CHAPTER ONE

INTRODUCTION

The goal of this book is to explain in plain language for the nonspecialist how and where carbonate rocks form, how they do, or do not, become reservoirs, how to explore for carbonate reservoirs or aquifers in the subsurface, and how to develop them once they have been found. The book is organized around a genetic classification of carbonate porosity and ways it can be employed in exploration and development. The genetic categories include three end members—depositional pores, diagenetic pores, and fractures. Genetic pore categories are linked with geological processes that created, reduced, or enlarged pores during lithification and burial. In the end, a chronology of pore origin and evolution is developed to put in the larger stratigraphic context for identification of reservoir flow units, baffles, and barriers. Connectivity can be evaluated by determining the range of porosity and permeability values for the different pore categories within reservoirs. Connected pore systems can be correlated stratigraphically to identify reservoir zones that have the highest combined porosity and permeability and the least resistance to the passage of fluids. Such zones are defined in this book as reservoir *flow units* somewhat similar to the definition of Ebanks (1987; Ebanks et al., 1992) but different in that rock units that impede flow are defined as baffles and units that prevent flow are defined as barriers. Each end-member reservoir type generally has characteristic pore-scale features (porosity and permeability) that correspond to petrologic and stratigraphic properties (borehole-scale features). When the zones with good, fair, and poor connectivity are identified, the characteristic petrologic and stratigraphic features that correspond with them can become *proxies for connectivity*. The larger scale features, or proxies, are generally easier to identify in borehole cores, on wireline log traces, and in some sequence stratigraphic "stacking patterns." When mode and time of origin of the proxies are known, geological concepts can be formulated to predict the

Geology of Carbonate Reservoirs: The Identification, Description, and Characterization of Hydrocarbon Reservoirs in Carbonate Rocks
By Wayne M. Ahr

spatial distribution of reservoir flow units at field scale. In other words, the fundamental rock properties that correspond to good, fair, and poor combined values of porosity and permeability can be identified and put in larger stratigraphic context, or "scaled-up." Then the temporal and genetic characteristics of the large-scale petrologic and stratigraphic properties (proxies) are used for reservoir prediction and flow unit mapping.

Carbonate reservoir porosity usually represents the combined effects of more than one geological process. Sometimes it reflects multiple episodes of change during burial history; therefore particular care must be given to identification of the sequence of events that led to the final array of rock properties and pore characteristics. Usually it is possible to identify *cross-cutting relationships* between rock properties so that their relative times of origin are distinguishable. Reservoir porosity governed only by depositional rock properties, a rather uncommon occurrence, will not exhibit cross-cutting relationships because rock texture, fabric, porosity, and permeability share a single mode and time of origin. In that case, reservoir architecture and spatial distribution conform to depositional facies boundaries. These reservoirs are referred to as *stratabound*, and porosity is *facies-selective, fabric-selective*, or both. Diagenesis and fracturing do not always follow depositional unit boundaries. Although carbonate reservoirs exist in which diagenetic porosity corresponds with depositional rock properties (fabric-selective or facies-selective diagenesis), in many instances it does not. In the latter case, it is especially important to identify the type of alteration, how it was formed, when it was formed, and what cross-cutting relationships it shares with other diagenetic and fracture attributes. Fractures cut across most rock boundaries but there are some fundamental rock properties that dictate how and where fractures will form. Fractures happen as a result of brittle failure under differential stress, usually in conjunction with faulting or folding. Fault and fold geometry can be determined; therefore it follows that associated fracture patterns can also be determined. In short, there are many rock and petrophysical characteristics in carbonates that expose a wealth of information about the origin and architecture of carbonate reservoirs.

