Overview of a Comprehensive Resource Database for the Assessment of Recoverable Hydrocarbons Produced by Carbon Dioxide Enhanced Oil Recovery

Chapter 16 of
Section C, Computer Programs
Book 7, Automated Data Processing and Computations

Techniques and Methods 7–C16

U.S. Department of the Interior
U.S. Geological Survey
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By Marshall Carolus, Khosrow Biglarbigi, Peter D. Warwick, Emil D. Attanasi, Philip A. Freeman, and Celeste D. Lohr

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## Conversion Factors

<table>
<thead>
<tr>
<th>Multiply By</th>
<th>To obtain</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Length</strong></td>
<td></td>
</tr>
<tr>
<td>foot (ft)</td>
<td>0.3048 meter (m)</td>
</tr>
<tr>
<td>kilometer (km)</td>
<td>0.6214 mile (mi)</td>
</tr>
<tr>
<td><strong>Area</strong></td>
<td></td>
</tr>
<tr>
<td>square inch (in²)</td>
<td>6.452 square centimeter (cm²)</td>
</tr>
<tr>
<td>acre</td>
<td>43,560 square foot (ft²)</td>
</tr>
<tr>
<td><strong>Volume</strong></td>
<td></td>
</tr>
<tr>
<td>barrel (bbl) of petroleum</td>
<td>42 gallon (gal)</td>
</tr>
<tr>
<td>barrel (bbl) of petroleum</td>
<td>0.1590 cubic meter (m³)</td>
</tr>
<tr>
<td>thousand barrels (Mbbl) of petroleum</td>
<td>1,000 barrel (bbl) of petroleum</td>
</tr>
<tr>
<td>million barrels (MMbbl) of petroleum</td>
<td>1,000,000 barrel (bbl) of petroleum</td>
</tr>
<tr>
<td>cubic foot (ft³)</td>
<td>0.02832 cubic meter (m³)</td>
</tr>
<tr>
<td>thousand cubic feet (Mcf)</td>
<td>28.32 cubic meter (m³)</td>
</tr>
<tr>
<td>million cubic feet (MMcf)</td>
<td>2,832 cubic meter (m³)</td>
</tr>
<tr>
<td>billion cubic feet (Bcf)</td>
<td>28,316,847 cubic meter (m³)</td>
</tr>
<tr>
<td><strong>Mass</strong></td>
<td></td>
</tr>
<tr>
<td>pound, avoirdupois (lb)</td>
<td>0.4536 kilogram (kg)</td>
</tr>
<tr>
<td><strong>Pressure</strong></td>
<td></td>
</tr>
<tr>
<td>pound-force per square inch (lbf/in² or psi)</td>
<td>6.895 kilopascal (kPa)</td>
</tr>
<tr>
<td>or psia) absolute measured in a vacuum</td>
<td>6.895 kilopascal (kPa)</td>
</tr>
<tr>
<td><strong>Pressure gradient</strong></td>
<td></td>
</tr>
<tr>
<td>pound-force per square inch per foot (lbf/in²/ft or psi/ft)</td>
<td>22.62 kilopascal per meter (kPa/m)</td>
</tr>
<tr>
<td><strong>Geothermal gradient</strong></td>
<td></td>
</tr>
<tr>
<td>degrees Fahrenheit per foot (°F/ft)</td>
<td>1.82 degrees Celsius per meter (°C/m)</td>
</tr>
<tr>
<td><strong>Permeability</strong></td>
<td></td>
</tr>
<tr>
<td>millidarcy (mD)</td>
<td>9.869 x 10⁻¹⁶ square meter (m²)</td>
</tr>
<tr>
<td><strong>Viscosity</strong></td>
<td></td>
</tr>
<tr>
<td>centipoise (cP)</td>
<td>1 millipascal second (mPa · s)</td>
</tr>
<tr>
<td><strong>Energy</strong></td>
<td></td>
</tr>
<tr>
<td>British thermal unit (Btu)</td>
<td>1 1,055.055558262 joules (J)</td>
</tr>
</tbody>
</table>

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:

\[ °C = (°F - 32) / 1.8 \]

Temperature in degrees Fahrenheit (°F) may be converted to degrees Rankine (°R) as follows:

\[ °R = °F + 460 \]

1 barrel of oil equivalent (BOE) = 1 barrel of crude oil (42 gallons) = 6,000 cubic feet of natural gas = 1.5 barrels of natural gas liquids
Abbreviations

\( a \) reservoir production proration factor one, two, or three
\( A \) coefficient value determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975)
\( ACPROD \) producing area, in acres
\( API \) American Petroleum Institute gravity of oil, in degrees API (°API)
\( Area \) reservoir area, in acres
\( Area\text{\textunderscore}OOIP \) calculated recoverable original oil in place, in stock tank barrels (STB) or thousands of stock tank barrels (MSTB)
\( B \) is an exponent determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975)
bbl barrel
Bcf billions of cubic feet
\( \text{BCO}_{2} \) CO\(_{2}\) formation volume factor, in decimal format
\( \text{BGC} \) current gas formation volume factor, in decimal format
\( \text{BGI} \) initial gas formation volume factor, in decimal format
\( \text{BOC} \) current oil formation volume factor, in decimal format
\( \text{BOE} \) barrel of oil equivalent
\( \text{BOI} \) initial oil formation volume factor, in decimal format
Btu British thermal unit
CO\(_{2}\) carbon dioxide
cP centipoise
CRD Comprehensive Resource Database
crespro NRG cumulative production of the reservoir (2008–2010), in thousands of barrels (Mbbl) or billions of cubic feet (Bcf)
cumprod cumulative oil production, in thousands of barrels (Mbbl); or the cumulative gas production, in billions of cubic feet (Bcf)
\( Dary(i,16) \) depth of play, in feet (ft) in year \( i \), 16th numerical position in Fortran computer code
\( Dary(i,17) \) temperature of play, in degrees Fahrenheit (°F) in year \( i \), 17th numerical position in Fortran computer code
dist fraction of proration factor “a” for the reservoir
dist\(_{(a,\text{res})}\) reservoir distribution factor
EIA U.S. Energy Information Administration
EIA ID U.S. Energy Information Administration identification
EOR enhanced oil recovery
\( ER \) recovery factor after waterflood, in decimal format
$EUR$ estimated ultimate recovery, in standard cubic feet (Scf) or millions of cubic feet (MMcf)

$EV_1$ pseudo-volumetric sweep efficiency, in decimal format

$EV_2$ pseudo-volumetric sweep efficiency, in decimal format

$\exp$ exponent to the base $e$ (the base of natural logarithms approximately equal to 2.71828)

$F$ coefficient for the initial oil formation volume factor equation

$\text{fact}_\text{one}(\text{res})$ is proration factor one

$\text{fact}_\text{two}(\text{res})$ is proration factor two

$\text{fact}_\text{three}(\text{res})$ is proration factor three

$fdata(\text{ifld,}i\text{yr})$ annual field production of oil, gas, or natural gas liquids (NGL) in year analyzed ($i\text{yr}$)

$\text{fldwell}(\text{ifld,}i\text{yr})$ annual number of wells in the field in year analyzed ($i\text{yr}$)

$F\text{Master Nehring Associates (2012)}$ (NRG) field reservoir data

$\text{ft}$ feet

$GIPVOL$ original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre)

$GOR$ gas-oil ratio

$H_2S$ hydrogen sulfide

$i$ year

$\text{ifld}$ field that is matched to the reservoir

$I\text{HS IHS Inc. (2012)}$ (IHS) annual oil or gas production from the field, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf)

$i\text{yr}$ year analyzed

$k$ play being analyzed

$KR_{\text{gas}}$ Nehring Associates (2012) (NRG) known gas recovery (cumulative production plus reported reserves), in millions of cubic feet (MMcf)

$KR_{\text{NGL}}$ Nehring Associates (2012) (NRG) known natural gas liquids (NGL) recovery (cumulative production plus reported reserves), in thousands of barrels (Mbbl)

$KR_{\text{oil}}$ Nehring Associates (2012) (NRG) known oil recovery (cumulative production plus reported reserves), in thousands of barrels (Mbbl)

$\text{Mbbl}$ thousands of barrels

$\text{Mcf}$ thousands of cubic feet

$mD$ millidarcy

$\text{MMbbl}$ millions of barrels

$\text{MMcf}$ millions of cubic feet

$\text{MMP}$ minimum miscibility pressure
MSTB  thousands of stock tank barrels
N$_2$  nitrogen
NETL  National Energy Technology Laboratory
NetPay  net reservoir thickness, in feet (ft)
NGL  natural gas liquids
NOGA  USGS National Oil and Gas Assessment
NPC  National Petroleum Council
nres  number of reservoirs in the field
NRG  Nehring Associates (2012) database
NRG ID  Nehring Associates (2012) database identification number
num_thick  number of non-zero values in the play or province
OGIP  original gas in place, in standard cubic feet (Scf) or billions of cubic feet (Bcf)
OOIP  original oil in place, in stock tank barrels (STB) or thousands of stock tank barrels (MSTB)
OrgArea(i)  calculated reservoir area, in acres in year (i)
playthick  non-zero average thickness of the reservoir in the play or province, in feet (ft)
Ply_PresGr  average pressure gradient of play, in pound-force per square inch per foot (psi/ft)
Ply_TempGr  average temperature gradient of play, in degrees Fahrenheit per foot (°F/ft)
Por  reservoir rock porosity, in decimal format
PRESC  current reservoir pressure, in pound-force per square inch absolute (psia)
PresCal  calculated initial reservoir pressure, in pound-force per square inch absolute (psia)
PRESIN  initial reservoir pressure, in pound-force per square inch absolute (psia)
psi  pound-force per square inch
psia  pound-force per square inch absolute
RECY  gas reservoir recovery factor, in decimal format
res  reservoir analyzed
respro  annual reservoir oil, gas, or natural gas liquid (NGL) production, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf)
respro(res,iyr)  annual reservoir production of oil, gas, or natural gas liquids (NGL) in year analyzed (iyr)
resprod(res,iyr)  annual production of oil, gas, or natural gas liquid (NGL) converted to barrels of oil equivalent (BOE) in year analyzed (iyr)
reswell(res,iyr)  annual number of wells in the reservoir in year analyzed (iyr)
RMaster  Nehring Associates (2012) (NRG) reservoir properties and production data
RS  solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB)
Scf  standard cubic foot at standard conditions (14.73 pound-force per square inch [psi] and 60 degrees Fahrenheit [°F])
Scf/acre  standard cubic feet per acre
SGC  current gas saturation, in decimal format
SGG  specific gravity of the gas, air=1
SGI  initial gas saturation, in decimal format
SGO  specific gravity of oil
SOC  current oil saturation, in decimal format
SOI  initial oil saturation, in decimal format
SORW  residual oil saturation after waterflood, in decimal format
STB  stock tank barrel (volume of treated oil stored in stock tanks at surface conditions; the size of a stock tank barrel is the same as the size of a regular barrel [bbl])
SWC  current water saturation, in decimal format
SWI  initial water saturation, in decimal format
thick  non-zero thickness of the reservoir in the play or province
Tres  reservoir temperature, in degrees Fahrenheit (°F)
Tres,  current reservoir temperature, in degrees Fahrenheit (°F)
Tres,i  initial reservoir temperature, in degrees Fahrenheit (°F)
U.S.  United States
USGS  U.S. Geological Survey
VCO₂  carbon dioxide viscosity, in centipoise (cP)
VDP  pseudo-Dykstra-Parsons coefficient
VWAT  water viscosity, in centipoise (cP)
WATIN  reservoir water influx (volume)
WLSPC  well spacing
WOR  water-oil ratio
X  coefficient for the Beggs and Robinson (1975) correlation equation
Yg  coefficient for the solution gas-oil ratio equation
Zₖ  current gas compressibility factor, dimensionless
ZₖCO₂  CO₂ compressibility factor, CO₂ dimensionless Z-factor
Z factor  compressibility of gas
Z,i  initial gas compressibility factor
µ  oil viscosity, in centipoise (cP)
µ_DEAD  dead oil viscosity (no dissolved gas), in centipoise (cP)
µ_LIVE  live oil viscosity (with dissolved gas), in centipoise (cP)
Overview of a Comprehensive Resource Database for the Assessment of Recoverable Hydrocarbons Produced by Carbon Dioxide Enhanced Oil Recovery

