Energy Resources Program

National Assessment of Carbon Dioxide Enhanced Oil Recovery and Associated Carbon Dioxide Retention Resources—Results

Circular 1489

U.S. Department of the Interior
U.S. Geological Survey

Cover. View of outcrops near Cathedral Mountain at the southern margin of the Permian Basin in Texas. Rocks exposed here are equivalent in age to Permian reservoirs that are undergoing carbon dioxide enhanced oil recovery operations in the central part of the Permian Basin. Photograph by Peter D. Warwick, U.S. Geological Survey, May 10, 2016.

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Conversion Factors

Multiply	By	To obtain
	Length	
foot (ft)	0.3048	meter (m)
	Area	
square inch (in^2)	6.452	square centimeter (cm^2)
	Volume	
barrel (bbl; petroleum, 1 barrel = 42 gallons)	0.1590	cubic meter (m^3)
stock tank barrel (STB)	0.1590	cubic meter (m^3)
thousand barrels petroleum (Mbbl)	0.1590	thousand cubic meters (m^3)
million barrels petroleum (MMbbl)	0.1590	million cubic meters (m^3)
standard cubic foot (cf, ft^3)	0.02832	standard cubic meter (m^3)
thousand cubic feet (Mcf, 1,000 ft^3)	28.32	cubic meter (m^3)
thousand standard cubic feet (Mscf) of natural gas at standard conditions of 60 degrees Fahrenheit (°F) and 14.7 pound-force per square inch, absolute (psia)	28.31	cubic meters (m^3) of natural gas at standard conditions of 15 degrees Celsius (°C) and 101.325 kilopascals (kPa)
thousand standard cubic feet (Mscf) of carbon dioxide (CO_2) at standard conditions of 60 degrees Fahrenheit (°F) and 14.7 pound-force per square inch, absolute (psia)	0.0529	metric ton (t) of carbon dioxide (CO_2) at standard conditions of 15 degrees Celsius (°C) and 101.325 kilopascals (kPa)
million cubic feet (MMcf)	28,317	cubic meter (m^3)
billion cubic feet (Bcf)	28,316,847	cubic meter (m^3)
cubic meter (m^3)	6.290	barrel (bbl; petroleum, 1 barrel = 42 gallons)
	Mass	
pound, avoirdupois (lb)	0.4536	kilogram (kg)
ton, short (2,000 lb)	0.9072	megagram (Mg)
ton, long (2,240 lb)	1.016	megagram (Mg)
ton, metric (2,204.62 lb)	1.000	megagram (Mg)
milligram (mg)	0.00003527	ounce, avoirdupois (oz)
kilogram (kg)	2.205	pound avoirdupois (lb)
megagram (Mg) = 1 metric ton (t) (1,000 kg)	1.102	ton, short (2,000 lb)
megagram (Mg)	0.9842	ton, long (2,240 lb)
million metric tons = 1 megaton (Mt)	1.102	million short tons
billion metric tons = 1 gigaton (Gt)	1.102	billion short tons

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

$$°F = (1.8 \times °C) + 32.$$

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

$$°C = (°F - 32) / 1.8.$$

Abbreviations

Ø	porosity, expressed as a volume, fraction, or percentage of the rock
Bbbl	billion petroleum barrels
bbl	petroleum barrel or barrels
BOEM	Bureau of Ocean Energy Management
CCUS	carbon capture, use, and storage
CO_2	carbon dioxide
CO_2-EOR	carbon dioxide enhanced oil recovery
CRD	Comprehensive Resource Database
EOR	enhanced oil recovery
EOR_v	incremental oil volume produced by enhanced oil recovery
Gt	gigaton = billion metric tons
IHS	IHS Inc. became IHS Markit, Inc. in 2016
k	permeability, in darcies or millidarcies
MMbbl	millions of petroleum barrels
Mscf	thousands of standard cubic feet
Mt	megaton = million metric tons
NOGA	National Oil and Gas Assessment
OOIP	original oil in place, in thousands of stock tank barrels
RF	recovery factor for oil or gas
ROZ	residual oil zone
scf	standard cubic foot
SOI	initial or original oil saturation, expressed as a fraction
STB	stock tank barrel
U.S.	United States
USGS	U.S. Geological Survey
VDP	Dykstra-Parsons coefficient

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Abstract

In 2020, the U.S. Geological Survey (USGS) completed a probabilistic assessment of the volume of technically recoverable oil resources available if current carbon dioxide enhanced oil recovery (CO_2-EOR) technologies were applied to amenable oil reservoirs underlying the onshore and State waters areas of the conterminous United States. The assessment also includes estimates of the mass of CO_2 that could be stored (retained) as a result of CO_2-EOR activities. The USGS assessment team evaluated more than 3,500 oil reservoirs that were miscible to injected CO_2. The assessed reservoirs are in 185 previously defined USGS plays in 33 petroleum provinces of 7 national regions. The assessment team estimated that the technically recoverable oil associated with CO_2-EOR ranges from approximately 25,000 million barrels (MMbbl) at the P_5 percentile to as much as 32,000 MMbbl at the P_{95} percentile, with a mean of 29,000 MMbbl. The associated CO_2 retention ranges from approximately 7,400 million metric tons (Mt) at the P_5 percentile to as much as 9,500 Mt at the P_{95} percentile, with a mean of 8,400 Mt. The West Texas and Eastern New Mexico region and the Gulf Coast region together contain 60 percent of the mean assessed CO_2-EOR oil potential and 61 percent of the mean assessed CO_2 retention. Other regions with significant resource potential include the Midcontinent region and Rocky Mountains and Northern Great Plains region.

Introduction

The Energy Independence and Security Act of 2007 (U.S. Congress, 2007) authorized the U.S. Geological Survey (USGS) to conduct a national assessment of geologic storage resources for carbon dioxide (CO_2) and requested the USGS to estimate the "potential volumes of oil and gas recoverable by injection and sequestration of industrial carbon dioxide in potential sequestration formations" (42 U.S.C. 17271(b)(4)). The USGS developed a probability-based methodology to assess the Nation's technically accessible geologic storage resources available for sequestration of CO_2 (Brennan and others, 2010; Blondes, Brennan, and others, 2013) and published the results of the assessment (U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a, b, c).

A workshop on developing a methodology to assess CO_2-enhanced oil recovery (CO_2-EOR) potential and associated carbon storage was held at Stanford University, California, in May 2011, to seek advice from academia, natural resource agencies and laboratories of the Federal Government, State and international geologic surveys, and representatives from the oil and gas industry (Verma and Warwick, 2011). Following the workshop recommendations, the USGS developed a national database that contains the geologic and engineering parameters to screen oil reservoirs amenable to CO_2-EOR methods (Carolus and others, 2017). In 2019, the USGS published a probabilistic methodology for assessing oil reservoirs for their technically recoverable hydrocarbon potential associated with CO_2-EOR (Warwick and others, 2019). Also included in the methodology is a way to estimate the associated storage of CO_2 in the reservoirs after the completion of the CO_2-EOR process.

The use of CO_2-EOR techniques can increase the recoverable hydrocarbon resource volumes. Because some of the injected CO_2 is retained in the reservoir, use of anthropogenic CO_2 in the EOR process could potentially help reduce the amount of CO_2 released to the atmosphere that might contribute to global warming as a greenhouse gas. The International Energy Agency (2015) estimated that oil produced by using anthropogenic CO_2 in the CO_2-EOR process averages about 63 percent less carbon emitted than oil produced through traditional methods (National Petroleum Council, 2019).

Previous global and national assessments of recoverable oil resources and associated CO_2 retention in oil reservoirs have utilized various assessment methods and economic constraints and have produced a wide range of results. Advanced Resources International (2021) reported that oil produced as a result of CO_2-EOR in the conterminous United States amounted to approximately 300,000 barrels of oil per day in 2019. Oil production related to CO_2-EOR will likely increase in the United States because the Bipartisan Budget Act of 2018 (Public Law 115–123) aims to increase oil production related to CO_2-EOR by increasing tax credits that operators receive for injecting and sequestering anthropogenic CO_2.

The objective of this circular is to present the results of a USGS assessment of (1) the volumes of oil that could be technically recoverable by applying the CO_2-EOR process to suitable oil reservoirs underlying onshore and State waters areas of the conterminous United States[1] and (2) the mass of CO_2 that could be stored (retained) in assessed petroleum reservoirs after the completion of the CO_2-EOR process. The assessment results for each assessed play, province, and region and the national results are reported in millions of barrels (MMbbl) of recoverable oil, and the volumes of CO_2 retained are reported in millions of metric tons (Mt). The methodology used for the assessment (Warwick and others, 2019) follows the current practice in industry to maximize oil production rather than CO_2 retention because, in the general absence of regulations or economic incentives, the industry practice is to reduce the cost of CO_2 purchased for EOR (Jahangiri and Zhang, 2010). This assessment does not include economic, logistical, legal, environmental, or political constraints, such as the availability of pipelines for CO_2 supply, surface ownership, or infrastructure for separating CO_2 from the produced hydrocarbons. For a general review of the CO_2-EOR process, please refer to Verma (2015).

Two other products are being published in conjunction with this assessment results circular, and the reader may refer to them for additional information. The companion data release (Warwick and others, 2022a) contains (1) a generic list of assessed reservoirs in each play with primary reservoir lithology (summarized as clastic or carbonate), estimated reservoir mean original oil in place (*OOIP*) values, and estimated reservoir oil recovery factors and CO_2 retention values related to the CO_2-EOR process and (2) pairwise statistical correlation[2] matrices specifying geological and methodological dependencies among plays, provinces, and regions that are needed for aggregation of results outside of the means. The related fact sheet summarizes the final results of this assessment (Warwick and others, 2022b).

[1]State waters are defined in the "Glossary."

[2]The terms "statistical correlation" or "correlation" used in this report should not be confused with the "correlations" that might be used in stratigraphic, structural, or especially reservoir engineering contexts.

National Subdivisions

The oil reservoirs evaluated in this assessment are organized by previously defined USGS plays, petroleum provinces (all assessed provinces were sedimentary basins), and regions (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Beeman and others, 1996; Carolus and others, 2017; Warwick and others, 2019). This arrangement was chosen because the primary databases used for the initial national oil and natural gas resource assessment were organized by USGS plays, provinces, and regions. See the section of this circular below on "Data Sources" for more details on the various datasets used in the assessment.

The U.S. Geological Survey National Oil and Gas Resource Assessment Team (1995, p. 6) defined a play as "a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration patterns, timing, trapping mechanism, and hydrocarbon type." Confirmed plays are plays where one or more accumulations of minimum size (1 million barrels of oil or 6 billion cubic feet of gas) have been discovered in the play (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995).

The U.S. Geological Survey National Oil and Gas Resource Assessment Team (1995) aggregated the U.S. oil and gas resources in plays by province and region. For that study, the United States was divided into 8 regions and 71 provinces. The regions are geographic and provide broad geologic groupings of provinces. The provinces are based on natural geologic entities and may include a single dominant structural element or several contiguous elements. The provinces are named for structural or geographic features within their boundaries (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995).

Data Sources

The Comprehensive Resource Database (CRD) was developed to identify candidate reservoirs for CO_2-EOR and to provide a basis for the assessment of the technically recoverable hydrocarbons from conventional oil reservoirs (Carolus and others, 2017; Warwick and others, 2019). The data within the CRD either are not available or have limited availability owing to restrictions associated with the proprietary databases used to build the CRD. Contact the Director, Energy Resources Program, U.S. Geological Survey, Reston, Va., for more information. Data in the CRD include location information for fields and reservoirs along with reservoir fluid properties and production data from the proprietary database by Nehring Associates (2012), "The Significant Oil and Gas Fields of the United States Database," and proprietary production and drilling data by well from IHS Inc. (2012). The reservoirs in the CRD were organized by the geologic plays and petroleum provinces as described above.

The commercial databases provide information on the geologic characteristics of reservoirs, formations, and fields; the reservoir properties; and some production data; however, they differ in the type of data they report. The Nehring Associates (2012) database reports production by individual reservoir or field, whereas the IHS Inc. (2011, 2012) databases report production by individual well or producing entity such as a lease. Carolus and others (2017) described the parameters from the Nehring Associates and IHS databases that were used to create the CRD. The IHS data were used to augment the production data from the Nehring database for years 2011 and 2012. Well and lease production data from IHS were aggregated to the field level, and, for fields where the two databases matched, the extended production data for IHS were allocated to the reservoirs in the Nehring database according to each reservoir's historical production. Several publicly available reservoir engineering databases were used as secondary sources to complement or verify the estimates and ranges of reservoir values found in the CRD and include those developed by the National Petroleum Council (1984b) and those compiled by (1) the Appalachian Oil and Natural Gas Research Consortium (1996), (2) the Midwest Regional Carbon Sequestration Partnership (Riley and others, 2010), and (3) the Midwest Geological Sequestration Consortium (2012).

The CRD contains the location, key petrophysical properties, production, and well counts from the Nehring Associates (2012) database for approximately 26,000 significant oil and gas reservoirs in the United States; a significant reservoir has more than 0.5 million barrels of oil equivalent of reserves and cumulative production. To supplement the Nehring Associates (2012) database, values of some properties were estimated by using various analogs and algorithms that primarily relied on play and province averages.[3] The reservoirs in the combined datasets were screened for their suitability for miscible or immiscible CO_2-EOR. More than 3,500 oil reservoirs were identified as candidates for miscible CO_2-EOR and are included in this assessment. Reservoirs identified as candidates for the immiscible CO_2-EOR recovery process were not assessed because there are few of them (approximately 250), and their combined *OOIP* is insignificant compared to that of the miscible reservoirs (Warwick and others, 2019). For details on the development of the CRD and reservoir screening criteria, see Carolus and others (2017). The companion data release (Warwick and others, 2022a) for this circular contains a nonproprietary generic list of assessed reservoirs in each play along with primary reservoir lithology (summarized as clastic or carbonate) and an estimated mean *OOIP* value for each reservoir.

[3]As described in Carolus and others (2017), play averages are used for 28 percent of reservoir attribute records for over 22,000 reservoirs. Less than 11 percent of the oil resource uses a play average, 1.2 percent uses a province average, and 0.2 percent uses a region average. Freeman and Attanasi (2015) described the properties of most reservoirs for which data are in the CRD and provided ranges of empirical and default values of the oil reservoir characteristics within a play and across plays.

Assessment Process

To implement the methodology (Warwick and others, 2019) used for this assessment process, assessment geologists from the USGS reviewed the literature, the CRD, and other available reservoir databases for each province and play in the United States. The primary purpose of the review was to compare the values in the CRD with the values reported in the literature and by the National Petroleum Council (1984b). The geologic and reservoir input data described in appendixes 1 and 3 of Warwick and others (2019) were verified by an assessment geologist, presented to an assessment panel, and agreed upon by unanimous group consensus. If significant discrepancies were found, the new values were entered into a modified version of the proprietary CRD. Completion of the assessment required the geologist to estimate correlations for aggregating the resources by play, petroleum province, region, and the onshore and State waters areas of the conterminous United States (Warwick and others, 2019). The aggregation process for the assessment results is described in Warwick and others (2019) and summarized below in the "Aggregation Dependencies and General Guidelines" section of this report.

Assessment Assumptions and Constraints

As discussed in Warwick and others (2019), the basic requirement for CO_2-EOR is to have a reliable source of CO_2, which could be either natural (for example, CO_2-rich natural gas reservoirs) or anthropogenic (for example, CO_2 captured at industrial facilities). The methodology (Warwick and others, 2019) used for this assessment relies on the assumption that an adequate source of CO_2 that is more than 90-percent pure will be available from either natural or anthropogenic sources for CO_2-EOR projects. Another assumption in the methodology is that the CO_2 retained in the reservoir after cessation of the CO_2-EOR process will not be removed for reuse in other CO_2-EOR projects.