1.1 DEFINITION OF CARBONATE RESERVOIRS

1.1.1 Carbonates

Carbonates are anionic complexes of $(CO_3)^{2-}$ and divalent metallic cations such as Ca, Mg, Fe, Mn, Zn, Ba, Sr, and Cu, along with a few less common others. The bond between the metallic cation and the carbonate group is not as strong as the internal bonds in the CO_3 structure, which in turn are not as strong as the covalent bond in carbon dioxide (CO_2). In the presence of hydrogen ions, the carbonate group breaks down to produce CO_2 and water. This breakdown reaction, commonly experienced when acid is placed on limestone, is the chemical basis for the fizz test that distinguishes carbonates from noncarbonates. It is also used to distinguish dolostones, which fizz slowly, from limestones, which fizz rapidly. Carbonates occur naturally as sediments and reefs in modern tropical and temperate oceans, as ancient rocks, and as economically important mineral deposits. The common carbonates are grouped into families on the basis of their crystal lattice structure, or the internal arrangement of atoms. The families are known by the crystal systems in which they form, namely, the hexagonal, orthorhombic, and monoclinic crystallographic systems. The most common carbonate minerals are in the hexagonal system, notably calcite ($CaCO_3$) and dolomite ($Ca,Mg(CO_3)_2$) (Figures 1.1 and 1.2). Aragonite has the same composition as calcite, $CaCO_3$, but it crystallizes in the orthorhombic system. The monoclinic system is characterized by the beautiful blue and green copper carbonates—azurite and malachite, respectively. Calcite and aragonite are polymorphs of calcium carbonate because they share the same composition but have different crystal structures. Dolomite, like calcite, crystallizes in the hexagonal

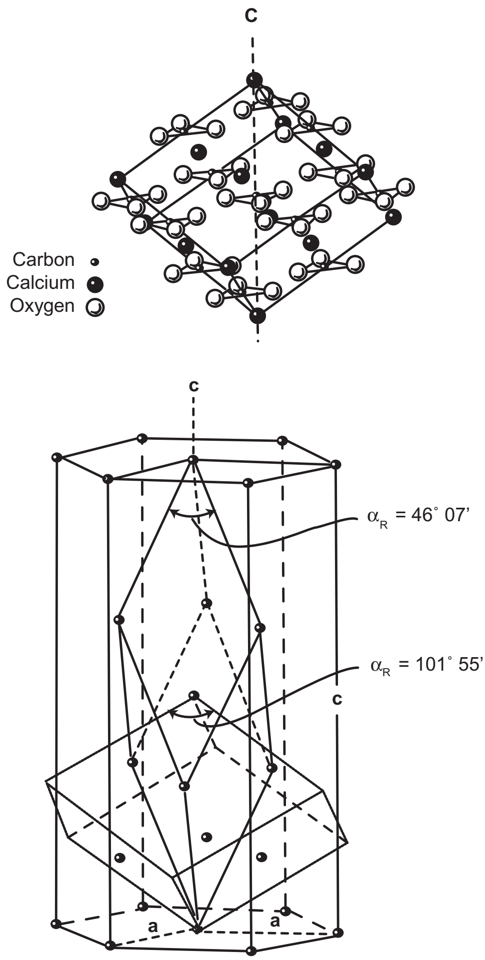

Figure 1.1 Internal atomic (lattice) structure of calcite. The ball-and-stick model at the top of the figure shows the position and orientation of calcium and carbonate ions in layers, or sheets, within the lattice. Note that the orientation of the triangular carbonate ions changes in alternate layers from top to bottom. The bottom drawing shows the hexagonal crystal structure of calcite, the scalenohedral calcite unit cell, and the position of cleavage rhombs with respect to the c crystallographic axes. (Adapted from illustrations in Hurlbut and Klein (1977).)

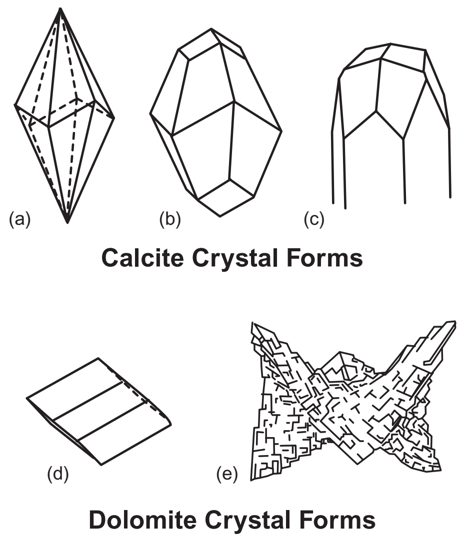

Figure 1.2 Typical calcite and dolomite crystal forms found in carbonate reservoir rocks: (a) the scalenohedral form of calcite sometimes called "dogtooth spar"; (b) a compound rhombohedral form; (c) a hexagonal prism with rhombohedral faces, sometimes called "nail-head spar"; two common forms of dolomite crystals include (d) the ordinary rhombohedron, typical of most low-temperature dolomites, and (e) the distorted, curved form called "saddle dolomite." Saddle dolomite is typically formed in the deep burial diagenetic environment and is sometimes, perhaps confusingly, referred to as "hydrothermal" dolomite. (Adapted from illustrations in Hurlbut and Klein (1977).)

