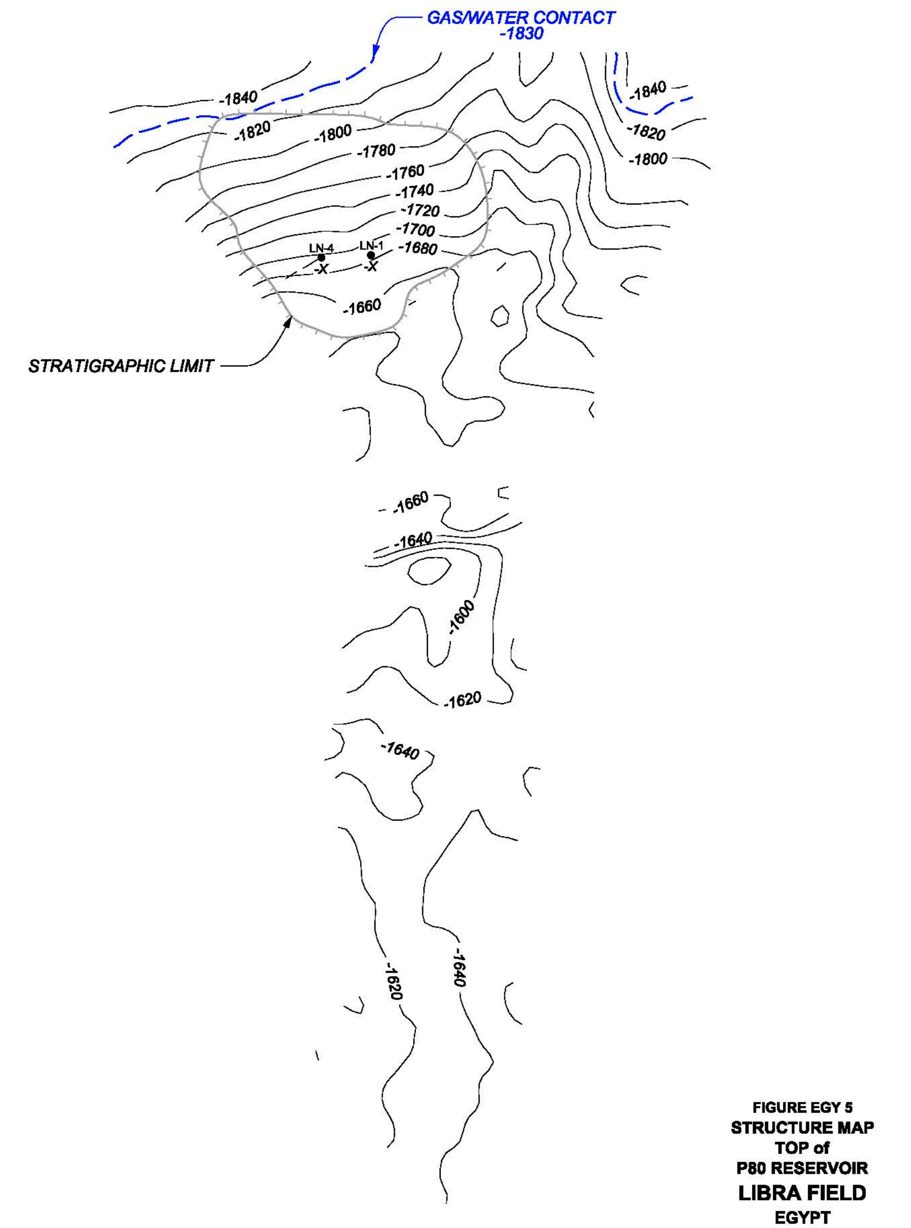

FIGURE EGY 5
STRUCTURE MAP
TOP of
P80 RESERVOIR
LIBRA FIELD
EGYPT
CONTOUR INTERVAL: 20 METERS

Additional appraisal wells were drilled in the field and confirmed the presence of gas-saturated channel levee sandstone reservoirs consisting of the P78 Channel, P78 Splay, P80 Splay, and P76 Levee reservoirs. The field is dominated by the P80 Channel complex, which trends southeast to northwest. The reservoirs range in depth from approximately 1,100 to 2,500 meters TVDSS. Figure EGY 5 presents a structure map on the top of the P76/P80 reservoir in the Libra field.

Production from the field began in March 2017 from two wells and consists of lean gas with low CGR of less than 1 bbl/10^6ft^3. The P76 and P80 reservoirs are the primary reservoirs contributing to the production. The produced gas is transported via pipeline to the existing Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Burullus facility and then exported via the Burullus condensate export system into the PPC pipeline.

Proved, probable, and possible developed reserves were estimated based on performance analysis of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration of March 24, 2037.

Raven Field

The Raven field is a gas field located in the Mediterranean Sea approximately 60 kilometers northwest of Alexandria, Egypt. The field was discovered by the Raven--1 well in 2004 and is part of the West Nile Delta Concession area. The field was further appraised by the Raven-2, Raven-3, and Raven-4 wells. The water depth over the field ranges from 500 to 700 meters.

The main reservoir in the field is the Miocene (Langhian) M40 reservoir, which consists of an amalgamated channel complex within a large deeply incised northwest/southeast-trending confined system that drapes over the northeast-plunging Raven anticline. Reservoir depths range from approximately 4,100 meters TVDSS near the crest to approximately 4,520 meters TVDSS at the north flank gas/water contact (GWC). Figure EGY 6 presents a structure map on the top of the M40D member of the M40 reservoir. Although reservoir net thickness varies across the M40 channel complex, the average reservoir thickness is less than 25 meters. Reservoir properties are generally good; average porosity and S_w for the individual channels within the M40 reservoir were estimated to be greater than 15 percent and less than 46 percent, respectively. Permeability was estimated to range from 0.1 to over 1,000 millidarcys with an average of several hundred millidarcys.

Production from the Raven field began in the first quarter of 2021 through eight development wells. The production license expires on February 5, 2039. The produced gas is routed to the Rosetta East facilities for processing with no substantial LPG production. The gas is rich with an estimated condensate yield of greater than 30 bbl/10^6ft^3.

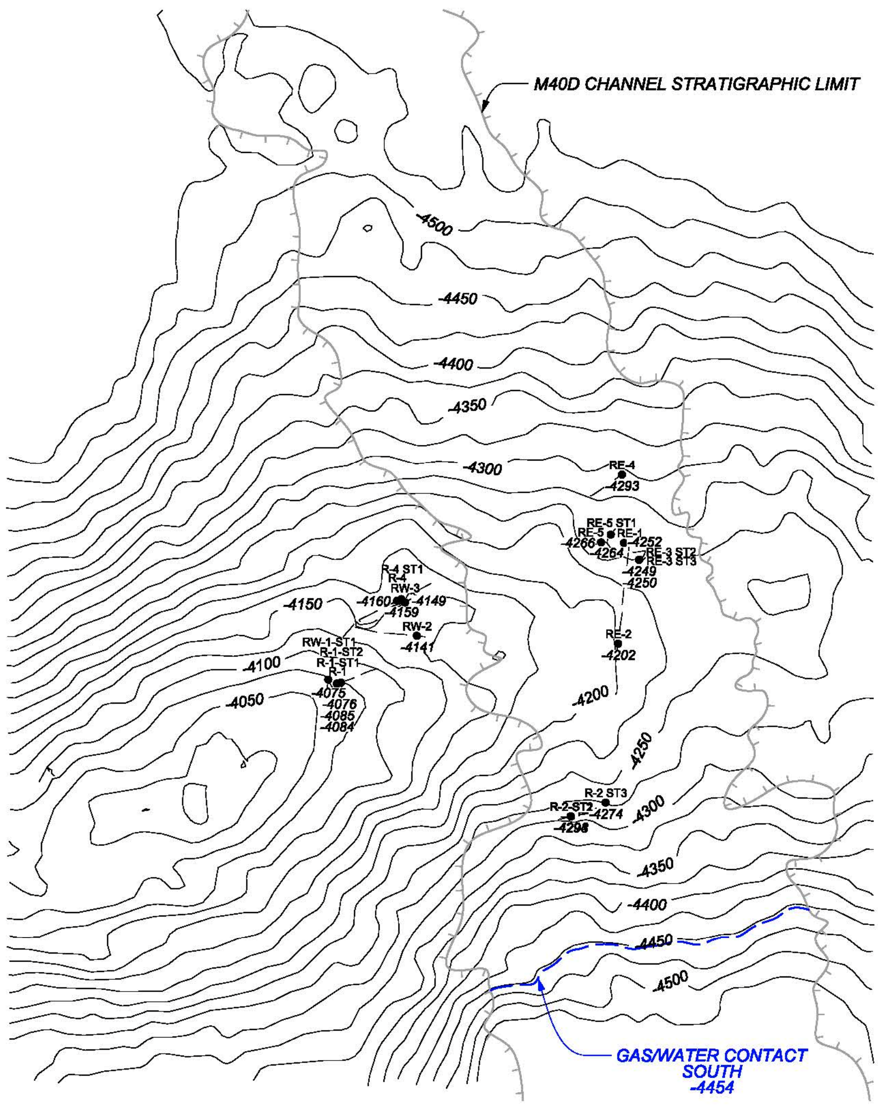

FIGURE EGY 6
STRUCTURE MAP
TOP of
M40D RESERVOIR
RAVEN FIELD
EGYPT
CONTOUR INTERVAL: 25 METERS
Scale
1000 0 1000
Meters
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2023

Reserves for the Raven field were estimated volumetrically. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this area were estimated to be 60, 70, and 80 percent, respectively. The recovery and well performance estimates were based on well-test information acquired from the Raven field as well as analogy to other comparable fields in the region.

Raven West M40E Field

The Raven West M40E field is a gas field located several kilometers to the west of the main Raven field in the Mediterranean Sea approximately 65 kilometers northwest of Alexandria, Egypt. The field was discovered by the Raven West-3 ST1 well and is part of the North Alexandria Concession area. The water depth over the field ranges from 500 to 700 meters.

The main reservoir in the field is the Miocene (Langhian) M40E reservoir located at a depth of approximately 4,437 meters TVDSS. Although reservoir net thickness varies across the M40E channel complex, the average reservoir thickness is less than 20 meters. Reservoir properties are generally good; average porosity and S_w for the M40E reservoir were estimated to be greater than 18 percent and less than 29 percent, respectively.

The Raven West M40E field is scheduled to commence producing gas and condensate, under normal depletion, in 2025 through the Raven West-5 development well, which is currently being drilled. The production license expires on February 5, 2039. The produced gas will be routed to the existing Rosetta East facilities for processing with no substantial LPG production. The gas is anticipated to be rich with an estimated condensate yield of 30 bbl/10^6ft^3 based on analogy to the main Raven field.

Reserves for the Raven West M40E field were estimated volumetrically and take into consideration the expected deliverability of the Raven West-5 development well, which produces at a maximum rate of 50 million cubic feet per day. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this area were estimated to be 60, 70, and 80 percent, respectively. The proved reserves were estimated to be zero based on economic considerations. The probable and possible reserves estimated for the field are classified as undeveloped because a significant amount of capital expenditures remain for drilling and completing the Raven West-5 development well. The recovery and well performance estimates were based on analogy to well-test information acquired from the Raven field as well as other comparable fields in the region. Reserves estimated herein are expected to be produced prior to the license expiration on February 5, 2039.

Raven West Serravallian 4 Field

The Raven West Serravallian 4 field is a gas field located several kilometers to the west of the main Raven field in the Mediterranean Sea approximately 65 kilometers northwest of Alexandria, Egypt. The field was discovered by the Raven West-3 ST1 well and is part of the North Alexandria Concession area. The water depth over the field ranges from 500 to 700 meters.

The main reservoir in the field is the Miocene Serravallian 4 reservoir located at a depth of approximately 3,592 meters TVDSS. Although reservoir net thickness varies across the Serravallian 4 channel complex, the average reservoir thickness is less than 15 meters. Reservoir properties are generally good; average porosity and S_w for the Serravallian 4 reservoir were estimated to be than 19 percent and less than 36 percent, respectively.

The Raven West Serravallian 4 field is scheduled to commence producing gas and condensate, under normal depletion, following drainage of the Raven West M40E reservoir through an uphole recompletion of the Raven West-5 development well, which is currently being drilled. The production license expires on February 5, 2039. The produced gas will be routed to the existing Rosetta East facilities for processing with no substantial LPG production. The gas is anticipated to be rich with an estimated condensate yield of 30 bbl/10^6ft^3 based on analogy to the main Raven field.

Reserves for the Raven West Serravallian 4 field were estimated volumetrically and take into consideration the expected deliverability of the Raven West-5 development well producing at a maximum rate of 50 10^6ft^3/d. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus- possible reserves in this area were estimated to be 60, 70, and 80 percent, respectively. The proved reserves were estimated to be zero based on economic considerations. The probable and possible reserves estimated for the field are classified as undeveloped because a significant amount of capital expenditures remain for drilling and completing the Raven West-5 development well. The recovery and well performance estimates were based on analogy to well-test information acquired from the Raven field as well other comparable fields in the region. Reserves estimated herein are expected to be produced prior to the license expiration on February 5, 2039.

Taurus Field

The Taurus field is a gas field located in the Mediterranean Sea approximately 80 kilometers north-northwest of Alexandria, Egypt and is part of the West Nile Delta Concession area. The field was discovered by the HJ-1X exploration well in 2000 while testing gas in Pliocene channel sandstone reservoirs.

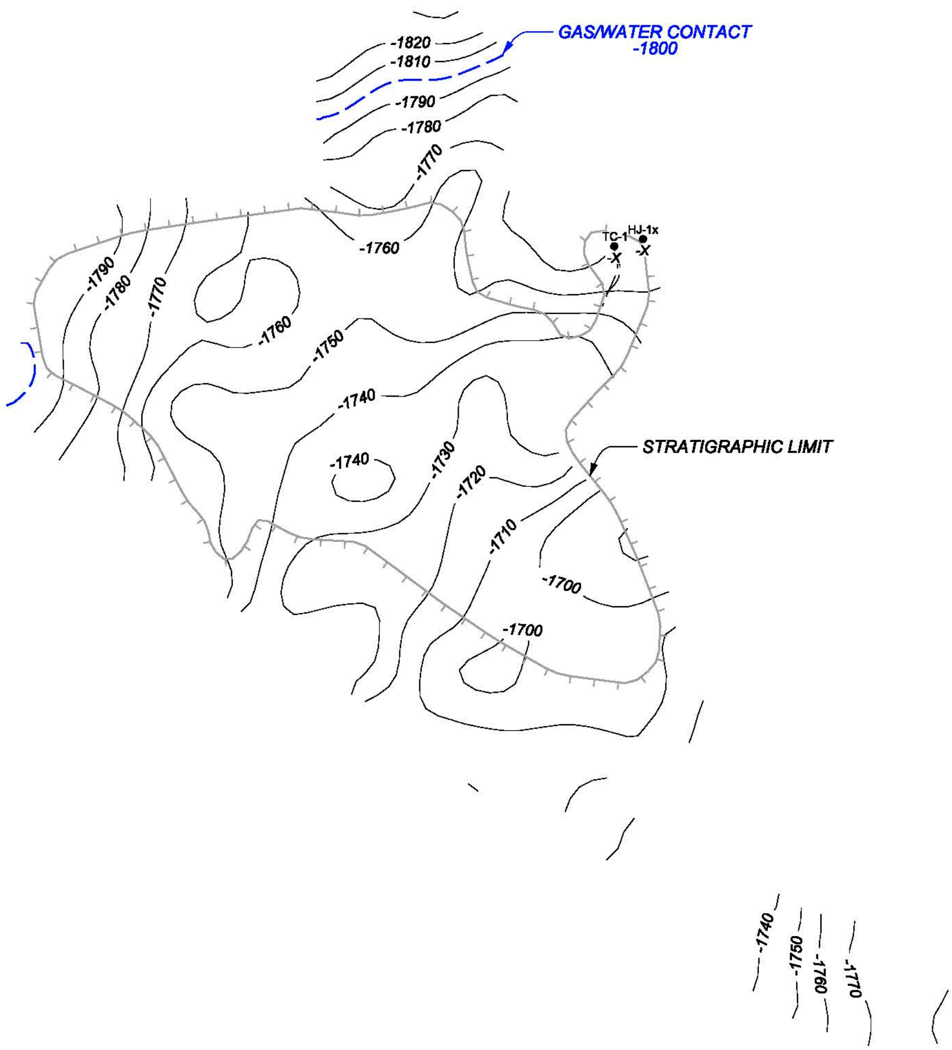

FIGURE EGY 7
STRUCTURE MAP
TOP of
P80 RESERVOIR
TAURUS FIELD
EGYPT
CONTOUR INTERVAL: 10 METERS
Scale
500 0 500
Meters
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December 2023

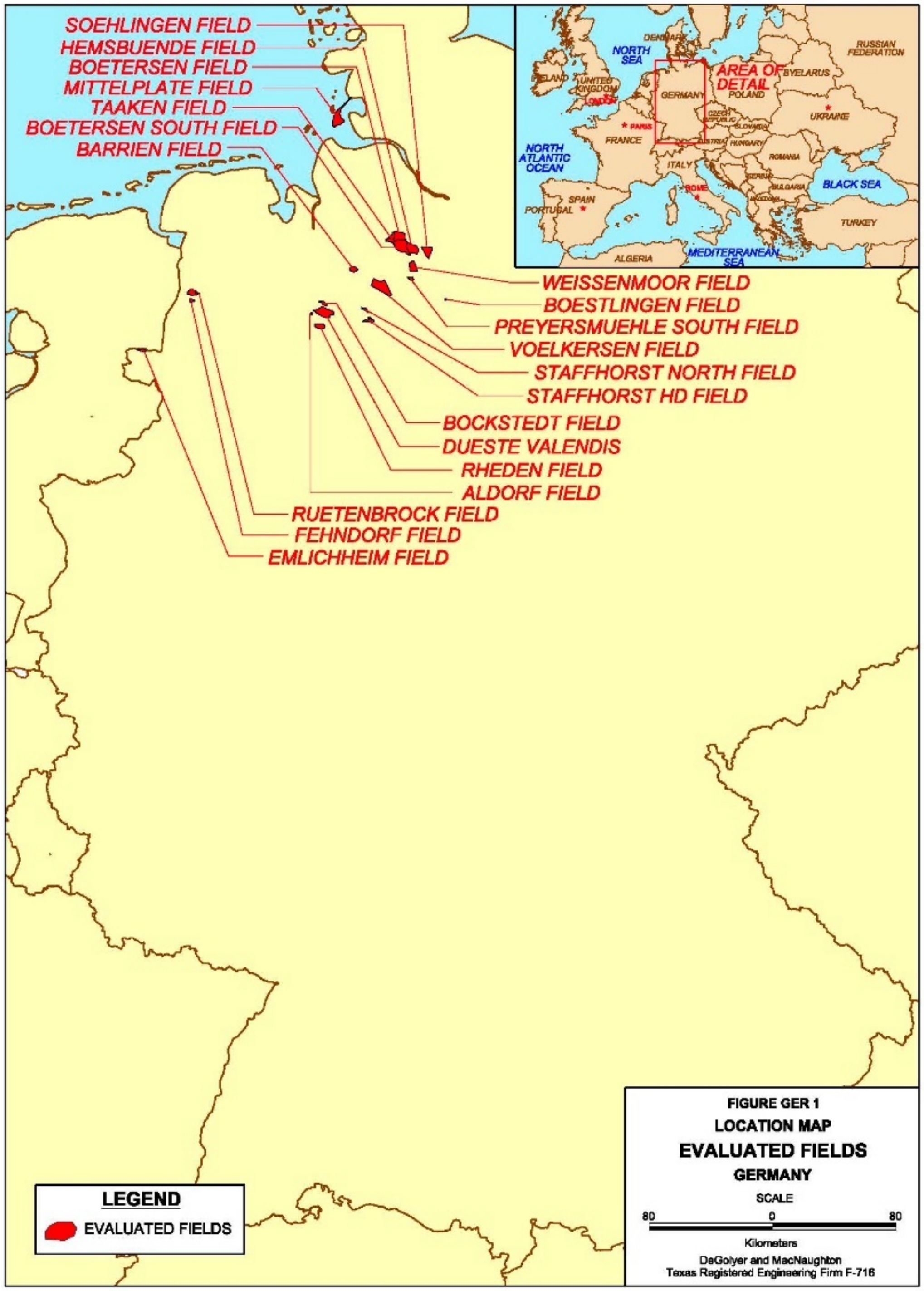
Additional appraisal wells were drilled in the field and confirmed the presence of gas-saturated channel sandstone reservoirs consisting of the P78 Channel, P78 Splay, P80 Splay, and P76 Levee reservoirs. The field is dominated by the P78 Channel complex, which trends southeast to northwest. The reservoirs range in depth from approximately 1,100 to 2,500 meters TVDSS. Figure EGY 7 presents a structure map on the top of the P80 reservoir in the Taurus field.

Production from the Taurus field began in March 2017. The field produces lean gas from six wells with a low CGR of less than 1 bbl/10^6ft^3. The P78 reservoir is the primary reservoir contributing to production. The produced gas is transported via pipeline to the existing Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Burullus facility and then exported via the Burullus condensate export system into the PPC pipeline.

Proved, probable, and possible developed reserves were estimated based on performance analysis of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration of March 24, 2037.

Germany

There are 20 fields located in Germany evaluated herein (Figure GER 1). Other than the Mittleplate field, reserves associated with the fields in Germany were projected to the economic limit and were not limited by license dates, as licenses are routinely extended to the economic limit in Germany. The Mittleplate field is expected to cease production at the license expiration date of December 31, 2041. The Emlichheim, Mittelplate, and Voelkersen fields are discussed in detail herein.



<u>Emlichheim Field</u>

The Emlichheim field is operated by Wintershall Dea and is located in the western Emsland region on the German-Dutch border. Production began in 1944. The field currently contains 69 producing wells and 9 injection wells, 5 of which are steam injection wells.

The Emlichheim field consists of a structural trap in the form of an anticline situated on the western part of an inversion axis that formed during Upper Cretaceous time. The Lower Cretaceous-age Bentheimer and Gildehaus sandstone reservoirs were deposited in a shallow marine environment and rest conformably atop the Wealden Formation. Overlying shelf mudstones, deposited during a global sea level rise, represent the seal for the two reservoirs. Porosity was estimated to range from 23 to 30 percent, initial S_w was estimated to range from 20 to 37 percent, and permeability was estimated to range from 300 to 15,000 millidarcys.