The fundamentals of applying the CO_2-EOR process in conventional reservoirs are well understood (Verma, 2015). Recent advancements have been made (1) by applying the CO_2-EOR process in residual oil zones (ROZs; Hill and others, 2013) and continuous oil accumulations such as tight oil shale (Jin and others, 2017; Kuuskraa and others, 2020) and (2) by using advanced "next generation" or "net carbon negative oil" CO_2-EOR technologies. These advancements may increase the potential for technically recoverable hydrocarbon volumes along with maximized CO_2 storage (Kuuskraa and others, 2011; Nuñez-López and others, 2019). Uses of ROZs and continuous reservoirs and advanced technologies are typically not part of present oil-field CO_2-EOR production practices and are not addressed in this assessment. Specifically, the recovery factors used for this assessment are based on current proven CO_2-EOR practices.

The technology to inject CO_2 for enhanced gas and condensate recovery exists (Mamora and Seo, 2002; Oldenburg and Benson, 2002; van der Meer and others, 2005); however, there are no known reports of commercial fieldwide applications of the enhanced gas recovery process, likely because of economic constraints, such as the cost of gas separation facilities and the availability and cost of CO_2 (Warwick and others, 2019). As there are no current enhanced gas recovery projects operating, they are not included in this assessment (Warwick and others, 2019).

This national assessment is a geology- and petroleum engineering-based examination of more than 3,500 conventional oil reservoirs in the onshore and State waters areas of the conterminous United States. Reservoirs that had initiated any form of EOR were excluded because additional reservoir-specific data are required to model the remaining oil recovery factors with the CO_2 Prophet software used in the assessment methodology (Dobitz and Prieditis, 1994; Attanasi, 2017; Warwick and others, 2019). Potential CO_2-miscible reservoirs in Alaska were not evaluated because there were only a few (25 reservoirs), and they were primarily developed with horizontal and deviated wells, thus making recovery factors difficult to model with CO_2 Prophet. Hawaii was considered unlikely to have oil resources because of its unfavorable petroleum geology.

Resource Calculations

Warwick and others (2019) described the various steps used in the CO_2-EOR screening process for oil reservoirs that have undergone primary or secondary oil production. For any reservoir found to be amenable to CO_2-EOR, the incremental oil volume produced by enhanced oil recovery (EOR_v) is determined by multiplying the original oil in place (*OOIP*) by the incremental oil recovery factor (*RF*) as follows:

$$EOR_v = OOIP \times RF \qquad (1)$$

To make a probabilistic estimate of technically recoverable hydrocarbon volume, estimates of the *OOIP* and *RF* values, as well as their uncertainty, are needed for each reservoir (Warwick and others, 2019). The *OOIP* and *RF* values are made into continuous random variables with a defined mean and spread by the methods described in Warwick and others (2019). Once the *OOIP* and *RF* distributions are obtained, they are sampled 10,000 times and multiplied together in a Monte Carlo simulation to generate a numerical range of estimates for the CO_2-EOR production volume and associated CO_2 retention of each reservoir within the conterminous United States that has passed the screening criteria (Warwick and others, 2019). Summary statistics, including the mean, P_5, P_{50}, and P_{95},[4] or any other percentile, can be calculated directly from this distribution (Warwick and others, 2019).

The volume of CO_2 retained in the reservoir is determined by multiple factors acting generally in combinations that vary according to the geology of the reservoir and the implementation and type of recovery process (Olea, 2015; Warwick and others, 2019). In this assessment, CO_2 retention is the percentage of injected CO_2, measured in thousands of standard cubic feet (Mscf), that remains in the subsurface as a result of the CO_2 flooding.[5] The volume of CO_2 retained in each reservoir was converted to mass of CO_2 measured in millions of metric tons (Mt) (Warwick and others, 2019) to allow ease of comparison to other CO_2 storage assessment results such as those reported by the U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b). The percentage of reservoir CO_2 retention is calculated as follows:

$$CO_2 \ retention = 100 \times \frac{CO_2 \ remaining \ at \ subsurface}{cumulative \ CO_2 \ injected} \qquad (2)$$

where the quantity of cumulative injected CO_2 is equivalent to the CO_2 that is purchased rather than the gross injected volume, which includes recycled CO_2.

Additional details on each step in this assessment process are described in Warwick and others (2019). Please refer to the data release (Warwick and others, 2022a) supporting this circular for a list of assessed reservoirs and their estimated mean *OOIP* values, *RF* values, and CO_2 retention values related to the CO_2-EOR process.

Aggregation Dependencies and General Guidelines

As described in Warwick and others (2019), the probability distribution at the play level and beyond cannot be determined without taking dependencies, or correlations, between reservoirs into account. These dependencies are introduced as part of the aggregation process and have a strong effect on the uncertainty of the summed distributions. In general, for distributions with a positive skew (which are typical for geologic data), as the correlations increase, the distributions for the aggregated resources have lower medians and higher dispersions (Blondes, Schuenemeyer, and others, 2013). For this assessment, a correlation matrix was generated with values that represent the dependencies between reservoirs according to expert estimates elicited from the assessment geologists (Meyer and Booker, 2001; Warwick and others, 2019). The matrix was used to induce a rank correlation structure between the reservoir probability distributions as they were combined to form an aggregate sum (Kaufman and others, 2018). An example aggregation for the Horseshoe Atoll play is shown in Warwick and others (2019, app. 3).

[4]P_5, P_{50}, and P_{95} are probability percentiles and represent the 5-, 50-, and 95-percent probabilities, respectively, that the true storage resource, either recoverable oil or stored (retained) CO_2, is less than or equal to the value shown. The terminology used in this report differs from that used by the petroleum industry (which lists the percentiles in reverse order) and follows standard statistical practice (for example, Everitt and Skrondal, 2010), where percentiles, or fractiles, represent the value of a variable below which a certain proportion of observations falls. The percentiles were calculated by using the aggregation method described in U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b) and in Blondes, Schuenemeyer, and others (2013).

[5]The net CO_2 utilization (gross CO_2 injection minus the produced CO_2 volume) for each reservoir in the play is estimated by using a net CO_2 utilization factor per stock tank barrel of oil recovered (at surface conditions) multiplied by the recoverable oil to generate the volume of CO_2 (at surface conditions) that will be retained for each value of *OOIP* simulated by CO_2 Prophet (Warwick and others, 2019).

Table 1. Ranges of values used for correlation coefficients to obtain play, province, region, and national distributions for the conterminous United States.

Distribution area	Range
Play distributions from reservoirs	0.62 to 0.86
Province distributions from plays	0.50 to 0.70
Region distributions from provinces	0.35 to 0.55
National distributions from regions	0.20 to 0.40

The correlation coefficients used in this assessment for reservoirs, plays, provinces, and regions are described in the sections below. The data release by Warwick and others (2022a) contains the pairwise correlation matrices that specify the dependencies among plays, provinces, and regions that were used for the aggregation of results outside of the means.

The sections below describe the applied ranges of correlation values among reservoirs, plays, provinces, and regions. Table 1 summarizes the ranges that were used.

Reservoirs Within a Play

Statistical correlation values for reservoirs within a play were automatically assigned on the basis of the source of the values for porosity (*Ø*) and initial or original oil saturation (*SOI*) (Carolus and others, 2017; Warwick and others, 2019). As described in Carolus and others (2017), the source of the data for each estimated reservoir property is designated by a "CRD shadow code." A shadow code of 1 indicates that the data values were obtained from the Nehring Associates (2012) reservoir database or verified from other reservoir-specific data sources; a shadow code of 2 indicates that the data value is a play average; and a shadow code of 3 indicates that the data value is a province average. Table 2 describes the assigned pairwise correlation values based on the reservoir *Ø* and *SOI* shadow codes.

Plays Within a Province

Statistical correlations among plays within a province were determined by the following criteria. Each assessment geologist evaluated the plays in an assigned province to determine if the plays correlated at the "high," "medium," or "low" level. Play correlation defaulted to the medium level unless there was a geologic reason the plays within a province were or were not correlated. Play properties that were considered include the geologic controls on porosity (*Ø*), original oil saturation (*SOI*) as a proxy for petroleum charge, permeability (*k*) as a proxy for the Dykstra-Parsons coefficient (*VDP*), and diagenesis (the degree of lithification and cementation of the reservoir rock).

Table 2. Values used for the correlation of reservoirs within a play based on pairs of reservoir shadow codes for porosity (*Ø*) and initial oil saturation (*SOI*) reported in the Comprehensive Resource Database (CRD) of Carolus and others (2017).

[Possible reservoir shadow code values are 1, 2, or 3 individually, and pairwise possible values for *Ø*, *SOI* are (1, 1), (1, 2 or 3), (2 or 3, 1), or (2 or 3, 2 or 3)]

Ø, *SOI*	Reservoir shadow code		
	1, 1	1, 2 or 3; 2 or 3,1	2 or 3, 2 or 3
1, 1	0.66	0.7	0.74
1, 2 or 3; 2 or 3,1		0.78	0.82
2 or 3, 2 or 3			0.86

The geologic controls also included depositional environment, hydrocarbon trapping style, source rocks, and diagenetic history among other factors, such as the degree of reservoir fracturing and structural deformation. A correlation matrix was generated with values that represent the dependencies between plays according to expert estimates elicited from the assessment geologists. The correlation matrix values (table 3) were determined by group consensus. More details about each correlation category are provided below.

High: All plays within the province are very similar; they are geologic twins with similar reservoir primary lithologies and geologic characteristics; or one of the shadow codes for porosity or *SOI* is a value of 3, which is the province average.

Medium: Medium was used as the default correlation value. The plays within the province are not similar. For example, the reservoirs within the plays may have mixed lithologies or differing diagenetic histories but may share other geologic characteristics or reservoir properties.

Low: The plays within the province are very dissimilar; they have very different geologic characteristics, including reservoir properties and diagenetic histories.

Correlations Among Provinces Within a Region and Among Regions

Correlations among provinces within a region and among regions within the conterminous United States were determined by using the same general criteria that were used for plays within a province, as described above (table 3). No CRD reservoir shadow codes were considered in the correlation process at this level, as values existed for all reservoir properties so regional- and national-level averages did not have to be supplied.

Table 3. Correlation values used for the aggregation of plays within a province, provinces within a region, and regions within the conterminous United States (CONUS).

Correlation levels	Correlation values		
	Plays within a province	Provinces within a region	Regions of the CONUS
High	0.7	0.55	0.4
Medium	0.6	0.45	0.3
Low	0.5	0.35	0.2

Results of the Assessment of Carbon Dioxide Enhanced Oil Recovery and Associated Carbon Dioxide Retention Resources

The assessment results provide an estimate of the volume of oil that could be produced by applying the CO_2-EOR process in amenable reservoirs underlying onshore and State waters areas of the conterminous United States. They also provide an estimate of the potential mass of associated subsurface CO_2 retention. The results are summarized below and illustrated in tables 4, 5, and 6 and figures 1, 2, 3, 4, 5, and 6. Table 4 contains the national results, whereas table 5 contains the assessment results aggregated by region and province. Table 6 (at end of report) presents the results by province and individual play. All results are rounded to two significant figures because too many digits imply a higher level of precision than is justified by the original data used for the assessment. Mean values sum to totals but are reported to only two significant figures.

Following the procedures described in Warwick and others (2019), the assessment team estimated that in existing reservoirs underlying onshore and State waters areas of the conterminous United States, the technically recoverable oil resulting from the application of the CO_2-EOR process ranges from approximately 25,000 MMbbl at the P_5 percentile to as much as 32,000 MMbbl at the P_{95} percentile, with a mean of 29,000 MMbbl. The associated CO_2 retention was estimated to range from approximately 7,400 Mt at the P_5 percentile to as much as 9,500 Mt at the P_{95} percentile, with a mean of 8,400 Mt (table 4). Figure 1 illustrates the results obtained from a Monte Carlo simulation in which each input distribution was sampled 10,000 times for the national technically recoverable volumes of oil and the total mass of subsurface CO_2 retention associated with the CO_2-EOR process. Similar simulations were run to generate the assessment results presented in tables 4, 5, and 6 and figures 2, 3, 4, 5, and 6.

Table 4. Total estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and total mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States.

[Estimates of volumes of oil that could be produced with CO_2-EOR are in millions of petroleum barrels (MMbbl), and estimates of the mass of associated CO_2 that could be stored (retained) are in millions of metric tons (Mt). P_5, P_{50}, and P_{95} are probability percentiles and represent the 5-, 50-, and 95-percent probabilities, respectively, that the true resource is less than or equal to the value shown. The terminology used in this report differs from that used by the petroleum industry and follows standard statistical practice (for example, Everitt and Skrondal, 2010), where percentiles, or fractiles, represent the value of a variable below which a certain proportion of observations falls. The percentiles were calculated by using the aggregation method described in U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b) and in Blondes, Schuenemeyer, and others (2013). Percentile values do not sum to totals because the aggregation procedure used partial dependencies between assessment units. Values are reported to only two significant figures]

Resource type	P_5	P_{50}	P_{95}	Mean
Oil produced during CO_2-EOR (MMbbl)	25,000	29,000	32,000	29,000
CO_2 retention (Mt)	7,400	8,400	9,500	8,400

Carbon Dioxide Enhanced Oil Recovery

The mean technically recoverable volume of oil that could be produced from the application of CO_2-EOR in existing reservoirs underlying onshore and State waters areas of the conterminous United States is equivalent to approximately 29,000 MMbbl (P_5 = 25,000 MMbbl, and P_{95} = 32,000 MMbbl) (table 4). The CO_2-EOR assessment regions that are estimated to contain the highest amounts of oil producible by the application of CO_2-EOR include West Texas and Eastern New Mexico, Gulf Coast, Midcontinent, and Rocky Mountains and Northern Great Plains (figs. 2*A*, 3*A*, 4*A*). Six provinces that are estimated to contain mean amounts greater than 1,000 MMbbl of technically recoverable volumes of oil are listed in decreasing order: (1) Permian Basin, 11,000 MMbbl; (2) Western Gulf, 3,500 MMbbl; (3) East Texas Basin and Louisiana-Mississippi Salt Basins, 1,800 MMbbl; (4) Williston Basin, 1,300 MMbbl; (5) Bend Arch-Fort Worth Basin, 1,300 MMbbl; and (6) Anadarko Basin, 1,200 MMbbl (table 5; figs. 5*A*, 6*A*).

