LITHOLOGIC CONTROLS OF TIERED PRESSURE

DISTRIBUTIONS IN SELECTED

SEDIMENTARY BASINS

By

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TABLE OF CONTENTS

Chapter Page

LIST OF TABLES

LIST OF FIGURES

Figure Page

CHAPTER I

INTRODUCTION

Pressure-depth data, quantified from Repeat Formation Tests (RFT), Drill Stem Tests (DST), shut-in pressures, and mud weight conversions, were gathered and analyzed for more than 75 basins worldwide (Figure 1). Most of these sedimentary basins exhibit distinct patterns of subsurface pore-fluid pressure distribution. Data analysis established that basins with like depositional histories contain similar spatial distributions of pressure that appear to be lithofacies controlled.

Pressure distribution patterns in sedimentary basins can be classified into two systems, linear or tiered. Linear systems (Figure 2) represent a systematic increase in pressure with increasing depth. A tiered system contains distinct pressure domains or compartments whose distribution patterns are categorized as stepped, recessed, and ledged. Pressures in a stepped system (Figure 3) increase with depth and form a staircase pattern. Recessed systems (Figure 4) are formed by a subnormally pressured interval, amid normal pressures, above and below. Ledged systems (Figure 5) consist of an overpressured domain or compartment with subjacent and superjacent normally pressured intervals.

Abnormal pressures (Figure 6) can be defined as pressures that deviate from the normal hydrostatic pressure at any given depth (Fertl, 1976). Depending on the location

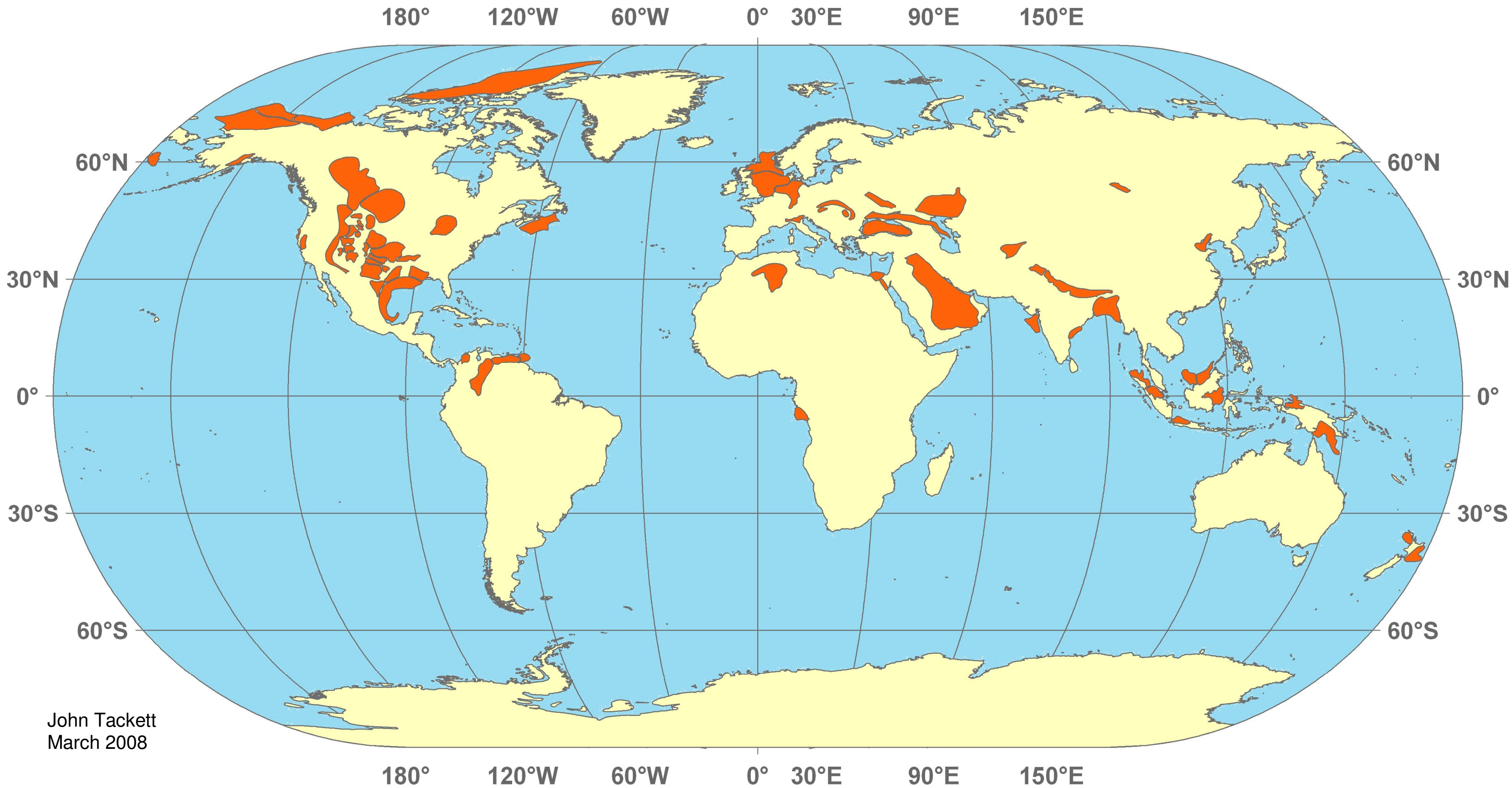

Figure 1. Global distribution of sedimentary basins (orange) where PDP data was used. Basin terminology used in this study is referenced to St. John and other, 1984.

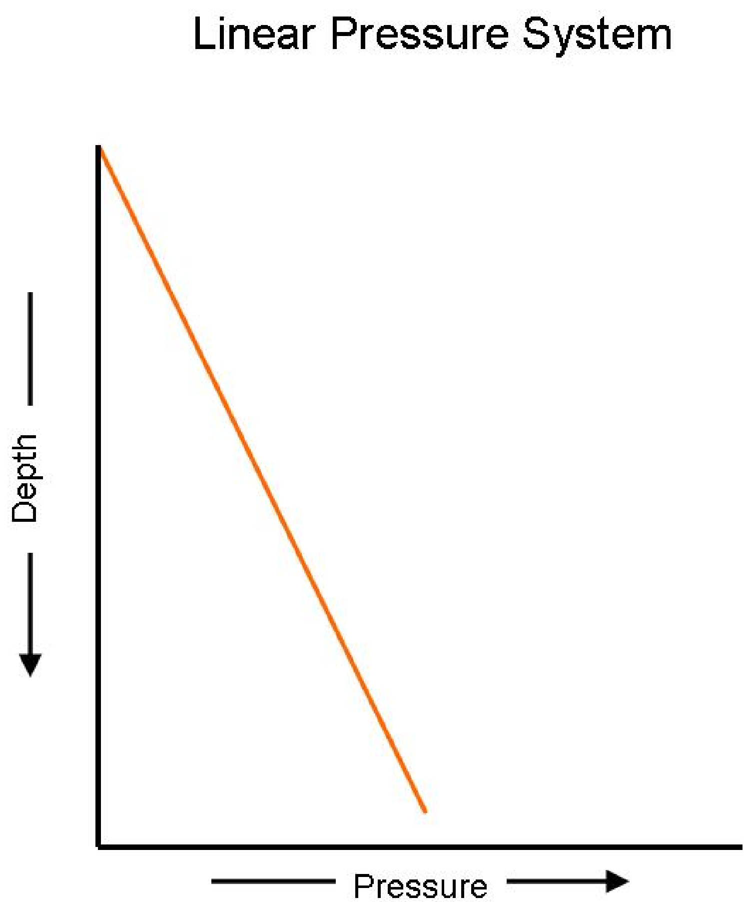

Figure 2. A graphical generalization of a linear pressure distribution.

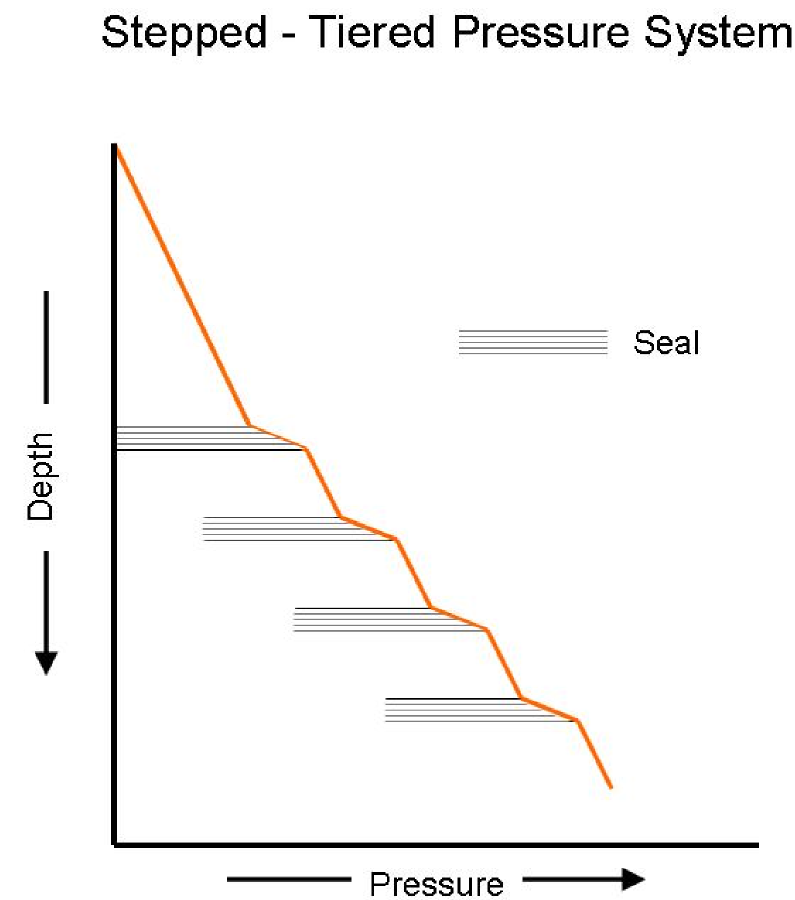

Figure 3. Graphical representation of a stepped-tiered pressure distribution. Profile is distinguished by an upper normally-pressured regime and a stepped-overpressured regime.

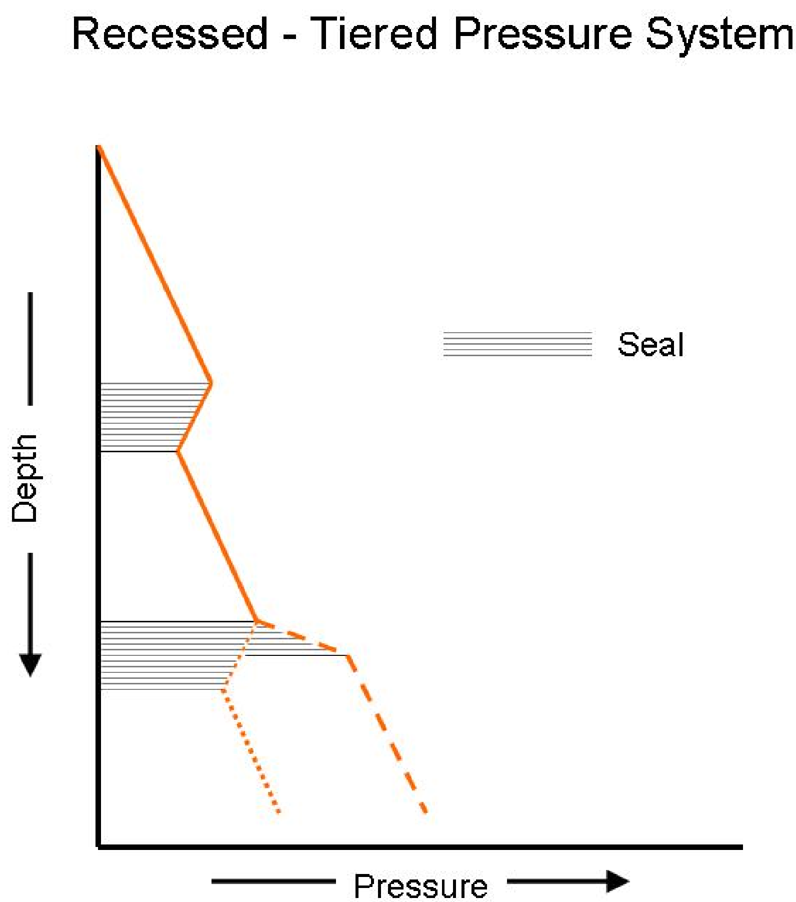

Figure 4. Graphical representation of a recessed-tiered pressure distribution, which is identifiable by underpressured regimes below a normally pressure regime, in some cases pressures can advert back to normally pressured below the underpressured regime.

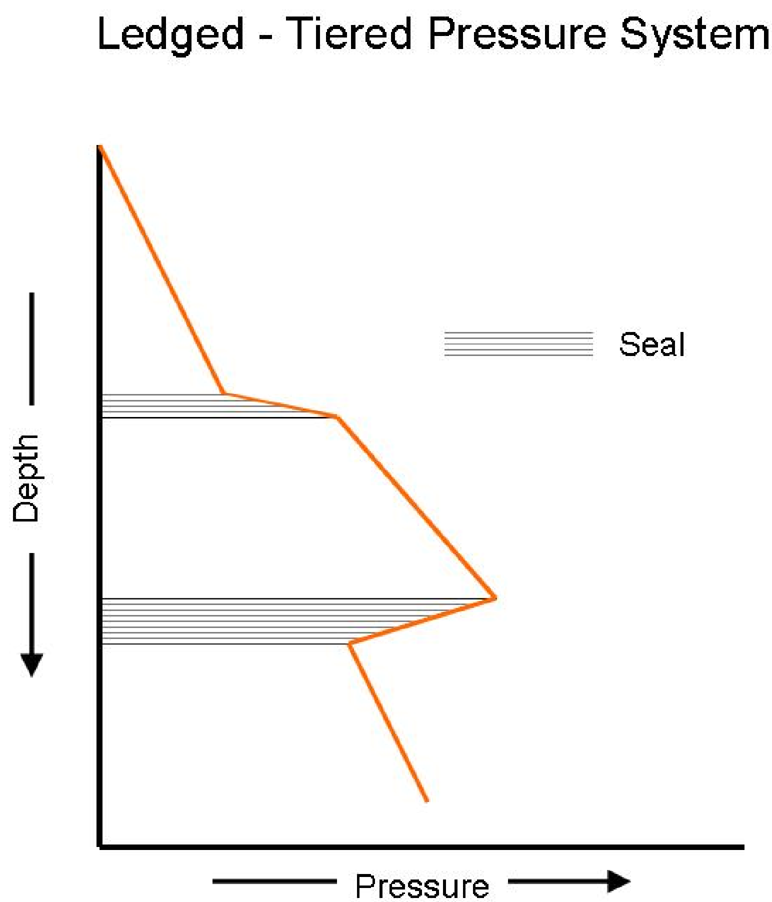

Figure 5. A graphical representation of a ledged-tiered pressure distribution, distinguished by a normally pressured regime overlying and underlying an overpressured regime.

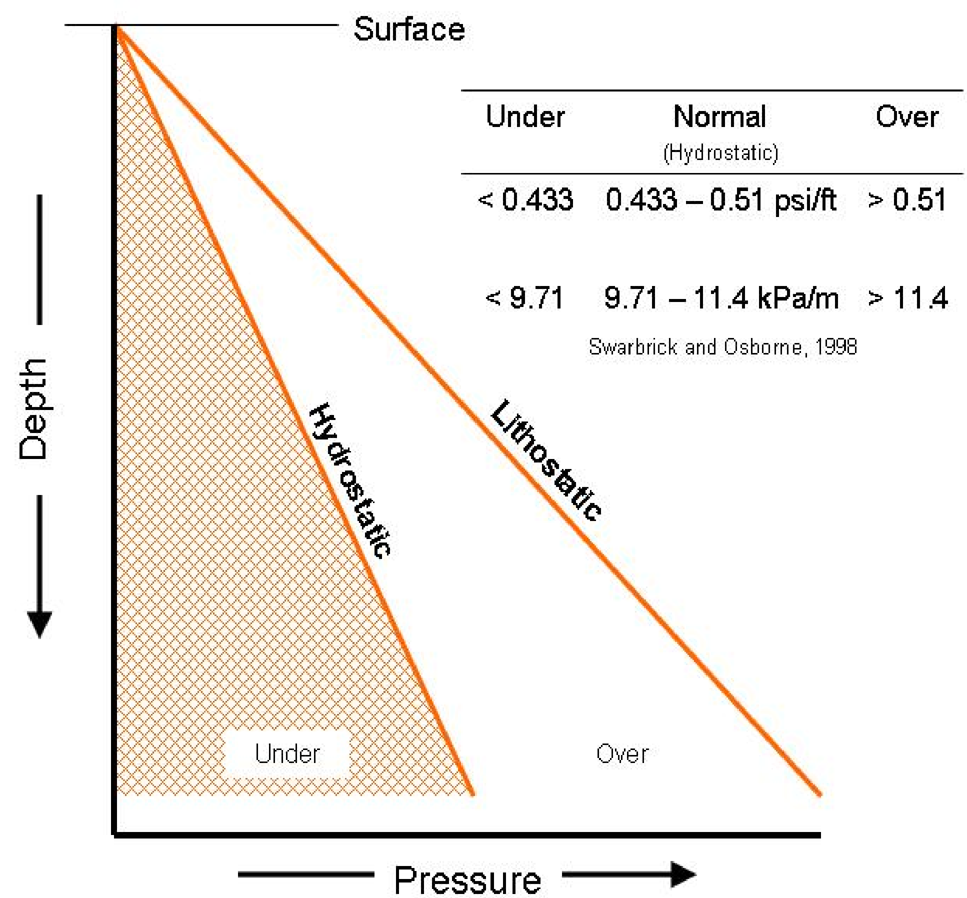

Figure 6. A graphical representation of abnormal pressures in the subsurface.

and type of formation water present, normal pressures are those that are maintained with a range of gradients that fall between 0.433 and 0.51 psi/ft (9.71-11.4 kPa/m). Overpressures (surpressures) and underpressures (subpressures) can thus be defined as those that are greater than 0.51 psi/ft (11.4 kPa/m) or less than 0.433 psi/ft (9.71 kPa/m), respectively. Swarbrick and Osborne (1998) suggested that abnormal pressures are a function of four principal variables: permeability of the rocks, timing and rate of pressure generation/depletion, fluids within the rock, and causal mechanisms that generate the abnormal pressures. These variables are all important in understanding the distribution of pressures and are discussed in more detail in a following chapter.

The occurrence and magnitude of abnormal pressures in tiered pressure systems have a profound impact on the petroleum industry. Prior to the mid-1980s, abnormal pressures were studied because of concerns for drilling and completion practices, and the safety thereof. If the pressures were too high and not controlled, a blow out could occur. If abnormally low pressures were encountered, a loss of circulation might occur, causing drilling difficulties such as pipe sticking, presumably damaging equipment and the possible loss of the hole. A recent shift in the focus regarding abnormal pressures has occurred. Today, abnormal pressures are an important factor in the exploration and development of hydrocarbon reservoirs. The possible implications of abnormal pressures on exploration and production are numerous. Further studies may lead to a better understanding of fluid migration and accumulation. Eventually research may lead to the development of better procedures for the exploration, development, and production of hydrocarbons.

Patterns of pressure distribution in sedimentary basins led to the following conceptual models. If lithologies in tiered sedimentary basins influence or are associated with certain pressure regimes, (e.g., high, normal, or under), an understanding of this relationship would ultimately facilitate the evaluation of hydrocarbon potential for provinces within these basins. The research in this thesis is based on the hypothesis that pressure regimes in sedimentary basins are associated with certain lithologies. Understanding the relationships between the fluid pressures and lithology/stratigraphy could help allow pressure prediction and help alleviate or mitigate risks associated with drilling, and improve hydrocarbon recovery. Furthermore understanding the relationship between pressure and fluid migration path and hydrocarbon accumulations in tiered basins, enhances our ability to find and produce oil and gas. While pressure distribution patterns can be generalized, the shear dynamics and complexities of the Earth are often demonstrated when subtle changes in patterns reflect significant changes.

To test the hypothesis that certain pressure domains and patterns are influenced by lithology, over 300 individual pressure-depth profiles (PDPs) from more than 75 sedimentary basins (Table 1) were collected and analyzed. The location of each PDP was plotted in their respective basin using ARC GIS. Data from the PDPs were then tabulated. The resulting table allowed the pressure distribution in each basin to be classified as either the linear or tiered system. The tiered basins were then further subdivided and classified as: ledged, stepped, or recessed.

With the completion of the classification of each PDP, nine basins (Figure 7) were chosen for further examination, three from each tiered pressure system: stepped – North Sea, Nile Delta, Sacramento, recessed – Wind River, Big Horn, Alberta, and ledged –

Table 1

BASIN	COUNTRY	PRESSURE SYSTEM	TIERED CLASSIFICATION	# OF PDPs
AL AZRAQ	JORDAN	TIERED	RECESSED	1
ALBERTA	CANADA	TIERED	RECESSED	12
ANADARKO	USA	TIERED	LEDGED	39
ARABIAN	MIDDLE EAST	TIERED	STEPPED	3
ARKOMA	USA	TIERED	RECESSED	4
BENGAL	BANGLADESH/BURMA/INDIA	TIERED	STEPPED	2
BIG HORN	USA	TIERED	RECESSED	3
BLACK SEA	RUMANIA/USSR/TURKEY	TIERED	multiple	1
BOHAI	CHINA	TIERED	STEPPED	1
BOMBAY	INDIA	TIERED	STEPPED	1
BRUNEI-SABAH	MALAYSIA	TIERED	STEPPED	1
CABINDA	CONGO/GABON/ZAIRE/ANGOLA(CABINDA)	LINEAR	none	1
CARPATHIAN	CZECHOSLAVAKIA/POLAND/RUMANIA/USSR	LINEAR	none	1
CASPIAN NORTH	USSR	LINEAR	none	1
CAUCASAS NORTH	RUSSIA	TIERED	STEPPED	1
CENTRAL SUMATRA	INDONESIA	LINEAR	none	2
COOK INLET	USA - ALASKA	TIERED	STEPPED	1
CRAZY MOUNTAINS	USA	LINEAR	none	1
DALHART	USA	TIERED	multiple	14
DENVER	USA	TIERED	RECESSED	8
DNEPR-DONETS	USSR	TIERED	STEPPED	1
EAST TEXAS SALT DOME	USA	TIERED	LEDGED	7
EEL RIVER	USA	TIERED	STEPPED	1
FT. WORTH	USA	LINEAR	none	1
GANGES	INDIA	TIERED	STEPPED	1
GREEN RIVER	USA	TIERED	LEDGED	2
GULF COAST	MEXICO/USA	TIERED	STEPPED	36
GULF OF SUEZ	EGYPT	TIERED	STEPPED	5

Table 1 (cont.)