By Marshall Carolus,1 Khosrow Biglarbigi,1 Peter D. Warwick,2 Emil D. Attanasi,2 Philip A. Freeman,2 and Celeste D. Lohr2

Abstract

A database called the “Comprehensive Resource Database” (CRD) was prepared to support U.S. Geological Survey (USGS) assessments of technically recoverable hydrocarbons that might result from the injection of miscible or immiscible carbon dioxide (CO2) for enhanced oil recovery (EOR). The CRD was designed by INTEK Inc., a consulting company under contract to the USGS. The CRD contains data on the location, key petrophysical properties, production, and well counts (number of wells) for the major oil and gas reservoirs in onshore and State waters of the conterminous United States and Alaska. The CRD includes proprietary data on petrophysical properties of fields and reservoirs from the “Significant Oil and Gas Fields of the United States Database,” prepared by Nehring Associates in 2012, and proprietary production and drilling data from the “Petroleum Information Data Model Relational U.S. Well Data,” prepared by IHS Inc. in 2012. The CRD was designed by INTEK Inc., a petroleum engineering consulting company under contract to the USGS (contract G13PC00006). The CRD contains data relating to the location, key petrophysical properties, production, and the “well count” (number of wells) for the major oil and gas reservoirs in the onshore and State waters areas of the conterminous United States and Alaska. The data within the CRD are proprietary because they include (1) field and reservoir properties data from the proprietary sources “Significant Oil and Gas Fields of the United States Database” (also referred to as “NRG” or “NRG database” in this report) prepared by Nehring Associates in 2012, and (2) proprietary production and drilling data from “Petroleum Information Data Model Relational U.S. Well Data” (also referred to as “IHS” in this report) prepared by IHS Inc. in 2012.

The following sections provide a description of (1) the CRD computer program and its methodology, (2) a list of the key data sources used in its development, (3) a description of the steps and routines used to prepare the CRD, (4) the screening criteria for miscible or immiscible CO2 flooding applied to the CRD, and (5) the database outputs. The resulting CRD contains a deterministic representation of reservoir properties that will be used in a probabilistic methodology that the USGS is developing to estimate technically recoverable oil resulting from the application of the CO2-EOR process. A description of the equations used in the calculations, a list of the input and output reservoir property data, the computer code, and the CRD are on file at the USGS Eastern Energy Resources Science Center located in Reston, Virginia.

Introduction

The Comprehensive Resource Database (CRD) was developed to support U.S. Geological Survey (USGS) assessments of technically recoverable hydrocarbons that could be potentially recovered from qualifying reservoirs through enhanced oil recovery (EOR) using carbon dioxide (CO2). The

Program Structure

Program Language and Compilation

The computer code that generated the CRD was developed using Lahey Fortran 90® (software owned by INTEK) and the Lahey/Fujitsu Fortran Professional v7.3® (owned by USGS). The model was coded using Fortran 77 standards and compiled using the LF95 Lahey/Fujitsu optimized compiler.
Structure

The computer code that generated the CRD contains files and executables in three main directories. The directories are Input, Code, and Output. The data files used to prepare the CRD are contained in the Input directory. The executable and source code for the program are contained in the Code directory. The processed data files, created by the CRD computer code, are contained in the Output directory. Descriptions of the input and output files are provided in the respective sections of this report. The three directories are not part of this report, and will not be available to the public because of their proprietary nature.

Model Methodology

Model Objective

The computer code that generated the CRD uses a series of Fortran 90® routines, based upon petroleum engineering principles, to ensure the completeness and internal consistency of the Nehring Associates (2012) data contained within the resource database. As discussed in this report, the routines check the values contained in the Nehring Associates (2012) database, modify those which are inconsistent with production or other reservoir properties, and estimate the missing values with average values calculated from reservoirs of the same play or province. The reservoirs were organized by the geologic plays and provinces identified in the USGS 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996). In addition, the routines determine the classification of the reservoir (as oil or gas) and incorporate reservoir production and drilling data from IHS Inc. (2012). This methodology has previously been applied to the “Comprehensive Oil and Gas Analysis Model” prepared by the U.S. Department of Energy National Energy Technology Laboratory (2004), and to the “Onshore Lower 48 Oil and Gas Supply Submodule” (INTEK Inc. and Resource Consultants Inc., 2006) within the National Energy Modeling System at the U.S. Energy Information Administration.

Logic of Data Processing Structure

The computer code that generated the CRD has a modular structure with seven major components (fig. 1). The steps described below utilize the various data elements listed in tables 1 through 5. These seven principal components of the processing logic include:

1. **Read NRG data and supplemental data**: opens and reads the input files used in the module.

2. **Calculate average properties for oil and gas reservoirs**: uses the Nehring Associates (2012) data along with supplemental data (described below) to calculate the average values for key petrophysical properties for each play, province, and region. The key properties are listed in table 1.
3. **Determine default reservoir production and well counts:** the Nehring Associates (2012) database is used for annual oil, gas, and natural gas liquids (NGL) production data and well counts for each reservoir.

4. **Identify reservoir type:** for purposes of classifying reservoirs as oil or gas and noting that only oil reservoirs will be candidates for CO$_2$ enhanced oil recovery (EOR), an oil reservoir was defined as having less 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 Kootungal (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 standard cubic feet per barrel (Scf/bbl) limit used in USGS assessments of undiscovered oil and gas resources (Klett and others, 2005).

5. **Fill in oil and gas properties:** computes the oil and gas properties in the database (shown as steps 5a and 5b in fig. 1). In addition, an accompanying “shadow” database is created that specifies the data source for each estimated property. Table 2 displays the calculated oil and gas properties.

6. **Update production and well counts using IHS data:** updates the reservoir production, and well counts using IHS Inc. (2012) data.

7. **Screen reservoirs and create final database:** creates the final reservoir database by applying screening criteria (described below) to determine the candidates for miscible and immiscible CO$_2$-EOR.

---

**Table 1.** Key petrophysical properties from the Nehring Associates (2012) database used in the Comprehensive Resource Database (CRD).

<table>
<thead>
<tr>
<th>Oil and gas reservoirs</th>
<th>Oil reservoirs</th>
<th>Gas reservoirs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net pay (thickness)</td>
<td>Initial oil saturation</td>
<td>Initial gas saturation</td>
</tr>
<tr>
<td>Depth</td>
<td>Initial water saturation</td>
<td>Initial water saturation</td>
</tr>
<tr>
<td>Temperature gradient</td>
<td>Initial formation volume factor</td>
<td>CO$_2$ concentration</td>
</tr>
<tr>
<td>Pressure gradient</td>
<td>API gravity of oil</td>
<td>N$_2$ concentration</td>
</tr>
<tr>
<td>Porosity</td>
<td>Specific gravity of the gas</td>
<td>H$_2$S concentration</td>
</tr>
<tr>
<td>Permeability</td>
<td>Well spacing</td>
<td>Specific gravity of the gas</td>
</tr>
<tr>
<td></td>
<td>Sulfur content</td>
<td>Heat content</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sulfur content</td>
</tr>
</tbody>
</table>

---

**Data Sources**

The database is assembled from the following three data types and sources: (1) reservoir and field production data and properties from the Nehring Associates (2012) database, (2) field-level production and well-count data from IHS Inc. (2012), and (3) supplemental data from several different sources (fig. 2). The routines and equations discussed below are used to ensure that the data from these sources are complete and internally consistent. This section describes the data sources.

Nehring Associates (2012) provides reservoir (RMaster) and field (FMaster) production data, well counts, and key petrophysical properties for the major oil and gas fields and reservoirs in the United States. Production and well-count data are current through 2010 in the database from Nehring Associates (2012). These two Nehring Associates (2012) files (RMaster, FMaster) are used in the assembly of the reservoir data in the CRD. All data in the CRD from Nehring Associates (2012) are provided in English units unless otherwise noted.

**Nehring Associates (2012) RMaster File**

The Nehring Associates (2012) RMaster file contains data for approximately 26,000 oil and gas reservoirs in the United States. There are three basic types of reservoir data in the NRG RMaster file, including: (1) reservoir identification information, (2) reservoir characteristics and properties, and (3) reservoir production and reserves through 2010. The computer code that generates the CRD uses the input values from the NRG RMaster file for these 3 types of reservoir data shown in table 3.
Table 2. Calculated oil and gas reservoir properties in the Comprehensive Resource Database (CRD).

[The averaged property values in the CRD are indicated by footnote 1. Abbreviations: API, American Petroleum Institute; CO₂, carbon dioxide; H₂S, hydrogen sulfide; N₂, nitrogen; NGL, natural gas liquids; Z factor, compressibility of gas]

<table>
<thead>
<tr>
<th>Oil properties</th>
<th>Gas properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>¹Net pay (thickness)</td>
<td>¹Net pay (thickness)</td>
</tr>
<tr>
<td>¹Depth</td>
<td>¹Depth</td>
</tr>
<tr>
<td>¹Temperature gradient</td>
<td>¹Temperature gradient</td>
</tr>
<tr>
<td>¹Pressure gradient</td>
<td>¹Pressure gradient</td>
</tr>
<tr>
<td>¹Porosity</td>
<td>¹Porosity</td>
</tr>
<tr>
<td>¹Permeability</td>
<td>¹Permeability</td>
</tr>
<tr>
<td>¹Initial oil saturation</td>
<td>¹Initial gas saturation</td>
</tr>
<tr>
<td>¹Initial water saturation</td>
<td>¹Initial water saturation</td>
</tr>
<tr>
<td>¹Initial formation volume factor</td>
<td>¹CO₂ concentration</td>
</tr>
<tr>
<td>¹API gravity of oil</td>
<td>¹N₂ concentration</td>
</tr>
<tr>
<td>¹Specific gravity of the gas</td>
<td>¹H₂S concentration</td>
</tr>
<tr>
<td>¹Well spacing</td>
<td>¹Specific gravity of the gas</td>
</tr>
<tr>
<td>Reservoir area</td>
<td>¹Heat content</td>
</tr>
<tr>
<td>Active wells</td>
<td>¹Sulfur content</td>
</tr>
<tr>
<td>²Original oil in place</td>
<td>Initial gas formation volume factor</td>
</tr>
<tr>
<td>Recovery factor</td>
<td>Lithology type</td>
</tr>
<tr>
<td>Current pressure</td>
<td>Well spacing</td>
</tr>
<tr>
<td>Current formation volume factor</td>
<td>Producing area</td>
</tr>
<tr>
<td>Current oil saturation</td>
<td>Gas compressibility</td>
</tr>
<tr>
<td>Current water saturation</td>
<td>Gas-in-place volume</td>
</tr>
<tr>
<td>Current gas saturation</td>
<td>Recovery factor</td>
</tr>
<tr>
<td>Gas-to-oil ratio</td>
<td>Original gas in place</td>
</tr>
<tr>
<td>Swept zone oil saturation</td>
<td>Current gas formation volume factor</td>
</tr>
<tr>
<td>Viscosity</td>
<td>Current temperature</td>
</tr>
<tr>
<td>Pseudo Dykstra-Parsons coefficient</td>
<td>Current oil saturation</td>
</tr>
<tr>
<td>Size class</td>
<td>Current water saturation</td>
</tr>
<tr>
<td>Lithology</td>
<td>Current gas saturation</td>
</tr>
<tr>
<td>Current gas saturation</td>
<td>Current Z factor</td>
</tr>
<tr>
<td>Water influx</td>
<td>NGL-to-gas ratio</td>
</tr>
<tr>
<td>NGL-to-gas ratio</td>
<td>Condensate-to-gas ratio</td>
</tr>
<tr>
<td>Condensate-to-gas ratio</td>
<td>Viscosity</td>
</tr>
<tr>
<td>Viscosity</td>
<td>Size class</td>
</tr>
</tbody>
</table>