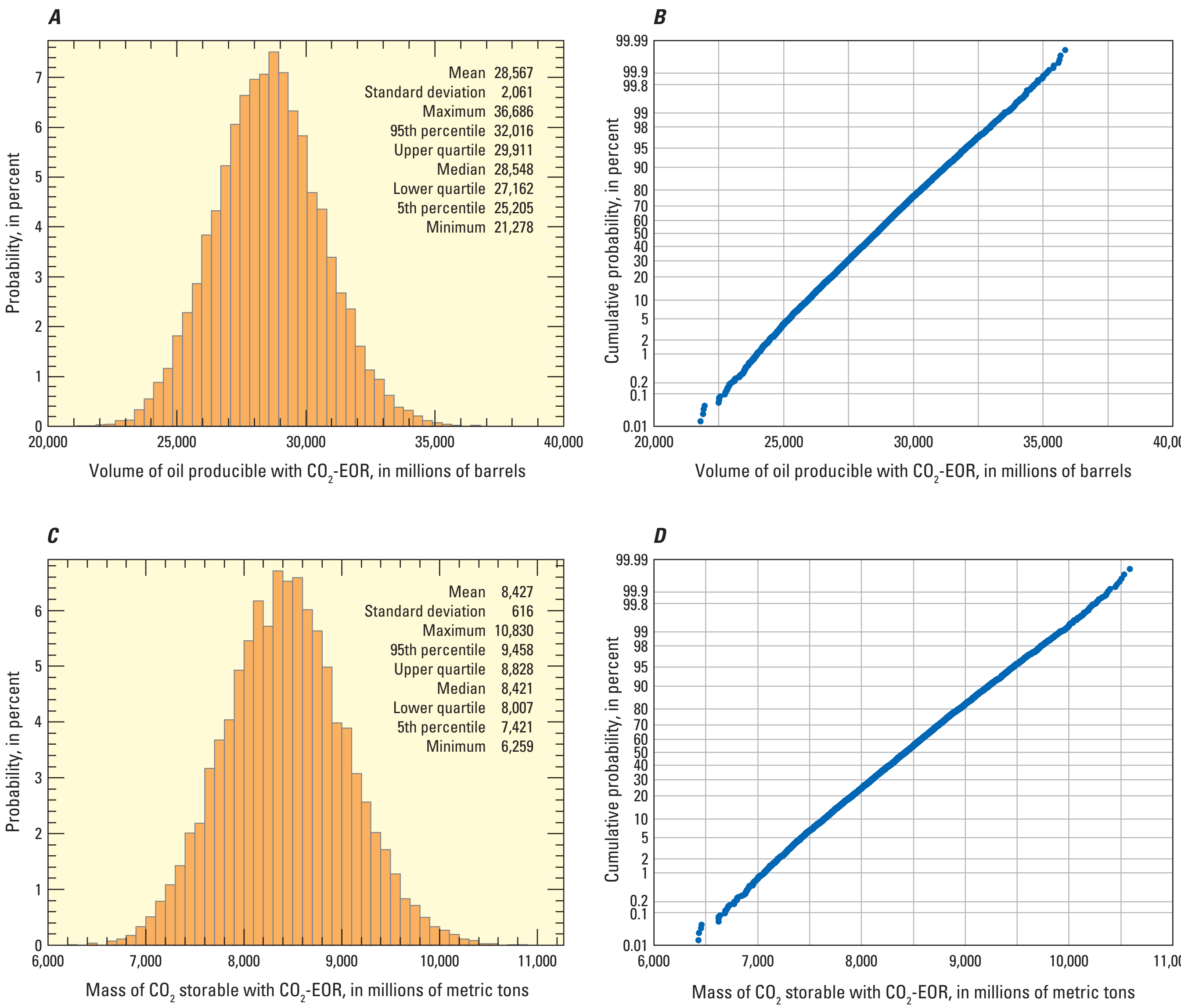

Figure 1. Graphs showing probabilities for estimates of national technically recoverable volumes of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and of the national total mass of associated subsurface CO_2 that could be stored (retained) with the application of CO_2-EOR. The graphs show the results obtained from a Monte Carlo simulation in which each input distribution was sampled 10,000 times. The results incorporate probabilistic aggregation and different assumptions of correlation between assessed reservoirs that underlie onshore and State waters areas of the conterminous United States. The data table values in parts *A* and *C* are not rounded to illustrate the full range of the Monte Carlo simulation results. See Warwick and others (2019) for more details about the assessment process. *A*, Histogram of probabilities for estimates of oil volumes that could be produced. *B*, Point graph of the cumulative distribution of probabilities for estimates of oil volumes that could be produced. *C*, Histogram of probabilities for estimates of the mass of CO_2 that could be stored (retained). *D*, Point graph of the cumulative distribution of probabilities for estimates of the mass of CO_2 that could be stored.

Table 5. Estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and estimated mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States, aggregated by region and province.

[Estimates of volumes of oil that could be produced with CO_2-EOR are in millions of petroleum barrels (MMbbl), and estimates of the mass of associated CO_2 that could be stored (retained) are in millions of metric tons (Mt). P_5, P_{50}, and P_{95} are probability percentiles and represent the 5-, 50-, and 95-percent probabilities, respectively, that the true resource is less than or equal to the value shown. The terminology used in this report differs from that used by the petroleum industry and follows standard statistical practice (for example, Everitt and Skrondal, 2010), where percentiles, or fractiles, represent the value of a variable below which a certain proportion of observations falls. The percentiles were calculated by using the aggregation method described in U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b) and in Blondes, Schuenemeyer, and others (2013). Percentile values do not sum to totals because the aggregation procedure used partial dependencies between assessment units. The P_{50} (median) values may be less than mean values because most output distributions are right skewed. Values are reported to only two significant figures, and mean entries may not sum to totals because of rounding. A four-digit code identifies the USGS-specific province. Components of this assessment unit code are explained in the "Glossary." Resources in Alaska (Region 1), Hawaii, and federally owned offshore areas were not assessed]

Province number	Province name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Region 2–Pacific Coast								
5009	Sacramento Basin	6.7	8.7	11	8.7	1.7	2.2	2.7	2.2
5010	San Joaquin Basin	690	850	1,000	850	190	230	270	230
5011	Central Coastal	5.0	6.5	8.0	6.5	1.1	1.5	1.8	1.5
5013	Ventura Basin	710	880	1,100	880	210	260	310	260
5014	Los Angeles Basin	620	760	890	760	150	190	220	190
	Aggregated total	**2,100**	**2,500**	**2,900**	**2,500**	**580**	**680**	**780**	**680**
	Region 3–Colorado Plateau and Basin and Range								
5020	Uinta-Piceance Basin	240	320	400	320	78	100	130	100
5021	Paradox Basin	53	66	79	66	17	20	25	21
5022	San Juan Basin	380	530	690	530	100	140	180	140
	Aggregated total	**710**	**910**	**1,100**	**910**	**210**	**260**	**320**	**260**
	Region 4–Rocky Mountains and Northern Great Plains								
5028	North-Central Montana	60	73	87	73	16	19	23	19
5031	Williston Basin	1,100	1,300	1,600	1,300	370	460	560	460
5033	Powder River Basin	740	890	1,000	890	210	260	300	260
5034	Big Horn Basin	330	400	480	400	90	110	130	110
5035	Wind River Basin	69	87	100	87	17	22	26	22
5036	Wyoming Thrust Belt	5.5	7.6	10	7.7	2.1	2.9	3.9	2.9
5037	Southwestern Wyoming	40	49	58	49	12	14	17	14
5038	Park Basins	0.84	1.2	1.5	1.2	0.25	0.35	0.46	0.35
5039	Denver Basin	300	380	470	380	82	100	130	100
5040	Las Animas Arch	23	29	35	29	6.9	8.6	10	8.6
	Aggregated total	**2,800**	**3,200**	**3,800**	**3,300**	**850**	**1,000**	**1,200**	**1,000**
	Region 5–West Texas and Eastern New Mexico								
5044	Permian Basin	8,600	11,000	13,000	11,000	2,700	3,300	3,900	3,300
5045	Bend Arch-Fort Worth Basin	1,000	1,300	1,500	1,300	300	370	440	370
	Aggregated total	**9,800**	**12,000**	**14,000**	**12,000**	**3,000**	**3,700**	**4,300**	**3,700**

Table 5. Estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and estimated mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States, aggregated by region and province.—Continued

[Estimates of volumes of oil that could be produced with CO_2-EOR are in millions of petroleum barrels (MMbbl), and estimates of the mass of associated CO_2 that could be stored (retained) are in millions of metric tons (Mt). P_5, P_{50}, and P_{95} are probability percentiles and represent the 5-, 50-, and 95-percent probabilities, respectively, that the true resource is less than or equal to the value shown. The terminology used in this report differs from that used by the petroleum industry and follows standard statistical practice (for example, Everitt and Skrondal, 2010), where percentiles, or fractiles, represent the value of a variable below which a certain proportion of observations falls. The percentiles were calculated by using the aggregation method described in U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b) and in Blondes, Schuenemeyer, and others (2013). Percentile values do not sum to totals because the aggregation procedure used partial dependencies between assessment units. The P_{50} (median) values may be less than mean values because most output distributions are right skewed. Values are reported to only two significant figures, and mean entries may not sum to totals because of rounding. A four-digit code identifies the USGS-specific province. Components of this assessment unit code are explained in the “Glossary.” Resources in Alaska (Region 1), Hawaii, and federally owned offshore areas were not assessed]

Province number	Province name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
				Region 6–Gulf Coast					
5047	Western Gulf	2,900	3,500	4,100	3,500	760	920	1,100	930
5049	East Texas Basin and Louisiana-Mississippi Salt Basins	1,500	1,800	2,100	1,800	400	480	570	480
5050	Florida Peninsula	3.5	4.7	5.9	4.7	1.3	1.7	2.2	1.7
	Aggregated total	**4,500**	**5,300**	**6,100**	**5,300**	**1,200**	**1,400**	**1,600**	**1,400**
				Region 7–Midcontinent					
5053	Cambridge Arch-Central Kansas Uplift	410	530	670	540	110	140	180	140
5055	Nemaha Uplift	660	870	1,100	870	190	250	320	250
5058	Anadarko Basin	890	1,200	1,500	1,200	270	350	440	350
5059	Sedgwick Basin	150	200	260	200	44	59	76	59
5060	Cherokee Platform	550	740	960	750	150	200	260	200
5061	Southern Oklahoma	500	690	910	690	140	200	260	200
5062	Arkoma Basin	48	64	83	65	14	19	25	19
	Aggregated total	**3,500**	**4,300**	**5,100**	**4,300**	**990**	**1,200**	**1,500**	**1,200**
				Region 8–Eastern					
5063	Michigan Basin	220	290	370	290	72	94	120	95
5064	Illinois Basin	84	110	140	110	23	29	37	29
5067	Appalachian Basin	98	120	150	120	39	49	59	49
	Aggregated total	**420**	**520**	**640**	**530**	**140**	**170**	**210**	**170**

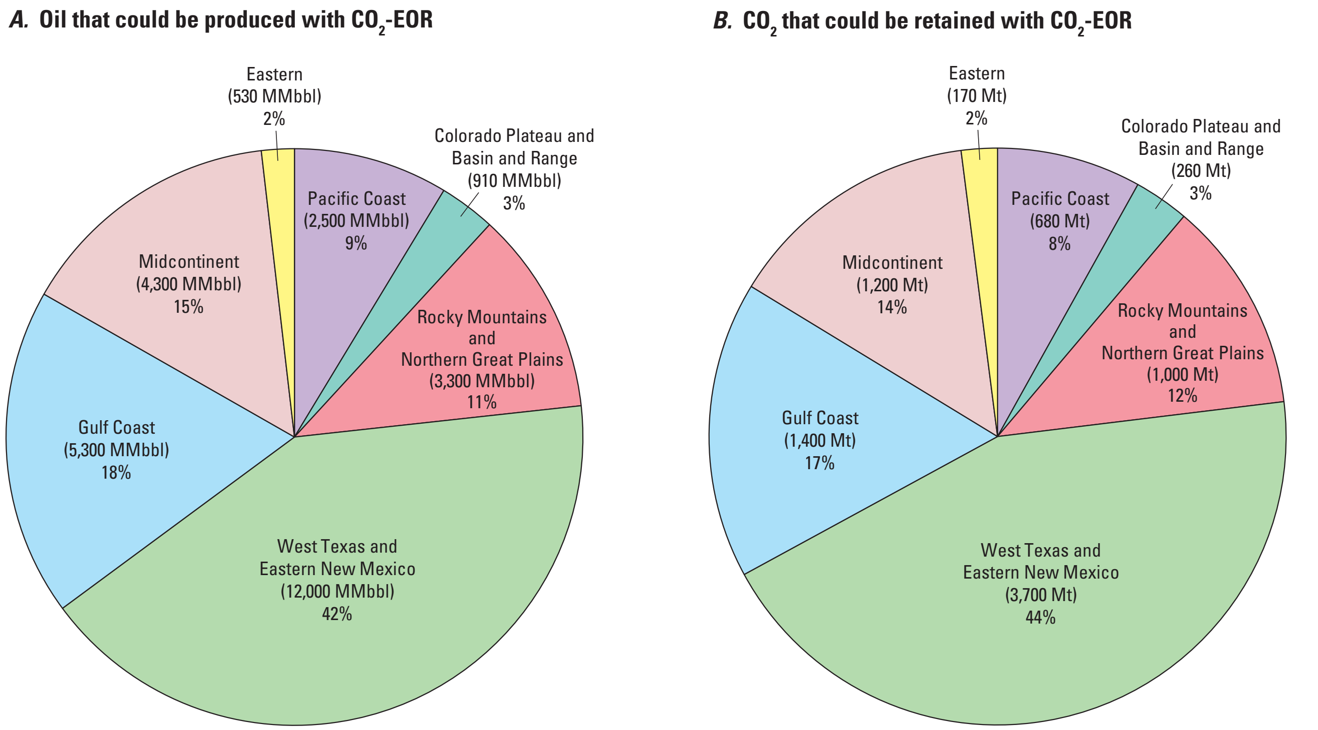

Figure 2. Pie charts showing regional mean estimates by the U.S. Geological Survey in 2020 of (*A*) technically recoverable volumes of oil that could be produced with the application of the carbon dioxide enhanced oil recovery (CO_2-EOR) process and (*B*) masses of associated subsurface carbon dioxide (CO_2) that could be stored (retained) with the application of the CO_2-EOR process in existing reservoirs underlying onshore and State waters areas of the conterminous United States. A mean total of 29,000 million barrels (MMbbl) of oil was estimated to be producible from reservoirs amenable to the CO_2-EOR process. A mean total of 8,400 million metric tons (Mt) was estimated for subsurface CO_2 retention associated with the application of the CO_2-EOR process. Resources in Alaska, Hawaii, and federally owned offshore areas were not assessed. Mean values sum to totals but are reported to only two significant figures. Regional outlines are shown in figure 3.

Carbon Dioxide Retention Resources

The assessed mean subsurface CO_2 retention resources resulting from the application of CO_2-EOR in the assessed reservoirs are equivalent to approximately 7,400 Mt at the P_5 percentile to as much as 9,500 Mt at the P_{95} percentile, with a mean of 8,400 Mt (table 4). The CO_2-EOR assessment regions with the highest estimates for CO_2 retention mass are the same as those with the highest estimates for oil production and include West Texas and Eastern New Mexico, Gulf Coast, Midcontinent, and Rocky Mountains and Northern Great Plains (figs. 2*B*, 3*B*, 4*B*). Six provinces that are estimated to contain mean amounts greater than 300 Mt of CO_2 retention resources are listed in decreasing order: (1) Permian Basin, 3,300 Mt; (2) Western Gulf, 930 Mt; (3) East Texas Basin and Louisiana-Mississippi Salt Basins, 480 Mt; (4) Williston Basin, 460 Mt; (5) Bend Arch-Fort Worth Basin, 370 Mt; and (6) Anadarko Basin, 350 Mt (table 5; figs. 5*B*, 6*B*).

Discussion of Results

The numerical results of the assessment reveal various aspects about the potential volumes of oil that could be produced and the associated CO_2 that may be retained in the subsurface by applying the CO_2-EOR process to amenable reservoirs underlying the onshore and State waters areas of the conterminous United States. The following list explains some of the key findings of this assessment.

1. The estimated ultimate recovery of existing oil reservoirs in the United States may be increased with the use of CO_2-EOR methods. The results of this assessment indicate that the application of CO_2-EOR methods to oil reservoirs underlying the onshore and State waters areas of the conterminous United States can potentially add, at the mean estimate, 29,000 MMbbl to the U.S. techni-

cally recoverable oil resource base. For context, the USGS recently estimated a mean of 3,591 MMbbl of undiscovered, technically recoverable oil resources in conventional accumulations in six conventional assessment units underlying the central North Slope of Alaska (Houseknecht and others, 2020). The U.S. Energy Information Administration (2020) reported that the 2019 annual crude oil production in the United States was 4,464.8 MMbbl.

2. Two regions—the West Texas and Eastern New Mexico region and the Gulf Coast region—contain 60 percent of the mean assessed CO_2-EOR recoverable oil potential and 61 percent of the mean assessed CO_2 retention. Other regions with significant resource potential include the Midcontinent region and the Rocky Mountains and Northern Great Plains region (figs. 2, 3, 4; table 5).