BASIN	COUNTRY	PRESSURE SYSTEM	TIERED CLASSIFICATION	# OF PDPs
HAWKES BAY	NEW ZEALAND	TIERED	LEDGED	1
HENRY MOUNTAINS	USA	TIERED	RECESSED	1
IRKUTSK	USSR	TIERED	LEDGED	1
KAIPOROWITS	USA	LINEAR	none	1
KRISHNA	INDIA	TIERED	STEPPED	1
LLANOS DE CASANARE	COLOMBIA/VENEZUELA	LINEAR	none	1
LOWER MAGDALENA	COLOMBIA	TIERED	STEPPED	1
MACKENZIE	CANADA	LINEAR	none	3
MAHAKAM	INDONESIA	none	none	1
MATURIN	VENEZUELA	TIERED	LEDGED	1
MEERVLAKTE	INDONESIA	TIERED	STEPPED	1
MICHIGAN	USA	TIERED	LEDGED	8
MISSISSIPPI SALT DOME	USA	TIERED	STEPPED	4
NAVARIN	USA - ALASKA/USSR	TIERED	STEPPED	5
NILE DELTA	EGYPT	TIERED	STEPPED	2
NORTHLAND	NEW ZEALAND	TIERED	STEPPED	1
NORTH SLOPE	USA - ALASKA	TIERED	STEPPED	1
NORTHERN NORTH SEA	NORWAY/UNITED KINGDOM	TIERED	STEPPED	7
NORTHWEST GERMAN	NETHERLANDS/WEST GERMANY	LINEAR	none	1
NUWUK	USA - ALASKA	TIERED	STEPPED	1
ORINOCO DELTA	TRINIDAD/VENEZUELA	TIERED	STEPPED	7
PALO DURO	USA	LINEAR	none	8
PAPUAN	PAPUA NEW GUINEA	TIERED	STEPPED	1
PARADOX	USA	LINEAR	none	1
PERMIAN	USA	TIERED	LEDGED	36
PO	ITALY	TIERED	STEPPED	1
POTWAR	PAKISTAN	TIERED	LEDGED	2
POWDER RIVER	USA	TIERED	RECESSED	2
RATON	USA	LINEAR	none	2
RED DESERT	USA	TIERED	STEPPED	2

Table 1 (cont.)

BASIN	COUNTRY	PRESSURE SYSTEM	TIERED CLASSIFICATION	# OF PDPs
SACRAMENTO	USA	TIERED	STEPPED	3
SAHARA	ALGERIA	LINEAR	none	1
SAN JUAN	USA	TIERED	LEDGED	2
SARAWAK	MALAYSIA	TIERED	STEPPED	1
SCOTIA SHELF	CANADA	TIERED	STEPPED	2
SOUTH TEXAS SALT DOME	USA	TIERED	STEPPED	2
SOUTHERN NORTH SEA	NETHERLANDS/UNITED KINGDOM/DENMARK	TIERED	STEPPED	7
SUMATRA	INDONESIA	none	none	1
SVERDRUP	CANADA	LINEAR	none	1
TADZHIK	AFGHANISTAN/USSR	TIERED	STEPPED	1
TRANSYLVANIAN	RUMANIA	TIERED	STEPPED	1
UINTA	USA	TIERED	RECESSED	1
VIENNA	AUSTRIA	TIERED	LEDGED	1
WASHAKIE	USA	LINEAR	none	2
WEST JAVA	INDONESIA	TIERED	STEPPED	1
WESTERN OVERTHRUST	USA	LINEAR	none	1
WILLISTON	CANADA/USA	TIERED	STEPPED	4
WIND RIVER	USA	TIERED	RECESSED	1

Table 1. Listing of basins with PDP data. The table lists some of the attributes for each basin. Under "tiered classification", "multiple" = a basin with more than one classification (i.e. Black Sea = tiered & ledged) and "none" = does not fall into tiered classification.

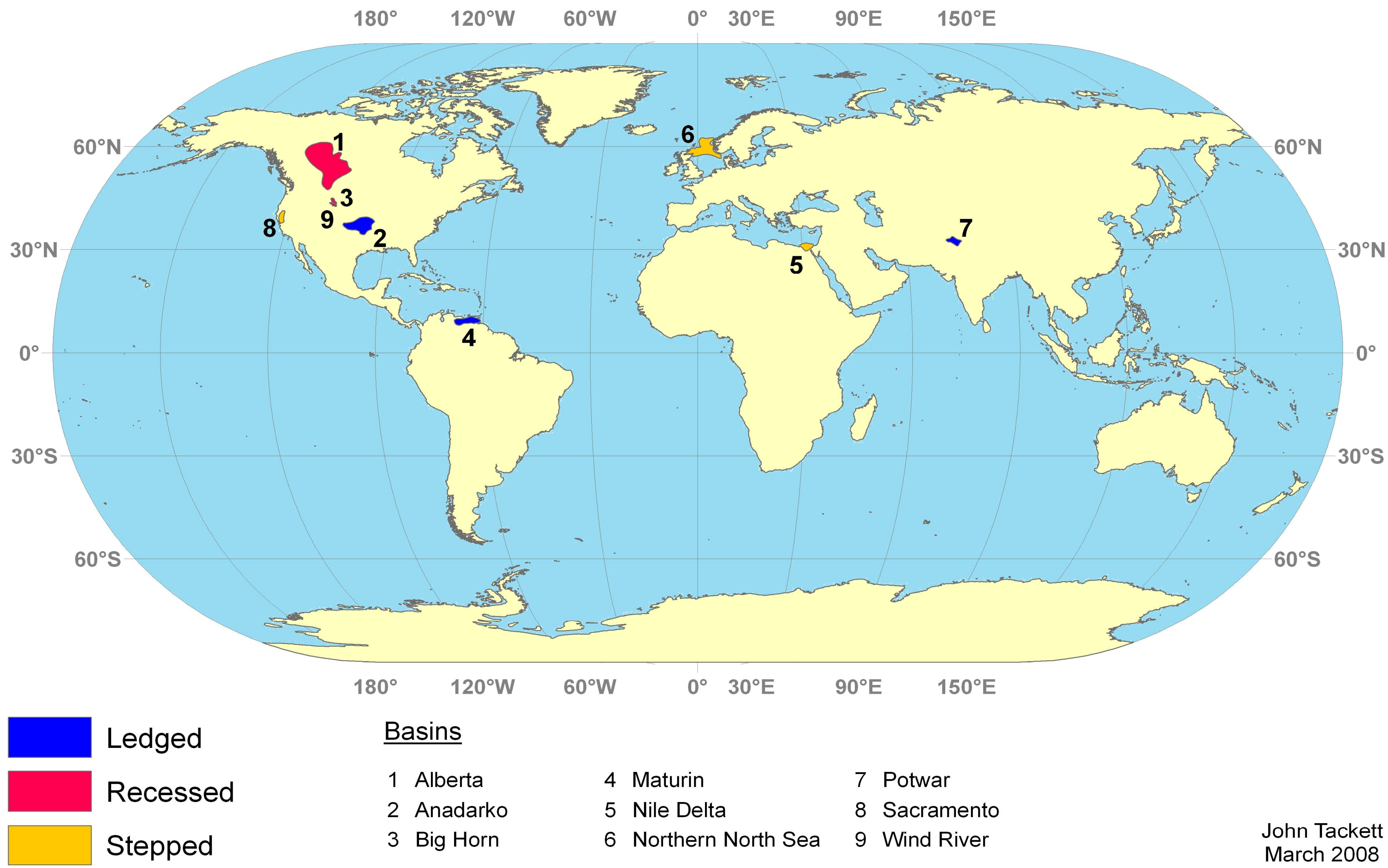

Figure 7. Map showing the location of the basins chosen for a further in depth study of the relationship of pressures and lithologies.

Anadarko, Maturin, Potwar. Published data from literature pertaining to the geologic history, stratigraphy, and pressure distribution for each basin were used to establish stratigraphy and basin evolution. Individual PDPs for each of the nine basins were correlated to stratigraphy. Lithotypes within each stratigraphic section were determined using well data and the descriptions from literature sources and plotted with the pressure data on the PDP. Generalized lithologic columns were constructed and related to their respective pressure domains. The relationship between pressure and lithology within each basin was established using there stratigraphically constrained PDPs.

CHAPTER II

FUNDAMENTAL REVIEW OF ABNORMAL PRESSURES

Abnormal pressures occur in almost every sedimentary basin. Understanding the evolution and preservation of abnormal pressures is paramount to the research set forth. As such, it is important to fully understand the mechanisms that generate abnormal pressures and the architecture required.

Swarbrick and Osborne (1998) identified four principal aspects that one must know in order to understand abnormal pressures. They are mechanisms that generate abnormal pressures, permeability, timing and rate of pressure generation/depletion, and fluid type. Most research done on the subject of abnormal pressures seems to encompass one or a combination of these topics. Identifying such aspects of abnormal pressures is of interest to petroleum geologist because they affect the productivity and economic evaluation of the reservoirs, ultimately enhancing the effectiveness of exploration programs (Bradley, 1975).

Fluid Type

The most common type of fluid in any basin is water, either fresh or brine. Total dissolved solids within the fluid, which affects density and viscosity and influences flow properties, determines the pressure gradient (Swarbrick and Osborne, 1998). Fluid and flow properties, where oil and gas are present, are dependant on the composition of the hydrocarbons, temperature, hydrocarbon saturation, and rock properties. Hydrocarbons seem to have a significant influence on overpressures, where their buoyancy and capillary effects can control relative permeability and entry pressure (Swarbrick and Osborne, 1998). However, buoyancy is inversely related to fluid density. Areas with elevated pressures often contain less dense fluids, which are more buoyant. An example is the Central North Sea graben where the deeper reservoirs with higher pressures have higher API liquids than the shallow, lower pressured reservoirs (Isaksen, 2004).

Timing and Rate of Pressure Generation/Depletion

Abnormal pressures tend to be in disequilibrium and will change over geologic time depending on the rate of generation or dissipation. This change depends on the evolution and dynamics of the system, including effective permeability, which may stay the same or approach zero, the phase of the pressures (over- or under), and are they static (is pressure being generated or dissipated?). In most cases it is unlikely, and very difficult, to maintain static pressures over geologic time (Swarbrick and Osborne, 1998). Two contrasting models for the development of abnormal pressures can be differentiated on the basis of timing and rate of pressure generation/depletion: the static model, not time dependant, of Hunt (1990) and the dynamic model, time dependant, of Bredehoeft et al.

(1994). Because of the ephemeral nature of pressures, always seeking equilibrium, they will change given enough time.

Permeability

Permeability is an intrinsic property of a rock that is controlled by size, shape, and tortuosity of grains and the fluids within (Swarbrick and Osborne, 1998). In a petroleum system, permeability differences distinguish the reservoir and non-reservoir rocks. The non-reservoir rocks, or seals, are the primary requirement for the existence of abnormal formation pressures; without a seal, the pressures would equalize and become normally pressured (Bradley, 1975). There are two distinct types of sealing mechanisms for reservoirs; (1) a seal which forms an impermeable boundary on one or more sides of a reservoir that is still in hydraulic continuity with the surface, and (2) seals that completely isolate a compartment from its' surroundings.

A seal is defined as a rock which prevents the natural buoyancy-related upwards migration of hydrocarbons. Seals can be classified as the following types:

Stratigraphic Seals: These seals are made up of a single, roughly uniform lithologic unit that has been compacted or cemented due to its original chemistry or texture. Examples of this type of seal are shales and anhydrite beds (Ortoleva, 1994).

Diagenetically Banded Seals: Seals that have internally layered structure that developed through diagenesis and are more locally oriented when compared to the lithologic unit. Horizontal and vertical diagenetically banded seals have been observed (Ortoleva, 1994).

Repetitively Banded Seals: Seals where banding involves many alterations of the same textural repetition unit. Dewers and Ortoleva (1988) observed two distinct patterns: one was roughly regularly spaced arrays of stylolites, dissolution seams, and related features, and the other was bands of augmented compaction and porosity alternating with bands of relatively highly cemented rock (Ortoleva, 1994).

Precipitated Seals: These are seals that resulted from the precipitation of cements. The most notable precipitated seal is carbonate cemented sandstone, where the carbonate has filled pores or fractures or even replaced entire grains (Ortoleva, 1994).

Gradational Seals: These are seals that follow gradational changes of textures within the rock itself. They do not necessarily follow the lithologic boundaries (Ortoleva, 1994).

Fault Associated Seals: Seals can be associated with faults in the subsurface. The fault itself may be the seal, contain, or have served as a disturbance or nucleus that developed a seal adjacent to it through an interaction of the fault and its environment during diagenesis (Ortoleva, 1994).

Compartments are defined as "a domain of rock of relatively good hydraulic connectivity and porosity surrounded by a shell-like domain of rock of sufficiently low permeability that the fluids within the compartment do not have appreciable exchange with the environment for long periods of geologic time" by Ortoleva (1998) (p. 41). Compartments can be classified as one of the following types:

Powley-Bradley Compartments: This type of compartmentalization (Figure 8-A) occurs as a framework of boxes, where individual compartments are stacked or laid side-by-side in a sedimentary basin. Each "box" or compartment has its own pressure regime and associated seals.

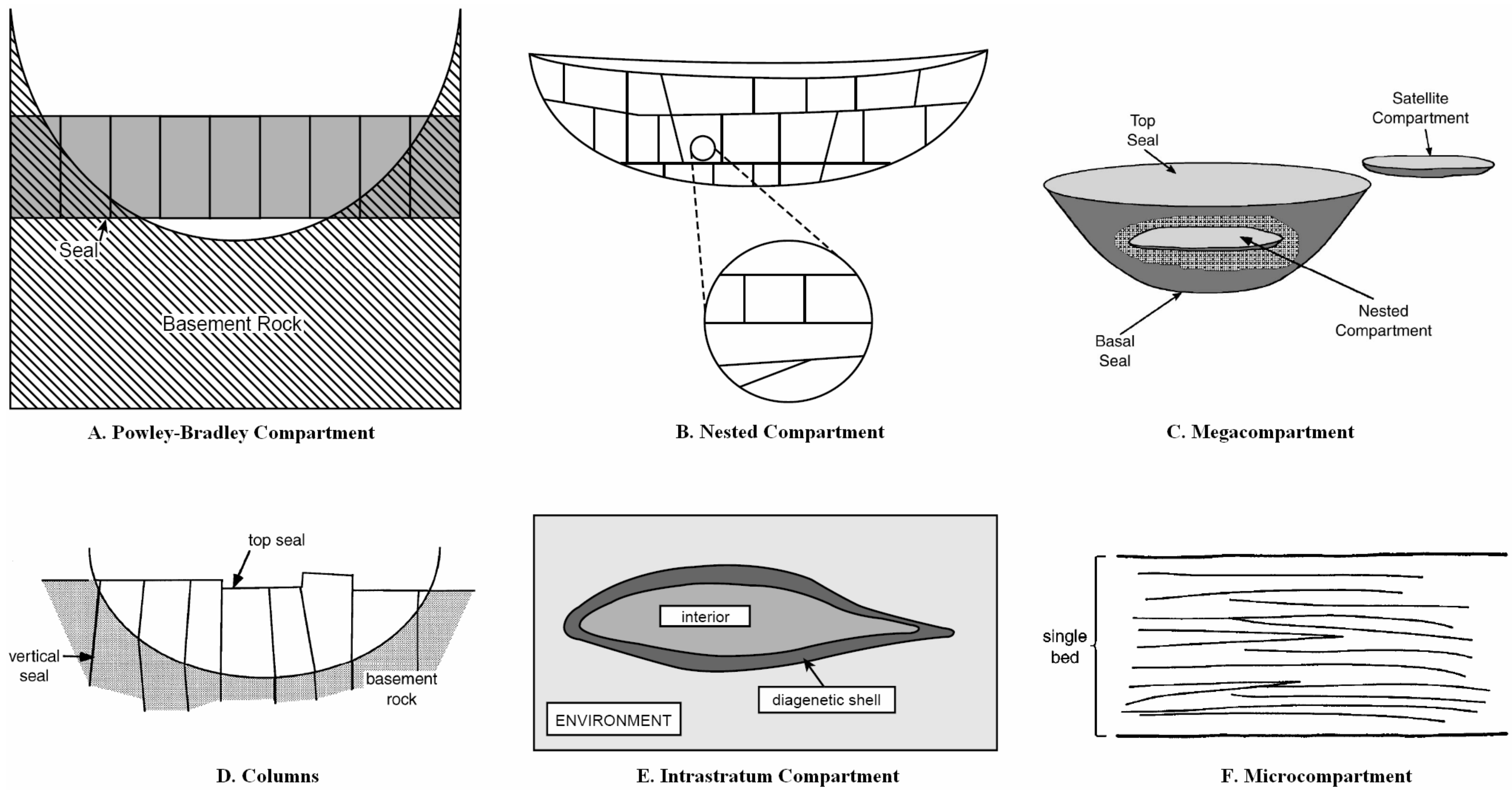

Figure 8. Concepts of the different compartments that are theorized to occur in the subsurface (Ortoleva, 1994).

Nested Compartments: Nested compartments (Figure 8-B) reside within other compartments. The nesting can occur at a regional-basinal scale to the local-sub-meter scale (Ortoleva, 1994).

Megacompartment: A megacompartment (Figure 8-C) is a basin-scale compartment with a diagenetic top seal and stratigraphic basal seal. A megacompartment is often associated with an assemblage of nested and satellite compartments creating a megacompartment complex (Ortoleva, 1994).

Columns: A column (Figure 8-D) is an elongate compartment that has no outright recognizable basal seal. Either the basal seal is gradational or the base extends to the basement rock (Ortoleva, 1994).

Intrastratum Compartment: This is a compartment (Figure 8-E) where the entire compartment lies within an individual stratum. The bounding seal may exist either within the stratum or be associated with the boundary between it and the surrounding rock. This type develops both the seal and compartment original to the sedimentary stratum (Ortoleva, 1994).

Microcompartment: This type of compartment (Figure 8-F) is a very thin layer of rock lying wholly within a single stratum that is hydraulically isolated from the surrounding strata. This type of compartment may appear as a layered sequence (Ortoleva, 1994).

In a single phase system, pressures cannot be maintained by a single seal and therefore must rely on compartmentalization, but in a multiphase system, containing water-oil-gas; abnormal pressures can be maintained by a seal because of the buoyancy effect of the hydrocarbons in water (Bradley, 1975). Abnormal pressures are not static so the implication for seals and compartments should only be used in terms of a restriction to flow (Swarbrick and Osborne, 1998). This restriction to flow assists in the creation of abnormal pressures and hydrocarbon accumulations.

Mechanisms that Generate Abnormal Pressure

The amount and rate at which abnormal pressures are generated relate directly to the mechanisms that generate them. A wide variety of mechanisms have been proposed for the generation of abnormal subsurface pressures (Table 2). These mechanisms can be grouped into three main categories: stress-related, fluid volume, and fluid movement and buoyancy (Swarbrick and Osborne, 1998). Both overpressures and underpressures are generated by mechanisms that fit into each of these categories. Some of the more important mechanisms are those that evolve by mechanical means (Swarbrick and Osborne, 1998).

Overpressure Mechanisms

Mechanisms that generate overpressures are at the front among abnormal pressure research because of the ease at which they can be observed worldwide (Fertl, 1976). Hunt (1990) identifies 180 areas worldwide where overpressures have been recognized. Although in most cases hydrocarbons are associated with the overpressures, a universal relationship between overpressures and hydrocarbons is not recognizable (Swarbrick and Osborne, 1998).

Table 2

Abnormal Pressure Mechanisms

Mechanism	Summary	Type Locality	Reference
<u>Overpressures</u>			
Stress Related			
Disequilibrium Compaction	fluids can not be expelled fast enough when compacted by overburden	Adriatic Basin, Italy	Carlin & Dainelli, 1998
Tectonic Stress	“” when compacted by horizontal compressive stresses	Sacramento Basin, USA	Berry, 1973 Lico & Kharaka, 1983
Fluid Volume Changes			
Temperature Increase	fluids are heated creating a change in volume	NA	Barker, 1972
Mineral Transformation	water is released during transformations	Dampier sub-Basin, Australia	Nyein et al., 1977
Hydrocarbon Generation	HC generated from solid immobile kerogen	Dnieper-Donets Basin, Ukraine	Polutranko, 1998
Cracking of Oil to Gas	gas generated from oil	Williston Basin, USA	Meissner, 1978
Fluid Movement & Buoyancy			
Osmosis	fluid movement based on differences in concentration	Anadarko Basin, USA	Breeze, 1973
Hydraulic Head	forces of water in recharge area	NA	Nuezil, 1995
Buoyancy	density differences of oil, gas, water	NA	Swarbrick & Osborne, 1998
<u>Underpressures</u>			
Stress Related			
Rock Dilatancy	dilation of pores from uplift, erosion, or unloading	Songliao Basin, China	Xie et al., 2003
Fluid Volume Changes			
Thermal Effects	fluids are cooled creating a change in volume	NA	Barker, 1972
Fluid Movement & Buoyancy			
Osmosis	fluid movement based on differences in concentration	Anadarko Basin, USA	Breeze, 1973
Differential Gas Flow	gas expels faster than it is generated	San Juan, Basin, USA	Law & Dickinson, 1985
Groundwater Flow	groundwater is discharged faster than recharged	Denver Basin, USA	Belitz & Bredehoeft, 1988
<u>Transference</u>	pressures are transferred	North Sea Basin, UK	Cayley, 1987

Table 2. Tabulation of mechanisms that generate abnormal pressures and some localities where these mechanisms are believed to function.

Stress-Related Mechanisms

Disequilibrium Compaction (Vertical Loading Stress)

This mechanism is related to the vertical stresses on rocks during burial. Under normal conditions, in either rapid or slow sedimentation, the equilibrium between overburden stress and reduction of pore fluid volume is easily maintained by the expulsion of fluids with simultaneous compaction. However in those cases where the fluids cannot be expelled fast enough, the pressure of pore fluids increases, causing disequilibrium compaction (Swarbrick and Osborne, 1998).

Tectonic (Lateral Compressive Stress)

The same outcome as the disequilibrium compaction is generated from tectonic stresses. Compaction and incomplete dewatering occurs, but in this case the stresses are applied by horizontal tectonic compression. This is often the overpressure mechanism along major fault zones, both within the fault and adjacent strata (Swarbrick and Osborne, 1998).

Fluid Volume (Increase) Mechanism

Temperature Increase (Aquathermal Expansion)

This principle is based on the expansion of water when heated above 4°C. There is a critical condition that must be met though. For this mechanism to increase pressure, the reservoir must be completely contained and isolated from surrounding pressure environments with no change in pore volume (Swarbrick and Osborne, 1998). While several studies have shown that the conditions for this mechanism are rarely met, Hunt

(1990) suggests that there are deep (≈ 3.0 km) diagenetic seals that are laterally extensive enough to satisfy the conditions for aquathermal expansion.

Mineral Transformation – Water release due to mineral diagenesis

This mechanism generates overpressures as bound water is released during mineral transformations. The most common of these transformations is smectite dehydration. Smectite dehydration can increase the volume of pore fluids by 4.0%, but only if the reservoir is compartmentalized (Swarbrick and Osborne, 1998). The transformation of gypsum to anhydrite can potentially generate pressures in excess of lithostatic stresses (Swarbrick and Osborne, 1998). This transformation is important in evaporite dominated sections. The transformation of a potentially water-saturated smectite to illite can also generate overpressures, but the overall volume change from the reaction are not well constrained (Swarbrick and Osborne, 1998). Most mineral transformations are thought to be secondary mechanisms for overpressure generation; often they occur in conjunction with some degree of disequilibrium compaction (Swarbrick and Osborne, 1998).

Hydrocarbon Generation

The generation of liquid and gaseous hydrocarbons from solid kerogen has been linked to the generation of overpressures in the subsurface (Swarbrick and Osborne, 1998). The generation of hydrocarbons from mature source rocks releases fluids (oil and gas) into the pore spaces. If the pores are already saturated and the fluid can not migrate, either due to seals or compartmentalization, the formation pressures should increase. Oil generation can increase fluid volumes by 25% while gas generation has shown volume increases of 50 to 100% (Swarbrick and Osborne, 1998). In any sedimentary basin, the overpressures generated by this mechanism are dependant upon the availability of maturing source rocks within hydraulic connectivity of the reservoir.

Oil and Bitumen to Gas Cracking

Thermal cracking of oil and bitumen to gas is initiated at temperatures of 120°-140°C and completed at temperatures in excess of 180°C. This process increases one volume of standard crude oil to 534.3 volumes of gas and residue. If the reservoir is compartmentalized or sealed very well there would be an immediate and dramatic increase in pressure as the oil cracks to gas (Swarbrick and Osborne, 1998).