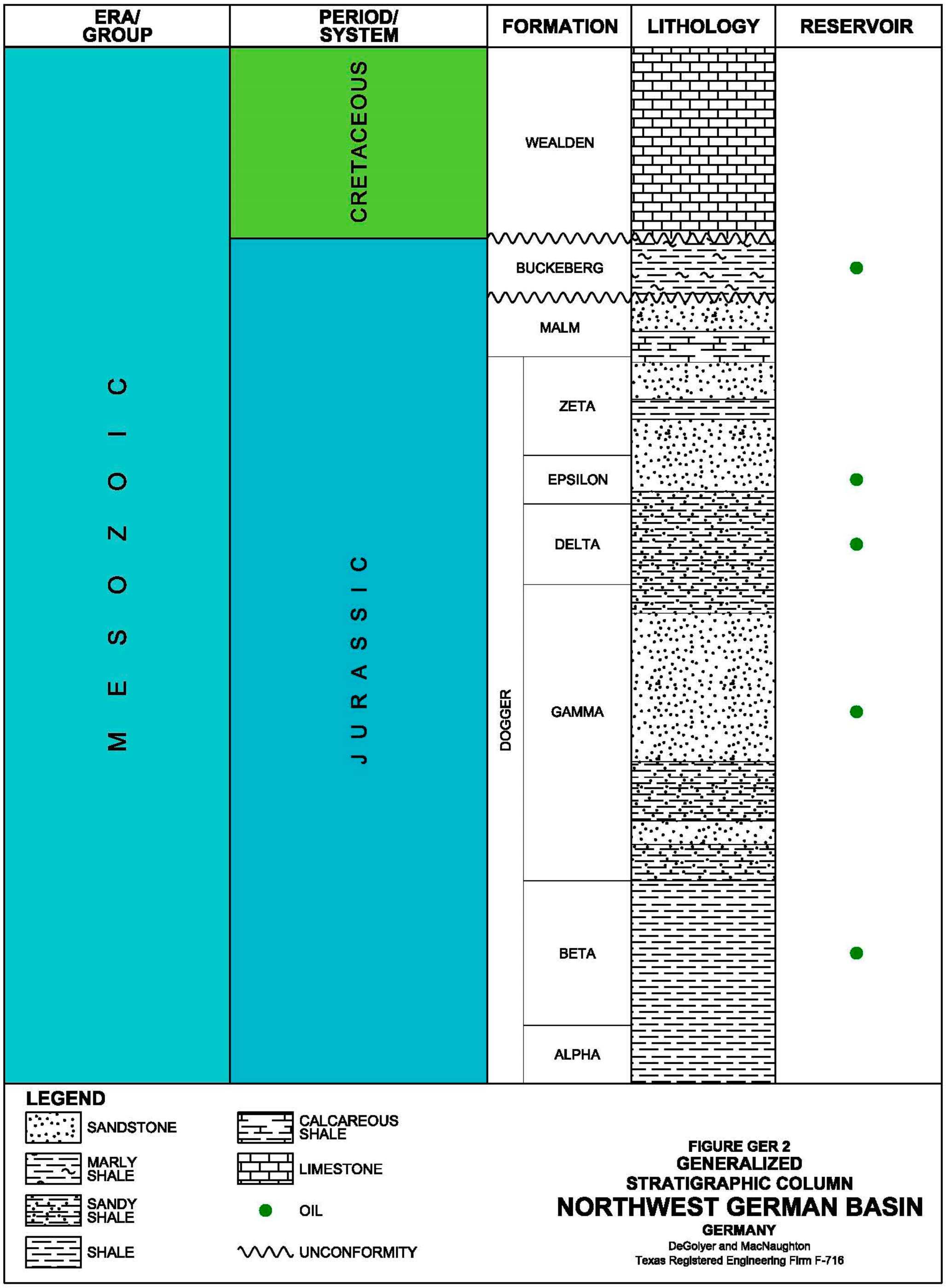
Production from the Bentheimer and Gildehaus reservoirs consists of 245 centipoise, 25 degrees API heavy oil. The initial reservoir pressure was 1,233 pounds per square inch (psi) in both reservoirs, with no aquifer pressure support, and an initial gas/oil ratio (GOR) of 73 cubic feet per barrel. The field was put under steam flooding in 1981, which will be converted to hot water injection after 2025.

Proved developed reserves were estimated by decline-curve analysis. Proved undeveloped reserves were estimated by applying a recovery factor to the estimated OOIP and limiting future development well counts and production rates to those provided in the development plans provided by Wintershall Dea. Probable and possible incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

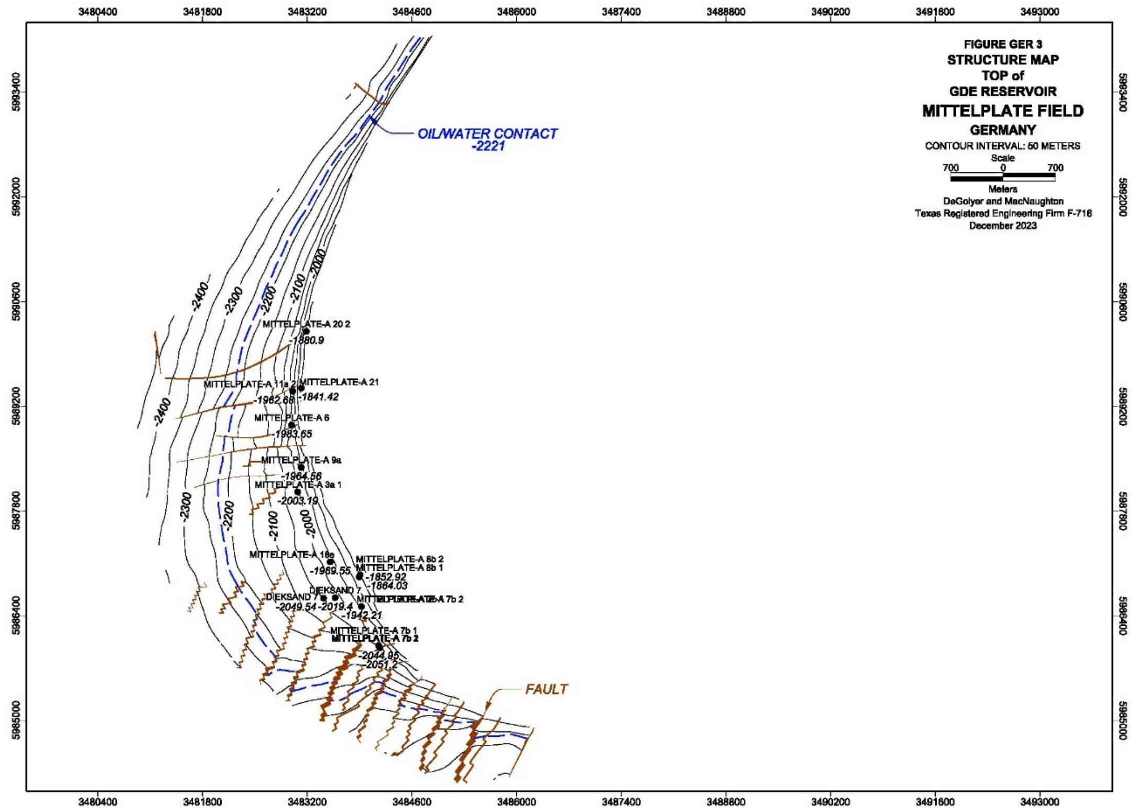
Mittelplate Field

The Mittelplate field is operated by Wintershall Dea and is located 7 kilometers off the German North Sea coast on the southern edge of the Wadden Sea national park in the State of Schleswig-Holstein, Germany.

The field was discovered in 1981 through the Mittelplate 1 well, where oil was discovered in the Jurassic-age Dogger sandstone (Figure GER 2). The field began production in 1987 and currently has 27 producing wells and 10 injection wells. Offshore operations are conducted from the Mittelplate artificial island, a drilling and production facility built in 1985, and onshore operations began in 2000 from the Dieksand production facility.



The Mittelplate structure consists of a three-way closure against a salt dome that flanks the field to the east (Figure GER 3). The field is productive from the Jurassic-age Dogger Beta, Dogger Gamma/Delta/Epsilon, and Lower Cretaceous-age Buckeberg sandstone reservoir (not currently on production). These reservoirs were deposited in a shallow marine setting and represent tide-dominated deltaic facies.



Porosity was estimated to range from 19 to 23 percent, initial S_w was estimated to range from 17 to 27 percent, and average permeability was estimated to range from 800 millidarcys in the Beta reservoir to up to 7 darcys in the Delta reservoir.

Oil quality varies from 19 degrees API in the Beta reservoir to 26 degrees API in the Gamma/Delta/Epsilon reservoirs. Initial reservoir pressure was 4,365 psi in the Beta reservoir with a weak aquifer drive mechanism and 3,394 psi in the Gamma/Delta/Epsilon reservoirs with a strong aquifer drive. Water injection provides pressure support in all reservoirs.

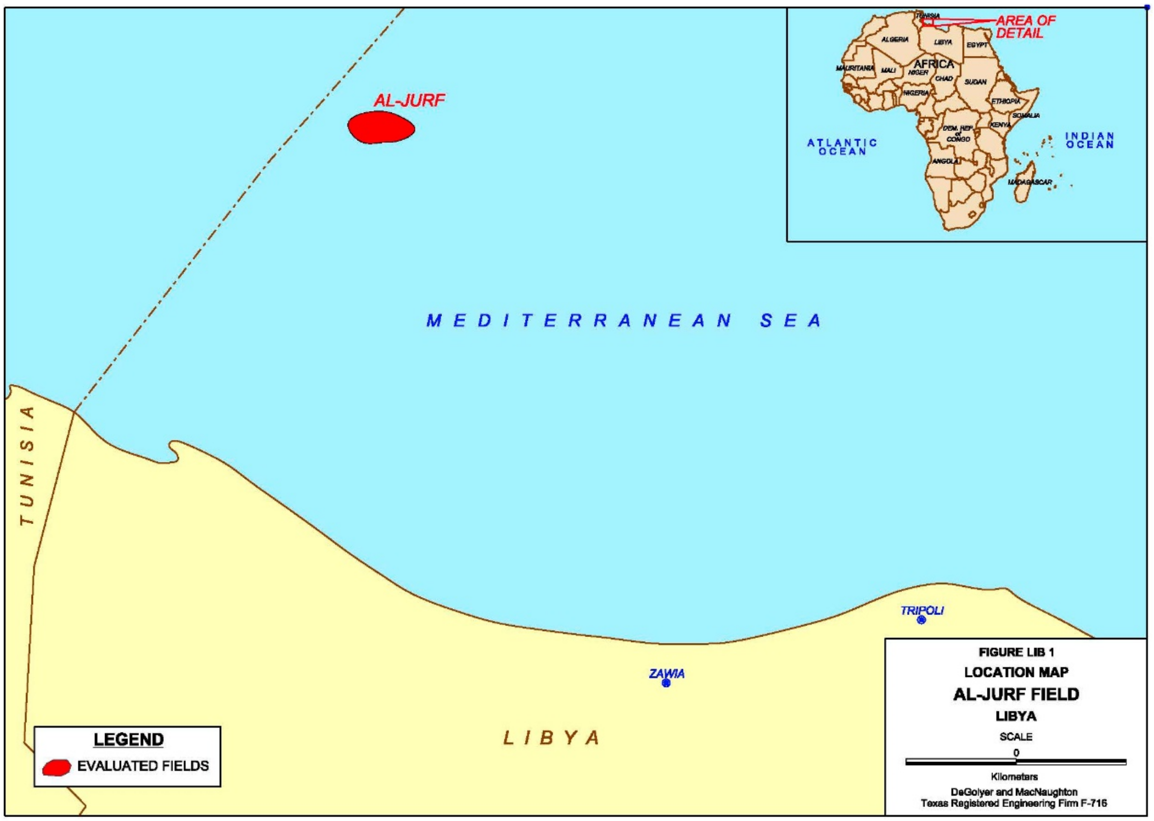
Proved developed producing reserves were estimated by decline-curve analysis and undeveloped reserves were estimated using type wells. Probable and possible incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Voelkersen field

The Voelkersen field was discovered in 1992 and began producing in 1994. The field produces from 14 wells. Production has occurred from four reservoirs: Havel, Niendorf, Wustrow, and Heidburg. The Havel reservoir is the largest contributor. Reserves were estimated based on performance analysis of the field.

Libya

The Al-Jurf field in Libya was evaluated herein, and reserves projections include a 5-year extension to the license date of April 10, 2035, to April 10, 2040. The location of the Al-Jurf field is shown on Figure LIB 1.

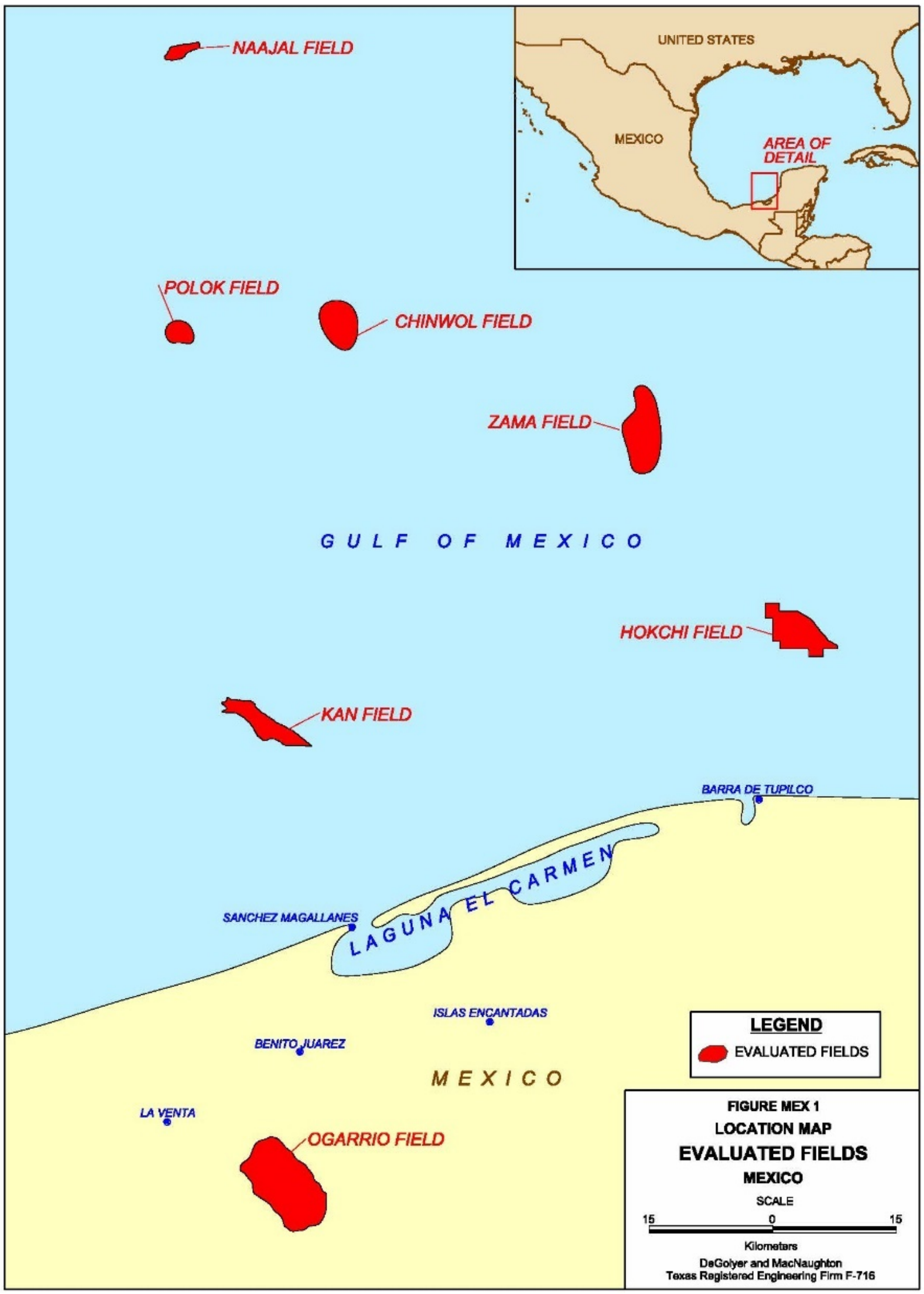


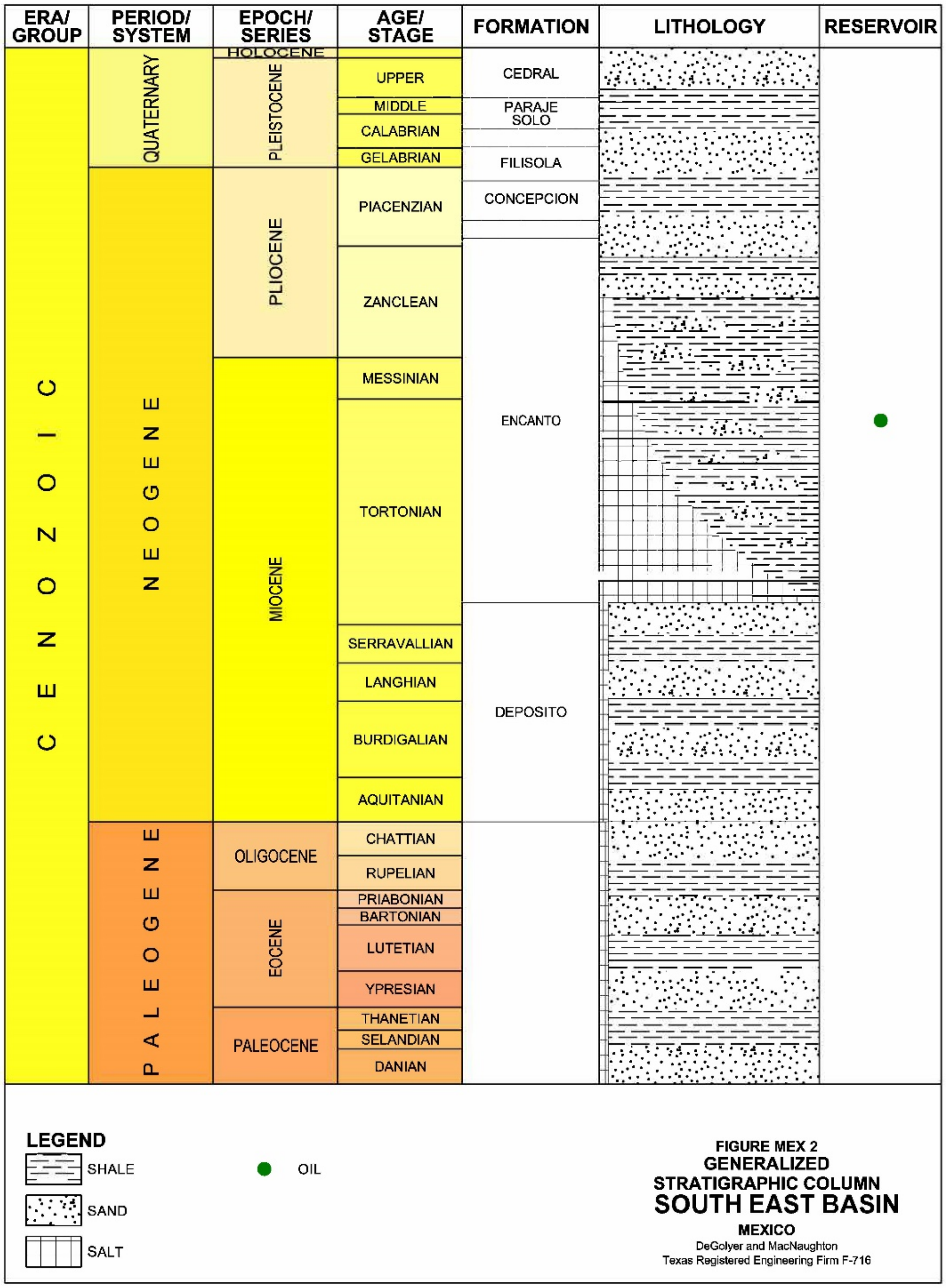
Al-Jurf Field

The Al-Jurf field commenced production in 2003 and 13 wells have been drilled to date. Developed reserves estimates were based on performance analysis of the producing wells, and no future development is planned. Probable and possible reserves estimates were based on better well performance than projected for proved reserves.

Mexico

There are seven fields within Mexico evaluated herein: Chinwol, Hokchi, Kan, Naajal, Ogarrio, Polok, and Zama (Figure MEX 1). Reserves associated with the fields in Mexico were limited to those to be recovered by the license dates with no consideration given to license extensions. The Hokchi and Ogarrio fields are discussed in detail herein.





Hokchi Field

The Hokchi field is located offshore, approximately 27 kilometers northwest of the city of Dos Bocas, in a transitional position between the Salina del Este and Comalcalco Sub-Basins. The average water depth is around 30 meters.

Pemex's exploratory activity in the area, leading to the discovery of the Hokchi field, was aimed primarily at investigating the petroleum potential of the middle Miocene and Pliocene interval, as represented by the turbiditic-origin clastic deposits, that constitute the reservoir rock of the field.

Seven wells were drilled in the Hokchi area during exploration and appraisal phases. Two of those wells were drilled by Pemex during the exploratory phase between 2009 and 2011 (Hokchi-1 and 101). Both were permanently abandoned. The remaining five wells (Hokchi-2DEL, 3-DEL, 4-DEL, 5-DEL, and 6-DEL) were drilled by Hokchi Energy between 2016 and 2017, during the evaluation phase, and all were temporarily abandoned in all cases.

The reservoir rock consists of a section of fine-grained sandstones (Figure MEX 2) with a thickness of up to 40 meters with around 10-percent clay matrix and carbonate cement, moderate to good sorting, angular to subangular clasts, and predominantly intergranular porosity. It includes intercalations of gray sandy shales in beds that are 1 to 3 meters thick. Overall, the interval does not show a clearly defined vertical granulometric trend. From a petrophysical perspective, the average porosity of the reservoir, based on laboratory measurements and petrophysical log analysis, was estimated to be about 25 percent, and permeability was estimated to range between 100 and 700 millidarcys with an average of 250 millidarcys. Sampled oil gravity varies from 22 to 29 degrees API.

The trapping mechanism is both structural and stratigraphic and is the result of salt tectonics. To the north, the accumulation is defined by a normal fault with inclination in the same direction, while the southern limit is associated with another fault, in this case, inclined to the south (Figure MEX 3). The eastern limit of the field is stratigraphic, a result of wedging of the different sandy intervals that make up the reservoir rock eastward, where a salt diapir is located. Finally, the western limit of the field is determined by the end of the accumulation and the contact with the corresponding aquifer for each sandy interval.

