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TORIS DATA PREPARATION GUIDELINES

Final Report
March 1995

By
Hugh Guinn
Don Remson

March 1999

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BDM-Oklahoma, Inc.
Bartlesville, Oklahoma

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Rhonda Lindsey, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
BDM-Oklahoma, Inc.
P.O. Box 2565
Bartlesville, OK 73005

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1.0 Overview

The objective of this manual is to present guidelines and procedures for the preparation of new data for the Tertiary Oil Recovery Information System (TORIS) data base. TORIS is an analytical system currently maintained by the Department of Energy's (DOE) Bartlesville Project Office. It uses an extensive field- and reservoir-level data base to evaluate the technical and economic recovery potential of specific crude oil reservoirs.

The data base has been continuously updated and expanded in order to maintain the system's usefulness as a research tool; therefore, data acquisition from various state agencies and contractors is necessary. In the past, the data received have been frequently plagued with errors and inconsistencies which seem to indicate that the data prepares were not aware of which data elements are critical to TORIS and how they are used in the models. The guidelines set forth herein should help assure better data quality as well as accelerate the process of bringing new reservoirs into the TORIS system.

This chapter presents the basic concepts of the TORIS system and data base as well as guidelines for the collection of accurate, critical, and useful data. The chapter is organized into the following sections:

- Section 2 presents an overview of the TORIS system, its application, and a description of the data base. A discussion of the original design of the system as well as the subsequent expansion of the system capability is also provided.

- Section 3 develops a set of procedures that: (1) acquaints data preparers with the TORIS system; (2) identifies the most critical reservoir/geology data elements to TORIS, and (3) guides the preparer in compiling data elements required for the reservoir/geology data file.

- Section 4 presents the format of specialty records needed to describe reservoirs amenable to steam and insitu combustion applications.

- Section 5 acquaints the data preparer with the format and structure of the TORIS Production Master File and all the data elements required for this file.

- Section 6 describes quality assurance procedures. It describes the data validation software provided on the diskette accompanying this guide and lists the errors frequently committed in the preparation of TORIS data.

- Appendix A summarizes all the required data for the Reservoir/Geology data file and provides tables that will help data preparers select appropriate geologic codes for this file.

- Appendix B provides a procedural guide to assist in the task of completing the geologic classification form.

- Appendix C provides a guideline to assist in the documentation of data sources.

2.0. TORIS System Overview

TORIS was originally developed by the National Petroleum Council (NPC) for its 1984 assessment of the nation's enhanced oil recovery (EOR) potential. The analysis was requested by the U.S. Secretary of Energy. In this effort, the EOR committee utilized and built upon data bases of individual oil reservoirs and computer models that were then under development by DOE, Office of Fossil Energy. After augmentation, adaptation, and validation, these oil reservoir data bases and models were remanded to the DOE's Bartlesville Project Office (BPO) for maintenance, updating, and subsequent application. The data bases and models become components of a larger system known as TORIS.

The TORIS data base currently contains over 2,540 oil reservoirs, accounting for over 64% of the original oil-in-place estimated to exist in discovered crude oil reservoirs in the U.S. TORIS utilizes its comprehensive data base and detailed engineering and economic methodologies at the reservoir level to estimate crude oil recovery, investment and operating costs, and ultimately project economics.

TORIS can analyze resource potential at two levels of technology: implemented and advanced. The implemented technology case assumes recovery processes that are currently available for implementation in the field. The advanced technology case assumes improvements in recovery technologies and reductions in extraction costs that will result from successful research and development (R&D) within a reasonable period of time. Each reservoir in the data base is subjected to a screening process to identify the technical applicability of alternative potential recovery processes.

TORIS is an analytical tool that has been utilized by DOE to support state agencies, federal agencies, Congress and industry by addressing broad policy issues in the areas of R&D, tax incentives, and environmental impacts. Through agreement with DOE, the Interstate Oil and Gas Compact Commission (IOGCC) has used the TORIS models and data base to evaluate the recovery potential by EOR and advanced secondary methods for its member States under a long-term project known as Advanced Oil Recovery and States.

2.1 Brief Description of the TORIS Models

The NPC's 1984 evaluation of the EOR resource focused on the recovery potential of immobile or water flood residual oil only. In 1988, the system's capabilities were expanded to include evaluation of the potential unrecovered mobile oil (UMO) in Texas, Oklahoma, and New Mexico. The system is being enlarged (beginning in 1993) to consider the recovery potential of extended primary and advanced secondary recovery (ASR) operations in unswept portions of the reservoir in a manner consistent with the NPC's EOR methodology. Currently, ASR and EOR analyses include such techniques as infill drilling, polymer water flood, profile modification, miscible CO2 flooding, alkaline and surfactant/polymer flooding, steam flooding, and in-situ combustion.

The system's approach follows a step-by-step evaluation process of each reservoir, as described below:

- *Reservoir Data Compilation.* Detailed data describing the properties of individual oil reservoirs are compiled. The data elements are then reviewed for accuracy and consistency before inclusion into the data base.

- *Resource Screening Models.* Each reservoir is subjected to a screening process based on its characteristics (e.g., depth, temperature, permeability) to identify the technical applicability of alternative recovery processes under implemented and advanced technology cases.

- *Process Performance Models.* Each reservoir that passes the screening criteria is then analyzed by a detailed process performance model at each level of technical applicability. These models estimate the reservoir's incremental oil recovery potential, as a function of reservoir properties and process design.

- *Economic Evaluation.* Each reservoir is then evaluated for its economic viability by estimating the income attributable to the incremental production and the investment, operating costs, and taxes required to support the process implementation as designed and installed in the field. Detailed costing algorithms reflect project design, reservoir depth, region, and other factors. A discounted cash flow analysis is conducted for each reservoir based on oil price and a specified rate of return.

- *Technology Development.* For each reservoir determined to be economic at a given oil price, the performance of each applicable recovery process is compared. Each reservoir is then assigned to the process that produces the greatest quantity of incremental oil.

2.2 Description of the Data Base

The TORIS data base consists of three entities: (1) the reservoir/geologic data file; (2) the Production Master File; and (3) the operator master file.

- *The Reservoir/Geologic Data File.* This data file is a field- and reservoir-level data base containing over 2,540 reservoirs representing more than 64% of the oil discovered to date in the United States. The file contains 5 records and 61 data elements per reservoir, and is the sole source for all the engineering and geologic data contained in TORIS.

- *Thermal Process-Specific Files.* These files contain override data used in the modeling of the steamflood and insitu combustion processes. The entries in this file allow the customization of the modeling of these processes by enabling the entry of override values for parameters normally contained in the Reservoir/Geologic file or calculated by the models.

- *The Production Master File.* The Production Master File (PMF) contains historical production data pertaining to fields and reservoirs included in the reservoir data base. The PMF currently contains production data for over 1,700 reservoirs in 25 States and represents 81% of the resource contained in the reservoir data base.

  The PMF contains annual oil production data beginning in 1970; annual gas and water production data beginning in 1981; annual producing oil well counts beginning in 1981; and cumulative oil, gas, and water production. The primary source of PMF data is the Petroleum Data System data base maintained by the Energy Information Agency (EIA). This data base is managed and updated by Dwight's Energy Data Inc.

- *The Operator Master File.* The Operator Master File was prepared for DOE by Petroleum Information Incorporated (PI). This file contains data for almost 14,000 operators producing from 2,185 reservoirs which represent about 84% of the resource contained in the TORIS reservoir data base. Key data elements in this file consist of oil and gas produced by each operator during 1989; total oil and gas produced by the operator during the years 1985 to 1989; the operator's share of production; and the number of wells produced by each operator.

3.0 Data Preparation for the Reservoir/Geologic Data File

The usefulness of TORIS as a planning tool is limited only by the accuracy of the data elements that serve as input into the TORIS models. Where feasible, the input data should be actual field/reservoir measured data, not derived or defaulted data. Critical data elements are used by the models to establish the basic reservoir descriptions while other data elements are used to reinforce or support the reservoir description.

3.1 General Data Element Requirements and Guidelines

The data elements have several levels of priority. Elements marked as "critical" (C) are essential to the models. Elements marked as "important" (I) and "derivable" (D) should be obtained wherever possible. Elements marked S will be supplied by the TORIS software. If an element is unobtainable or will be supplied by TORIS, a value of -1 should be entered into the data field. Sources of data should be recorded in a separate disk file in accordance with the instructions presented in Appendix C.

In the TORIS system, each reservoir is modeled as an aggregate of five spot (seven spot in in-situ combustion) patterns. The calculations are performed for only one quarter of the pattern. The solution is extrapolated to the entire five spot pattern and then to the entire reservoir. Because of this approach, the critical data elements which are part of the input file must be representative of the entire reservoir. These values must consist of weighted averages for the entire reservoir, not just the best nor the worst values from the reservoir. To pick a high or low value would be unduly optimistic or pessimistic for the reservoir as a whole.

The critical data elements which must submitted as weighted averages should be based on measurements recorded from individual wells. Examples are net and gross pay, porosity, saturation, depth, pressure, and permeability. In calculating an average value for these data elements the individual measurements should each be weighted by the reservoir volume of oil the measurement will represent. This means that each measurement should be weighted by :

$$A \cdot h \cdot \phi \cdot So_i$$

Sometimes production values are reported for an entire field instead of the individual reservoirs. TORIS modeling requires that this production be split out into the individual TORIS reservoirs. The most appropriate method to apportion this production into individual reservoirs is by their relative transmissivity. Calculate the product of:

$$k \cdot h \cdot \text{\# of producing wells in reservoir}$$

for each reservoir in the field. The ratio obtained by dividing this product by the sum of the products for all reservoirs in the field will represent the fraction of field production attributable to the reservoir.

3.2 Data File Format

The data elements are input into the Reservoir/Geologic data file. This ASCII file consists of an identification record which must be in a strict columnar format and the data records which are in free format. Within each of the fixed format lines, the numeric entries must be right justified and the alphabetic entries must be left justified.

The data file consists of five records per reservoir with up to 250 bytes per record. As shown in Table 1, the first record contains the basic identification for the reservoir. The next three records contain reservoir data and the last record contains geological descriptions of the reservoir. In this table, the source of tabular data and data lengths for record 1 are given in parentheses. For records 2 through 5, the units in which the data elements should be entered are given in parentheses. The priority code in the last column indicates the level of priority and importance in obtaining the data element.

Table 2 shows the format of Record 1. Records 2 through 5 have free formats (data are separated by a comma, a space, or a comma and a space). An example of free formats is shown here for records 2 through 4.

- Record 2 (comma delineated)
  400, 350, 40, 10, 35, 40, 18, 75, -1, 20, -1, 5, -1, 1.02, 1.04, 4115, 163

- Record 3 (space delineated)
  350 175 211 27 .32 210 25000 .33 0.11 11000 1993 -1 25 11000 1992

- Record 4 (space and commas delineated)
  325, 250 1 10, 0, 18 225 3, -1 0 1 1 0, -1 -1 41

Note that unlike Record 1, decimals are allowed in the other records and a value of (-1) is entered for unknown data or data that will be assigned by the TORIS System.

The summary of all required data elements in the Reservoir/Geologic data file is presented in Appendix A. The following subsections discuss the critical reservoir and geologic data elements in more detail.

Table 1 Toris Reservoir/Geologic File Format

5 Records per Reservoir

Record 1: Fixed Format (1X,I6,1X,A2,I2,1X,I3,1X,9A4,1X,12A4,1X,I5,1X,I4,1X,12A4)	Priority
DOE Field Code (6 digits) State Postal Code (Table A-7) (2 characters)	S C
Lithology Code (-1, 0=Unknown; 1=Sandstone; 2=Carbonate; 3=Dolomite) (2 digits) Geologic Age Code, AAPG (Table A-1) (3 digits)	C I
Field Name (36 characters) Reservoir Name (48 characters)	C C
DOE Reference Number (5 digits) Preparer's Reference Number (4 digits)	S C
Formation Name (48 characters)	C
Record 2: Free Read Format	
(1) Field Acres (Acres) (2) Proven Acres (Acres)	I C
(3) Well Spacing (Acres) (4) Total Wells (Number)	C D
(5) Net Pay (Feet) (6) Gross Pay (Feet)	C C
(7) Porosity (%) (8) Initial Oil Saturation (%)	C C
(9) Current Oil Saturation (%) (10) Initial Water Saturation (%)	I C
(11) Current Water Saturation (%) (12) Initial Gas Saturation (%)	I C
(13) Current Gas Saturation (%) (14) Initial Oil Formation Volume Factor (Res. BBL/STB)	I C
(15) Current Oil Formation Volume Factor (Res. BBL/STB) (16) True Vertical Depth (Feet)—Mid-Perforation	I C
(17) Formation Temperature (°F)	C

Table 1 (Continued)

Record 3: Free Read Format		Priority
(18)	Current Formation Pressure (PSI)	I
(19)	Permeability (MD)	C
(20)	Geologic Age Code, AAPG (Table A-1)	I
(21)	API Gravity (°API)	C
(22)	Oil Viscosity (CP) @ Reservoir Conditions	C
(23)	Formation Salinity (PPM TDS)	C
(24)	OOIP (BBL)	C
(25)	Primary Recovery Factor (Fraction of OOIP)	I
(26)	Secondary Recovery Factory (Fraction of OOIP)	I
(27)	Cumulative Oil Production (BBL)	C
(28)	Year for Cumulative Oil Production (Example: 1986)	I
(29)	Technical Availability Date (Year) (Example: 1990)	S
(30)	Primary Recovery (BBL/AC.-FT.)	I
(31)	Primary Recovery (BBL)	I
(32)	Year For Primary Recovery (Example: 1984)	I
(33)	Current Producing GOR (SCF/BBL)	I
(34)	Initial Producing GOR (SCF/BBL)	I
Record 4: Free Read Format		
(35)	Reservoir Acres (Acres)	C
(36)	Initial Formation Pressure (PSI)	I
(37)	Reservoir Dip (Degrees)	I
(38)	Production Wells (Number)	C
(39)	Injection Wells (Number)	C
(40)	Swept Zone Oil Saturation (%) (Residual to Water)	I
(41)	Injection Water Salinity (PPM TDS)	I
(42)	Clay Content (%)	I
(43)	Dykstra-Parsons Coefficient (Fraction)	I
(44)	Current Injection Rate (BBL/Day/Well)	I

Table 1 (Continued)

		Priority
(45)	Fractured-Fault (Y,N; N=0, Y=1)	I
(46)	Shale Break or Laminations (Y,N; N=0, Y=1)	I
(47)	Major Gas Cap (Y,N; N=0, Y=1)	I
(48)	Reserved for future expansion	S
(49)	District Code (California and Texas RRC Only)	C
(50)	Production Rate (MBBL/Day) for the Year Shown in Element 28	I
(51)	Ultimate Recovery Factor, Fraction of OOIP (Primary plus Secondary)	S
Record 5: Free Read Format		
(52)	Geologic Play (Four-digit integer code as shown in Table A-2)	C
(53)	Depositional System (Three-digit integer code as shown in Table A-3)	C
(54)	Depositional System Degree of Confidence (One-digit integer code; 1=Highest, 2=Moderate, 3=Lowest)	I
(55)	Diagenetic Overprint (Two-digit integer code as shown in Table A-4)	C
(56)	Diagenetic Overprint Degree of Confidence (One-digit integer code; 1=Highest, 2=Moderate, 3=Lowest)	I
(57)	Structural Compartmentalization (Two-digit integer code as shown in Table A-5)	C
(58)	Structural Compartmentalization Degree of Confidence (One-digit integer code; 1=Highest, 2=Moderate, 3=Lowest)	I
(59)	Predominant Element of Reservoir Heterogeneity (One-digit integer code; 1=Depositional System, 2=Diagenetic Overprint, 3=Structural Compartmentalization)	I
(60)	Trap Type (One-digit integer code; 1=Stratigraphic, 2=Structural, 3=Combination)	I
(61)	Geologic Province (Three-digit integer code as shown in Table A-6)	C

Priority Legend

C	Critical	Of highest importance. In many cases, the models will not run without this parameter
I	Important	Should be obtained if at all possible
D	Derivable	Parameter is routinely derived by models through values of other elements or through correlations
S	Supplied	Will be supplied by DOE regardless of value given (enter -1)

Table 2 Reservoir / Geologic File Format - Record 1

```
         1         2         3         4         5         6         7         8
12345678901234567890123456789012345678901234567890123456789012345678901234567890
ƀNNNNNNƀAANNƀNNNƀAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAƀAAAAAAAAAAAAAAAAAAAAAAAAAA
 <---->  <> <>  <->  <---------------------------------->  <-----------------------
 Field   |  |   |    Field Name (36 characters)             Reservoir Name (48 characters)
 Code    |  |   |--> Geologic Age Code
         |  |------> Lithology Code
         |---------> State Postal Code

                              1         1         1         1         1         1
         9                    0         1         2         3         4         5         6
1234567890123456789012345678901234567890123456789012345678901234567890123456789012
AAAAAAAAAAAAAAAAAAAAAAƀNNNNNƀNNNNƀAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAAA
---------------------> <---> <--> <---------------------------------------------->
                       |     |    Formation Name (48 characters)
                       |     |--> Preparer's Reference Number
                       |--------> DOE Reference Number
```

A = Alphabetic Character (Left Justified)
N = Numeric Character (Right Justified)
ƀ = Blank

3.3 Review of Critical Reservoir Data Elements

The following is a detailed review of the critical and more important reservoir data elements in the Reservoir/Geology data file. The descriptions of the elements are generally presented in the order of their position in the data file.