3. The Permian Basin is the largest single resource-rich province in the conterminous United States and contains about 38 percent of the assessed national mean CO_2-EOR recoverable oil and 39 percent of the CO_2 retention potential. Resource estimates for CO_2-EOR in the province represent more than 3 times the recoverable oil (11,000 MMbbl, mean) and CO_2 retention potential (3,300 Mt, mean) than the next largest province, the Western Gulf (means of 3,500 MMbbl and 930 Mt, respectively) (table 5; figs. 5, 6).

4. The U.S. Environmental Protection Agency (2020) reported that the 2018 annual amount of anthropogenic CO_2 emissions from all sources in the United States was estimated to be 5,424.9 Mt. The International Energy Agency (2019) suggested that carbon capture with geologic storage should contribute about 9 percent to the overall effort to prevent global temperatures from rising no more than 2 degrees Celsius (2° C) from those at the beginning of the industrial revolution in the late 1800s. The results of this report indicate that in order to achieve the long-term geologic CO_2 storage goals put forward by the International Energy Agency (2019), standard CO_2-EOR practices that use CO_2 from anthropogenic sources will need to be combined with other strategies to enhance storage of CO_2 in amenable oil reservoirs. In addition, other geologic CO_2 storage options may be utilized such as CO_2 storage projects in saline formations, abandoned natural gas reservoirs, or basaltic and ultramafic rocks (U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013a, b, c; Blondes and others, 2019). The CO_2 storage associated with CO_2-EOR in residual oil zones or unconventional shale reservoirs may also be important future geologic storage options.

5. The National Petroleum Council (2019) report, “Meeting the Dual Challenge—A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage,” provided a 25-year road map for the United States to achieve “at scale” deployment of carbon capture, use, and storage (CCUS) technologies. These “at scale” technologies could be used to store in geologic reservoirs approximately 500 Mt of anthropogenic CO_2 annually, or about 20 percent of the emissions from stationary sources. The results of the USGS 2020 CO_2-EOR assessment indicate that if CO_2 were to be stored only in oil reservoirs undergoing CO_2-EOR operations, it would take between 14.8 to 19 years (based on the P_5 and P_{95} CO_2 retention values reported in table 4) to utilize the national CO_2-EOR reservoir storage capacity. Once again, the results of the USGS 2020 CO_2-EOR assessment underscore the need to develop injection projects to store anthropogenic CO_2 in other underground reservoirs such as saline formations, abandoned natural gas reservoirs, or basaltic or ultramafic rocks to meet the CO_2 storage goals set out in the report by the National Petroleum Council (2019).

6. The International Energy Agency (2015) estimated that if anthropogenic CO_2 is used in the process, oil produced through conventional CO_2-EOR practices, which aim to maximize oil production with a minimal amount of CO_2 use, averages about 63 percent less carbon emissions than oil produced through traditional methods (National Petroleum Council, 2019). The results of this USGS assessment are also based on current industry CO_2-EOR practices that minimize CO_2 use and storage (Warwick and others, 2019) and could be comparable to the conventional CO_2-EOR classification in the study by the International Energy Agency (2015). However, if CO_2-EOR methods to produce “net carbon negative oil” are applied, as described by Nuñez-López and others (2019), the CO_2-EOR process has the potential to further offset the carbon emissions of the produced oil and reduce CO_2 emissions to the atmosphere.

A. **Oil that could be produced with CO_2-EOR**

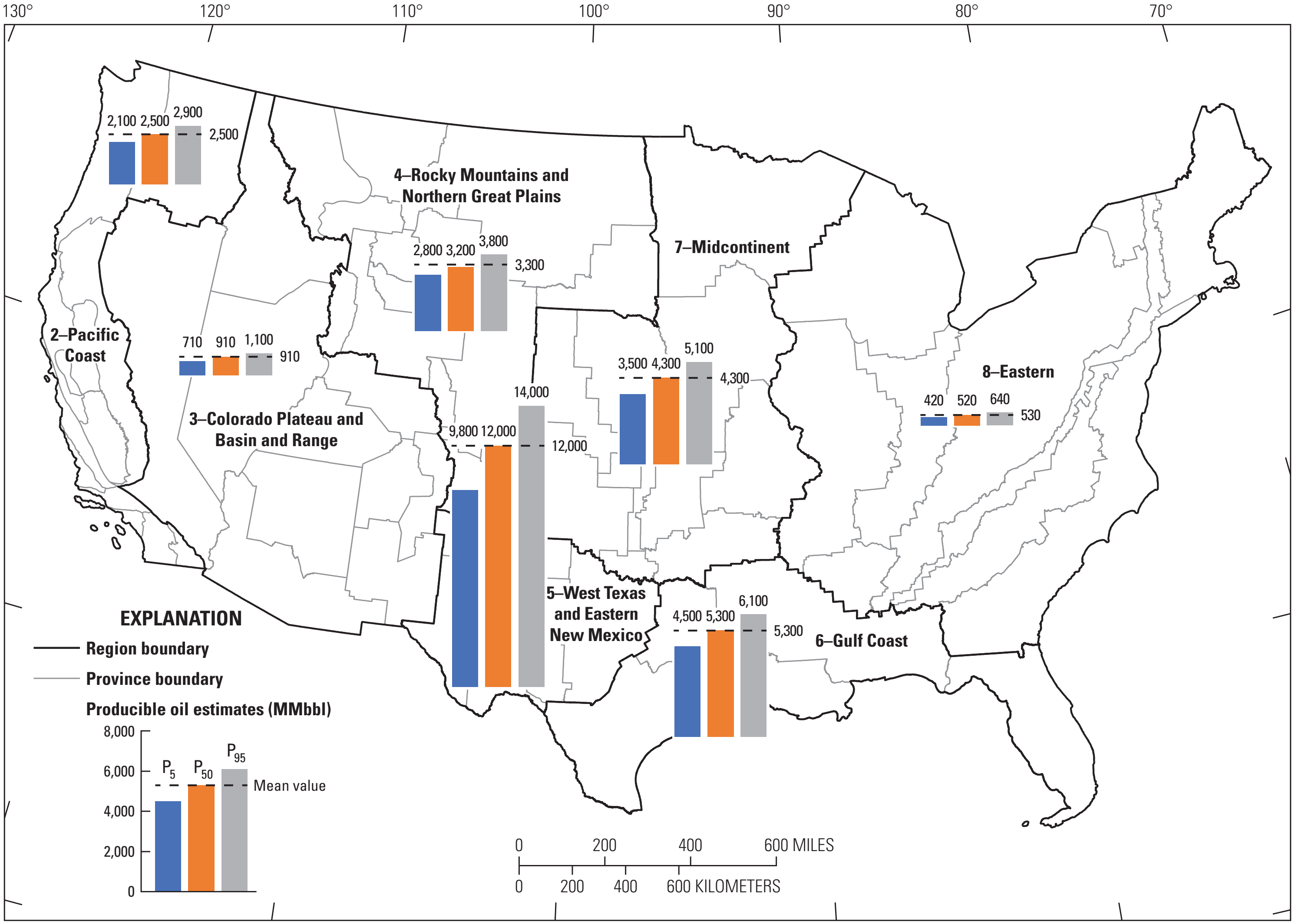

Figure 3. Maps of the conterminous United States and bar graphs showing regional estimates by the U.S. Geological Survey in 2020 of (*A*) technically recoverable volumes of oil, in millions of petroleum barrels (MMbbl), that could be produced with the application of the carbon dioxide enhanced oil recovery (CO_2-EOR) process and (*B*) masses of associated subsurface carbon dioxide (CO_2), in millions of metric tons (Mt), that could be stored (retained) with the application of the CO_2-EOR process in existing miscible oil reservoirs underlying onshore and State waters areas of the conterminous United States. The bar graphs show mean estimates and the P_5, P_{50}, and P_{95} probability percentiles, which represent the 5-, 50-, and 95-percent probabilities, respectively, that the true resource is less than or equal to the value shown. Regional results are also illustrated by pie charts in figure 2 and cumulative probability graphs in figure 4 and are listed in table 5. Values are reported to only two significant figures. Resources in Alaska (Region 1), Hawaii, and federally owned offshore areas were not assessed. Petroleum region and province boundaries are from the U.S. Geological Survey's 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996).

B. **CO_2 that could be retained with CO_2-EOR**

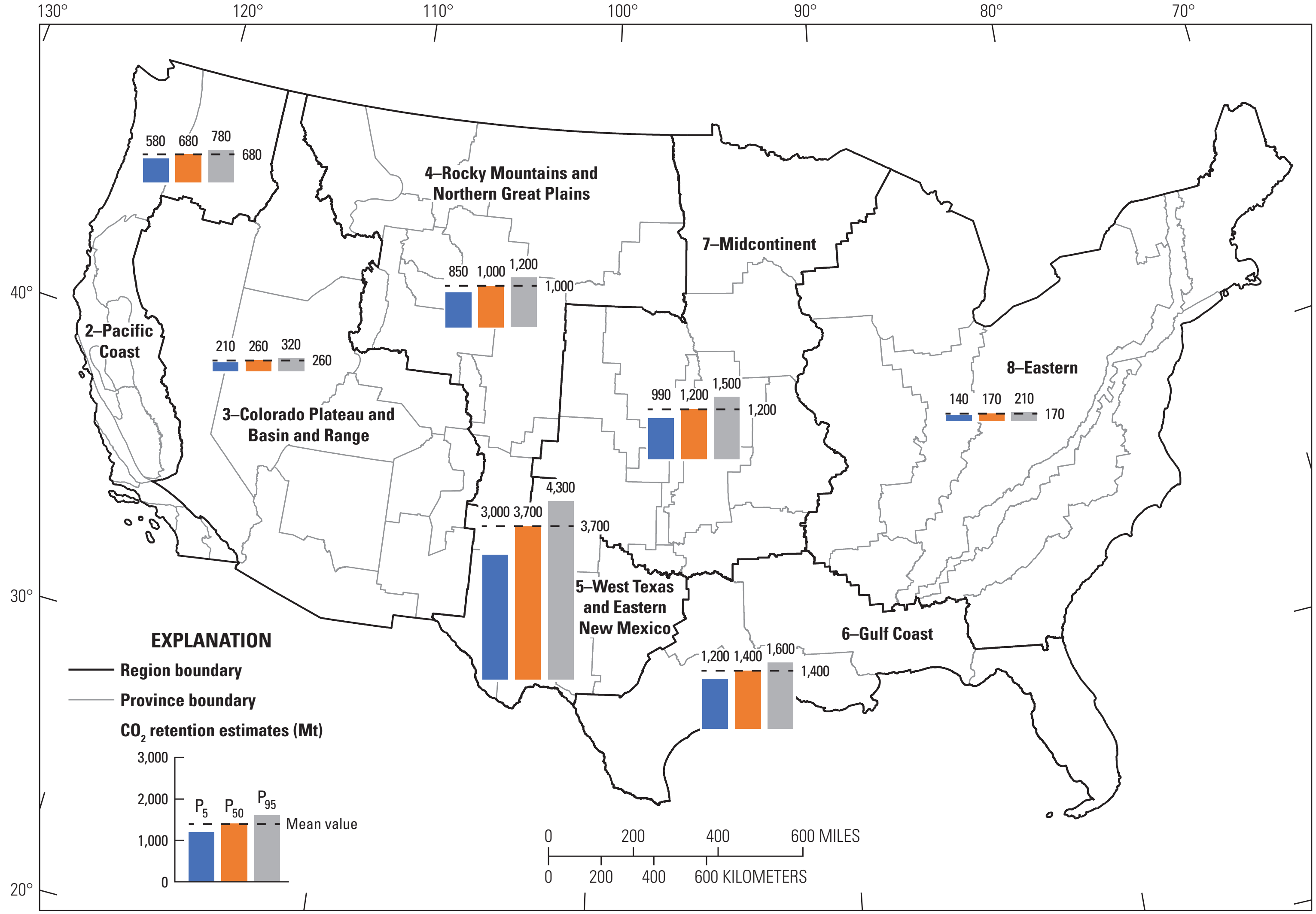

Figure 3. Continued

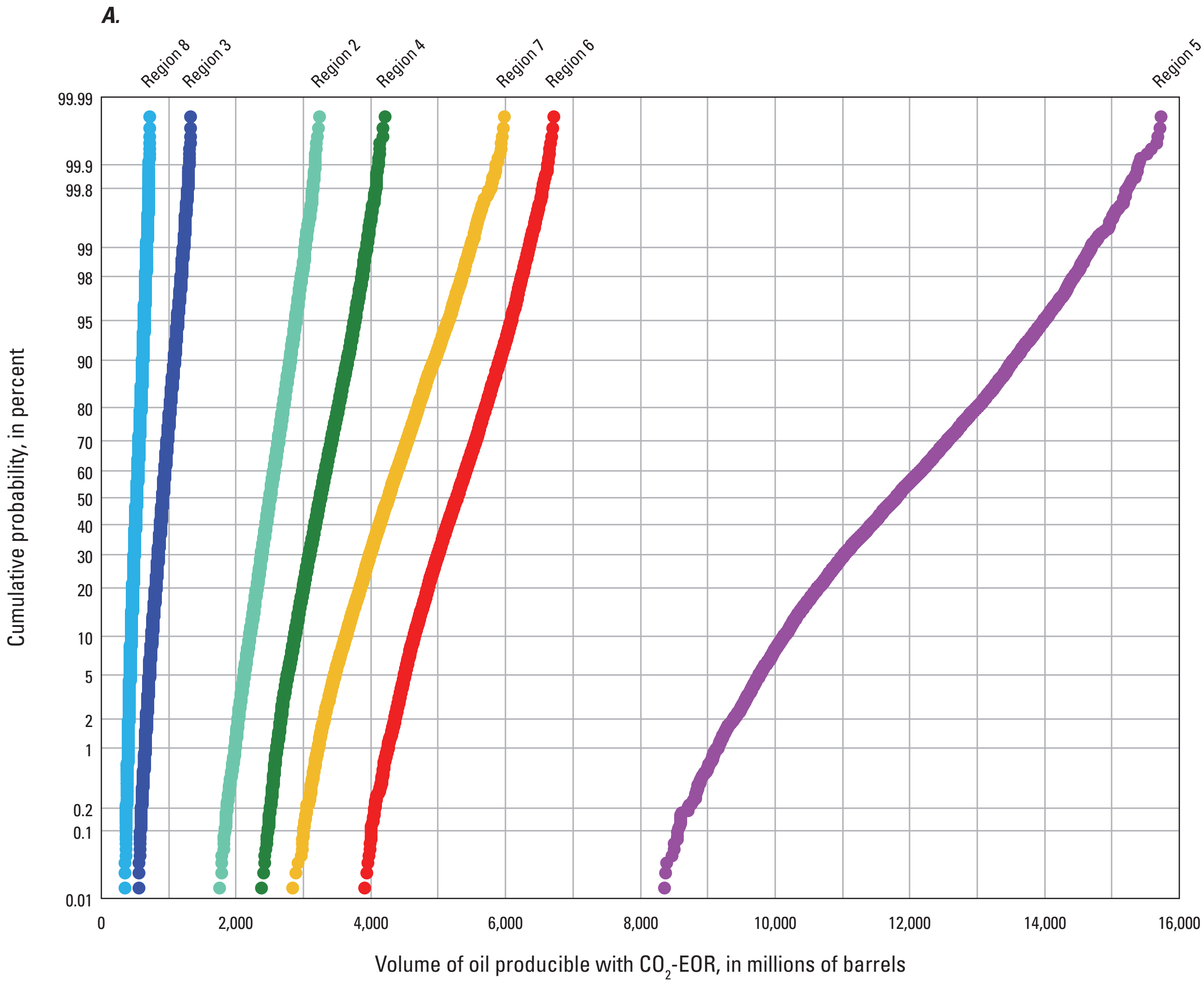

Figure 4. Cumulative probability graphs showing the regional results of a probabilistic assessment by the U.S. Geological Survey in 2020 of (*A*) technically recoverable volumes of oil, in millions of petroleum barrels (MMbbl), that could be produced with the application of the carbon dioxide enhanced oil recovery (CO_2-EOR) process and (*B*) masses of associated subsurface carbon dioxide (CO_2), in millions of metric tons (Mt), that could be stored (retained) with the application of the CO_2-EOR process in existing reservoirs underlying onshore and State waters areas of the conterminous United States. Region numbers by the graph lines refer to the following regions, which are shown in figure 3: Region 2–Pacific Coast, Region 3–Colorado Plateau and Basin and Range, Region 4–Rocky Mountains and Northern Great Plains, Region 5–West Texas and Eastern New Mexico, Region 6–Gulf Coast, Region 7–Midcontinent, and Region 8–Eastern.