The geological structure of Hokchi corresponds to the axial zone of an anticline (Figure MEX-3). Such a structure is the result of the inversion of the inclination direction of synclinal limbs due to the collapse and evacuation of salt diapirs that previously limited the depocenter.

The Hokchi field started production in May 2020. By the end of 2023, the field was producing at rates of 23,000 barrels per day of oil and approximately 9 million cubic feet per day of gas. Water injection started in April 2023. Wells were drilled from two wellhead platforms in water depths of around 30 meters. No further wells are envisioned in the current development plan. The artificial-lift system consists of electric submersible pumps (ESP). Multiphase production is processed at an onshore plant that also provides the platforms with injection water and electrical power services.

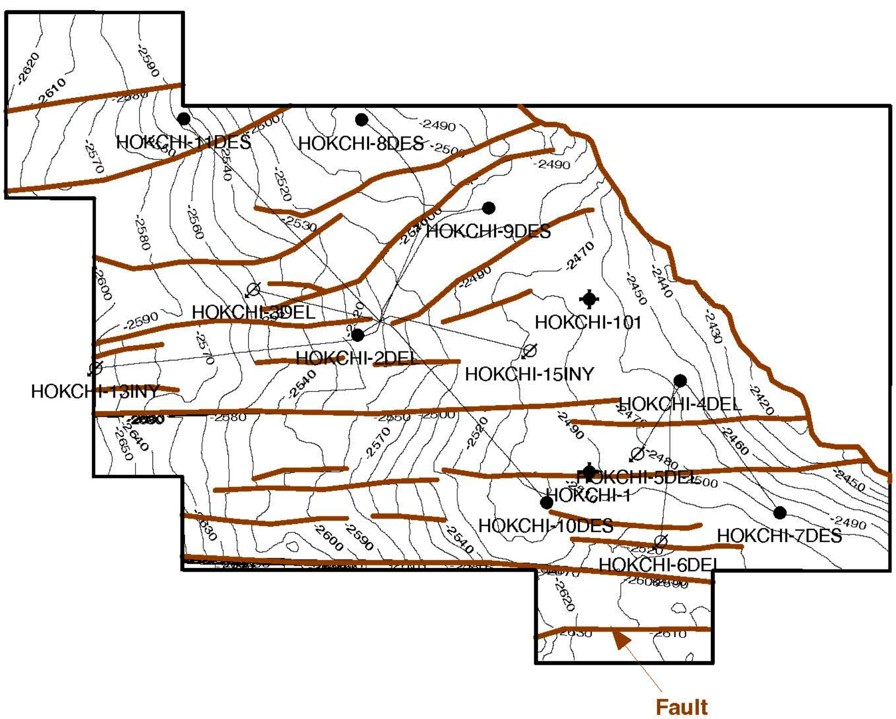


FIGURE MEX 3
STRUCTURE MAP
TOP of
MIOCENE-PLIOCENE RESERVOIR
HOKCHI FIELD
MEXICO
CONTOUR INTERVAL: 10 METERS
0 500 1000 1500m

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Proved reserves were estimated by applying a recovery factor to the estimated OOIP considering future production rates. Probable and possible incremental reserves were also estimated associated with incremental recovery greater than quantities estimated for proved and probable reserves, respectively. The field is considered to be fully developed.

Ogarrio Field

The Ogarrio field is operated by Wintershall Dea and is located in the Ogarrio Contract Area in the central-eastern region of the Salina del Istmo Basin, southeast Mexico. The field is divided into two blocks, Block A to the southwest and Block BC to the northeast, due to a salt intrusion that structured the area into two independent accumulations (Figure MEX 4). The discovery and development of this field began in 1957 with the drilling of the Ogarrio-1 well in the Block BC area.

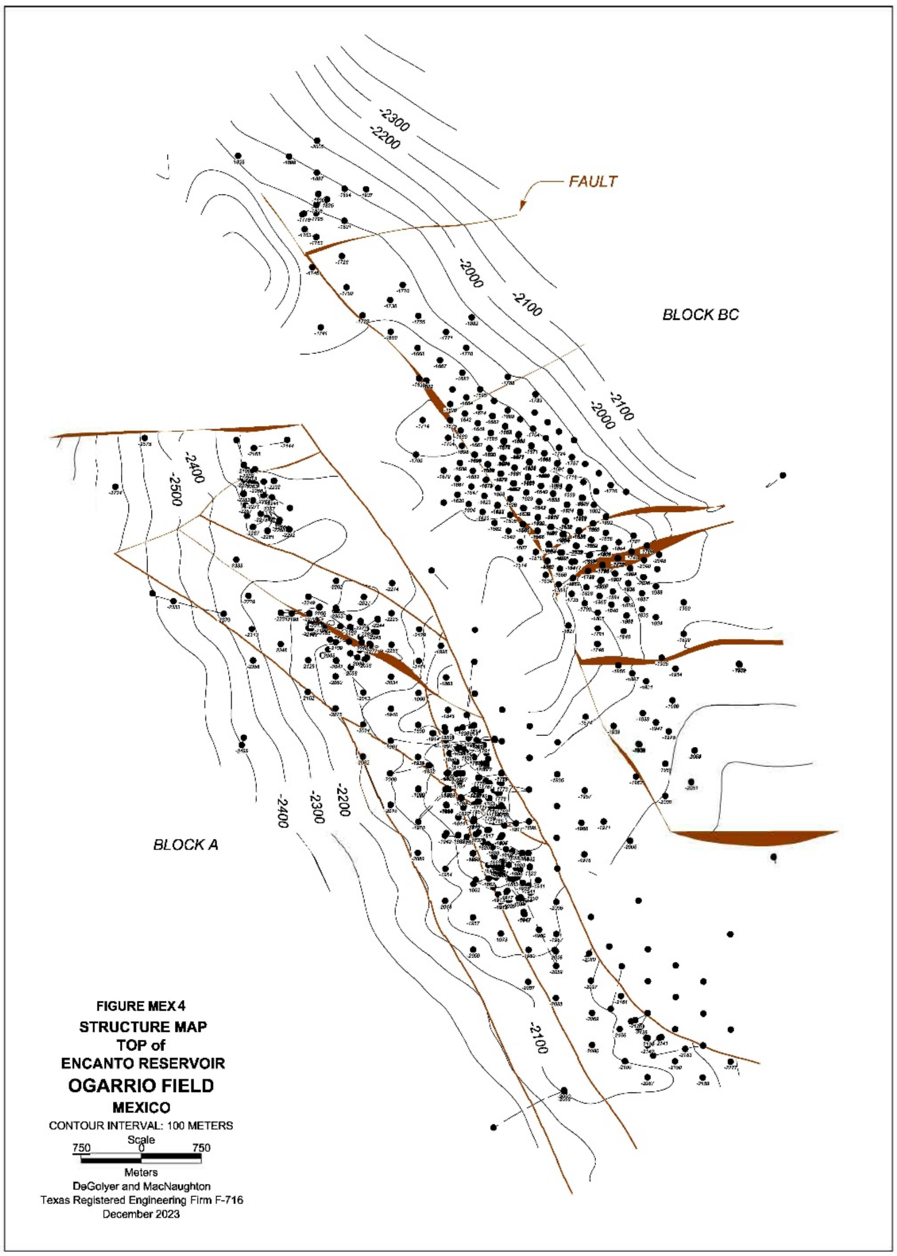
The producing reservoirs in this field are Tertiary sandstones of upper Miocene age of the Encanto Formation (Figure MEX 2). These clastic reservoirs were originally associated with a variety of sub-environments, deepwater turbidities, and submarine fans deposited in the Miocene slope basin. This formation was affected by salt tectonics, which contributed to the generation of normal faults and, together with the top of the salt dome, work as seals for this field.

In the Encanto Formation in the Ogarrio field, average S_w values for Block A and Block BC were estimated to be 28 and 30 percent, respectively. The average effective porosity in both blocks was estimated to be approximately 22 percent, and the average permeability was estimated to range from 60 to 136 millidarcys in both blocks. The average gross thickness is 805 and 975 meters for Block A and Block BC, respectively. The average net thickness is 29 and 71 meters for Block A and Block BC, respectively.

The reservoir fluid is black oil and has a density varying from 36 to 39 degrees API. The viscosity ranges from 0.3 to 0.5 centipoise, and the initial GOR is approximately 1,180 cubic feet per barrel. The initial pressure is approximately 4,150 psi and the bubblepoint pressure is 2,830 psi.

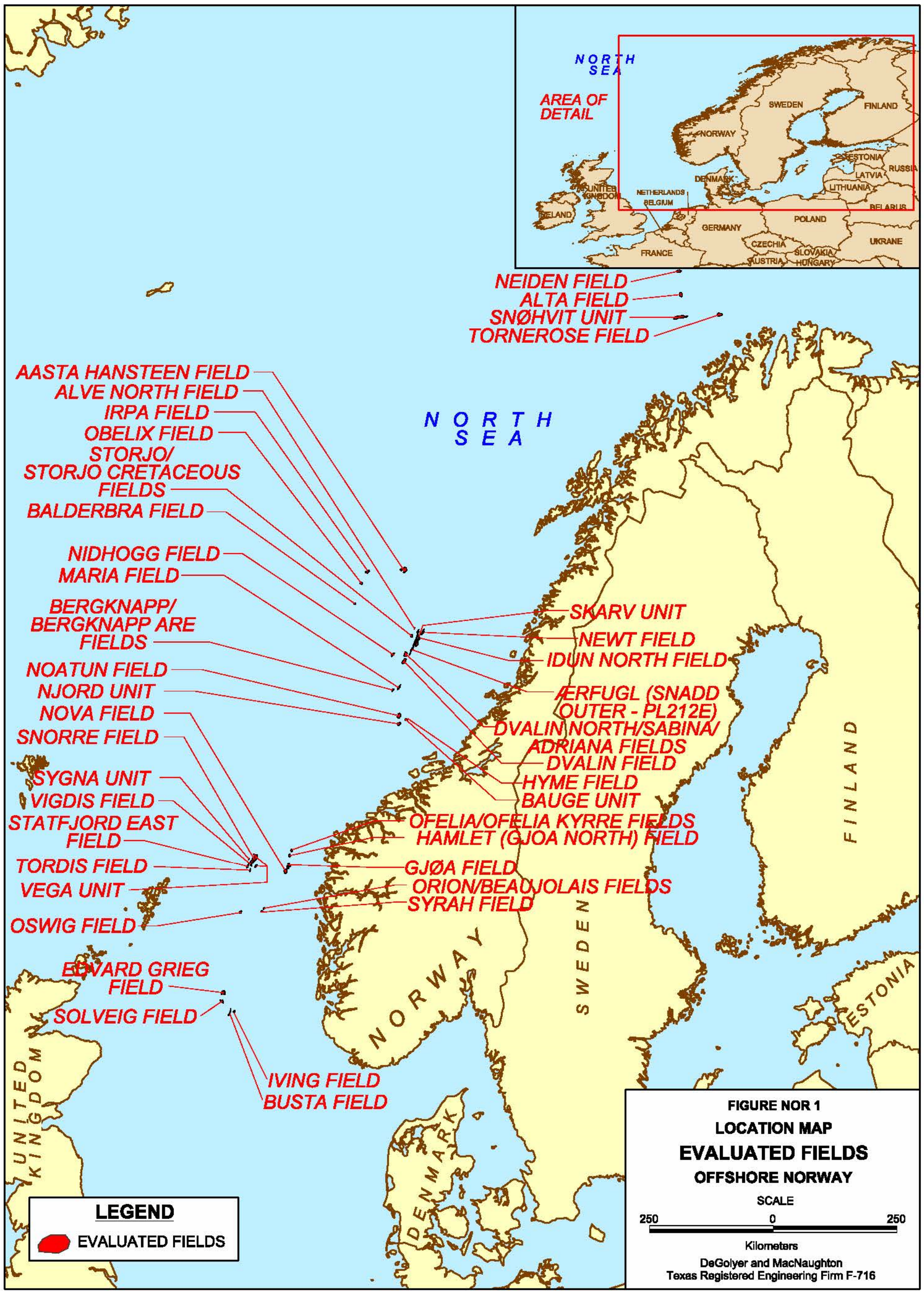
By the end of 2023, a total of 234 million barrels of oil had been recovered from the field, corresponding to a recovery factor of 18 percent. In December 2023, the field was producing at average rates of 4,900 barrels per day of oil and 8 million cubic feet per day of gas from 91 wells. Production forecasts are in accordance with the expected activity levels as stated in the Ogarrio field development plan, performance review of individual active wells, 101 well interventions carried out in 2022 and 2023, and the results of new wells.

Proved developed producing reserves were estimated using performance-based methods, primarily decline-curve analysis of oil rate versus time of individual wells and oil rate versus cumulative oil production. Developed non-producing and undeveloped reserves were estimated by analogy (type-well analysis) with nearby wells producing from the targeted reservoirs. Probable and possible incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.



Norway

There are 46 fields located within Norway evaluated herein (Figure NOR 1). Reserves associated with the fields in Norway were projected to the economic limit and were not limited by license dates, as licenses are routinely extended to the economic limit in Norway. Production occurs mainly from Jurassic and Cretaceous reservoirs as noted in the stratigraphic column below (Figure NOR 2). Selected fields are discussed in detail herein.



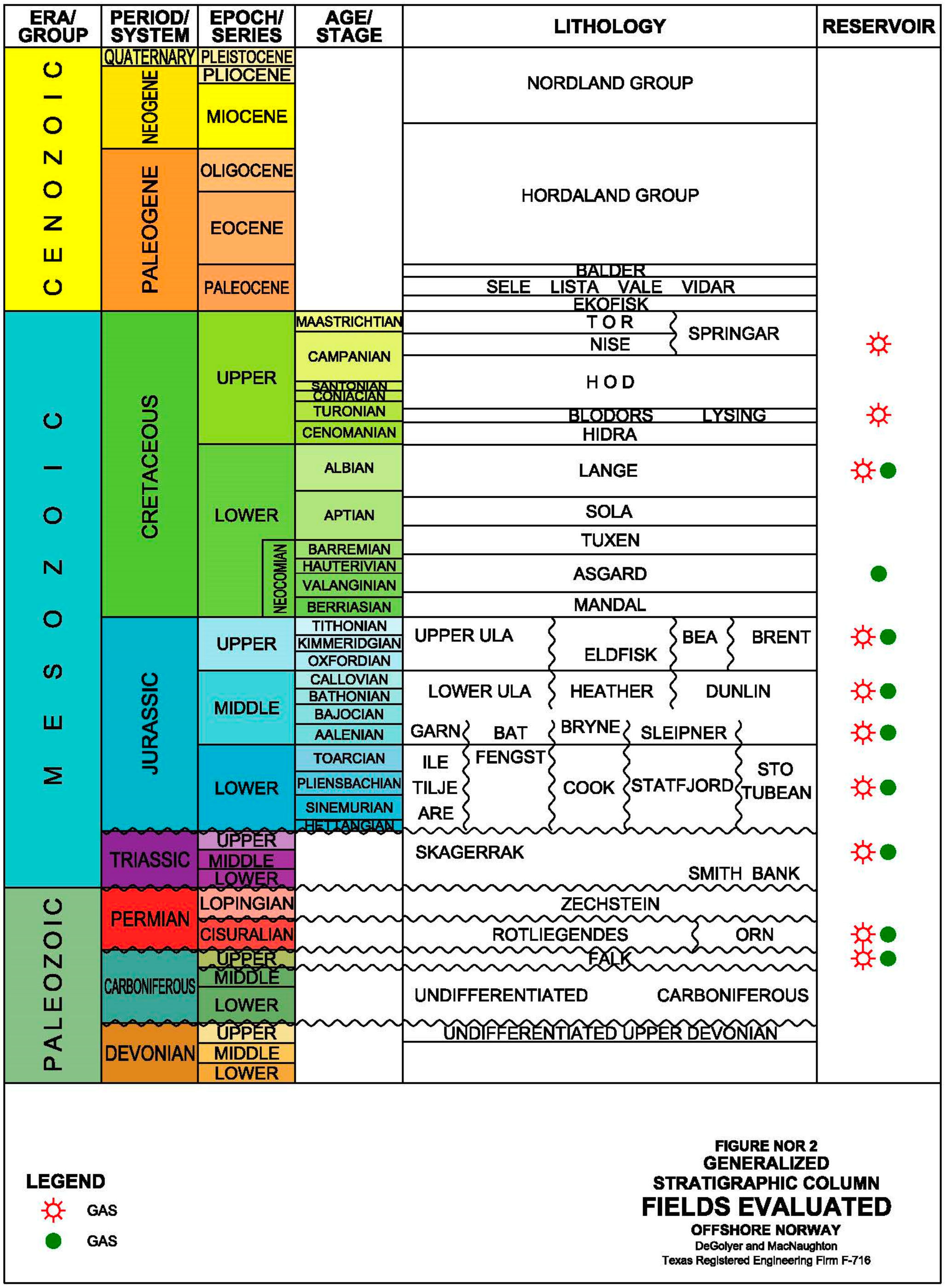


FIGURE NOR 2
GENERALIZED
STRATIGRAPHIC COLUMN
FIELDS EVALUATED
OFFSHORE NORWAY
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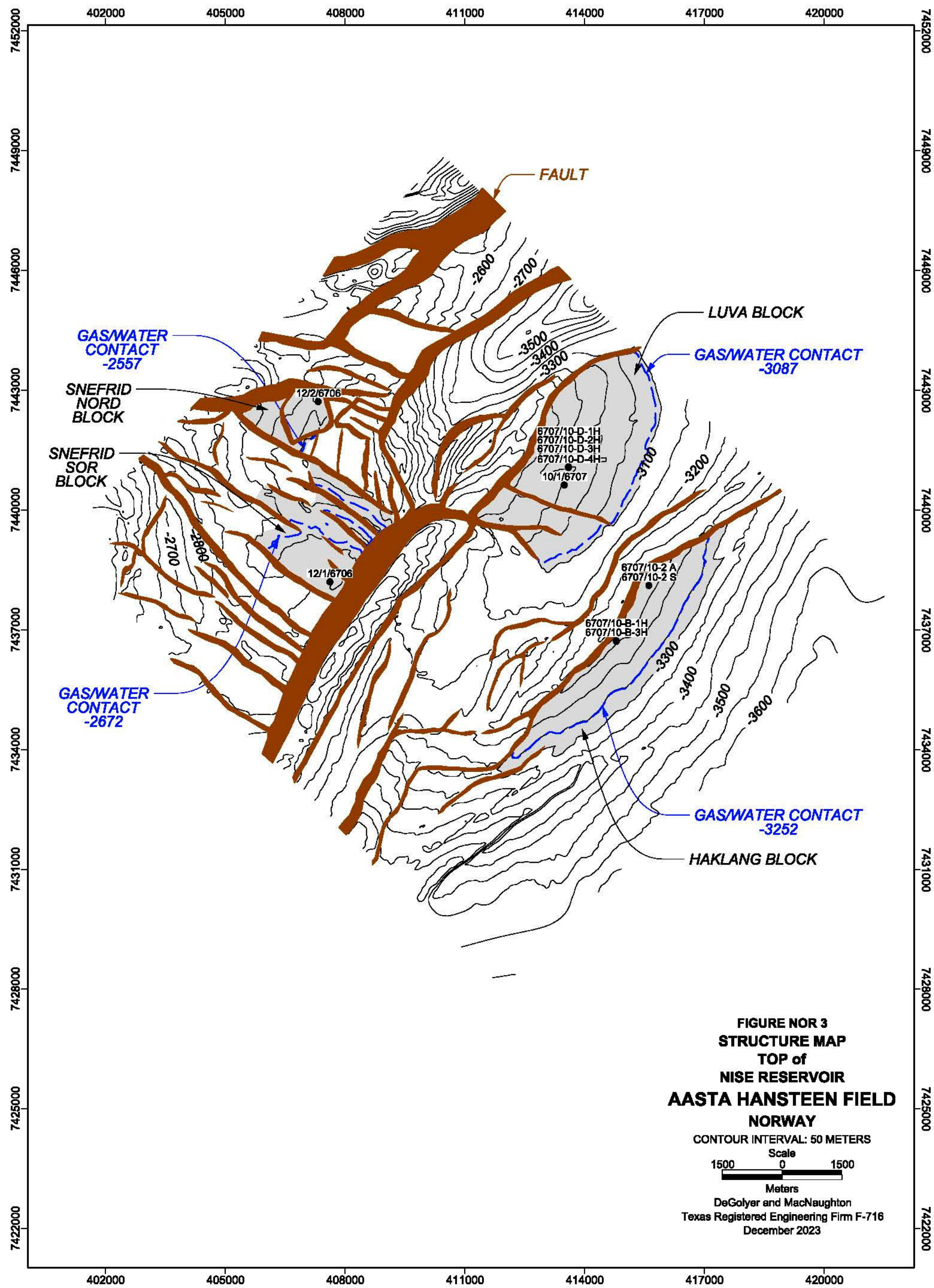
Aasta Hansteen Field

The Aasta Hansteen field is located in PL218 and PL218B of the Norwegian North Sea, approximately 300 kilometers offshore in 1,260 meters of water. The field was discovered in 1997 when well 6707/10-1 was drilled into the Upper Cretaceous-age, gas-charged Nise Formation. The structure is composed of four tilted fault blocks: Haklang, Luva, Snefrid North, and Snefrid South. The primary trapping mechanism within the field is composed of three-way or four-way closures associated with these tilted fault blocks (Figure NOR 3).