- *State Postal Code.* A two-character postal abbreviation (e.g., CA, TX, etc.) of the name of the state in which the reservoir is located. Table A-7 contains a comprehensive list of these codes

- *Lithology Code.* A numeric code describing the predominant lithology in the reservoir (Sandstone, Carbonate, or Dolomite). A distinction is made between a calcareous sandstone and a sandy limestone. The former is a sandstone and the latter is a limestone.

- *Field Name.* The officially registered field name, with no abbreviation.

- *Reservoir Name and Formation Name.* The officially registered full names. Abbreviations will not be accepted. The Reservoir Name is not necessarily the same as the Formation Name. While reservoirs are almost always named after the geologic formation in which they reside, this is not the case in every situation.

- *Preparer's Reference Number.* An arbitrarily-assigned integer number in the range of 8001 to 9999. The number assigned to each field/reservoir entity must be unique and the reference numbers of a reservoir which exists in both the reservoir and production files must be *identical.*

- *Reservoir Acres (Acres).* The actual surface of the reservoir - corrected for dipping, folding, faulting, or other distortions of the rock. Note that this definition may result in the reservoir acres being greater than the field acres for highly slanted or distorted formations. This is the acreage used in the volumetric calculation of OOIP.

- *Proven Acres (Acres).* That part of the reservoir that has been developed by drilling and has been in communication with the well bores.

- *Well Spacing (Acres).* The result obtained when the proven acreage is divided by the actual number of wells in the reservoir. The TORIS value for Well Spacing for a reservoir may differ considerably from that obtained using the traditional concept of well spacing. For example, consider that it is planned to develop the XYZ Field's A Reservoir on a 40 acre spacing. But currently there are 10 injectors and 5 producers in the field and only 5 injectors and 2 producers are completed in the A reservoir. Given that there are 400 proven acres in this reservoir, this would yield a 57 acre spacing (400/7) and not the eventual planned 40 acre spacing.

- *Net Pay (Feet).* That portion of the oil interval in the reservoir which is determined to have reservoir quality values of permeability and porosity. The methods of determining net pay cutoff limits and the means of measuring them are region specific and are generally based on prior experience. Do not include any gas zones in the net pay determination.

- *Gross Pay (Feet).* The thickness of the entire oil interval in the reservoir including intervals which fall below the permeability and porosity standards used to determine net pay. This element is primarily used by the steamflood model in accounting for heat loss. Do not include any gas zones in the gross pay determination.

- *Porosity (%).* Obtained from whole core studies or more commonly from electric log data. This should be the porosity value used in calculating Swi, from which Soi is obtained. The value must be a weighted average representative of the entire reservoir and must be greater then 7%. The source of the porosity data should be documented in the source file. Appendix C gives an example of a source file.

- *Initial Oil, Gas and Water Saturation, (%).* These values should be determined at reservoir conditions and should represent the entire reservoir. The values are usually derived from electric log analysis. The three saturations must sum to 100 percent.

- *Initial Formation Volume Factor, Boi (Res. BBL/STB).* The value at initial conditions best obtained from a fluid analysis test. The next best method of obtaining Boi is to estimate it using empirical correlations. Again, this should be a representative value for the entire reservoir.

- *True Vertical Depth (Feet).* The distance from the Kelly Bushing to the mid-point of the perforations in the reservoir under consideration, expressed as a positive (not subsea) number. This should be a representative value for the entire reservoir.

- *Formation Temperature (°F).* The best source for this datum is usually the maximum recorded temperature from the electric wireline logs or temperature logs. Both numbers should be corrected for "time since circulation stopped" to get a correct static reservoir temperature. Downhole samplers often include high-quality temperature measuring devices and should not be overlooked as possible sources. If no temperature measurement is available, it is acceptable to use the local temperature gradient to calculate the temperature at the midpoint of the perforations. Regardless of which source is used, it must be documented.

- *Permeability (MD).* The effective, dynamic, horizontal permeability of the reservoir in millidarcies. Preferentially this should come from whole core studies, but it may be calculated from pressure buildup test or sidewall core analysis.

- *API Gravity (°API).* The initial producing API gravity of the oil, as specified in the American Petroleum Institute guidelines. This value should be taken from early producing data before the introduction of stimulating fluids which could alter the composition of the produced oil. It is permissible to approximate the gravity from field curves. This should be a representative value for the entire reservoir.

- *Oil Viscosity (CP).* The dynamic oil viscosity. It is generally estimated by correcting the easily measured dead oil viscosity for reservoir temperature, pressure, and gas in solution. The source of the data should be documented in the source file.

- *Formation Salinity (PPM TDS).* The total dissolved solids in parts per million, best obtained from the downhole sampler or with a lesser degree of accuracy from the BS&W count at the surface separator. This surface sample must taken early in the production, before any stimulation fluids are added. Alternately, it can be obtained after all of the stimulation fluids have disappeared from the stream. Formation salinity is an important data element as it is used as a screen for types of chemical and polymer floods.

- *OOIP (BBL).* The OOIP for this system *must be volumetrically derived.* Since the TORIS models use rock and fluid properties to estimate tertiary recovery, the OOIP must represent those physical quantities. This means that the OOIP must be consistent with the volumetric data. OOIPs derived from material balance equations or from decline curves will not necessarily agree with the volumetric OOIP. The volumetric equation used to determine OOIP is as follows:

$$OOIP = \frac{7758 A h \phi So_i}{Bo_i}$$

where

OOIP	=	Volumetric Original Oil in Place (bbl)
A	=	Reservoir Area (acres)
h	=	net pay (feet)
ϕ	=	porosity (fraction)
So_i	=	Initial Oil Saturation (fraction)
Bo_i	=	Initial Formation Volume Factor (res. bbl/stb)

- *Cumulative Oil Production (BBL).* The cumulative oil production as of the last full calendar year for which there are complete data. The combined cumulative production for the field needs to be apportioned into the individual reservoirs. This may be accomplished by using a weight-averaging technique which considers the proven acreage as well as transmissibility.

- *Year for Cumulative Oil Production.* The year associated with the cumulative production determined above, expressed as a 4-digit integer number (example: 1993).

- *Current Producing GOR (SCF/BBL).* This should be obtained preferably from downhole samples or surface separator volumes, but it can be calculated from the current (last full year's) gas production divided by that year's oil production.

- *Number of Production Wells.* The number of currently *active* producing wells. This data element is essential for economic analysis to determine the number of wells that need to be drilled in the future.

- *Number of Injection Wells.* The number of injectors currently completed in the reservoir. This number does not include disposal wells. The sum of production and injection wells should equal to the total number of wells entered in the database.

- *District Code.* This code is important for California and Texas only. For all California districts and those Texas districts which have a strictly numeric code, enter the district code directly. Some Texas district codes may consist of a numeric part and an alphabetic part (for example, 8A). To obtain the TORIS code for such districts, multiply the numeric part by 10 and replace the alphabetic part with A=1, B=2, C=3, etc. Then add the two numbers. Therefore Texas district 8A would be entered as $8 \times 10 + 1 = 81$.

3.4 Review of Critical Geologic Data Elements

Record 5 in the Reservoir/Geology data file contains various types of geologic data. Some of the data can be assigned directly by inspection of the Geologic Tables (Tables A-1 through A-6) in Appendix A. The Diagenetic Overprint (55), the Structural Compartmentalization (57), and the Geologic Province (61) can be picked directly from the Tables. If the reservoir in question matches one of the Geologic Plays (52) or Depositional Systems (53) listed in Appendix A, then enter that code. If not, then the preparer should assign a new code. The new code should be constructed such that it is numerically higher than the highest code in the applicable table. All new codes must be thoroughly documented in writing by the preparer when the data are submitted to the DOE.

3.5 Description of Geologic Reservoir Classification System

The following discussion will help familiarize the data preparer with the geological classification system used in TORIS. The classification in TORIS incorporates an individual assessment of the: (1) depositional system, (2) diagenetic overprint, and (3) structural compartmentalization, in order that the reservoir can be compared to other reservoirs with similar properties.

In practice, the primary decision in applying the classification first requires the determination of the lithology of the reservoir, i.e., carbonate or siliciclastic. Each lithologic type is secondarily characterized by the three basic elements as outlined in Figure 1. Each element axis includes a series of categories that are designed to include the range of most likely possibilities for that particular element but still be mutually exclusive. Each category has been further subdivided into subcategories in order to capture more detailed facies information if it is available.

Definition and characteristics of individual categories of the element axes are based on current acceptable usage as defined in standard geologic texts (Scholle and Spearing, 1982; Scholle et al., 1983; Galloway and Hobday, 1983; McDonald and Surdam, 1984; and Roehl and Choquette, 1985). Boundary conditions between categories are gradational and by their very nature interpretive, thus creating a subjective element in the classification. However, the categories are made sufficiently broad in order to minimize differences in interpretation.

Depositional System. The physical, chemical, and biologic processes active in specific depositional environments and resulting depositional facies determine many attributes that are directly or indirectly related to hydrocarbon generation, migration, entrapment, and reservoir producibility (Fisher and Galloway, 1983).

The concept of depositional systems (Fisher et al., 1969) encompasses interpretation of depositional environments and implies that component facies are spatially related and comprise predictable three-dimensional stratigraphic units. Recognition and delineation of depositional systems provide a framework for facies differentiation and mapping. This approach to facies analysis relies heavily on reconstruction of basin morphology and bedding architecture, determination of gross lithology, and recognition of vertical and lateral succession of facies that comprise individual reservoirs.

Carbonate Reservoirs

Depositional System	Diagenetic Overprint	Structural Compartment
Lacustrine	Compaction/ Cementation	Unstructured
Peretidal	Grain Enhancement	Natural Fracture Porosity
Shallow Shelf	Dolomitization (Evaporites)	Faulted
Shelf Edge	Dolomitization	Folded
Reef	Massive Dissolution	
Slope/Basin	Silicification	
Basin		

Siliciclastic Reservoirs

Depositional System	Diagenetic Overprint	Structural Compartment
Eolian	Compaction/ Cementation	Unstructured
Lacustrine	Grain Dissolution	Natural Fracture Porosity
Alluvial Fan	Authigenic Clay	Faulted
Fluvial	Chertification	Folded
Delta		Faulted/ Folded
Strandplain		
Shelf		
Slope/Basin		
Deep Basin		

Figure 1 Geological Reservoir Classification System

Individual components of a depositional system can have gradational or sharp lateral and vertical boundaries. Delineation of facies components provides the basis for establishing the field-wide internal reservoir architectural style. In most cases, individual reservoirs produce from more than one facies because reservoir quality facies can be vertically stacked and laterally juxtaposed. Variations within an individual facies component produce reservoir heterogeneities at an intra-reservoir scale.

The depositional system categories and their component facies as used in this classification have been defined in sufficiently broad terms to group more discrete depositional entities together in order to keep subjectivity to a minimum. Subdivisions of the categories have been defined to capture more detailed descriptions of depositional systems if available.

Carbonate Depositional Systems. In the classification used here seven major carbonate depositional categories are recognized (See Figure 2). The categories are differentiated primarily based on position of their depositional environment as a function of relative water depth and basin morphology. Table 3 provides the subcategories to capture more detailed facies information if readily available.

- *Lacustrine carbonates* are best known as source rocks for lacustrine siliciclastic reservoirs (Dean and Fouch, 1983). They form the principal oil-shale deposits of the Green River Formation in the western United States. Carbonate lacustrine reservoirs are not common. An example is the fractured carbonates of the Green River Formation, located in the Uinta Basin in Utah.

- *Peritidal reservoirs* are composed of sediments that were deposited in subtidal to supratidal environments on and adjacent to tidal flats. Fenestral and pisolite porosity is locally well developed in supratidal mudstones and grainstones, but most production is from subtidal grainstones deposited as bars and beaches and associated dolomitized wackestones. Examples are the Slaughter/Levelland (San Andres) reservoirs in the Permian Basin and the Red River reservoirs in the Williston Basin. These reservoirs produce from stacked subtidal-supratidal cycles. Supratidal, intertidal, and subtidal facies are broken out as subcategories.

- *Shallow shelf reservoirs* are developed in a wide variety of facies that were deposited on a broad carbonate platform under shallow water depths. The best reservoir facies include locally developed grainstones, deposited as bars, reworked beaches and reefs. Associated widespread burrowed wackestones and packstones represent carbonates deposited under quiet-water conditions below wave base. The low-energy carbonates locally provide reservoirs particularly where regionally dolomitized or locally dolomitized. Examples are the Wasson (San Andres) reservoir in the Permian Basin and the Mondak (Mississippian) reservoir in the Williston Basin. Open shelf and restricted shelf subcategories are based on open marine versus restricted marine fossil assemblages.