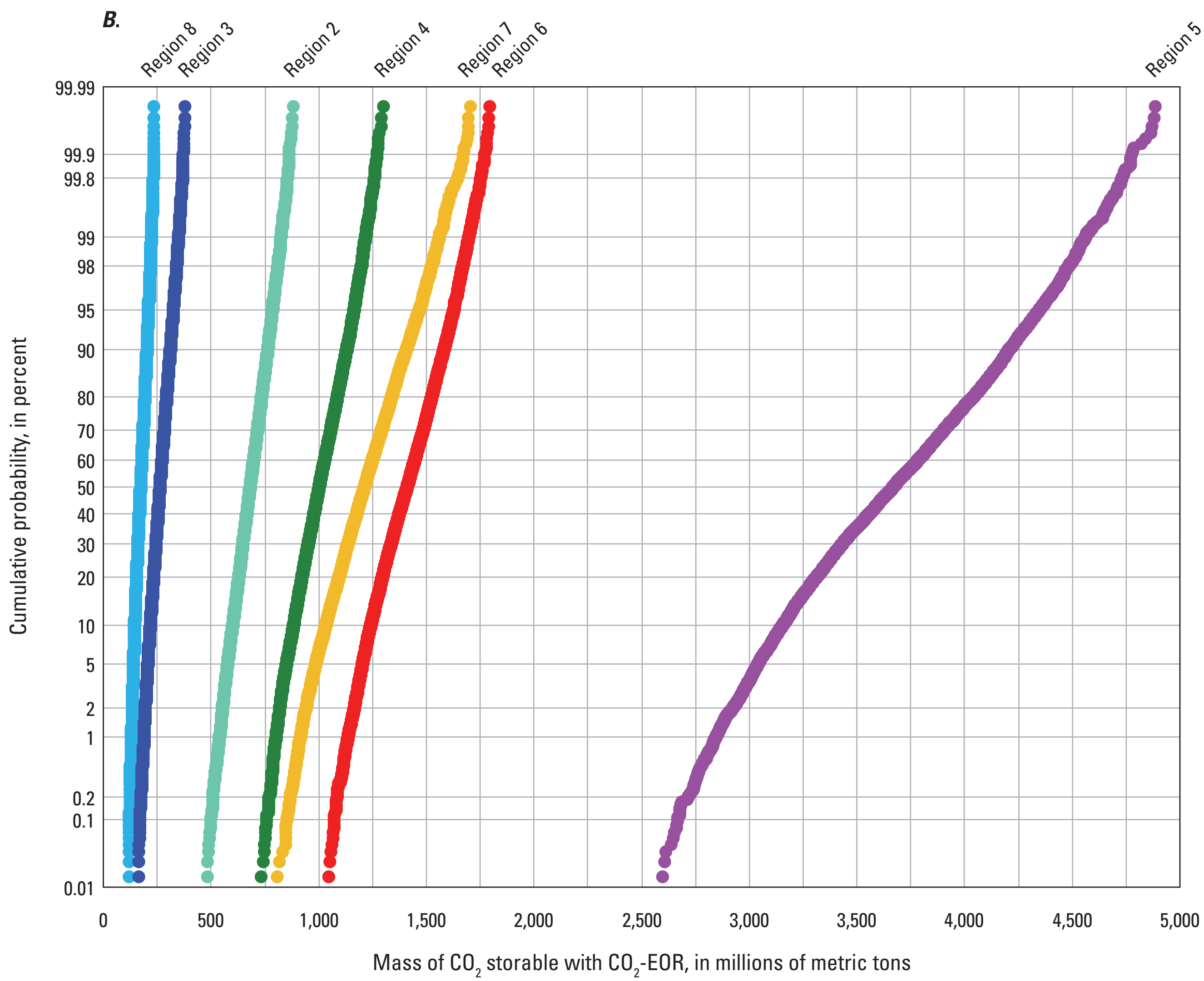

Figure 4. Continued

A. **Oil that could be produced with CO_2-EOR**

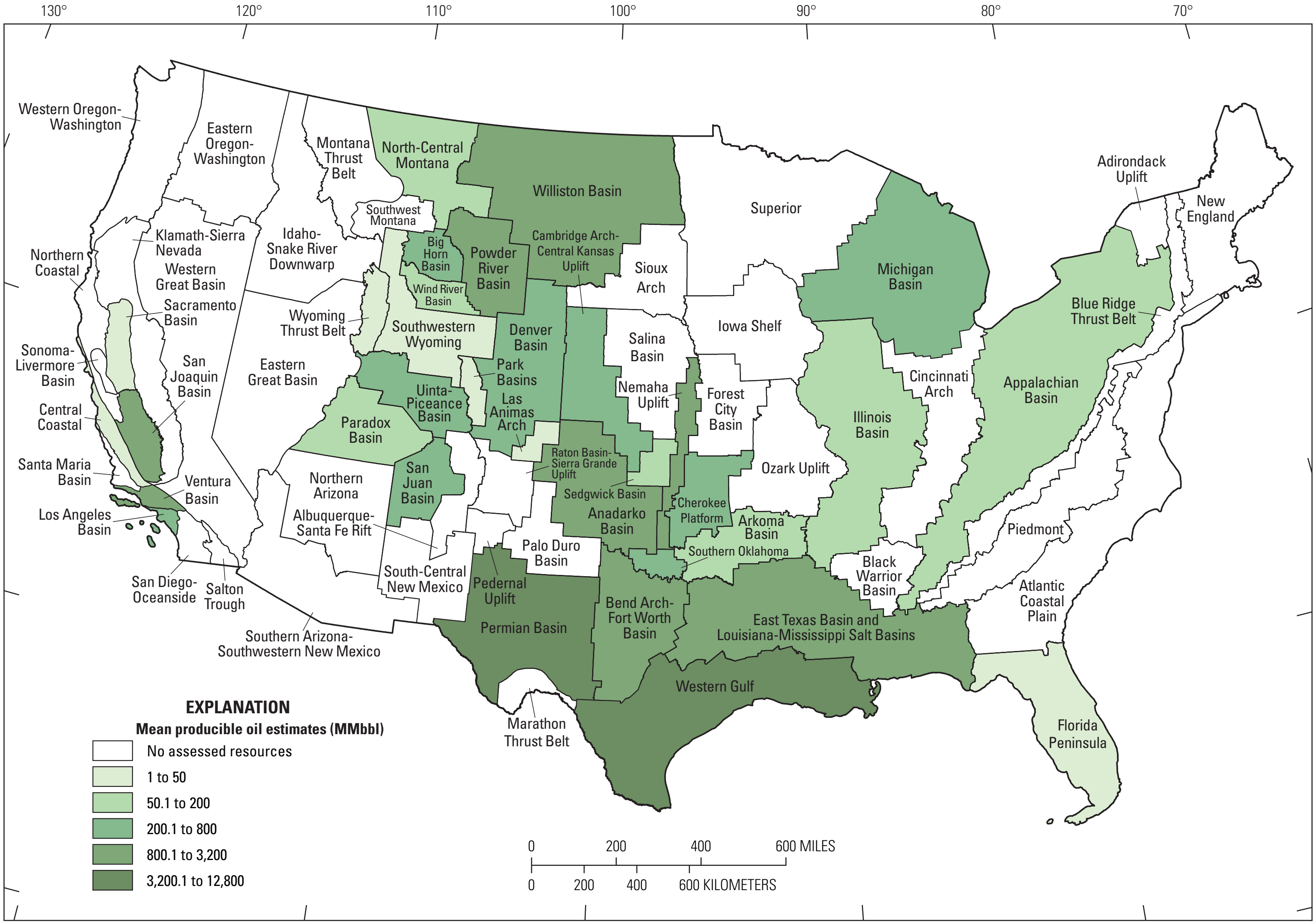

Figure 5. Maps of the conterminous United States showing 33 petroleum provinces (shaded and labeled) that were assessed by the U.S. Geological Survey in 2020 for (*A*) mean technically recoverable volumes of oil, in millions of petroleum barrels (MMbbl), that could be produced with the application of the carbon dioxide enhanced oil recovery (CO_2-EOR) process and (*B*) mean masses of associated subsurface carbon dioxide (CO_2), in millions of metric tons (Mt), that could be stored (retained) with the application of the CO_2-EOR process in existing reservoirs underlying onshore and State waters areas of the conterminous United States. Province results are also illustrated in figure 6 and are listed in table 6. Resources in unshaded provinces and in Alaska, Hawaii, and federally owned offshore areas were not assessed. Petroleum province boundaries are from the U.S. Geological Survey's 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996).

B. **CO_2 that could be retained with CO_2-EOR**

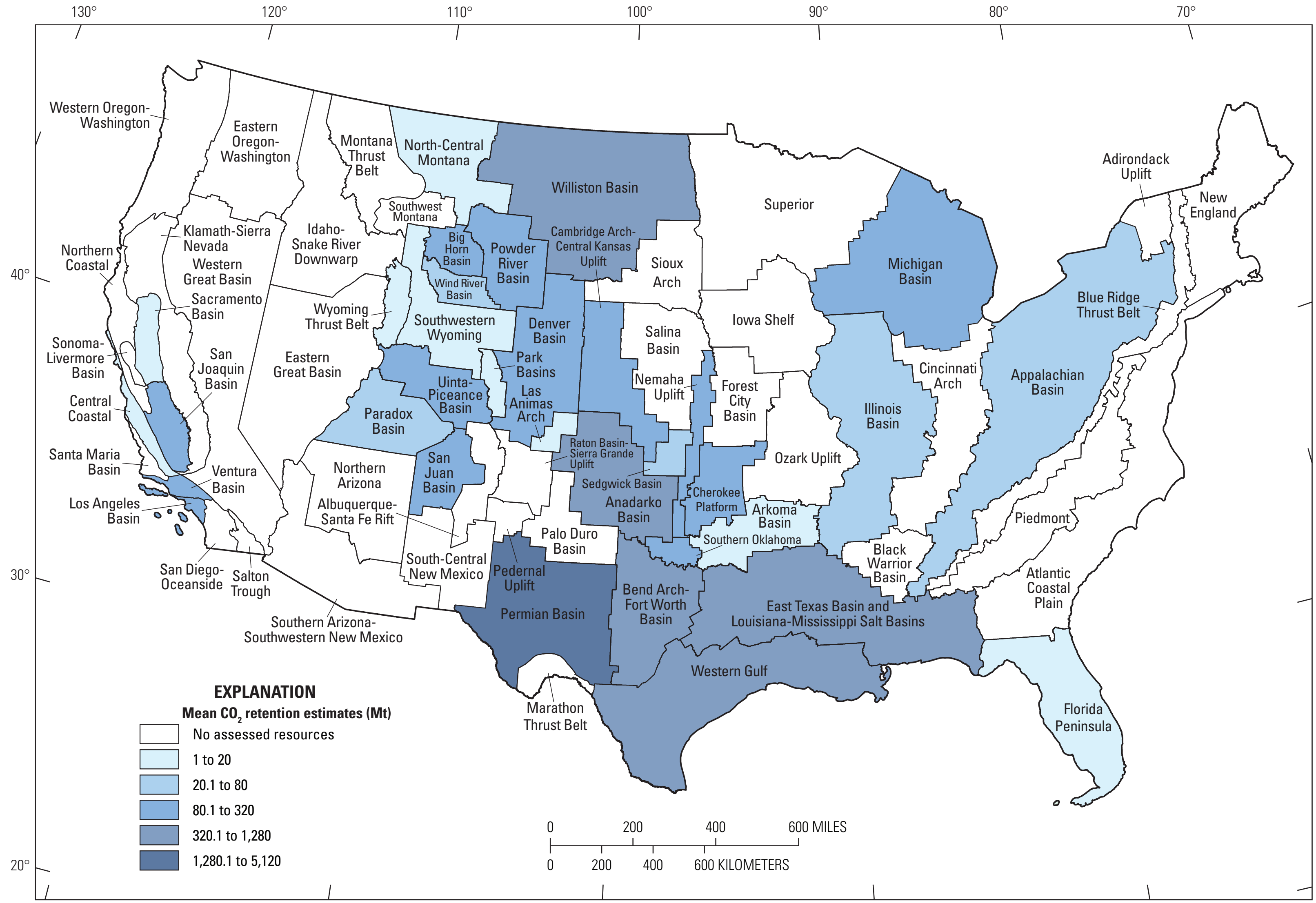

Figure 5. Continued

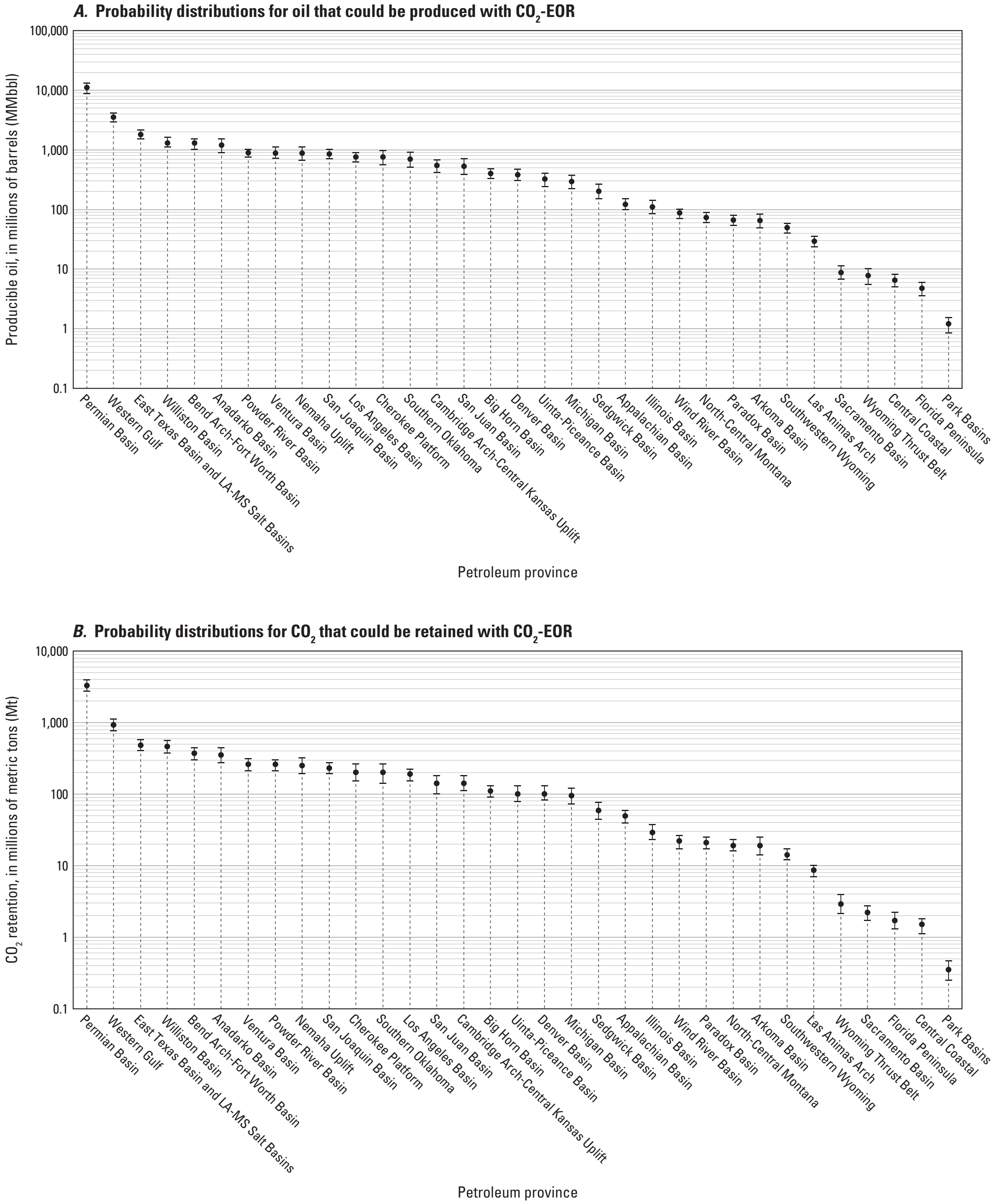

Figure 6. Graphs showing the probability distributions for the provinces estimated by the U.S. Geological Survey in 2020 for (*A*) technically recoverable volumes of oil, in millions of petroleum barrels (MMbbl), that could be produced with the application of the carbon dioxide enhanced oil recovery (CO_2-EOR) process and (*B*) masses of associated carbon dioxide (CO_2), in millions of metric tons (Mt), that could be stored (retained) with the application of CO_2-EOR for each assessed province in the conterminous United States. Each center dot represents the mean assessed resource. The lower bound is the P_5 percentile, representing a 5-percent probability that the true resource is less than the value shown. The upper bound is the P_{95} percentile, representing a 95-percent probability that the true resource is less than the value shown. Values are presented on a logarithmic scale. Province outlines are shown in figure 5, and resource estimates are summarized in table 5. LA-MS, Louisiana-Mississippi.