¹Averaged property values in the CRD.
²Adjusted if recovery factor is greater than 35 percent. Adjusted volumetrics are checked against the play range and unpublished U.S. Geological Survey data.
The IHS Inc. (2012) (“IHS”) data contains well identification, production, and field information. All data from IHS are provided in English units unless otherwise noted. The USGS summed the IHS data to the field level and matched them with the corresponding NRG database fields. The summation process involved creating a file based on IHS data that contains the well counts, well type, and production data matched to the fields in the NRG database. The resulting


<table>
<thead>
<tr>
<th>Reservoir identification</th>
<th>Reservoir characteristics and properties</th>
<th>Reservoir production and reserves data through 2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>NRG ID</td>
<td>Depth to top</td>
<td>Oil, gas, and NGL</td>
</tr>
<tr>
<td>Field and reservoir names</td>
<td>Well spacing</td>
<td>- Annual production (1991–2010)</td>
</tr>
<tr>
<td>State name</td>
<td>Thickness</td>
<td>- Known recovery (1991–2010)</td>
</tr>
<tr>
<td>County name</td>
<td>Permeability</td>
<td>- Cumulative production</td>
</tr>
<tr>
<td>Province name</td>
<td>Oil viscosity</td>
<td>- Proved reserves</td>
</tr>
<tr>
<td>NRG play number</td>
<td>Initial oil saturation</td>
<td></td>
</tr>
<tr>
<td>U.S. play number</td>
<td>Initial gas saturation</td>
<td></td>
</tr>
<tr>
<td>EIA ID</td>
<td>Initial water saturation</td>
<td></td>
</tr>
<tr>
<td>State code</td>
<td>Pressure</td>
<td></td>
</tr>
<tr>
<td>County code</td>
<td>Lithology</td>
<td></td>
</tr>
<tr>
<td>Province code</td>
<td>Gas impurities</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Oil formation volume factor</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Reservoir area</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Number of spacing units</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Porosity</td>
<td></td>
</tr>
<tr>
<td></td>
<td>API gravity of oil</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Specific gravity of the gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Temperature</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gas Btu</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Recovery factor</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Age rank</td>
<td></td>
</tr>
</tbody>
</table>

Nehring Associates (2012) FMaster File

The Nehring Associates (2012) FMaster file contains data on approximately 17,000 oil and gas fields in the United States. There are four categories of field data in the NRG FMaster file, including: (1) field identification, (2) field properties, (3) production data through 2010, and (4) well counts (number of wells). The computer code that generates the CRD uses the input values from the NRG FMaster file for these 4 categories of field data shown in table 4.
Comprehensive Resource Database for Hydrocarbons Produced by Carbon Dioxide Enhanced Oil Recovery


<table>
<thead>
<tr>
<th>Field identification</th>
<th>Field properties</th>
<th>Production data through 2010</th>
<th>Well counts</th>
</tr>
</thead>
<tbody>
<tr>
<td>NRG ID</td>
<td>Field area</td>
<td>Oil, gas, and NGL</td>
<td>Active wells</td>
</tr>
<tr>
<td>Field name</td>
<td>Original oil in place</td>
<td>- Annual production</td>
<td>Producing wells</td>
</tr>
<tr>
<td>State name</td>
<td>Current oil recovery factor</td>
<td>- Known recovery</td>
<td></td>
</tr>
<tr>
<td>County name</td>
<td></td>
<td>- Cumulative production</td>
<td></td>
</tr>
<tr>
<td>Province name</td>
<td></td>
<td>- Proved reserves</td>
<td></td>
</tr>
<tr>
<td>EIA ID</td>
<td></td>
<td>BOE</td>
<td></td>
</tr>
</tbody>
</table>

Table 5. IHS Inc. (2012) field identification, production data, and well counts.

<table>
<thead>
<tr>
<th>Field identification</th>
<th>Production data</th>
<th>Well counts</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field name</td>
<td>- Oil</td>
<td>- Producing oil wells</td>
</tr>
<tr>
<td>State abbreviation</td>
<td>- Condensate</td>
<td>- Producing gas wells</td>
</tr>
<tr>
<td>County number</td>
<td>- Gas</td>
<td>- Injection wells</td>
</tr>
<tr>
<td>County name</td>
<td>- Casinghead gas</td>
<td>- New oil wells</td>
</tr>
<tr>
<td>Formation number</td>
<td>- Water produced</td>
<td>- New gas wells</td>
</tr>
<tr>
<td>Formation name</td>
<td>- Water injected</td>
<td>- New injection wells</td>
</tr>
</tbody>
</table>

IHS file contains the matched NRG identification number (NRG ID), annual production for 2000 to 2012, cumulative production, and annual and cumulative well counts (number of wells), as shown in table 5. The field production and well counts prior to the year 2000 were added as cumulative totals. The computer code uses the IHS data to extend the NRG production and well data to the most recent years (2010–2012).

The computer code that generates the CRD starts by matching the NRG cross reference to IHS data for each NRG ID. The program then finds the corresponding IHS data field and gathers all the well information by first assembling all the producing leases and wells (called “entities” in IHS) for the given IHS field. Once the program has all the entities, it loops through each entity by first counting all the oil, gas, and injection wells by summing the totals from year to year, then calculating the new well totals as positive values between years, and finally calculating the cumulative wells by adding all the new well totals together. After the well counts have been summed, the program calculates the production totals for oil, condensate, gas, casinghead gas, water produced, and water injected by looping through the monthly production table and summing all the monthly data to obtain yearly totals. The IHS fields “well counts” and “production data” are retrieved from the IHS data and then related to the associated NRG field in the cross reference. The program will also categorize these totals according to the U.S. State (determines State totals). Totals are converted from barrels (bbl) and thousands of cubic feet (Mcf) of gas to millions of barrels (MMbbl) and millions of cubic feet (MMcf) and then written to a formatted text file.

Supplemental Data

Some additional sources of information not contained in the Nehring Associates (2012) (“NRG”) database and IHS Inc. (2012) (“IHS”) data were required to help prepare the CRD. The following supplemental data were used in building the CRD:
• IHS/NRG lookup table—Provides a cross reference between fields in the IHS data and NRG database. The version available to USGS was developed by Nehring Associates (2008).

• Active EOR projects—Projects tracked by the “Oil and Gas Journal” that is published semiannually as a special survey report. The reports used in the CRD are by Koottungal (2012, 2014), which list most active projects that are using either CO₂, chemical, or thermal EOR processes. The EOR fields described by Koottungal (2012, 2014) were matched to a NRG ID. The CRD identifies these reservoirs as currently undergoing EOR.

• Water-oil ratios by State—Provided from the Argonne National Laboratory study by Clark and Veil (2009). The study reports hydrocarbon-specific water-oil ratios (WOR) for 15 States. For the remainder of States, the produced oil and water was used to calculate the WOR.

• State level oil and gas production—Provided by the U.S. Energy Information Administration (2013a, b). The petroleum online database provides annual data estimates on a continuing updated basis. These data are used to update reservoir totals in U.S. States where IHS does not provide current data.

• Default lithologies—Based on the dominant lithology of each USGS play reported in the USGS National assessment of the United States oil and gas resources by Gautier and others (1995) and are applied to the reservoirs for which the lithology in the NRG database is not provided.

• Unpublished USGS data—Reservoir type (conventional or continuous), temperature, pressure, and formation volume factor data are included in the CRD model. Reservoirs (accumulations) were designated as either conventional or continuous based on previous USGS assessment evaluations. Klett and others (2005) defines conventional reservoirs as having a discrete accumulation commonly bounded by a down-dip water contact and significantly affected by the buoyancy of petroleum in water; continuous accumulations are those that are pervasive throughout a large area, not significantly affected by hydrodynamic influences, and lack well-defined down-dip water contacts. The temperature, pressure, and formation volume factor data in the CRD were compiled at the province level from the National assessment of geologic CO₂ storage (U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013). Temperature and pressure data were provided by Marc Buursink (USGS, written commun., 2013) and formation volume factor data were provided by Hossein Jahediesfanjani (contractor with USGS, written commun., 2013). The data were used to limit the calculated formation volume factor and to fill in missing pressure and temperature values.

• Gas contaminates data—Supplemented from the USGS Energy Resources Program Geochemistry Database (2014). Reservoir contaminates included in the CRD module are carbon dioxide (CO₂) in 34 States, hydrogen sulfide (H₂S) in 30 States, and nitrogen (N₂) in 33 States. In addition to state level averages, a Nation average is calculated for each contaminant. These were used to fill in missing properties for the gas reservoirs contained in the NRG database.

Data Preparation

To prepare the CRD, (1) average reservoir properties are calculated, (2) the reservoirs are characterized as either oil or gas, (3) the petrophysical properties are calculated and validated for consistency and completeness (as discussed in sections below on oil and gas reservoir properties), (4) the production and well counts are updated, (5) the final resource characterization is completed, and (6) the reservoirs are screened to determine candidates for CO₂ flooding. This section provides details on the preparation of the data. In each step of the process, a “shadow” value is assigned that identifies the data source for each property (NRG database, IHS data, or supplemental data).

Geographic Regions

To ensure completeness of the CRD, the algorithm calculates average values for several volumetric properties. These averages are calculated at the following levels:

• Play
• Province
• Region
• Nation

The reservoirs in the CRD are classified by the plays, provinces, and regions based on definitions from the USGS 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996). Maps of the provinces and regions are provided in figure 3.

Calculating Averages

Table 7 provides a list of the properties which are calculated for three reservoir categories: (1) oil and gas reservoirs, (2) oil reservoirs, and (3) gas reservoirs. Averages are calculated for properties that apply to both oil and gas reservoirs and for properties that are specific to either oil reservoirs or gas reservoirs. The averages that apply to both oil and gas reservoirs are calculated before the averages for either oil reservoirs or gas reservoirs. The averages that are specific to either oil reservoirs or gas reservoirs are calculated after the initial reservoir type has been determined.
Figure 3. Maps showing the petroleum regions and provinces of the conterminous United States and Alaska. A, Petroleum regions and provinces in onshore and State offshore areas in the conterminous United States. Heavy lines are region boundaries; lighter lines are province boundaries. B, Petroleum provinces of the onshore and State offshore areas of Alaska. Regions and provinces shown in figures 3A and 3B are listed by name and number in table 6. From the U.S. Geological Survey’s 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996; Attanasi, 1998).
Table 6. List of petroleum regions and provinces of onshore and State offshore areas in the conterminous United States and Alaska.