Fluid Movement and Buoyancy Mechanism

Osmosis

Osmotic pressure arises when two solutions of different salinities are separated by a semipermeable seal (Fertl, 1976). Diffusion will result in the transfer solute from the less dilute to the more dilute solution. If the reservoir on the more concentrated side of the seal is already saturated then it should in theory become overpressured. There is some doubt concerning the effectiveness of this mechanism though. It has been observed the brines in overpressured zones tend to be of lower salinity than adjacent normally pressured brine, which would act to reduce the pressure in the overpressured zones (Swarbrick and Osborne, 1998).

Hydraulic Head

The hydraulic head or potentiometric head resulting from elevation of the water table in recharge areas will produce an artesian affect if the reservoir is overlain by a seal. This artesian affect, which produces water flow at the surface due to excess pressure, will create overpressured reservoirs in the subsurface if the reservoir maintains lateral continuity beneath a seal (Swarbrick and Osborne, 1998). Also the recharge must remain constant.

Hydrocarbon Buoyancy (Density Contrasts)

All gases and most oils have a lower density than the associated formation waters and therefore will always create overpressures where there is a column of oil or gas lying on top of water (Swarbrick and Osborne, 1998). This mechanism is restricted to structural and stratigraphic traps of hydrocarbons, and does not create regional overpressures (Swarbrick and Osborne, 1998). The amount of overpressures generated by this mechanism is a function of the pressure gradients of oil, gas, and water and the height of the hydrocarbon column. Buoyancy driven pressures are often not regarded as "abnormal", but an addition to those pressures (Swarbrick and Osborne, 1998). This is in part because the addition of these pressures is minute when compared to the effects of the other mechanisms (Swarbrick and Osborne, 1998).

Transference of Pressure Mechanism

Transference is the redistribution of excess pressures in the subsurface. Transference is not a primary mechanism, but can be the principal control on the distribution of overpressures in a sedimentary basin (Swarbrick and Osborne, 1998). The migration of hydrocarbons and other fluids is driven by the differences in pressure and controlled by the permeability of the rocks. Fluids will always want to migrate from higher to lower pressures.

Subnormal Pressure Mechanisms

Subnormal pressure generating mechanisms are not as well understood as overpressure mechanisms. This is probably due to abnormally low pressures occurring les frequently than the abnormally high formation pressures worldwide (Fertl, 1976). Nevertheless, subnormal pressures are associated with many areas where hydrocarbon production occurs (Fertl, 1976).

Stress-Related Mechanisms

Rock Dilatancy

During unloading, dilation of the pores can occur (Figure 9-D). The increase in pore volume may and often does facilitate the dissipation of pressures. Ultimately the amount of dilation is related to the rate of overburden removal and rock permeability (Swarbrick and Osborne, 1998). Recent modeling suggests that uplift and erosional forces resulting in rock dilatancy are a major cause of subnormal pressures (Swarbrick and Osborne, 1998).

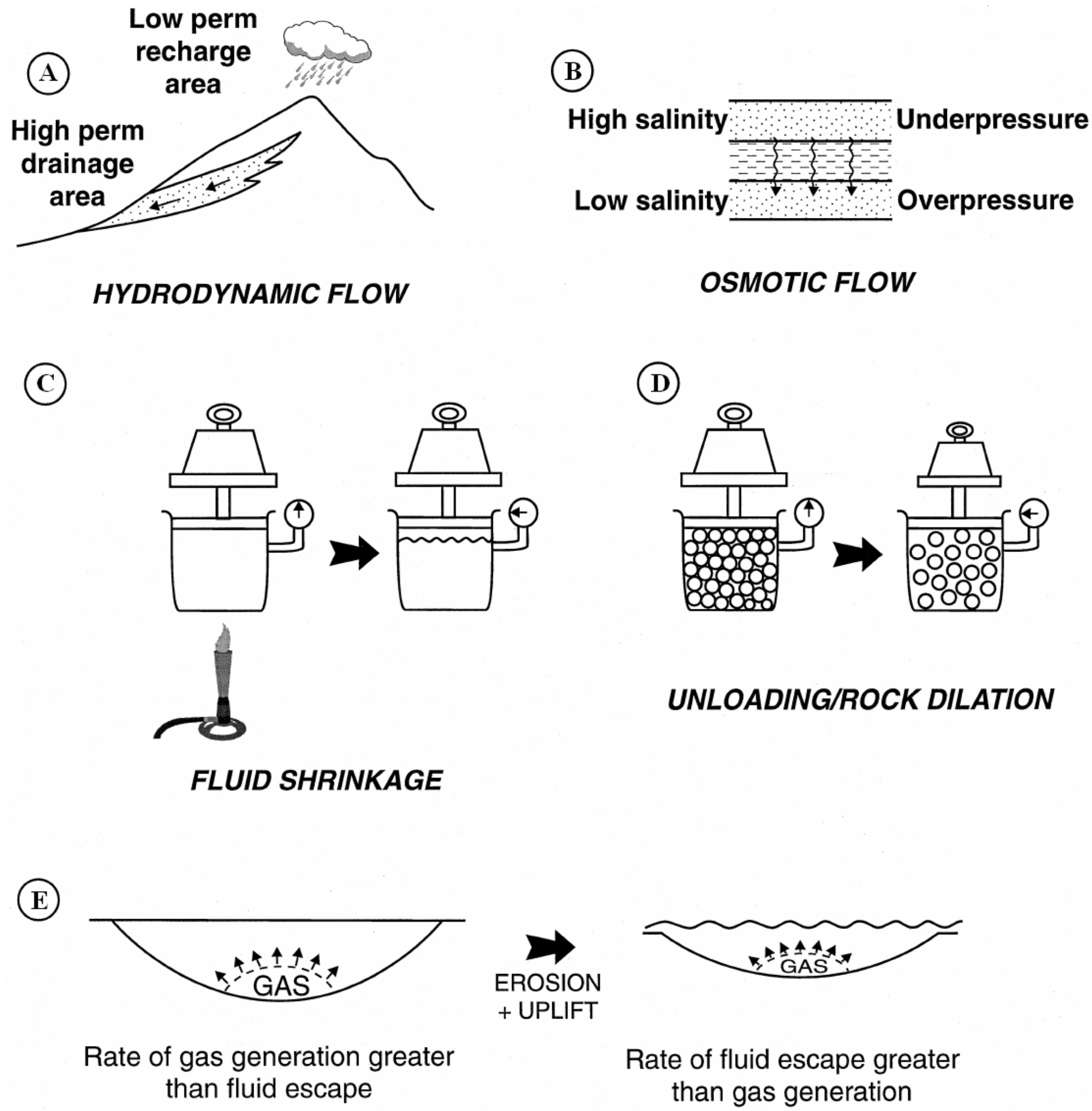

Figure 9. Summary diagram for the major mechanisms thought to generate underpressured reservoirs (Swarbrick and Osborne, 1998).

Fluid Volume (Decrease) Mechanism

Thermal Effects

When water and/or hydrocarbons in a compartment are cooled, fluid density will decrease, resulting in a fluid volume reduction. The volume changes in hydrocarbons are greater than those in the formation waters because of the higher compressibility of oil and gas (Swarbrick and Osborne, 1998). This mechanism (Figure 9-C) is thought to produce underpressured reservoirs where there is compartmentalization.

Fluid Movement and Buoyancy Mechanism

Differential Discharge – Groundwater Flow

Subnormal pressures can occur where groundwater flow is active in the subsurface (Figure 9-A). In a topographically-driven flow system where there are very low permeability rocks in the recharge area, and highly permeable rocks in the outflow area, subnormal pressures can occur because the flow out of the system will exceed inflow. As a result, a continuous column of water to drive normal hydraulic pressures is lacking (Swarbrick and Osborne, 1998). Also, underpressuring due to steady-state regional ground water flow is possible in any subaerial, topographically tilted basin that is capped by a thick sequence of low permeability rocks (Swarbrick and Osborne, 1998). This mechanism can also operate where low-permeability barriers disconnect a highly permeable rock in the deep basin from its exposed overlying correlative strata (Swarbrick and Osborne, 1998).

Differential Gas Flow

This mechanism (Figure 9-E) generates underpressured reservoirs during uplift, when gas exsolves due to reduction in the temperature and confining pressure. The gas migrates out of the low permeable reservoirs at a greater rate than is produced from the source rock. The imbalance between migration and generation leads to the formation of subnormal pressures (Swarbrick and Osborne, 1998).

Osmosis

The osmosis mechanism (Figure 9-B) is the same as the one identified for the generation of overpressures. There is one difference. Instead of focusing on the generation of overpressures in a reservoir, this mechanism would relieve pressures. This mechanism is not fully accepted because of the reverse mechanism that generates overpressures (Swarbrick and Osborne, 1998).

CHAPTER III

STEPPED-TIERED BASINS

This section examines three stepped-tiered basins. Included are information concerning the geologic history, stratigraphy, pressures measured, and a summary of the mechanisms that generated the pressures. The relationship between pressure and lithologies/stratigraphy for each basin is evaluated. Graphical data supporting each evaluation are provided.

Northern North Sea Basin

Geologic Setting

The Northern North Sea Basin is an intracratonic rift basin that lies beneath the present day North Sea. It is surrounded by the United Kingdom, Netherlands, Germany, Denmark, and Norway and covers an area of approximately 280,000 sq mi. (Watson and Swanson, 1975). The Hercynian orogeny along with the earlier Caledonian tectonism controlled the formation of the basin and its principal structural elements: the Viking Graben, Moray Firth, and Central Trough (Isaksen, 2004). For the purposes of this research, the Northern North Sea Basin will be limited to the Viking Graben area, in particularly, the Frigg Field.

Frigg Field of the Viking subbasin is one of the world's largest offshore gas fields (Heritier et al., 1979). Frigg Field is located approximately 190 km west-northwest of Haugesund, Norway, 180 km east of the Shetland Islands, and 390 km northeast of Aberdeen, Scotland (Figure 10). The field straddles the border of the British and Norwegian continental shelf and lies under about 100 meters of water.

In general, the history of the Viking Graben can be broken into two major geologic periods divided by the Cimmerian orogeny (Heritier et al., 1990). The pre-Cimmerian period was a positive epicontinental sedimentary cycle that began in the Triassic and ended in the Late Jurassic (Oxfordian); (Heritier et al., 1979). Next, the Cimmerian extensional phase initiated antithetic Jurassic fault blocks, as the Viking Graben subbasin formed in a north-south direction between the Shetland platform and Norwegian shelf (Heritier et al., 1990). The post-Cimmerian period was a negative open-marine sedimentary cycle that began in the Late Jurassic (Kimmeridgian) and ends with the present (Heritier et al., 1979).

Heritier et al. (1979) states that the pre-Cimmerian period comprises the continental Triassic red clastics, the Lower to Middle Lias fluviodeltaic sandy deposits, middle to Upper Lias marine shales, Dogger regressive deltaic sandstones, and the Callovian-Oxfordian marine shales. The source for the clastic sediment during this period began mainly from the Norwegian shield in the northeast, but later, during the Oxfordian shifted, more sediment was derived from the Shetland platform (Heritier et al., 1979). This period ended with the Cimmerian orogeny. This tectonic activity led to the breakup of the basin into individual subbasins and three distinctive major fault blocks, the Bruce,

Figure 10. Index map of central and northern North Sea, showing the general location of Frigg Field (adapted from Heritier, 1979).

Frigg, and Øst Frigg (Figure 11), which are present beneath the Cimmerian unconformity (Heritier et al., 1979).

After the Cimmerian orogeny, the basin received much wider transgressive infilling (Heritier et al., 1979). Sedimentation began in the late Oxfordian-Kimmeridgian with the deposition of black, organic-rich radioactive shales (Heritier et al., 1990). During the Early Cretaceous, the area became more influenced by the Boreal Sea, which caused a Lower and Middle Cretaceous shaly sequence to drape on the fault-block relief of the pre-Cimmerian period (Heritier et al., 1979). During the Aptian, Cenomanian, and Turonian stages the presence of a few regional limestone beds emphasizes the eustatic lowstand of the sea (Heritier et al., 1979). The Upper Cretaceous in the Viking Graben area consists mostly of shale but does include chalky limestone beds, while in the southern North Sea this period is represented by chalk (Heritier et al., 1979). At the end of the Cretaceous, the collapse of the Utsira High and the rejuvenation of the Shetlands-Orcadian belt was the main cause of the strong offlap of sediments from west to east, which characterizes the Tertiary strata in the area (Heritier et al., 1979). Sedimentation during the Paleocene originated in the west and was brought into the basin by turbidity currents creating fan complexes at the base of the Shetland shelf (Heritier et al., 1990). The Eocene started with an important phase of shaly sedimentation, known as the Ypresian Frigg sands and transitioned into shaly marine sequences of the Oligocene (Heritier et al., 1979). The shaly marine sediments of the Oligocene graded into more sandy intervals which dominated during the Miocene-Pliocene periods (Heritier et al., 1990).

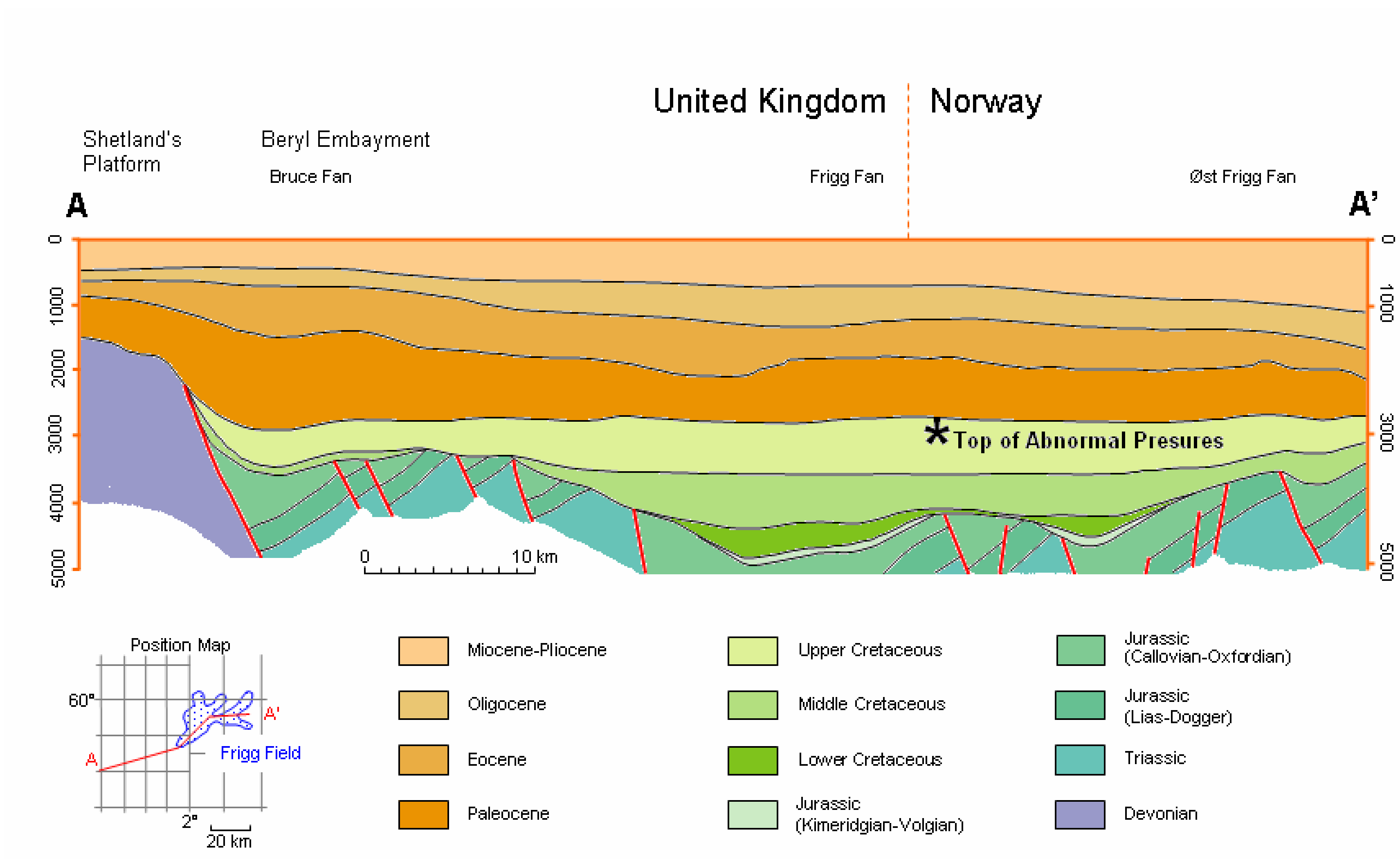

Figure 11. Generalized cross section (A-A') of Frigg Field, Northern North Sea Basin, United Kingdom and Norway (adapted from Heritier et al., 1979 and Chiarelli and Duffaud, 1980).

Pressures

The Frigg Field of the Northern North Sea Basin falls into the "Stepped-Tiered System". The general distribution of pressures on the pressure-depth profile has two portions: an upper normal and a lower overpressured (Figure 12).

The upper normal pressures occur from the seafloor to the base of the Santonian-Coniacian interval. This corresponds to Miocene-Pliocene sediments through the unconformity at the base of the Santonian-Coniacian on the stratigraphic column for the Frigg Field (Figure 13).

The lower overpressured domain occurs from the Late Cretaceous through the Triassic. This distribution encompasses sediment from the Turonian through Triassic.

Stratigraphy

Permian

The Permian system in the North Sea has two main divisions, the Zechstein and the Rotliegendes (Kent, 1967). The Rotliegendes is a sandstone that in some areas, like the Auk and Argyle fields in the central part of the North Sea, has proven to be a significant reservoir and reserve, containing 99.2 trillion cubic feet of gas and 0.9 billion barrels of oil (Watson and Swanson, 1975). The overlying Zechstein is a thick sequence of evaporites, with thick salt in the basin center that grades to carbonates toward the basin margins (Watson and Swanson, 1975). The Zechstein is also the provenance for some of the salt diapirs that form in some localities of the North Sea (Kent, 1967).

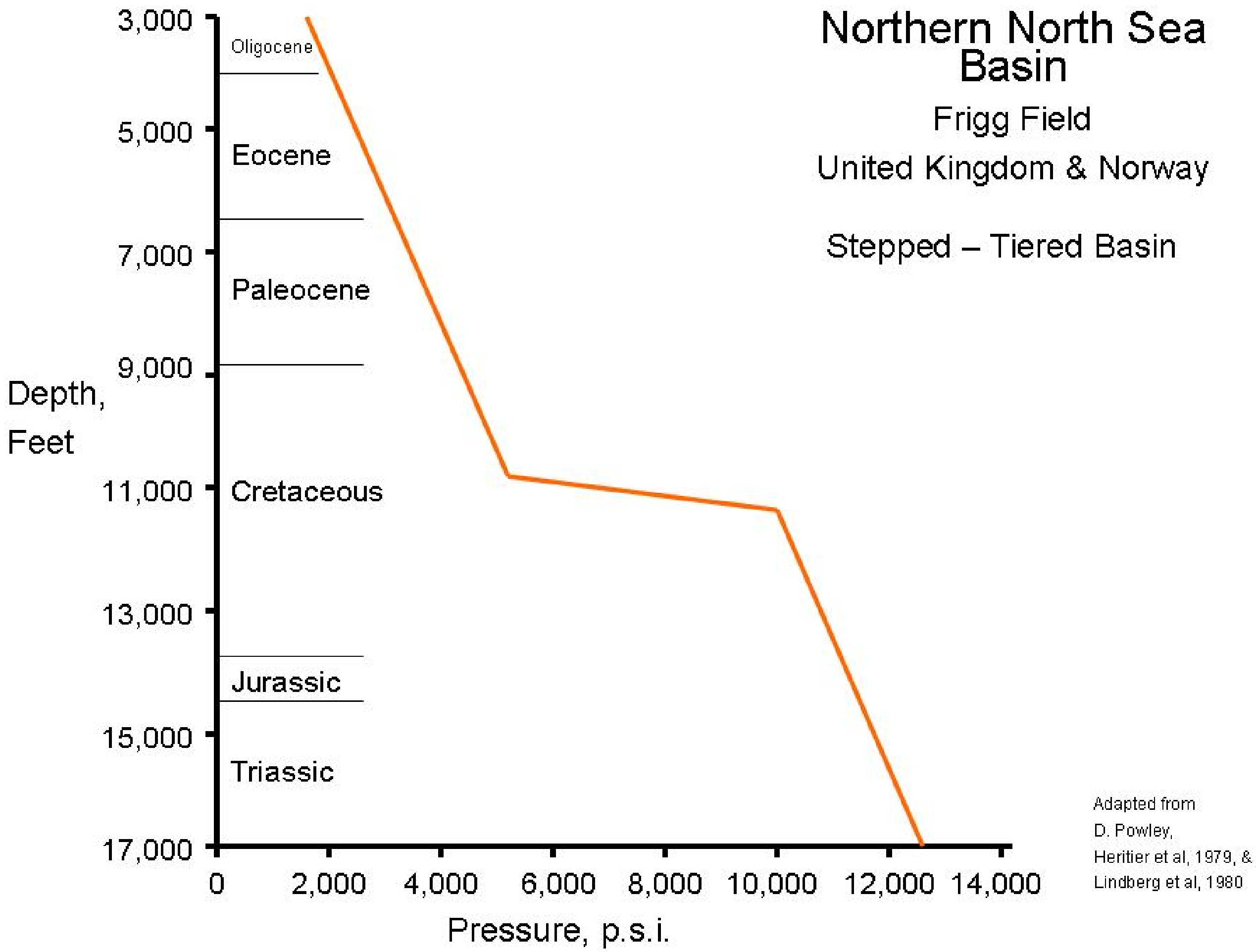

Figure 12. Pressure-depth profile from the Frigg Field, Northern North Sea Basin, United Kingdom and Norway. The profile shows the relationship between subsurface pressures and stratigraphy.

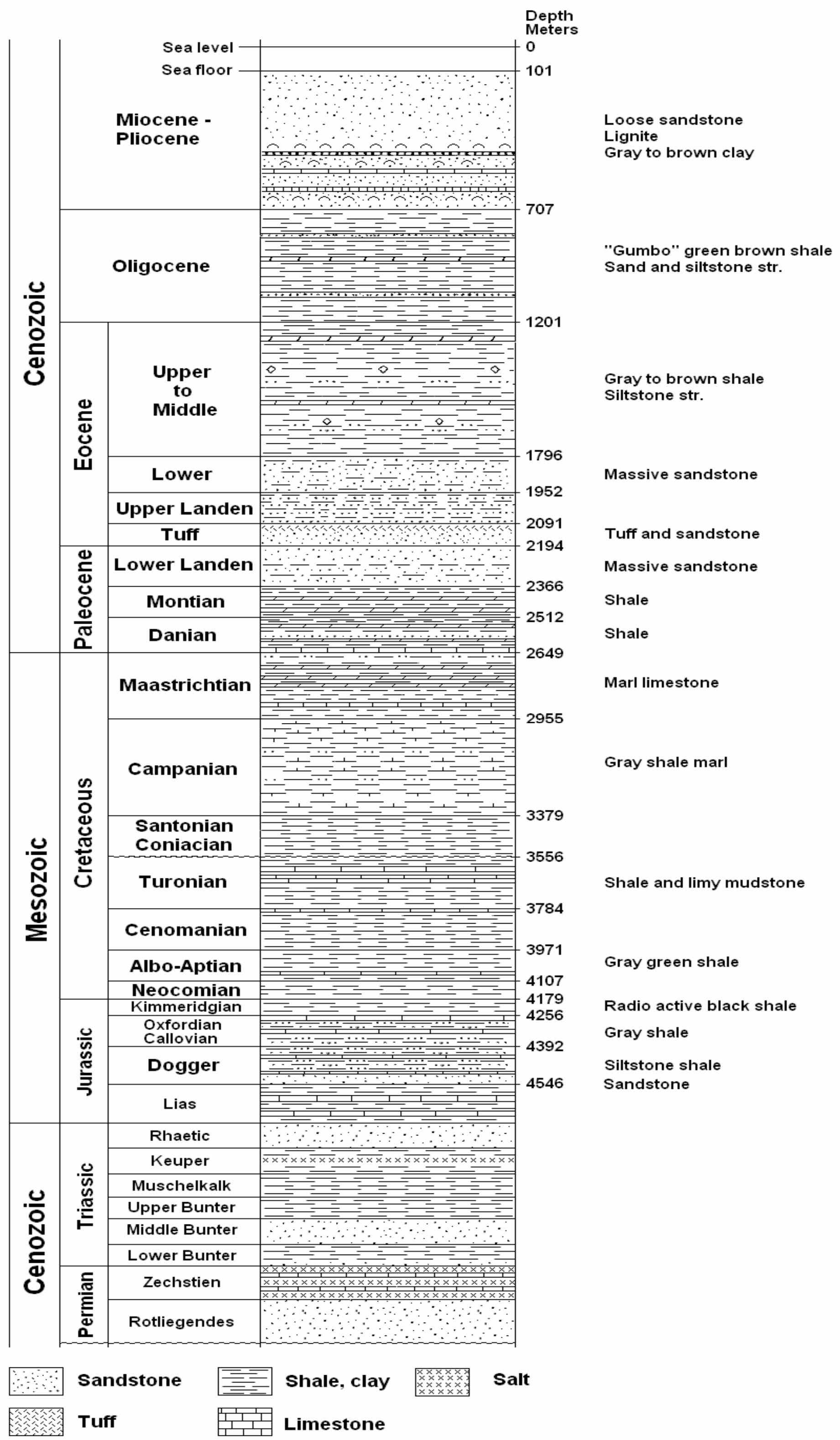

Figure 13. Generalized stratigraphic column of the Frigg Field, Northern North Sea Basin (adapted from Watson & Swanson, 1975, Heritier et al., 1979, and Isaksen, 2004).