system, but it is different from calcite. The small size of Mg ions compared to calcium ions causes a change in the dolomite lattice resulting in a loss of rotational symmetry. Aragonite is common in the modern oceans but it is rare in the ancient rock record; therefore it is safe to say that carbonate reservoirs and aquifers are composed of calcite and dolomite—limestones and dolostones. Together, those rocks make up about 90% of all naturally occurring carbonates (Reeder, 1983). Only a small fraction of the remaining 10% of carbonate minerals includes azurite and malachite, which are semiprecious stones and are commonly found in jewelry or other ornaments.

1.1.2 Reservoirs

Reservoirs are usually defined as storage receptacles. To a petroleum geoscientist, reservoirs are porous and permeable rock bodies that contain commercial amounts of hydrocarbons. Reservoirs owe their porosity and permeability to processes of deposition, diagenesis, or fracturing—individually or in combination. Although we will focus on hydrocarbon reservoirs in carbonate rocks, many porous and permeable carbonates are groundwater aquifers. Reservoirs are three-dimensional bodies composed of rock matrix and networks of interconnected pores. If the three-dimensional geometry (size and shape) of a connected pore system is known, it is possible to (1) determine drilling locations in exploration or development prospects, (2) estimate the volume of the resource in the reservoir or aquifer, (3) achieve optimum extraction of the resource, (4) determine the practicality of drilling additional (infill) wells to achieve the optimum spacing between field wells during development, and (5) predict the path that will be taken by injected fluids as they "sweep" remaining hydrocarbons during secondary and enhanced recovery. In the broad sense, reservoir studies include reservoir geology, reservoir characterization, and reservoir engineering. To avoid confusion in terminology about carbonate reservoirs, some common terms are discussed in the following paragraphs.

Reservoir geology deals with the origin, spatial distribution, and petrological characteristics of reservoirs. The reservoir geologist utilizes information from sedimentology, stratigraphy, structural geology, sedimentary petrology, petrography, and geochemistry to prepare *reservoir descriptions*. Those descriptions are based on both the fundamental properties of the reservoir rocks and the sequence of geological events that formed the pore network. Data for these descriptions comes from direct examination of rock samples such as borehole cores and drill cuttings. Borehole logs and other geophysical devices provide useful information, but they are indirect measurements of derived and tertiary rock properties. They are not direct observations. Direct observations of depositional textures, constituent composition, principal and accessory minerals, sedimentary structures, diagenetic alterations, and pore characteristics provide the foundation for reservoir descriptions. The geological history of reservoir formation can be traced by interpreting depositional, diagenetic, and tectonic attributes. The goal of such interpretations is to formulate *geological concepts* to guide in predicting reservoir size, shape, and performance characteristics. In the absence of direct lithological data from wells, as in the case of frontier exploration and wildcat drilling, geologists commonly study nearby outcrops of the same age and geological formation as the expected reservoir. A measure of care is given to interpreting reservoir geology from distant outcrops because depositional and diagenetic characteristics may vary significantly from place to place and from outcrops that have been altered by surface weathering to subsurface reservoirs that have never been exposed to weathering.

Reservoir characterization, like reservoir geology, deals with physical characteristics of the reservoir. It differs from geological description in that data on petrophysics and fluid properties are included. In addition to data from direct examination of reservoir rocks, reservoir characterization involves interpretation of borehole logs, porosity–permeability measurements, capillary pressure measurements, reservoir fluid saturations, and reservoir drive mechanisms.

Reservoir engineering deals with field development after discovery. The main goal of the reservoir engineer is to optimize hydrocarbon recovery as part of an overall economic policy. Reservoirs are studied throughout their economic lives to derive the information required for optimal production. In addition to geological data and borehole log characteristics, reservoir engineering deals with reservoir pressures, oil–water saturation, and gas–oil ratio in order to provide estimates of in-place hydrocarbon volumes, recoverable reserves, and production potential for each well in a field (Cossé, 1993).