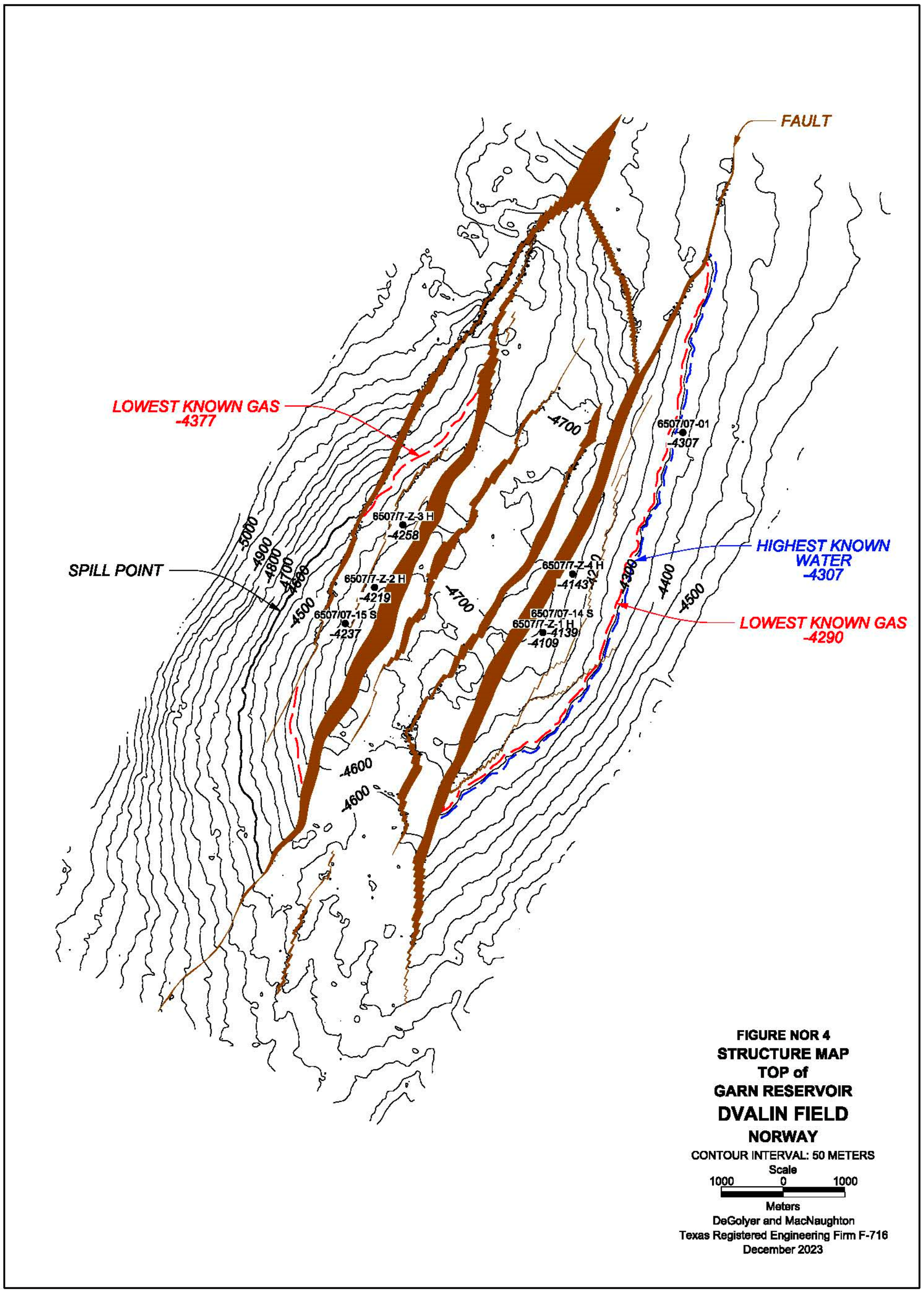
The Nise Formation is composed of unconsolidated turbidite sands sourced from the Western Greenland Margin. The sands were deposited in a deep, bathyal paleoenvironment. At the Aasta Hansteen field, reservoir porosity was estimated to range from 24 percent in the Snefrid North Block to 30 percent in the Snefrid South Block. The GWCs differ between the four fault blocks: 3,087 meters true vertical depth subsea (TVDSS) in the Luva Block; 3,252 meters TVDSS in the Haklang Block; 2,672 meters TVDSS in the Snefrid South Block; and 2,557 meters TVDSS in the Snefrid North Block.

The last development well, E-1 HT2, was completed in the main portion of the field in November 2018, and production started in December 2018. The field produces gas and a small amount of condensate; gas is transported via the Polarled pipeline to the Nyhamna gas processing facility and condensate is stored on the SPAR platform and offloaded to shuttle tankers.

Proved, probable, and possible reserves were estimated volumetrically with recovery factor estimates ranging from 69 to 82 percent based on depletion drive. A total of eight wells were drilled in the development of the Haklang, Luva, Snefrid South, and Snefrid Nord structures. Estimates of future performance from the wells took into account sales capacity constraints and expectations of future production efficiency.

Dvalin Field

The Dvalin field, formerly known as the Zidane field, is located northwest of the Heidrun field in the Norwegian North Sea and is operated by Wintershall Dea. The field is a faulted anticline that is separated into western and eastern accumulations (Figure NOR 4). The eastern accumulation was discovered in 2010 and the western accumulation was discovered in 2012. The development targets in the field are the Jurassic-age Garn and Ile sandstones, which produce gas and condensate. The Garn is the larger of the two reservoirs and has more favorable reservoir characteristics. The average NGR in the Garn reservoir is approximately 90 percent, and the Ile reservoir has an average NGR of approximately 50 percent. Permeability of the Garn Formation was estimated to range from 0.1 to 1,000 millidarcys with an average of approximately 100 millidarcys. Permeability of the Ile reservoir permeability was estimated to range from 0.01 to 1 millidarcy. Average porosity in the Garn and Ile reservoirs was estimated to be approximately 10 percent and S_w was estimated to range from 17 to 40 percent.



The Dvalin field began producing to the Heidrun facilities in 2020. Proved, probable, and possible reserves were estimated using volumetrics. The OGIP associated with proved reserves in this accumulation considers a vertical limit at the lowest known gas seen in the discovery well. The proved-plus-probable-plus-possible scenario considers the structure to be gas saturated to the structural spillpoint. The proved-plus-probable scenario considers a vertical limit at a depth halfway between the lowest known gas and the spillpoint of the structure. Recovery factors were estimated to range from 74 to 76 percent based on estimated abandonment pressures.

Dvalin North

The Dvalin North field is located approximately 10 kilometers north of the Dvalin field in the Norwegian North Sea and is operated by Wintershall Dea. The field is a faulted closure with three blocks: East, Graben, and West. The 6507/4-2S discovery well was drilled in the East block in 2021. The development target in the field is the Jurassic-age Garn Sandstone, which contains gas and condensate.

The average NGR in the Garn reservoir was estimated to be approximately 90 percent. Permeability in the Garn Formation was estimated to range from 0.01 to 2,000 millidarcys with an average of approximately 10 millidarcys. Average porosity in the Garn reservoir was estimated to range from approximately 12 to 15 percent and average S_w was estimated to range from approximately 20 to 25 percent.

The Dvalin North development will consist of three slanted producing wells tied back to the Dvalin field, which will be produced to the Heidrun facility. Dvalin North production will be combined with production from the Dvalin field to maintain a production plateau rate based on facility capacity.

Proved, probable, and possible reserves were estimated using volumetrics, and each fault block was considered separately for recovery. Successive fault blocks farther away from the drilled discovery well are less certain to contribute to recovery based on current data. Recovery factors may range up to 76 percent based on estimated abandonment pressure.

Irpa Field

The Irpa field is a single-well discovery located in the Voring Basin approximately 70 kilometers west of the Aasta Hansteen field. The field was discovered in 2009 by well 6705/10-1, which encountered gas in the turbidite sands of the Late Cretaceous-age Springar Formation. The Irpa structure is defined by a northeast-trending, double-plunging anticline with stratigraphic pinchouts to the northwest and southeast. A GWC was observed at 3,276 meters TVDSS. Due to the depositional environment and lack of well control, uncertainties in lateral reservoir continuity were the primary consideration for estimating recovery.

Reserves associated with the Irpa field were estimated by applying a recovery factor to the estimated OGIP and limiting future development well counts and production rates to those provided in the development plans provided by Wintershall Dea. The Irpa field is currently being developed as a tie-in to Aasta Hansteen.

Maria Field

The Maria field is located in the Norwegian North Sea and is operated by Wintershall Dea. The field is a one-accumulation stratigraphic trap with two structural highs to the north and south separated by a structural low. The Maria field was discovered in 2010 and has been producing since 2017. The development target in the field is the Jurassic-age, oil-bearing Garn Formation. The sandstones of the Garn Formation were deposited in a shallow marine progradational depositional setting.

The NGR in the Garn ranges from 55 to 85 percent with an average of 70 percent. Permeability was estimated to range from 1 to 1,000 millidarcys with an average of 150 millidarcys, porosity was estimated to range from 11 to 18 percent with an average of 14 percent, and S_w was estimated to range from 15 to 60 percent with an average of 40 percent.

Nine wells have been drilled to develop the Maria field, plus three exploration wells. Water used for water injection is supplied from the Heidrun platform and gas used for gas lift is supplied from the Åsgard B platform. Oil is transported through the Kristin platform to the Åsgard C offloading and export facility.

Reserves for the Maria field were estimated based on volumetric analysis. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated to range from 28 to 43 percent.

Njord Field

The Njord field is located in the Norwegian Sea, 30 kilometers west of the Draugen field in a water depth of 330 meters, and is operated by Equinor ASA. The Njord field was discovered in 1986 through the 6407/7-1 S well, where oil was discovered in the Jurassic-age Tilje, Ile, and Åre Formations. The field consists of a highly faulted anticlinal structure with fluid contacts that vary by fault block. The Tilje Formation was deposited in a fluvial-tidal environment with some shallow marine influence, while the Ile Formation was deposited in a shallow tidal marine environment. The Åre Formation was deposited in a fluvial setting.

For the Tilje Formation, porosity was estimated to range from 16 to 19 percent with an average of 17 percent and S_w was estimated to range from 36 to 37 percent with an average of 37 percent.

For the Ile Formation, porosity was estimated to range from 16 to 19 percent with an average of 18 percent, permeability was estimated to range from 7 to 287 millidarcys with an average of 101 millidarcys, and S_w was estimated to range from 36 to 37 percent with an average of 37 percent.

For the Åre Formation, porosity was estimated to range from 14 to 16 percent with an average of 15 percent, permeability was estimated to range from 1 to 35 millidarcys with an average of 24 millidarcys, and S_w was estimated to range from 53 to 55 percent with an average of 54 percent.

The Njord field began production in 1997 and currently consists of nine producing wells and two injection wells. The field produces through the Njord A production platform and exports through the Njord Bravo storage and offloading facility. The field was temporarily shut in for new drilling, upgrades, and repairs in 2016. Production was re-established in December 2022.

Reserves for the Njord field were estimated based on volumetric analysis. The recovery factors for the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated to range from 20 to 25 percent for the oil-producing formations and from 50 to 60 percent for the gas-producing formations.

Nova Field

The Nova field is an oil and gas field located in the northeastern North Sea, 17 kilometers from the Gjøa platform, and is operated by Wintershall Dea. The field is a faulted, angular unconformity trap consisting of several fault blocks. The Nova field was discovered in 2012 and appraised in 2013 and 2014. Production began in 2022. The development targets in the field are the Middle Oxfordian- and Bathonian-age deepwater turbidite Heather sandstone reservoirs.

The NGR in the Intra Heather sandstone reservoirs ranges from 55 to 80 percent with an average of 70 percent. Porosity was estimated to range from 1 to 24 percent with an average of 14 percent, permeability was estimated to range from 0.01 to 1,000 millidarcys with an average of 200 millidarcys, and S_w was estimated to range from 10 to 60 percent with an average of 30 percent.

The Nova field is tied back to the Gjøa platform for processing and export. The Gjøa platform also provides lift gas to the field and water injection for pressure support.

Reserves estimates for the Nova field were based on volumetric analysis and performance to date. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated to range from 29 to 45 percent.

Skarv Unit

The Skarv Unit in inclusive of three Skarv accumulations (A, B, and C) as well as the Ærfugl, Gråsel, and Idun accumulations, but does not include the Idun North or Ærfugl North discoveries, which are separate accumulations north of the Skarv and Idun structures on a separate license.

The Skarv field, inclusive of Idun, (Figure NOR 5) was discovered in 1998 and the plan for development and operation was approved in June 2007. Production began in 2013 to a floating production, storage, and offloading vessel (FPSO) which services the subsea templates of the Skarv Unit, as well as tie-backs off license. Similar to a number of fields in this area, the field produces a combination of gas, LPG, condensate, and oil. The produced oil and condensate are comingled on the FPSO for storage and export, and the LPG is extracted from the rich gas export stream at the Karsto plant onshore.

The Skarv field contains four producing wells and two injection wells in Accumulation A, two producing wells and one converted gas producer well in Accumulation B, and two producing wells and one injection well in Accumulation C. The Idun accumulation was historically produced from two gas wells, both of which are shut-in. Gas was historically injected into all three of the Skarv accumulations, but now only Accumulation A has active injection for pressure support; however, injection is expected to end in the near future. Undeveloped reserves were estimated for the planned gas blowdown to start subsequent to the end of injection. Fuel gas and costs were allocated among the fields (including Ærfugl) contributing to the FPSO.

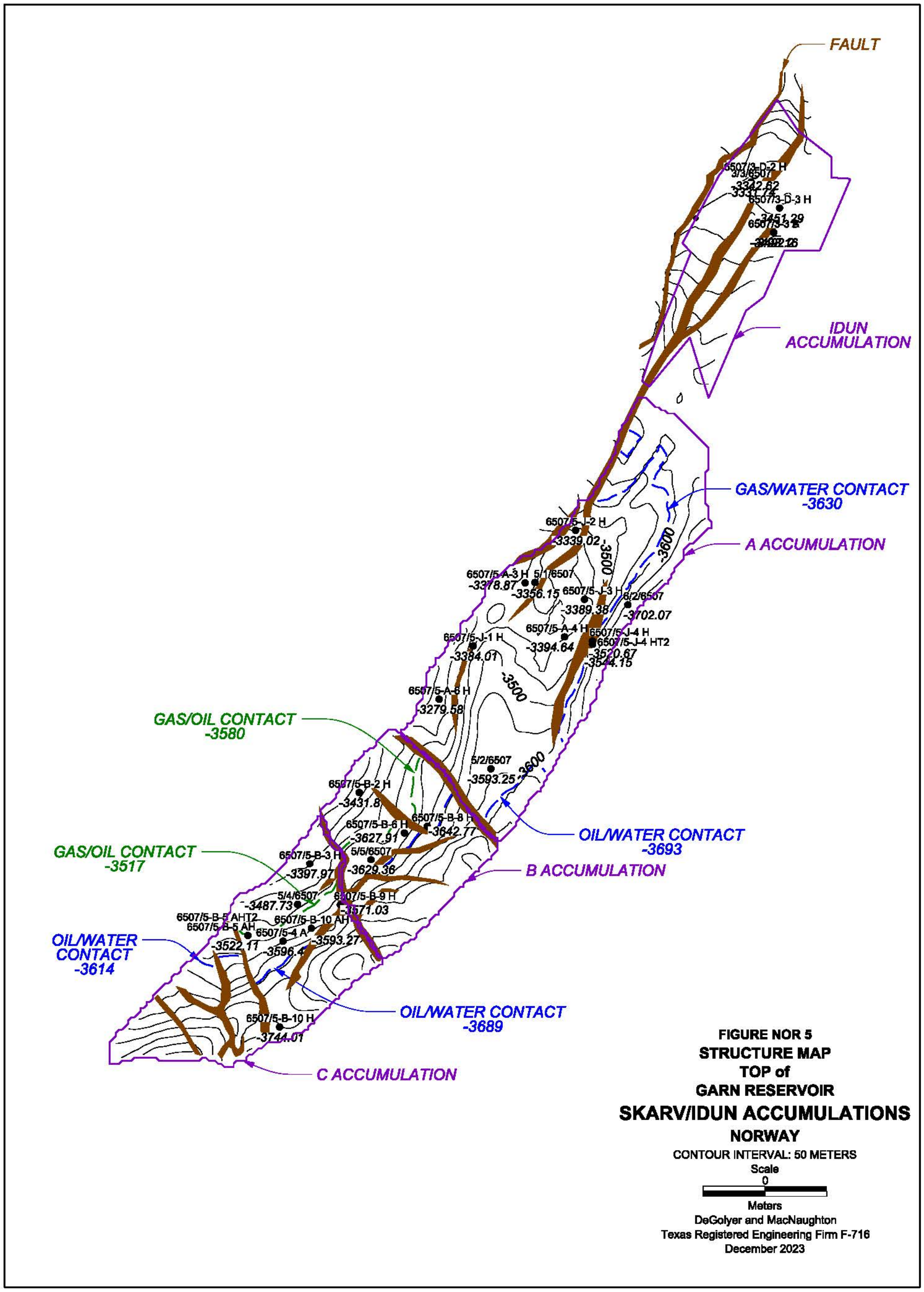


FIGURE NOR 5
STRUCTURE MAP
TOP of
GARN RESERVOIR
SKARV/IDUN ACCUMULATIONS
NORWAY
CONTOUR INTERVAL: 50 METERS
Scale
0
Meters
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
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The main reservoirs in the Skarv accumulations and Idun accumulation are the Lower and Middle Jurassic-age sandstones of the Garn, Tilje, and Ile Formations. These reservoirs were deposited in varied environments of deposition ranging from progradational shallow marine for the Garn reservoir, to shallow tidal marine for the Ile reservoir, to fluvial-tidal, lagoonal, and shelfal environments for the Tilje reservoir. The average reservoir depth is 3,500 meters below mean sea level. The Skarv field is broken into three main fault blocks, each with different fluid contacts and each with different hydrocarbon compositions. There is additional minor faulting in all three fault blocks that may serve as baffles to flow within each fault block.

The porosity in the Garn Formation was estimated to range from 14 to 19 percent with an average of 15.5 percent and S_w was estimated to range from 8 to 18 percent with an average of 12 percent. The average permeability was estimated to be 1,500 millidarcys and average net hydrocarbon thickness was estimated to be 80 meters.

The porosity in the Ile Formation was estimated to range from 13 to 16 percent with an average of 14 percent and S_w was estimated to range from 30 to 55 percent with an average of 32 percent. The average permeability was estimated to be 10 millidarcys and the average net hydrocarbon thicknesses was estimated to be 37 meters.

The porosity in the Tilje Formation was estimated to range from 12 to 17 percent with an average of 15 percent and S_w was estimated to range from 31 to 52 percent with an average of 35 percent. The average permeability was estimated to be 40 millidarcys and the average net hydrocarbon thickness was estimated to be 65 meters.

Produced liquids from the Garn, Ile, and Tilje reservoirs in the Skarv field consist primarily of oil with a gravity of 33 degrees API. There are some deeper gas-condensate reservoirs not currently producing. The producing GOR of the Skarv field has risen steadily over the past several years of gas injection and is currently approximately 88,000 cubic feet per barrel.

The Idun accumulation is split by a central fault into the East and West fault blocks. It is interpreted that there is limited pressure communication between the two fault blocks. The produced fluid is gas-condensate.

Developed reserves estimates for the Skarv field and Idun accumulation were based on performance analysis of existing individual wells and the declines they manifested and were supported by volumetric calculations. As oil production ceases in parts of the Skarv Unit, gas injectors are converted to gas producers. The gas recovery associated with the gas blowdown is included in estimates of reserves. Gas rate projections are constrained to accommodate FPSO limits, inter-field connection limits, and operator annual rate maximums.

<u>Snorre Field</u>

The Snorre field began producing in 1992. It produces from 24 wells with pressure support from water injection, gas injection, and water-alternating-gas (WAG) injection wells. Developed reserves estimates reflect performance analysis of the existing active wells. Undeveloped reserves estimates were based on projected performance from an ongoing infill drilling program. Reserves were estimated up to the technical lifetime of the platform, ending in 2050.

<u>Vega Field</u>

The Vega field, located in the North Sea 30 kilometers west of the Gjøa field in 370 meters of water, was discovered by well 35/8-1 in 1981. The field is operated by Wintershall Dea and is located in licenses PL090C and PL248. The production of gas-condensate commenced in 2010.

The Vega field consists of three separate structures, Vega North, Vega Central, and Vega South, which are separated by north-trending extensional faults crossed by secondary northeast-trending faults that formed during Late Jurassic time. The Middle Jurassic-age Brent Group sandstones were deposited in a shallow marine, delta-dominated environment. The overlying shelf mudstones of the Viking group, deposited during a global sea level rise, represent the seal for the reservoir. Porosity was estimated to range from 11 to 22 percent and initial S_w was estimated to range from 16 to 52 percent.

The field is currently producing, and hydrocarbons are transported via pipeline and processed at the Gjøa facilities. The field was evaluated based on performance analysis using decline-curve analysis.

Reserves Summary

The estimated gross proved, probable, and possible reserves, as of December 31, 2023, 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 (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	26,414	19,186	2,987,893	579,152
Probable	7,374	5,270	1,000,454	191,297
Proved plus Probable	33,788	24,456	3,988,347	770,449
Possible	6,424	2,437	1,072,002	200,290
Proved plus Probable plus Possible	40,212	26,893	5,060,349	970,739
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	67,866	0	326,648	126,196
Probable	34,849	0	159,894	63,402
Proved plus Probable	102,715	0	486,542	189,598
Possible	20,850	0	119,816	42,245
Proved plus Probable plus Possible	123,565	0	606,358	231,843
Mexico				
Proved	91,518	0	50,299	100,500
Probable	24,681	0	27,095	29,519
Proved plus Probable	116,199	0	77,394	130,019
Possible	16,562	0	19,577	20,058
Proved plus Probable plus Possible	132,761	0	96,971	150,077
North Africa				
Proved	67,471	111	975,118	241,710
Probable	13,438	209	514,002	105,433
Proved plus Probable	80,909	320	1,489,120	347,143
Possible	14,431	200	483,582	100,985
Proved plus Probable plus Possible	95,340	520	1,972,702	448,128
Norway				
Proved	843,535	160,286	7,591,809	2,359,501
Probable	217,812	61,795	2,231,688	678,123
Proved plus Probable	1,061,347	222,081	9,823,497	3,037,624
Possible	224,067	54,642	2,596,081	742,295
Proved plus Probable plus Possible	1,285,414	276,723	12,419,578	3,779,919
Total Proved	**1,096,804**	**179,583**	**11,931,767**	**3,407,059**
Total Probable	**298,154**	**67,274**	**3,933,133**	**1,067,774**
Total Proved plus Probable	**1,394,958**	**246,857**	**15,864,900**	**4,474,833**
Total Possible	**282,334**	**57,279**	**4,291,058**	**1,105,873**
Total Proved plus Probable plus Possible	**1,677,292**	**304,136**	**20,155,958**	**5,580,706**

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 a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated working interest proved, probable, and possible reserves, as of December 31, 2023, 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):

	Working Interest Reserves			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	35,712	0	22,896	39,801
Probable	10,223	0	12,678	12,487
Proved plus Probable	45,935	0	35,574	52,288
Possible	6,919	0	9,168	8,556
Proved plus Probable plus Possible	52,854	0	44,742	60,844
North Africa				
Proved	9,204	111	249,044	53,787
Probable	2,804	209	138,481	27,742
Proved plus Probable	12,008	320	387,525	81,529
Possible	2,919	200	123,211	25,121
Proved plus Probable plus Possible	14,927	520	510,736	106,650
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**243,062**	**47,293**	**2,728,956**	**777,669**
Total Probable	**94,681**	**23,452**	**1,241,235**	**339,782**
Total Proved plus Probable	**337,743**	**70,745**	**3,970,191**	**1,117,451**
Total Possible	**77,272**	**16,667**	**1,246,026**	**316,444**
Total Proved plus Probable plus Possible	**415,015**	**87,412**	**5,216,217**	**1,433,895**

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 a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated net interest proved, probable, and possible reserves, as of December 31, 2023, 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 (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	22,549	0	20,018	26,124
Probable	6,317	0	11,291	8,333
Proved plus Probable	28,866	0	31,309	34,457
Possible	4,410	0	8,138	5,863
Proved plus Probable plus Possible	33,276	0	39,447	40,320
North Africa				
Proved	5,517	61	133,124	29,350
Probable	1,933	113	82,195	16,724
Proved plus Probable	7,450	174	215,319	46,074
Possible	2,089	108	79,360	16,368
Proved plus Probable plus Possible	9,539	282	294,679	62,442
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**226,212**	**47,243**	**2,610,158**	**739,555**
Total Probable	**89,904**	**23,356**	**1,183,562**	**324,610**
Total Proved plus Probable	**316,116**	**70,599**	**3,793,720**	**1,064,165**
Total Possible	**73,933**	**16,575**	**1,201,145**	**304,998**
Total Proved plus Probable plus Possible	**390,049**	**87,174**	**4,994,865**	**1,369,163**

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 a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The reserves in fields that were evaluated according to the terms of a PSA, as summarized under the Valuation of Reserves heading of this report, can vary. Net reserves in such fields are estimated from the future net revenue attributable to Wintershall Dea under the terms of the respective PSA. The components of that future net revenue are cost revenue, profit revenue, and tax revenue (where applicable). Cost revenue is the revenue entitlement attributable to the PSA contractor for its share of operating expenses and capital costs. Profit revenue is the portion of the sales revenue that remains after cost revenue is contractually apportioned to the contractor based on the PSA terms. Tax revenue, where applicable, is the estimated income tax to be paid by the host on behalf of the contractor. The revenues are converted to entitlement quantities by dividing the revenues by a prevailing product price or prices. The entitlement quantities (net reserves or resources) are based on Wintershall Dea's working interest in the respective PSA. Net reserves or resources under each PSA can vary according to the schedule of production, expended costs, and product prices. Therefore, net reserves or resources can vary by category and under different economic scenario assumptions. Further, a different projection of any component of the estimate could result in a varying net entitlement interest.