Triassic

Triassic lithologies consist of continental fluvial, interbedded, red to variegated claystones, siltstones, shales, and sandstones (Kirk, 1980), which grade into the red marl with salt and gypsum sequence of the Keuper (Kent, 1967). The middle Bunter sandstone has proven to be a good reservoir in some fields where it yields approximately 6.2 Tcf of gas (Watson and Swanson, 1975). The Triassic rocks represent uniform, blanket deposition that for the most part was unbroken (Kent, 1980).

Jurassic

The Jurassic system is represented by a sequence of clay limestone, dark, organic-rich shale, and sandstone, largely of marine origin (Kent, 1967); (Watson and Swanson, 1975). The Early Jurassic Lias is principally shale with some interbedded carbonate. The Middle Jurassic Dogger consists of interbedded sandstone and shale (Watson and Swanson, 1975). The Late Jurassic is dominated by shale. During the Jurassic the Kimmerian tectonic event profoundly restructured the North Sea (Watson and Swanson, 1975). This was the period where tensional forces created an elongate, north-south trending graben system (Watson and Swanson, 1975). Erosion and subsidence left the Jurassic rocks variable in thickness and discontinuous in extent (Kent, 1967). The erratic Jurassic stratum contains the principle source and reservoir rocks for the North Sea, where approximately 9 billion bbl of oil and 17.5 Tcf of gas have been found (Watson and Swanson, 1975).

Cretaceous

Throughout the whole of the North Sea, the Lower Cretaceous is predominantly marine shale with minor sandstone and limestone beds (Watson and Swanson, 1975). The overlying Upper Cretaceous is represented mainly by chalk, which in some areas is 5,000 feet thick, but in the northern portion of the North Sea the chalk changes facies to marls, limestones, and shales. The Cretaceous sediments were draped over the irregular and structurally complex Jurassic strata (Figure 15). The covering of the Jurassic sediments by the Cretaceous form the main seal rocks for the Mesozoic reservoirs (Isaksen, 2004).

Paleocene

The Paleocene, in the Frigg Field area, can be divided into three formations, Maureen, Lista, and Sele (Heritier et al., 1990). The Maureen Formation (Danian) consists of both carbonaceous and sandy shales with abundant microflora and a basal massive, clean sandstone (Heritier et al., 1990). The Lista Formation (Montian) is a green-gray to brown shale with some carbonate and sandstone beds (Heritier et al., 1990). The Sele Formation (Thanetian) contains sandstone beds of variable thicknesses with some clay or sandy clay interbeds (Heritier et al., 1990).

Eocene

Heritier et al. (1990) divided the Eocene into five zones. The Balder Formation lies at the base and consists of somewhat massive, fine- to medium-grained sandstone with thin interbeds of grayish-green shale and volcanic tuff becoming less sandy towards the north and east (Heritier et al. 1990). Above the Balder is the Frigg Formation, which is one of the top five gas-producing intervals for the North Sea with 11 Tcf of reserves (Watson and Swanson, 1975). The Frigg Formation is divided into an upper and lower (Heritier et al., 1990). The lower Frigg has sandy beds with tuff intercalations at is base and a massive sandstone above (Heritier et al., 1990). The upper Frigg contains massive, sandstone beds that contain coarser grain and shale pebble inclusions (Heritier et al., 1990). Above the Frigg are two more zones, dominated by marine shales that act as the seal for the underlying gas. The accumulation of hydrocarbons in the Eocene tends to be on compaction anticlines or stratigraphic pinchouts (Heritier et al., 1990).

Oligocene, Miocene – Pliocene

The Oligocene consists of a lower greenish-brown, soft, silty mudstone and an upper brown, soft gumbo clay (Heritier et al., 1979). The Miocene – Pliocene system includes the sediment from the top of the Oligocene to the sea floor. In the Frigg field this portion consist of poorly consolidated sandstones, lignite, carbonate, and gray to brown mudstone. The upper portion of this interval is somewhat sandier compared to the lower (Heritier et al., 1979).

Lithologies, Pressures, and Mechanisms (Table 3)

The pressure-depth data analyzed for the Northern North Sea Basin is specific to the Frigg Field in the Viking Graben subbasin. It indicates an upper normal and lower overpressured distribution which would fit into the "Stepped-Tiered" pressure system. Although this data is specific, other research has concluded that a similar pressure

Table 3

Northern North Sea Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent – Cretaceous Chalk	shale and sandstone	stratigraphic	• equilibrium of pressure escape during compaction
lower over	Cretaceous Chalk - Triassic	shales	structure & stratigraphic	• disequilibrium compaction • hydrocarbon generation • thermal cracking of oil

Bally Classification: 1211 – Located on the rigid lithosphere, not associated with formation of megastructure; located on pre-Mesozoic continental lithosphere; cratonic basin; located on earlier rifted grabens
Klemme Classification: IIIA – Continental rifted basin; craton and accreted zone rift

(St. John et al., 1984)

distribution occurs throughout much of the North Sea (Isaksen, 2004, Japsen, 1998, Chiarelli and Duffaud, 1980).

The upper normal pressures in the Frigg Field tend to be bound on the top by the Miocene – Pliocene shales and extend through the middle of the Cretaceous Chalk, which contains mudrocks. These normal pressures are probably the result of fluids being able to escape during periods of subsidence (Chiarelli and Duffaud, 1980). In some outlying cases this interval has been found to sustain abnormal pressures, which are related to uplifting by salt diapirs (Holm, 1998). While this interval does produce hydrocarbons, most petroleum systems are associated with the lobate, turbidite fans. Most of the traps are associated with compaction anticlines and porosity pinchouts of the lithologies (Heritier et al., 1990).

The lower overpressured distribution occurs from the middle of the Cretaceous Chalk through the Triassic in the Frigg Field. Isaksen (2004), Japsen (1998), and Chiarelli and Duffaud (1980) also found like overpressured distributions in the same stratal intervals in other locations in the North Sea, but most of them seem to be confined to the central portion of the graben systems. This evidence supports interpretations of the evolution and presence of overpressures. Many researchers conclude that the best explanation of overpressures in this portion of rock is due to the disequilibrium compaction created by the vertical overburden stresses, hydrocarbon generation, and thermal cracking of oil (Chiarelli and Duffaud, 1980, Holm, 1998, Isaksen, 2004, Japsen, 1998). What should be suspect about the overpressures is the occurrence they have with known hydrocarbon production areas. Maps created delineating the extent of the pressures are often closely related to the position of oil and gas fields in the North Sea

(Isaksen, 2004). Petroleum systems seem to be associated with lateral structural and horizontal stratigraphic constraints. These trapping mechanisms occasionally are breached by the intense overpressures, usually associated with salt diapirism and the buoyancy of large hydrocarbon columns (Isaksen, 2004), creating gas chimneys and unexpected petroleum encounters (Heritier et al., 1990).

Nile Delta Basin

Geologic Setting

The Nile Delta basin lies at the mouth of the Nile River in Egypt on the north continental to marine transitional margin of the African and Sinai plates. The delta includes two main areas, the Nile Delta and North Sinai, which together cover an area of approximately 30,000 mi^2 (Nashaat, 1998). The Nile delta basin can be subdivided into three distinct geologic provinces, easterly middle-late Miocene, central early Miocene to late Oligocene, and early Cretaceous (Figure 14-A); (Nashaat, 1988). The basin is bound on the south by the hinge fault zone on the stable carbonate shelf; the northern boundary extends offshore to the deeper parts of the Mediterranean; to the west by the upper Cretaceous platform; and to the east by a northeast-southwest trending transcontinental megashear (Nashaat, 1998).

The Nile Delta Basin was affected by major tectonic activity throughout its geologic history (Alsharhan and Salah, 1996). The major tectonic elements of the area can be divided into three important phases (Alsharhan and Salah, 1996).

The first phase is characterized by the rifting of Africa-Arabia in the Late Triassic extending through the Early Cretaceous (Nashaat, 1998). This phase marked the creation of the Tethys and the reactivation of ENE-WSW-oriented deep-seated faults (Alsharhan and Salah, 1996). The southern and central areas were uplifted, relative to the northern, resulting in the development of a thick wedge of Early and Middle Mesozoic sediments (Triassic, Jurassic, and Early Cretaceous); (Alsharhan and Salah, 1996). Normal faulting of the sediments occurred caused by the NW-SE extension (Alsharhan and Salah, 1996).

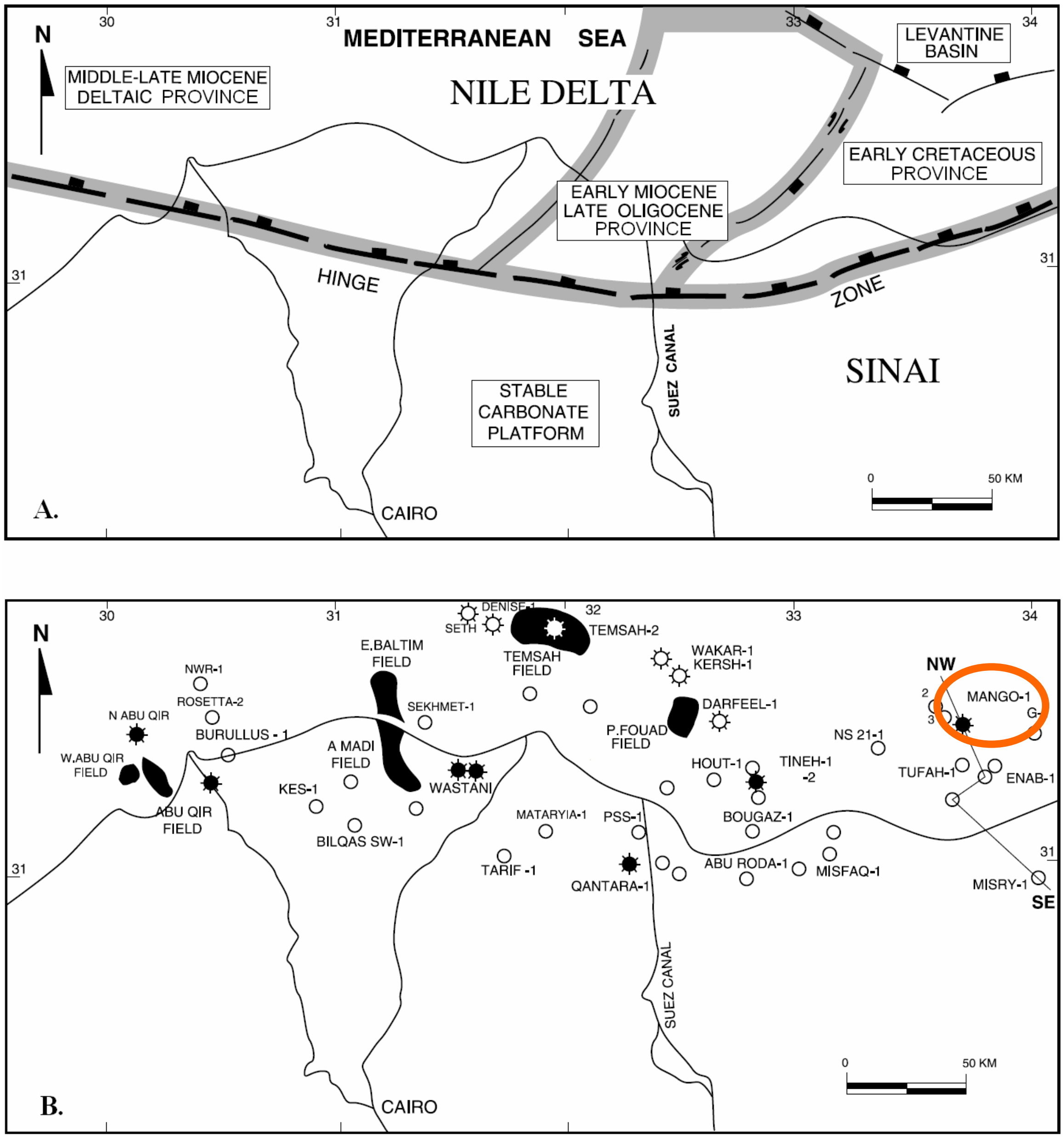

Figure 14.

A. Location map of the Nile Delta and North Sinai area showing the distinct geologic provinces (from Nashaat, 1998).

B. Location map of oil and gas fields and selected wells of the Nile Delta and North Sinai area. Circled location is that of the PDP data. Location of cross section NW-SE (Figure 20) is indicated (from Nashaat, 1998).

The second phase occurred during Late Cretaceous to Early Tertiary, Laramide time, where the African plate move west-northwest relative to Eurasia (Alsharhan and Salah, 1996). The tectonism closed the Tethys Sea and produced a right-lateral shear couple, beginning in the Turonian and ending in the Eocene (Alsharhan and Salah, 1996). This tectonic event produced a series of en echelon northeast-southwest trending, double plunging anticlines called the Syrian Arc Structures of northern Sinai (Nashaat, 1998).

The third phase began by ENE-WSW trending tensional stresses of the late Oligocene through early Miocene, marking the development of the rifting of the Gulf of Suez (Alsharhan and Salah, 1996). More rifting occurred during the Late Miocene to recent, opening the Gulf of Aqaba (Alsharhan and Salah, 1996). At the end of this phase, the Nile Delta basin area was uplifted and separation began from the Arabian platform and Levantine basin (Nashaat, 1998). Finally, a northwest-southeast wrench fault system developed in the northern offshore area during the early Pliocene (Nashaat, 1998).

Sedimentation of the Nile delta began in the late Oligocene-early Miocene just west of is present day location (Nashaat, 1998). Coinciding with the rifting of the Gulf of Suez in the late Oligocene to early Miocene, the delta shifted to a more northeast position; and did not rest in its current position until the middle to late Miocene (Nashaat, 1998).

Pressures

The Nile Delta basin falls into the “Stepped-Tiered System”. The general distribution of pressures on the pressure-depth profile has two portions: an upper normal and a lower overpressured-stepped (Figure 15).

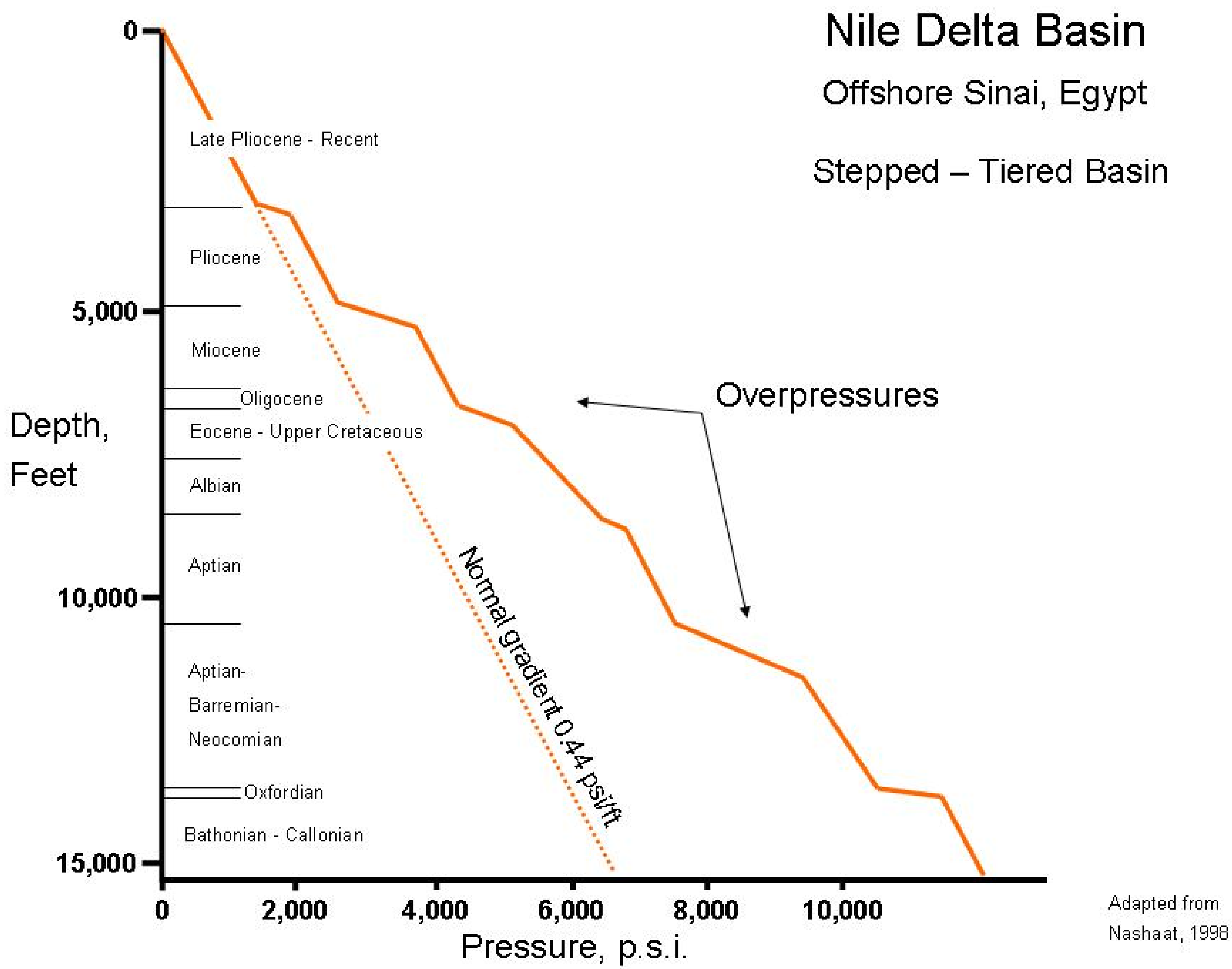

Figure 15. Pressure-depth profile from the Mango-1, offshore Sinai, Nile Delta Basin, Egypt (adapted from Nashaat, 1998). The profile shows the subsurface pressures along with the stratigraphy.

The upper normal pressures occur from the seafloor to the Late Pliocene. This corresponds to Pleistocene-Recent sediments through the base of the Wastani or Bilqas Formation on the stratigraphic column for the Nile Delta and North Sinai area (Figure 16).

The lower overpressured-stepped domain occurs from the Jurassic through the Upper Pliocene.

Stratigraphy

Pre-Cretaceous

Pre-Cretaceous deposits occur in the Nile Delta basin, but most have not been reached in the offshore fields. In locations where pre-Cretaceous strata have been drilled, the lithologies are dominantly carbonates with sandstone and shale interbeds. Some areas, mostly toward the south, contain a more proximal facies and are sandstone-rich. To the north marine influence increased and the Pre-Cretaceous deposits include more shale.

Cretaceous

The Cretaceous system in the Nile Delta basin is usually divided into two sequences, a lower and an upper. The Lower Cretaceous rocks are mainly composed of shale and sandstone with minor, thin beds of dolomitic limestone (Nashaat, 1998). These Lower Cretaceous beds contain the most prolific source rocks, especially, those offshore (Alsharhan and Salah, 1996). Nashaat (1998) also highlights the reservoir properties of these rocks. The Upper Cretaceous is composed of chalky and marly limestones with

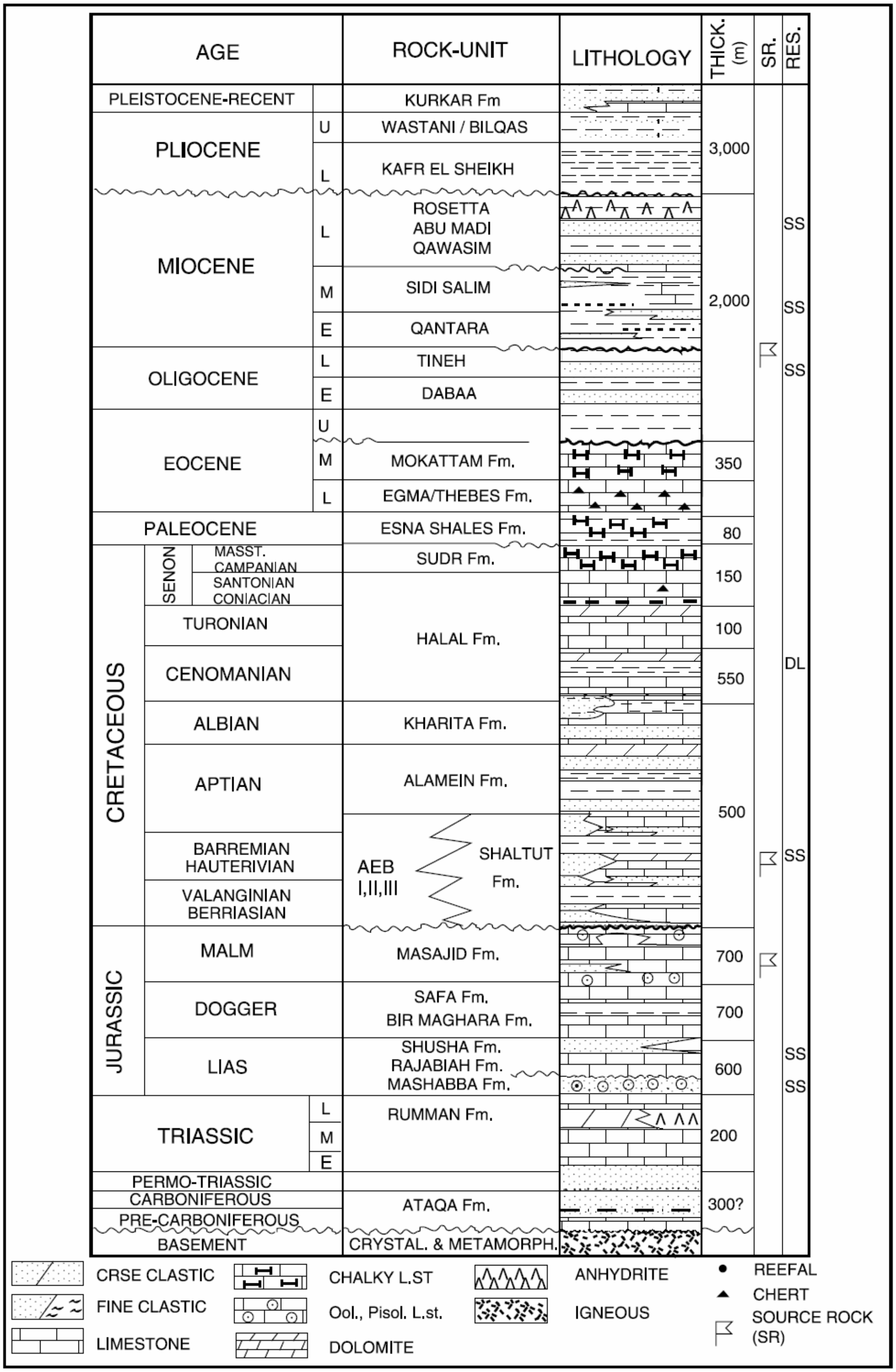

Figure 16. Generalized stratigraphic column of the Nile Delta and North Sinai area, Egypt, Nile Delta Basin (adapted from Nashaat, 1998).

some thin shale interbeds (Nashaat, 1998). These beds tested oil in areas where dolomite and sandstones act as reservoirs (Nashaat, 1998).