[From the U.S. Geological Survey’s 1995 National Oil and Gas Assessment (NOGA) (Beeman and others, 1996; Attanasi, 1998). Province numbers have leading zeros as shown below; to save space, those zeros are not shown in figure 3]

<table>
<thead>
<tr>
<th>Province number</th>
<th>Province name</th>
<th>Province number</th>
<th>Province name</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Northern Alaska</td>
<td>037</td>
<td>Southwest Wyoming</td>
</tr>
<tr>
<td>002</td>
<td>Central Alaska</td>
<td>038</td>
<td>Park basins</td>
</tr>
<tr>
<td>003</td>
<td>Southern Alaska</td>
<td>039</td>
<td>Denver basin</td>
</tr>
<tr>
<td>004</td>
<td>Western Oregon-Washington</td>
<td>040</td>
<td>Las Animas arch</td>
</tr>
<tr>
<td>005</td>
<td>Eastern Oregon-Washington</td>
<td>041</td>
<td>Raton Basin-Sierra Grande uplift</td>
</tr>
<tr>
<td>006</td>
<td>Klamath-Sierra Nevada</td>
<td>042</td>
<td>Pedernal uplift</td>
</tr>
<tr>
<td>007</td>
<td>Northern Coastal</td>
<td>043</td>
<td>Palo Duro basin</td>
</tr>
<tr>
<td>008</td>
<td>Sonoma-Livermore basin</td>
<td>044</td>
<td>Permian basin</td>
</tr>
<tr>
<td>009</td>
<td>Sacramento basin</td>
<td>045</td>
<td>Bend Arch-Fort Worth basin</td>
</tr>
<tr>
<td>010</td>
<td>San Joaquin basin</td>
<td>046</td>
<td>Marathon thrust belt</td>
</tr>
<tr>
<td>011</td>
<td>Central Coastal</td>
<td>047</td>
<td>Western Gulf</td>
</tr>
<tr>
<td>012</td>
<td>Santa Maria basin</td>
<td>048</td>
<td>East Texas basin</td>
</tr>
<tr>
<td>013</td>
<td>Ventura basin</td>
<td>049</td>
<td>Louisiana-Mississippi salt basins</td>
</tr>
<tr>
<td>014</td>
<td>Los Angeles basin</td>
<td>050</td>
<td>Florida Peninsula</td>
</tr>
<tr>
<td>015</td>
<td>San Diego-Oceanside</td>
<td>051</td>
<td>Superior</td>
</tr>
<tr>
<td>016</td>
<td>Salton trough</td>
<td>052</td>
<td>Iowa Shelf</td>
</tr>
<tr>
<td>017</td>
<td>Idaho-Snake River downwarp</td>
<td>053</td>
<td>Cambridge arch-central Kansas</td>
</tr>
<tr>
<td>018</td>
<td>Western Great basin</td>
<td>054</td>
<td>Salina basin</td>
</tr>
<tr>
<td>019</td>
<td>Eastern Great basin</td>
<td>055</td>
<td>Nemaha uplift</td>
</tr>
<tr>
<td>020</td>
<td>Uinta-Piceance basin</td>
<td>056</td>
<td>Forest City basin</td>
</tr>
<tr>
<td>021</td>
<td>Paradox basin</td>
<td>057</td>
<td>Ozark uplift</td>
</tr>
<tr>
<td>022</td>
<td>San Juan basin</td>
<td>058</td>
<td>Anadarko basin</td>
</tr>
<tr>
<td>023</td>
<td>Albuquerque-Santa Fe rift</td>
<td>059</td>
<td>Sedgwick basin</td>
</tr>
<tr>
<td>024</td>
<td>Northern Arizona</td>
<td>060</td>
<td>Cherokee basin</td>
</tr>
<tr>
<td>025</td>
<td>Southern Arizona-Southwestern New Mexico</td>
<td>061</td>
<td>Southern Oklahoma</td>
</tr>
<tr>
<td>026</td>
<td>South-central New Mexico</td>
<td>062</td>
<td>Arkoma basin</td>
</tr>
<tr>
<td>027</td>
<td>Montana thrust belt</td>
<td>063</td>
<td>Michigan basin</td>
</tr>
<tr>
<td>028</td>
<td>Central Montana</td>
<td>064</td>
<td>Illinois basin</td>
</tr>
<tr>
<td>029</td>
<td>Southwest Montana</td>
<td>065</td>
<td>Black Warrior basin</td>
</tr>
<tr>
<td>031</td>
<td>Williston basin</td>
<td>066</td>
<td>Cincinnati arch</td>
</tr>
<tr>
<td>032</td>
<td>Sioux arch</td>
<td>067</td>
<td>Appalachian basin</td>
</tr>
<tr>
<td>033</td>
<td>Powder River Basin</td>
<td>068</td>
<td>Blue Ridge thrust belt</td>
</tr>
<tr>
<td>034</td>
<td>Big Horn basin</td>
<td>069</td>
<td>Piedmont</td>
</tr>
<tr>
<td>035</td>
<td>Wind River Basin</td>
<td>070</td>
<td>Atlantic Coastal Plain</td>
</tr>
<tr>
<td>036</td>
<td>Wyoming thrust belt</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 7. Average reservoir properties calculated for the Comprehensive Resource Database (CRD).

[Abbreviations: API, American Petroleum Institute; CO₂, carbon dioxide; H₂S, hydrogen sulfide; N₂, nitrogen]

<table>
<thead>
<tr>
<th>Oil and gas reservoirs</th>
<th>Oil reservoirs</th>
<th>Gas reservoirs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net pay (thickness)</td>
<td>Initial oil saturation</td>
<td>Initial gas saturation</td>
</tr>
<tr>
<td>Depth</td>
<td>Initial water saturation</td>
<td>Initial water saturation</td>
</tr>
<tr>
<td>Temperature gradient</td>
<td>Initial formation volume factor</td>
<td>CO₂ concentration</td>
</tr>
<tr>
<td>Pressure gradient</td>
<td>API gravity of oil</td>
<td>N₂ concentration</td>
</tr>
<tr>
<td>Porosity</td>
<td>Specific gravity of the gas</td>
<td>H₂S concentration</td>
</tr>
<tr>
<td>Permeability</td>
<td>Well spacing</td>
<td>Specific gravity of the gas</td>
</tr>
<tr>
<td></td>
<td>Sulfur content</td>
<td>Heat content</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sulfur content</td>
</tr>
</tbody>
</table>

Figure 4. Chart showing the steps taken to estimate missing reservoir production data and the number of active and producing wells (well counts). Abbreviation: NRG, Nehring Associates (2012).
The averages are calculated in the following manner (equation 1):

\[ \text{playthick} = \frac{\sum \text{thick}}{\text{num\_thick}} \]  

(1)

where

- \( \text{playthick} \) is the non-zero average thickness of the reservoirs in the play or province, in feet;
- \( \text{thick} \) is the non-zero thickness (in feet), of the reservoir in the play or province; and
- \( \text{num\_thick} \) is the number of non-zero values in the play or province.

Estimation of Reservoir Production and Well Counts

The reservoir level database from Nehring Associates (2012) (“NRG”) contains production data through 2010. However, it does not provide production data for all reservoirs. In the case where the production data are missing at the reservoir level, it is estimated using the production data contained in the NRG database. After the production is calculated for all reservoirs in the database, the number of active and producing wells is calculated for each reservoir. This section describes the steps taken to estimate the missing reservoir production data and the number of active and producing wells (fig. 4).

The first step shown in figure 4 is to identify the missing properties for oil and gas reservoirs. These properties determine the flow of fluids through the reservoir and include reservoir area, porosity, permeability, net pay thickness, and viscosity. If reservoir data are not available from the NRG database, then they are estimated using the following averages: play, province, region, or Nation (fig. 4, step 2).

The number of reservoirs in the field is determined by counting the number of reservoirs that share a unique field (NRG ID) (fig. 4, step 3) and then validating the reservoir production against the field production (fig. 4, step 4). If any reservoir in the field is missing production data for both oil and gas (fig. 4, step 4), three proration factors are calculated (listed in order of preference in equations 2, 3, and 4) (fig. 4, step 5); however, only one factor is chosen, based on available data:

\[ \text{factor one:} \quad \text{fact\_one}(\text{res}) = \frac{\text{area} \times \text{pay} \times \text{porosity} \times \text{permeability}}{\text{viscosity}} \]  

(2)

\[ \text{factor two:} \quad \text{fact\_two}(\text{res}) = \text{area} \times \text{pay} \times \text{porosity} \times \text{permeability} \]  

(3)

\[ \text{factor three:} \quad \text{fact\_three}(\text{res}) = \text{area} \times \text{pay} \times \text{porosity} \]  

(4)

where

- \( \text{fact\_one}(\text{res}) \) is proration factor one;
- \( \text{fact\_two}(\text{res}) \) is proration factor two;
- \( \text{fact\_three}(\text{res}) \) is proration factor three;
- \( \text{area} \) is the reservoir area, in acres;
- \( \text{pay} \) is the reservoir productive interval thickness, in feet;
- \( \text{porosity} \) is the reservoir rock porosity, in decimal format;
- \( \text{permeability} \) is the reservoir rock permeability, in millidarcies (mD); and
- \( \text{viscosity} \) is the viscosity of the reservoir oil, in centipoise (cP).

After the factors have been calculated for all reservoirs in the field, reservoir distributions are calculated for each factor. The distributions are calculated as shown in equation 5.

\[ \text{dist\_}(\text{fact\_a, res}) = \frac{\text{fact\_a}(\text{res})}{\sum_{i} \text{fact\_a}(\text{res})} \]  

(5)

where

- \( \text{dist\_}(\text{fact\_a, res}) \) is the reservoir distribution factor;
- \( \text{fact\_a} \) is reservoir production proration factor one, two, or three;
- \( \text{res} \) is the reservoir analyzed; and
- \( \text{nres} \) is the number of reservoirs in the field.
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The distributions are calculated using a common, complete set of proration factors. The allocation of the field production to the reservoir is determined according to equation 6.

\[
respro(res, iyr) = dist_{(fact_a, res)} \times fdata(ifld, iyr)
\]

where
- \(respro(res, iyr)\) is the annual reservoir production of oil, gas, or NGL in year analyzed (\(iyr\));
- \(res\) is the reservoir analyzed;
- \(iyr\) is the year analyzed;
- \(dist_{(fact_a, res)}\) is the reservoir distribution factor;
- \(fact_a\) is reservoir production proration factor one, two, or three;
- \(fdata(ifld, iyr)\) is the annual field production of oil, gas, or NGL in year analyzed (\(iyr\)); and
- \(ifld\) is the field that is matched to the reservoir.

If reservoir production data are absent for all reservoirs in the field, or a complete set of proration factors cannot be calculated for all reservoirs matched to the field, then the production is prorated evenly among all reservoirs in the field (equation 7).

\[
respro(res, iyr) = \frac{fdata(ifld, iyr)}{nres}
\]

where
- \(respro(res, iyr)\) is the annual reservoir production of oil, gas, or NGL in year analyzed (\(iyr\));
- \(res\) is the reservoir analyzed;
- \(iyr\) is the year analyzed;
- \(fdata(ifld, iyr)\) is the annual field production of oil, gas, or NGL in year analyzed (\(iyr\));
- \(ifld\) is the field that is matched to the reservoir; and
- \(nres\) is the number of reservoirs in the field.

After the production is calculated for all reservoirs in the database, the number of active and producing wells (well counts) is calculated for each reservoir (fig. 4, step 6). As the well counts are provided only at the field level, they are prorated for each reservoir. The proration factors are calculated according to the distribution of production (in barrels of oil equivalent, BOE) for each reservoir in the field (equation 8).

\[
reswell(res, iyr) = \frac{respro(res, iyr)}{\sum_{res=1}^{nres} respro(res, iyr)} \times fldwell(ifld, iyr)
\]

where
- \(reswell(res, iyr)\) is the annual number of wells in the reservoir in year analyzed (\(iyr\));
- \(res\) is the reservoir analyzed;
- \(iyr\) is the year analyzed;
- \(respro(res, iyr)\) is the annual production of oil, gas, or NGL converted to BOE in year analyzed (\(iyr\));
- \(nres\) is the number of reservoirs in the field;
- \(fldwell(ifld, iyr)\) is the annual number of wells in the field in year analyzed (\(iyr\)); and
- \(ifld\) is the field that is matched to the reservoir.

The number of prorated wells is then rounded to the nearest integer. Additional steps, such as ensuring that there is a well in each year with production, are applied to ensure the reasonableness of the well count. The reservoir production data and the number of active and producing wells (well counts) are written to the CRD file (fig. 4, step 7).
Figure 5. Flowchart showing the process for identifying reservoir type (oil or gas reservoir). Abbreviations: NRG, Nehring Associates (2012); Scf/bbl, standard cubic feet per barrel.

Figure 6. Flowchart showing the steps taken to estimate and calculate oil and gas property values. Abbreviations: CRD, Comprehensive Resource Database; NRG, Nehring Associates (2012).