Comparison of Results With Findings From Previous Assessments

Previous assessments of recoverable oil resources resulting from applying the CO_2-EOR process in the United States have included various assessment methods and economic constraints and have resulted in a wide range of estimates. An initial study by the National Petroleum Council (1976) evaluated three EOR methods: chemical flooding, miscible flooding, and thermal recovery. The study was based on data from 245 reservoirs in California, Texas, and Louisiana. The recovery results obtained from these reservoirs were extrapolated to all reservoirs in the three States and to the United States as a whole. For miscible CO_2-EOR, national estimates of ultimate oil recoveries were based on a range of oil prices and resulted in 3 billion barrels (Bbbl) of oil at 10 U.S. dollars per barrel sales price, and 4.4 to 10 Bbbl of oil recovery at 25 U.S. dollars per barrel. The National Petroleum Council (1976, table 45) also presented a summary of previous estimates of EOR potential using various EOR methods (chemical, miscible, and thermal). The results range from 2.2 Bbbl of oil at 5 U.S. dollars per barrel (National Petroleum Council, 1976) to as high as 51 to 76 Bbbl of oil at 15 U.S. dollars per barrel (Gulf Universities Research Consortium, 1976).

A second study by the National Petroleum Council (1984a) also evaluated various EOR methods (chemical, miscible, and thermal). That study identified 436 candidate reservoirs nationwide that are suitable for miscible flooding with CO_2 or other gases. An economic analysis that included drilling and completion costs and a base economic case using a sales price of 30 U.S. dollars per barrel of oil and a 10-percent minimum discounted cash flow rate of return resulted in an estimated 5.5 Bbbl of oil recovery.

More recent studies also have reported various results. Mohan and others (2008) identified 1,673 potential candidate reservoirs that were miscible to CO_2-EOR flooding in the onshore conterminous United States and estimated technically recoverable oil to be about 20 Bbbl. In 2009, a report by Advanced Resources International and Melzer Consulting (International Energy Agency Greenhouse Gas Research and Development Programme, 2009) estimated original oil in place for 54 petroleum-bearing basins worldwide and suggested, on the basis of data about oil properties and production history, that applying CO_2-EOR techniques to known world oil reservoirs that are miscible to CO_2-EOR flooding would result in 468.5 Bbbl of oil that are technically recoverable and 139 gigatons (Gt) of CO_2 retention in amenable reservoirs. If undiscovered oil resources were added, the world totals would be more than 1 trillion barrels of oil that are technically recoverable and about 400 Gt of CO_2 retention in CO_2-EOR amenable reservoirs. They also estimated that known reservoirs in 14 basins in the United States would yield 60 Bbbl of recoverable oil and 17 Gt of CO_2 retention (International Energy Agency Greenhouse Gas Research and Development Programme, 2009).

A study sponsored by the U.S. Department of Energy National Energy Technology Laboratory (Kuuskraa and others, 2011) found that between 67 and 119 Bbbl of oil would be technically recoverable with between 19.8 and 38 Gt of CO_2 retained by applying various "next generation" CO_2-EOR processes to CO_2-miscible conventional reservoirs in the United States (including Alaska and the Federal offshore areas). Kuuskraa and others (2011) also estimated that if residual oil zones and near-miscible CO_2-EOR reservoirs were included, an additional 0.2 to 17.5 Bbbl of oil would be technically recoverable and between 0.1 and 7.3 Gt of CO_2 could be stored. The U.S. Department of Energy, National Energy Technology Laboratory (2015) suggested that if current technology were considered, then the total assessment results reported by Kuuskraa and others (2011) might be modified to indicate that the onshore areas of the conterminous United States hold an estimated resource of economically recoverable oil of 24 Bbbl and associated CO_2 storage of approximately 9 Gt.

The International Energy Agency (2015) suggested that globally over the next 50 years, as much as 375 Bbbl may be technically recovered through miscible CO_2-EOR using "Maximum Storage EOR+" activities aimed to maximize CO_2 storage and oil production. The associated global CO_2 storage potential of "Maximum Storage EOR+" activities ranges from 60 to 360 Gt of CO_2. The International Energy Agency (2015) estimated that approximately 10 percent of those resources, or 37.5 Bbbl of technically recoverable oil and 36 Gt of CO_2 storage, are located in the United States.

Finally, the National Petroleum Council (2019, table 8–1) reported that the CO_2 storage capacity for the conventional oil reservoirs in the United States associated with CO_2-EOR ranges from 30 to 45 Gt, whereas the national storage capacity could be as great as 55 to 119 Gt if the CO_2-EOR storage potential in ROZs and offshore conventional reservoirs were included in the estimate. The National Petroleum Council (2019) suggested that development of new technologies and economic incentives such as tax breaks for CO_2 storage or carbon taxes or fines for CO_2 emissions could add significant CO_2 demand and associated storage capacity, potentially enabling the total CO_2 storage associated with CO_2-EOR to range between 274 and 479 Gt. No assessment considerations or methods were presented in the National Petroleum Council (2019) report.

As is apparent from this summary, previous estimates for technically recoverable oil from CO_2-EOR with associated CO_2 retention using current techniques in the United States range from 2.2 to 119 Bbbl of oil (National Petroleum Council, 1976; Kuuskraa and others, 2011) and from 17 to 38 Gt of CO_2 retained in the reservoir (International Energy Agency Greenhouse Gas Research and Development Programme, 2009). The results of the 2020 U.S. Geological Survey assessment provided in this circular, with a mean of 29 Bbbl of technically recoverable oil and 8.4 Gt of CO_2 stored, are comparable to the results of previous assessments summarized above.

Conclusions

The U.S. Geological Survey (USGS) recently completed an evaluation of the technically recoverable oil resources that may be produced by using current carbon dioxide enhanced oil recovery (CO_2-EOR) technologies in amenable oil reservoirs underlying the onshore and State waters areas of the conterminous United States. The assessment also includes estimates of the masses of CO_2 that could be retained in the assessed oil reservoirs following the application of CO_2-EOR. By using the assessment methodology of Warwick and others (2019), the assessment team members obtained mean estimates of approximately 29,000 million barrels (MMbbl) of technically recoverable oil and 8,400 million metric tons (Mt) of CO_2 retention.

The USGS assessment team evaluated more than 3,500 oil reservoirs that were determined to be miscible to injected CO_2. The assessed reservoirs are located in 185 previously defined USGS plays in 33 petroleum provinces of 7 national regions; all assessed petroleum provinces were sedimentary basins. The West Texas and Eastern New Mexico region and the Gulf Coast region contain 60 percent of the mean assessed CO_2-EOR recoverable oil potential and 61 percent of the mean assessed CO_2 retention. Other regions with significant CO_2-EOR resource potential include the Midcontinent region and the Rocky Mountains and Northern Great Plains region.

The National Petroleum Council (2019) proposed a roadmap for the development of "at scale" carbon capture, use, and storage (CCUS) technologies such as CO_2-EOR, to help reduce national CO_2 emissions. The roadmap proposes that the United States store approximately 500 Mt of anthropogenic CO_2 annually in geologic reservoirs, or about 20 percent of the emissions from stationary sources in the United States. The results of the USGS 2020 CO_2-EOR assessment indicate that the CO_2-EOR process can help to meet only part of the goal set forth by the National Petroleum Council (2019). Therefore, to meet the goal of storing 500 Mt of CO_2 annually, there is a need to use several approaches simultaneously: (1) couple standard CO_2-EOR practices with strategies to enhance storage of CO_2 in oil reservoirs and (2) develop injection projects to store anthropogenic CO_2 in other underground reservoirs such as saline formations, abandoned natural gas reservoirs, or basaltic or ultramafic rocks. This assessment fulfills the requirements of the Energy Independence and Security Act of 2007 (U.S. Congress, 2007) that requested the USGS to estimate the "potential volumes of oil and gas recoverable by injection and sequestration of industrial carbon dioxide in potential sequestration formations" (42 U.S.C. 17271(b)(4)).

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Glossary

The following definitions are modified from Brennan and others (2010), U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b), Warwick and others (2019), and other sources indicated.

assessment unit code For each assessment unit, the six-digit code (shown in table 6 as the play number) identifies the USGS-specific play from the U.S. Geological Survey's 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996). In code 503402, for example, the first digit (5) denotes the world region, the following three digits (034) denote the North America NOGA province, and the following two digits (02) denote the play. The plays for each province are numbered 01, 02, 03, and so on. The code for a province (tables 5, 6) has four digits, such as 5034. In this report, the NOGA province and basin names are the same.

carbon dioxide (CO_2) A clear gas that is commonly found in nature and is a minor component of air (about 0.04 percent) (U.S. Department of Energy, National Energy Technology Laboratory, 2021). Carbon dioxide is the primary greenhouse gas emitted through human activities such as the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation, industrial processes, and anthropogenic land-use changes (U.S. Environmental Protection Agency, 2018).

carbon sequestration Both natural and deliberate processes by which CO_2 is either removed from the atmosphere or diverted from emission sources and stored in the ocean, terrestrial environments (vegetation, soils, and sediment), and geologic formations.

CO_2 Prophet A reservoir model developed for the U.S. Department of Energy by Texaco Inc. and used to determine the incremental recovery factors for oil during the CO_2-EOR process, on an individual reservoir basis (Prieditis and Brugman, 1993; Dobitz and Prieditis, 1994). The model is also used to estimate the volume of CO_2 remaining in the reservoir after the CO_2-EOR process is complete (Attanasi, 2017; Warwick and others, 2019).

continuous accumulation A petroleum accumulation that is pervasive throughout a large area, that is not significantly affected by hydrodynamic influences, and for which the chosen methodology for assessment of sizes and number of discrete accumulations is not appropriate. Continuous accumulations lack well-defined down-dip water contacts. The terms "continuous accumulation" and "continuous-type accumulation" are used interchangeably (Klett and others, 2005). Continuous accumulations are also known as unconventional accumulations.

conventional accumulation A discrete petroleum accumulation commonly bounded by a down-dip water contact and significantly affected by the buoyancy of petroleum in water. This geologic definition does not involve factors such as water depth, regulatory status, or engineering techniques (Klett and others, 2005).

Dykstra-Parsons coefficient (*VDP*) The Dykstra-Parsons coefficient (Dykstra and Parsons, 1950; Willhite, 1986; Lake, 1989) is a measure of the vertical reservoir heterogeneity, which is important in modeling recovery efficiency of waterfloods and CO_2-EOR projects. It is calculated from permeability measurements obtained from well logs and core samples. A completely homogeneous reservoir has a Dykstra-Parsons coefficient value of 0, whereas an infinitely heterogeneous reservoir has a Dykstra-Parsons coefficient value of 1. For most reservoirs, the Dykstra-Parsons coefficient ranges from 0.5 to 0.9 (Willhite, 1986; Jensen and others, 1997). For this assessment methodology, the variability of *VDP* for each reservoir was set at a fixed range of 0.51 to 0.89.

enhanced oil recovery (EOR) Injection of steam, gas, or other chemical compounds into hydrocarbon reservoirs to stimulate the production of usable oil beyond what is possible through natural pressure, water injection, and pumping at the wellhead. In CO_2-EOR, carbon dioxide gas is injected into a reservoir.

federally owned offshore areas Federal jurisdiction for offshore submerged lands begins at 3 geographic (nautical) miles from the established baseline for the coast and extends to an outer limit of 200 nautical miles. However, there are special cases. Because of claims existing at the dates of statehood, Texas and the Gulf Coast of Florida have a proprietary interest in a submerged belt of land, 9 geographic miles wide, extending seaward along the coast (Thormahlen, 1999). Resource assessments in federally owned offshore areas are typically performed by the Bureau of Ocean Energy Management (BOEM).

gas reservoir A subsurface accumulation of hydrocarbons primarily in the gas phase that is contained in porous or fractured rock formations. A gas reservoir in the Comprehensive Resource Database (CRD) used for this assessment methodology was defined by Carolus and others (2017, p. 13) as having greater than 10,000 standard cubic feet (scf) of natural gas per stock tank barrel (STB) of oil. This classification conforms to the demonstrated CO_2-EOR projects listed in Koottungal (2012, 2014) and is used by some regulatory agencies to determine the primary product of hydrocarbon reservoirs (British Columbia Oil and Gas Commission, 2014). This value is lower than the 20,000 cubic feet/barrel or greater of oil used in U.S. Geological Survey (USGS) assessments of undiscovered oil and gas resources (Klett and others, 2005).

geologic storage of CO_2 A type of carbon sequestration that utilizes the long-term retention of carbon dioxide in subsurface geologic formations.

gross CO_2 utilization In a CO_2-EOR project, gross CO_2 utilization includes the total amount of CO_2 injected, which incorporates both purchased and recycled CO_2 volumes into the calculation (Azzolina and others, 2015).

initial oil saturation (*SOI*) The fraction (0–1) of pore space in an oil reservoir occupied by oil prior to production.

minimum field size The lower limit for inclusion of oil and gas field information in assessment calculations. Following the USGS oil and gas assessment methodology (Schmoker and Klett, 2005), volumetric data from accumulations with less than 0.5 million barrels of oil equivalent total production were not included in any of the calculations in the methodology used for this assessment.