TABLE 3 Depositional Systems - Carbonate Reservoirs

- Lacustrine

- Peritidal
  - Supratidal (sup)
  - Intertidal (it)
  - Subtidal (sub)

- Shallow Shelf
  - Open shelf (os)
  - Restricted shelf (rs)

- Shelf margin
  - Rimmed shelf (rs)
  - Ramp (rp)

- Reef
  - Pinnacle (pin)
  - Bioherm (bio)
  - Atoll (at)

- Slope/Basin
  - Debris fan (df)
  - Turbidite fans (tf)
  - Mounds (m)

- Basin
  - Drowned shelf (ds)
  - Deep basin (db)

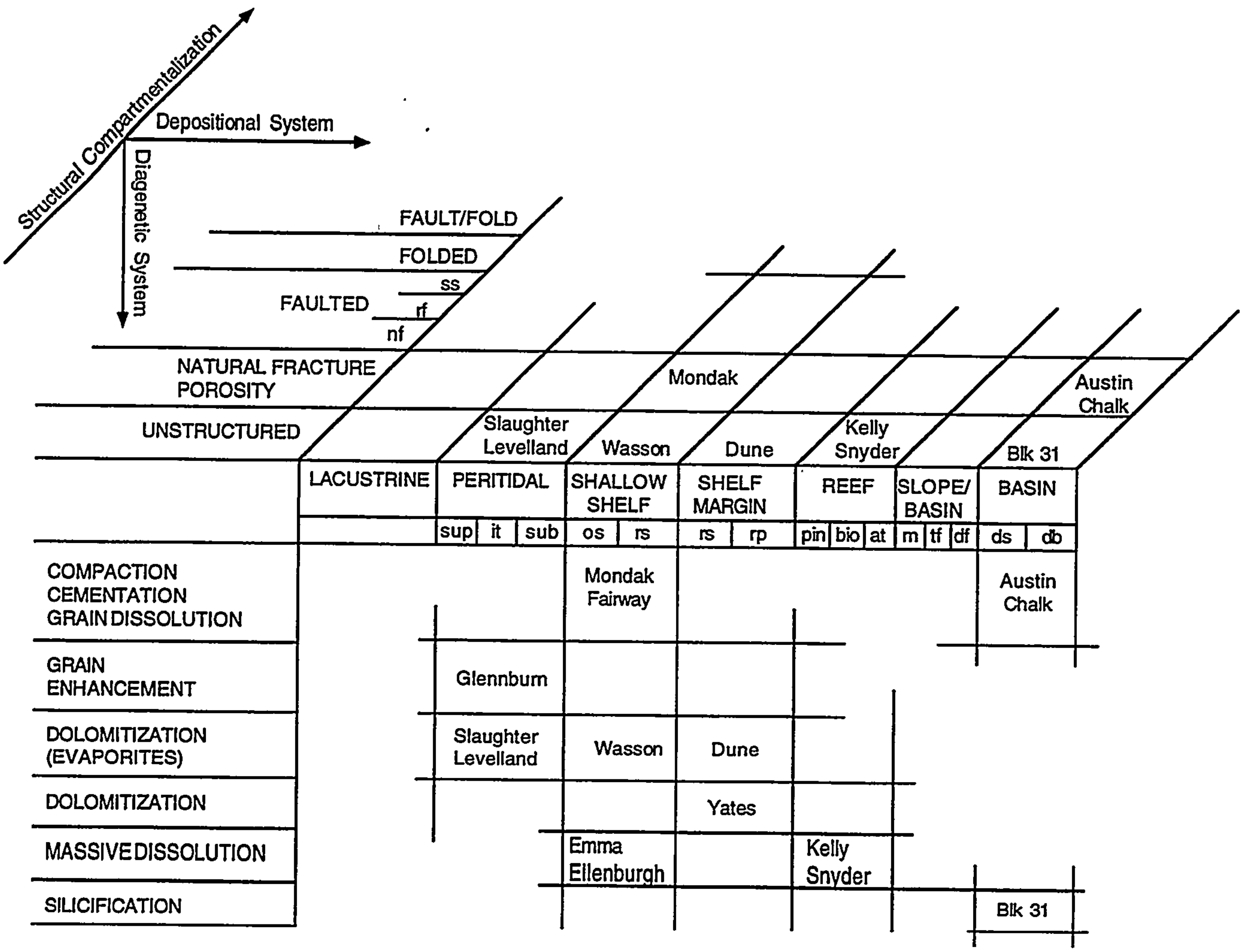

Figure 2 Geologic Classification - Carbonate Reservoirs

- *Shelf-edge reservoirs* produce from thick sections of subtidal grainstone bars and banks deposited along the outer edge of carbonate platform or ramps. Carbonate facies deposited in these settings lack well-defined reefs and are characterized by broad, low-relief bar, bank, and island facies deposited under low- to high-energy conditions. The Grayburg reservoirs of the Dune and McElroy fields along the eastern edge of the Central Basin Platform, West Texas, are examples of this type of reservoir. Two subcategories of the shelf-edge reservoirs are recognized: rimmed shelves, which may contain a barrier reef facies, and ramps.

- *Reef reservoirs* produce from stratigraphic reefs which commonly attain significant topographic relief. Framework and binding organisms are common constituents in the reef facies; associated facies include grainstones that accumulated as flanking beds around the reefs. Reefal reservoirs include the Michigan Basin pinnacle reefs and the Pennsylvanian /Permian Kelly Snyder reservoir of the Horseshoe Atoll, Midland Basin, Texas. Reefal reservoirs are further subdivided into pinnacle reefs, atolls, and bioherms.

- *Slope/Basin reservoirs* are developed in carbonate submarine-fan and debris-flow deposits associated with basin slopes. Reservoirs developed in these deeper basinal positions are not common, but examples are known in the Bone Springs Formation in the Delaware Basin, West Texas, and the Poza Rica trend in northern Mexico. This category is subdivided into turbidity flows, debris flows, and carbonate mounds.

- *Basinal reservoirs* occur in chalk deposits that accumulated from the raining down of pelagic organisms (coccoliths, coccospheres) onto drowned platforms and basin floors. Scholle and others (1983) recognize three categories of chalk reservoirs: (1) those that have never been deeply buried, lack significant compaction, and have high primary porosity (Niobrara Formation of western Kansas, eastern Colorado, and Nebraska); (2) those that have been buried to a moderate depth and must be extensively fractured to enhance porosity (Austin Chalk on the Texas Gulf Coast); and (3) those that have been deeply buried but with high pore pressure to preserve high primary porosity. The category is subdivided into basin floor and drowned platforms based on basin morphology.

Siliciclastic Depositional Systems. Nine categories of siliciclastic depositional systems are defined in the classification (See Figure 3). The categories are differentiated, similar to the carbonates, on the basis of depositional environment as a function of water depth and inferred sedimentary processes. Table 4 provides subcategories to capture more detailed facies information if available.

- *Eolian reservoirs* can develop in a variety of depositional environments, e.g., associated with alluvial fans and braided streams, coastal zones, as well as desert regions. The geometry and internal characteristics of eolian reservoirs vary as a function of their depositional environment. In general, they are characterized by their complex internal stratification and limited lateral continuity. The Rangely field (Weber) is an example of an eolian reservoir in western Colorado. Subcategories are ergs and coastal dunes. Subcategories are provided to capture more detailed facies information if available.

- *Lacustrine reservoirs* can be composed of a variety of sand-body types, e.g., beaches, deltas, and offshore bars that are associated with lakes. Examples of lacustrine reservoirs in the U.S. are the Duchesne field and Altamont field (Eocene) in the Uinta Basin in western Wyoming. Subcategories include basin margin and basin center.

- *Alluvial-fan reservoirs* are comprised primarily of braided-stream deposits. Alluvial fans are generally formed under relatively high-energy conditions, commonly along the front of higher standing mountain blocks. Alluvial-fan environments commonly grade downstream into braided-stream and/or playa-lake environments. Some fans build directly into standing bodies of water and are then referred to as fan deltas. Examples of alluvial-fan reservoirs include the Prudhoe Bay field (Triassic), North Slope of Alaska, and the Kern River field (Jurassic) of the San Joaquin Basin in California. Subcategories include stream-dominated fans, fan delta, and arid/semi-arid fans.

- *Fluvial reservoirs* are composed of sand-body types ranging from braided-stream sheets to coalescing point-bars of meandering streams. Fluvial reservoirs in general are characterized by their lack of lateral and vertical continuity. Meandering fluvial sheet sands in the form of coalescing point-bars are not as continuous as braided-sheet sands and are characterized by oxbow clay plugs that form lateral flow barriers and seals. Examples of fluvial reservoirs are the Cutbank field (Cretaceous) of northern Montana and the incised Morrow Channel fields (Pennsylvanian) of southeast Colorado and southwest Kansas. Subcategories are meandering and braided.

- *Deltaic reservoirs* in the main are characterized by distributary channel and stream-mouth bar type sand bodies and associated delta fringe strike sands. The size and shapes of deltas vary widely and, hence, so can the thickness and lateral extent of associated reservoirs. Based on the dispersal energy of the receiving basin relative to the volume of sediment being introduced, deltas can be generally placed into one of three subcategories. Fluvial-dominated deltas are characterized by higher concentrations of sand in distributary channels and stream-mouth bars. Wave-dominated deltas are characterized by thick sequences of well-sorted, strike beach deposits. Tide-dominated deltas are characterized by tidal channel and delta deposits. Examples of deltaic reservoirs are the Mercy and Livingston (Eocene) fields in southeast Texas and the giant East Texas Woodbine field (Cretaceous).

Table 4 Depositional Systems - Siliciclastic Reservoirs

- Eolian
  - Ergs (erg)
  - Coastal dunes (cd)
- Lacustrine
  - Basin margin (bm)
  - Basin center (bc)
- Alluvial Fan
  - Humid (stream-dominated) (h)
  - Arid/semi-arid (a)
  - Fan deltas (fd)
- Fluvial
  - Meandering (m)
  - Braided (b)
- Delta
  - Wave-dominated (wd)
  - Fluvial-dominated (fd)
  - Tide-dominated (td)
- Strandplain
  - Barrier core (bc)
  - Barrier shoreface (bs)
  - Back barrier (bb)
  - Tidal channel (tc)
  - Washover fan/Tidal delta (td)
- Shelf
  - Sand wave (sw)
  - Sand ridge/bars (sb)
- Slope/Basin
  - Turbidite fan (tf)
  - Debris fan (df)
- Deep Basin
  - Pelagic

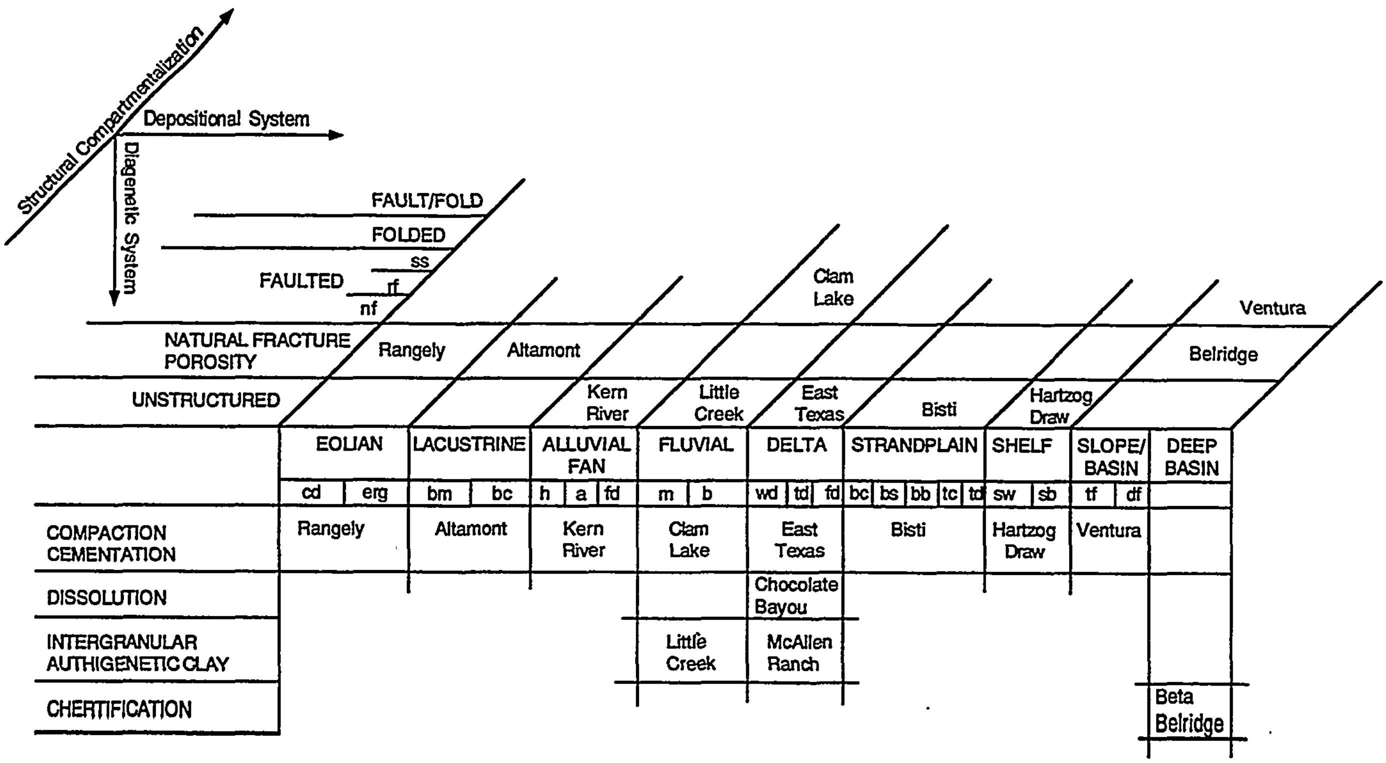

Figure 3 Geologic Classification - Siliciclastic Reservoirs

- *Strandplain reservoirs* occur in long narrow belts paralleling paleoshorelines. They are subdivided into a number of sand-body types: barrier core, barrier shoreface, back barrier, tidal channel, washover fan, and tidal delta. Barrier island core sand bodies are the highest quality strandplain reservoirs and are characterized by laterally continuous reservoirs in a strike sense. Examples of strandplain reservoirs are the Bisti field (Cretaceous) in the San Juan Basin and the TCB-East field (Oligocene) of South Texas.

- *Shelf reservoirs* are usually relatively thin and form poorer quality reservoirs. For the most part, they are comprised of sand ridge/bars composed of reworked deposits formed during a transgression. There are exceptions where thick sand waves can develop on shallow marine shelves and serve as excellent high-quality reservoirs. Examples of shelf reservoirs are the House Creek and Hartzog Draw fields (Cretaceous) in the Powder River Basin of Wyoming.

- *Slope/basin reservoirs* are divided into turbidite fans and debris fans. Submarine fans typically contain three distinct sand-body types: (1) thicker channel sands occur across the length of the upper and middle fan and thin downfan, (2) thinner lobate suprafan sands associated with distributary channels occur across the middle to distal end of the fan, and (3) thinly bedded sheet sands occur basinward of the fan proper. Fans, in general, provide excellent quality reservoirs. Examples of submarine-fan reservoirs are provided by the Tertiary fields in southern California, in particular the Elk Hills fields (Stevens) in the San Joaquin Basin and the Ventura field (Pliocene) in the Santa Barbara Basin.

- *Deep-basin reservoirs* are reserved for those pelagic siliceous deposits that have accumulated in deep ocean basins and tectonic trenches. In many instances these types of deposits serve as both a major hydrocarbon source and reservoir. Four conditions are required for their formation: (1) high production rates of diatoms, radiolarians, etc., (2) low dilution by terrigenous sourced sediments, (3) adequate burial for advanced diagenesis, and (4) fracturing of the resultant deposit to increase permeability and porosity. The most important deep-basin siliceous reservoirs in North America are those associated with the Monterey Formation (Miocene) in the southern California area.

Diagenetic Overprint. Diagenesis can be generally defined as the chemical, physical, and biological changes and alterations undergone by a sediment after its initial deposition and during and after its burial and lithification. It encompasses a wide range of processes, such as compaction, cementation, authigenesis, replacement, crystallization, leaching, hydration, bacterial action, and karsting, etc. Whereas depositional systems occupy a specific time and space and can be defined to have finite spatial boundaries, diagenetic processes cannot be so delineated. In contrast, multiple diagenetic processes can occur in the same space over variable time spans and with varying intensities.

Over the past few years, the importance of diagenetic processes in controlling reservoir quality has been better recognized. Many hydrocarbon reservoirs have significant diagenetic components directly affecting porosity and permeability characteristics. Modification of reservoirs by diagenetic processes can either reduce or enhance reservoir heterogeneities depending on specific circumstances.

In the classification presented here, diagenetic effects are not defined in spatial terms but in terms of the diagenetic processes that most directly influenced the present-day flow characteristics of the reservoir. The focus of the diagenetic overprint categories is on: (1) pore types present in the reservoir, (2) the diagenetic process most responsible for producing the pore types, and (3) the relationship of the pore types to reservoir-flow characteristics.

Carbonate Diagenesis. The most common diagenetic processes that nearly all carbonate reservoirs have undergone are compaction, cementation, and some degree of selective grain dissolution. Collectively, these processes are referred to as lithification. The most common pore types for this stage of diagenesis are intergranular and separate-vug. Compaction and cementation directly reduce intergranular pore space. Selective grain dissolution creates ineffective, nonconnected separate-vug pore spaces and provides a source of $CaCO_3$ for cementation of adjacent intergranular pore space. All three processes reduce reservoir quality. Categories of carbonate reservoir diagenesis include:

- The *grain enhancement* category is included to identify reservoirs in which early subaerial diagenetic processes improve reservoir quality by altering mud-dominated tidal-flat sediment to fenestral and interpisolitic pore types. An example is the Glenburn field, Mississippian of the Williston Basin (Gerhard, 1985).

- The *dolomitization with evaporites* category includes those reservoirs that produce from dolomites that contain considerable volumes of anhydrite or gypsum and whose principal pore types are intercrystalline, intergranular, and separate-vug. Examples are the Dune (Grayburg) reservoir and the Wasson (San Andres) reservoir of the Permian Basin.

- The *dolomitization* category is included to identify dolomite reservoirs that produce from intercrystalline, intergranular, and separate-vug pore types but do not contain sulfates. Yates (San Andres) field is an example of this category.