Paleocene

The Paleocene is represented by the Esna Shale. It consists of soft fossiliferous shale with limestone interbeds. It represents deposition in lower shoreface to shelf environments (Alsharhan and Salah, 1995).

Eocene

The Eocene of the Nile Delta rests unconformably on the Paleocene and consists of three dominant lithologies. The lower portion, the Egma/Thebes Formation, is predominantly limestone with some chert (Nashaat, 1998). The middle, Mokattam Formation, is more of a chalky limestone; this grades into the upper shale-dominated interval (Nashaat, 1998).

Oligocene

The Dabaa and Tineh rock units make up the lower and upper portions of the Oligocene (Nashaat, 1998). The Dabaa has a basal sandstone that fines upward into shale (Nashaat, 1998). The Tineh is represented by marine shales interbedded with sandstones, possibly of turbidite origin (Nashaat, 1998). The source and reservoir potential of the Oligocene rocks is high in the west, but is lacking in other areas both onshore and offshore (Alsharhan and Salah, 1996 and Nashaat, 1998).

Miocene

In the Nile Delta basin the Miocene rocks include the Qantara, Sidi Salim, Qawasim, Abu Madi, and Rosetta Formations (Nashaat, 1998). At the base of the sequence, the Early Miocene Qantara Formation consists of shale, limestone, and marl with some sandstone interbeds (Nashaat, 1998). The Sidi Salim, Middle Miocene, is mostly shale with some interbeds of limestone and sandstone (Nashaat, 1998). The Qawasim Formation is sandstone and conglomerate in the south, which become progressively shalier northward (Nashaat, 1998). The Abu Madi Formation is a series of sandstones, conglomeratic sandstones, and shales (Nashaat, 1998). The latest Miocene Formation, Rosetta, consists of evaporites interbedded with thin claystone beds (Nashaat, 1998). The hydrocarbon potential of Miocene strata, both as reservoirs and source beds follows the same trend as the Oligocene and is better in the west, but poor elsewhere (Alsharhan and Salah, 1996).

Pliocene – Recent

The Pliocene rests unconformably on top of the Miocene strata (Nashaat, 1998). The sediment of the Pliocene – Recent section can reach approximately 9,000 feet thick and consists of rapidly deposited claystones and siltstones with a few sandstone interbeds (Nashaat, 1998).

<u>Lithologies, Pressures, and Mechanisms (Table 4)</u>

The pressure-depth data analyzed for the Nile Delta Basin is specific to Offshore Sinai. It indicates an upper normal and lower overpressured-stepped distribution, which

Table 4

Nile Delta Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent – Late Pliocene	shale and sandstone	structures &/or stratigraphic	• equilibrium of pressure escape during compaction
lower over	Pliocene - Triassic	shale and carbonate	structure & stratigraphic	Primary: disequilibrium compaction Secondary: hydrocarbon generation thermal cracking of oil tectonic stresses temperature increases transference

Bally Classification: 114 – Located on the rigid lithosphere, not associated with formation of megastructure; related to formation of oceanic crust; "Atlantic-type" passive margins (shelf, slope, & rise) which straddle continental and oceanic crust

Klemme Classification: IV – Delta basin

(St. John et al., 1984)

would fit into the "Stepped-Tiered" pressure system. Although this data is area specific, other research has concluded that similar pressure distribution patterns occur throughout much of the Nile Delta and Sinai areas (Nashaat, 1998).

The upper normal pressures are bounded by the sea floor at the top and extend through the Late Pliocene. These normal pressures are likely the result of adequate permeability allowing fluid to escape during periods of subsidence. In some outlying cases, this interval sustains abnormal pressures, which are related to pressure compartments (Nashaat, 1998). Abnormal pressures in this regime are believed to be associated with rapid sedimentation rates causing compaction disequilibrium (Nashaat, 1998). The normally pressured interval produces hydrocarbons; most petroleum systems are associated with the Oligocene and Miocene sandstone and shale (Nashaat, 1998). Traps are associated with structures, but have a stratigraphic component (Alsharhan and Salah, 1996).

The lower overpressured-stepped distribution occurs in the Jurassic – Pliocene section of the offshore Sinai area. Nashaat (1998) documents similar overpressured distributions in the same stratal intervals in other locations around the Nile Delta, where pressure-depth gradient values exceed 0.8 psi/ft. This evidence helps support the contention the overpressures were generated and preserved throughout the basin. There is also evidence supporting for the presence of pressure compartments with well defined vertical and lateral seals associated with faults, salt or mud diapirs, or facies changes (Figure 17); (Nashaat, 1998). The best explanation, and primary cause, of overpressures in this portion the section is due to the disequilibrium compaction created by the vertical overburden stresses (Nashaat, 1998). Maps delineating the extent of overpressure show

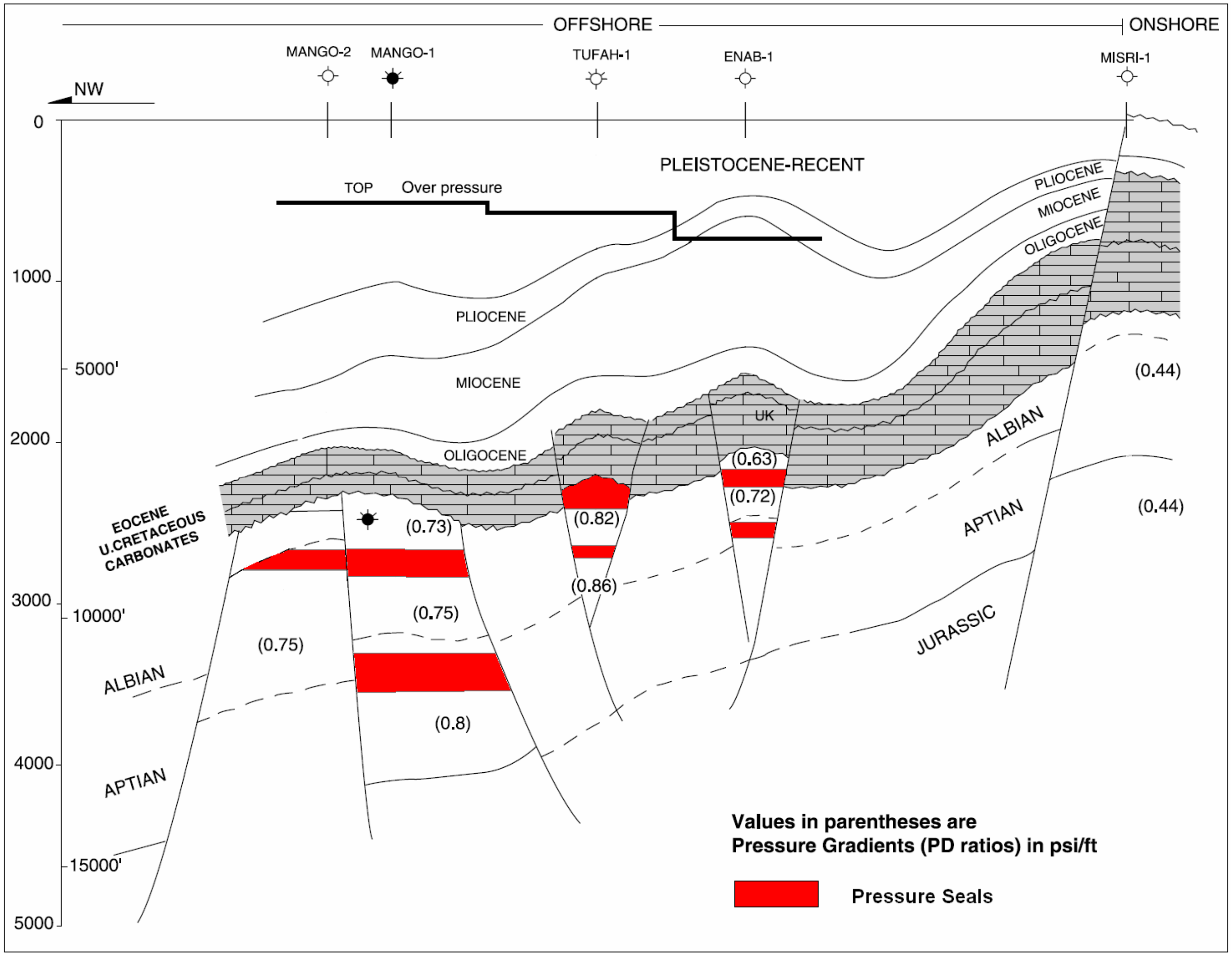

Figure 17. Structural cross section (NW-SE) showing pressure compartments within the Nile Delta Basin, Egypt (adapted from Nashaat, 1998). Location shown on figure 16-B.

that abnormal pressures are often closely related to the position of higher sedimentation rates during the Pliocene and Pleistocene (Nashaat, 1998). Petroleum systems and abnormally high pressures seem to be associated with basin compartmentalization by vertical and lateral seals. These compartments are evident on pressure-depth profiles as steps, where each step represents a seal and a reservoir. The pressure-depth profile for offshore Sinai shows three compartments.

Although data and research suggest disequilibrium compaction as the primary source of overpressures in the Nile Delta, secondary mechanism like hydrocarbon generation, tectonic stresses, temperature increases, transference, or cracking of oil to gas, may contribute to the abnormal pressures evident in the Nile Delta Basin.

Sacramento Basin

Geologic Setting

The Sacramento Basin occupies the northern portion of the Great Valley of California (Figure 18) and is bordered on the west by the Coast Ranges and Franciscan subduction complex, on the north by the Klamath Mountains, on the east by the Cascade Range and Sierra Nevada, and on the south by the Stockton arch (Magoon and Valin, 1995). St. John et al. (1984) classified the Sacramento basin in combination with the San Joaquin basin, but later research, by Johnson (1990), conclude that the Sacramento has not been subjected to transform fault tectonism and therefore the Bally and Klemme classifications are different.

The Sacramento Basin began to form in Late Jurassic to Early Cretaceous time as the Farallon plate began subducting beneath the North American plate (Johnson, 1990). The resulting is a southerly dipping, asymmetric, elongate, north-northwest-trending forearc basin (Johnson, 1990). The western limb of the basin exhibits moderate eastward dips and complicated thrust faulting (Johnson, 1990). The eastern side lies on top of metavolcanic and plutonic basement rocks, dips gently westward, and includes normal faulting (Jenden and Kaplan, 1989).

Sedimentation in the Sacramento Basin began in the Late Jurassic with the first major uplift of the Nevadan Mountains (precursor to the current Sierra Nevada), which supplied the sediment for the Jurassic and Cretaceous (McPherson and Garven, 1999) fluvial, deltaic, shelf and slope sediments (Garcia, 1981). Although Jurassic and Early Cretaceous deposits can be found on the western margins, none can be found, either from

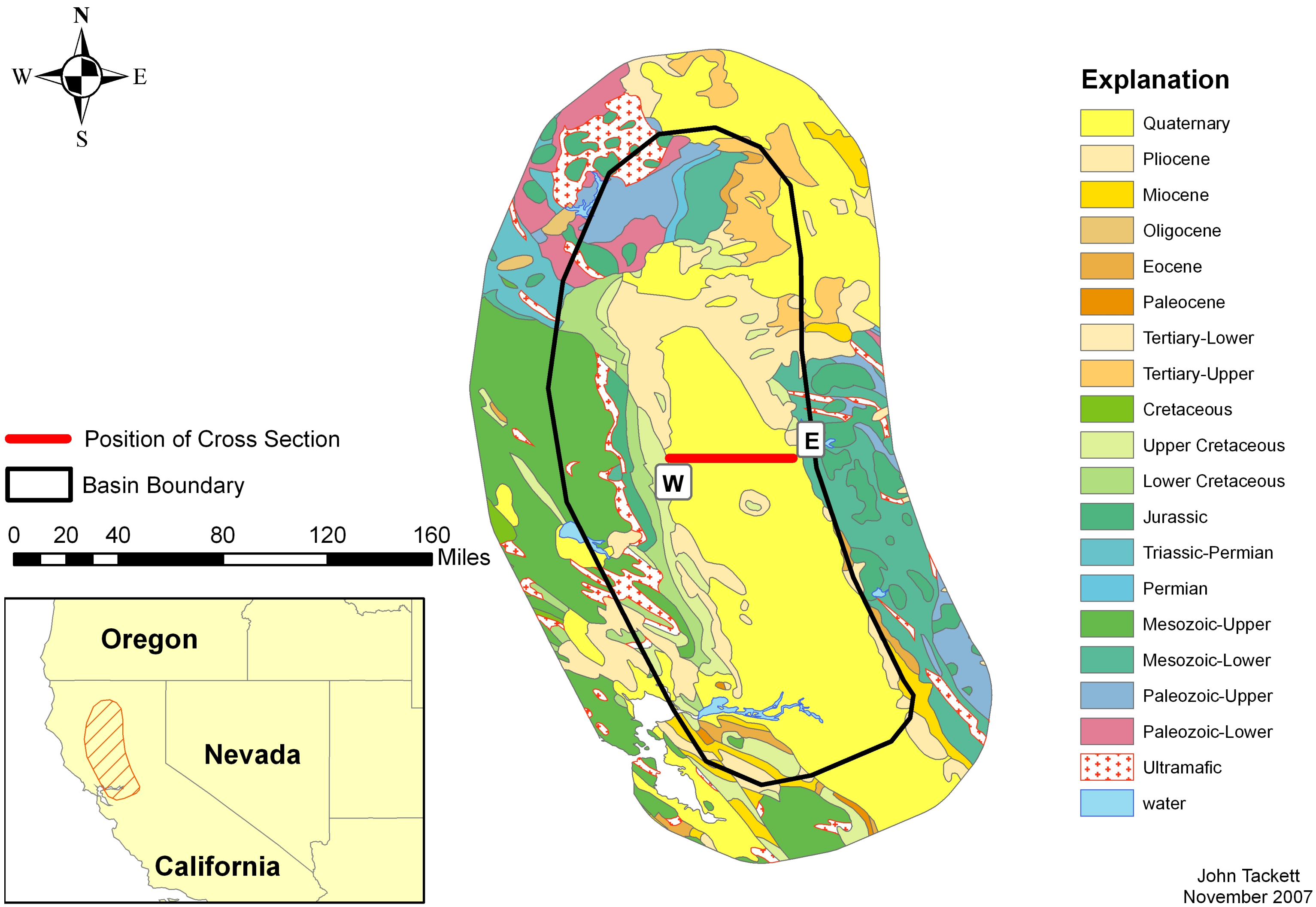

Figure 18. Generalized geologic map of the Sacramento Basin showing the location of the cross section. The map shows the surface geology of the basin and 30 miles beyond. The data used for the map was adapted from the United States Geological Survey

erosion or nondeposition, on the eastern margins (Jenden and Kaplan, 1989). These older sedimentary rocks contain a number of oil and gas seeps, but none have led to the recovery of commercially economic oil and gas accumulations (Jenden and Kaplan, 1989).

The Sacramento Basin filled with slope deposits from the start of the Late Cretaceous through the deposition of the Upper Cretaceous Forbes Formation (Garcia, 1981). Post-Forbes Upper Cretaceous sediment was deposited in a series of fluvial-deltaic, slope, and submarine fans that prograded southwestward (Jenden and Kaplan, 1989). A high-constructive delta system deposited the Kione atop the Forbes during a shoaling that occurred to north, followed by a brief marine transgression during which the Sacramento Shale formed (Jenden and Kaplan, 1989). This was followed by deposition of more deltaic sediments, the Winters and Strarkey-Tracy Sands (Jenden and Kaplan, 1989). These were followed by deposition of the Mokelumme and Lower Paleocene deltaic Sandstones (Jenden and Kaplan, 1989).

During the Paleogene, repeated cycles of uplift and subsidence created four canyons with some 2,000 feet of relief, which were subsequently filled with mud (Jenden and Kaplan, 1989). Three of the canyons, the Martinez, Meganos, and Markley occurred in the southern portion of the basin; while only one, the Princeton, occurred in the northern portion (Jenden and Kaplan, 1989). The last marine transgression in the Sacramento Basin occurred in the early Eocene and deposited the Capay Formation, which corresponds to the Princeton Canyon Fill (Jenden and Kaplan, 1989). These marine sediments are overlain by nonmarine sediments of the Pliocene and younger age in the north, but in the south marine sediment of the Domengine, Nortonville Shale, and Markley strata were deposited atop the Capay (Jenden and Kaplan, 1989).

Neogene strata in the northern Sacramento Basin are locally folded, faulted, and cut by or interbedded with volcanic rocks (Safonov, 1968). Volcanism and structural deformation of these rocks has been associated with the progressive shift from convergent to transform tectonics along the western boundary of the North American plate (Jenden and Kaplan, 1989).

Pressures

The data for the Sacramento Basin is specific to the Willows-Beehive Bend field, which falls into the "Stepped-Tiered System". The general distribution of pressures on the pressure-depth profile forms two trends: an upper normal and a lower overpressured (Figure 19).

The upper normal pressure trend occurs from the surface to the Forbes Formation. This corresponds to an interval that begins in Quaternary sediments and extends through a seal in the shale-rich Forbes Formation. The rock units of this interval are shown on the stratigraphic column for the Sacramento Basin (Figure 20).

The lower overpressured domain begins in the Upper Cretaceous and extends to the basement. This interval includes the section from the Forbes Formation through the Venado Formation.

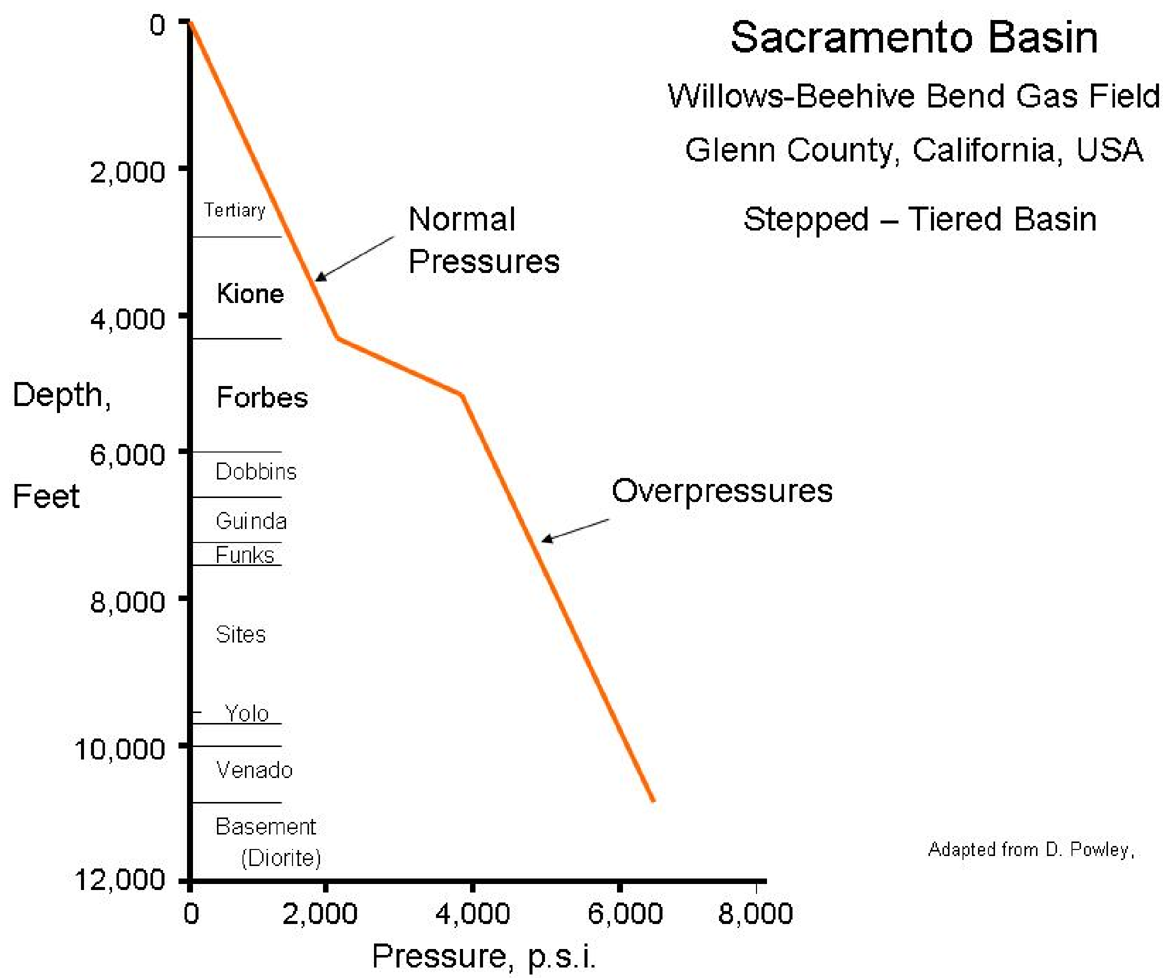

Figure 19. Pressure-depth profile from the Willows-Beehive Bend Field, Sacramento Basin (adapted from D. Powley).