Petroleum geoscientists not only study reservoirs, but they also study *traps, seals*, and *source rocks* that make up most of the petroleum system described by Magoon and Dow (1994). *Traps* are bodies of rock where hydrocarbons accumulate after migrating from their source and are restricted from further movement. It is convenient to think of traps as large-scale geometrical features that form boundaries around porous and permeable reservoir rocks. Traps are created by structural, stratigraphic, hydrodynamic, or diagenetic processes. It is important to recognize that the geometry of the reservoir–trap system may or may not correspond with present-day structural configurations. Subsurface structures may form and then be deformed by later episodes of tectonism. Ancient or paleo-highs may become present-day lows or saddles. Likewise, paleo-lows may be tectonically elevated to exhibit present-day structural closure and be "high and dry." This is called structural inversion and it is especially characteristic of basins with mobile salt or shale in the subsurface and in some structural settings where multiple episodes of tectonism have changed older structures.

Seals are the physical mechanisms that restrict fluids from flow out of the trap and are usually described in terms of capillary pressures. Seals may extend along the top, side, or bottom of the trap. Later we will define seals on the basis of the high capillary pressure exhibited by the seal rock as compared to the reservoir rock. These differences usually correspond to changes in rock type such as a change from sandstone to siltstone or shale in the case of siliciclastics, or porous grainstone to mudstone in carbonates. Most seals are not completely impermeable and will allow some leakage of hydrocarbons. Less commonly, seals may consist of totally impermeable barriers to flow such as evaporite deposits.

Source rocks are rich in kerogen, the parent organic matter that produces petroleum hydrocarbons when it reaches a threshold temperature during burial and thermal maturation. Source rocks usually consist of shales or lime mudstones that were deposited in oxygen-deficient environments where lipid-rich organic matter was preserved and converted to kerogen on further burial.

An integrated petroleum exploration program includes geophysical and geological studies of basin stratigraphy and structure to isolate the regions where reservoir rocks are most likely to be found, where structural, stratigraphic, or diagenetic processes have formed traps and seals, and where the basin contains an ample thickness of source rocks buried to a depth at which the temperature would have been high enough to liberate hydrocarbons from kerogen. In the initial phases of exploration, knowledge of how and where reservoir rocks form is critical; however, until a well is drilled the reservoir remains a hypothetical entity. Trap configurations may be identified as structural and stratigraphic anomalies, but without a hydrocarbon-filled reservoir, they only beckon explorationists to drill dry holes. After a successful well is drilled, the discovery is evaluated to predict the size and shape of the reservoir, to estimate its economic value, and to formulate a development program. At this stage, knowledge of reservoir characteristics is obviously the most important consideration.

1.2 FINDING AND DEVELOPING CARBONATE RESERVOIRS

The main reasons to study carbonate reservoirs and aquifers are to learn more about how to find, extract, and manage the oil, gas, usable water, or other resources they contain. Carbonates hold about half of the world's oil and gas, much of its groundwater, and extensive deposits of metallic ores, yet of the relatively few texts on reservoir geology, only a handful deal with carbonates. Carbonate reservoirs occur in the subsurface so most of the data used to study them comes from borehole cores, drill cuttings, logs, well tests, production data, and geophysical measurements. Modern reservoir geological studies are much more than geological descriptions of reservoir rocks. They include detailed research on the origin and spatial distribution of effective porosity, how it is connected through pore throats, and how rock and pore properties influence fluid storage and transmission.

In the following chapters, depositional, diagenetic, and fractured reservoirs are described and interpreted to illustrate methods of critical analysis of reservoirs rather than offering case histories that may be applied uncritically as analogs, or "look-alikes," for exploration and development programs. Petrophysical as well as petrological and structural characteristics of carbonate reservoirs are described, borrowing from both reservoir characterization and reservoir engineering. The study of *flow units* that make up all or part of a reservoir is emphasized throughout the book. Flow units are the rock bodies that transmit fluids, to a greater or lesser degree, through connected porosity. Identification and mapping of flow units requires knowledge of reservoirs in three or four dimensions (porosity in three dimensions plus a fourth dimension that may include connectivity or fluid saturation, for example). Such knowledge involves understanding the timing and mode of origin of the pore systems. Mapping flow units also requires a basic knowledge of subsurface mapping techniques and methods for evaluating reservoir connectivity. In the end, accurate and realistic reservoir models to provide the basis for finding new reservoirs and developing existing ones can be constructed from flow unit maps. I hope these discussions will stimulate analytical and synthetic thinking that will enable you to evaluate each reservoir on its petrological and petrophysical characteristics—not on its similarity to a "look-alike." Finding and developing carbonate reservoirs requires critical analysis and interpretation of essential geological data. Some of the kinds of data used in reservoir studies are mentioned in the following section.