Valuation of Reserves

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Wintershall Dea and certain forecast price, expense, and cost assumptions as described below. Three economic scenario cases (Base Case Prices, Low Case Prices, and High Case Prices) were evaluated. Gross, working interest, and net reserves estimated herein were based on the Base Case price, expense, and cost estimations. The Low Case Prices and High Case Prices sensitivity cases were forecast to the Base Case Prices projected limit or the economic limit, whichever occurred first. The economic assumptions for the sensitivity cases differ from the Base Case Prices only in the forecast product prices.

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; this adjustment would be necessary in order to make values associated with probable and possible reserves comparable to values associated with proved reserves.

Revenue associated with 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 fiscal terms described herein.

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

Oil, Condensate, LPG, and Gas Prices

Base Case Price Assumptions

The products and locations vary considerably in the portfolio evaluated herein. Historical pricing was provided for properties across the portfolio by Wintershall Dea, including prices as of December 31, 2023. Forecast pricing for this report was based on projections of a marker price for oil (Brent), gas prices (title transfer facility virtual trading point (TTF)), and Henry Hub Gas prices reflective of conditions on December 31, 2023. The initial marker prices used in this evaluation were U.S.$76.84 per barrel for oil and U.S.$12.41 per thousand cubic feet (10^3ft^3) for gas. In December 2023, the Brent oil price was U.S.$76.64 per barrel, the TTF gas price was U.S.$10.70 per 10^3ft^3, and the Henry Hub gas price was U.S.$3.96 per 10^3ft^3. The prices received at the field level vary from the marker prices due to location, quality, heating value content, and contractual sales agreements. The field-level prices, including differentials where appropriate, were applied to the analysis herein. Marker prices used to estimate reserves and future net revenue herein under the Base Case Prices assumptions are shown below, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3ft^3$):

	Base Case Prices				
Year	Brent Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	LPG (U.S.$/bbl)	TTF Gas (U.S.$/$10^3ft^3$)	Henry Hub Gas (U.S.$/$10^3ft^3$)
2024	76.84	74.53	61.44	12.41	2.92
2025	73.70	71.49	55.80	12.13	3.86
2026	71.40	69.26	48.77	10.67	4.06

Year	Base Case Prices – *(Continued)* Brent Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	LPG (U.S.$/bbl)	TTF Gas (U.S.$/10³ft³)	Henry Hub Gas (U.S.$/10³ft³)
2027	69.48	67.40	42.19	9.18	4.50
2028	70.98	68.85	46.48	9.36	4.60
2029	72.52	70.34	50.80	9.55	4.69
2030	74.09	71.86	57.26	9.74	4.79
2031	75.69	73.42	58.14	9.93	4.88
2032	77.32	75.00	59.07	10.13	4.97
2033	79.00	76.63	60.06	10.33	5.08
2034	81.54	79.09	61.73	10.54	5.18
2035	84.15	81.63	63.71	10.75	5.28
2036	86.84	84.23	65.74	10.97	5.39
2037	89.60	86.91	67.83	11.19	5.49
2038	92.43	89.66	69.98	11.41	5.61
2039	95.34	92.48	72.18	11.64	5.71
2040	98.33	95.38	74.44	11.87	5.82
2041	101.41	98.36	76.77	12.11	5.95
2042	104.56	101.43	79.16	12.35	6.06
2043	107.80	104.57	81.61	12.60	6.19
2044	109.96	106.66	83.25	12.85	6.31
2045	112.16	108.79	84.91	13.11	6.44
2046	114.40	110.97	86.61	13.37	6.56
2047	116.69	113.19	88.34	13.63	6.70
2048	119.02	115.45	90.11	13.91	6.83
2049	121.40	117.76	91.91	14.19	6.96
2050	123.83	120.12	93.75	14.47	7.10
2051	126.31	122.52	95.62	14.76	7.25
2052	128.84	124.97	97.54	15.05	7.39
2053	131.41	127.47	99.49	15.36	7.54
2054	134.04	130.02	101.48	15.66	7.69
2055	136.72	132.62	103.51	15.98	7.85
2056	139.46	135.27	105.58	16.12	8.00
2057	141.91	137.65	107.44	16.45	8.16

Notes:
1. Prices were held constant from 2057 forward.
2. TTF gas prices were utilized for properties located in Algeria, Argentina, Denmark, Egypt, Germany, Libya, and Norway.
3. Henry Hub gas prices were utilized for properties located in Mexico.

Low Case Price Assumptions

Oil, condensate, gas, and LPG prices for the Low Case Prices scenario are 10 percent lower than those used in the Base Case Prices scenario. Reserves estimates herein were based on the Base Case Prices scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case Prices scenario limit of projected production or when an annual economic limit is reached, whichever occurs first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case Prices scenario herein. Marker prices used to estimate reserves and future net revenue herein under the Low Case Prices scenario assumptions are shown below, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	Low Case Prices				
Year	**Brent Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**LPG (U.S.$/bbl)**	**TTF Gas (U.S.$/$10^3$ft^3)**	**Henry Hub Gas (U.S.$/$10^3$ft^3)**
2024	69.16	67.08	55.30	11.17	2.63
2025	66.33	64.34	50.22	10.92	3.48
2026	64.26	62.33	43.90	9.60	3.65
2027	62.53	60.66	37.97	8.26	4.05
2028	63.88	61.97	41.84	8.42	4.14
2029	65.27	63.31	45.72	8.59	4.22
2030	66.68	64.68	51.53	8.76	4.31
2031	68.12	66.08	52.32	8.94	4.39
2032	69.59	67.50	53.16	9.12	4.47
2033	71.10	68.96	54.05	9.30	4.57
2034	73.38	71.18	55.56	9.49	4.66
2035	75.74	73.46	57.34	9.68	4.76
2036	78.15	75.81	59.17	9.87	4.85
2037	80.64	78.22	61.05	10.07	4.94
2038	83.19	80.69	62.98	10.27	5.04
2039	85.81	83.23	64.96	10.47	5.14
2040	88.50	85.84	67.00	10.68	5.24
2041	91.26	88.53	69.09	10.90	5.35
2042	94.11	91.28	71.24	11.11	5.46
2043	97.02	94.11	73.45	11.34	5.57
2044	98.96	96.00	74.92	11.56	5.68
2045	100.94	97.92	76.42	11.79	5.79
2046	102.96	99.87	77.95	12.03	5.90
2047	105.02	101.87	79.51	12.27	6.03
2048	107.12	103.91	81.10	12.52	6.15
2049	109.26	105.99	82.72	12.77	6.27
2050	111.45	108.11	84.37	13.02	6.39
2051	113.68	110.27	86.06	13.28	6.52
2052	115.95	112.47	87.78	13.55	6.65
2053	118.27	114.72	89.54	13.82	6.78
2054	120.64	117.02	91.33	14.10	6.92
2055	123.05	119.36	93.16	14.38	7.06
2056	125.51	121.75	95.02	14.51	7.20
2057	127.72	123.89	96.69	14.80	7.34

Notes:
1. Prices were held constant from 2057 forward.
2. TTF gas prices were utilized for properties located in Algeria, Argentina, Denmark, Egypt, Germany, Libya, and Norway.
3. Henry Hub gas prices were utilized for properties located in Mexico.

High Case Price Assumptions

Oil, condensate, gas, and LPG prices for the High Case Prices scenario are 10 percent higher than those used in the Base Case Prices scenario. Reserves estimates herein were based on the Base Case Prices scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case Prices scenario limit of projected production or when an annual economic limit is reached, whichever occurs first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case Prices scenario herein. Marker prices used to estimate reserves and future net revenue herein under the High Case Prices scenario assumptions are shown below, expressed in United States dollars per barrel (U.S.\$/bbl) and United States dollars per thousand cubic feet (U.S.\$/10^3ft^3):

	High Case Prices				
Year	**Brent Oil (U.S.\$/bbl)**	**Condensate (U.S.\$/bbl)**	**LPG (U.S.\$/bbl)**	**TTF Gas (U.S.\$/10^3ft^3)**	**Henry Hub Gas (U.S.\$/10^3ft^3)**
2024	84.52	81.99	67.59	13.66	3.21
2025	81.07	78.64	61.38	13.35	4.25
2026	78.54	76.18	53.65	11.74	4.46
2027	76.43	74.14	46.40	10.09	4.96
2028	78.08	75.74	51.13	10.30	5.06
2029	79.77	77.38	55.88	10.50	5.16
2030	81.49	79.08	62.98	10.71	5.26
2031	83.26	80.76	63.95	10.93	5.37
2032	85.06	82.50	64.98	11.14	5.47
2033	86.90	84.29	66.06	11.37	5.58
2034	89.69	87.00	67.90	11.59	5.70
2035	92.57	89.79	70.08	11.83	5.81
2036	95.52	92.65	72.32	12.06	5.93
2037	98.55	95.60	74.61	12.30	6.04
2038	101.67	98.62	76.97	12.55	6.17
2039	104.88	101.73	79.40	12.80	6.28
2040	108.17	104.92	81.89	13.06	6.41
2041	111.55	108.20	84.45	13.32	6.54
2042	115.02	111.57	87.08	13.58	6.67
2043	118.58	115.03	89.78	13.86	6.81
2044	120.96	117.33	91.57	14.13	6.94
2045	123.38	119.67	93.40	14.42	7.08
2046	125.84	122.07	95.27	14.70	7.22
2047	128.36	124.51	97.18	15.00	7.36
2048	130.93	127.00	99.12	15.30	7.51
2049	133.55	129.54	101.10	15.60	7.66
2050	136.22	132.13	103.12	15.92	7.81
2051	138.94	134.77	105.19	16.23	7.97
2052	141.72	137.47	107.29	16.56	8.13
2053	144.55	140.22	109.44	16.89	8.29
2054	147.44	143.05	111.63	17.23	8.46

	High Case Prices – *(Continued)*				
Year	**Brent Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**LPG (U.S.$/bbl)**	**TTF Gas (U.S.$/$10^3$ft^3)**	**Henry Hub Gas (U.S.$/$10^3$ft^3)**
2055	150.39	145.88	113.86	17.57	8.63
2056	153.40	148.80	116.14	17.73	8.80
2057	156.10	151.42	118.18	18.09	8.97

Notes:
1. Prices were held constant from 2057 forward.
2. TTF gas prices were utilized for properties located in Algeria, Argentina, Denmark, Egypt, Germany, Libya, and Norway.
3. Henry Hub gas prices were utilized for properties located in Mexico.

Operating Expenses, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by Wintershall Dea 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 Wintershall Dea. A 2-percent cost escalation per year was applied for fixed operating expenses, capital costs, and abandonment costs for 2024 and beyond. Generally, abandonment costs, which can be substantial in mature fields, 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 Wintershall Dea. Economic limits for each field were estimated based on annual operating expenses with no consideration of German corporate income taxes.

Exchange Rates

Certain information on costs was provided in currencies other than U.S.$. Where applicable, an exchange rate of €0.93 per U.S.$1.00 was used for this report. Other exchange rates used herein include DKK6.95 per U.S.$1.00, and NOK10.61 per U.S.$1.00. These currency exchange rates were held constant for this report.

Fiscal Regime

Fields in all countries are governed by concessionary (working interest) regimes, except for certain fields located in Algeria, Libya, and Egypt, as well as the Hokchi and Ogarrio fields in Mexico, which are governed by PSAs. Selected key parameters of fiscal regimes evaluated herein are summarized as follows:

	Parameters					
	Cash Royalty (percent)	Royalty in Kind (percent)	Cost Recovery Limit (percent)	Profit Sharing (percent)	Production Taxes (percent)	Host-Country Taxes (percent)
Algeria	NA	NA	NA	50 to 60	NA	NA
Argentina	12 to 18	NA	NA	NA	2.4 to 3.0	35.00
Denmark	NA	NA	NA	NA	52	25.00
Egypt	NA	NA	40	27 to 32	NA	40.55
Egypt: Disouq	NA	NA	35	17 to 30	NA	40.55
Libya	NA	NA	25 to 50	80 to 90	NA	65.00
Germany	4 to 10	NA	NA	NA	NA	30.10
Mexico: Hokchi	NA	1.2 to 12.0	60	31	NA	30.00
Mexico: Ogarrio	20.5 to 25.0	NA	NA	NA	NA	30.00
Norway	NA	NA	NA	NA	56	22.00

Notes:
1. Production bonuses are paid in the Egyptian concessions, calculated on the basis of total cumulative production in the concession. None of the fields evaluated reach the required production to pay a production bonus.
2. Production is shared with the Algerian government based on a formula referred to as the K*A-B formula, resulting in an entitlement share between 50 and 60 percent.
3. Production tax in Algeria consists of the excess profits tax (TPE) and is applied only to liquids.
4. Unless otherwise noted herein, "Royalty in Kind" is a reduction in ownership and not reflected as a negative revenue.
5. "NA" is not applicable.

In certain instances, commercial terms for concessions and PSAs may be subject to strict confidentiality restrictions that prevent stating specific terms. As such, specific terms, as provided by Wintershall Dea, may not be described herein, but were applied as appropriate for each country and property evaluated. Generally, the terms of the concession area licenses and PSAs include royalty in-kind considerations, cost recovery limits, profit sharing percentages, certain production taxes, and the host country income tax. Production bonuses are a consideration in the PSAs.

Income Taxes

For the purposes of this report, German corporate income taxes were not considered in this report; however, field-level estimates of host-country income taxes, where applicable, were included in the evaluation of each individual field located in each respective host country, including Germany. Production taxes were applied as appropriate in each country.

As in any evaluation, there may be a risk of unexpected cost variances and timing delays or accelerations. For this evaluation, consideration was 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, 2023, of the properties evaluated under the Base Case Prices economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

	Valuation of Reserves – Base Case Prices		
	Proved (10^3U.S.$)	**Proved plus Probable (10^3U.S.$)**	**Proved plus Probable plus Possible (10^3U.S.$)**
Future Gross Revenue	45,225,814	64,793,427	83,203,526
Operating Expenses	11,152,380	14,048,407	16,549,209
Capital Costs	2,890,632	3,255,024	3,332,452
Abandonment Cost	3,271,678	3,402,041	3,467,421
Royalty (Cash)	2,510,072	3,649,268	4,533,424
Taxes	14,986,890	23,964,603	33,214,786
Future Net Revenue	10,414,162	16,474,084	22,106,234
Present Worth at 6 Percent	8,508,852	12,568,051	16,196,493
Present Worth at 8 Percent	7,983,892	11,593,251	14,779,665
Present Worth at 10 Percent	7,371,082	10,528,176	13,282,049
Present Worth at 12 Percent	7,087,189	10,001,149	12,515,256

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 net proved, proved-plus-probable, and proved-plus-probable-plus-possible quantities, as of December 31, 2023, of the properties evaluated under the Low Case Prices and High Case Prices economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

	Valuation of Quantities – Price Sensitivity Cases					
	Low Case Prices			High Case Prices		
	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	40,473,092	58,058,420	74,657,865	49,790,884	71,339,456	91,620,309
Operating Expenses	10,984,127	13,874,353	16,434,413	11,152,013	14,047,969	16,548,718
Capital Costs	2,885,432	3,255,023	3,332,449	2,890,632	3,255,023	3,332,449
Abandonment Cost	3,263,367	3,391,343	3,456,419	3,271,558	3,401,920	3,467,302
Royalty (Cash)	2,226,405	3,253,747	4,044,621	2,778,325	4,038,898	5,018,407
Taxes	12,309,076	20,140,056	28,282,780	17,673,898	27,795,976	38,152,385
Future Net Revenue	8,804,685	14,143,898	19,107,183	12,024,458	18,799,670	25,101,048
Present Worth at 6 Percent	7,289,099	10,876,591	14,088,821	9,719,797	14,243,953	18,289,707
Present Worth at 8 Percent	6,854,990	10,047,673	12,871,823	9,102,196	13,122,214	16,672,921
Present Worth at 10 Percent	6,336,988	9,130,797	11,573,915	8,393,520	11,908,822	14,976,320
Present Worth at 12 Percent	6,102,659	8,684,333	10,916,575	8,058,669	11,301,044	14,100,595

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

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.

When applicable, the volumetric method was used to estimate original quantities of OGIP or OOIP. 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 geophysical and geological data, well-test results, production data, and pressure and core data available through December 31, 2023. The development and economic status of the properties evaluated was based on the status as of December 31, 2023.

Oil and condensate contingent resources estimated herein are to be recovered by normal field separation. LPG contingent resources estimated herein consist primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and LPG contingent resources included in this report are expressed in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate contingent resources have been estimated separately and are presented herein as a summed quantity.

Gas quantities associated with contingent resources estimated herein are expressed as separator gas and sales gas contingent resources. Separator gas is defined as the total gas produced from the reservoir after field separation but before reduction for field use (including fuel usage), flare, and gas injection. Sales gas is defined as the quantities of separator gas available to be sold after field use (including fuel usage), flare, and gas injection. Gas contingent resources estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60°F and at a pressure base of 14.7 psia. Gas quantities included in this report are expressed in 10^6ft^3.

For the purposes of this report, sales gas contingent resources estimated herein were converted to oil equivalent volumes using a factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Wintershall Dea.

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.

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 Wintershall Dea approval or partner agreement for commitment to develop and produce, production tails beyond license limits, and uneconomic projects. No contingent resources were estimated for reserves projected beyond the economic limit. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves.

The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.

The classification of contingent resources estimates presented herein is generally based on a lack of development plans, a lack of sales contracts, and quantities to be recovered after current license expiration.

Procedure and Methodology

Oil, condensate, LPG, and sales gas contingent resources were estimated for certain fields evaluated herein. Tables summarizing the gross, working interest, and net contingent resources are presented by country and by area in Tables A-6, A-7, and A-8, respectively.

For the purposes of this report, net contingent resources for fields evaluated in this report were calculated by multiplying Wintershall Dea's working interest by the gross contingent resources. As such, net contingent resources equals working interest contingent resources.

Selected fields from all countries containing contingent resources estimated herein are discussed in detail as follows.

Algeria

Contingent resources associated with the Reggane Nord fields evaluated herein include a 10-year license extension from the license date of November 1, 2041, to November 1, 2051.

Argentina

Aguada Pichana East Vaca Muerta Field

Contingent resources estimated for the Aguada Pichana East Vaca Muerta field are associated with future development projects, including approximately 760 wells to be drilled. Contingent resources estimates were based on type-well analysis performed using well data from analogous wells in the Vaca Muerta reservoir, for which more complete historical performance data were available.

Ara South Field

Contingent resources estimated for the Ara South field are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

Cañadon Alfa Complex

Contingent resources estimated for the Cañadon Alfa complex are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

Carina Field

Contingent resources estimated for the Carina field are associated with three different projects: a 10-year license extension from May 2041 until May 2051, the Carina Phase 2 project, and the Carina Phase 3 project. The license extension project consists of the continued operation of the active wells beyond May 2041. Contingent resources estimated for the Carina Phase 2 project in the Carina field are associated with the drilling of two additional gas producer wells targeting the Springhill Formation. The Carina Phase 3 project consists of the installation of an offshore facility compression system. Contingent resources were estimated for each project using a 3–D integrated reservoir simulation model.

Contingent resources estimated for the Fenix Phase 2 project are associated with the drilling of three satellite wells. Contingent resources estimated for the Fenix Phase 3 project are associated with offshore compression. The license extension project consists of the continued operation of the wells active as of May 2041 for a period of 10 years, until May 2051. Contingent resources were estimated for each project using a 3–D integrated reservoir simulation model.

Hidra Field

Contingent resources estimated for the Hidra field are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

Kaus Field

Contingent resources estimated for the Kaus field are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

San Roque Vaca Muerta Field

Contingent resources estimated for the San Roque Vaca Muerta field are associated with future development projects, including drilling locations for 636 horizontal wells. Contingent resources estimates were based on type-well analysis performed using well data from analogous wells in the Vaca Muerta Formation for which more complete historical performance data were available.

Vega Pleyade Field

Contingent resources estimated for the Vega Pleyade field are associated with two different projects: a 10-year license extension from May 2041 until April 30, 2051 and the drilling of a third gas production well targeting the Springhill Formation. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2041. Contingent resources were estimated for both projects using a 3–D integrated reservoir simulation model.

Egypt

Raven West M40E Field

Contingent resources for the Raven West M40E field were estimated volumetrically and include volumes that are potentially recoverable from additional drilling that has not yet been approved. The gas recovery factors were estimated to range from 60 to 80 percent.