- The *massive dissolution* category is included because carbonates are susceptible to karsting processes that result in collapse breccias, connected vugs, cave fills, and fracturing. These processes are independent of lithology and, indeed, often provide flow paths for later dolomitizing solutions. The primary pore types in these reservoirs are fractures, interbreccia-block, large connected vugs, and caverns. Intercrystalline, intergranular, and separate-vug pore types may also be present. The Emma (Ellenburger) reservoir in West Texas is an example of this category.

- The *Silicification* of carbonate sediment is the dominant diagenetic process in some reservoirs. Pore space is located between small quartz crystals or globules and in small separate vugs. The Block 31 reservoir (Devonian) of the Permian Basin is an example.

Siliciclastic Diagenesis. Compaction and cementation are the major processes that reduce primary, intergranular porosity in sandstones. All sandstones lose some porosity by compaction and cementation, but extreme amounts of compaction, cementation, or both, can destroy almost all original porosity. Examples of reservoirs in this category include portions of the Nugget Sandstone in Anschutz Ranch East field, Utah, which have lost porosity dominantly by mechanical compaction and intergranular pressure solution, and the Travis Peak Formation in North Appleby field, East Texas Basin, which has lost porosity mainly by extensive quartz cementation.

- The *dissolution* category is restricted to intergranular dissolution. This process improves reservoir quality. Many oversized pores are probably hybrid, representing primary pores that have been enlarged by dissolution. An example of a reservoir in which porosity has been secondarily enhanced by dissolution is the Frio Formation in Chocolate Bayou field in coastal Texas.

- The precipitation of *interstitial clay* category in a sandstone will alter reservoir characteristics by increasing water saturation and decreasing permeability, while having little effect on porosity. Preservation of porosity at depth has been ascribed to the presence of clay coatings on sand grains. The most common authigenic clays are illite, smectite, mixed-layer illite-smectite, chlorite, and kaolinite. Dissolution of unstable framework grains, such as feldspars and rock fragments, results in the formation of grain molds and in the precipitation of interstitial clay. Examples include reservoirs that produce from the Aux Vases Formation in the Illinois Basin and the lower Tuscaloosa Little Creek reservoir in Mississippi.

- The *Chertification* category is not a common process, but it strongly influences reservoir properties where it occurs. Silica for chertification is derived from diagenetic alteration of siliceous organisms, forming a porcelaneous cement that later recrystallizes to chert. Reservoirs that contain abundant porcelaneous cement are characterized by high porosity but relative low permeability. Much of the total porosity in the rock is microporosity contained within the porcelaneous cement, and fluid flow is restricted in the micropore system. Examples include reservoirs in the Miocene Monterey Formation, California, and laterally equivalent turbidite sandstones in Beta and Wilmington fields, Los Angeles Basin.

Structural Compartmentalization. The structural compartmentalization element has been incorporated into the classification in order to identify those reservoirs where structural complexities have induced intra-reservoir heterogeneities that effectively compartmentalize or significantly alter production response of reservoirs. Examples include reservoirs where natural fracture porosity controls production performance, faulting partitions the reservoir, and where folding subdivides the reservoir. Structural compartmentalization is not to be confused with structural trap. The latter defines the reservoir boundaries, not the internal heterogeneity.

As in the case of diagenesis, structural activity can be recurring and results in superimposed structural elements. Therefore, the object of the classification is to select the structure category that best characterizes reservoir productivity. Five broad categories have been selected: (1) unstructured, (2) natural fracture porosity, (3) fault partitioned, (4) fold compartmentalized, and (5) combined folded and faulting.

- The *unstructured* category refers to reservoirs that do not exhibit significant structurally induced heterogeneities. Examples of unstructured reservoirs are the Dune (Grayburg) field in the Permian Basin and the East Texas (Woodbine) field.

- The *natural-fracture porosity* category is used to classify those reservoirs where tectonic fracture porosity is the principal permeability control in the reservoir. This category is reserved for fracture porosity produced principally by tectonic forces. Thus, massive dissolution reservoirs with fracture porosity resulting from collapse should not be included in this category. Examples of tectonically fractured reservoirs are Mondak (Mississippian) field, Williston Basin, and Spraberry (Permian) field, Permian Basin.

- The *fault* category should be selected only for those reservoirs where faults effectively compartmentalize the reservoir at the inter-reservoir scale and where natural fracture porosity is not significant. The Clam Lake field, a piercement salt-dome field in the Texas Gulf Coast, is an example of a fault-partitioned reservoir. The fault category has been further divided into normal, reverse, and strike-slip faults.

- The *fold* category is proposed for those instances where the reservoir has been effectively compartmentalized by complex folding. The combined fold and fault category has been added to classify those reservoirs where folding and faulting compartmentalized are equally important.

4.0 Preparation of the Thermal Process-Specific Data Files

As stated above, the thermal process-specific files contain override values for selected data elements used in the modeling of reservoirs in which it is technically feasible to attempt recovery using the steamflood and insitu combustion processes. This capability was provided in order to achieve predictions that more accurately reflect the conditions in individual reservoirs. Thus these files should be provided only when the values in the data base or provided by the model are not appropriate for modeling specific reservoirs. Table 5 lists the data to be provided for reservoirs which are steamflood candidates and Table 6 lists the data to be provided for reservoirs which are candidates for the insitu combustion process.

Table 5 Record Format for Data Overrides for Steamflood Candidate Reservoirs

1 Record per Reservoir

Record 1: Free Read Format	
(1)	DOE Reference Number
(2)	Preparer's Reference Number
(3)	Class (1=Ongoing; 2=Future)
(4)	Cost Scenario (1=Low cost; 2=Average cost; 3=High Cost)
(5)	Development Years (Years)
(6)	Fuel Type (0=Natural Gas; 1=Lease Crude)
(7)	Development Acres (Acres)
(8)	Generator Cost ($)
(9)	Generator Fuel Rating (BTU/UNIT)
(10)	Gross Thickness (Feet)
(11)	Injection Wells Drilled Per Pattern (Number)
(12)	Producing Wells Drilled Per Pattern (Number)
(13)	Natural Gas Price ($/MSCF)
(14)	Generator Fuel Price ($/UNIT)
(15)	Operating Cost ($MM)
(16)	Generator Operating Cost ($/BBL)
(17)	Pattern Spacing (Acres/Pattern)
(18)	Steam Rate (BCWE/Day/Pattern)
(19)	Reserved for Future Use

Review of Specialty Parameters for Steamflood Candidate Reservoirs

The following is a detailed review of the specialty data parameters which may be entered in the Steamflood Candidate Reservoir data file. The descriptions of the elements are presented in the order of their position in the data file.

- *DOE Reference Number.* Supplied by DOE (enter -1)

- *Preparer's Reference Number.* An arbitrarily-assigned integer number in the range of 8001 to 9999. The number assigned to each field/reservoir entity must be unique and match the reference number assigned to the same entity in the reservoir file.

- *Class.* An indication of the current status of the reservoir. Enter a 1 for a reservoir currently under steamflood. Enter a 2 to indicate that the reservoir is being considered for future steamflooding.

- *Cost Scenario.* A provision which enables the user to more closely approximate a suite of costs (operating, drilling, steam generation, etc.) for a specific reservoir which has exceptionally low or high costs. A value of 1 will cause the model to employ costs which are below average, 2 will invoke average costs (default), and 3 will invoke costs which are above average.

- *Development Years.* The number of years expected to elapse before all injector/producer patterns are completed. The default for this entry is 20 years.

- *Fuel Type.* A provision which allows the user to override the default assumption that lease crude is burned to provide steam. The user may enter a 0 to specify natural gas as the generator fuel.

- *Development Acres (Acres).* The total reservoir acreage which is slated to be developed. This value will be used preferentially over the value in data base element 35 (record 4).

- *Generator Cost ($).* The cost, dollars, of a single steam generation device. The purpose of this entry is to enable users to fine-tune their prediction by overriding the default generator cost.

- *Generator Fuel Rating (BTU/UNIT).* A measure of the capacity of the fuel (lease crude or natural gas) to produce heat, in units of British Thermal Units per barrel (lease crude) or British Thermal Units per thousand standard cubic feet (natural gas), depending on the fuel used to generate steam. This value must be consistent with the Fuel Type specified above.

- *Gross Pay (Feet).* The thickness of the entire oil interval in the reservoir including intervals which fall below the permeability and porosity standards used to determine net pay. This element is used by the steamflood model in accounting for heat loss. Do not include any gas zones in the gross pay determination. This value will be used preferentially over the value in data base element 6 (record 2).

- *Injection Wells Drilled Per Pattern.* An override for the value calculated by the model using the data from the first 51 elements of the data base. This enables the user to fine-tune the prediction.

- *Producing Wells Drilled Per Pattern.* The number of oil-producing wells in each pattern as an override to the data base. This number should be consistent with the number of injection wells or pattern geometry.

- *Natural Gas Price ($/MSCF).* The price of natural gas in dollars per thousand standard cubic feet. This price will be used in the model to calculate steam generation costs when the generator is fueled by natural gas.

- *Generator Fuel Price ($/UNIT).* The price of the fuel used to generate the steam for the flood. This value enables the user to assign a price to the crude oil used in generating steam. If natural gas is used to fuel the generator, the price must be identical to the Natural Gas Price.

- *Operating Cost ($MM).* The operating cost specific to the property under steamflood. This value overrides the default values provided in the model.

- *Generator Operating Cost ($/BBL).* The generator operating cost which reflects the known costs for a specific property under steamflood. This value overrides the default values provided in the model.

- *Pattern Spacing (Acres/Pattern).* The areal space occupied by one injection/production pattern. This entry enables the user to customize the number of patterns that will be developed during the steamflood.

- *Steam Rate (BCWE/Day/Pattern).* For a typical pattern, the rate at which steam is injected into the reservoir, in units of barrels of cold water equivalent per day per pattern.

Table 6 **Record Format for Data Overrides for Insitu Combustion Candidate Reservoirs**

1 Record per Reservoir

Record 1: Free Read Format	
(1)	DOE Reference Number
(2)	Preparer's Reference Number
(3)	Class (1=Ongoing; 2=Future)
(4)	Development Acres (Acres)
(5)	Development Years (Years)
(6)	Compressor Fuel (1=Lease Crude; 2=Natural Gas)
(7)	Air Injection Rate (MSCF/Day/Pattern)
(8)	Maximum Volume Swept (Fraction)
(9)	Compressor Cost ($/HP)
(10)	Injection Wells Drilled Per Pattern (Number)
(11)	Producing Wells Drilled Per Pattern (Number)
(12)	Net Pay (Feet)
(13)	Oil Price ($/BBL)
(14)	Fixed Operating Cost ($/Pattern)
(15)	Variable Operating Cost ($/Pattern)
(16)	Compressor Operating Cost ($/KWHP)
(17)	Type Fireflood (1=Wet; 2=Dry)
(18)	Current Oil Saturation (%)
(19)	Pattern Spacing (Acres)

Review of Specialty Parameters for In Situ Combustion Candidate Reservoirs

The following is a detailed review of all the data elements to be entered in the Insitu Combustion Candidate Reservoir data file. The descriptions of the elements are presented in the order of their position in the data file.

- *DOE Reference Number.* Supplied by DOE (enter -1).

- *Preparer's Reference Number.* An arbitrarily-assigned integer number in the range of 8001 to 9999. The number assigned to each field/reservoir entity must be unique and match the reference number assigned to the same entity in the reservoir file.

- *Class.* An indication of the current status of the reservoir. Enter a 1 for a reservoir currently being produced by insitu combustion. Enter a 2 to indicate that the reservoir is slated for a future insitu combustion project.

- *Development Acres (Acres).* The total reservoir acreage which is slated to be developed. This value will be used preferentially over the value in data base element 35 (record 4).

- *Development Years.* The number of years expected to elapse before all injector/producer patterns are completed. By default this entry will be set to approximately 20 years.

- *Compressor Fuel.* An indication of what kind of fuel is burned to power the compressors which supply air to the underground combustion process. A value of 1 indicates lease crude. An entry of 2 specifies natural gas (default).

- *Air Injection Rate (MSCF/Day/Pattern).* The rate at which air is injected into the reservoir in units of thousand standard cubic feet per day per pattern. This entry overrides the default value calculated by the model.

- *Maximum Volume Swept (Fraction).* The fraction of the reservoir expected to be contacted by the insitu combustion process. This value overrides the default value which is based on the pattern area.

- *Compressor Cost ($/HP).* The unit cost, dollars, of installing one horsepower of compressor capacity. This value enables the user to override the model-provided default in cases of exceptionally high or low compressor costs.

- *Injection Wells Drilled Per Pattern.* The number of air injection wells in each pattern (ongoing projects) or projected injection wells per pattern (future projects).

- *Producing Wells Drilled Per Pattern.* The number of oil-producing wells in each pattern (ongoing projects) or projected (future projects).

- *Net Pay (Feet).* That portion of the oil interval in the reservoir which is determined to have reservoir quality values of permeability and porosity. The methods of determining net pay cutoff limits and the means of measuring them are region specific and are generally based on prior experience. Do not include any gas zones in the net pay determination.

- *Oil Price ($/BBL).* The price of oil used as compressor fuel, in dollars per barrel.

- *Fixed Operating Cost ($/Pattern).* An override for model-provided defaults.

- *Variable Operating Cost ($/Pattern).* An override for model-provided defaults.

- *Compressor Operating Cost ($/KWHP).* An override for model-provided defaults.

- *Type Fireflood.* A value of 1 indicates the co-injection of water concurrently with the insitu combustion process; enter a 2 to indicate that no water is being injected.

- *Current Oil Saturation (%).* The saturation of the oil in the zone contacted by insitu combustion.

- *Pattern Spacing (Acres).* The areal space occupied by one injection/production pattern.

5.0 Preparation of the Production Data File

The TORIS Production data input file is simpler than the Reservoir/Geologic data input file. There are two fixed-format records (File Header Record and Record 1) and nine free-format records (Records 2-10) for each reservoir's production. All input data elements are critical to the model. Remember that all of the production data must be apportioned to the proper reservoirs and that the proportionality comes from the well counts and relative transmissibility. If a data element is unobtainable, a value of -1 should be entered into the data field. Table 7 summarizes the data elements contained in each record.