1.2.1 Sources of Data on Reservoirs

Carbonate reservoirs may have mixed-origin pore systems, but an understanding of the end-member categories, how and when they formed, and how they are connected is necessary before a geological concept for exploration or development can be created. The most important data for reservoir studies comes from direct examination of rock samples. Basic rock properties studied in cores and cuttings include texture, mineral and grain composition, fossil content (taxonomic diversity), and sedimentary structures. These properties provide data on depositional characteristics. Petrographic study provides data about the diagenetic history of both the rock matrix and the pore system. Microscopic descriptions of borehole cores also provide data on the presence or absence of through-going, natural fractures. Porosity and permeability are measured from cores and porosity can be calculated from appropriate borehole logs. The statistical relationship between porosity and permeability is commonly used to distinguish between pore systems of different geological origins. Fractured reservoirs may exhibit high permeability at comparatively low porosity, for example. Another important kind of data is capillary pressure measurements. These measurements on cores provide data on the behavior of fluids in the reservoir pore system. Plots of capillary pressure at different fluid saturations within the reservoir rock sample, or capillary pressure curves, are related to pore throat size distribution, pore throat characteristics, and height of the hydrocarbon column above free water in a reservoir. Capillary pressure data are also used in estimating connectivity, fluid recovery efficiency, reservoir quality, thickness of the hydrocarbon column in reservoirs, and in evaluating seal capacity.

Data from indirect measurements made with wireline logs are the "bread and butter" of everyday work in subsurface geology. Some logs provide much more than others, however. Laboratory measurements of nuclear magnetic resonance (NMR) responses to different pore characteristics in carbonates are helping us develop better methods for interpreting reservoir quality from new-generation NMR log data. Of course, the traditional wireline log data are analyzed to extract useful information about reservoirs, traps, and seals. Of these logs, gamma ray, acoustic, resistivity, photoelectric effect, neutron, and density logs are typically included in modern logging runs. Even ordinary mud logs with drilling times, mud characteristics, and basic "lith log" descriptions of borehole cuttings can offer valuable information to the well analyst. Other indirect measurements of reservoir characteristics include reflection seismic traces that can be interpreted to reveal trap geometry and, in some cases, reservoir rock attributes. Borehole testing such as pressure transient tests helps confirm the presence or absence of fracture permeability. When used with cores or imaging logs, fractured reservoirs can be classified according to the relative contribution of fractures to overall reservoir performance.

Gravity and magnetic measurements are less commonly used in exploring for carbonate reservoirs than for terrigenous sandstone reservoirs, probably because gravity anomalies associated with shallow salt domes are comparatively easy to identify and are relatively common in sand–shale geological provinces such as the Gulf of Mexico onshore areas. Magnetic anomalies may sometimes be useful in identifying paleostructural trends associated with depositional carbonate reservoir trends that overlie magnetically susceptible basement rocks.

Reflection seismology is a widely used and fundamental tool in exploration for carbonate reservoirs. In some cases, particularly with today's high-resolution, three-dimensional (3D) seismic data, seismic attribute analyses might be used in field development where the analyses can help discriminate between reservoir and non-reservoir zones. High porosity zones, high fracture intensity, or strong contrasts in fluid content might be detectable as a seismic wave characteristic, or attribute. Seismic data usually provide the essential information to identify structural anomalies and can sometimes pinpoint stratigraphic anomalies if the anomalies are large enough. A rule of thumb is that the target reservoir zone must be thicker than one-quarter of the seismic wavelength. Also, the impedance contrast between reservoir and nonreservoir horizons must be strong enough for the difference between them to be detected. Seismic records are commonly helpful in detecting fractured reservoirs and a substantial literature exists on this subject. Suggestions for additional reading are presented at the end of each chapter of this book.