National Oil and Gas Assessment (NOGA) The U.S. Geological Survey Energy Resources Program provides periodic assessments of the oil and natural gas endowment of the United States and was responsible for the 1995 National Oil and Gas Assessment (NOGA) (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995).

net carbon negative oil Approximately 300 to 600 kilograms (kg) of CO_2 are injected by CO_2-EOR processes for each barrel of oil produced in the United States, although the amount of CO_2 injected varies between fields and across the life of projects (McGlade, 2019). According to carbon life-cycle-analysis estimates, one barrel of oil releases around 400 kg of CO_2 when combusted and around 100 kg of CO_2 on average during the production, processing, and transport of the oil (McGlade, 2019). If anthropogenic CO_2 captured from negative emission technologies like bioenergy electric powerplants or direct air capture is used in the CO_2-EOR process, and more CO_2 remains in the subsurface than is released to the atmosphere by the production, processing, transport, and combustion of the oil, then the produced oil can be described as “carbon-negative oil” (McGlade, 2019) or “net carbon negative oil” (Nuñez-López and Moskal, 2019; Nuñez-López and others, 2019).

net CO_2 utilization factor In a CO_2-EOR project, the net CO_2 utilization factor is calculated as the quantity of gross CO_2 injected minus the CO_2 produced divided by the oil in barrels produced. Net CO_2 utilization does not include the recycled CO_2 component and incorporates only the purchased CO_2 volumes into the calculation (Azzolina and others, 2015).

oil reservoir A subsurface accumulation of hydrocarbons composed primarily of oil that is contained in porous or fractured rock formations. An oil reservoir in the Comprehensive Resource Database (CRD) used for this assessment methodology was defined by Carolus and others (2017, p. 13) as having less than or equal to 10,000 scf of natural gas per STB of oil. This classification conforms to the demonstrated CO_2-EOR projects listed in Koottungal (2012, 2014) and is used by some regulatory agencies to determine the primary product of hydrocarbon reservoirs (British Columbia Oil and Gas Commission, 2014). This value is lower than 20,000 scf per STB of oil used in USGS assessments of undiscovered oil and gas resources (Klett and others, 2005).

original oil in place (*OOIP*) The volume of original oil in a reservoir prior to production. Typically, the units are in thousands of stock tank barrels (Mbbl in STB).

percentile In values sorted by increasing magnitude, any of the 99 dividers that produce exactly 100 groups with equal number of values (Everitt and Skrondal, 2010). The dividers are used to denote the proportion of values above and below them. The dividers are sequential integer numbers starting from the one between the two groups with the lowest values. For example, in the modeling of sequestration capacity, a 95th percentile of 10 gigatons (Gt) denotes that 10 Gt divides all likely values into 95 percent of them equal to or below 10 Gt and 5 percent above it.

permeability (*k*) A measure of the ability of a rock to permit fluids to be transmitted through it; permeability is controlled by pore size, pore throat geometry, and pore connectivity. Permeability is typically reported in darcies or millidarcies.

play A set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration patterns, timing, trapping mechanism, and hydrocarbon type. Confirmed plays are plays where one or more accumulations of minimum size (1 million barrels of oil or 6 billion cubic feet of gas) have been discovered in the play (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Klett and others, 2005). Since 2000, the U.S. Geological Survey Energy Resources Program oil and gas assessments have used subdivisions of the total petroleum system, termed assessment units, as the basic level of assessment. A total petroleum system consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks (Schmoker and Klett, 2005, p. 5).

porosity (*Ø*) The part of a rock that is occupied by voids or pores. Pores can be connected by passages called pore throats, which allow for fluid flow, or pores can be isolated and inaccessible to fluid flow. These conditions can be overcome by hydraulic fracture stimulation wherein the pores are forcibly connected with high-pressure fluid injection and propping open of the induced fracture. Porosity is typically reported as a volume, fraction, or percentage of the rock.

primary production After discovery, an oilfield is initially developed and produced using primary production mechanisms in which natural reservoir energy—expansion of dissolved gases, change in rock volume, gravity, and aquifer influx—drive the hydrocarbon fluids from the reservoir to the wellbores as pressure declines with fluid (oil, water, or gas) production. Primary oil recoveries range between 5 and 20 percent (Stalkup, 1983) of the original oil in place (*OOIP*) (Verma, 2015, p. 2).

residual oil zone (ROZ) The interval of the reservoir below the oil-water contact where oil saturation varies from its highest value in the upper section to almost approaching zero percent at the base of the interval.

secondary production Secondary production methods entail injecting water and (or) natural gas into the reservoir for repressurizing and (or) pressure maintenance and to potentially act as a water and (or) gas drive to displace oil. This helps to sustain higher production rates and extends the productive life of the reservoir. Normal practice has been to inject natural gas into the gas cap or at the top of the reservoir and inject water below the oil-water contact. The oil recoveries at the end of both the primary and secondary recovery phases are generally in the range of 20–40 percent of the *OOIP*, although in some cases, recoveries could be lower or higher (Stalkup, 1983). Tzimas and others (2005) have reported a slightly higher recovery range of 35–45 percent of *OOIP* at the end of secondary recovery in their study of North Sea oil reservoirs (Verma, 2015, p. 2).

State waters State jurisdiction begins at the established baseline for the coast and extends seaward 3 geographic (nautical) miles. However, there are special cases. Because of claims existing at the dates of statehood, Texas and the Gulf Coast of Florida have a proprietary interest in a submerged belt of land, 9 geographic miles wide, extending seaward along the coast (Thormahlen, 1999).

trapping The physical and geochemical processes by which injected CO_2 is retained in the subsurface.

Table 6. Estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and estimated mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States, aggregated by province and play

Estimates of volumes of oil that could be produced with CO_2-EOR are in millions of petroleum barrels (MMbbl), and estimates of the mass of associated CO_2 that could be stored (retained) are in millions of metric tons (Mt).

P_5, P_{50}, and P_{95} are probability percentiles and represent the 5-, 50-, and 95-percent probabilities, respectively, that the true resource is less than or equal to the value shown. The terminology used in this report differs from that used by the petroleum industry and follows standard statistical practice (for example, Everitt and Skrondal, 2010), where percentiles, or fractiles, represent the value of a variable below which a certain proportion of observations falls. The percentiles were calculated by using the aggregation method described in U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team (2013b) and in Blondes, Schuenemeyer, and others (2013). Percentile values do not sum to totals because the aggregation procedure used partial dependencies between assessment units. The P_{50} (median) values may be less than mean values because most output distributions are right skewed.

Values are reported to only two significant figures, and mean entries may not sum to totals because of rounding. Four- and six-digit codes identify the USGS-specific province and play, respectively. Components of the assessment unit code (play number) are explained in the "Glossary." Resources in Alaska, Hawaii, and federally owned offshore areas were not assessed.

Table 6. Estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and estimated mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States, aggregated by province and play.

[MMbbl, millions of petroleum barrels; Mt, millions of metric tons. Probability percentiles (P_5, P_{50}, and P_{95}) are defined on p. 29]

Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Sacramento Basin (5009)								
500903	Western Winters through Domengine	6.7	8.7	11	8.7	1.7	2.2	2.7	2.2
	Aggregated total	**6.7**	**8.7**	**11**	**8.7**	**1.7**	**2.2**	**2.7**	**2.2**
	San Joaquin Basin (5010)								
501002	Southeast Stable Shelf	5.8	7.3	8.8	7.3	1.5	1.9	2.3	1.9
501003	Lower Bakersfield Arch	210	260	310	260	61	76	90	76
501004	West Side Fold Belt Sourced by Post-Lower Miocene Rocks	34	43	51	43	8.6	11	13	11
501005	West Side Fold Belt Sourced by Pre-Middle Miocene Rocks	380	480	570	480	100	130	150	130
501006	Northeast Shelf of Neogene Basin	11	14	18	14	2.6	3.5	4.5	3.5
501007	Northern Area Non-associated Gas	1.8	2.4	2.9	2.3	0.49	0.64	0.77	0.63
501008	Tejon Platform	38	47	56	47	11	14	16	14
	Aggregated total	**690**	**850**	**1,000**	**850**	**190**	**230**	**270**	**230**
	Central Coastal (5011)								
501107	Western Cuyama Basin	5.0	6.5	8.0	6.5	1.1	1.5	1.8	1.5
	Aggregated total	**5.0**	**6.5**	**8.0**	**6.5**	**1.1**	**1.5**	**1.8**	**1.5**
	Ventura Basin (5013)								
501301	Paleogene-Onshore	140	190	250	200	39	53	68	53
501302	Neogene-Onshore	540	680	810	680	160	200	240	200
501303	Pliocene Stratigraphic	9.0	12	14	12	3.3	4.3	5.1	4.2
	Aggregated total	**710**	**880**	**1,100**	**880**	**210**	**260**	**310**	**260**
	Los Angeles Basin (5014)								
501401	Santa Monica Fault System and Las Cienegas Fault and Block	58	73	89	73	16	21	25	21
501403	Newport-Inglewood Deformation Zone and Southwestern Flank of Central Syncline	140	170	200	170	36	44	51	43
501404	Whittier Fault Zone and Fullerton Embayment	330	420	500	420	79	99	120	99
501405	Northern Shelf and Northern Flank of Central Syncline	77	99	120	99	17	22	27	22
	Aggregated total	**620**	**760**	**890**	**760**	**150**	**190**	**220**	**190**

Table 6. Estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and estimated mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States, aggregated by province and play.—Continued

[MMbbl, millions of petroleum barrels; Mt, millions of metric tons. Probability percentiles (P_5, P_{50}, and P_{95}) are defined on p. 29]

Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Uinta-Piceance Basin (5020)								
502002	Uinta Tertiary Oil and Gas	240	240	240	240	76	100	130	100
502005	Permian-Pennsylvanian Sandstones and Carbonates	6.4	8.4	10	8.4	1.6	2.1	2.6	2.1
	Aggregated total	**240**	**320**	**400**	**320**	**78**	**100**	**130**	**100**
	Paradox Basin (5021)								
502102	Porous Carbonate Buildup	38	49	59	49	12	15	19	16
502106	Permo-Triassic Unconformity	13	17	21	17	3.8	5.0	6.2	5.0
	Aggregated total	**53**	**66**	**79**	**66**	**17**	**20**	**25**	**21**
	San Juan Basin (5022)								
502204	Entrada	2.0	2.5	3.0	2.5	0.58	0.73	0.87	0.73
502206	Basin Margin Dakota Oil	3.3	4.4	5.4	4.4	0.98	1.3	1.6	1.3
502207	Tocito/Gallup Sandstone Oil	380	520	680	520	100	140	180	140
	Aggregated total	**380**	**530**	**690**	**530**	**100**	**140**	**180**	**140**
	North-Central Montana (5028)								
502805	Devonian-Mississippian Carbonates	28	36	44	36	7.7	10	12	10
502806	Tyler Sandstone	19	23	28	23	4.7	5.9	7.0	5.9
502808	Jurassic-Cretaceous Sandstones	11	14	17	14	2.8	3.6	4.4	3.6
	Aggregated total	**60**	**73**	**87**	**73**	**16**	**19**	**23**	**19**
	Williston Basin (5031)								
503101	Madison (Mississippian)	590	770	960	770	210	270	340	270
503102	Red River (Ordovician)	170	230	290	230	65	85	110	85
503103	Middle and Upper Devonian (Pre-Bakken-Post-Prairie Salt)	57	74	93	75	21	27	34	27
503105	Pre-Prairie Middle Devonian and Silurian	150	190	230	190	47	60	73	60
503106	Post-Madison through Triassic Clastics	51	65	79	65	14	18	22	18
503107	Pre-Red River Gas	0.50	0.72	0.99	0.73	0.18	0.27	0.37	0.27
	Aggregated total	**1,100**	**1,300**	**1,600**	**1,300**	**370**	**460**	**560**	**460**
	Powder River Basin (5033)								
503302	Basin Margin Anticline	79	100	120	100	20	26	31	26
503304	Upper Minnelusa Sandstone	120	140	170	140	32	40	47	40
503306	Fall River Sandstone	44	55	66	55	12	15	18	15
503307	Muddy Sandstone	160	200	240	200	52	64	76	64

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[MMbbl, millions of petroleum barrels; Mt, millions of metric tons. Probability percentiles (P_5, P_{50}, and P_{95}) are defined on p. 29]

Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Powder River Basin (5033)—Continued								
503309	Deep Frontier Sandstone	36	46	57	46	10	13	16	13
503310	Turner Sandstone	35	46	57	46	10	13	16	13
503312	Sussex-Shannon Sandstone	74	93	110	93	23	29	35	29
503313	Mesaverde-Lewis	160	200	260	210	46	59	74	59
	Aggregated total	**740**	**890**	**1,000**	**890**	**210**	**260**	**300**	**260**
	Big Horn Basin (5034)								
503402	Basin Margin Anticline	270	330	400	330	73	91	110	91
503406	Phosphoria Stratigraphic	56	71	87	71	15	20	24	20
	Aggregated total	**330**	**400**	**480**	**400**	**90**	**110**	**130**	**110**
	Wind River Basin (5035)								
503502	Basin Margin Anticline	63	80	97	80	16	20	24	20
503503	Deep Basin Structure	2.8	3.6	4.5	3.6	0.75	0.98	1.2	0.98
503504	Muddy Sandstone Stratigraphic	1.5	2.0	2.5	2.0	0.48	0.61	0.76	0.61
503515	Shallow Tertiary-Upper Cretaceous Stratigraphic	0.95	1.2	1.5	1.2	0.24	0.32	0.39	0.32
	Aggregated total	**69**	**87**	**100**	**87**	**17**	**22**	**26**	**22**
	Wyoming Thrust Belt (5036)								
503604	Absaroka Thrust	5.5	7.6	10	7.7	2.1	2.9	3.9	2.9
	Aggregated total	**5.5**	**7.6**	**10**	**7.7**	**2.1**	**2.9**	**3.9**	**2.9**
	Southwestern Wyoming (5037)								
503701	Rock Springs Uplift	1.6	2.0	2.5	2.0	0.45	0.59	0.74	0.59
503702	Cherokee Arch	2.2	2.8	3.5	2.8	0.61	0.80	1.00	0.80
503703	Axial Uplift	11	14	17	14	3.1	4.0	5.0	4.0
503704	Moxa Arch-LaBarge	12	16	19	16	4.1	5.2	6.4	5.2
503707	Platform	12	15	18	15	2.9	3.7	4.4	3.7
	Aggregated total	**40**	**49**	**58**	**49**	**12**	**14**	**17**	**14**
	Park Basins (5038)								
503801	Cretaceous-Upper Jurassic Structural	0.84	1.2	1.5	1.2	0.25	0.35	0.46	0.35
	Aggregated total	**0.84**	**1.2**	**1.5**	**1.2**	**0.25**	**0.35**	**0.46**	**0.35**
	Denver Basin (5039)								
503901	Pierre Shale Sandstones	35	47	60	47	10	13	16	13
503905	Dakota Group (Combined J and D Sandstones)	250	320	400	320	68	86	110	87
503907	Basin-Margin Structural	6.6	8.4	10	8.3	2.2	2.8	3.5	2.8
503908	Permian-Pennsylvanian	2.9	3.8	4.7	3.8	1.0	1.4	1.7	1.4
	Aggregated total	**300**	**380**	**470**	**380**	**82**	**100**	**130**	**100**

Table 6. Estimated volume of oil that could be produced with carbon dioxide enhanced oil recovery (CO_2-EOR) and estimated mass of associated carbon dioxide (CO_2) that could be stored (retained) in existing reservoirs underlying onshore and State waters areas of the conterminous United States, aggregated by province and play.—Continued

[MMbbl, millions of petroleum barrels; Mt, millions of metric tons. Probability percentiles (P_5, P_{50}, and P_{95}) are defined on p. 29]

Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Las Animas Arch (5040)								
504004	Lower Pennsylvanian (Morrowan) Sandstone Oil, Gas, and Natural Gas Liquids	1.3	1.7	2.1	1.7	0.47	0.61	0.74	0.61
504005	Mississippian Carbonate	21	27	33	27	6.3	8.0	9.8	8.0
	Aggregated total	**23**	**29**	**35**	**29**	**6.9**	**8.6**	**10**	**8.6**
	Permian Basin (5044)								
504401	Pre-Pennsylvanian, Delaware-Val Verde Basins	4.3	5.7	7.1	5.7	1.5	2.0	2.5	2.0
504402	Pre-Pennsylvanian, Central Basin Platform	790	1,000	1,300	1,000	250	330	410	330
504403	Pre-Pennsylvanian, Northwestern and Eastern Shelves	260	340	430	340	83	110	140	110
504404	Lower Pennsylvanian (Bend) Sandstone	61	79	98	79	17	22	28	22
504405	Horseshoe Atoll, Upper Pennsylvanian-Wolfcampian	340	430	520	430	110	140	170	140
504406	Upper Pennsylvanian, Northwestern and Eastern Shelves, Northern Delaware and Midland Basins and Northern Central Basin Platform	730	940	1,200	940	230	300	370	300
504407	Upper Pennsylvanian and Lower Permian Shelf, Slope and Basin Sandstones	120	160	190	160	36	46	56	46
504408	Wolfcampian Carbonate, Eastern and Southern Margins of the Central Basin Platform	210	270	330	270	69	87	110	87
504409	Spraberry-Dean	290	370	440	370	99	130	150	130
504410	San Andres-Clearfork, Central Basin Platform and Ozona Arch	2,500	3,100	3,700	3,100	780	980	1,200	980
504411	San Andres-Clearfork, Northwestern and Eastern Shelves	2,200	2,800	3,600	2,900	650	850	1,100	860
504412	Delaware Sandstones	740	940	1,100	940	240	310	380	310
	Aggregated total	**8,600**	**11,000**	**13,000**	**11,000**	**2,700**	**3,300**	**3,900**	**3,300**

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Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
				Bend Arch-Fort Worth Basin (5045)					
504501	Pre-Mississippian Carbonate	52	74	100	74	16	23	31	23
504502	Mississippian Carbonate	100	130	170	140	31	40	51	41
504504	Lower Pennsylvanian (Bend) Sandstone and Conglomerate	170	220	260	220	54	68	82	68
504505	Strawn (Desmoinesian)	620	780	940	780	170	220	260	220
504506	Post-Desmoinesian	59	75	91	75	16	20	25	20
	Aggregated total	**1,000**	**1,300**	**1,500**	**1,300**	**300**	**370**	**440**	**370**
				Western Gulf (5047)					
504701	Houston Salt Dome Flank Oil and Gas	490	600	710	600	120	140	170	140
504705	Lower Cretaceous Carbonate Shelf/Shelf Edge Gas and Oil	48	63	79	63	17	22	28	22
504708	Buda Downdip Oil	2.1	3.1	4.2	3.1	0.74	1.1	1.4	1.1
504710	Woodbine South Angelina Flexure Oil and Gas	32	40	48	40	10	12	15	12
504715	Upper Cretaceous Sandstones Fault Zone Oil	14	17	21	17	3.6	4.5	5.4	4.5
504716	Upper Cretaceous Sandstones Maverick Basin Oil	25	32	40	32	7	8.6	11	8.6
504719	Lower Wilcox Fluvial Oil and Gas	22	30	38	30	5.0	6.6	8.5	6.7
504722	Upper Wilcox Shelf-Edge Gas and Oil	67	86	100	86	20	26	32	26
504724	Middle Eocene Sandstones Downdip Gas	2.1	2.8	3.7	2.9	0.58	0.79	1.0	0.79
504725	Middle Eocene Sandstones Updip Fluvial Oil and Gas	23	29	36	29	6.2	7.8	9.5	7.8
504726	Yegua Updip Fluvial-Deltaic Oil and Gas	68	86	110	86	17	22	27	22
504728	Jackson Updip Gas and Oil	6.5	8.3	9.9	8.2	1.6	2.0	2.4	2.0
504730	Vicksburg Updip Gas	3.7	4.9	6.1	4.9	0.9	1.2	1.5	1.2
504731	Vicksburg Downdip Gas	5.4	7.0	8.5	7.0	1.5	1.9	2.3	1.9
504732	Frio South Texas Downdip Gas	0.59	0.77	0.93	0.76	0.17	0.23	0.27	0.22
504733	Frio South Texas Mid-Dip Oil and Gas	200	250	300	250	50	63	74	62

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Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Western Gulf (5047)—Continued								
504734	Frio Updip Fluvial Gas and Oil	17	21	26	21	3.9	4.9	6.0	5.0
504735	Frio SE Texas/S. Louisiana Mid-Dip Gas and Oil	230	290	350	290	61	78	94	78
504736	Frio SE Texas/S. Louisiana Downdip Gas	66	86	110	86	20	26	33	26
504737	Hackberry Sandstone Gas and Oil	11	14	17	14	2.9	3.7	4.5	3.7
504738	Anahuac Sandstone Gas and Oil	170	240	320	240	46	64	85	65
504739	Lower Miocene Fluvial Sandstone Oil and Gas	4.8	6.5	8.4	6.6	1.1	1.5	1.9	1.5
504740	Lower Miocene Deltaic Sandstone Gas and Oil	58	75	92	75	15	19	23	19
504741	Lower Miocene Slope and Fan Sandstone Gas	70	91	110	91	19	24	30	24
504743	Middle Miocene Deltaic Sandstone Gas and Oil	510	650	790	650	150	190	240	190
504745	Upper Miocene Deltaic Sandstone Gas and Oil	480	620	750	620	130	160	200	160
504746	Plio-Pleistocene Fluvial Sandstone Oil	45	60	76	60	11	15	19	15
504747	Austin Chalk-Pearsall	33	47	64	48	8.7	12	17	12
	Aggregated total	**2,900**	**3,500**	**4,100**	**3,500**	**760**	**920**	**1,100**	**930**
	East Texas Basin and Louisiana-Mississippi Salt Basins (5049)								
504901	Piercement Salt Dome Flanks Oil and Gas	18	22	27	22	4.5	5.7	6.9	5.7
504905	Norphlet Salt Basin Oil and Gas	2.6	3.3	4.0	3.3	0.65	0.82	0.99	0.82
504910	Smackover Alabama/Florida Peripheral Fault Zone Oil and Gas	41	51	60	51	14	17	21	17
504911	Smackover Alabama/Florida Updip Oil	0.72	0.93	1.1	0.93	0.29	0.38	0.46	0.38
504912	Smackover Salt Basins Gas and Oil	180	230	270	230	52	65	79	65
504916	Smackover East Texas-Southern Arkansas Fault Zone Oil and Gas	57	73	88	73	16	20	25	20
504917	Smackover East Texas-South Arkansas Updip Oil	4.3	5.5	6.8	5.5	1.2	1.5	1.9	1.5
504918	Haynesville Salt Basins Gas and Oil	33	42	51	42	9.6	12	15	12

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Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	East Texas Basin and Louisiana-Mississippi Salt Basins (5049)—Continued								
504919	Haynesville Updip Alabama-Florida Oil	1.7	2.4	3.4	2.5	0.41	0.6	0.8	0.6
504921	Cotton Valley Updip Oil	110	140	180	140	29	38	47	38
504925	Hosston Updip Oil	23	29	35	29	5.9	7.4	9.1	7.5
504926	Hosston/Travis Peak Salt Basins Gas	6.8	9.1	12	9.1	1.9	2.5	3.3	2.5
504928	Sligo/Pettet Updip Oil	62	77	92	77	18	23	27	23
504929	Sligo/Pettet Salt Basins Gas	30	38	46	38	10	12	15	12
504930	Pettet Southern Sabine Uplift Gas and Oil	25	31	38	32	7.6	9.6	12	10
504931	James Limestone Gas	2.3	3.0	3.7	3.0	0.61	0.79	0.97	0.79
504932	Glen Rose/Rodessa Updip Oil	340	430	520	430	89	110	130	110
504934	Paluxy Updip Oil	99	120	150	120	24	31	37	31
504935	Paluxy Downdip Gas	13	16	21	16	3.5	4.5	5.7	4.5
504936	Tuscaloosa Peripheral Fault Zone Oil	5.9	7.4	8.9	7.4	1.5	1.9	2.2	1.9
504937	Tuscaloosa/Woodbine Structural Oil and Gas	100	130	160	130	27	34	41	34
504938	Tuscaloosa Stratigraphic Oil and Gas	93	120	140	120	25	32	38	32
504939	Woodbine/Tuscaloosa Sabine Flanks Oil	5.7	7.4	9.0	7.4	1.4	1.8	2.2	1.8
504940	Eutaw/Tokio Updip Oil	4.6	6.0	7.4	6.0	0.97	1.3	1.6	1.3
504945	Wilcox Salt Basins Oil	160	210	260	210	38	48	59	48
	Aggregated total	**1,500**	**1,800**	**2,100**	**1,800**	**400**	**480**	**570**	**480**
	Florida Peninsula (5050)								
505001	Upper Sunniland Tidal Shoal Oil	3.5	4.7	5.9	4.7	1.3	1.7	2.2	1.7
	Aggregated total	**3.5**	**4.7**	**5.9**	**4.7**	**1.3**	**1.7**	**2.2**	**1.7**
	Cambridge Arch-Central Kansas Uplift (5053)								
505304	Mississippian and Devonian	24	31	38	31	6.4	8.1	10	8.2
505305	Pennsylvanian Cyclical Carbonates and Sandstones	210	280	360	280	55	74	97	75
505308	Ordovician	27	36	46	36	7.6	10	13	10
505309	Early Ordovician/Cambrian Arbuckle	140	190	240	190	38	51	65	51
	Aggregated total	**410**	**530**	**670**	**540**	**110**	**140**	**180**	**140**

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Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Nemaha Uplift (5055)								
505501	Pre-Woodford Paleozoic	280	390	530	390	79	110	150	110
505503	Mississippian	110	140	190	150	30	40	52	40
505504	Pennsylvanian-Permian Structural	130	180	240	180	43	59	79	59
505505	Pennsylvanian Stratigraphic	120	150	200	150	27	36	46	37
	Aggregated total	**660**	**870**	**1,100**	**870**	**190**	**250**	**320**	**250**
	Anadarko Basin (5058)								
505801	Deep Structural Gas	18	25	36	26	6.0	8.6	12	8.8
505802	Uppermost Arbuckle	6.1	8.9	12	9.0	1.6	2.4	3.3	2.4
505804	Wichita Mountains Uplift	19	27	38	28	5.3	7.6	10	7.7
505805	Simpson Oil and Gas	8	11	14	11	2.3	3.1	4	3.1
505809	Hunton Stratigraphic-Unconformity Gas and Oil	18	24	31	24	4.2	5.6	7	5.6
505810	Misener Oil	20	26	32	26	6.3	8.1	10	8.2
505812	Deep Stratigraphic Gas	2.4	3.4	4.5	3.4	0.81	1.1	2	1.2
505813	Lower Mississippian Stratigraphic Oil and Gas	120	210	320	210	36	60	94	62
505814	Upper Mississippian Stratigraphic Gas and Oil	45	61	78	61	14	19	24	19
505815	Springer Stratigraphic Gas and Oil	2.5	3.4	4.4	3.4	0.75	1.0	1.3	1.0
505816	Morrow Sandstone Gas and Oil Stratigraphic	190	260	330	260	55	73	95	74
505819	Lower Desmoinesian Stratigraphic Gas and Oil	55	74	96	74	16	21	28	22
505820	Upper Desmoinesian Oil and Gas	120	160	210	170	38	51	65	51
505821	Lower Missourian Stratigraphic Oil and Gas	74	98	130	98	25	33	43	33
505822	Upper Missourian Oil and Gas	44	61	82	62	13	18	24	18
505823	Lower Virgilian Sandstone Gas and Oil	51	65	78	65	17	21	26	21
505824	Upper Virgilian Stratigraphic Oil and Gas	17	23	30	23	5.0	6.7	8.7	6.8
505827	Washes	7.5	10	13	10	2.5	3.3	4.2	3.3
	Aggregated total	**890**	**1,200**	**1,500**	**1,200**	**270**	**350**	**440**	**350**

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Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Sedgwick Basin (5059)								
505901	Lower Paleozoic Combination Traps	46	64	86	65	12	17	23	17
505902	Mississippian Combination Traps	94	130	170	130	29	40	52	40
505903	Pennsylvanian Combination Traps	5.5	7.6	10	7.7	1.5	2.1	2.8	2.1
	Aggregated total	**150**	**200**	**260**	**200**	**44**	**59**	**76**	**59**
	Cherokee Platform (5060)								
506001	Pre-Woodford Paleozoic	470	640	850	650	130	170	230	170
506003	Mississippian	17	23	29	23	4.6	6.0	7.6	6.0
506004	Pennsylvanian Structural	18	23	29	23	4.6	6.0	7.5	6.0
506005	Pennsylvanian Stratigraphic	36	49	64	49	9.8	13	18	13
	Aggregated total	**550**	**740**	**960**	**750**	**150**	**200**	**260**	**200**
	Southern Oklahoma (5061)								
506101	Deep Gas	0.54	0.84	1.2	0.85	0.16	0.25	0.36	0.26
506102	Arbuckle Oil	79	110	160	120	22	32	44	32
506103	Simpson Structural Oil	110	150	180	150	29	38	48	38
506104	Viola Oil and Gas	23	49	86	51	5.4	11	20	12
506105	Hunton Oil	72	120	180	120	22	36	55	37
506107	Misener-Woodford-Sycamore Gas and Oil	110	140	170	140	33	42	53	43
506108	Springer Sandstone Oil and Gas	0.73	1.0	1.30	1.0	0.20	0.28	0.37	0.28
506109	Atokan Sandstone Oil	53	78	110	79	15	22	31	22
506110	Desmoinesian Sandstone Oil	25	35	48	36	7.8	11	15	11
506111	Missourian Sandstone Oil and Gas	3.8	5.0	6.3	5.0	1.1	1.5	1.9	1.5
	Aggregated total	**500**	**690**	**910**	**690**	**140**	**200**	**260**	**200**
	Arkoma Basin (5062)								
506204	Morrowan Shallow Marine Sandstone and Limestone Gas	0.86	1.2	1.7	1.3	0.22	0.31	0.43	0.32
506205	Arbuckle through Misener Basement Fault and Shelf Gas	47	63	82	63	14	19	25	19
	Aggregated total	**48**	**64**	**83**	**65**	**14**	**19**	**25**	**19**

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Play number	Play name	Oil produced with CO_2-EOR (MMbbl)				CO_2 retention with CO_2-EOR (Mt)			
		P_5	P_{50}	P_{95}	Mean	P_5	P_{50}	P_{95}	Mean
	Michigan Basin (5063)								
506301	Anticline	95	130	170	130	30	40	53	41
506307	Northern Niagaran Reef	39	58	83	59	15	22	32	23
506308	Southern Niagaran Reef	16	21	28	22	4.9	6.5	8.5	6.6
506311	Trenton-Black River	62	84	110	85	18	25	33	25
	Aggregated total	**220**	**290**	**370**	**290**	**72**	**94**	**120**	**95**
	Illinois Basin (5064)								
506401	Illinois Basin-Post-New Albany	33	44	56	44	8.9	12	15	12
506402	Illinois Basin-Hunton	24	32	41	32	6.1	8.2	11	8.2
506404	Illinois Basin-Middle and Upper Ordovician Carbonate	24	33	43	33	6.7	9.2	12	9.3
	Aggregated total	**84**	**110**	**140**	**110**	**23**	**29**	**37**	**29**
	Appalachian Basin (5067)								
506703	Beekmantown/Knox Carbonate Oil/Gas	22	28	35	28	6.1	8.1	10	8.1
506732	Clinton/Medina Sandstone Oil/Gas	59	75	92	75	27	35	43	35
506737	Upper Devonian Sandstone Oil/Gas	15	18	22	18	4.8	6.1	7.4	6.1
	Aggregated total	**98**	**120**	**150**	**120**	**39**	**49**	**59**	**49**

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