**Identify Reservoir Type**

Next, as illustrated in figure 5, the reservoirs are classified as one of two types:
- Oil reservoir
- Gas reservoir

Such classification uses a calculated gas-oil ratio (GOR) based on the cumulative oil and gas production from the NRG database (fig. 5). For the purposes of EOR screening, a GOR of 10,000 Scf/bbl or less is used to define oil reservoirs and a GOR of greater than 10,000 Scf/bbl is used to define gas reservoirs. In addition, the list of existing CO₂-EOR projects (Koottungal, 2012, 2014) is used to indicate the active projects and whether the project is a miscible or immiscible CO₂ flood. During the initial reservoir type screening (fig. 5), the reservoirs are not classified as active or abandoned. This is determined after the production and well data is updated using the IHS Inc. (2012) data.
Assignment of Database Values

Next, the values of petrophysical properties for each oil and gas reservoir are checked for completeness and internal consistency. If values for the properties listed in table 7 are missing in the NRG database (fig. 6), the program estimates those values for oil or gas reservoirs using play, province, region, or Nation averages. Table 2 lists the properties for which the values are calculated or estimated as default values. Figure 6 shows the steps taken to estimate or calculate oil and gas property values. The defaults used for estimating missing property values are derived from play, province, region, or Nation averages according to the steps provided below. Play averages are used for 28 percent of reservoir attribute records for over 22,000 reservoirs. If the reservoirs are weighted by known recovery of oil, then 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. Other missing property values are estimated by calculations based on known physical relationships (not shown in fig. 6). In table 2, the missing property values that are estimated by averages are indicated by footnote 1. Other variables listed are calculated.

Average property values are determined using the following procedure:

Step 1. If the NRG has a value >0 (missing property values = “No” in fig. 6), then use the NRG value and output the value to the CRD file;
Step 2. If the NRG value equals 0 (missing property values = “No” in fig. 6), then set to play average;
Step 3. If the NRG value equals 0 and the USGS has additional data, use the USGS data. This step is applicable to pressure and temperature only;
Step 4. If the NRG value is still equal to 0, then set to province average;
Step 5. If the NRG value is still equal to 0, then set to region average;
Step 6. If the NRG value is still equal to 0, then set to Nation average;
Step 7. Output all estimated property values to the CRD file.

In addition, if USGS data are not available, then temperature and pressure require a calculation when using average NRG data.

Temperature

Step 1. If the NRG has a value greater than 0, then use the NRG value;
Step 2. If the NRG value is less than or equal to 0 and NRG has values for temperature gradient and depth, then calculate the temperature with equation 9 using the play-level default. If play-level data are not available in the NRG, then region or Nation averages may be used.

\[ Dary(i,17) = 60 + Ply\_TempGr\(k\) \times Dary(i,16) \]  

where

- \(Dary(i,17)\) is the temperature of play, in degrees Fahrenheit (°F) in year \(i\);
- \(i\) is the year;
- 60 is standard temperature in degrees Fahrenheit (°F);
- \(Ply\_TempGr\) is the average temperature gradient of play, in degrees Fahrenheit per foot (°F/ft);
- \(k\) is the play being analyzed; and
- \(Dary(i,16)\) is the depth of play, in feet (ft) in year \(i\).

Pressure

Step 1. If the NRG initial pressure is greater than 80 percent of the calculated pressure, then use the NRG initial pressure;
Step 2. If the NRG initial pressure is less than or equal to 80 percent of the calculated pressure, then use the calculated initial reservoir pressure (\(PresCal\)). The calculation is shown in equation 10 using the play-level default. If play-level data are not available in the NRG, then region or Nation averages may be used.
\[ \text{PresCal} = 14.7 + \text{Ply}_\text{PresGr}(k) \times \text{Dary}(i,16) \]  

(10)

where

- \( \text{PresCal} \) is the calculated initial pressure, in pound-force per square inch absolute (psia);
- 14.7 is standard atmospheric pressure in pound-force per square inch per foot (psi/ft);
- \( \text{Ply}_\text{PresGr} \) is the average pressure gradient of play, in pound-force per square inch per foot (psi/ft);
- \( k \) is the play being analyzed;
- \( \text{Dary}(i,16) \) is the depth of play, in feet (ft) in year \( i \); and
- \( i \) is the year.

Oil Reservoir Area

Oil reservoir area is needed to calculate the original oil in place (OOIP) for reservoirs with incomplete OOIP data in the NRG database.

Step 1. If NRG has reservoir area (in acres), then use the NRG area;

Step 2. If NRG reservoir area value is \( \leq 0 \), then calculate reservoir area using:

\[ \text{Area} = \text{well spacing} \times \text{spacing units} \]  

(11)

where

- \( \text{spacing units} \) is the number of wells in each reservoir with equal well spacing.

Step 3. If area is still less than or equal to 0, then calculate the reservoir area using equation 12.

\[ \text{OrgArea}(i) = \text{OOIP} \times \text{BOI} / (7,758 \times \text{NetPay} \times (\text{Porosity} / 100) \times \text{SOI}) \]  

(12)

where

- \( \text{OrgArea}(i) \) is the calculated reservoir area, in acres in year \( i \);
- \( \text{OOIP} \) is the original oil in place, in stock tank barrels (STB);
- \( \text{BOI} \) is the initial oil formation volume factor, in decimal format;
- 7,758 is the conversion factor from acre-feet to barrels;
- \( \text{NetPay} \) is the net reservoir thickness, in feet (ft);
- \( \text{Porosity} \) is the porosity of the oil reservoir rock, in percent; and
- \( \text{SOI} \) is the initial oil saturation, in decimal format.

Step 4. Then, if the reservoir area is greater than the field area, use equation 13.

\[ \text{Reservoir area} = \text{field area} \]  

(13)

Well Spacing

Well spacing is needed to calculate the reservoir area (in acres) for reservoirs with incomplete well spacing data in the NRG database.

Step 1. If active wells equals 0, then set the effective well spacing equal to 0 acres;

Step 2. If there are wells, use the number of wells and the active area (in acres) to calculate the well spacing;

Step 3. Estimate the maximum well spacing, in acres:

a. If NRG provides one (of two) well spacing values, use the maximum value;

b. If the calculated value is above the maximum, use the maximum value;
c. If the well spacing has been estimated in step 3b, and if NRG provides both well spacing values, use the average value;

Step 4. If no NRG well spacing data are available, then the maximum well spacing is set as 80 acres.

Original Oil in Place

To verify that the reservoir original oil in place (OOIP) values in the NRG database are reasonable, the NRG OOIP is checked against the reservoir area, the cumulative production, and the estimated NRG known oil recovery (KRoil, cumulative production plus reported reserves). Reservoir volumetric values are adjusted as necessary before a final OOIP calculation is made. If reservoir area is unknown, and assuming that reservoirs areas are larger than the current production area, then three times the current producing area is an initial attempt to start the iterative process of estimating area when reservoir oil recovery has already exceeded 35 percent of the NRG OOIP. The area was varied in the steps afterwards in order to calculate a more realistic OOIP than the initial OOIP reported in the NRG. The approach uses the following steps to calculate the reservoir OOIP:

Step 1. If the initial oil formation volume factor is missing, then the OOIP is calculated using the reservoir properties;

Step 2. Evaluate the NRG KR_{oil}:
   a. If the KR_{oil} is less than or equal to 35 percent of the OOIP, keep the OOIP without any changes to the volumetric values.
   b. If KR_{oil} is greater than 35 percent of the OOIP, then adjust the variables as follows:
      i. Determine the maximum area: three times the current producing area or field area;
      ii. Estimate the area necessary for a 35 percent recovery factor;
      iii. If the estimated area is less than or equal to the maximum area, then set the NRG area equal to the estimated area, or;

Step 3. If the estimated area is greater than the maximum area, then set the NRG area equal to the maximum area and check NetPay, Porosity, SOI, and BOI, assuming an equal contribution of the difference and adjusting NetPay last;

Step 4. Allow up to 10 percent change in any of the parameters;

Step 5. Check that the revised values are within the range for the play. For example, for a given play, the minimum SOI is ≤ calculated SOI is ≤ maximum SOI.

Step 6. Recalculate OOIP using a recalculated OrgArea(i) using equations 14 to 16:

\[
\text{AreaOOIP} = \text{KR}_{oil} \times 0.35
\]

\[\text{(14)}\]

where

- \(\text{AreaOOIP}\) is the calculated recoverable original oil in place, in thousands of stock tank barrels (MSTB);
- \(\text{KR}_{oil}\) is the NRG known oil recovery (cumulative production plus reported reserves, in thousands of barrels [Mbbl]); and
- 0.35 is an assumed 35 percent reservoir recovery factor.

\[
\text{OrgArea}(i) = \frac{\text{AreaOOIP} \times \text{BOI} \times (7,758 \times \text{NetPay} \times (\text{Porosity}/100) \times \text{SOI}}{\text{(15)}}
\]

where

- \(\text{OrgArea}(i)\) is the calculated reservoir area, in acres in year \((i)\);
- \(\text{AreaOOIP}\) is the calculated recoverable original oil in place, in thousands of stock tank barrels (MSTB);
- \(\text{BOI}\) is the initial oil formation volume factor, in decimal format;
- 7,758 is the conversion factor from acre-feet to barrels;
- \(\text{NetPay}\) is the net reservoir thickness, in feet (ft);
- \(\text{Porosity}\) is the porosity of the reservoir rock, in percent; and
- \(\text{SOI}\) is the initial oil saturation, in decimal format.
\[ OOIP = (7,758 \times \text{OrgArea}(i) \times \text{NetPay} \times (\text{Porosity}/100) \times \text{SOI}) / \text{BOI} \]  

(16)

where

- \( OOIP \) is the original oil in place, in stock tank barrels (STB);
- 7,758 is the conversion factor from acre-feet to barrels (bbl);
- \( \text{OrgArea}(i) \) is the calculated reservoir area, in acres in year \((i)\);
- \( \text{NetPay} \) is the net reservoir thickness, in feet (ft);
- \( \text{Porosity} \) is the porosity of the reservoir rock, in percent;
- \( \text{SOI} \) is the initial oil saturation, in decimal format; and
- \( \text{BOI} \) is the initial oil formation volume factor, in decimal format.

**Critical Gas Reservoir Properties**

Critical NRG gas reservoir properties that require estimates of missing data include (1) well spacing, (2) gas-in-place volume, (3) recovery factor, and (4) producing area. The process of estimating each property is described below.

1. Reservoir well spacing is estimated using the following steps:
   - **Step 1.** If the number of total wells is equal to 0, set the well spacing equal to 0 acres;
   - **Step 2.** Use well-spacing data provided by the NRG database; check that the well spacing is between 80 and 320 acres. If the well spacing is less than 80 acres, it is set equal to 80 acres. If well spacing is greater than 320 acres, it is set equal to 320 acres.

2. Reservoir gas-in-place volume per unit area \((GIPVOL)\) is estimated using the following steps:
   - **Step 1.** Calculate the gas compressibility factor \((Z \text{ factor})\) following methods described in Standing and Katz (1942) and Wichert and Aziz (1971) using the gas specific gravity, its content of carbon dioxide \((\text{CO}_2)\) and hydrogen sulfide \((\text{H}_2\text{S})\), reservoir pressure, and reservoir temperature;
   - **Step 2.** Use the calculated \(Z \text{ factor}\) to calculate the \(GIPVOL\) as shown in equation 17:
     
     \[
     GIPVOL = \frac{43,560 \times \text{Por} \times \text{NetPay} \times \text{SGI}}{0.02829 \times Z \text{ factor} \times (Tres + 460)}
     \]

     (17)

   where
   - \( GIPVOL \) is the original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre);
   - 43,560 is the conversion factor from acre-feet to cubic feet \((\text{ft}^3)\);
   - \( \text{Por} \) is the porosity of the reservoir rock, in decimal format;
   - \( \text{NetPay} \) is the net reservoir thickness, in feet (ft);
   - \( \text{SGI} \) is the initial gas saturation, in decimal format;
   - 0.02829 is the conversion factor for the compressibility of gas at standard conditions \((14.7 \text{ psia and } 60 \text{ °F})\);
   - \( Z \text{ factor} \) is the compressibility of gas;
   - \( Tres \) is the reservoir temperature, in degrees Fahrenheit \((\text{°F})\);
   - 460 is the conversion factor for degrees Rankine \((\text{°R})\); and
   - \( \text{PRESIN} \) is the initial reservoir pressure, in pound-force per square inch absolute (psia).