Table 7 TORIS Production Master File Format

FILE HEADER RECORD: Effective Years of Update (fixed format)

Character Position	Contents	Priority
1-1	Blank	-
2-5	Most recent year for annual oil production	C
6-6	Blank	-
7-10	Most recent year for annual gas production	C
11-11	Blank	-
12-15	Most recent year for annual water production	C
16-16	Blank	-
17-20	Most recent year for annual producing well counts	C

Record 1: Identification Information (fixed format)

Character Position	Contents	Priority
1-5	Preparer's Reference Number	C
6-6	Blank	-
7-41	Field name	C
42-43	Blank	-
44-78	Reservoir name	C
79-80	Blank	-
81-82	Numeric state code	C
83-83	Dash (-)	I
84-89	DOE field code	S
90-91	Blank	-
92-100	PDS unique identification number	S
101-114	Cumulative water injection (BBL)	I

Table 7 (Continued)

115-116	Blank	-
117-120	Year for cumulative water injection	I

Record 2: Annual Oil Production, 1970-1979 (free format)

Data Item	Contents	Priority
1	Annual oil production, 1970 (STB)	C
2	Annual oil production, 1971 (STB)	C
3	Annual oil production, 1972 (STB)	C
4	Annual oil production, 1973 (STB)	C
5	Annual oil production, 1974 (STB)	C
6	Annual oil production, 1975 (STB)	C
7	Annual oil production, 1976 (STB)	C
8	Annual oil production, 1977 (STB)	C
9	Annual oil production, 1978 (STB)	C
10	Annual oil production, 1979 (STB)	C

Record 3: Annual Oil Production, 1980–1989 (free format)

Data Item	Contents	Priority
1	Annual oil production, 1980 (STB)	C
2	Annual oil production, 1981 (STB)	C
3	Annual oil production, 1982 (STB)	C
4	Annual oil production, 1983 (STB)	C
5	Annual oil production, 1984 (STB)	C
6	Annual oil production, 1985 (STB)	C
7	Annual oil production, 1986 (STB)	C
8	Annual oil production, 1987 (STB)	C
9	Annual oil production, 1988 (STB)	C
10	Annual oil production, 1989 (STB)	C

Table 7 (Continued)

Record 4: Annual Oil Production, 1990-1999 (free format)

Data Item	Contents	Priority
1	Annual oil production, 1990 (STB)	C
2	Annual oil production, 1991 (STB)	C
3	Annual oil production, 1992 (STB)	C
4	Annual oil production, 1993 (STB)	C
5	Annual oil production, 1994 (STB)	C
6	Annual oil production, 1995 (STB)	C
7	Annual oil production, 1996 (STB)	C
8	Annual oil production, 1997 (STB)	C
9	Annual oil production, 1998 (STB)	C
10	Annual oil production, 1999 (STB)	C

Record 5: Annual Gas Production, 1981-1990 (free format)

Data Item	Contents	Priority
1	Annual gas production, 1981 (MSCF)	C
2	Annual gas production, 1982 (MSCF)	C
3	Annual gas production, 1983 (MSCF)	C
4	Annual gas production, 1984 (MSCF)	C
5	Annual gas production, 1985 (MSCF)	C
6	Annual gas production, 1986 (MSCF)	C
7	Annual gas production, 1987 (MSCF)	C
8	Annual gas production, 1988 (MSCF)	C
9	Annual gas production, 1989 (MSCF)	C
10	Annual gas production, 1990 (MSCF)	C

Table 7 (Continued)

Record 6: **Annual Gas Production, 1991-2000 (free format)**

Data Item	Contents	Priority
1	Annual gas production, 1991 (MSCF)	C
2	Annual gas production, 1992 (MSCF)	C
3	Annual gas production, 1993 (MSCF)	C
4	Annual gas production, 1994 (MSCF)	C
5	Annual gas production, 1995 (MSCF)	C
6	Annual gas production, 1996 (MSCF)	C
7	Annual gas production, 1997 (MSCF)	C
8	Annual gas production, 1998 (MSCF)	C
9	Annual gas production, 1999 (MSCF)	C
10	Annual gas production, 2000 (MSCF)	C

Record 7: **Annual Water Production, 1981-1990 (free format)**

Data Item	Contents	Priority
1	Annual water production, 1981 (STB)	C
2	Annual water production, 1982 (STB)	C
3	Annual water production, 1983 (STB)	C
4	Annual water production, 1984 (STB)	C
5	Annual water production, 1985 (STB)	C
6	Annual water production, 1986 (STB)	C
7	Annual water production, 1987 (STB)	C
8	Annual water production, 1988 (STB)	C
9	Annual water production, 1989 (STB)	C
10	Annual water production, 1990 (STB)	C

Table 7 (Continued)

Record 8: Annual Water Production, 1991-2000 (free format)

Data Item	Contents	Priority
1	Annual water production, 1991 (STB)	C
2	Annual water production, 1992 (STB)	C
3	Annual water production, 1993 (STB)	C
4	Annual water production, 1994 (STB)	C
5	Annual water production, 1995 (STB)	C
6	Annual water production, 1996 (STB)	C
7	Annual water production, 1997 (STB)	C
8	Annual water production, 1998 (STB)	C
9	Annual water production, 1999 (STB)	C
10	Annual water production, 2000 (STB)	C

Record 9: Cumulative Production and Producing Well Counts 1981-1990 (free format)

Data Item	Contents	Priority
1	Cumulative oil production (STB)	C
2	Year for cumulative oil production	C
3	Cumulative gas production (MSCF)	C
4	Year for cumulative gas production	C
5	Cumulative water production (BBL)	C
6	Year for cumulative water production	C
7	Annual producing well count, 1981	C
8	Annual producing well count, 1982	C
9	Annual producing well count, 1983	C
10	Annual producing well count, 1984	C
11	Annual producing well count, 1985	C
12	Annual producing well count, 1986	C
13	Annual producing well count, 1987	C

Table 7 (Continued)

Data Item	Contents	Priority
14	Annual producing well count, 1988	C
15	Annual producing well count, 1989	C
16	Annual producing well count, 1990	C

Record 10: Producing Well Counts 1991-2010 (free format)

Data Item	Contents	Priority
1	Annual producing well count, 1991	C
2	Annual producing well count, 1992	C
3	Annual producing well count, 1993	C
4	Annual producing well count, 1994	C
5	Annual producing well count, 1995	C
6	Annual producing well count, 1996	C
7	Annual producing well count, 1997	C
8	Annual producing well count, 1998	C
9	Annual producing well count, 1999	C
10	Annual producing well count, 2000	C
11	Annual producing well count, 2001	C
12	Annual producing well count, 2002	C
13	Annual producing well count, 2003	C
14	Annual producing well count, 2004	C
15	Annual producing well count, 2005	C
16	Annual producing well count, 2006	C
17	Annual producing well count, 2007	C
18	Annual producing well count, 2008	C
19	Annual producing well count, 2009	C
20	Annual producing well count, 2010	C

File Header Record

The file header record has a fixed format. The four entries in this record are numeric and represent years. The first entry is the most recent year for which there exists annual oil production. The second entry is the most recent year for which there is annual gas production and the third entry is the most recent year for which there is water production. The fourth entry is the most recent year for which there is information on annual producing wells. Note that all these entries imply full year's production or well count.

Record 1

The fixed format of this record includes the following elements (numeric entries should be right justified and alphabetic entries should be left-justified):

- *Reference Number.* The same reference number assigned to the field or reservoir in the Reservoir/Geology data file.
- *Field Name.* The field name, 35 characters or less, which should be the same as the field name in the Reservoir/Geology data file. If the field name is longer than 35 characters, truncate the name to 35 characters
- *Reservoir Name.* The reservoir name, 35 characters or less, which should be the same as the reservoir name in the Reservoir/Geology data file. If the reservoir name is longer than 35 characters, truncate the name to 35 characters
- *Numeric State Code.* The two-digit number identifying which state the field/reservoir is located in. This number should be obtained from Table A-7.
- *Dash.* Enter a dash (-).
- *DOE Field Code.* Supplied by TORIS (enter -1)
- *PDS Unique I.D. Number.* Supplied by TORIS (enter -1)
- *Cumulative Water Injection.* The cumulative water which has been injected into the reservoir, measured in barrels.
- *Year for Cumulative Water Injection.* The last full year for which there are complete water injection data, entered as a four-digit number.

Records 2 - 8

These records are entered in free format (comma delineated, space delineated, or comma and space delineated) as in the free format records of the Reservoir/Geologic data file. All data in Records

2, 3, and 4 represent the annual oil production from 1970-1999 in units of stock tank barrels. Records 5 and 6 are populated by the annual gas production for 1981-2000 in units thousands of standard cubic feet of gas. Records 7 and 8 contain annual water production for 1981-2000 in stock tank barrels.

Records 9 - 10

These two records are also in free format. Record 9 includes the following data elements:

- *Cumulative Oil Production.* The total cumulative oil production in stock tank barrels.
- *Year for Cumulative Oil Production.* The last full year for which there is oil production, entered as a four-digit number.
- *Cumulative Gas Production.* The total cumulative gas production in MSCF.
- *Year for Cumulative Gas Production.* The last full year for which there is gas production, entered as a four-digit number.
- *Cumulative Water Production.* The total cumulative water production in stock tank barrels
- *Year for Cumulative Water Production.* The last full year for which there is water production, entered as a four-digit number.

The remaining elements 7-16 of record 9 and all of the elements of record 10 are the number of producing wells in each year from 1981-2010.

The record descriptions shown in Table 7 will become obsolete at the turn of the century since they have no provision for annual oil production in the year 2000 or beyond. However, the TORIS production software is dimensioned such that without reprogramming, it can accommodate annual oil production data until the year 2029, annual gas and water production data until the year 2030, and annual producing well count data until the year 2030. Future expansion will be achieved by simply adding additional records of the appropriate type when needed to include annual production or well count data for a date that is beyond the system's current capability. The future records must be formatted as follows:

Record Type	Format
Annual Oil Production	Free format, 10 entries per record
Annual Gas Production	Free format, 10 entries per record
Annual Water Production	Free format, 10 entries per record
Producing Well Counts	Free format, 20 entries per record

NOTE: The purpose of the header record is to indicate to the TORIS software the maximum number of annual values respectively for oil, gas, and water production and producing well counts that can be expected for any reservoir in the file. Since the years in the header record apply globally to all the production data that follow, every reservoir in the file must contain precisely the maximum number of values for annual production and well counts implied by the pertinent date in the header record. Although the actual ending dates for the annual production and well count data may vary between individual fields/reservoirs and indeed are not required to be uniform for any given reservoir, the annual production and well count entries should be padded with values of -1 to achieve the number of values indicated by the pertinent date in the header record. For example, consider a Production data file whose header record contains the following dates:

Most recent year for annual oil production	1992
Most recent year for annual gas production	1992
Most recent year for annual water production	1991
Most recent year for annual producing well counts	1993

Each reservoir contained in the file should have the following number of years of annual data.

Annual oil production	23
Annual gas production	12
Annual water production	11
Annual producing well counts	13

If, for example, the most recent annual oil production datum for a reservoir in the file is 18000 barrels in 1990, then the value of 18000 in record 4 (see Table 7) should be followed by two occurrences of -1 (minus one) as follows:

18000, -1, -1.

6.0 Quality Assurance

6.1 Quality Assurance Software

The preparation of TORIS reservoir and production data requires considerable attention to detail. Regardless of how carefully it has been prepared, the first "cut" of new data is likely to contain errors. In order to assist the preparer with the detection of errors and inconsistencies, a computer program has been provided which will perform an extensive set of validations on the data. It is imperative that all data prepared for the TORIS system be verified by this program prior to submission to the DOE.

The processing performed by the program falls into four categories:

- Data entry error checks
- Checks for missing critical data
- Data consistency checks
- Checks for potential data errors

A complete list of the validations performed by the program on the reservoir and geologic data is given in Table 8. Table 9 lists the validations performed on the production data.

Table 8 Validations Performed on the Reservoir/Geologic Data by the TORISCHK Program

DATA ENTRY ERROR CHECKS

Invalid state postal code
Invalid lithology code
Invalid geologic age code
Initial oil, gas, or water saturation > 100 percent
Current oil, gas, or water saturation > 100 percent
Initial gas saturation + initial water saturation > 99 percent (gas condensate well)
Initial oil, gas, or water saturation entered as a fraction rather than as a percent
Current oil, gas, or water saturation entered as a fraction rather than as a percent
Primary recovery factor ≥ 1
Secondary recovery factor ≥ 1
Swept zone oil saturation > 100 percent
Swept zone oil saturation entered as a fraction
Clay content > 100 percent
Dykstra-Parsons coefficient ≥1
Ultimate recovery factor entered as a percent rather than as a fraction
Invalid geologic play code
Invalid depositional system code
Invalid depositional system code degree of confidence
Invalid diagenetic overprint code
Invalid diagenetic overprint degree of confidence
Invalid structural compartmentalization code
Invalid structural compartmentalization degree of confidence
Invalid predominant element of reservoir heterogeneity code
Invalid trap type code
Invalid geologic province code
Cumulative oil production > original mobile oil in place

CHECKS FOR MISSING CRITICAL DATA

Missing field name
Missing reservoir name
Missing preparer's reference number
Missing formation name
Missing proven acres
Missing well spacing
Missing net pay
Missing gross pay
Missing porosity
Missing both initial oil saturation and initial water saturation

DATA CONSISTENCY CHECKS

Well spacing * (number of production wells + number of injection wells) ≠ proven acres ± 5 percent
Total wells ≠ number of production wells + number of injection wells
Net pay > gross pay
Sum of initial saturations > 100 percent
Sum of current saturations > 100 percent

Current oil saturation ≥ initial oil saturation
Current oil FVF > initial oil FVF

Geologic age code in record 1 ≠ that in record 3
OOIP and volumetric calculation thereof disagree by > 5 percent
Cumulative oil production OOIP
Primary oil recovery ≥ OOIP
Primary recovery factor + secondary recovery factor ≥1
Swept zone oil saturation ≥ initial oil saturation
Swept zone oil saturation ≥ current oil saturation
Ultimate recovery factor * OOIP ≤ cumulative oil production
Lithology inconsistent with geologic class
Lithology inconsistent with depositional system
Lithology inconsistent with diagenetic overprint
Reservoir acres > field acres

CHECKS FOR POTENTIAL ERRORS

Initial formation pressure > 0.6 * true vertical depth
Current formation pressure > 0.6 * true vertical depth
Ultimate recovery > 0.65* OOIP
Volumetric sweep factor > 70%
Reservoir dip > 25 degrees
Porosity < 7%
Depth > maximum depth drilled in state to date
Permeability > 5000 md
Initial oil saturation > 80 %
Well spacing > 180 acres/well
Current GOR > 5000 scf/bbl
API > 50 degrees API

Table 8 (continued)

DATA ENTRY ERROR CHECKS
Missing initial gas saturation
Missing initial formation volume factor
Missing true vertical depth
Missing formation temperature
Missing permeability
Missing API gravity
Missing oil viscosity
Missing formation salinity
Missing OOIP
Missing cumulative oil production
Missing reservoir acres
Missing production wells (number)
Missing injection wells (number)
Missing district code (California and Texas)
Missing geologic data necessary for classification

Table 9 Validations Performed on the Production Data by the TORISCHK Program

DATA ENTRY ERROR CHECKS

Invalid state postal code

DATA CONSISTENCY CHECKS

Reference number not matched in Reservoir/Geology file

Field name not matched in Reservoir/Geology file

Reservoir name not matched in Reservoir/Geology file

Numeric state code does not correspond to the state postal code in the Reservoir/Geology file

Year for cumulative injection > year of most recent oil production

Cumulative oil production < sum of annual oil production

Cumulative oil production ≠ cumulative oil production in Reservoir/Geology file

Date of cumulative oil production ≠ date of most recent annual oil production

Date of cumulative oil production ≠ cumulative oil production date in Reservoir/Geology file

Cumulative gas production < sum of annual gas production

Date of cumulative gas production ≠ date of most recent annual gas production

Cumulative water production < sum of annual water production

Date of cumulative water production ≠ date of most recent annual water production

Most recent well count > total wells in Reservoir/Geology file

Most recent well count ≠ number of production wells in Reservoir/Geology file

CHECKS FOR POTENTIAL ERRORS

Annual oil production varies by more than 100 percent between two consecutive years

Annual gas production varies by more than 100 percent between two consecutive years

Annual water production varies by more than 100 percent between two consecutive years

The data entry error checks identify entries which are clearly invalid. For example, if the non-existent state postal code "XX" has been entered, it will be flagged as an error.

The checks for missing critical data items identify the data elements in Table 1 which have been entered as -1. For example, if a value of -1 has been entered for net pay, the program will generate a diagnostic.

The checks for data consistency detect data items whose values are illogical when compared to the values of other data items for the same reservoir. For example, if the value for net pay is greater than that for gross pay, a diagnostic will be produced.

The checks for potential data errors identify data values which may or may not be in error. Messages falling into this category should be considered as warnings rather than as a definitive indication of errors. For example, if the value for current formation pressure is greater than the value for initial formation pressure, a diagnostic will be written by the program.

Table 10 contains an inventory of the validation program executable code and supporting input files which are resident on the diskette accompanying this guide. The name of the validation program is TORISCHK.EXE. It is designed for use with IBM and IBM-compatible personal computers. The hardware configuration required to support the program includes an 80-286 or higher processor, a 3.5 inch 1.44 megabyte high-density diskette drive, a 10 megabyte hard drive, and a printer capable of printing 132-character lines.

The validation software and files should be installed on a hard drive by simply creating a new directory on the drive and copying all the files from the diskette into the directory. Since the program expects to find all the supporting input files in the directory from which it is run, do not segregate the input files in a separate directory.

The program is not designed to run in a Windows environment. It is invoked from a DOS prompt as follows:

TORISCHK <Enter>

A maximum of three interactive inputs are required. Upon execution, the program will display a banner screen containing the program name, version number, copyright notice, and a prompt to press the "Enter" key to contilnue. When the user presses the "Enter" key, the program will prompt for title information which will appear in the heading of each page of the output report. Next the program will request the file name of the TORIS reservoir/geologic data, followed by a prompt for the file name of the TORIS production data. If either of these files is not available, do not enter a name for the absent file. Instead, simply depress the "Enter" button to input a null file name. Validation processing will be performed only on the files for which a non-null name has been entered.