Raven West Serravallian 4 Field

Contingent resources for the Raven West Serravallian 4 field were estimated volumetrically and include volumes that are potentially recoverable from additional drilling in the field not yet approved. The gas recovery factors were estimated to range from 60 to 80 percent.

Germany

Emlichheim Field

Contingent resources estimated for the Emlichheim field include volumes associated with continued drilling programs and developing the area of the field that is within 50 meters of the Dutch border.

Mittelplate Field

Contingent resources estimated for the Mittelplate field are associated with two additional production wells to be drilled and a polymer injection pilot, all targeting the Dogger Beta reservoir.

Mexico

Hokchi Field

Contingent resources estimated for the Hokchi field correspond to production volumes to be produced after the contract expiration date of December 31, 2040.

Kan Field

The Kan field was discovered in 2023 and is not on production. Planned development includes a waterflood production scheme with seven producers and three water injectors, but the development plan has not yet been finalized. The first producer is planned to be drilled in 2028. The first water injector is planned to be drilled in 2030.

Polok Field

The Polok field was discovered in 2020 and is not on production. Planned development includes a waterflood production scheme with four producers and two water injectors, but the development plan has not yet been finalized. Drilling may start in 2026 with injectors drilled 2 years later.

Zama Field

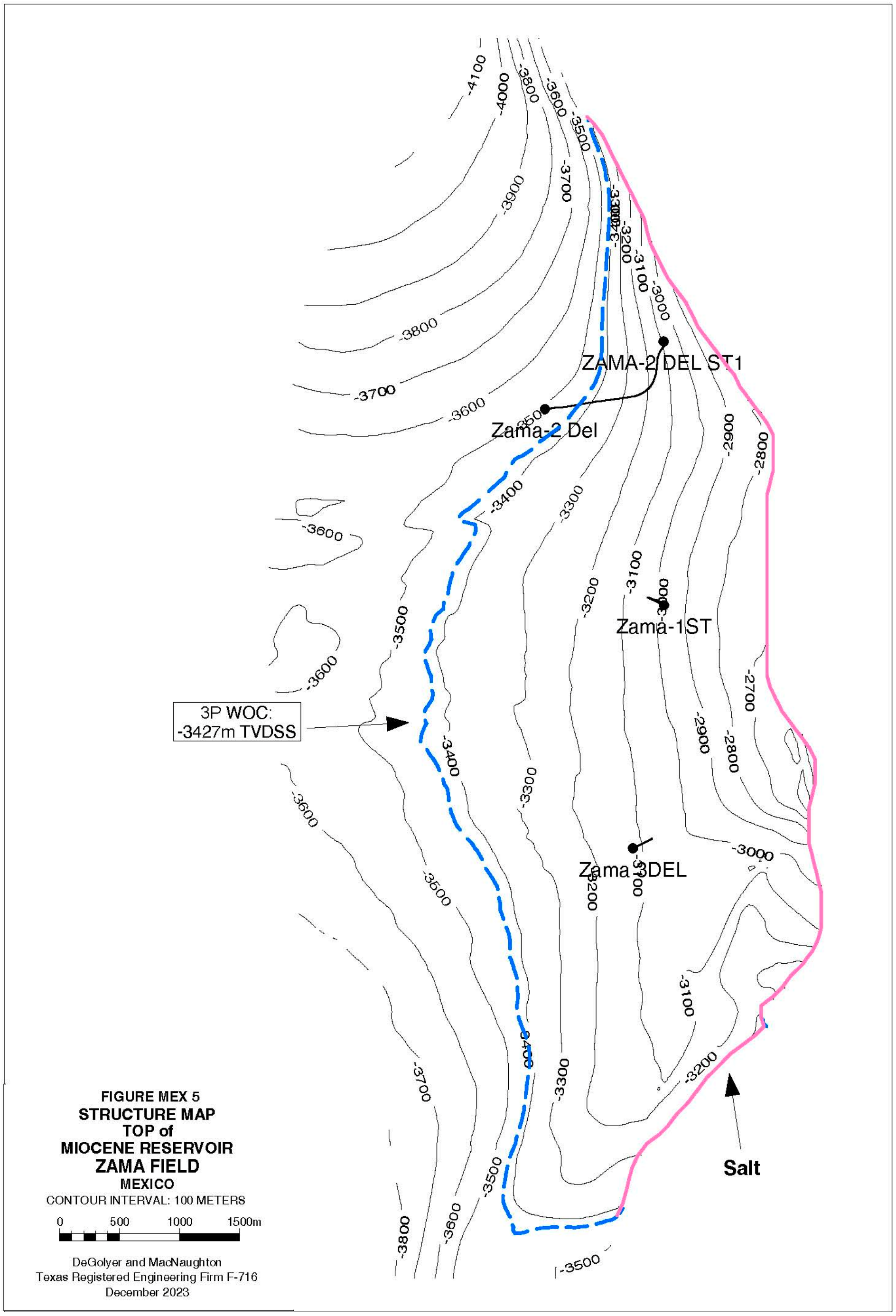
The Zama field is located in the Bay of Campeche, in the South East Basin, 60 kilometers southeast from Dos Bocas, México (Figure MEX 1, page 54).

The Zama-1 discovery well was drilled in 2017 and reached a total depth of 3,360 meters subsea. The well was designed to test a series of stacked Miocene amplitude anomalies that exhibit a “common” downdip amplitude termination (flat spot) with good amplitude versus offset. The Zama-1 well tested the Miocene clastic reservoirs (Figure MEX 2, page 55) that developed as a result of gravity flows from sand sediment in a talus environment. The well encountered more than 500 meters of turbiditic sandstone with a porosity of 25 percent and S_w of 36 percent in the net pay intervals. The structure was identified as a three-way dip structure sealed against a salt diapir (Figure MEX 5, page 91).

In 2019, two appraisal wells (Zama-2 Del and Zama-2 Del ST) were drilled north of the Zama discovery well. A third appraisal well, Zama-3 Del, was drilled to the south in 2021.

In the Miocene sandstone reservoirs of the Zama field, average S_w was estimated to be 33 percent, average effective porosity in all the compartments was estimated to be approximately 25 percent, and average permeability was estimated to range from 95 to 175 millidarcys. The average gross thickness is 160 meters and the average net thickness is 110 meters. Oil gravities vary between 19 and 29 degrees API with an average of 27 degrees API.

The volumetric method was used to estimate the OOIP in the Zama field. Structure maps for the main reservoirs were provided by Wintershall Dea and were prepared using well data and 3–D seismic data. The resulting geological structure maps were reviewed to compare the results to regional geological structural trends.



These comparisons confirmed that the structural interpretations were consistent with structural interpretations in the region. Wireline electrical logs, radioactivity logs, wireline formation pressure tests, wireline fluid sample tests, and other data were acquired in wells drilled in the Zama field. When available, drill cuttings, hole cores, and sidewall cores were analyzed. These combined analyses of the well data were used to establish the petrophysical properties. Petrophysical interpretations of the well-log data were compared to the results of wells in nearby fields; these comparisons confirmed that the local petrophysical interpretations were consistent with geological stratigraphy trends and petrophysical interpretations in the region.

Geocellular models were constructed for the Zama field. Lithological facies and petrophysical properties were propagated in the static models, and vertical fluid limits were defined for the 1C, 2C, and 3C contingent resources scenarios. OOIP was estimated using the volumetric method and net pay isopach maps. These isopach maps were constructed using the 3–D model.

The Zama field is undeveloped. The development plan envisions the drilling of 29 producer wells, a peripheric waterflood scheme with 17 injector wells, the construction of two platforms in water depths between 150 and 180 meters, and an onshore processing facility. Lower completions are to be performed using hydraulic fracturing and gravel packing. Phased implementation of artificial lift using ESP is envisioned.

The 1C, 2C, and 3C ultimate recovery was estimated by applying a recovery factor to the estimated OOIP considering the future development well counts and production rates provided in the development plans. Not all parties have fully committed to the development plan, and the contingent resources estimated herein for the Zama field include quantities to be produced both during and after the license expiration date of September 4, 2045.

Norway

Aasta Hansteen Field

Contingent resources estimated for the Aasta Hansteen field are associated with improved recovery resulting from a reduction in the inlet separator pressure to 40 bars.

Adriana Field

Contingent resources estimated for the Adriana discovery are associated with an undeveloped gas accumulation in the Cretaceous Lysing Reservoir. The results of one well, the 6507/4-2 S, were included in this evaluation.

Alta Field

Contingent resources associated with the Alta field were estimated based on drilling opportunities in the Alta proven area, Alta South and West areas, and gas blowdown.

Bergknapp and Bergknapp Åre Fields

Contingent resources estimated for the Bergknapp and Bergknapp Åre discoveries are associated with undeveloped accumulations in the Jurassic Garn, Tilje, and Åre reservoirs. The results of two wells, the 6406/3-10 and the 6406/3-10 A, were included in this evaluation.

Njord Field

Contingent resources associated with the Njord field were estimated based on additional infill drilling opportunities in the Åre, North Flank, and Northwest Flank reservoirs, improved oil recovery, and low pressure production.

Noatun Field

Contingent resources associated with the Noatun field were estimated based on development with three multi-stage fractured wells in the Ile, Lower Tilje, and Åre reservoirs.

Nova Field

Contingent resources estimated for the Nova field are associated with the development of the gas cap.

Sabina Field

Contingent resources estimated for the Sabina discovery are associated with an undeveloped gas accumulation in the Cretaceous Lange Reservoir. The results of one well, the 6507/4-2 S, were included in this evaluation.

Snøhvit Field

Contingent resources associated with the Snøhvit field were estimated based on development opportunities in Snøhvit Beta and Snøhvit Vest, future projects of electrification, offshore compression, and formation water handling, and production after the current technical limit.

Snorre Field

Contingent resources estimated for the Snorre field consist of multiple projects including a template expansion to allow for additional infill wells, additional development drilling, extended producing lifetime, and gas blowdown.

Storjo Field

Contingent resources estimated for the Storjo discovery are associated with undeveloped gas accumulations in the Cretaceous Lysing and Jurassic Tilje reservoirs. The results of one well, the 6507/2-6 were included in this evaluation.

Contingent Resources Summary

The estimated gross, working interest, and net 1C, 2C, and 3C contingent resources, as of December 31, 2023, 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			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	819,246	47,135	8,649,610	2,410,954
2C	1,725,147	96,091	17,832,473	5,005,607
3C	2,961,243	149,985	33,140,193	9,029,120

	Working Interest Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

	Net Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

Notes:
1. For the purposes of this report, net contingent resources are set equal to working interest contingent resources.
2. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
3. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
4. The contingent resources reported herein have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
5. Sales gas contingent resources estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet per 1 boe.
6. The oil equivalent contingent resources reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

Tables summarizing the gross, working interest, and net contingent resources are presented by country and by area in Tables A-6, A-7, and A-8, respectively.

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, an Executive Vice President and Division Manager with DeGolyer and MacNaughton, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, and the European Association of Geoscientists & Engineers. He has over 40 years of oil and gas industry experience.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

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

TABLE A-1
PROPERTIES EVALUATED
as of
DECEMBER 31, 2023
with interests attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Country Field/Discovery	Working Interest (%)	Fiscal Regime	License Expiration
Algeria			
Azrafil Southeast	24.00	PSA	November 1, 2041
Kahlouche	24.00	PSA	November 1, 2041
Kahlouche South	24.00	PSA	November 1, 2041
Reggane	24.00	PSA	November 1, 2041
Sali	24.00	PSA	November 1, 2041
Tiouliline	24.00	PSA	November 1, 2041
Argentina			
Aguada Pichana East Residual	27.27	Concession	July 17, 2052
Aguada Pichana East Vaca Muerta	22.50	Concession	July 17, 2052
Aguada San Roque	24.71	Concession	November 14, 2027
Ara South	37.50	Concession	April 30, 2031
Aries	37.50	Concession	April 30, 2041
Cañadón Alfa	37.50	Concession	April 30, 2031
Carina	37.50	Concession	April 30, 2041
Fenix	37.50	Concession	April 30, 2041
Hidra	37.50	Concession	April 30, 2031
Kaus	37.50	Concession	April 30, 2031
Leo	37.50	Concession	October 23, 2038
Loma Las Yeguas	24.71	Concession	November 14, 2027
Rincon Chico	24.71	Concession	November 14, 2027
San Roque Vaca Muerta	24.71	Concession	November 14, 2027
Tauro-Unicornio-Sirius	35.00	Concession	October 23, 2038
Vega-Pleyade	37.50	Concession	April 30, 2041
Denmark			
Cecilie	43.59	Concession	June 18, 2032
Nini	42.857	Concession	June 18, 2032
Egypt			
Disouq 1-3	100.00	PSA	August 11, 2034
Disouq 1-5	100.00	PSA	August 11, 2034
Disouq 2	100.00	PSA	August 11, 2034
East Damanhour	40.00	PSA	September 26, 2043
El Arish P00 Seg 1	17.25	Concession	February 5, 2039
Fayoum	17.25	Concession	February 5, 2039
Giza	17.25	Concession	February 5, 2039
Hodoa Aquitan (M15 Top sand)	17.25	PSA	August 8, 2026
Libra	17.25	Concession	March 24, 2037
Libra DA	9.4875	Concession	March 24, 2037
Libra P80 Seg 1a	17.25	Concession	March 24, 2037
Maadi P80 Seg 1 (includes Seg 2 and Levee)	17.25	PSA	August 8, 2026
Maadi Segment 3	17.25	PSA	August 8, 2026
North Sidi Ghazy-1	100.00	PSA	August 11, 2034
North Sidi Ghazy-2-1	100.00	PSA	August 11, 2034
North Sidi Ghazy-2-3	100.00	PSA	August 11, 2034
North Sidi Ghazy-4	100.00	PSA	August 11, 2034
Northwest Khilala	100.00	PSA	September 2, 2033
Northwest Sidi Ghazy-1	100.00	PSA	August 11, 2034
Northwest Sidi Ghazy-7	100.00	PSA	August 11, 2034
Polaris Pliocene P78 Ch	17.25	PSA	August 8, 2026
Polaris Pliocene P78 Ch Splay	17.25	PSA	August 8, 2026

Country Field/Discovery	Working Interest (%)	Fiscal Regime	License Expiration
Egypt – *(Continued)*			
Raven	17.25	Concession	February 5, 2039
Raven West M15	17.25	Concession	February 5, 2039
Raven West M20	17.25	Concession	February 5, 2039
Raven West M40D2	17.25	Concession	February 5, 2039
Raven West M40E	17.25	Concession	February 5, 2039
Raven West Serravallian 2	17.25	Concession	February 5, 2039
Raven West Serravallian 4	17.25	Concession	February 5, 2039
Ruby P78 R1 Seg 1	17.25	Concession	February 5, 2039
Sidi Salam Southeast-1	100.00	PSA	August 11, 2034
Sidi Salam Southeast-2	100.00	PSA	August 11, 2034
Sidi Salam Southeast-3	100.00	PSA	August 11, 2034
Sidi Salam Southeast-6	100.00	PSA	August 11, 2034
South Sidi Ghazy-1-1	100.00	PSA	August 11, 2034
South Sidi Ghazy-1-2	100.00	PSA	August 11, 2034
Taurus	17.25	Concession	March 24, 2037
Taurus Deep Serravallian SV7	17.25	Concession	March 24, 2037
Taurus Deep Serravallian SV8	17.25	Concession	March 24, 2037
Taurus P80 Seg 1	17.25	Concession	March 24, 2037
Taurus P86 Seg 2	17.25	Concession	March 24, 2037
Viper P83 Viper Channel and Aband	17.25	PSA	August 8, 2026
Germany			
Aldorf	100.00	Concession	June 30, 2030
Barrien	50.00	Concession	September 13, 2040
Bockstedt	100.00	Concession	January 31, 2030
Boetersen	20.812	Concession	September 30, 2045
Boetersen South	0.85	Concession	August 31, 2033
Boestlingen	50.00	Concession	October 31, 2027
Dueste Valendis	100.00	Concession	June 30, 2030
Emlichheim	90.00	Concession	May 31, 2043
Fehndorf	70.00	Concession	December 31, 2035
Hemsbuende	36.279	Concession	September 30, 2045
Mittelplate	100.00	Concession	December 31, 2041
Preyersmuehle South	8.273	Concession	December 31, 2045
Rehden	100.00	Concession	December 31, 2040
Ruetenbrock	100.00	Concession	September 30, 2034
Soehlingen	27.48	Concession	December 31, 2045
Staffhorst HD	50.00	Concession	August 7, 2030
Staffhorst North	50.00	Concession	April 17, 2024
Taaken	14.28	Concession	December 5, 2040
Voelkersen	100.00	Concession	December 31, 2028
Weissenmoor	40.00	Concession	January 27, 2028
Libya			
Al-Jurf	12.50	PSA	April 10, 2035
Mexico			
Chinwol	25.00	Concession	May 7, 2053
Hokchi	37.00	PSA	December 31, 2040
Kan	40.00	PSA	March 31, 2024
Naajal	50.00	Concession	March 7, 2052
Ogarrio	50.00	Concession	March 6, 2043
Polok	25.00	Concession	May 7, 2053
Zama	19.83	PSA	September 4, 2045

Country Field/Discovery	Working Interest (%)	Fiscal Regime	License Expiration
Norway			
Aasta Hansteen	24.00	Concession	February 2, 2041
Adriana	40.00	Concession	February 2, 2032
Ærfugl North (Snadd Outer PL212E)	25.00	Concession	February 2, 2033
Alta	30.00	Concession	May 14, 2051
Alve North	20.00	Concession	December 31, 2036
Balderbrå	30.00	Concession	February 10, 2027
Bauge	27.50	Concession	December 17, 2029
Beaujolais	40.00	Concession	June 4, 2035
Bergknapp	40.00	Concession	February 5, 2026
Bergknapp Åre	40.00	Concession	February 5, 2026
Busta	20.00	Concession	February 6, 2025
Dvalin	55.00	Concession	October 3, 2041 / February 2, 2032
Dvalin North	55.00	Concession	October 3, 2041
Edvard Grieg	15.00	Concession	December 17, 2029
Gjøa	28.00	Concession	July 8, 2028
Hamlet (Gjøa North)	28.00	Concession	July 8, 2028
Hyme	27.50	Concession	December 17, 2029
Idun North	40.00	Concession	December 31, 2036
Irpa	19.00	Concession	June 18, 2041
Iving	6.50	Concession	February 5, 2026
Maria	50.00	Concession	February 28, 2036
Neiden	30.00	Concession	May 14, 2051
Newt	10.00	Concession	June 2, 2027
Nidhogg	20.00	Concession	March 1, 2028
Njord Unit	50.00	Concession	April 10, 2034
Noatun	45.00	Concession	April 10, 2034
Nova	39.00	Concession	February 16, 2041
Obelix	10.00	Concession	February 19, 2027
Ofelia	20.00	Concession	September 2, 2026
Ofelia Kyrre	20.00	Concession	September 2, 2026
Orion	40.00	Concession	June 4, 2035
Oswig	20.00	Concession	February 19, 2027
Sabina	40.00	Concession	February 2, 2032
Skarv Unit	28.0825	Concession	March 3, 2029
Snøhvit Unit	2.81	Concession	October 1, 2035
Snorre Unit	8.5711	Concession	December 31, 2040
Solveig	15.00	Concession	January 6, 2036
Statfjord East Unit	1.40	Concession	August 10, 2026
Storjo	30.00	Concession	May 12, 2036
Storjo Cretaceous	30.00	Concession	May 12, 2036
Sygna Unit	1.26	Concession	August 10, 2026
Syrah	40.00	Concession	June 4, 2035
Tordis	2.80	Concession	December 31, 2040
Tornerose	2.80	Concession	December 17, 2035
Vega Unit	56.70	Concession	June 4, 2035
Vigdis	2.80	Concession	December 31, 2040

Note: In certain cases, the working interests shown are not representative of Wintershall Dea net reserves entitlement due to certain fields being subject to the terms of production sharing agreements.