3. The recovery factor is estimated using the NRG known gas recovery \((\text{KR}_\text{gas})\) and the original gas in place \((\text{OGIP})\) in the following steps:
   - **Step 1.** Divide the \(\text{KR}_\text{gas}\) by the \(\text{OGIP}\);
   - **Step 2.** If the reservoir is conventional, and
     - If the estimated ultimate recovery \((EUR)\) is greater than 80 percent, set the recovery factor equal to 0.8;
     - If the \(EUR\) is less than 40 percent, set the recovery factor equal to 0.4.
   - **Step 3.** If the reservoir is coal or shale, and
• If the \( EUR \) is greater than 30 percent, set the recovery factor equal to 0.3;
• If the \( EUR \) is less than 10 percent, set the recovery factor equal to 0.1.

4. The reservoir producing area is estimated using one of the following sequence of steps; if data are not available for an individual step, then the next step is used until the reservoir producing area has been estimated:

   Step 1. Use the gas reservoir area provided by NRG, or;
   Step 2. Use the number of wells and the well spacing provided by NRG to calculate the reservoir area, or;
   Step 3. Use the number of wells and the calculated well spacing to calculate the reservoir area, or;
   Step 4. Assume that there is only one well per 40 acres.

---

Figure 7. Flowchart showing the process steps for updating Nehring Associates (2012) production and well-count data with IHS Inc. (2012) field production and well-count data. State production data are from the U.S. Energy Information Administration (EIA, 2013a, b). Abbreviations: IHS, IHS Inc. (2012); NRG, Nehring Associates (2012).
## Updating with IHS Data

As previously discussed, the NRG database production and well-count data are current through 2010. To update the data to 2012 in the CRD, the NRG database is supplemented by the IHS field production and well-count data. The major steps of this process are illustrated in figure 7 and described in this section.

Some NRG oil or gas fields that do not have IHS production data available are not subject to be updated, and no further supplementation of these fields is possible. A list of these oil or gas fields that do not have IHS data available is noted in a separate file in the CRD.

The following steps are for updating NRG production and well-count data with IHS data:

**Step 1.** Determine whether the IHS oil or gas field data are available. If data are not available from IHS, then the NRG production data for the CRD will be updated with prorated State production data from the U.S. Energy Information Administration (2013a, b);

**Step 2.** If data are available from IHS, then match IHS field and production data with NRG reservoir and field production data;

**Step 3.** Determine if IHS production data are available for 2011 and 2012. If no data are available for one or both years, then assume no production in that year;

**Step 4.** Determine how many reservoirs (and which reservoirs) are matched to the oil or gas field. For each reservoir, prorate the updated IHS oil or gas field production data using ratios calculated from the last three years (2008–2010) of the NRG production data (equation 18). A three-year period was selected in order to capture the recent production trends of the reservoirs within the field.

\[
respro(res,iyr) = \frac{\sum_{res} crespro(res) \times ihsprod(ifld,iyr)}{\sum_{res} crespro(res)}
\]  

(18)

where

- \(respro\) is the annual reservoir oil or gas production, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf);
- \(res\) is the reservoir analyzed;
- \(iyr\) is the year analyzed;
- \(crespro\) is the NRG cumulative production of the reservoir (2008–2010), in thousands of barrels (Mbbl) or billions of cubic feet (Bcf);
- \(nres\) is the number of reservoirs in the field;
- \(ihsprod\) is the IHS Inc. (2012) (IHS) annual oil or gas production from the field, in thousands of barrels (Mbbl) or millions of cubic feet (MMcf); and
- \(ifld\) is the field that is matched to the reservoir.

**Step 5.** After the production has been updated, the reservoir level well count (number of wells) is also updated, using equation 19.

\[
reswell(res,iyr) = \frac{\sum_{nres} resprod(res,iyr) \times fldwell(ifld,iyr)}{\sum_{res} resprod(res,iyr)}
\]  

(19)

where

- \(reswell(res,iyr)\) is the annual number of wells in the reservoir in year analyzed (iyr);
- \(res\) is the reservoir analyzed;
- \(iyr\) is the year analyzed;
- \(resprod(res,iyr)\) is the annual production of oil and gas, converted to barrels of oil equivalent (BOE) in year analyzed (iyr);
- \(nres\) is the number of reservoirs in the field;
- \(fldwell(ifld,iyr)\) is the annual number of wells in the field in year analyzed (iyr); and
- \(ifld\) is the field that is matched to the reservoir.

As in the previous step, the number of wells is converted to an integer and the results are checked for errors.

**Step 6.** Assign reservoir type as oil, gas, or abandoned;
Step 7. Update the NRG reservoir properties;
Step 8. Output the updated production data to a file for use in the CRD.

Assigning Final Reservoir Type

The updated production data is used to recalculate the gas-oil ratio (GOR) for the reservoir, and the final reservoir type is determined.

Three categories are considered for the final reservoir type assignment:

- Oil reservoir, if GOR is less than or equal to 10,000 Scf/bbl;
- Gas reservoir, if GOR is greater than 10,000 Scf/bbl;
- Abandoned reservoir, if no production is available in the last three years of data.

The oil and abandoned reservoirs are considered for CO$_2$-EOR in the Screening Module section of this report.

Updating Properties

In addition to updating the production and the well counts (discussed previously), several reservoir properties are updated in the NRG database (that is updated for the CRD) using IHS data. These properties are listed in table 8.

Screening Module

The screening module determines the potential oil and abandoned reservoirs, which are candidates for miscible and immiscible CO$_2$-EOR flooding. When CO$_2$ is injected under conditions of miscibility, the CO$_2$ aids in the recovery of oil by (1) swelling the crude oil, (2) lowering the viscosity of crude oil, and by (3) miscible displacement of the oil when the reservoir pressure is at least equal to the minimum miscibility pressure (MMP). When miscibility of two fluids occurs, the fluids are mixed with no interface between them. Miscibility of CO$_2$ with oil does not generally occur at the first contact, but will occur along multiple contacts if the MMP is maintained in the reservoir (Taber and others, 1997). Minimum miscibility pressure depends on the reservoir temperature, pressure, and oil composition and is calculated using curves based on experimental data that were constructed by Holm and Josendal (1974) and Mungan (1981). The curves from figure 3 of Mungan (1981) were digitized and for the CRD, the MMP was calculated by interpolation of Mungan (1981) curve values based on the CRD reservoir temperature and the molecular weight of pentanes and heavier fractions of the reservoir’s oil. A list of all applied screening criteria for miscible and immiscible flooding is provided in table 9.

Outputs

The program code that generates the CRD creates 14 major outputs. These outputs contain the properties and production data for the various reservoirs evaluated by the screening criteria (table 9). Table 10 lists 14 major output files and provides a brief description of each. Included in these 14 output files that the module creates is a series of 5 “shadow” output files. The 5 shadow files identify the data sources that are used for every property value of every reservoir. These files can be used to track how the CRD computer model filled in missing property values, when an average or default was used, and if the original NRG value is retained.

<table>
<thead>
<tr>
<th>Oil and abandoned reservoirs</th>
<th>Gas reservoirs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current oil saturation (SOC)</td>
<td>Current gas saturation (SGC)</td>
</tr>
<tr>
<td>Current water saturation (SWC)</td>
<td>Current water saturation (SWC)</td>
</tr>
<tr>
<td>Gas-oil ratio (GOR)</td>
<td>Condensate-to-gas ratio</td>
</tr>
<tr>
<td>Producing wells</td>
<td>Producing wells</td>
</tr>
<tr>
<td>Injection wells</td>
<td>Injection wells</td>
</tr>
<tr>
<td>Total wells</td>
<td>Total wells</td>
</tr>
<tr>
<td>Well spacing</td>
<td>Well spacing</td>
</tr>
<tr>
<td>Cumulative production</td>
<td>Cumulative production</td>
</tr>
<tr>
<td>Current oil formation volume factor (BOC)</td>
<td>Current gas formation volume factor (BGC)</td>
</tr>
<tr>
<td>Current pressure</td>
<td>Current pressure</td>
</tr>
<tr>
<td>Current temperature</td>
<td>Current temperature</td>
</tr>
<tr>
<td>Water influx</td>
<td></td>
</tr>
</tbody>
</table>
Table 9. Screening criteria for miscible and immiscible flooding.

[Abbreviations: API, American Petroleum Institute; °API, degrees API; cP, centipoise; ft, feet; psi, pound-force per square inch]

<table>
<thead>
<tr>
<th>Screening criteria properties (units)</th>
<th>Miscible flooding</th>
<th>Transitional</th>
<th>Immiscible flooding</th>
</tr>
</thead>
<tbody>
<tr>
<td>API gravity of oil (°API)</td>
<td>1&gt;25</td>
<td>22 &gt; API ≤ 25</td>
<td>213 ≤ API ≤ 22</td>
</tr>
<tr>
<td>Viscosity (cP)</td>
<td>3&lt;10</td>
<td>3&lt;10</td>
<td>3&lt;10</td>
</tr>
<tr>
<td>Minimum miscibility pressure (psi)</td>
<td>≤ fracture pressure – 400</td>
<td>≤ fracture pressure – 400</td>
<td>Not applicable</td>
</tr>
</tbody>
</table>

1National Petroleum Council (1984a).
3Andrei and others (2010).
4To maintain a reasonable level of safety, the minimum miscibility pressure of candidate reservoirs must be at least 400 psi below the reservoir fracture pressure. The 400 psi safety margin is an estimate of current industry practice.

Table 10. Major output files generated in creation of the Comprehensive Resource Database (CRD).

[Abbreviations: IHS, IHS Inc. (2012); NRG, Nehring Associates (2012) database]

<table>
<thead>
<tr>
<th>File name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir.out</td>
<td>Reservoirs with backfilled/updated data; contain data based on both NRG and IHS files.</td>
</tr>
<tr>
<td>Hypothetical.out</td>
<td>Reservoirs with backfilled/updated data; contain data solely on IHS files.</td>
</tr>
<tr>
<td>Oil.out</td>
<td>All oil reservoirs.</td>
</tr>
<tr>
<td>Gas.out</td>
<td>All gas reservoirs.</td>
</tr>
<tr>
<td>Abn.out</td>
<td>All abandoned reservoirs.</td>
</tr>
<tr>
<td>Immiscible_pot.out</td>
<td>Active oil reservoirs eligible for immiscible flooding.</td>
</tr>
<tr>
<td>Immiscible_abn.out</td>
<td>Abandoned reservoirs eligible for immiscible flooding.</td>
</tr>
<tr>
<td>Miscible_pot.out</td>
<td>Active oil reservoirs eligible for miscible flooding.</td>
</tr>
<tr>
<td>Miscible_abn.out</td>
<td>Abandoned reservoirs eligible for miscible flooding.</td>
</tr>
<tr>
<td>Shadowdata.out</td>
<td>Maps changes in database property values; corresponds to reservoir.out.</td>
</tr>
<tr>
<td>Shadowhypo.out</td>
<td>Maps changes in database property values; corresponds to hypothetical.out.</td>
</tr>
<tr>
<td>Shadowoil.out</td>
<td>Contains the “shadow” property values for oil.out.</td>
</tr>
<tr>
<td>Shadowgas.out</td>
<td>Contains the “shadow” property values for gas.out.</td>
</tr>
<tr>
<td>Shadowabn.out</td>
<td>Contains the “shadow” property values for abn.out.</td>
</tr>
</tbody>
</table>
Additional Fluid Properties in Oil Reservoirs

Current reservoir pressure \( (PRES) \) is the current pressure in the reservoir after production or waterflood operations. Current reservoir pressure is calculated using equation 20:

\[
PRES = (0.433 \timesDEPTH) + 14.7
\]  
(20)

where

\( PRES \) is the current reservoir pressure, in pound-force per square inch absolute (psia);

0.433 is the normal hydrostatic pressure gradient for freshwater in pound-force per square inch per foot (psi/ft);

\( DEPTH \) is the reservoir depth, in feet (ft); and

14.7 is the standard atmospheric pressure, in pound-force per square inch (psi).