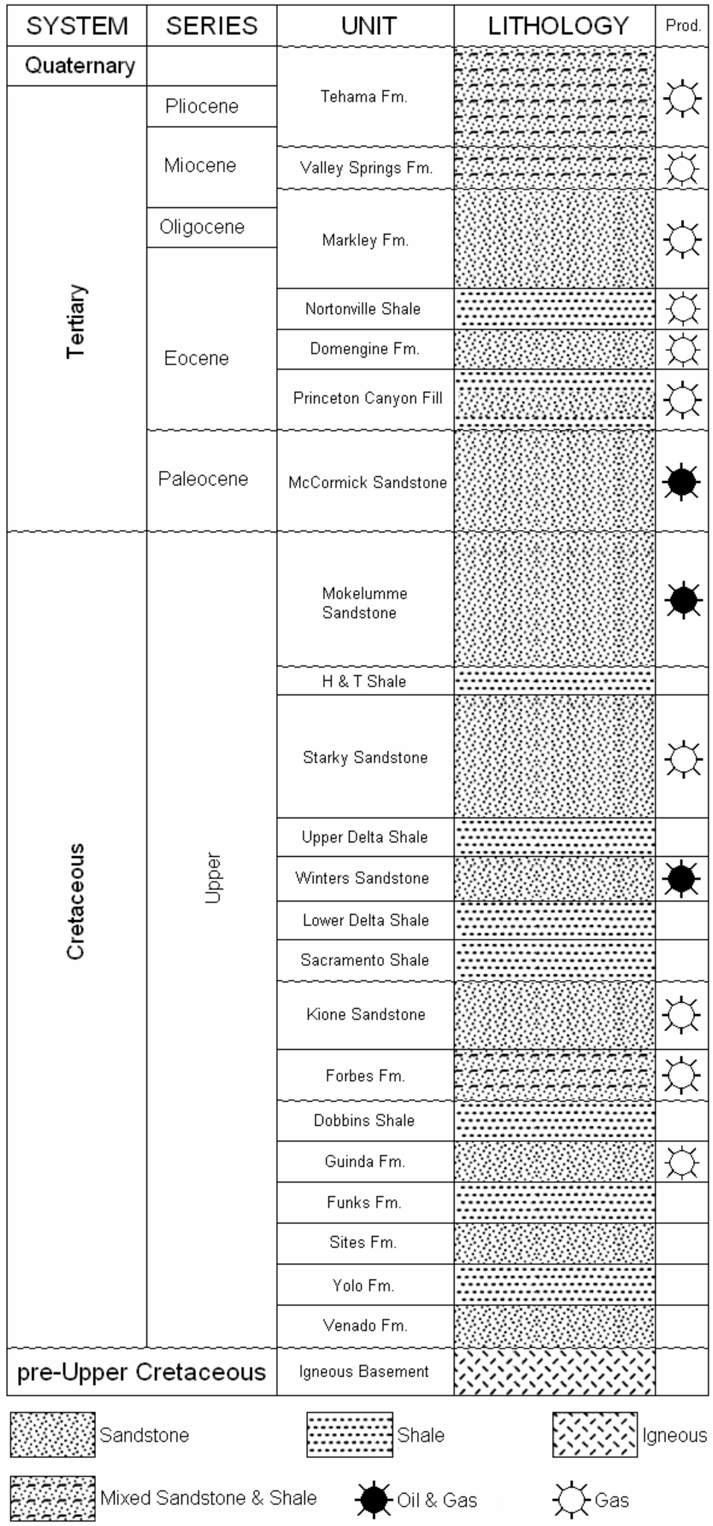

Figure 20. Generalized stratigraphic column of the Sacramento Basin (adapted from McPherson and Garven, 1999 and Jenden and Kaplan, 1989).

Stratigraphy

Pre-Upper Cretaceous

Pre-Upper Cretaceous rocks in the Sacramento Basin include the Lower Cretaceous Shasta Formation, Upper Jurassic Knoxville Formation, and metavolcanic and plutonic basement rocks. The Lower Cretaceous and Upper Jurassic rocks are not found on the eastern limb, including the Willows-Beehive Bend Field, of the basin due either to erosion or to nondeposition, which was possibly related to faulting along the contact between oceanic crust and the arc massif (Jenden and Kaplan, 1989). These rocks include granite and other more basic igneous rocks in the basement (Weagant, 1972), and shale and interbedded thin sandstones of the Upper Jurassic and Lower Cretaceous (Morrison et al., 1971). This section has given shows of oil and gas, but it is speculated that they were not of commercial quantities (Jenden and Kaplan, 1989).

Upper Cretaceous

The Upper Cretaceous is the thickest package of rocks in the Willows-Beehive Bend field and includes, in ascending order, the Venado, Yolo, Sites, Funks, Guinda, Dobbins Shale, Forbes, and Kione Sandstone. In other parts of the basin the Upper Cretaceous also contains the Sacramento Shale, Lower Delta Shale, Winters Sandstone, Upper Delta Shale, Starkey Sandstone, H & T Shale, and Mokelumme Sandstone, which are not recognized in the Willows-Beehive Bend field. This interval of strata is characteristic of multiple transgression and regression episodes, depositing many alternating beds of sandstone and shale.

The Upper Cretaceous deposits in the Willows-Beehive Bend field begins with the Venado Formation, a massive to bedded concretionary sandstone or rhythmically banded sandstone with minor shale breaks (Kirby, 1943). The Yolo lies atop the Venado and is a siltstone to shale interval. Above the Yolo is the massive to bedded sandstone with minor siltstone breaks of the Sites Formation. The Funks Formation, atop the Sites Formation, is dominated by shale with some siltstone. The Guinda and Dobbins include gray soft shales, siltstones, sandstones, and conglomerates (Kirby, 1943). The Forbes Formation consists of interbedded dark gray claystones and siltstones and gray, fine-grained, friable, lenticular sandstones (Weagant, 1972). Above the Forbes Formation is the Kione Sandstone. The Kione is gray, fine- to medium-grained sandstones interbedded with gray siltstones (Weagant, 1972) and marks the top of the Cretaceous sediment in the Willows-Beehive Bend field.

The Upper Cretaceous rocks in the Sacramento Basin are amongst the most important hydrocarbon producing rocks in the basin (Morrison et al., 1971). They produce gas and oil from stratigraphic pinch out traps and fault closures (Johnson, 1990, Weagant, 1972, and Morrison et al., 1971).

Eocene

Above the Upper Cretaceous strata lies the Eocene age Princeton Canyon Formation. The Princeton Canyon is equivalent to the Capay Formation in other areas of the Sacramento Basin. This formation filled a scour, some 2,000 feet deep, with light gray, glauconitic shale with a glauconitic gritstone at the base (Weagant, 1972). Above the Princeton Canyon are undifferentiated marine and nonmarine strata that are equivalent to the Domengine through Valley Springs formations (Weagant, 1972). These strata are conglomeratic, poorly sorted sandstones, and thin interbedded gray shales (Weagant, 1972).

Pliocene – Recent

Pliocene through Recent strata includes the Tehama Formation. The Tehama is a thick sequence of interbedded continental sandstones, conglomerates, and shales (Weagant, 1972).

Lithologies, Pressures, and Mechanisms (Table 5)

The pressure-depth data analyzed for the Sacramento Basin is specific to the Willows-Beehive Bend Field. It indicates an upper normal and lower overpressured distribution, which would fit into the "Stepped-Tiered" pressure system. Although this data is specific, other research has concluded that a similar distribution occurs throughout much of the Sacramento Basin (McPherson and Garven, 1999, Weagant, 1972, and D. Powley).

The upper normal pressures in the Willows-Beehive Bend are bound by the Tehama Formation at the top and extend through the middle of the Forbes Formation. This interval consists mostly of sandstone with shale lenses and beds. These normal pressures occur in permeable rocks formed from sediments that allowed fluid to escape during periods of subsidence or are subjacent to steady-state ground water flow. In some cases this interval has been found to sustain abnormal pressures, but this presence is associated with shallow structural elements like faults or tight folding (McPherson and

Table 5

Sacramento Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent – Forbes Fm.	sandstone with shale lenses	structures &/or stratigraphic	• equilibrium of pressure escape during compaction
lower over	Forbes Fm. – basement	shale & sandstone	structure & stratigraphic	Primary: tectonic stress Secondary: hydrocarbon generation compaction disequilibrium

Bally Classification: 332 – Episutural basins located and mostly contained in compressional megastructure; basin related to episutural megashear systems; 'California-type' basin
Klemme Classification: IIIBb – Continental rifted basin; rifted convergent margin – oceanic consumption; transform

(St. John et al., 1984)

Bally Classification: 311 – Episutural basins located and mostly contained in compressional megastructure; associated with B-subduction zone; forearc basin
Klemme Classification: V – Forearc basins

(Johnson, 1990)

Garven, 1999). This interval produces hydrocarbons, and most petroleum systems are associated with the lobate, turbidite fans.

The lower overpressured distribution occurs from the middle Forbes Formation through the basement in the Willows-Beehive Bend Field. Weagant (1972) and McPherson and Garven (1999) described similar overpressured distributions in the same strata intervals in other parts of the Sacramento Basin. This evidence would help support the evolution and presence of overpressures. Overpressures in this regime have been prescribed to be the result of disequilibrium compaction created by the vertical overburden stresses, hydrocarbon generation, and tectonic stresses, but the later is more prevalent due to the regionality of the measured overpressures (McPherson and Garven, 1999 and Weagant, 1972). Overpressures in the Sacramento Basin have an inverse relationship with known high volume hydrocarbon producing areas. Weagant (1972) suggests that areas where the pressures are lowest are areas where the volumes of oil and gas accumulations are the highest. Weagant (1972) states that this is in accordance with the hydrodynamic theory, where hydrocarbons will tend to migrate from higher pressures to lower pressures. Overpressured petroleum systems seem to be associated with accumulation that exhibit lateral structural and horizontal stratigraphic constraints, as seen in Figure 21. Strata bound by lateral fault seals and impermeable horizontal barriers become compartments that when filled with hydrocarbons and/or compacted, could initiate and maintain overpressures.

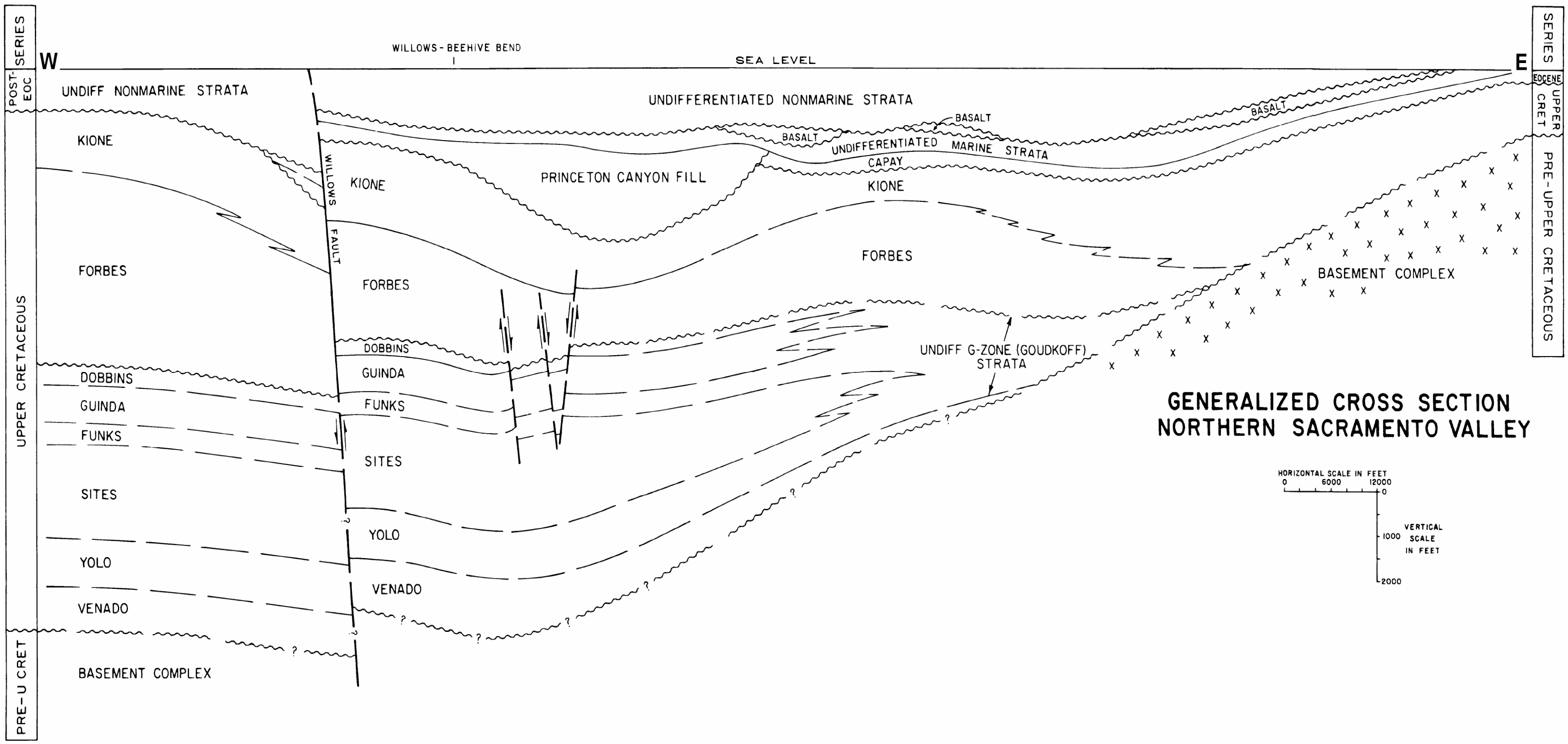

Figure 21. Geologic cross section (W-E) through Willows-Beehive Bend Gas Field, Sacramento Basin, California, USA (adapted from California Department of Oil, Gas, and Geothermal Resources, 1982).

CHAPTER IV

RECESSED-TIERED BASINS

This section reviews the three recessed-tiered basins. Included is information concerning the geologic history, stratigraphy, fluid pressures, and proposed mechanisms to generate the pressures. The relationship between the lithologies for each basin is analyzed. Graphical data supporting each evaluation are provided.

Wind River Basin

Geologic Setting

The Wind River Basin is an asymmetrical intermontane syncline with an area of about 8,100 square miles in west-central Wyoming (Rieke and Kirr, 1984) that formed during the Laramide deformation (Keefer and Johnson, 1993). The basin is confined in Fremont County and the western part of Natrona County, Wyoming (Figure 22). The Wind River Basin is bounded on the southwest by the Wind River Mountains, the south by the Granite Mountains, and along the northern boundary by the Owl Creek and Absaroka Mountains and the Casper Arch (Rieke and Kirr, 1984).

The maximum thickness of sedimentary rocks in the Wind River Basin is approximately 33,000 feet and occurs in the northeastern portion near the Owl Creek

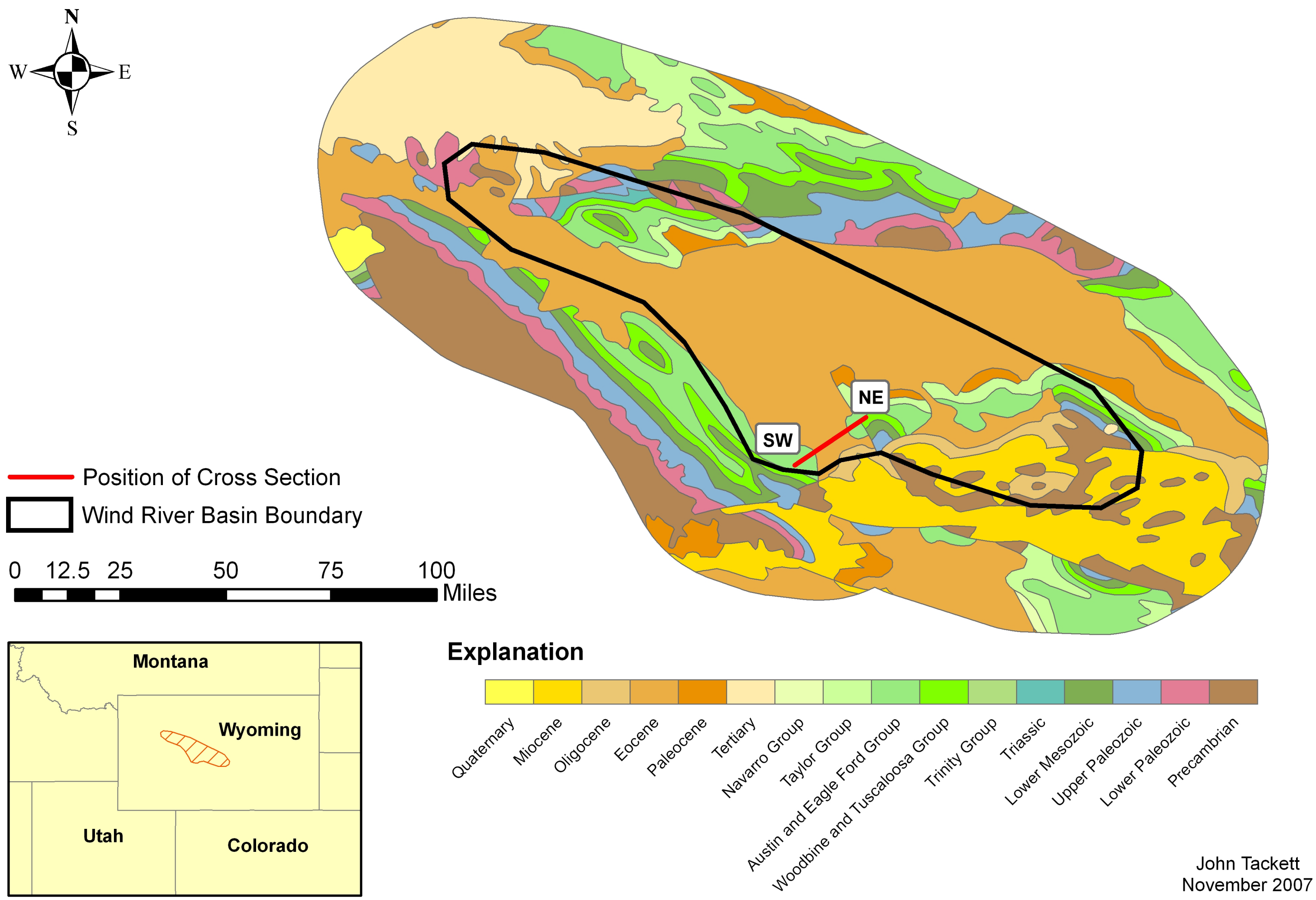

Figure 22. Generalized geologic map of the Wind River Basin showing the location of the cross section. The map shows the surface geology of the basin and 30 miles beyond. The data used for the map was adapted from the United States Geological Survey.

Mountains and Casper Arch. Three-fourths of the basin is covered by Tertiary rocks with a maximum thickness of 13,000 feet (Paape, 1968).

From the Paleozoic Era until the Late Cretaceous, the Wind River Basin and surrounding area was part of the vast foreland or stable shelf along the east side of the main Cordilleran geosyncline (Keefer, 1969). Sediments from all systems except the Silurian were deposited during repeated transgressions and regressions of the epicontinental seas in central Wyoming (Keefer and Johnson, 1993). These stratigraphic sequences, although relatively complete, are thin and discontinuous when compared to the thick geosynclinal accumulations farther west in Idaho (Keefer, 1969). The thickening of sediments to the west was caused by the steepening of the Precambrian basement surface. Toward the end of the Paleozoic, the average dip was about 15 ft/mi on the Precambrian, whereas at the beginning of the Laramide deformation (beginning of Lance deposition) it had steepened to about 40 ft/mi (Keefer, 1969).

During the Paleozoic and Lower Mesozoic, deposition occurred in shallow marine settings that were influenced by fluctuations in sea level and local tectonics. As a result the Paleozoic and Lower Mesozoic sections contain unconformities (Keefer, 1969).

Beginning in the Late Cretaceous, the seaways shifted east and a thick sequence of alternating marine and nonmarine sediments (Frontier, Cody, Mesaverde, Lewis, and Meeteetse Formations) were deposited (Keefer, 1969). Laramide deformation began during this time and continued through the Paleocene and culminated in early Eocene (Keefer, 1969). These tectonic/orogenic events of the Laramide are preserved in more than 18,000 feet of fluvial and lacustrine strata of the Lance, Fort Union, Indian Meadows, and Wind River Formations (Keefer, 1969). During the Late Cretaceous through the early Eocene, the petroleum-bearing structures were established (Keefer, 1969).

The Laramide tectonism ended by the end of the Wind River Formation deposition (early Eocene) and an additional 3,000 feet of volcanic sediment were deposited later in the Tertiary (Keefer, 1969). By the Late Tertiary the basin had completely filled with sediment and was elevated by 5,000 feet. This regional uplifting caused a period of erosion that continues today (Paape, 1968). Currently, the erosion has progressed to the point were only the Lower Eocene and older sedimentary strata remain (Keefer, 1969).

Pressures

The Wind River Basin, particularly the Beaver Creek Anticline area, is classified as a “Recessed – Tiered System”. A general pressure-depth profile for this area has three parts: an upper normal pressured, a middle underpressured, and a deep normal pressured distribution (Figure 23).

The upper normal pressured regime begins in surface Tertiary rocks and extends to the Upper Cretaceous .Mesaverde Formation. (Figure 24).

The middle underpressured zone extends from the Upper Cretaceous Cody Shale to the base of the Triassic Dinwoody Formation.

The deep normally pressured interval extends from the Permian Phosphoria Formation to the Precambrian basement.

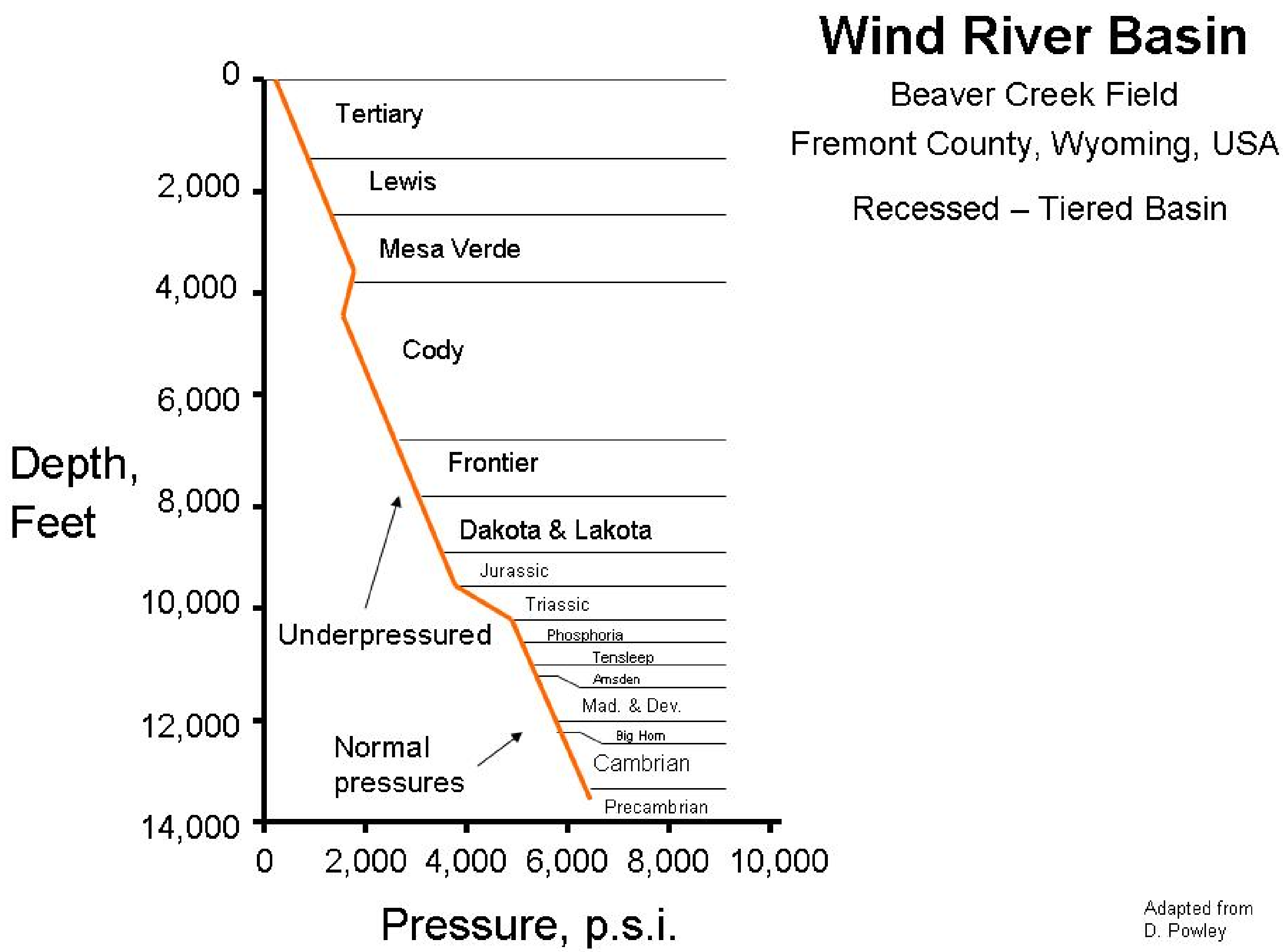

Figure 23. Pressure-depth profile from the Beaver Creek Field, Wind River Basin (adapted from D. Powley)..