TABLE A-2
SUMMARY of NET RESERVES and REVENUE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DEGOLYER AND MACNAUGHTON
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Reserves Category	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Present Worth at 6 Percent (10^3U.S.$)	Present Worth at 8 Percent (10^3U.S.$)	Present Worth at 12 Percent (10^3U.S.$)
Total Proved	226,212	47,243	2,610,158	739,555	10,414,162	7,371,082	8,508,852	7,983,892	7,087,189
Proved plus Probable	316,116	70,599	3,793,720	1,064,165	16,474,084	10,528,176	12,568,051	11,593,251	10,001,149
Proved plus Probable plus Possible	390,049	87,174	4,994,865	1,369,163	22,106,234	13,282,049	16,196,493	14,779,665	12,515,256

Notes:
1. 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.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-3
SUMMARY of GROSS RESERVES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
with interests attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

Country/Region	Total Proved				Proved plus Probable				Proved plus Probable plus Possible			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina	26,414	19,186	2,987,893	579,152	33,788	24,456	3,988,347	770,449	40,212	26,893	5,060,349	970,739
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	67,866	0	326,648	126,196	102,715	0	486,542	189,598	123,565	0	606,358	231,843
Mexico	91,518	0	50,299	100,500	116,199	0	77,394	130,019	132,761	0	96,971	150,077
North Africa	67,471	111	975,118	241,710	80,909	320	1,489,120	347,143	95,340	520	1,972,702	448,128
Norway	843,535	160,286	7,591,809	2,359,501	1,061,347	222,081	9,823,497	3,037,624	1,285,414	276,723	12,419,578	3,779,919
Total	**1,096,804**	**179,583**	**11,931,767**	**3,407,059**	**1,394,958**	**246,857**	**15,864,900**	**4,474,833**	**1,677,292**	**304,136**	**20,155,958**	**5,580,706**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-4
SUMMARY of WORKING INTEREST RESERVES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Total Proved				Proved plus Probable				Proved plus Probable plus Possible			
Country/Region	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina	9,336	7,194	1,000,626	195,213	11,908	9,173	1,331,278	258,809	14,118	10,085	1,684,259	324,964
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	66,949	0	135,026	91,061	101,591	0	217,631	140,454	122,189	0	282,015	172,549
Mexico	35,712	0	22,896	39,801	45,935	0	35,574	52,288	52,854	0	44,742	60,844
North Africa	9,204	111	249,044	53,787	12,008	320	387,525	81,529	14,927	520	510,736	106,650
Norway	121,861	39,988	1,321,364	397,807	166,301	61,252	1,998,183	584,371	210,927	76,807	2,694,465	768,888
Total	**243,062**	**47,293**	**2,728,956**	**777,669**	**337,743**	**70,745**	**3,970,191**	**1,117,451**	**415,015**	**87,412**	**5,216,217**	**1,433,895**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-5
SUMMARY of NET RESERVES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

	Total Proved				Proved plus Probable				Proved plus Probable plus Possible			
Country/Region	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina	9,336	7,194	1,000,626	195,213	11,908	9,173	1,331,278	258,809	14,118	10,085	1,684,259	324,964
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	66,949	0	135,026	91,061	101,591	0	217,631	140,454	122,189	0	282,015	172,549
Mexico	22,549	0	20,018	26,124	28,866	0	31,309	34,457	33,276	0	39,447	40,320
North Africa	5,517	61	133,124	29,350	7,450	174	215,319	46,074	9,539	282	294,679	62,442
Norway	121,861	39,988	1,321,364	397,807	166,301	61,252	1,998,183	584,371	210,927	76,807	2,694,465	768,888
Total	**226,212**	**47,243**	**2,610,158**	**739,555**	**316,116**	**70,599**	**3,793,720**	**1,064,165**	**390,049**	**87,174**	**4,994,865**	**1,369,163**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-6
SUMMARY of GROSS CONTINGENT RESOURCES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
with interests attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

Country/Region	1C Oil and Condensate (10^3bbl)	1C LPG (10^3bbl)	1C Sales Gas (10^6ft^3)	1C Combined Oil Equivalent (10^3boe)	2C Oil and Condensate (10^3bbl)	2C LPG (10^3bbl)	2C Sales Gas (10^6ft^3)	2C Combined Oil Equivalent (10^3boe)	3C Oil and Condensate (10^3bbl)	3C LPG (10^3bbl)	3C Sales Gas (10^6ft^3)	3C Combined Oil Equivalent (10^3boe)
Argentina	35,900	9,078	5,218,440	976,842	204,569	16,587	11,720,864	2,314,167	633,521	21,379	22,394,691	4,653,952
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	18,990	0	103,604	37,491	74,216	0	216,943	112,956	108,172	0	342,027	169,248
Mexico	466,532	0	178,438	498,396	926,462	0	303,252	980,614	1,408,490	0	495,763	1,497,019
North Africa	8,753	0	727,889	138,733	25,544	31	1,521,774	297,320	70,458	128	3,613,734	715,896
Norway	289,071	38,057	2,421,239	759,492	494,356	79,473	4,069,640	1,300,550	740,602	128,478	6,293,978	1,993,005
Total	**819,246**	**47,135**	**8,649,610**	**2,410,954**	**1,725,147**	**96,091**	**17,832,473**	**5,005,607**	**2,961,243**	**149,985**	**33,140,193**	**9,029,120**

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. All of the contingent resources estimated in this report have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-7
SUMMARY of WORKING INTEREST CONTINGENT RESOURCES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
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	1C				2C				3C			
Country/Region	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina	10,288	3,394	1,401,194	263,895	52,619	6,207	3,006,006	595,613	159,452	8,002	5,543,828	1,157,423
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	18,865	0	64,576	30,396	73,971	0	136,169	98,287	107,839	0	212,894	145,856
Mexico	110,231	0	53,673	119,815	226,091	0	95,017	243,058	358,639	0	158,415	386,927
North Africa	1,521	0	129,587	24,662	4,516	31	273,267	53,345	12,568	128	648,613	128,520
Norway	52,288	15,769	360,789	132,484	91,276	33,416	686,393	247,262	148,728	54,554	1,163,513	411,052
Total	**193,193**	**19,163**	**2,009,819**	**571,252**	**448,473**	**39,654**	**4,196,852**	**1,237,565**	**787,226**	**62,684**	**7,727,263**	**2,229,778**

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. All of the contingent resources estimated in this report have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-8
SUMMARY of NET CONTINGENT RESOURCES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

	1C				2C				3C			
Country/Region	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina	10,288	3,394	1,401,194	263,895	52,619	6,207	3,006,006	595,613	159,452	8,002	5,543,828	1,157,423
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	18,865	0	64,576	30,396	73,971	0	136,169	98,287	107,839	0	212,894	145,856
Mexico	110,231	0	53,673	119,815	226,091	0	95,017	243,058	358,639	0	158,415	386,927
North Africa	1,521	0	129,587	24,662	4,516	31	273,267	53,345	12,568	128	648,613	128,520
Norway	52,288	15,769	360,789	132,484	91,276	33,416	686,393	247,262	148,728	54,554	1,163,513	411,052
Total	**193,193**	**19,163**	**2,009,819**	**571,252**	**448,473**	**39,654**	**4,196,852**	**1,237,565**	**787,226**	**62,684**	**7,727,263**	**2,229,778**

Notes:
1. For the purposes of this report, net contingent resources are set equal to working interest contingent resources.
2. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
3. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
4. All of the contingent resources estimated in this report have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
5. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

TABLE A-9
SUMMARY FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	126,413	16,360	1,450,873	29,982	5,315	403,753	1,090,682	962,737	94,113
2025	111,126	17,551	1,224,793	27,083	5,896	362,278	1,027,208	728,425	14,299
2026	101,513	17,393	1,188,085	25,169	5,981	346,366	1,035,672	380,200	18,491
2027	90,666	16,651	1,048,177	22,608	5,824	299,882	998,693	206,071	26,774
2028	81,547	15,324	920,437	20,437	5,224	263,484	912,960	104,844	174,986
2029	71,262	12,831	785,478	17,374	4,136	208,850	768,533	89,320	137,900
2030	62,726	11,061	674,592	14,885	3,281	165,352	707,086	99,106	29,697
2031	55,130	9,703	559,035	12,741	2,716	122,881	619,990	56,067	86,272
2032	50,185	8,229	494,415	11,201	2,058	99,064	554,705	42,694	92,595
2033	45,177	7,051	451,483	9,649	1,564	84,351	510,983	59,663	80,753
2034	40,323	6,505	417,980	8,565	1,367	73,925	495,437	41,149	6,481
2035	36,789	5,647	390,042	7,670	955	63,325	424,808	14,426	172,887
2036	33,190	4,881	351,186	6,884	735	52,554	368,758	17,391	253,856
2037	30,498	4,711	334,600	6,252	658	47,385	363,365	10,341	5,918
2038	27,922	4,177	293,878	5,755	433	37,523	279,288	22,466	217,161
2039	24,336	4,111	283,877	4,801	386	33,964	244,692	12,026	303,102
2040	20,656	3,843	254,962	3,791	317	28,476	181,155	10,374	216,481
2041	15,517	3,381	210,303	2,727	161	14,132	146,343	3,543	844,174
2042	12,417	2,862	166,326	875	81	5,581	56,972	8,797	0
2043	11,034	2,317	134,341	791	65	4,504	54,332	2,830	12,016
2044	10,200	2,186	126,336	729	61	4,140	53,097	9,152	0
2045	8,792	1,536	88,798	653	43	3,036	50,360	2,944	22,859
2046	7,930	1,272	74,053	597	36	2,415	47,066	3,003	0
2047	5,955	0	1,596	510	0	359	39,726	3,063	30,845
2048	5,552	0	1,504	477	0	338	39,696	0	0
Subtotal	**1,086,856**	**179,583**	**11,927,150**	**242,206**	**47,293**	**2,727,918**	**11,071,607**	**2,890,632**	**2,841,660**
Remaining	9,948	0	4,617	856	0	1,038	80,773	0	430,018
Total	**1,096,804**	**179,583**	**11,931,767**	**243,062**	**47,293**	**2,728,956**	**11,152,380**	**2,890,632**	**3,271,678**

TABLE A-10
SUMMARY FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	144,677	18,846	1,609,356	34,762	6,173	441,359	1,130,767	1,104,009	88,742
2025	134,591	23,898	1,458,208	33,853	8,523	430,612	1,116,793	877,751	17,862
2026	125,474	22,236	1,382,713	32,116	7,865	404,843	1,103,424	429,033	17,111
2027	114,017	22,437	1,323,398	29,707	8,064	385,068	1,097,738	218,360	25,341
2028	103,349	21,313	1,208,938	27,470	7,339	346,932	1,056,327	105,109	8,878
2029	93,317	19,259	1,105,934	24,787	6,475	313,750	977,358	91,643	8,856
2030	82,318	16,742	989,262	21,594	5,319	274,485	877,489	100,088	239,133
2031	72,974	14,907	890,022	19,079	4,581	244,532	838,248	56,513	9,465
2032	65,299	12,258	778,269	16,682	3,435	205,375	783,447	42,942	7,133
2033	59,357	10,392	693,351	14,702	2,640	172,744	714,829	59,917	6,949
2034	53,790	9,370	623,893	13,207	2,321	150,099	688,862	41,809	37,851
2035	47,867	8,643	571,795	11,658	2,120	132,364	635,431	14,486	207,779
2036	43,766	7,345	508,566	10,634	1,651	108,723	585,694	18,303	6,483
2037	40,084	6,240	459,634	9,674	1,180	90,917	486,731	10,828	227,784
2038	36,876	5,460	397,559	9,068	966	72,487	434,457	22,886	259,774
2039	33,864	4,854	359,455	8,292	680	60,056	335,320	13,341	273,426
2040	29,926	4,611	326,689	7,384	633	54,171	304,054	11,098	26,874
2041	21,845	3,581	240,287	5,501	315	27,022	253,967	3,959	1,035,897
2042	15,679	2,884	179,142	1,788	139	10,564	128,803	10,229	175,035
2043	13,069	2,534	162,137	960	71	8,832	71,329	3,680	213,422
2044	12,050	2,304	146,939	887	65	7,780	69,020	10,030	5,457
2045	11,009	2,056	130,578	814	58	6,925	66,432	2,944	0
2046	10,063	1,801	116,118	749	50	6,254	65,107	3,003	0
2047	9,174	1,567	101,373	688	44	5,577	63,801	3,063	39,611
2048	8,360	1,319	81,681	632	38	4,043	58,231	0	0
Subtotal	**1,382,795**	**246,857**	**15,845,297**	**336,688**	**70,745**	**3,965,514**	**13,943,659**	**3,255,024**	**2,938,863**
Remaining	12,163	0	19,603	1,055	0	4,677	104,748	0	463,178
Total	**1,394,958**	**246,857**	**15,864,900**	**337,743**	**70,745**	**3,970,191**	**14,048,407**	**3,255,024**	**3,402,041**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-11
SUMMARY FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	155,938	19,582	1,716,532	37,566	6,396	465,687	1,161,553	1,124,231	88,503
2025	149,411	25,063	1,609,630	37,633	8,949	469,481	1,170,109	906,956	17,704
2026	147,259	24,428	1,587,066	37,777	8,699	463,709	1,198,559	449,099	17,016
2027	137,217	26,719	1,614,368	36,321	9,828	475,620	1,256,913	219,576	25,290
2028	124,124	24,932	1,465,296	33,554	8,758	427,583	1,153,847	105,330	8,048
2029	112,612	22,977	1,340,710	30,758	7,840	388,361	1,060,750	89,554	7,801
2030	98,798	20,323	1,198,037	26,896	6,587	342,717	995,291	100,089	163,074
2031	88,168	18,476	1,104,880	23,806	5,797	310,734	950,141	58,687	10,592
2032	80,376	16,029	1,008,706	21,411	4,678	278,912	882,141	42,942	87,196
2033	74,246	14,461	949,123	19,400	3,990	258,962	856,872	59,917	6,995
2034	67,081	13,466	878,840	17,306	3,614	236,727	827,822	41,809	30,444
2035	61,316	11,948	812,338	15,771	3,189	217,063	775,591	14,691	14,330
2036	54,615	10,051	732,393	13,909	2,557	195,255	730,281	18,512	85,157
2037	48,831	8,618	653,702	12,529	2,137	168,694	682,321	11,041	17,107
2038	45,107	6,338	543,811	11,725	1,314	132,543	567,034	23,539	414,818
2039	41,021	5,544	495,278	10,642	909	114,016	485,381	13,563	200,838
2040	36,835	5,434	464,353	9,575	852	102,980	466,287	11,324	5,444
2041	26,588	4,149	326,315	6,982	456	58,582	375,260	4,190	966,099
2042	20,846	3,499	232,986	2,825	223	23,528	229,686	10,465	21,693
2043	17,544	3,287	215,129	1,585	102	13,768	116,862	3,680	331,669
2044	16,133	3,027	200,029	1,497	90	12,591	108,903	10,030	93,486
2045	14,556	2,533	167,600	1,368	75	10,798	103,981	4,089	229,063
2046	12,554	2,336	157,518	933	66	9,954	76,986	3,917	113,453
2047	11,571	2,079	140,886	863	58	9,093	75,573	4,006	39,611
2048	10,603	1,769	115,291	801	50	6,945	68,780	1,215	0
Subtotal	**1,653,350**	**297,068**	**19,730,817**	**413,433**	**87,214**	**5,194,303**	**16,376,924**	**3,332,452**	**2,995,431**
Remaining	23,942	7,068	425,141	1,582	198	21,914	172,285	0	471,990
Total	**1,677,292**	**304,136**	**20,155,958**	**415,015**	**87,412**	**5,216,217**	**16,549,209**	**3,332,452**	**3,467,421**

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

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-12
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
ARGENTINA

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	2,986	1,397	345,460	1,001	524	107,464	127,642	178,187	0
2025	2,846	1,464	328,916	976	548	105,646	109,222	100,404	4,294
2026	2,853	1,470	334,473	983	551	109,282	106,960	6,309	8,035
2027	2,522	1,468	285,382	871	549	94,022	92,950	6,436	16,988
2028	2,157	1,424	248,047	777	534	84,489	79,481	1,218	0
2029	1,979	1,415	218,805	714	530	75,155	71,744	1,242	0
2030	1,716	1,407	186,727	622	528	64,262	62,604	0	0
2031	1,396	1,262	155,968	505	474	53,579	53,553	0	0
2032	1,214	1,188	137,518	439	446	47,315	48,284	0	0
2033	1,092	1,080	123,452	395	405	42,578	44,671	0	0
2034	981	966	110,508	356	363	38,165	41,286	0	0
2035	905	903	101,569	330	337	35,178	39,053	0	0
2036	833	831	92,991	301	313	32,264	36,964	0	0
2037	753	751	84,083	274	282	29,195	34,635	0	0
2038	684	709	70,261	254	265	25,431	28,873	0	0
2039	634	658	64,822	232	247	23,498	27,618	0	0
2040	582	602	59,428	215	226	21,565	26,142	0	0
2041	198	191	21,970	72	72	7,600	13,289	0	173,244
2042	10	0	2,249	3	0	506	1,378	0	0
2043	10	0	2,086	2	0	469	1,306	0	0
2044	10	0	1,947	2	0	438	1,246	0	0
2045	8	0	1,814	2	0	408	1,186	0	0
2046	8	0	1,700	2	0	382	1,136	0	0
2047	8	0	1,596	1	0	359	1,090	0	0
2048	7	0	1,504	2	0	338	1,050	0	0
Subtotal	**26,392**	**19,186**	**2,983,276**	**9,331**	**7,194**	**999,588**	**1,053,363**	**293,796**	**202,561**
Remaining	22	0	4,617	5	0	1,038	3,406	0	181,414
Total	**26,414**	**19,186**	**2,987,893**	**9,336**	**7,194**	**1,000,626**	**1,056,769**	**293,796**	**383,975**

TABLE A-13
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
ARGENTINA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	3,172	1,605	366,036	1,056	603	113,333	133,600	178,187	0
2025	3,176	1,572	367,689	1,080	591	117,848	121,506	100,404	4,294
2026	3,237	1,540	379,454	1,110	578	123,286	121,658	6,309	8,035
2027	2,989	1,548	350,809	1,028	581	115,784	113,138	6,436	16,988
2028	2,521	1,558	302,452	903	583	102,531	95,874	1,218	0
2029	2,377	1,555	276,999	856	584	94,712	90,020	1,242	0
2030	2,092	1,563	241,847	757	586	82,750	79,776	0	0
2031	1,751	1,414	211,276	630	530	72,226	70,816	0	0
2032	1,530	1,325	192,188	551	497	65,812	65,040	0	0
2033	1,446	1,323	177,832	523	495	61,063	61,263	0	0
2034	1,391	1,315	167,569	503	493	57,743	59,049	0	0
2035	1,323	1,312	155,609	480	491	53,709	55,338	0	0
2036	1,291	1,322	149,028	468	496	51,628	54,443	0	0
2037	1,236	1,286	140,208	450	483	48,677	52,365	0	0
2038	1,197	1,312	127,891	439	492	45,555	47,520	0	0
2039	1,159	1,284	122,730	425	481	43,808	46,689	0	0
2040	1,104	1,221	116,594	407	458	41,679	45,241	0	0
2041	399	401	47,627	141	151	15,980	22,431	0	172,350
2042	60	0	13,618	16	0	3,372	10,778	0	0
2043	53	0	12,538	14	0	3,101	10,573	0	0
2044	51	0	11,569	12	0	2,858	10,393	0	0
2045	44	0	10,610	11	0	2,618	10,197	0	0
2046	41	0	9,716	11	0	2,393	10,024	0	0
2047	37	0	8,801	10	0	2,161	9,859	0	0
2048	35	0	8,054	8	0	1,974	9,721	0	0
Subtotal	**33,712**	**24,456**	**3,968,744**	**11,889**	**9,173**	**1,326,601**	**1,407,312**	**293,796**	**201,667**
Remaining	76	0	19,603	19	0	4,677	23,157	0	182,482
Total	**33,788**	**24,456**	**3,988,347**	**11,908**	**9,173**	**1,331,278**	**1,430,469**	**293,796**	**384,149**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-14
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
ARGENTINA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	3,335	1,810	384,250	1,102	679	118,327	138,669	178,187	0
2025	3,412	1,645	394,437	1,157	617	125,503	129,289	100,404	4,294
2026	3,588	1,576	430,190	1,223	591	139,356	135,325	6,309	8,035
2027	3,426	1,620	412,056	1,178	608	135,817	129,587	6,436	16,988
2028	2,934	1,689	369,725	1,051	631	125,194	113,419	1,218	0
2029	2,836	1,685	349,956	1,019	633	119,617	109,239	1,242	0
2030	2,642	1,708	325,694	953	640	111,837	104,168	0	0
2031	2,170	1,549	278,819	780	581	95,289	90,444	0	0
2032	1,889	1,431	256,549	677	537	87,772	84,628	0	0
2033	1,802	1,444	240,542	648	541	82,502	81,457	0	0
2034	1,708	1,442	224,576	617	542	77,134	78,114	0	0
2035	1,664	1,479	216,113	600	554	74,500	76,813	0	0
2036	1,614	1,482	206,927	584	556	71,528	75,323	0	0
2037	1,551	1,467	195,301	560	551	67,608	72,869	0	0
2038	1,494	1,479	181,155	545	555	63,881	67,818	0	0
2039	1,454	1,470	173,944	531	550	61,440	66,792	0	0
2040	1,405	1,440	165,658	513	540	58,571	65,119	0	0
2041	528	477	70,826	186	179	23,243	32,063	0	172,350
2042	102	0	24,209	26	0	5,975	15,277	0	0
2043	94	0	22,642	24	0	5,587	15,004	0	0
2044	90	0	21,185	23	0	5,226	14,758	0	0
2045	82	0	19,780	22	0	4,878	14,504	0	0
2046	77	0	18,503	20	0	4,563	14,309	0	0
2047	71	0	17,091	17	0	4,209	14,127	0	0
2048	67	0	15,911	18	0	3,914	13,974	0	0
Subtotal	**40,035**	**26,893**	**5,016,039**	**14,074**	**10,085**	**1,673,471**	**1,753,089**	**293,796**	**201,667**
Remaining	177	0	44,310	44	0	10,788	44,149	0	182,503
Total	**40,212**	**26,893**	**5,060,349**	**14,118**	**10,085**	**1,684,259**	**1,797,238**	**293,796**	**384,170**

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

TABLE A-15
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
DENMARK

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Remaining	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

TABLE A-16
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
DENMARK

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Remaining	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-17
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
DENMARK

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Remaining	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

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

TABLE A-18
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
GERMANY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	6,203	0	41,275	6,098	0	20,205	163,684	142,734	83,493
2025	5,990	0	42,011	5,894	0	20,192	158,853	104,696	0
2026	5,781	0	39,578	5,692	0	18,721	156,750	52,186	330
2027	5,403	0	34,906	5,325	0	16,295	158,427	80,239	1,013
2028	5,197	0	30,829	5,119	0	14,201	159,001	36,718	92,718
2029	4,957	0	22,762	4,883	0	7,867	103,900	8,679	0
2030	4,427	0	19,655	4,366	0	6,736	99,862	8,523	22,102
2031	3,936	0	14,722	3,886	0	4,763	93,928	8,290	33,239
2032	3,625	0	12,487	3,578	0	4,053	90,263	6,712	0
2033	3,320	0	11,136	3,276	0	3,594	90,721	6,657	0
2034	3,067	0	9,759	3,027	0	3,127	89,177	6,632	0
2035	2,811	0	8,771	2,775	0	2,803	87,787	8,243	0
2036	2,648	0	7,630	2,614	0	2,421	91,905	5,811	0
2037	2,468	0	6,887	2,440	0	2,178	90,913	4,252	0
2038	2,332	0	6,257	2,302	0	1,979	90,514	4,331	0
2039	2,185	0	5,468	2,158	0	1,709	90,146	17	203,402
2040	1,813	0	5,004	1,812	0	1,558	79,121	12	0
2041	1,702	0	4,261	1,704	0	1,359	78,885	6	647,928
2042	0	0	1,208	0	0	499	3,028	0	0
2043	0	0	876	0	0	343	2,708	0	12,016
2044	1	0	617	0	0	224	2,202	0	0
2045	0	0	549	0	0	199	2,186	0	22,859
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**67,866**	**0**	**326,648**	**66,949**	**0**	**135,026**	**1,983,961**	**484,738**	**1,119,100**
Remaining	0	0	0	0	0	0	0	0	0
Total	**67,866**	**0**	**326,648**	**66,949**	**0**	**135,026**	**1,983,961**	**484,738**	**1,119,100**