However, if the initial pressure is less than current pressure, then current pressure is set equal to 90 percent of initial pressure.

Current oil saturation \( (SOC) \) is calculated using equation 21:

\[
SOC = SOI \times \left(1 - \frac{cumprod}{OOIP} \right) \times \frac{BOC}{BOI}
\]  
(21)

where

\( SOC \) is the current oil saturation, in decimal format;

\( SOI \) is the initial oil saturation, in decimal format;

\( cumprod \) is the cumulative oil production, in thousands of barrels (Mbbbl);

\( OOIP \) is the original oil in place, in thousands of stock tank barrels (MSTB);

\( BOC \) is the current oil formation volume factor, in decimal format; and

\( BOI \) is the initial oil formation volume factor, in decimal format.

Initial oil formation volume factor \( (BOI) \) is from the NRG database, or it is calculated using the methods described in Standing (1948) and Satter and others (2008), as shown in the following steps and equations 22 to 26:

Step 1. The coefficient \( (Yg) \) is calculated for the solution gas-oil ratio equation (equation 22) as:

\[
Yg = 0.00091 \times Tres - 0.0125 \times API
\]  
(22)

where

\( Yg \) is the coefficient for the solution gas-oil ratio equation;

0.00091 is a constant value obtained from curve fitting by Standing (1948);

\( Tres \) is the reservoir temperature, in degrees Fahrenheit (°F);

0.0125 is a constant value obtained from curve fitting by Standing (1948); and

\( API \) is the American Petroleum Institute gravity of oil, in degrees API (°API).

Step 2. The solution gas-oil ratio \( (RS) \) is calculated using equation 23:

\[
RS = SGG \times \left[ \left( \frac{PRES}{(18 \times 10^9)} \right) \right]^{1.204}
\]  
(23)

where

\( RS \) is the solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB);

\( SGG \) is the specific gravity of the gas;

\( PRES \) is the initial reservoir pressure, in pound-force per square inch absolute (psia);

\( Yg \) is the coefficient for the solution gas-oil ratio equation;

18 is a constant obtained by rewriting the Standing correlation equation (Standing, 1948); and

1.204 is a constant obtained by rewriting the Standing correlation equation (Standing, 1948).
Step 3. The specific gravity of oil (SGO) is calculated using equation 24:

\[
SGO = \frac{141.5}{131.5 + API}
\]  

(24)

where

- \( SGO \) is the specific gravity of oil; and
- \( API \) is the American Petroleum Institute gravity of oil, in degrees API (°API) and is defined as \((141.5/SGO) \times 60°F - 131.5\).

Step 4. The coefficient \( F \) is calculated for the initial oil formation volume factor equation using equation 25 as:

\[
F = RS \times (SGG/SGO)^{0.5} + 1.25 \times T_{res}
\]

(25)

where

- \( F \) is the coefficient for the initial oil formation volume factor equation;
- \( RS \) is the solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB);
- \( SGG \) is the specific gravity of the gas;
- \( SGO \) is the specific gravity of oil;
- 0.5 is a curve-fitting exponent obtained by Standing (1948);
- 1.25 is a constant value obtained from curve fitting by Standing (1948); and
- \( T_{res} \) is the reservoir temperature, in degrees Fahrenheit (°F).

Step 5. The initial oil formation volume factor (BOI) is calculated using equation 26:

\[
BOI = 0.972 + 0.000147 \times F^{1.175}
\]

(26)

where

- \( BOI \) is the initial oil formation volume factor, in decimal format;
- 0.972 is a constant for the correlation equation developed by Standing (1948) as published in Lyons (1999);
- 0.000147 is a constant for the correlation equation developed by Standing (1948) as published in Lyons (1999);
- \( F \) is the coefficient for the initial oil formation volume factor equation; and
- 1.175 is a constant for the correlation equation developed by Standing (1948) as published in Lyons (1999).

Both \( T_{res} \) and \( P_{RESIN} \), in equations 22 and 23 respectively, are from the NRG database, or calculated using temperature and pressure gradients as discussed in an earlier section (equations 9 and 10).

Specific gravity of the gas (SGG) is provided by the NRG database or is estimated by the play or province average where its value is not provided. If no data are available, the default value of 0.8 is assumed.

Current oil formation volume factor (BOC) can also be calculated using equation 26 by using current reservoir temperature and pressure. If the calculated \( BOC \) is equal to or larger than \( BOI \), then it is set equal to 99 percent of \( BOI \).

Current water saturation (SWC) is calculated using equation 27:

\[
SWC = 1 - SOC - SGI
\]

(27)

where

- \( SWC \) is the current water saturation, in decimal format;
- \( SOC \) is the current oil saturation, in decimal format; and
- \( SGI \) is the initial gas saturation, in decimal format.

Current gas saturation (SGC) is assumed to be the same as initial gas saturation, unless NRG data have values for initial gas saturation (SGI), then it is calculated using equation 28:

\[
SGI = 1 - SOI - SWI
\]

(28)

where

- \( SGI \) is the initial gas saturation, in decimal format;
- \( SOI \) is the initial oil saturation, in decimal format; and
- \( SWI \) is the initial water saturation, in decimal format.
Oil viscosity ($\mu$), if not provided in the NRG data, is calculated by first finding the dead (with no dissolved gas) oil viscosity using the Beggs and Robinson (1975) correlation (equation 29).

Dead oil viscosity ($\mu_{\text{DEAD}}$) is calculated as:

$$\mu_{\text{DEAD}} = 10^x - 1$$  \hspace{1cm} (29)

where

- $\mu_{\text{DEAD}}$ is the dead oil viscosity (no dissolved gas), in centipoise (cP); and
- $x$ is a dummy variable that relates two other variables (°API gravity of oil and temperature) in a rather complex formula (equation 30), and is defined as:

$$x = \frac{10^{3.0324 - (0.02023 \times \text{API})}}{(T_{\text{res}})^{1.163}}$$  \hspace{1cm} (30)

where

- 3.0324 is a curve-fitting exponent determined by Beggs and Robinson (1975);
- 0.02023 is a curve-fitting exponent determined by Beggs and Robinson (1975);
- API is the American Petroleum Institute gravity of oil, in degrees API (°API);
- $T_{\text{res}}$ is the reservoir temperature, in degrees Fahrenheit (°F); and
- 1.163 is a curve-fitting exponent determined by Beggs and Robinson (1975).

The conversion to live oil (with dissolved gas) is based on Beggs and Robinson (1975), Vasquez and Beggs (1980), and the dead oil viscosity.

The viscosity of live oil ($\mu_{\text{LIVE}}$) is calculated using equation 31:

$$\mu_{\text{LIVE}} = A \times \mu_{\text{DEAD}}^B$$  \hspace{1cm} (31)

where

- $\mu_{\text{LIVE}}$ is the live oil (with dissolved gas) viscosity, in centipoise (cP);
- $A$ is a variable coefficient whose value is determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975);
- $\mu_{\text{DEAD}}$ is the dead oil (no dissolved gas) viscosity, in centipoise (cP); and
- $B$ is an exponent determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975).

$A$ and $B$ are defined in equations 32 and 33 as:

$$A = 10.715 \times (RS + 100)^{0.515}$$  \hspace{1cm} (32)

$$B = 5.44 \times (RS + 150)^{0.338}$$  \hspace{1cm} (33)

where

- $A$ is a variable coefficient whose value is determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975);
- 10.715 is a constant for the correlation equation determined by Beggs and Robinson (1975);
- $RS$ is the solution gas-oil ratio, in standard cubic feet per stock tank barrel (Scf/STB);
- 100 is a constant for the correlation equation determined by Beggs and Robinson (1975);
- 0.515 is a curve-fitting exponent determined by Beggs and Robinson (1975);
- $B$ is an exponent determined by the value of the solution gas-oil ratio (Beggs and Robinson, 1975);
- 5.44 is a constant for the correlation equation determined by Beggs and Robinson (1975);
- 150 is a constant for the correlation equation determined by Beggs and Robinson (1975); and
- 0.338 is a curve-fitting exponent determined by Beggs and Robinson (1975).

CO$_2$ viscosity ($V_{\text{CO}_2}$) is based on two-dimensional linear interpolations of CO$_2$ viscosity data associated with specific reservoir temperature and reservoir pressure data as presented in U.S. Department of Energy and Ministry of Energy and Mines of the Republic of Venezuela (1986).
**CO₂ compressibility factor** ($Z_{CO₂}$) is based on two-dimensional linear interpolations of CO₂ compressibility factor data associated with specific reservoir temperature and pressure data, as presented in U.S. Department of Energy and Ministry of Energy and Mines of the Republic of Venezuela (1986).

**Water viscosity** ($VWAT$) is calculated based on the Van Wingen correlation (American Petroleum Institute, 1950) with equation 34:

$$VWAT = \exp(1.003 – 0.01479 \times Tres + 0.00001982 \times Tres^2)$$  \hspace{1cm} (34)

where
- $VWAT$ is the water viscosity, in centipoise (cP);
- 1.003 is a constant value obtained from curve fitting by Van Wingen (American Petroleum Institute, 1950);
- 0.01479 is a constant value obtained from curve fitting by Van Wingen (American Petroleum Institute, 1950);
- $Tres$ is the reservoir temperature, in degrees Fahrenheit (°F); and
- 0.00001982 is a constant value obtained from curve fitting by Van Wingen (American Petroleum Institute, 1950).

**CO₂ formation volume factor** ($B_{CO₂}$) is calculated using the dimensionless CO₂ compressibility factor (Z factor) (Towler, 2006) by equation 35:

$$B_{CO₂} = (0.00503676) \times (Z_{CO₂} \times Tres + 460)/PRESIN$$ \hspace{1cm} (35)

where
- $B_{CO₂}$ is the CO₂ formation volume factor, in decimal format;
- 0.00503676 is a conversion factor for reservoir barrels per standard cubic foot (Scf);
- $Z_{CO₂}$ is the CO₂ compressibility factor, dimensionless;
- $Tres$ is the reservoir temperature, in degrees Fahrenheit (°F);
- 460 is the conversion factor for degrees Rankine (°R); and
- PRESIN is the initial reservoir pressure, in pound-force per square inch absolute (psia).

**Pseudo-Dykstra-Parsons coefficient** ($VDP$) is computed from the calculated waterflood sweep efficiency and mobility ratio for each reservoir in the CRD database. The procedure was used for the National Petroleum Council’s (NPC) 1984 study of enhanced oil recovery and followed a procedure by Robl and others (1986) and Hirasaki and others (1989). The data for the relationships between $VDP$, pseudo-volumetric sweep efficiency, and mobility ratios are presented in graphical form in Hirasaki and others (1984) and Willhite (1986). The graphical data were transferred into tabular data and interpolated with a two-dimensional function. When a $VDP$ could be calculated, and if the value was between 0.1 and 0.5, it was set equal to 0.5. When the value exceeded 0.98, it was set equal to 0.72 (Hirasaki and others, 1989). For some reservoirs having insufficient data, the $VDP$ value is set equal to 0, and the reservoir is no longer considered a miscible candidate.

**Pseudo-volumetric sweep efficiency** ($EV_1$) is defined as the ratio between the volume of oil contacted by the displacing fluid and the volume of original oil in place (Hirasaki and others, 1984; Lake, 1989) and is calculated using equation 36:

$$EV_1 = \frac{ER + (BOI/BOC) - 1.0}{(BOI/BOC)(1 - SORW/SOI)}$$ \hspace{1cm} (36)

where
- $EV_1$ is the pseudo-volumetric sweep efficiency, in decimal format;
- $ER$ is the recovery factor after waterflood, in decimal format, and is estimated by the NRG known oil recovery ($KR_{oil}$) divided by the original oil in place ($OOIP$);
- $BOI$ is the initial oil formation volume factor, in decimal format;
- $BOC$ is the current oil formation factor, in decimal format;
- $SORW$ is the residual oil saturation after waterflood, in decimal format; and
- $SOI$ is the initial oil saturation, in decimal format.