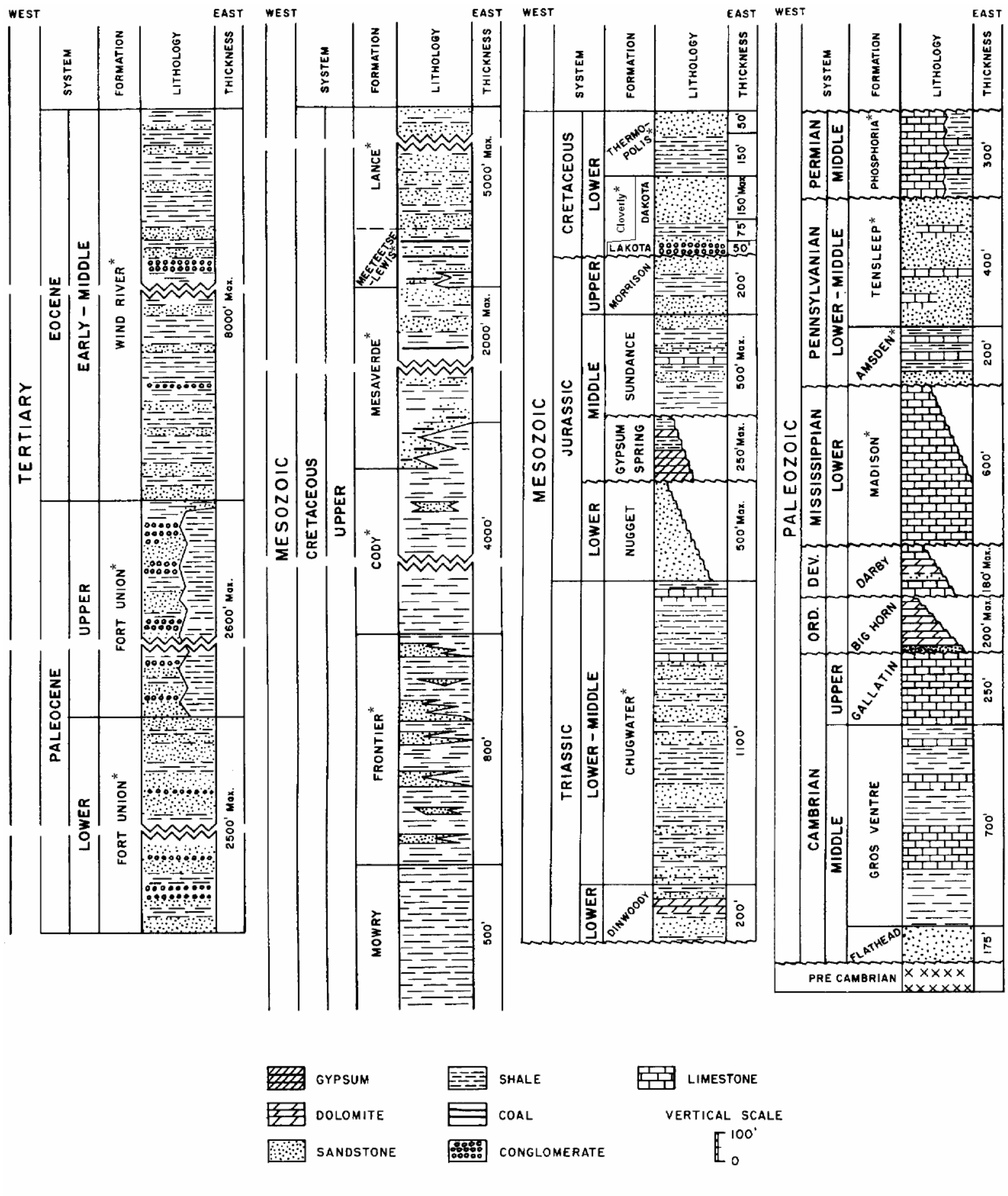

Figure 24. Generalized stratigraphic column of the Wind River Basin (adapted from Paape, 1968) Petroleum-producing formations are marked with an asterisk (*) (Keefer and Johnson, 1993).

Stratigraphy

Cambrian

The Cambrian rocks in the Wind River Basin conform to a classic and well-defined transgressive sequence. At the base is the Middle Cambrian Flathead Sandstone, is a fining-upward quartzitic sandstone with a conglomeratic base (Keefer, 1965). Above the Flathead Sandstone is the Middle Cambrian Gros Ventre Formation. The Gros Ventre Formation is dominated by shales with lenticular carbonate beds (Keefer, 1965). The uppermost unit is the Gallatin Limestone, which is mostly carbonate, but contains interbedded fine-grained detrital rocks near the base (Keefer, 1965). This sequence of Cambrian rocks is thickest to the northwest and thins to the east (Keefer, 1965). The contacts between the three units are gradational (Keefer, 1965). These Cambrian rocks are not petroleum producing within the Wind River Basin (Keefer and Johnson, 1993).

Ordovician

The Ordovician rocks in the Wind River Basin include the Lander Sandstone and the Bighorn Dolomite (Paape, 1968). The Lander Sandstone lies at the base of the Ordovician rocks and is a thin lenticular sandstone (Keefer, 1965). The Bighorn Dolomite is found above the Lander Sandstone and is a clastic-free carbonate that forms massive cliffs on the western and northern portions of the Wind River Basin (Keefer, 1965). There is no hydrocarbon production from this interval (Keefer and Johnson, 1993).

Silurian

The Silurian is not represented in the Wind River Basin.

Devonian

The Devonian rocks of the Wind River Basin are primarily the Darby Formation. The Darby Formation is composed of carbonates and clastic units, becoming more clastic toward the central part of the basin. These rocks are thickest in the western portion of the basin and thin to the east until they become nonexistent in the central portion of the basin near Lander, Wyoming (Keefer, 1965).

Mississippian

The Madison Limestone makes up the Mississippian age rocks in the Wind River Basin. The Madison is the oldest producing interval in the Wind River Basin and is divided into two parts, an upper and a lower (Kewanee Oil Company, 1961). The Upper Madison is micro to fine-crystalline, cherty limestone (Kewanee Oil Company, 1961). The Lower consists of almost entirely dolomitized limestone and karstic vuggy reservoirs, which produce oil and gas on structures.

Pennsylvanian

The Pennsylvanian rocks of the Wind River Basin are the Tensleep (Middle Pennsylvanian) and Amsden (Lower Pennsylvanian) Formations (Kewanee Oil Company, 1961). The Tensleep Formation consists mostly of massive, medium grained, sandstones with interbedded, thin, cherty and sandy limestone, and dolomitic sandstone (Kewanee Oil Company, 1961). The Amsden consists of the basal Darwin Sandstone and an upper varied sequence of dolomite, limestone, sandstone, and red shale (Keefer, 1969). This interval is thickest in the western portion at 650 feet thick and thins to 500 feet thick in the eastern portion (Kewanee Oil Company, 1961). Pennsylvanian rocks are one of the more important hydrocarbon producing strata in the Wind River Basin. They produce in 21 of the 64 major fields in (Keefer, 1969), where the primary traps are faulted anticlines (Kewanee Oil Company, 1961).

Permian

The Permian system of the Wind River Basin is represented by 250-300 feet of the Phosphoria Formation (Kewanee Oil Company, 1961). The Phosphoria Formation has very poor lateral continuity. In the west, were it is a prolific producer, the Phosphoria is cherty dolomites and limestones interbedded with thin, gray, dolomitic and phosphatic shales and siltstones (Kewanee Oil Company, 1961). These carbonates grade into anhydritic sandy shales and siltstones eastward, which cause a loss in reservoir potential (Kewanee Oil Company, 1961). Production in the Phosphoria Formation is associated with structures (Kewanee Oil Company, 1961).

Triassic

The Triassic system of the Wind River Basin is split into two formations, the Lower Triassic Dinwoody Formation and the Lower-Middle Triassic Chugwater Formation (Paape, 1968).

The Lower Triassic Dinwoody Formation was deposited on a shallow, locally restricted shelf and is characterized by yellowish-weathering, greenish-gray, calcareous siltstone or shale with variable amounts of carbonate, gypsum, sandstone, and claystone

(Paull and Paull, 1993). The Dinwoody is not an important oil and gas producing interval (Keefer and Johnson, 1993).

The Lower-Middle Triassic Chugwater Formation has three main members: Red Peak, Crow Mountain, and Popo Agie (High and Picard, 1967). The Red Peak Member is dominated by red, very-fine grained sandstone, silty claystone, and claystone (Picard, 1978). The Crow Mountain Member is siltstone, fine to coarse grained sandstone, and limestone (Alcova Limestone) (Kewanee Oil Company, 1961). The Popo Agie Member includes carbonate, red siltstone, claystone, and very fine-grained sandstone (Picard, 1978).

The Crow Mountain Member of the Chugwater Formation is the hydrocarbon reservoir for this interval (Kewanee Oil Company, 1961). Most traps are structurally controlled and found on anticlines and faulted anticlines (Pricard, 1978).

Jurassic

The Jurassic system in the Wind River Basin is divided into four formations: Nugget Sandstone (Lower Jurassic), Gypsum Spring (Middle Jurassic), Sundance (Upper-Middle Jurassic), and Morrison (Upper Jurassic) (Paape, 1968).

The Nugget Sandstone Formation is characterized by red to gray, thick-bedded to massive, fine- to medium-grained porous sandstone that contains thin beds of red shale (Keefer, 1969). The petrography and sedimentary structures (cross-bedding) indicate an eolian origin for the Nugget (Keefer, 1965).

During the Middle Jurassic, shallow seas invaded from the north, and carbonates, evaporites, and red silts were deposited that became the Gypsum Springs Formation. The

Gypsum Springs contains beds of gypsum and anhydrite greater than 100 feet thick (Keefer, 1965).

The Upper-Middle Jurassic Sundance Formation includes calcareous shale, limestone, and sandstone in the Wind River Basin. The Sundance also contains thick, gray, very fossiliferous shale beds (Keefer, 1969).

The Morrison Formation (Upper Jurassic) is interbedded sandstone and bright-colored variegated shale and claystone, mainly of nonmarine origin (Keefer, 1969).

The Jurassic in the Wind River Basin is a minor producer of oil and gas (Keefer, 1969). Most fields are found along the eastern edge of the basin where oil and gas accumulates in sandstones. The probable source of the oil and gas is proposed to be the fossiliferous shale beds within the section, but the lack of significant accumulations indicates that some if not most of the hydrocarbons were derived from older or younger sources by secondary migration through faults or fractures of tightly folded anticlines (Keefer, 1969).

Cretaceous

The Cretaceous System in the Wind River Basin is the thickest and has the highest hydrocarbon production potential. This interval is subdivided a number of different ways, but the most widely accepted is a lower and upper. The Lower Cretaceous contains the Cloverly, Thermopolis, and Mowry Formations. The Upper Cretaceous contains the Frontier, Cody, Mesaverde, Meeteetse-Lewis, and Lance Formations.

The Lower Cretaceous Cloverly Formation contains the Lakota, Fuson, and Dakota Members. The Lakota Member is a quartz sandstone with a conglomeratic base in many areas. The Lakota is overlain by the Fuson Shale that is mostly a variegated shale and claystone (Keefer, 1969). The uppermost member of the Cloverly is the Dakota sandstone or “Rusty Beds”. The Dakota is mostly shale and siltstones with some lenticular sandstones (Kewanee Oil Company, 1961). The Lakota is mainly gas bearing and the most prolific producer in the Cloverly Formation (Keefer, 1969).

The Lower Cretaceous Thermopolis Formation plays two roles in the production of hydrocarbons. The lower portion, which is the black, organic Thermopolis Shale, is a source rock (Fox and Dolton, 1995). Above the Thermopolis Shale is the Muddy Sandstone. The Muddy Sandstone is predominantly a fine- to coarse-grained sandstone interbedded with gray to black shale and siltstone (Keefer, 1969). The juxtaposition of hydrocarbon sources and the porosity/permeability of the sandstone make the Muddy a great reservoir rock in the Wind River Basin. Most of the hydrocarbons produced from the Muddy originated from primary stratigraphic entrapment.

The Lower Cretaceous Mowry Shale consists of “hard, black, siliceous shale and few thin beds of bentonite and hard quartzitic sandstone” (Keefer, 1969). The formation produces oil from the sandy zones, but is not a prime drilling prospect. The Mowry Shale is an important source rock. Studies show that localities where the Mowry has the highest organic content, coincide with the highest volumes of oil production from Cretaceous rocks in the region (Keefer, 1969).

The Frontier Formation in the Wind River Basin is a variable sequence of interbedded sandstone and shale of both marine and nonmarine origin (Keefer, 1969). In the Wind River Basin, the Frontier ranges in thickness from 650 to 1,000 feet (Thompson et al., 1949). The Frontier’s variable lithology is more precisely gray to black shale; gray, fine- to medium-grained, massive to thin-bedded sandstone, and a few beds of tuff and bentonite (Rieke and Kirr, 1984). Chert pebbles and abundant Niobrara-age fossils occur in the upper part (Rieke and Kirr, 1984). The petroleum, primarily gas, is widespread in the sandstone bodies of the Frontier Formation and is often the prime objective in areas near the basin margins. The relative abundance of both source and reservoir rocks in the Frontier provide more than favorable conditions for the generation and stratigraphic accumulation of hydrocarbons.

The Cody Shale is late Coniacian through early Campanian in age and varies in thickness from about 3,300 to 4,000 feet (Keefer and Johnson, 1993). The Cody Shale is a sequence of marine shale and fine-grained sandstone (Keefer, 1969) that is often informally subdivided into a lower shaly member and an upper sandy member (Keefer and Johnson, 1993). The shaly member consists of dark gray to black shale with numerous bentonite beds, bentonitic shales, and a prominent glauconitic sandstone (Keffer and Johnson, 1993). The sandy member is mainly fine- to very-fine silty and shaly sandstone with a few shale intervals (Keefer and Johnson, 1993). This upper sandy member has been found to contain commercial quantities of petroleum (Keefer, 1969) in stratigraphic accumulations (Fox and Dolton, 1995).

The Mesaverde Formation is Campanian in age and is about 1,800 to 2,150 feet thick in the Wind River Basin (Keefer and Johnson, 1993). The Mesaverde Formation is comprised of light- to dark-gray sandstone interbedded with shale, siltstone, ironstone, and coal (Rieke and Kirr, 1984). The sandstone in the Mesaverde Formation tends to be massive, quartz-rich, and highly lenticular (Rieke and Kirr, 1984). Gas is the primary play in the Mesaverde Formation sandstones (Fox and Dolton, 1995). Gas accumulations occur in regional stratigraphic traps created by low reservoir permeability and active gas generation (Fox and Dolton, 1995).

The Maastrichtian age Meeteetse Formation is a nonmarine unit that interfingers eastward with the marine Lewis Shale (Paape, 1968). The Meeteetse-Lewis Formation varies in thickness from about 800 to 1,400 feet and is divided into an upper and lower (Keefer and Johnson, 1993). The lower consists of sandstone, siltstone, shale, carbonaceous shale, and coal, while the upper is a massive, lenticular sandstone (Keefer and Johnson, 1993).

The Lance Formation (Maastrichtian) is a sequence of gray, medium-grained sandstones and brown, carbonaceous shales and coals (Rieke and Kirr, 1984). The lower portion of the sequence contains conglomerates with granule-size fragments and pebbles of chert and siliceous shale, and white, light-gray, and tan, medium- to coarse-grained massive to thinly crossbedded, lenticular sandstone (Keefer and Johnson, 1993). The upper portion is mostly gray to black, carbonaceous shales and claystones (Keefer and Johnson, 1993). Reservoirs in the Lance tend to be in the lenticular sandstone bodies and mainly produce gas and condensate from structural/stratigraphic traps.

Paleocene

The Paleocene system is represented by the Fort Union Formation (Paape, 1968). The Fort Union Formation ranges in thickness from a wedge edge to as much as 7,000 feet and is divided into an upper and lower unit. The Upper contains the Waltman Shale Member and the Shotgun Sandstone Member (Paape, 1968). The lower part of the Fort Union contains of interbedded lenticular sandstone, conglomerate, coal, and thin carbonaceous shale (Paape, 1968). The Waltman Shale Member is brown to black organic-rich shale and siltstone which probably serves as the source rock for the contiguous sandstone reservoirs (Keefer, 1969). The Shotgun Sandstone Member is characterized by shale, claystone, and siltstone with thin beds of sandstone, carbonaceous shale, and coal (Keefer and Johnson, 1993). Sandstone reservoirs in the Fort Union Formation commonly form on stratigraphic traps where facies changes are prominent (Fox and Dolton, 1995).

Eocene

The Wind River Formation was deposited during the Eocene and forms much of the surface rock throughout the central Wind River Basin. The Wind River Formation is dominated by varicolored claystone and siltstone interbedded with fine- to coarse-grained, partly conglomeratic sandstone (Keefer, 1969) (Paape, 1968). Early Eocene strata contains gray to black carbonaceous shale and claystone (Keefer, 1969). The juxtaposition of sandstone bodies and potential source rocks and the formation of shallow structures promotes accumulation of petroleum in the Wind River Formation (Keefer, 1969).

Lithologies, Pressures, and Mechanisms (Table 6)

The pressure-depth data analyzed for the Wind River Basin is from the Beaver Creek Field in Tps. 33-34 N., R. 96 W. of Fremont County, Wyoming. The Beaver Creek Field is the largest gas field in the Wind River Basin and produces primarily from the Cody (Cretaceous), Frontier (Cretaceous), Lakota of the Cloverly Group (Cretaceous),

Table 6

Wind River Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	Eocene - Mesaverde Fm.	alternating beds of shale & sandstone	structure &/or stratigraphic	• hydraulic connectivity • steady-state ground water flow
middle under	Cody Shale Fm. - Jurassic	sandstone	structure & stratigraphic	• hydrodynamic flow • unloading/rock dilation • differential hydrocarbon migration versus groundwater flow • depletion of hydrocarbons
deep normal	Triassic - Precambrian	carbonates	structure	• hydraulic connectivity • steady-state ground water flow

Bally Classification: 222 – Perisutural basins on rigid lithosphere associated with formation of compressional megastructure; Dominated by block faulting
Klemme Classification: IIA – Continental multicycle basin; Craton margin – composite

(St. John et al., 1984)

Tensleep (Pennsylvanian) and Madison (Mississippian) Formations. The pressure-depth plot identifies three fluid pressure regimes: an upper normal, a middle underpressured, and a deep normal. This type of distribution classifies the Beaver Creek Field as a “Recessed-Tiered” pressure system.

The upper normal pressure regime begins at the surface (Eocene) and extends to an approximate depth of 4,000 feet. This section includes the Eocene Wind River Formation through the Cretaceous-Campanian Mesaverde Formation. The lithologies in this interval tend to be dominated by clastic material (sandstone, conglomerate, siltstone, and shale) with lateral discontinuity. Often the coarse, clastic bodies grade into finer material as they become more distal. In the Beaver Creek Field, this interval is not a primary petroleum objective, but towards the eastern basinal margins, stratigraphic irregularities and/or subtle structures generate accumulations (Paape, 1968). The lithologies and pressures in the normally pressured interval point towards hydraulic connectivity and/or steady-state ground water flow as a pressure mechanism.

The underpressured regime detected in the central section of the PDP encompasses strata from the Upper Cretaceous Cody Shale to the beginning of the Lower Jurassic (Nugget Sandstone). The lithology of this interval is dominantly coarse, clastic material, i.e. sandstone. This sequence of beds contains some of the more productive reservoirs in the Wind River Basin. In the Beaver Creek Field, these reservoirs account for > 50% of the total producing wells (Paape, 1968). Trapping in the underpressured regime seem to rely on the buoyancy difference between hydrocarbons and water. Most accumulations are found on faulted anticlines, but some have a stratigraphic component. Suspected mechanisms for causing underpressure are one of or a combination of hydrodynamic flow, unloading/rock dilation, differential hydrocarbon migration versus groundwater flow or depletion of hydrocarbons.

The lower normal regime contains Triassic (Chugwater Group) through the Precambrian strata. The foremost lithology for this regime is carbonate. There are some coarser siliciclastic reservoirs, such as the Tensleep Sandstone, which are important in the production of hydrocarbons, but the comparative thickness of these to the carbonates is small. The Mississippian Madison and the Pennsylvanian Tensleep Formations are the producers in the Beaver Creek Field (Paape, 1968). These formations produce on structures (faulted anticlines) that act as trapping mechanisms for oil and gas accumulations which can be seen in Figure 25. The lithologies and pressures in this normally pressured interval point towards hydraulic connectivity and/or steady-state ground water flow as a pressure mechanism.

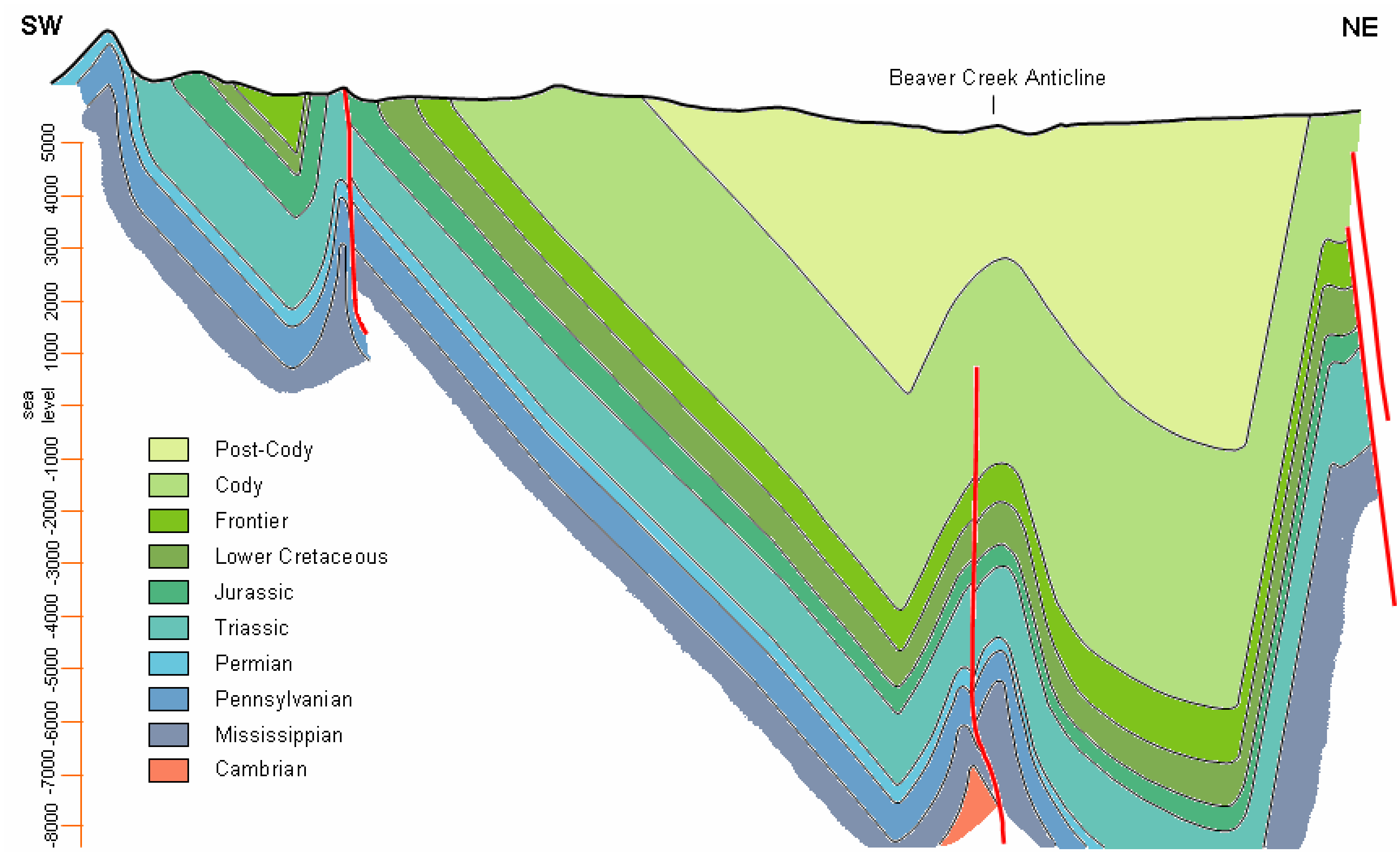

Figure 25. Generalized cross section (SW-NE) through the Beaver Creek Anticline, Wind River Basin, U.S.A. (adapted from Kewanee Oil Co, 1961).