TABLE A-19
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
GERMANY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	7,577	0	46,246	7,467	0	22,752	163,591	143,786	79,257
2025	7,919	0	48,632	7,813	0	23,833	160,430	105,178	4,407
2026	7,783	0	46,950	7,686	0	22,850	158,194	53,506	331
2027	7,297	0	42,785	7,210	0	20,744	160,014	80,500	0
2028	7,385	0	39,499	7,292	0	18,961	160,884	36,983	0
2029	7,276	0	35,824	7,189	0	17,074	146,948	8,913	1,054
2030	6,802	0	31,519	6,730	0	15,082	140,414	9,505	22,102
2031	6,336	0	26,017	6,277	0	12,377	132,472	8,534	0
2032	5,989	0	23,465	5,930	0	10,995	130,774	6,960	0
2033	5,456	0	21,229	5,402	0	9,884	129,462	6,911	0
2034	5,064	0	19,382	5,012	0	8,960	128,668	7,292	0
2035	4,716	0	17,791	4,666	0	8,161	125,829	8,303	106,504
2036	4,457	0	13,024	4,414	0	4,106	95,872	6,503	0
2037	4,201	0	11,871	4,159	0	3,734	94,821	4,739	37,432
2038	3,986	0	9,774	3,946	0	3,113	92,469	4,751	0
2039	3,768	0	8,564	3,731	0	2,689	91,824	383	0
2040	3,452	0	7,707	3,434	0	2,398	91,536	77	0
2041	3,249	0	7,074	3,232	0	2,193	91,302	30	840,349
2042	0	0	6,377	1	0	1,817	6,772	25	0
2043	0	0	5,952	0	0	1,694	6,661	0	12,016
2044	2	0	4,879	0	0	1,256	5,606	0	5,457
2045	0	0	4,266	0	0	1,055	4,464	0	0
2046	0	0	3,986	0	0	984	4,392	0	0
2047	0	0	3,729	0	0	919	4,328	0	39,611
2048	0	0	0	0	0	0	0	0	0
Subtotal	**102,715**	**0**	**486,542**	**101,591**	**0**	**217,631**	**2,327,727**	**492,879**	**1,148,520**
Remaining	0	0	0	0	0	0	0	0	0
Total	**102,715**	**0**	**486,542**	**101,591**	**0**	**217,631**	**2,327,727**	**492,879**	**1,148,520**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-20
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
GERMANY

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	8,737	0	48,053	8,624	0	23,644	165,166	143,787	79,257
2025	9,141	0	51,507	9,028	0	25,348	161,063	105,178	4,406
2026	9,115	0	50,496	9,012	0	24,747	158,985	53,506	331
2027	8,531	0	46,867	8,436	0	22,945	160,967	80,500	0
2028	8,520	0	44,029	8,418	0	21,400	161,976	36,983	0
2029	8,563	0	40,721	8,466	0	19,690	148,150	8,913	0
2030	8,033	0	36,911	7,953	0	17,837	141,856	9,506	22,104
2031	7,399	0	30,843	7,336	0	14,856	133,614	8,534	1,096
2032	7,094	0	28,131	7,024	0	13,632	131,777	6,960	0
2033	6,607	0	25,905	6,542	0	12,497	130,510	6,911	0
2034	6,233	0	23,888	6,173	0	11,368	129,763	7,292	0
2035	5,870	0	22,289	5,814	0	10,534	126,969	8,508	0
2036	5,559	0	20,882	5,509	0	9,813	130,446	6,712	0
2037	5,206	0	19,429	5,156	0	9,069	129,435	4,952	0
2038	4,942	0	18,163	4,894	0	8,432	129,030	5,404	0
2039	4,654	0	16,760	4,609	0	7,738	128,645	605	0
2040	4,271	0	15,771	4,246	0	7,224	128,631	303	0
2041	3,981	0	14,769	3,957	0	6,718	128,487	261	748,671
2042	292	0	10,763	261	0	3,139	21,667	261	0
2043	243	0	10,167	219	0	2,963	21,571	0	12,015
2044	303	0	9,137	268	0	2,554	20,590	0	42,997
2045	270	0	6,992	243	0	1,924	18,015	0	229,063
2046	0	0	6,205	0	0	1,659	6,568	0	0
2047	0	0	5,898	0	0	1,571	6,524	0	39,611
2048	0	0	639	0	0	256	1,322	0	0
Subtotal	**123,564**	**0**	**605,215**	**122,188**	**0**	**281,558**	**2,621,727**	**495,076**	**1,179,551**
Remaining	1	0	1,143	1	0	457	2,651	0	6,146
Total	**123,565**	**0**	**606,358**	**122,189**	**0**	**282,015**	**2,624,378**	**495,076**	**1,185,697**

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

TABLE A-21
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
MEXICO

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	9,699	0	6,379	3,801	0	2,854	44,073	21,596	8,441
2025	9,076	0	5,773	3,553	0	2,580	43,523	19,183	7,946
2026	8,624	0	5,325	3,369	0	2,375	43,333	9,294	7,502
2027	7,937	0	4,756	3,098	0	2,122	42,551	2,067	7,104
2028	7,422	0	4,302	2,894	0	1,923	42,143	2,325	6,752
2029	6,852	0	3,840	2,668	0	1,717	41,564	2,299	6,441
2030	6,100	0	3,475	2,379	0	1,574	40,469	2,542	6,167
2031	5,634	0	3,109	2,197	0	1,414	40,062	2,105	5,919
2032	5,199	0	2,754	2,027	0	1,259	39,714	2,235	5,699
2033	4,708	0	2,458	1,836	0	1,135	39,168	2,250	5,508
2034	4,106	0	2,100	1,610	0	990	38,282	2,356	5,338
2035	3,737	0	1,860	1,466	0	890	38,001	1,831	5,183
2036	3,348	0	1,585	1,318	0	773	37,641	1,741	5,044
2037	2,891	0	1,344	1,141	0	672	37,044	1,775	4,923
2038	2,588	0	1,239	1,024	0	618	36,880	970	4,817
2039	1,876	0	0	695	0	0	20,732	0	4,734
2040	1,721	0	0	636	0	0	20,658	0	4,828
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**91,518**	**0**	**50,299**	**35,712**	**0**	**22,896**	**645,838**	**74,569**	**102,346**
Remaining	0	0	0	0	0	0	26	0	0
Total	**91,518**	**0**	**50,299**	**35,712**	**0**	**22,896**	**645,864**	**74,569**	**102,346**

TABLE A-22
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
MEXICO

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	9,892	0	6,706	3,889	0	3,013	44,499	21,596	7,448
2025	9,543	0	6,565	3,763	0	2,966	44,565	19,183	7,215
2026	9,277	0	6,459	3,666	0	2,927	44,815	9,294	6,978
2027	8,970	0	6,147	3,541	0	2,785	44,982	2,067	6,741
2028	8,447	0	5,721	3,336	0	2,602	44,603	2,325	6,521
2029	8,011	0	5,336	3,160	0	2,425	44,408	2,299	6,319
2030	7,667	0	5,154	3,023	0	2,348	44,425	2,542	6,136
2031	7,269	0	4,777	2,863	0	2,180	44,277	2,105	5,965
2032	6,593	0	4,256	2,598	0	1,953	43,375	2,235	5,814
2033	6,165	0	3,943	2,431	0	1,816	43,077	2,250	5,683
2034	5,846	0	3,675	2,304	0	1,697	43,067	2,356	5,567
2035	5,537	0	3,427	2,182	0	1,589	43,054	1,831	5,463
2036	5,204	0	3,131	2,050	0	1,458	42,962	1,741	5,371
2037	4,767	0	2,823	1,879	0	1,324	42,540	1,775	5,293
2038	4,281	0	2,476	1,690	0	1,174	41,936	970	5,229
2039	3,961	0	2,192	1,564	0	1,048	41,799	949	5,178
2040	3,654	0	1,893	1,438	0	912	41,691	659	5,141
2041	592	0	1,439	296	0	720	17,164	392	196
2042	523	0	1,274	262	0	637	17,301	328	88
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**116,199**	**0**	**77,394**	**45,935**	**0**	**35,574**	**774,540**	**76,897**	**102,346**
Remaining	0	0	0	0	0	0	26	0	0
Total	**116,199**	**0**	**77,394**	**45,935**	**0**	**35,574**	**774,566**	**76,897**	**102,346**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-23
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
MEXICO

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	10,051	0	7,009	3,964	0	3,162	44,844	21,596	7,341
2025	9,935	0	7,291	3,943	0	3,323	45,432	19,183	7,164
2026	9,802	0	7,479	3,911	0	3,427	46,000	9,294	6,962
2027	9,574	0	7,274	3,822	0	3,340	46,373	2,067	6,745
2028	9,323	0	6,995	3,717	0	3,214	46,700	2,325	6,536
2029	8,879	0	6,599	3,539	0	3,030	46,522	2,299	6,340
2030	8,496	0	6,390	3,386	0	2,942	46,485	2,542	6,160
2031	8,158	0	6,024	3,247	0	2,776	46,537	2,105	5,990
2032	7,839	0	5,616	3,111	0	2,582	46,639	2,235	5,836
2033	7,518	0	5,307	2,981	0	2,442	46,713	2,250	5,701
2034	6,974	0	4,892	2,767	0	2,260	46,148	2,356	5,581
2035	6,559	0	4,560	2,605	0	2,114	45,900	1,831	5,474
2036	6,225	0	4,215	2,468	0	1,958	45,868	1,741	5,379
2037	5,938	0	3,921	2,349	0	1,821	45,947	1,775	5,299
2038	5,650	0	3,620	2,231	0	1,681	46,023	970	5,233
2039	5,358	0	3,299	2,112	0	1,534	46,056	949	5,180
2040	5,023	0	2,933	1,971	0	1,362	45,955	659	5,142
2041	775	0	1,886	388	0	943	17,711	392	196
2042	684	0	1,661	342	0	831	17,786	328	87
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**132,761**	**0**	**96,971**	**52,854**	**0**	**44,742**	**819,639**	**76,897**	**102,346**
Remaining	0	0	0	0	0	0	25	0	0
Total	**132,761**	**0**	**96,971**	**52,854**	**0**	**44,742**	**819,664**	**76,897**	**102,346**

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

TABLE A-24
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORTH AFRICA

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	9,637	48	188,018	1,515	48	51,389	72,853	54,438	2,179
2025	7,696	36	132,858	1,164	36	38,823	56,358	62,330	2,059
2026	6,785	27	111,137	997	27	32,564	50,939	13,438	1,848
2027	5,963	0	84,363	781	0	18,866	28,500	560	1,669
2028	5,373	0	89,023	701	0	20,260	25,620	571	1,587
2029	4,819	0	81,214	626	0	18,607	22,928	194	1,503
2030	4,352	0	65,804	565	0	15,087	22,040	198	1,428
2031	3,582	0	45,001	447	0	10,800	17,753	0	1,358
2032	3,276	0	37,518	410	0	9,003	15,919	0	1,296
2033	2,965	0	31,272	370	0	7,506	15,857	0	1,224
2034	2,628	0	26,184	329	0	6,283	17,262	0	1,143
2035	2,377	0	21,962	297	0	5,270	17,223	0	1,089
2036	2,163	0	18,502	270	0	4,441	16,554	0	1,044
2037	1,959	0	15,973	245	0	3,835	16,858	0	995
2038	1,802	0	14,304	225	0	3,433	16,014	0	965
2039	1,659	0	11,985	208	0	2,877	15,790	0	935
2040	435	0	0	54	0	0	(258)	0	21,864
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**67,471**	**111**	**975,118**	**9,204**	**111**	**249,044**	**428,210**	**131,729**	**44,186**
Remaining	0	0	0	0	0	0	0	0	0
Total	**67,471**	**111**	**975,118**	**9,204**	**111**	**249,044**	**428,210**	**131,729**	**44,186**

TABLE A-25
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORTH AFRICA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	11,751	55	254,635	1,903	55	64,733	77,870	81,200	2,037
2025	9,632	56	197,774	1,557	56	53,706	60,465	72,111	1,946
2026	8,050	50	160,197	1,286	50	46,342	53,148	13,438	1,767
2027	7,111	41	134,374	1,109	41	37,573	52,041	777	1,612
2028	6,192	34	121,909	942	34	32,109	46,774	571	1,550
2029	5,896	28	114,882	888	28	29,421	32,679	2,283	1,483
2030	5,480	23	110,619	820	23	26,807	31,586	198	1,424
2031	4,629	18	88,860	673	18	22,069	31,403	202	1,368
2032	3,798	15	63,521	534	15	16,601	22,668	0	1,319
2033	3,300	0	48,150	412	0	11,556	15,816	0	1,266
2034	3,047	0	41,256	382	0	9,901	17,173	0	1,231
2035	2,747	0	35,469	343	0	8,512	17,143	0	1,169
2036	2,477	0	27,779	309	0	6,667	16,488	0	1,112
2037	2,273	0	24,045	284	0	5,772	16,781	0	1,073
2038	2,081	0	21,357	260	0	5,127	15,942	0	1,035
2039	1,934	0	17,825	243	0	4,279	15,710	0	1,013
2040	511	0	14,568	63	0	3,493	9,100	0	282
2041	0	0	11,900	0	0	2,857	8,238	0	0
2042	0	0	0	0	0	0	0	0	21,606
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**80,909**	**320**	**1,489,120**	**12,008**	**320**	**387,525**	**541,025**	**170,780**	**44,293**
Remaining	0	0	0	0	0	0	0	0	0
Total	**80,909**	**320**	**1,489,120**	**12,008**	**320**	**387,525**	**541,025**	**170,780**	**44,293**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-26
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORTH AFRICA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	13,309	59	308,798	2,186	59	75,851	81,720	81,200	1,905
2025	11,993	60	271,867	1,974	60	68,579	66,221	72,111	1,840
2026	10,541	59	238,466	1,738	59	62,830	58,944	13,438	1,688
2027	8,298	59	177,369	1,363	59	49,266	54,282	776	1,557
2028	7,006	60	149,628	1,159	60	41,693	49,049	792	1,512
2029	6,229	55	122,964	1,017	55	34,545	32,674	194	1,461
2030	5,467	48	109,025	883	48	29,554	31,329	198	1,416
2031	4,984	40	100,996	788	40	27,008	31,375	2,376	1,374
2032	4,596	35	90,813	718	35	24,014	22,929	0	1,337
2033	4,296	29	85,157	662	29	22,162	22,792	0	1,294
2034	3,994	16	75,453	580	16	18,460	24,155	0	1,270
2035	3,613	0	64,040	474	0	14,413	18,013	0	1,247
2036	3,131	0	45,664	400	0	10,570	17,132	0	1,227
2037	2,663	0	35,314	332	0	8,475	16,684	0	1,169
2038	2,413	0	31,264	302	0	7,504	15,861	0	1,116
2039	2,218	0	25,711	278	0	6,173	15,643	0	1,081
2040	589	0	21,777	73	0	5,225	9,080	0	302
2041	0	0	18,396	0	0	4,414	8,238	0	0
2042	0	0	0	0	0	0	0	0	21,606
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**95,340**	**520**	**1,972,702**	**14,927**	**520**	**510,736**	**576,121**	**171,085**	**44,402**
Remaining	0	0	0	0	0	0	0	0	0
Total	**95,340**	**520**	**1,972,702**	**14,927**	**520**	**510,736**	**576,121**	**171,085**	**44,402**

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

TABLE A-27
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORWAY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	97,888	14,915	869,741	17,567	4,743	221,841	682,430	565,782	0
2025	85,518	16,051	715,235	15,496	5,312	195,037	659,252	441,812	0
2026	77,470	15,896	697,572	14,128	5,403	183,424	677,690	298,973	776
2027	68,841	15,183	638,770	12,533	5,275	168,577	676,265	116,769	0
2028	61,398	13,900	548,236	10,946	4,690	142,611	606,715	64,012	73,929
2029	52,655	11,416	458,857	8,483	3,606	105,504	528,397	76,906	129,956
2030	46,131	9,654	398,931	6,953	2,753	77,693	482,111	87,843	0
2031	40,582	8,441	340,235	5,706	2,242	52,325	414,694	45,672	45,756
2032	36,871	7,041	304,138	4,747	1,612	37,434	360,525	33,747	85,600
2033	33,092	5,971	283,165	3,772	1,159	29,538	320,566	50,756	74,021
2034	29,541	5,539	269,429	3,243	1,004	25,360	309,430	32,161	0
2035	26,959	4,744	255,880	2,802	618	19,184	242,744	4,352	166,615
2036	24,198	4,050	230,478	2,381	422	12,655	185,694	9,839	247,768
2037	22,427	3,960	226,313	2,152	376	11,505	183,915	4,314	0
2038	20,516	3,468	201,817	1,950	168	6,062	107,007	17,165	211,379
2039	17,982	3,453	201,602	1,508	139	5,880	90,406	12,009	94,031
2040	16,105	3,241	190,530	1,074	91	5,353	55,492	10,362	189,789
2041	13,617	3,190	184,072	951	89	5,173	54,169	3,537	23,002
2042	12,407	2,862	162,869	872	81	4,576	52,566	8,797	0
2043	11,024	2,317	131,379	789	65	3,692	50,318	2,830	0
2044	10,189	2,186	123,772	727	61	3,478	49,649	9,152	0
2045	8,784	1,536	86,435	651	43	2,429	46,988	2,944	0
2046	7,922	1,272	72,353	595	36	2,033	45,930	3,003	0
2047	5,947	0	0	509	0	0	38,636	3,063	30,845
2048	5,545	0	0	475	0	0	38,646	0	0
Subtotal	**833,609**	**160,286**	**7,591,809**	**121,010**	**39,988**	**1,321,364**	**6,960,235**	**1,905,800**	**1,373,467**
Remaining	9,926	0	0	851	0	0	77,341	0	248,604
Total	**843,535**	**160,286**	**7,591,809**	**121,861**	**39,988**	**1,321,364**	**7,037,576**	**1,905,800**	**1,622,071**

TABLE A-28
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORWAY

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	112,285	17,186	935,733	20,447	5,515	237,528	711,207	679,240	0
2025	104,321	22,270	837,548	19,640	7,876	232,259	729,827	580,875	0
2026	97,127	20,646	789,653	18,368	7,237	209,438	725,609	346,486	0
2027	87,650	20,848	789,283	16,819	7,442	208,182	727,563	128,580	0
2028	78,804	19,721	739,357	14,997	6,722	190,729	708,192	64,012	807
2029	69,757	17,676	672,893	12,694	5,863	170,118	663,303	76,906	0
2030	60,277	15,156	600,123	10,264	4,710	147,498	581,288	87,843	209,471
2031	52,989	13,475	559,092	8,636	4,033	135,680	559,280	45,672	2,132
2032	47,389	10,918	494,839	7,069	2,923	110,014	521,590	33,747	0
2033	42,990	9,069	442,197	5,934	2,145	88,425	465,211	50,756	0
2034	38,442	8,055	392,011	5,006	1,828	71,798	440,905	32,161	31,053
2035	33,544	7,331	359,499	3,987	1,629	60,393	394,067	4,352	94,643
2036	30,337	6,023	315,604	3,393	1,155	44,864	375,929	10,059	0
2037	27,607	4,954	280,687	2,902	697	31,410	280,224	4,314	183,986
2038	25,331	4,148	236,061	2,733	474	17,518	236,590	17,165	253,510
2039	23,042	3,570	208,144	2,329	199	8,232	139,298	12,009	267,235
2040	21,205	3,390	185,927	2,042	175	5,689	116,486	10,362	21,451
2041	17,605	3,180	172,247	1,832	164	5,272	114,832	3,537	23,002
2042	15,096	2,884	157,873	1,509	139	4,738	93,952	9,876	153,341
2043	13,016	2,534	143,647	946	71	4,037	54,095	3,680	201,406
2044	11,997	2,304	130,491	875	65	3,666	53,021	10,030	0
2045	10,965	2,056	115,702	803	58	3,252	51,771	2,944	0
2046	10,022	1,801	102,416	738	50	2,877	50,691	3,003	0
2047	9,137	1,567	88,843	678	44	2,497	49,614	3,063	0
2048	8,325	1,319	73,627	624	38	2,069	48,510	0	0
Subtotal	**1,049,260**	**222,081**	**9,823,497**	**165,265**	**61,252**	**1,998,183**	**8,893,055**	**2,220,672**	**1,442,037**
Remaining	12,087	0	0	1,036	0	0	81,565	0	280,696
Total	**1,061,347**	**222,081**	**9,823,497**	**166,301**	**61,252**	**1,998,183**	**8,974,620**	**2,220,672**	**1,722,733**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

TABLE A-29
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORWAY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	120,506	17,713	968,422	21,690	5,658	244,703	731,154	699,461	0
2025	114,930	23,358	884,528	21,531	8,272	246,728	768,104	610,080	0
2026	114,213	22,793	860,435	21,893	8,049	233,349	799,305	366,552	0
2027	107,388	25,040	970,802	21,522	9,161	264,252	865,704	129,797	0
2028	96,341	23,183	894,919	19,209	8,067	236,082	782,703	64,012	0
2029	86,105	21,237	820,470	16,717	7,152	211,479	724,165	76,906	0
2030	74,160	18,567	720,017	13,721	5,899	180,547	671,453	87,843	133,394
2031	65,457	16,887	688,198	11,655	5,176	170,805	648,171	45,672	2,132
2032	58,958	14,563	627,597	9,881	4,106	150,912	596,168	33,747	80,023
2033	54,023	12,988	592,212	8,567	3,420	139,359	575,400	50,756	0
2034	48,172	12,008	550,031	7,169	3,056	127,505	549,642	32,161	23,593
2035	43,610	10,469	505,336	6,278	2,635	115,502	507,896	4,352	7,609
2036	38,086	8,569	454,705	4,948	2,001	101,386	461,512	10,059	78,551
2037	33,473	7,151	399,737	4,132	1,586	81,721	417,386	4,314	10,639
2038	30,608	4,859	309,609	3,753	759	51,045	308,302	17,165	408,469
2039	27,337	4,074	275,564	3,112	359	37,131	228,245	12,009	194,577
2040	25,547	3,994	258,214	2,772	312	30,598	217,502	10,362	0
2041	21,304	3,672	220,438	2,451	277	23,264	188,761	3,537	44,882
2042	19,768	3,499	196,353	2,196	223	13,583	174,956	9,876	0
2043	17,207	3,287	182,320	1,342	102	5,218	80,287	3,680	319,654
2044	15,740	3,027	169,707	1,206	90	4,811	73,555	10,030	50,489
2045	14,204	2,533	140,828	1,103	75	3,996	71,462	4,089	0
2046	12,477	2,336	132,810	913	66	3,732	56,109	3,917	113,453
2047	11,500	2,079	117,897	846	58	3,313	54,922	4,006	0
2048	10,536	1,769	98,741	783	50	2,775	53,484	1,215	0
Subtotal	**1,261,650**	**269,655**	**12,039,890**	**209,390**	**76,609**	**2,683,796**	**10,606,348**	**2,295,598**	**1,467,465**
Remaining	23,764	7,068	379,688	1,537	198	10,669	125,460	0	283,341
Total	**1,285,414**	**276,723**	**12,419,578**	**210,927**	**76,807**	**2,694,465**	**10,731,808**	**2,295,598**	**1,750,806**

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