Analyses of these different kinds of data help to determine the size and shape of the reservoir body, the spatial distribution of the pore types within it, and how the pore system interacts with reservoir fluids. Evaluation of depositional characteristics draws from carbonate sedimentology to utilize depositional sequences and lithofacies in establishing links between depositional setting, sedimentary processes, and pore types. *Paleostructure* can have a strong influence on depositional facies, as is easily seen by examining depositional facies maps overlain on interval isopach maps. Diagenesis can be a pore-forming and a pore-destroying process. Diagenetic patterns are related to environments at the surface, in the shallow subsurface, and in the deep burial environment. Shallow diagenetic environments are commonly linked to depositional or paleostructural trends and these relationships can be seen with map overlays. Deep-burial diagenetic trends record the burial and thermal history of basin evolution, although the odd tectonic or geothermal event may also influence late diagenesis. Finally, natural fracture trends can be detected with a combination of special core analyses and acoustic or electronically generated borehole images. These combined types of data provide information on the size, intensity, and orientation of natural fractures. Fracture data plotted on structure maps can sometimes be correlated with reservoir geometry, because in most cases fracture trends correspond with geometrical orientation and position of the borehole with respect to the geometry of subsurface structures such as faults and folds. Cavernous and connected-vug pore systems could be mistaken for fractures, especially during drilling; therefore borehole log responses, digital imaging logs, drilling history characteristics, microscopic examination of drill cuttings, and the behavior of the drilling mud system are commonly used together to test for the presence of natural fractures. Pressure transient tests provide very important information to help confirm fracture behavior.

1.3 UNIQUE ATTRIBUTES OF CARBONATES

Texture is defined as the size, shape, and arrangement of detrital grains in a sedimentary rock. In siliciclastic rocks, it is strongly influenced by parent rock type, weathering, and transportation history. Most sandstones are classified on the basis of how much quartz, feldspar, rock fragments, and matrix they contain. Fossils are generally ignored. Sandstone diagenesis is usually treated as a process that alters depositional texture, fabric, and porosity only after extensive burial. Sandstone porosity and permeability are nearly always described as facies-specific; that is, the rock properties of the depositional facies determine reservoir characteristics. Fractured reservoirs in terrigenous clastics are less commonly reported in the literature than are fractured reservoirs in carbonates, although fractures are certainly not exclusive to one rock type or the other.

In contrast, carbonates have unique attributes that distinguish them from siliciclastics and that require different methods of study. Some of these attributes were recognized decades ago by Ham and Pray (1962). First, carbonates form within the basin of deposition by biological, chemical, and detrital processes. They do not owe their mineralogical composition to weathered, parent rocks and their textures do not result from transport down streams and rivers. Carbonates are largely made up of skeletal remains and other biological constituents that include fecal pellets, lime mud (skeletal), and microbially mediated cements and lime muds. Chemical constituents, including coated grains such as ooids and pisoids, cements, and lime mud, are common in carbonates but are absent in most siliciclastics. Clastic grains exist in carbonates, as they do in siliciclastics. In carbonates, however, these grains are mainly clasts of intraformational, lithified sediment (intraclasts) or of reworked, older rock (lithoclasts). The second major difference between carbonates and siliciclastics is that carbonates depend greatly on biological activity. They are composed mainly of biogenic constituents, component grains may have undergone size and shape changes as they were eaten by organisms, and the stratification of carbonate rock bodies is extensively modified by burrowing and boring organisms. The third major difference is that carbonates are susceptible to rapid and extensive diagenetic change. Carbonate minerals are susceptible to rapid dissolution, cementation, recrystallization, and replacement at ambient conditions in a variety of diagenetic environments. Finally, although not stressed by Ham and Pray (1962), fractured reservoirs are probably more common in carbonate rocks than in siliciclastics (as indicated in Table 1.1), but work by Laubach (1988, 1997) and Laubach et al. (2002) suggests that fractures are more common in siliciclastic reservoirs than was previously recognized. In short, porosity and permeability in carbonate reservoirs depend on a broad array of rock properties, on diagenetic episodes that may continue from just after deposition through deep burial, and on fracture patterns related more to the geometry of stress fields than to rock type. Choquette and Pray (1970) highlighted some of the differences between carbonate reservoirs and those in siliciclastics. A summary of their findings is given in Table 1.1.

Three other significant differences between carbonate and terrigenous sandstone reservoirs are: (1) electrofacies maps from gamma ray and resistivity log data *do not* indicate depositional facies in carbonates as they can do with terrigenous sandstones; (2) Focke and Munn (1987) demonstrated that a strong relationship exists between pore type and petrophysical characteristics in carbonate reservoirs such that saturation calculations using the Archie equation will vary greatly depending on the chosen "m" exponent and its dependence on the proportion of vuggy and moldic pores compared to interparticle pores; and (3) carbonates form in temperate as well as tropical environments. Because temperate carbonates have decidedly different mineralogical and component grain type compositions from tropical carbonates, their reservoir characteristics could also be different than expected.