The program generates an output file designed for printing on 11 1/2 by 14 inch computer paper. If file names are supplied for both the reservoir/geologic and production data, the report will begin with the diagnostics for the reservoir/geologic data, followed by the diagnostics for the production data. The output file name is TORISCHK.OUT. If this file already exists in the current directory, it will be overwritten when TORISCHK is executed.

Figure 4 contains a sample of the report generated by the TORISCHK program. If no errors or potential errors are detected for a given reservoir, a message will be written to this effect. Each reservoir reported in the output is segregated from others by a dashed line.

The diagnostics for a given reservoir begin with two lines of identification information. Beginning the second of these two lines is a datum labeled "Record no." This record number represents the absolute record/line number within the input data file of the first record of information pertaining to the reservoir. Since most editors display the absolute line number of the cursor position, the "Record no." should enable users to rapidly locate all reservoirs having errors.

In the diagnostics portion for a given reservoir, the labels FIRST RECORD, SECOND RECORD, THIRD RECORD, etc. will appear. These labels simply describe the position of the records relative to the beginning of the data records for a given field/reservoir

6.2 Errors Commonly Made During the Preparation of TORIS Data

Over the years, the personnel who operate the TORIS system in Bartlesville have observed that the following errors tend to frequently occur in data submitted for inclusion in the TORIS system:

- Values expressed as decimals rather than as percentages
- Values expressed as percentages rather than as decimals
- Values of original oil in place which are inconsistent with the volumetric calculation thereof
- Values for well spacing which are inconsistent with the result obtained when the proven acreage is divided by the sum of the producing and injection well counts.

The highlighting of these errors hopefully will enable the preparer to avoid them.

Table 10 Inventory of Files on Diskette Provided by DOE

Validation Software and Supporting Files	
File Name	**Contents**
TORISCHK.EXE	Executable version of TORISCHK program
DEGCONF.COD	TORIS degree of confidence codes
DEPSYSTM.COD	TORIS depositional system codes
DIAGENET.COD	TORIS diagenetic overprint codes
GEOAGE.COD	TORIS geologic age codes
GEOPLAY.COD	TORIS geologic play codes
GEOPROV.COD	TORIS geologic province codes
LITHOLOG.COD	TORIS lithology codes
NCSCLASS.NUM	TORIS geologic classification codes
NCSCLASS.TBL	TORIS geologic classification table
PCONFIG.FIL	Printer page length specification (number of lines per page)
PREDMHET.COD	TORIS predominant element of reservoir heterogeneity codes
STATEPOS.COD	TORIS state postal codes and numeric equivalents
STRUCTUR.COD	TORIS structural compartmentalization codes
TRAPTYPE.COD	TORIS trap type code
Data Source Documentation Files	
File Name	**Contents**
SOURCES.EX	Example data source documentation file
SOURCES.TMP	Data source documentation template
Sample Data Files	
File Name	Contents
RES.FIL	Example Reservoir/Geology file
PROD.FIL	Example Production file

02/14/1995 Sample Run on RES.FIL and PROD.FIL

RESERVOIR/GEOLOGY REPORT

Reference no.:	1	Field:	FIELD NAME	Reservoir:	RESERVOIR NAME
Record no.:	1	State:	OK	Formation:	FORMATION NAME

SECOND RECORD:

Well spacing * (number of producers + number of injectors) = 1040.0 <> proven acres = 2550.0 +- 5 percent

Missing initial gas saturation

Current oil saturation (Soc) = 35.425 not consistent with Soc = 41.759 volumetrically calculated using OOIP - cum. production

THIRD RECORD:

Current formation pressure = 3669.7 > initial formation pressure = 3513.0

OOIP = 103574000. not consistent with volumetrically-calculated OOIP = 88778119.

	Area	Net Pay	Porosity	Soi	Boi
Current values:	2550.0	60.00	12.400	76.000	1.260
Possible values:	2975.0	70.00	14.467	88.666	1.080

FOURTH RECORD:

Volumetric sweep = 97.1 > 70 %

02/14/1995 Sample Run on RES.FIL and PROD.FIL Page 1

PRODUCTION REPORT

Reference no.:	1	Field:	FIELD NAME	Reservoir: Reservoir Name
Record no.:	2	State:	OK	

FIRST RECORD:

Reservoir name does not match the reservoir name = RESERVOIR NAME in reservoir file

NINTH RECORD:

Cumulative oil production = 52003605. <> cumulative oil production = 51248800. in reservoir file

Date of cumulative oil production = 1993 <> cumulative oil production date = 1988 in reservoir file

TENTH RECORD:

Most recent well count = 12 in year 1993 <> production wells = 13 in reservoir file

Figure 4 **Sample Validation Report**

6.3 References

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APPENDICES

Appendix A
Summary of Required Reservoir/Geology Data Elements

As the critical reservoir and geologic data elements have been reviewed and discussed in detail, the following segment summarizes the units and boundaries for all data elements in the Reservoir/Geologic data file. All of the data (except those that refer explicitly to gas) are for the oil column only.

Record 1	
DOE Field Code	Supplied by TORIS (enter -1).
State Postal Code	Two-letter alphabetic postal abbreviation (e.g., NM for New Mexico, TX for Texas) of the name of the state in which the reservoir is located. The codes are listed in Table A-7.
Lithology Code	(-1, 0=Unknown; 1=Sandstone; 2=Carbonate; 3=Dolomite).
Geologic Age Code	A three digit code determined using Table A-1. It is set by locating the proper age in the right column of the table and entering the corresponding code from the left column.
Field Name	The full name of the field (up to 36 characters).
Reservoir Name	The full name of the reservoir (up to 48 characters).
DOE Reference Number	Supplied by DOE (enter -1)
Preparer's Reference Number	An arbitrarily-chosen integer number in the range of 8001 to 9999.
Formation Name	The full name of the formation (up to 48 characters).
Record 2	
(1) Field Acres	The surface area encompassed by the entire field which the reservoir in question is a part of. A field consists of all reservoirs which make up an individual geological structural feature and/or stratigraphic condition. In cases where reservoirs are stacked and overlapping, the field acreage should be smaller than the sum of the reservoir acreages..
(2) Proven Acres	That part of the reservoir that has been developed by drilling and has been in communication with the well bores.

Record 2 (Continued)	
(3) Well Spacing	The result obtained when the proven acreage is divided by the number of wells (completion & injection) perforated within the proven acreage.
(4) Total Wells	The sum of all completion and injection wells in the reservoir.
(5) Net Pay	That portion of the oil interval in the reservoir which is determined to have reservoir-quality values of permeability and porosity.
(6) Gross Pay	The thickness of the entire oil interval in the reservoir including intervals which fall below the permeability and porosity standards used to determine net pay.
(7) Porosity	The weighted average porosity of the reservoir expressed as an integer percentage.
(8) Initial Oil Saturation	The initial reservoir oil saturation, determined at reservoir conditions, expressed as a percentage.
(9) Current Oil Saturation	The current reservoir oil saturation expressed as a percentage
(10) Initial Water Saturation	The initial water saturation in the reservoir expressed as a percentage
(11) Current Water Saturation	The current water saturation in the reservoir expressed as a percentage
(12) Initial Gas Saturation	The initial gas saturation for the reservoir expressed as a percentage. Note that the sum of the initial oil, water and gas saturations is 100 percent.
(13) Current Gas Saturation	The current gas saturation expressed as a percentage. Note that the current oil, water, and gas saturation must also sum to 100 percent.
(14) Initial Oil Formation Volume Factor	The initial formation volume factor in reservoir barrels/stock tank barrels expressed as a decimal number.
(15) Current Oil Formation Volume Factor	The current reservoir formulation volume factor in reservoir barrels/stock tank barrels expressed as a decimal number.
(16) True Vertical Depth	The distance from the Kelly Bushing to the mid-point of the perforations in feet expressed as a positive (not subsea) number.
(17) Formation Temperature	The average temperature of the reservoir in degrees Fahrenheit

Record 3	
(18) Current Formation Pressure	The current pressure in the reservoir in pounds per square inch (psi)
(19) Permeability	The effective horizontal permeability of the reservoir in millidarcies
(20) Geologic Age Code	Identical to the Geologic Age Code entered in Record 1.
(21) API Gravity	The initial gravity of the oil in degrees API.
(22) Oil Viscosity	The oil viscosity at reservoir conditions, centipoise.
(23) Formation Salinity	The total dissolved solids in parts per million.
(24) OOIP	The volumetric original oil in place in the reservoir in barrels.
(25) Primary Recovery Factor	The fraction of the OOIP which will be produced under primary recovery expressed as a fraction of OOIP.
(26) Secondary Recovery Factor	The fraction of the OOIP which will be produced during secondary recovery expressed as a fraction of OOIP
(27) Cumulative Oil Production	The cumulative oil production in barrels as of the last full calendar year for which there are complete data.
(28) Year for Cumulative Oil Production	The year corresponding to the cumulative oil production, expressed as a four-digit integer number.
(29) Technical Availability Date	Supplied by TORIS (enter -1).
(30) Primary Recovery Factor	The recovery of oil under the primary drive expressed in barrels/acre-foot.
(31) Primary Recovery	The number of barrels of oil expected to be recovered under the primary drive.
(32) Year For Primary Recovery	The-four digit year in which primary recovery started
(33) Current Producing GOR	The current gas-oil ratio of the producing stream in standard cubic feet/barrel.
(34) Initial Producing GOR	The initial gas-oil ratio of the producing stream in standard cubic feet/barrel.

Record 4	
(35) Reservoir Acreage	The actual area of the reservoir (corrected for dip, faults or folds) expressed in acres.
(36) Initial Formation Pressure	The initial downhole reservoir pressure measured in pounds/square inch.
(37) Reservoir Dip	The average dip of the reservoir in degrees.
(38) Production Wells	The number of wells which are completed as producers in the reservoir.
(39) Injection Wells	The number of wells which are completed as injectors in the reservoir. Note that the sum of the injection wells and the production wells must equal the total wells (element 4)
(40) Swept Zone Oil Saturation	The oil saturation in that part of the reservoir that has been swept by water (via natural water drive or by secondary recovery) expressed as a percent.
(41) Injection Water Salinity	The total dissolved solids in the injected water, parts per million.
(42) Clay Content	The percentage of the reservoir that is clay.
(43) Dykstra-Persons Coefficient	The Dykstra-Parsons measure of vertical reservoir heterogeneity, expressed as a fractional number between 0 and 1.
(44) Current Injection Rate	The current injection rate for secondary recovery expressed in barrels per day per well
(45) Fractured-Fault	Is the reservoir fractured or faulted? Enter a value of 0 to indicate no fracturing or faulting. A value of 1 indicates that fracturing or faulting does exist in the reservoir.
(46) Shale Breaks or Laminations	Does the reservoir contain discernible shale breaks or laminations? Enter a value of 0 to indicate no shale breaks or laminations. A value of 1 indicates that either or both of these conditions does exist in the reservoir.
(47) Major Gas Cap	Is there a major gas cap over the oil column? Enter a value of 0 to indicate no major gas cap or a value of 1 to indicate the presence of a major gas cap.
(48) Field Multiplier	Supplied by TORIS (enter -1)

Record 4 (Continued)	
(49) District	This code applies solely to California and Texas. For California districts and those Texas districts which are strictly numeric, enter the district code directly. Some Texas districts are expressed alphamerically (combination of a number and a letter, such as 7C). For these districts, multiply the numeric part by 10. Replace the alphabetic part with A=1, B=2, C=3, etc. Then add the two numbers. For example, Texas district 7C would be entered as 73 (7 x 10 + 3).
(50) Production Rate	The production rate in thousands of barrels per day (MBBL/DAY) for the year in data element 28.
(51) Ultimate Recovery Factor	The fraction of the original oil in place expected to be recovered by primary and secondary production.
Record 5	
(52) Geologic Play	The play code from Table A-2. Find the play in the right column and enter the corresponding code from the left column
(53) Depositional System	The depositional system code from Table A-3. Find the description which must closely matches the reservoir in the right column and enter the corresponding code from the left column.
(54) Depositional System Degree of Confidence	A measure of how confident one is of the assignment of the reservoir to one of the systems in element 53. Is one confident that it is a fluvial-braided rather than a fluvial-meandering? Highest confidence enter 1, moderate confidence enter 2, low confidence enter 3
(55) Diagenetic Overprint	From Table A-4, determine which kind of diagenetic overprint is present in the reservoir. Find the diagenetic overprint in the right hand column and enter the corresponding code from the left hand column
(56) Diagenetic Overprint Degree of Confidence	A measure of the confidence of assigning the reservoir to one of the overprint categories in element 55. 1 = highest, 2 = moderate and 3 = lowest confidence
(57) Structural Compartmentalization	Is the reservoir faulted, fractured or folded? Using Table A-5 locate the compartmentalization that matches the reservoir (including unstructured) and enter the corresponding code from the left hand column

Record 5 (Continued)	
(58) Structural Compartmentalization Degree of Confidence	A measure of the confidence of assigning the reservoir to one of the structural compartmentalization categories for element 57. 1=highest, 2=moderate, 3=lowest confidence
(59) Predominant Element of Reservoir Heterogeneity	An indication of which process controls the reservoir heterogeneity. If the depositional system is dominant enter 1; if the diagenetic overprint is dominant enter 2; if the structural compartmentalization is dominant enter 3
(60) Trap Type	A code for which type of trap defines the reservoir. Enter 1 for a stratigraphic trap, enter 2 for a structural trap, and enter 3 for a combination trap
(61) Geologic Province	A code from Table A-6. Find the USGS province in the right hand column and enter the corresponding code from the left hand column

Table A-1 AAPG Stratigraphic Coding Procedure Geologic Age of Formation

Code	Geologic Age	Code	Geologic Age
-1	Unknown	237	Triassic/Lower
100	Cenozoic	300	Paleozoic
110	Quaternary	310	Permian
111	Holocene	311	Permian/Upper
112	Pleistocene	312	Permian/Ochoa
120	Tertiary	313	Permian/Guadalupe
121	Pliocene	317	Permian/Lower
122	Miocene	318	Permian/Leonard
123	Oligocene	319	Permian/Wolfcamp
124	Eocene	320	Pennsylvanian
125	Paleocene	321	Pennsylvanian/Upper
200	Mesozoic	322	Pennsylvanian/Virgil
210	Cretaceous	323	Pennsylvanian/Missouri
211	Cretaceous/Upper	324	Pennsylvanian/Middle
212	Cretaceous/Gulf	325	Pennsylvanian/Des Moines
213	Cretaceous/Coloradoan	326	Pennsylvanian/Atoka
217	Cretaceous/Lower	327	Pennsylvanian/Lower
218	Cretaceous/Comanche	328	Pennsylvanian/Morrow
219	Cretaceous/Coahuila	330	Mississippian
220	Jurassic	331	Mississippian/Upper
221	Jurassic/Upper	332	Mississippian/Chester
224	Jurassic/Middle	333	Mississippian/Meramec
227	Jurassic/Lower	337	Mississippian/Lower
230	Triassic	338	Mississippian/Osage
231	Triassic/Upper	339	Mississippian/Kinderhook
234	Triassic/Middle	340	Devonian

Table A-1 AAPG Stratigraphic Coding Procedure Geologic Age of Formation (continued)

Code	Geologic Age	Code	Geologic Age
341	Devonian/Upper	361	Ordovician/Upper
342	Devonian/Chautauquan	362	Ordovician/Cincinnatian
343	Devonian/Senecan	364	Ordovician/Middle
344	Devonian/Middle	365	Ordovician/Champlanian
345	Devonian/Erian	367	Ordovician/Lower
347	Devonian/Lower	368	Ordovician/Canadian
348	Devonian/Ulsterian	370	Cambrian
350	Silurian	371	Cambrian/Upper
351	Silurian/Upper	372	Cambrian/Croixian
352	Silurian/Cayugan	374	Cambrian/Middle
354	Silurian/Middle	375	Cambrian/Albertan
355	Silurian/Niagaran	377	Cambrian/Lower
357	Silurian/Lower	378	Cambrian/Waucoban
358	Silurian/Alexandrian	400	Precambrian