For clastic reservoirs, the value of the residual oil saturation after waterflood ($SORW$) was set equal to 0.25 (National Petroleum Council, 1984). The original $SORW$ value for carbonate reservoirs found in National Petroleum Council (1984) was later revised to 0.305 (D. Remson, U.S. Department of Energy, written commun., 2015). The value 0.305 is used in the CRD for carbonate reservoirs and the value 0.25 is used in the CRD for clastic reservoirs.

The development of $EV_1$ (equation 36) is only used as an internal variable to calculate the pseudo-Dykstra-Parsons coefficient ($VDP$). A second equation (equation 37), calculates the pseudo-volumetric sweep efficiency ($EV_2$) used in assessing the technically recoverable hydrocarbons that are producible using CO₂ enhanced oil recovery processes. $EV_2$ is calculated in equation 37 as:
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\[ EV_2 = \frac{KR_{oil} \times 1,000}{7,758 \times \text{NetPay} \times \text{Por} \times \left( \frac{\text{SOI}}{\text{BOI}} - \frac{\text{SORW}}{\text{BOC}} \right)} \]  

where

- \( EV_2 \) is the pseudo-volumetric sweep efficiency, in decimal format;
- \( KR_{oil} \) is the NRG known oil recovery (cumulative production plus reported reserves), in thousands of barrels (Mbbl);
- 1,000 is the conversion factor needed to convert \( KR_{oil} \) to barrels (bbl);
- 7,758 is the conversion factor from acre-feet to barrels (bbl);
- \( \text{Area} \) is the reservoir area, in acres;
- \( \text{NetPay} \) is the net reservoir thickness, in feet (ft);
- \( \text{Por} \) is the porosity of the reservoir rock, in decimal format;
- \( \text{SOI} \) is the initial oil saturation, in decimal format;
- \( \text{SORW} \) is the residual oil saturation after waterflood, in decimal format;
- \( \text{BOI} \) is the initial oil formation volume factor, in decimal format; and
- \( \text{BOC} \) is the current oil formation volume factor, in decimal format.

Gas Reservoir and Fluid Properties

Current reservoir pressure (\( \text{PRESC} \)) for gas reservoirs is calculated the same as for oil reservoirs (equation 20).

Current gas saturation (\( \text{SGC} \)) is calculated using equation 38, when the initial gas formation volume factor (\( \text{BGI} \)) and the original gas in place (\( \text{OGIP} \)) are greater than zero:

\[ \text{SGC} = \frac{\text{OGIP} - \text{cumprod}}{\text{OGIP}} \times \text{SGI} \times \frac{\text{BGC}}{\text{BGI}} \]  

where

- \( \text{SGC} \) is the current gas saturation, in decimal format;
- \( \text{OGIP} \) is the original gas in place, in billions of cubic feet (Bcf);
- \( \text{cumprod} \) is the cumulative gas production, in billions of cubic feet (Bcf);
- \( \text{SGI} \) is the initial gas saturation, in decimal format;
- \( \text{BGC} \) is the current gas formation volume factor, in decimal format; and
- \( \text{BGI} \) is the initial gas formation volume factor, in decimal format.

Original gas in place (\( \text{OGIP} \)) is calculated in equation 39 as:

\[ \text{OGIP} = \text{GIPVOL} \times \text{area} \]  

where

- \( \text{OGIP} \) is the original gas in place, in standard cubic feet (Scf);
- \( \text{GIPVOL} \) is the original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre); and
- \( \text{area} \) is the reservoir area, in acres.

Original gas-in-place volume per reservoir area (\( \text{GIPVOL} \)) for conventional reservoirs is calculated in equation 40 as:

\[ \text{GIPVOL} = \frac{43,560 \times \text{Por} \times \text{NetPay} \times \text{SGI}}{0.02829 \times Z_i \times (T_{res} + 460)} \times \text{PRESC} \]  

where

- \( \text{GIPVOL} \) is the original gas-in-place volume per reservoir area, in standard cubic feet per acre (Scf/acre);
- 43,560 is the conversion factor from acre-feet to cubic feet (ft^3);
- \( \text{Por} \) is the porosity of reservoir rock, in decimal format;
- \( \text{NetPay} \) is the net reservoir thickness, in feet (ft);
- \( \text{SGI} \) is the initial gas saturation, in decimal format;
- 0.02829 is the conversion factor for the compressibility of gas at standard conditions (14.7 psia and 60 °F);
$Z_i$ is the initial gas compressibility factor;
460 is the conversion factor for degrees Rankine (°R);
$T_{res}$ is the reservoir temperature, in degrees Fahrenheit (°F); and
$PRESIN$ is the initial reservoir pressure, in pound-force per square inch absolute (psia).

**Initial gas formation volume factor** ($BGI$) is calculated in equation 41 as:

$$BGI = \frac{520 \times PRESIN}{14.7 \times Z_i \times (T_{res} + 460)} \quad (41)$$

where

- $BGI$ is the initial gas formation volume factor, in decimal format;
- 520 is the coefficient for the current gas formation volume factor;
- $PRESIN$ is the initial reservoir pressure, in pound-force per square inch absolute (psia);
- 14.7 is the standard atmospheric pressure, in pound-force per square inch (psi);
- $Z_i$ is the initial gas compressibility factor;
- $T_{res}$ is the initial reservoir temperature, in degrees Fahrenheit (°F); and
- 460 is the conversion factor for degrees Rankine (°R).

**Current gas formation volume factor** ($BGC$) is calculated in equation 42 as:

$$BGC = \frac{520 \times PRESC}{14.7 \times Z_c \times (T_{res} + 460)} \quad (42)$$

where

- $BGC$ is the current gas formation volume factor, in decimal format;
- 520 is the coefficient for the current gas formation volume factor;
- $PRESC$ is the current reservoir pressure, in pound-force per square inch absolute (psia);
- 14.7 is the standard atmospheric pressure, in pound-force per square inch (psi);
- $Z_c$ is the current gas compressibility factor;
- $T_{res}$ is the current reservoir temperature, in degrees Fahrenheit (°F); and
- 460 is the conversion factor for degrees Rankine (°R).

Generally, $Z_c$ is assumed to be equal to the initial gas compressibility factor ($Z_i$).

**Initial pressure for gas reservoirs** ($PRESIN$) is calculated with the same procedure as for the oil reservoir initial pressure in the absence of values in the NRG database.

**Current pressure for gas reservoirs** ($PRESIN$) is calculated using equation 43, where $Z_c$ is assumed to be equal to $Z_i$:

$$PRESIN = \frac{PRESIN}{Z_c} \times \left(1 - \frac{cumprod}{OGIP}\right) \quad (43)$$

where

- $PRESIN$ is the current reservoir pressure, in pound-force per square inch absolute (psia);
- $PRESIN$ is the initial reservoir pressure, in pound-force per square inch absolute (psia);
- $cumprod$ is the cumulative gas production, in billions of cubic feet (Bcf);
- $Z_c$ is the current gas compressibility factor;
- $Z_i$ is the initial gas compressibility factor; and
- $OGIP$ is the original gas in place, in billions of cubic feet (Bcf).

**Initial gas compressibility factor** ($Z_i$) is calculated as a function of the specific gravity of gas, its content of carbon dioxide (CO$_2$) and hydrogen sulfide (H$_2$S), reservoir pressure, and reservoir temperature, and is based on correlations described in Standing and Katz (1942) and Wichert and Aziz (1971).

**Specific gravity of the gas** ($SGG$) is provided by the NRG database, or if the value is not provided in the NRG database, it is estimated by the play or province average. If average data are not available the default value is 0.8.

**Reservoir water influx volume** ($WATIN$) is calculated by equation 44 as:

$$WATIN = cumprod \times BGC - OGIP \times (BGC - BGI) \quad (44)$$
where

- \( WATIN \) is the reservoir water influx volume, in billions of cubic feet (Bcf);
- \( cumprod \) is the cumulative gas production, in billions of cubic feet (Bcf);
- \( BGC \) is the current gas formation volume factor, in decimal format;
- \( OGIP \) is the original gas in place, in billions of cubic feet (Bcf); and
- \( BGI \) is the initial gas formation volume factor, in decimal format.

**Estimated ultimate recovery** (EUR) for gas reservoirs is calculated with equation 45 (in the equation the contaminant gases, CO\(_2\), N\(_2\), and H\(_2\)S are in molecular percent of the total gas in the reservoir):

\[
EUR = \frac{KR_{gas}}{(100 - CO_2 - N_2 - H_2S)} + 1.302 \times KR_{NGL}
\]  

(45)

where

- \( EUR \) is the estimated ultimate recovery, in billions of cubic feet (Bcf);
- \( KR_{gas} \) is the NRG known gas recovery (cumulative production plus reported reserves), in millions of cubic feet (MMcf);
- \( CO_2 \) is carbon dioxide;
- \( N_2 \) is nitrogen;
- \( H_2S \) is hydrogen sulfide;
- 1.302 is the natural gas liquids (NGL) conversion factor; and
- \( KR_{NGL} \) is the NRG known natural gas liquids (NGL) recovery (cumulative production plus reported reserves) in thousands of barrels (Mbbl).

The EUR is the raw gas volume and includes the gas contaminants CO\(_2\), N\(_2\), and H\(_2\)S. The \( KR_{gas} \) and \( KR_{NGL} \) data are in the form of marketable gas (cumulative production plus reported reserves) and natural gas liquids, as reported in the NRG database at the end of 2010. All \( KR_{gas} \) and \( KR_{NGL} \) data used as inputs to the equations are from NRG database. The natural gas liquids (NGL) conversion factor converts barrels (bbl) to thousands of cubic feet (Mcf) using volume, and it is used to convert NGL to dry gas using British thermal units (Btu). These conversions are derived using equation 46:

\[
1.302 = \frac{5.614}{\frac{5.418}{1.250}}
\]  

(46)

where

- 1.302 is the natural gas liquids (NGL) conversion factor;
- 5.614 is the assumed cubic feet of gas per barrel of oil;
- 5.418 is million British thermal units per barrel of plant condensate (U.S. Energy Information Administration, 2012); and
- 1.250 is the assumed average British thermal units per cubic foot (Btu/ft\(^3\)) of liquids-rich dry gas (Braziel, 2012).

**Gas reservoir recovery factor** (RECY) is calculated using equation 47 as:

\[ RECY = \frac{EUR}{ACPROD \times GIPVOL} \]  

(47)

where

- \( RECY \) is the gas reservoir recovery factor, in decimal format;
- \( EUR \) is the estimated ultimate recovery, in standard cubic feet (Scf);
- \( ACPROD \) is the producing area, in acres; and
- \( GIPVOL \) is the original gas-in-place volume per unit area, in standard cubic feet per acre (Scf/acre).
Summary

The Comprehensive Resource Database (CRD) was developed to support hydrocarbon assessments prepared by the U.S. Geological Survey (USGS). The CRD contains the location, key petrophysical properties, production, and well counts for the major oil and gas reservoirs in the onshore and State waters areas of the conterminous United States and Alaska. The data within the CRD cannot be released to the public because it includes proprietary field and reservoir petrophysical property data from the Nehring Associates (2012) “Significant Oil and Gas Fields of the United States Database” and proprietary production and drilling data from “Petroleum Information Data Model Relational U.S. Well Data” prepared by IHS Inc. (2012). This report provides a description of (1) the CRD computer program and its methodology, (2) a list of the key data sources used in its development, (3) a description of the steps and routines used to prepare the CRD, (4) the screening criteria for miscible or immiscible CO$_2$ flooding applied to the CRD, (5) the database outputs, and (6) documentation of the computational procedures that were applied. The equations used in the calculations, a list of the input and output reservoir property data and variables, the computer code, and the CRD are on file at the USGS Eastern Energy Resources Science Center located in Reston, Va.

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