Differences between sandstone and carbonate reservoirs influence the way we study them. Sandstone porosity is mainly interparticle; therefore it is related geometrically to depositional texture and fabric. Because permeability usually correlates rather well with interparticle porosity in sandstones, it can be related to depositional texture and fabric, as illustrated in a study of pore geometry in sphere packs and in terrigenous sandstones (Berg, 1970). Assuming that porosity and permeability are closely related, laboratory measurements made on small core plugs of terrigenous sandstones may be assumed to be representative of large rock volumes. That is, small samples are representative of large populations if the populations are homogeneous. Carbonates do not always exhibit interparticle porosity; they may have a variety of pore sizes, shapes, and origins, and measured porosity values do not always correspond closely with permeability. In short, carbonate pore systems are not usually homogeneous. While a 1-inch perm-plug will provide reliable data on sandstone porosity and permeability, entire core segments 4 inches in diameter and 1 foot long may be required for reliable measurements on carbonates. Relatively simple porosity classification schemes are useful for siliciclastics but a compound scheme of genetic classification augmented by measurements of pore geometry is needed for carbonates. Carbonate porosity classifications are discussed in Chapter 2.

TABLE 1.1 A Comparison of Terrigenous Sandstone and Carbonate Reservoir Characteristics

Reservoir Characteristic	Terrigenous Sandstones	Carbonates
Amount of primary porosity	25–40%	40–70%
Amount of ultimate porosity	Half or more of primary porosity, commonly 15–30%	Small fraction of original porosity, commonly 5–15%
Type of primary porosity	Almost exclusively interparticle	May be interparticle, intraparticle, intercrystalline, moldic, vuggy, cavernous, fenestral, or "constructed void"
Type of ultimate porosity	Almost exclusively primary interparticle	Highly variable owing to different origins or pore types
Typical pore size	Diameter and throat sizes related to depositional texture	Diameter and throat size may not be related to depositional texture
Typical pore shape	Dependent on particle shape; typically a "negative" of particles	Varies from strongly related to particle shape to totally unrelated
Uniformity of pore size and shape distribution	May be relatively uniform in homogeneous sand bodies	Variable from fairly uniform to extremely heterogeneous—even within a body made up of a single rock type
Influence of diagenesis	Minor—usually reduction by compaction or cementation	Major—can create, obliterate, or totally modify porosity; cementation and solution important
Influence of fracturing	Not of major importance in reservoir properties	Major importance in reservoir properties if present
Visual estimation of porosity and permeability	Semiquantitative estimates may be relatively easy	Semiquantitative estimates may be easy or impossible; instrumental measurements commonly required
Adequacy of core analysis for reservoir evaluation	Core plugs of 1-inch diameter may be adequate to determine matrix porosity	Core plugs commonly inadequate; may require whole core analyses (~4-inch by 1-foot segments) for large pore sizes
Porosity–permeability relationships	Relatively consistent; may be dependent on particle texture	Highly varied; may be independent of particle texture
Reliability of log characteristics as indicators of depositional facies (electrofacies mapping)	Standard practice that may provide reliable proxies for depositional facies	Not reliable because logs cannot generally detect differences in carbonate grain types or textures

Source: Adapted from Choquette and Pray (1970).

SUGGESTIONS FOR FURTHER READING

A good general reference on carbonate sedimentology is by M. E. Tucker and V. P. Wright (1990), *Carbonate Sedimentology*; and an encyclopedic review of petroleum geology is by F. K. North (1985), *Petroleum Geology*.

REVIEW QUESTIONS

1.1. What is the difference between a reservoir and a trap?

1.2. What units of measure would you use to describe traps? To describe reservoirs?

1.3. What is the difference between a trap and a seal?

1.4. What measurements are used to determine the "efficiency," or capacity, of a seal?

1.5. What differentiates reservoir characterization from reservoir description? From reservoir engineering?

1.6. What are at least three differences between carbonate and terrigenous sandstone reservoirs?

1.7. What type of data would explorationists use to identify subsurface structural anomalies in untested areas?

1.8. What, according to Focke and Munn (1987), is a characteristic of carbonate reservoir porosity that must be taken into consideration when making fluid saturation calculations with the Archie equation?

1.9. Which wireline logs would you use to create depositional facies maps in carbonate reservoirs?

1.10. What is the main difference between carbonate reservoirs and carbonate aquifers?