TABLE A-2 Geologic Play Codes

Code	Geologic Play
-1	Unknown
1	Eocene Deltaic Sandstone
2	Yegua Deep-Seated Salt Domes
3	Yegua Salt Dome Flanks
4	Cap Rock
5	Frio Deep-seated Salt Domes
6	Frio (Buna) Barrier/Strandplain Sandstone
7	Frio Barrier Strandplain Sandstone
8	Wilcox Fluvial/Deltaic Sandstone
9	Jackson Barrier/Strandplain Sandstone
10	Frio Fluvial/Deltaic Sandstone (Vicksburg)
11	San Miguel/Olmos Deltaic Sandstone
12	Edwards Restricted Platform Carbonates
13	Austin/Buda Fractured Chalk
14	Glen Rose Carbonate (Strat/Structural Trap)
15	Paluxy Fault Line
16	Cretaceous Sandstone (Salt-Related Structure)
17	Glen Rose Carbonate (Salt-Related Structure)
18	East Texas Woodbine Sandstone
19	Woodbine Fluvial/Deltaic/Strandplain Sandstone

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
20	Woodbine Fault Line
21	Strawn Sandstone
22	Bend Conglomerate
23	Caddo Reef
24	Upper Pennsylvanian Shelf Sandstone
25	Pennsylvanian Reef/Bank
26	Upper Pennsylvanian Slope Sandstone
27	Eastern Shelf Permian Carbonate
28	Horseshoe Atoll
29	Spraberry/Dean Sandstone
30	Central Basin Platform Unconformity
31	Ellenburger Fractured Dolomite
32	Siluro-Devonian Ramp Carbonate
33	Siluro-Devonian Ramp Carbonate (SCBP)
34	Siluro-Devonian Ramp Carbonate (NCBP)
35	Yates Area
36	San Andres/Grayburg Carbonate (Ozona Arch)
37	San Andres/Grayburg Carbonate (SCBP)
38	San Andres/Grayburg Carbonate (NCBP)
39	Permian Sandstone and Carbonate

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
40	Clear Fork Platform Carbonate
41	Queen Platform/Strandplain Sandstone
42	Wolfcamp Platform Carbonate
43	Pennsylvanian Platform Carbonate
44	Northern Shelf Permian Carbonate
45	Delaware Sandstone
46	Panhandle Granite Wash/Dolomite
47	Panhandle Morrow Sandstone
48	Miscellaneous
101	Northwest Shelf Grayburg/San Andres
102	Northwest Shelf Queen, Yates & Seven River
103	Bone Springs with Shelf Edge Carbonate
104	Abo Reef
105	Northwest Shelf Morrow
106	Simpson Platform
107	Gallup Barrier Island
108	Dakota Barrier Island
109	Hermosa Patch Reef
201	Arbuckle Cambro-Ordovician
202	Southern Oklahoma Bromide (Ordovician)
203	Southern Oklahoma Devonian

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
204	Southern Oklahoma Lower Mississippian
205	Southern Oklahoma Springeran
206	Southern Oklahoma Desmoinesian
207	Southern Oklahoma Missourian
208	Southern Oklahoma Virgilian
209	Southern Oklahoma Pontotoc
210	Anadarko Shelf Hunton
211	Northern Anadarko Mississippian
212	Anadarko Morrow Fluvio-Deltaic
213	Southeast Anadarko Morrow-Springer
214	Anadarko Basin Desmoinesian
215	Anadarko Basin Missourian
216	Southeast Anadarko Wolfcampian
217	Nemaha Ridge Ordovician
218	Central Oklahoma Hunton
219	Nemaha Ridge Desmoinesian
220	Nemaha Ridge Missourian
221	Nemaha Ridge Virgilian
222	Seminole Platform Wilcox
223	Seminole Platform Simpson
224	Seminole Platform Oil Creek
225	Seminole Platform Viola

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
226	Northeast Oklahoma Wilcox
227	Central Oklahoma Misener
228	Northeast Oklahoma Mississippian
229	Southeast Chautaugua Atokan
230	Northeast Oklahoma Desmoinesian Sandstone
231	Northeast Oklahoma Desmoinesian Limestone
232	Northeast Oklahoma Missourian
233	Arkoma Morrowan
234	Arkoma Hunton
235	Seminole Platform Hunton
236	Arkoma Simpson
237	Arkoma Desmoinesian
301	Kuparuk River Shelf Sandstones
302	Sadlerochit Fluvial/Deltaic Sandstones
303	West Foreland/Hemlock/Tyonek Fluvial Sandstone
401	Chanac Fluvial/Alluvial Sandstones
402	San Joaquin Turbidite Sandstones
403	San Joaquin/Kern River/Deltaic/Lacustrine

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
404	San Joaquin/Tulare/Deltaic/ Lacustrine
405	Gatchell/McAdams Shelf/Strandplain Sandstone
406	Olcese/Zilch Fluvial/Alluvial Sandstones
407	Reef Ridge/McClure/Antelope/ Fractured Shelf
408	Reef Ridge/McClure/Antelope/ Fractured Shelf
409	Stevens Turbidite Sandstones
410	Temblor Deltaic/Shelf Sandstones
411	Vedder/Pyramid Hills Strandplain Sandstone
412	Pico/Repetto Turbidite Sandstones
413	Playa Del Ray Platform Schist Sandstones
414	Puente Turbidite Sandstones
415	Repetto Turbidite Sandstones
416	Repetto/Puente Turbidite Sandstones
417	Modello Turbidite Sandstones
418	Pico Turbidite Sandstones
419	Plio/Pleistocene Fluvial/Alluvial Sands
420	Sespe Fluvial Sandstones

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
421	Vaqueros/Alegria (Sespe Equiv.) Strandplain
422	Monterey Fractured Siliceous Shale
423	Sisquoc Shelf Sandstones
424	San Ardo-King City Shelf Sandstones
425	Vaqueros (Painted Rocks) Strandplain Sands
426	Eocene Shelf/Strandplain Sandstones
427	Eocene to Lower Miocene Turbidite Sands
428	Llajas Strandplain Sandstones
429	Non-defined
430	Pico Strandplain/Deltaic Sandstones
431	Santa Margarita Strandplain/Deltaic Sand
501	Denver Basin Cretaceous D-J Sands
502	Denver Basin Dakota-Muddy Sands
503	Denver Basin Permian Lyons Sand
504	Denver Basin Cretaceous Sussex-Shannon Sands
505	San Juan Basin Dakota-Morrison Sands
506	Paradox Basin Ismay Algal Mounds

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
507	Uinta-Piceance Basin Weber Sands
508	Uinta-Piceance Basin Morrison Sands
509	NW CO Jurassic Entrada Sands
510	NW CO Cretaceous Dakota Channel Sands
511	NW CO Eocene Wasatch Sands
512	Park Basin Lakota Sands
602	Sweetgrass Arch Kootenai Stratigraphic Trap
603	Sweetgrass Arch Pre-Jurassic Unconformity
604	Red River Stratigraphic
605	Central Montana Structural Traps
606	Sweetgrass Arch Swift Stratigraphic Trap
607	Tyler Sandstones
701	Moxa Arch Dakota Sands
702	Uinta Basin Fractured Lacustrine Trend
703	Paradox Basin Fractured Trend
704	Overthrust-Mesozoic Absaroka Thrust Trend
705	Paradox Basin Mississippian
706	Paradox Basin Devonian
707	Colorado Plateau Kaibab Carbonates
708	Southern Paradox Basin-Coconino

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
709	Uinta Basin Lacustrine Trend
801	Cretaceous Muddy Nearshore Sandstones
802	Tertiary Almy Lucustrine Sandstones-SW WY
803	Upper Cretaceous Almond Barrier Bars-SW WY
804	Lower Cretaceous Sandstones Commingled-SW WY
805	Lower Cretaceous Dakota Channel Sands-SW WY
806	Upper Jurassic Sundance Shelf Sandstones-SW WY
807	Permian/Pennsylvanian Eolian Sandstones-SW WY
808	Upper Mississippian Darwin Strandplain-SW WY
809	Mississippian Madison Carbonates-SW WY
810	Middle Cambrian Flathead Sandstones-SW WY
811	Lower Cretaceous Muddy Sandstones-Denver
812	Lower Cretaceous Lakota Fluvial Sandstones
813	Upper Cretaceous Cody Sandstone-Wind River
814	Upper Cretaceous Mesaverde Sandstone-Wind River
815	Lower Cretaceous Muddy Estuarine Sandstone
816	Permian Phosphoria (Empbar) Shelf Carbonates

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
817	Pennsylvanian Tensleep Eolian Sandstones
818	Mississippian Madison Carbonate-Wind River
819	Upper Cretaceous Frontier Marine Sandstone
820	Lower Cretaceous Lakota Fluvial Sandstones
821	Upper Jurassic Sundance Shelf Sandstones
822	Triassic Nearshore Sandstones-Bighorn Basin
823	Permian Phosphoria (Embar) Shelf Carbonates
824	Permian Phosphoria Facies Trap-Bighorn Basin
825	Pennsylvanian Tensleep Eolian Sandstones
826	Transgressive Amsden Deposits-Bighorn Basin
827	Mississippian Madison Carbonates-Bighorn Basin
828	Upper Ordovician Bighorn Shelf Carbonates
829	Upper Cretaceous Parkman Sandstone-Powder River
830	Upper Cretaceous Shelf Sandstones-Powder River
831	Upper Cretaceous Frontier Deltaic Sandstones
832	Lower Cretaceous Fluvial and Estuarine Sands

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
833	Lower Cretaceous Strandplain Sandstones
834	Lower Cretaceous Dakota Strandplain Deposits
835	Lower Cretaceous Dakota Deltaic Deposits
836	Lower Cretaceous Lakota Fluvial Sandstones
837	Upper Jurassic Sundance Shelf Sandstones
838	Permian Minnelusa Eolian Sandstones-Powder River
839	Pennsylvanian Minnelusa (Leo) Eolian Sands
840	Pennsylvanian Tensleep Eolian Sandstones
901	Aux Vases Tide-Dominated Delta
902	Borden Delta
903	Chesterian Fluvial-Deltaic
904	Chesterian Strandplain
905	Chesterian Tide-Dominated Delta
906	Middle Devonian Carbonate
907	Middle Devonian Sand
908	Middle Ordovician Open Shelf
909	Pennsylvanian Fluvial-Deltaic
910	Sub-Pennsylvanian Paleovalley
911	Upper Valmeyeran Oolite

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
912	Upper Valmeyeran Tide-Dominated Delta
913	Valmeyeran Open Shelf
914	Valmeyeran Restricted Shelf
1001	Chesterian Sand Play
1002	Lower Pennsylvanian Sand
1101	Mississippian Deltaic Sand
1102	Pennsylvanian Deltaic Sand
1201	Detroit River Sour Zone
1202	Dundee
1203	Niagaran Reef
1204	Richfield
1205	Trenton/Black River
1301	2nd Berea Deltaic Sandstone
1302	Berea Deltaic Sandstone
1401	Bradford Group Shelf Sand
1402	Elk Group Slope/Basin Turbidite
1403	Venango Group Strandplain Bar and Beach
1504	Berea Channel Sandstone
1505	Berea Shelf Sandstone
1506	Lower & Middle Pennsylvanian Fluvial Sands
1507	Middle Mississippian Dolomitic Shelf Sands
1508	Pocono Deltaic
1509	Pocono Slope

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
1510	Upper Devonian Deltaic Sandstone
1511	Upper Devonian Shelf Sandstone
1512	Upper Devonian Fluvial Sandstone
1601	Central Kansas Uplift
1602	Cherokee Group Sandstones
1603	Cherokee Platform
1604	Lansing-Kansas City Carbonates
1605	Layton Sandstones
1606	Morrow Sandstones
1607	Nemaha Uplift
1608	Osage Chert (Chat)
1609	Peru Sandstone
1610	Pratt Anticline
1611	Simpson Sandstones
1612	St. Louis Oolite
1701	Brocton-Froid
1702	Cedar Creek Anticline
1704	Northeast Montana
1706	Poplar Dome
1708	Wolf Creek Nose
1801	DJ Cambridge Arch
1901	Billings Nose Play
1902	Bowman County Red River
1903	Little Knife Structure

Table A-2 Geologic Play Codes (Continue)

Code	Geologic Play
1904	Medora-Fryburg
1905	NE Flank Williston Basin
1906	Nesson Anticline
2401	Cretaceous
2402	Eocene-Paleocene
2403	Jurassic
2404	Miocene
2405	Oligocene
2406	Pliocene
2407	Upper Cretaceous
2408	Wilcox
2409	Pleistocene
2410	Lower Tuscaloosa Stratigraphic Play
2411	West CBP Permian Shelf
2412	Shelf Sandstone
2413	Pennsylvanian Structural Play
2414	Piercement Salt Domesu
2431	Upper Jurassic Smackover Carbonate-Eastern Gulf

Table A-3 Depositional System Codes

Code	Depositional System
-1	Unknown
0	Depositional System does not apply to heterogeneity
100	Default
110	Eolian
111	Eolian/Ergs
112	Eolian/Coastal Dunes
120	Lacustrine
121	Lacustrine/Basin Margin
122	Lacustrine/Basin Center
130	Fluvial Undifferentiated
131	Fluvial Braided Stream
132	Fluvial Meandering Stream
140	Alluvial Fan
141	Alluvial Fan/Humid
142	Alluvial Fan/Semi-Arid
143	Alluvial Fan/Fan Deltas
150	Delta/Undifferentiated
151	Delta/Wave-Dominated
152	Delta/Fluvial-Dominated
153	Delta/Tide-Dominated
160	Strandplain/Undifferentiated
161	Strandplain/Barrier Core
162	Strandplain/Barrier Shoreface
163	Strandplain/Back Barriers
164	Strandplain/Tidal Channels
165	Strandplain/Washover Fan/Tidal Delta

Table A-3 Depositional System Codes (Continued)

Code	Depositional System
170	Shelf
171	Shelf/Sand Waves
172	Shelf/Sand Ridges/Bars
180	Slope-Basin (Clastic)
181	Slope-Basin/Turbidite Fans (Clastic)
182	Slope-Basin/Debris Fans (Clastic)
190	Basin (Clastic)
191	Basin/Pelagic
220	Peritidal
221	Peritidal/Supratidal
222	Peritidal/Intertidal
223	Peritidal/Subtidal
230	Shallow Shelf
231	Shallow Shelf/Open
232	Shallow Shelf/Restricted
240	Shelf Margin
241	Shelf Margin/Rimmed Shelf
242	Shelf Margin/Ramps
250	Reefs
251	Reefs/Pinnacle
252	Reefs/Bioherms
253	Reefs/Atolls
260	Slope-Basin (Carbonate)
261	Slope-Basin/Debris Fans (Carbonate)

Table A-3 Depositional System Codes (Continued)

Code	Depositional System
262	Slope-Basin/Turbidite Fans (Carbonate)
263	Slope-Basin/Mounds
270	Basin (Carbonate)
271	Basin/Drowned Shelf
272	Basin/Deep Basin

Table A-4 Diagenetic Overprint Codes

Code	Diagenetic Overprint
-1	Unknown
1	Compaction/Cementation
2	Grain Enhancement
3	Dolomitization
4	Dolomitization (Evaporites)
5	Massive Dissolution
6	Silicification
7	Intergranular Dissolution
8	Authigenic Clay
9	Chertification

Table A-5 Structural Compartmentalization Codes

Code	Structural Compartmentalization
-1	Unknown
10	Unstructured
20	Natural Fracture Porosity
30	Faulted
31	Normal Fault (Faulted)
32	Reverse Fault (Faulted)
33	Strike-Slip Fault (Faulted)
40	Fault/Fold
41	Normal Fault (Fault/Fold)
42	Reverse Fault (Fault/Fold)
43	Strike-Slip Fault (Fault/Fold)
50	Folded

Table A-6 Geologic Province Codes (USGS 1990)

Code	Geologic Province
-1	Unknown
58	Arctic Coastal Plain
59	Northern Foothills
60	Southern Foothills-Brooks Range
61	Yukon-Porcupine
62	Yukon-Koyukuk
63	Interior Lowlands
64	Bristol Basin
65	Hope Basin
66	Copper River Basin
67	Cook Inlet
68	Alaska Peninsula
69	Gulf of Alaska
70	Kodiak
71	Southeastern Alaska
72	Western Oregon-Washington
73	Sacramento Basin
74	San Joaquin Basin
75	Los Angeles Basin
76	Ventura Basin
77	Santa Maria Basin
78	Central Coastal Basin
79	Sonoma-Livermore Basins
80	Humbolt Basin
81	Eastern Oregon-Washington
82	Eastern Basin and Range
83	Western Basin and Range

Table A-6 Geologic Province Codes (USGS 1990) (Continued)

Code	Geologic Province
84	Idaho-Snake River Downwarp
85	Paradox Basin
86	Uinta-Piceance Eagle Basins
88	San Juan Basin
89	Albuquerque-Santa Fe-San Luis Rift Basin
90	Wyoming-Utah-Idaho Overthrust Belt
91	Northern Arizona
92	South Central New Mexico
93	Southern Arizona-Southwestern New Mexico
94	Williston Basin
95	Sioux Arch
96	Sweetgrass Arch
97	Central Montana
98	Montana Overthrust Belt
99	Southwestern Montana
100	Wind River Basin
101	Powder River Basin
102	Southwestern Wyoming Basins
103	Big Horn Basin
104	Denver Basin
105	Las Animas Arch
106	Raton Basin-Sierra Grande Uplift
107	Permian Basin
108	Palo Duro Basin
109	Pedernal Uplift
110	Bend Arch-Fort Worth Basin

Table A-6 Geologic Province Codes (USGS 1990) (Continued)

Code	Geologic Province
111	Marathon Fold Belt
112	Western Gulf Basin
113	East Texas Basin
114	Louisiana-Mississippi Salt Basins
115	Anadarko Basin
116	Arkoma Basin
117	Cambridge Arch-Central Kansas Uplift
118	Cherokee Platform
119	Forest City Basin
120	Nemaha Ridge
121	Salina Basin
122	Sedgwick Basin
123	Southern Oklahoma
124	Sioux Uplift
125	Iowa Shelf
127	Michigan Basin
128	Illinois Basin
129	Cincinnati Arch
130	Black Warrior Basin
131	Appalachian Basin
132	Blue Ridge Overthrust Belt
133	Piedmont
134	New England-Adirondack
135	Atlantic Coastal Plain
136	Florida Peninsula
137	Eastern Gulf Basin
810	Eastern California

Table A-7 TORIS Alpha and Numeric State Codes

State	Alpha State Postal Code	Numeric State Code	State	Alpha State Postal Code	Numeric State Code	State	Alpha State Postal Code	Numeric State Code
Alabama	AL	1	Kentucky	KY	16	North Dakota	ND	33
Alaska	AK	50	Louisiana	LA	17	Ohio	OH	34
Arizona	AZ	2	Maine	ME	18	Oklahoma	OK	35
Arkansas	AR	3	Maryland	MD	19	Oregon	OR	36
California	CA	4	Massachusetts	MA	20	Pennsylvania	PA	37
Colorado	CO	5	Michigan	MI	21	Rhode Island	RI	38
Connecticut	CT	6	Minnesota	MN	22	South Carolina	SC	39
Delaware	DE	7	Mississippi	MS	23	South Dakota	SD	40
District of Columbia	DC	8	Missouri	MO	24	Tennessee	TN	41
Florida	FL	9	Montana	MT	25	Texas	TX	42
Georgia	GA	10	Nebraska	NE	26	Utah	UT	43
Hawaii	HI	51	Nevada	NE	27	Vermont	VT	44
Idaho	ID	11	New Hampshire	NH	28	Virginia	VA	45
Illinois	IL	12	New Jersey	NJ	29	Washington	WA	46
Indiana	IN	13	New Mexico	NM	30	West Virginia	WV	47
Iowa	IA	14	New York	NY	31	Wisconsin	WI	48
Kansas	KS	15	North Carolina	NC	32	Wyoming	WY	49
							PO	52

Appendix B
Procedures for Geologic Classification of Reservoirs

The following procedural guide is provided to aid in the task of completing the geologic classification form titled Reservoir Heterogeneity Classification System for TORIS.

Before completing the classification forms, first locate the fields to be classified on the USGS Tectonic Province Map and then outline groups of reservoirs that have geographic proximity and geologic similarities (age, lithology, etc.). This is a first pass at defining a play so give the groups of reservoirs tentative play names. Final play names should be determined after the reservoirs have been classified.

Section 1. Reservoir Identification

- Reservoir Name, Field Name, State - The officially registered names.
- Reservoir Play - Tentative definition. Final play name to be determined after reservoirs have been classified.
- Geologic Province - Use USGS Tectonic Map.
- Geologic Age - System or better using local usage.
- Formation - Local usage is preferred.

Section 2. Depositional System

Refer to Description of Geologic Reservoir Classification System for definitions of depositional system categories. Select the one depositional system that best characterizes the most productive section of the reservoir. Rank the certainty of your selection 1, 2, or 3, with 1 signifying most confident. If you can further describe the reservoir using the subcategories from readily available data, please do so.

Section 3. Diagenetic Overprint

Refer to Description of Geologic Reservoir Classification System for definitions of diagenetic overprint categories. Select the one diagenetic process that has the most dominant control on the productive characteristics of the reservoir. Rank the certainty of your selection 1, 2, or 3, with 1 signifying most confident.

Reservoir Heterogeneity Classification System for TORIS

1. Reservoir Identification — **Reservoir Play:** ____________

Reservoir Name: ____________ Geologic Province: ____________ Date: ______

Field Name: ____________ Geologic Age: ____________ Prepared By: ______

State: ____________ Formation: ____________ Version: ______

2. Depositional System ☐1 ☐2 ☐3 Degree of Confidence in Selection (1 = Highest, 3 = Lowest)

Carbonate Reservoirs

☐ Lacustrine

☐ Peritidal
- ___ Supratidal
- ___ Intertidal
- ___ Subtidal

☐ Shallow Shelf
- ___ Open Shelf
- ___ Restricted Shelf

☐ Shelf Margin
- ___ Rimmed Shelf
- ___ Ramp

☐ Reefs
- ___ Pinnacle Reefs
- ___ Bioherms
- ___ Atolls

☐ Slope/Basin
- ___ Debris Fans
- ___ Turbidite Fans
- ___ Mounds

☐ Basin
- ___ Drowned Shelf
- ___ Deep Basin

Clastic Reservoirs

☐ Eolian
- ___ Ergs
- ___ Coastal Dunes

☐ Lacustrine
- ___ Basin Margin
- ___ Basin Center

☐ Fluvial
- ___ Braided Streams
- ___ Meandering Streams

☐ Alluvial Fan
- ___ Humid (Stream-Dominated
- ___ Arid/Semi-Arid

☐ Delta-Fan Deltas
- ___ Wave-dominated
- ___ Fluvial-Dominated
- ___ Tide-Dominated

☐ Strandplain
- ___ Barrier Cores
- ___ Barrier Shorefaces
- ___ Back Barriers
- ___ Tidal Channels
- ___ Washover Fan/Tidal Deltas

☐ Shelf (Accretionary Processes)
- ___ Sand Waves
- ___ Sand Ridges/Bars

☐ Slope/Basin
- ___ Turbidite Fans
- ___ Debris Fans

☐ Basin
- ___ Pelagic

3. Diagenetic Overprint ☐ 1 ☐2 ☐3 Degree of Confidence in Selection (1 = Highest, 3 = Lowest)

Carbonate Reservoirs

☐ Compaction/Cementation ☐ Dolomitization (Evaporites)

☐ Grain Enhancement ☐ Massive Dissolution

☐ Dolomitization ☐ Silicification

Clastic Reservoirs

☐ Compaction/Cementation ☐ Authigenic Clay

☐ Intergranular Dissolution ☐ Chertification

4. Structural Compartmentalization ☐ 1 ☐ 2 ☐3 Degree of Confidence in Selection (1 = Highest, 3 = Lowest)

☐ Natural Fracture ☐ Unstructured

☐ Faulted
- ___ Normal Fault
- ___ Reverse Fault
- ___ Strike-Slip Fault

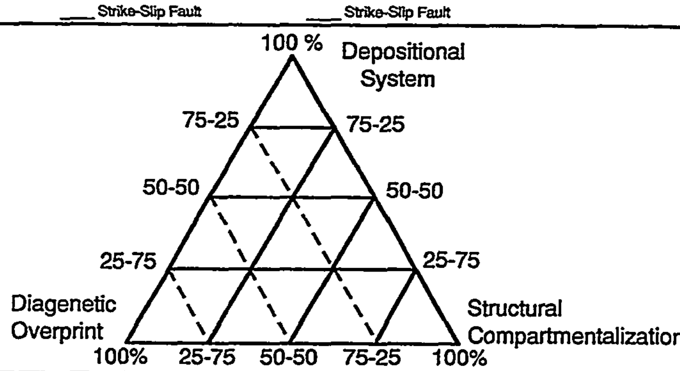
☐ Fault/Fold
- ___ Normal Fault
- ___ Reverse Fault
- ___ Strike-Slip Fault

☐ Folded

5. Reservoir Heterogeneity Ternary Diagram

Predominant Element of Reservoir Heterogeneity: (Check Only One)

- **Depositional System** ____
- **Diagenetic Overprint** ____
- **Structural Compartmentalization** ____



6. Trap Type ☐ Stratigraphic ☐ Structural ☐ Combination

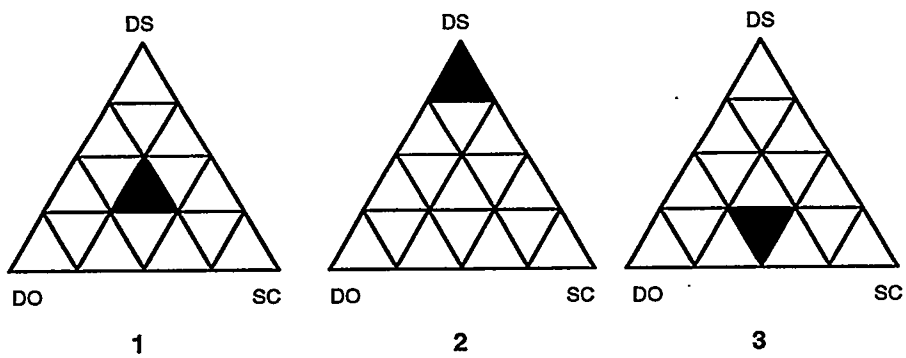
7. Optional Comments (References, Details on Above Selections, Etc.) ____________

Section 4. Structural Compartmentalization

Refer to Description of Geologic Reservoir Classification System for definition of structural compartmentalization categories. Select the one structural category that best describes the structural controls on reservoir heterogeneity. The unstructured category should be selected for all reservoirs except where fracture permeability dominates production performance or where faulting and/or folding significantly compartmentalize the reservoir at an intra-reservoir scale. Rank the certainty of your selection 1, 2, or 3, with 1 signifying most certain. If readily available for fault compartmentalized reservoirs, indicate the type of faulting that compartmentalizes the reservoir.

Section 5. Reservoir Heterogeneity Ternary Diagram

First select the predominant element that, in your judgement, controls reservoir heterogeneity. Next on the ternary diagram, indicate the relative importance of the three elements by selecting the appropriate area. Three examples are shown below.



Example 1 - Three heterogeneity elements have equal importance. Each contributes the same amount to defining the heterogeneity of the reservoir.

Example 2 - In this example, the heterogeneity is totally defined by the depositional system. The diagenetic overprint and structural compartmentalization have no importance in defining the heterogeneity of the reservoir.

Example 3 - In this example, the elements of diagenetic overprint and structural compartmentalization are equally important in defining the heterogeneity of the reservoir. The depositional system is of no importance in this reservoir.

Section 6. Trap Type

This is not part of the classification but has been added to capture this information for future reference. Select the trap type that, in your judgment, best characterizes the reservoir. Please note that unconformity traps are considered a type of the stratigraphic trap.

Appendix C
Documentation of Sources of Data

It is imperative that the sources of all data elements be identified in order to help resolve any future questions pertaining to the data. For this purpose, an ASCII file template, SOURCES.TMP, has been provided on the diskette accompanying this manual as well as file SOURCES.EX which is an example of how the template should be completed. The completed data source documentation file to be returned to the DOE should be an ASCII file named SOURCES.DAT. A listing of file SOURCES.EX is shown in Figure C-1.

DOCUMENTATION OF SOURCES FOR TORIS DATA

Company/Organization which prepared data: BDM-Oklahoma

Address: Address: 220 N. Virginia Ave
Bartlesville, OK 74003

Telephone number: 918-336-2400 FAX: 918-337-4365

FAX Verification: 918-336-2400

Data preparation staff:

Name	Title / Discipline	Telephone Number
Hugh Guinn	Principal Staff Member / Computer Analyst	918-337-4481
Don Remson	Principal Staff Member / Reservoir Engineer	918-337-4482

Date of submission of data: January 4, 1995

DOE contract number: DE-AC22-92PC91008

DOE contract administrator: Chandra Nautiyal

Field name: Prudhoe Bay State: AK
Reservoir name: Sadlerochit
Formation name: Ivashik
Reference number: 1 DOE Reference number (DOE use only):
Prepared by: Hugh Guinn Telephone number: 918-337-4481

Figure C-1 Data Source Template

RESERVOIR/GEOLOGY DATA	
RECORD 1	
Lithology Code:	United States Geological Survey (USGS)
Geologic Age Code:	USGS
Field Name:	DOE/EIA Oil and Gas Field Code Master List
Reservoir Name:	Alaska Conservation Commission
Formation name:	Alaska Conservation Commission
RECORD 2	
Field Acres:	Atlantic Richfield Corporation (ARCO)
Proven Acres:	ARCO
Well Spacing:	ARCO
Total Wells:	ARCO
Net Pay:	ARCO
Gross Pay:	ARCO
Porosity:	ARCO
Initial Oil Saturation:	ARCO
Current Oil Saturation:	ARCO
Initial Water Saturation:	ARCO
Current Water Saturation:	ARCO
Initial Gas Saturation:	ARCO
Current Gas Saturation:	ARCO
Initial Oil Formation Volume Factor:	ARCO
Current Oil Formation Volume Factor:	ARCO
True Vertical Depth:	ARCO
Formation Temperature:	ARCO

True Vertica Depth:	
Formation Temperature:	

RECORD 3

Current Formation Pressure:	ARCO
Permeability:	ARCO
Geologic Age Code:	USGS
API Gravity:	ARCO
Oil Viscosity:	ARCO
Formation Salinity:	ARCO
OOIP:	ARCO
Primary Recovery Factor:	ARCO
Secondary Recovery Factor:	ARCO
Cumulative Oil Production:	ARCO
Year for Cumulative Oil Production:	ARCO
Primary Recovery per Acre-Foot:	ARCO
Primary Recovery:	ARCO
Year for Primary Recovery:	ARCO
Current Producing GOR:	ARCO
Initial Producing GOR:	ARCO

RECORD 4

Reservoir Acreage:	ARCO
Initial Formation Pressure:	ARCO
Reservoir Dip:	ARCO
Production Wells:	ARCO
Injection Wells:	ARCO
Swept Zone Oil Saturation:	ARCO
Injection Water Salinity:	ARCO
Clay Content:	ARCO
Dykstra-Parsons Coefficient:	ARCO
Current Injection Rate:	ARCO
Fractured-Fault:	ARCO
Sale Break or Laminations:	ARCO
Major Gas Cap:	ARCO
District (California and Texas only):	ARCO
Daily Production Rate:	ARCO

RECORD 5	
Geologic Play:	Alaska State Geological Survey (ASGS)
Depositional System:	ASGS
Diagenetic Overprint:	ASGS
Structural Compartmentalization:	ASGS
Predominant Element of Reservoir Heterogeneity:	ASGS
Trap Type:	ASGS
Geologic Province:	ASGS
PRODUCTION DATA	
Cumulative water injection:	ARCO
Annual oil production:	ARCO
Annual gas production:	ARCO
Annual water production:	ARCO
Annual producing well count:	ARCO
Cumulative oil production:	ARCO
Cumulative gas production:	ARCO
Cumulative water production:	ARCO