Big Horn Basin

Geologic Setting

The Big Horn basin in northwestern Wyoming (Figure 26) is primarily of Laramide tectonic origin, but has been a part of larger sedimentary basins throughout most of geologic history (Thomas, 1965). The present Big Horn basin is bound by the Pryor-Big Horn Mountains to the east; the Owl Creek Mountains to the south; the Yellowstone-Absaroka volcanic plateau and Beartooth Mountains to the west; and on the north by the Nye-Bowler left-lateral wrench-fault zone (Stone, 1967).

The Big Horn basin was part of the Cordilleran geosyncline during the Paleozoic and much of the Mesozoic (Stone, 1967). During the pre-Laramide time, the basin experienced repeated "see-saw" tectonism (Thomas, 1965). It started with northerly tilting, deposition, emergence, and erosion resulting in the truncation of the Ordovician, Devonian, and Mississippian sediments from north to south (Thomas, 1965). This also facilitated the complete removal or nondeposition of Silurian sediments (Stone, 1967). After the northerly tilting, the area of the present basin underwent southerly tilting, deposition, erosion, and truncation of the Pennsylvanian, Permian, and Triassic sediments that are recognized by thinning of these intervals from south to north (Thomas, 1965).

This thinning plane of Pennsylvanian, Permian, and Triassic units to the north laid the foundation for the Jurassic and Lower Cretaceous Formations, which increase in thickness from south to north and regionally to the west towards the miogeosyncline (Stone, 1967). The thickening of the Jurassic and Early Cretaceous also support the

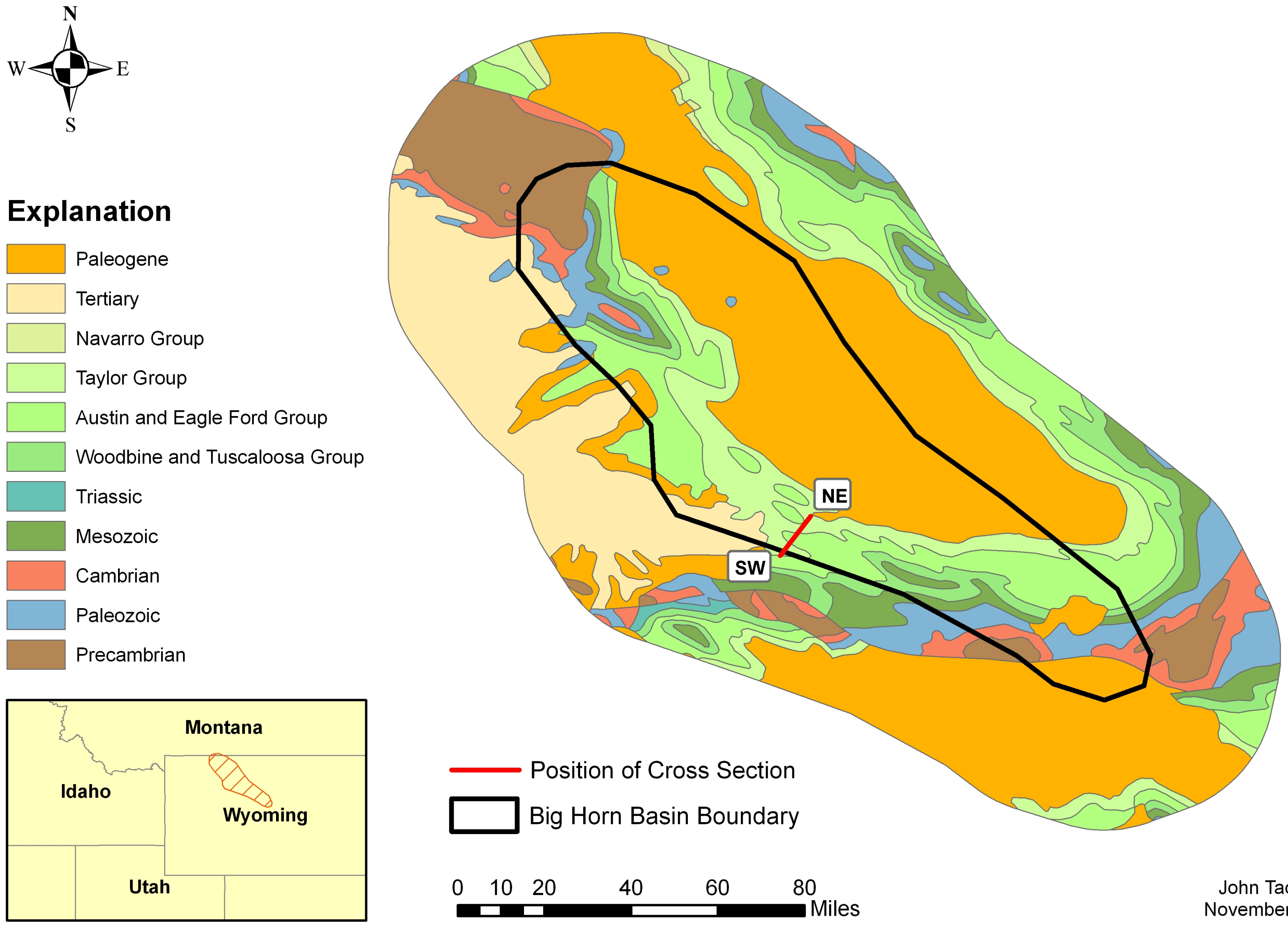

Figure 26. Generalized geologic map of the Big Horn Basin showing the location of the cross section. The map shows the surface geology of the basin and 30 miles beyond. The data used for the map was adapted from the United States Geological Survey.

development of a low-relief structural arch, possibly the buried northwest-plunging nose of the Casper arch and Laramie Range to the south (Thomas, 1965).

Some deposits of Early Cretaceous sediments seem to have been affected by the formation of a new structural basin (Thomas, 1965). Transgressions and regressions of the Cretaceous sea continued until the Laramide Orogeny (Thomas, 1965). The Laramide tectonism intensified during the beginning of the Paleocene and continued into the Eocene (Stone, 1967). This period of intense movement was accompanied by folding and faulting, and followed by the deposition and partial erosion of the Absaroka volcanics to the northwest (Stone, 1967).

Laramide tectonism resulted in mountain building, unconformities at basin margins, deposition of Tertiary sediments, and the development of the structures preserved today (Thomas, 1965). Most of the structures that produced the present oil and gas accumulations probably formed during the Laramide pulses and continued to tilt during the Tertiary time (Stone, 1967).

Pressure data is restricted to a structural feature located in the southern portion known as the Hamilton Dome. The Hamilton Dome is part of the more regional Thermopolis anticline (Krampert, 1947). The Hamilton Dome trends northwest and has a curved axis with a convex bend to the south (Krampert, 1947). The southern limb dips steeply, up to 90°, while as the northern limb dips more gently, 12°-14° (Krampert, 1947). Some faults are associated with the sharpness of the folding and are the result of tilting and vertical uplift over a large fault in the basement (Figure 27); (Krampert, 1947).

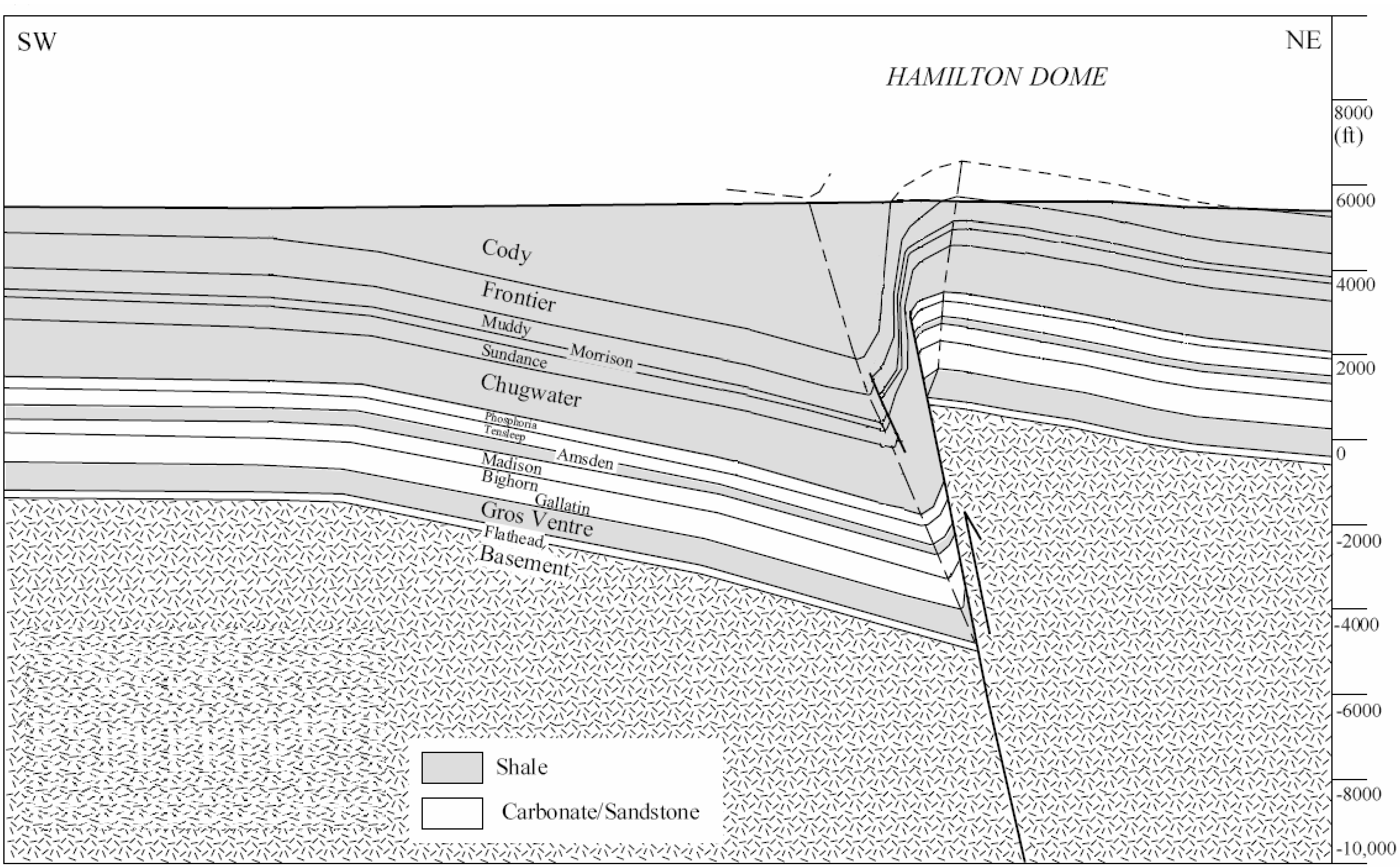

Figure 27. Geologic cross section (SW-NE) through the Hamilton Dome Area, Big Horn Basin, U.S.A. (from Mitra and Mount, 1998).

Pressures

The Big Horn basin, in particular the Hamilton Dome area, is classified into the "Recessed – Tiered System". A general pressure-depth profile for this area has two parts: an upper normal pressured and a lower underpressured (Figure 28).

The upper normal pressured regime occurs from the surface, Cretaceous, to the Triassic. This interval includes the section from the outcropping, Cody or Thermopolis Formation, to the Red Peak Member of the Chugwater Formation (Figure 29).

The lower interval of underpressured rocks includes the section from the Triassic Dinwoody Formation to the Precambrian basement.

Stratigraphy

Cambrian

The Cambrian in the Big Horn Basin overlies the granitic and metamorphic Precambrian basement. The base of the Cambrian is represented by the Flathead Sandstone. The Flathead Sandstone is coarse to fine-grained sandstone and conglomerate (Stone, 1967). Above the Flathead Sandstone is the Gros Ventre Formation, a clastic unit composed of glauconitic and sandy limestone and thin sandstone beds in dark grayish-green shale (Stone, 1967). The Gallatin Limestone, which identifies the top of the Cambrian, is glauconitic, locally pebbly, sandstone, limestone, and shale with thin sandstone beds (Stone, 1967). The Cambrian rocks produce oil and gas from the Flathead and upper part of the Gallatin.

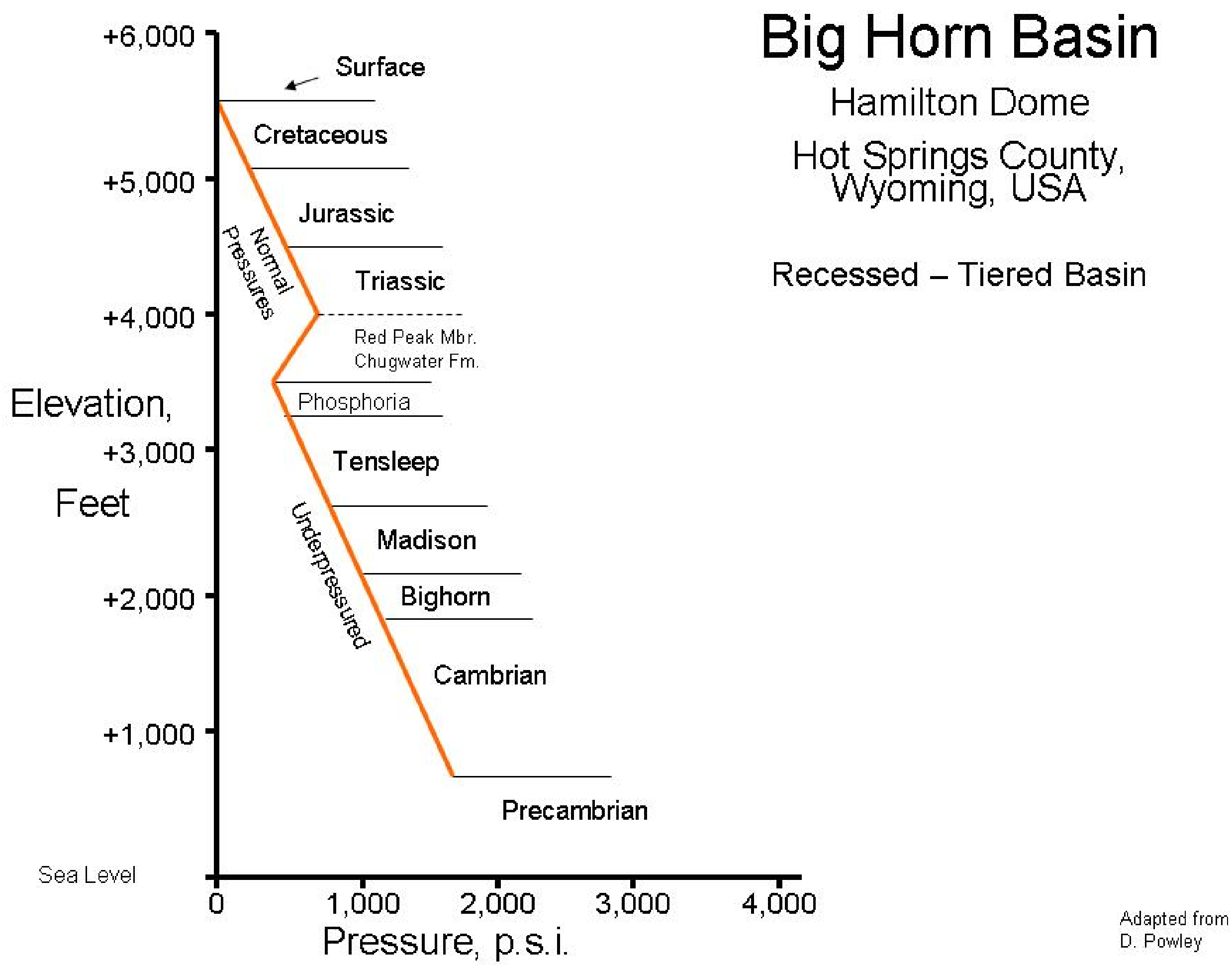

Figure 28. Pressure-depth profile from the Hamilton Dome Field, Big Horn Basin (adapted from D. Powley).

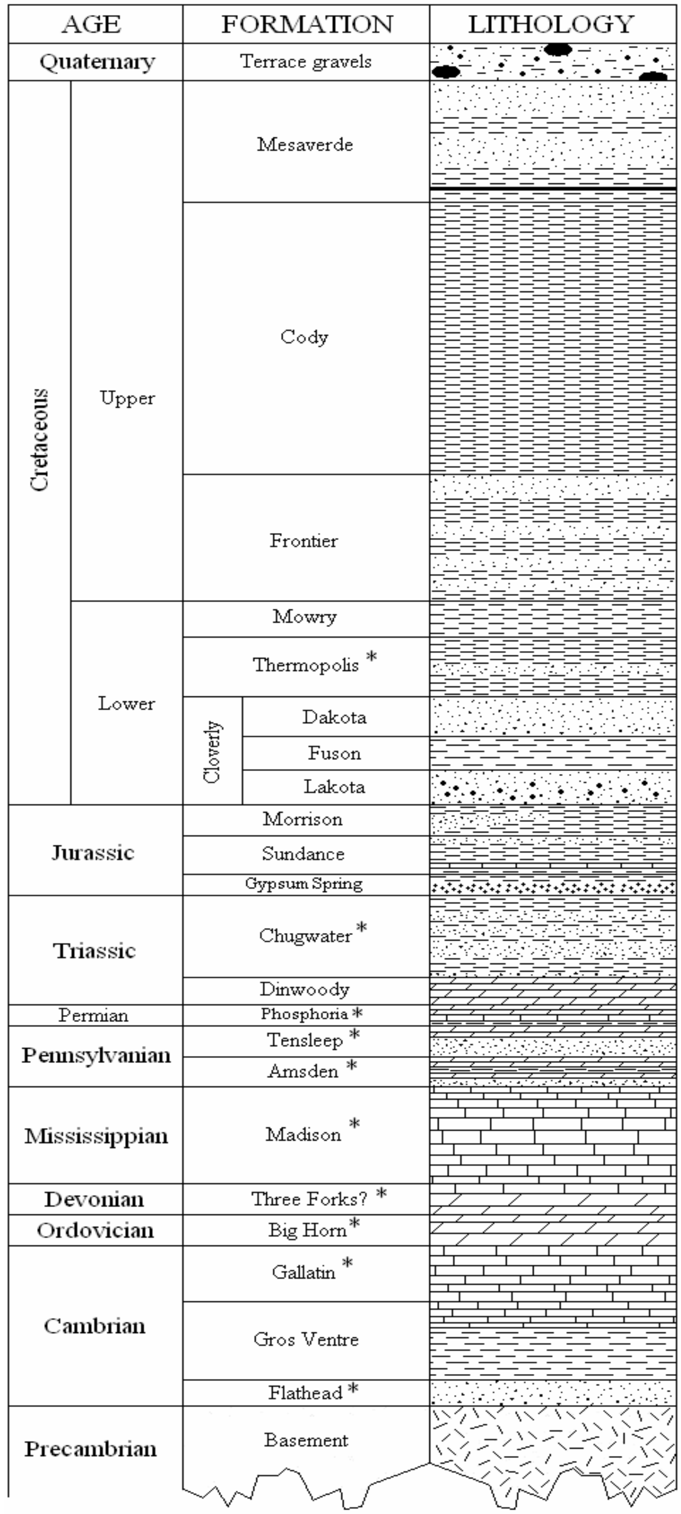

Figure 29. Stratigraphic column of the Hamilton Dome, Big Horn Basin (adapted from Krampert, 1947, Mitra and Mount, 1998, and WGA, 1952). Petroleum-producing formations are marked with an asterisk (*) (Chapman, 1989).

Ordovician

The Ordovician system is represented by a porous dolomite called the Bighorn Dolomite (Krampert, 1947). The Bighorn has a basal transgressive sandstone, but is predominantly a white, tan, and pink, finely crystalline to microsaccharoidal dolomite and cherty dolomite. The Bighorn produces oil in the Hamilton Dome, Garland, and Elk Basin fields (Stone, 1967).

Silurian

Silurian rocks have not been identified in the Big Horn basin. They were likely eroded prior to the Devonian (Stone, 1967).

Devonian

The Devonian is represented by dark gray or brown crystalline dolomite that is interbedded with pinkish or tan-colored carbonates and sandstones (Stone, 1967). The Devonian rocks were named Three Forks by the Wyoming Geological Association in 1952. This interval produces in the Elk Basin, Garland, and Hamilton Dome fields. The scarce production is likely the result of the thinning of Devonian section from 300 feet in the northwest to 0 feet in the southeast (Stone, 1967).

Mississippian

The Mississippian Madison Limestone is bound both above and below by regional unconformities. The Madison limestone is finely crystalline or saccharoidal, cherty, dolomite and limestone interbeds (Stone, 1967). The Madison rocks are massive and highly porous reservoirs that are notorious as a lost-circulation zone (Stone, 1967). The Madison is an important oil and gas reservoir that produces primarily from structural traps (Stone, 1967).

Pennsylvanian

The Pennsylvanian system is represented by the lower Amsden and upper Tensleep Formations (Krampert, 1947). The Amsden consist of a basal sandstone (Darwin Sandstone) and an upper sequence of dolomite, limestone, sandstone, and red shale (Keefer, 1969). The Tensleep Formation is the largest volume oil and gas producer in the Big Horn basin. The Tensleep is fine- to very fine-grained quartzose sandstone with dolostone interbeds (Stone, 1967).

Permian

The Permian system of the Big Horn Basin is represented by the 200-350 feet thick Phosphoria Formation (Stone, 1967). The Permian rocks are divided into two distinct facies: marine; and a red shale and evaporite. The marine facies includes tan, brown, and gray dolomite and limestone, interbedded with dark-colored, phosphatic, and organic-rich shale and cherty carbonate (Stone, 1967). The Phosphoria is an important oil and gas producer and the source for most of the hydrocarbons produced in the Big Horn Basin. Phosphoria reservoirs are unique to other Paleozoic oil and gas accumulations because they occur in both structural and stratigraphic traps (Stone, 1967).

Triassic

The Triassic system of the Big Horn Basin contains two formations, the Lower Triassic Dinwoody Formation and the Lower-Middle Triassic Chugwater Formation (Krampert, 1947).

The Dinwoody Formation was deposited on a shallow, locally restricted shelf and is characterized by approximately 60 feet of a green shaly dolomite that normally does not produce oil and gas (Krampert, 1947). The Chugwater Formation contains three members: Red Peak, Crow Mountain or “Curtis” Sandstone, and Popo Agie (High and Picard, 1967).

The Crow Mountain or “Curtis” Sandstone of the Chugwater Formation is an important oil and gas producing reservoir (Stone, 1967). Most oil and gas accumulations are structurally controlled and located on anticlines and faulted anticlines (Chapman, 1989).

Jurassic

The Jurassic system in the Big Horn Basin is divided into three formations: Gypsum Spring, Sundance, and Morrison (Krampert, 1947).

During the Middle Jurassic, shallow seas invaded from the north, and deposition resulted in evaporite and red siltstones of the Gypsum Springs Formation (Thomas, 1965). These evaporites are less than 100 feet thick in southern areas to greater than 200 feet in the northern part of the basin (Thomas, 1965).

The Middle-Upper Jurassic Sundance Formation is glauconitic limy sandstone, limy shale, red to brown shale, and oolitic limestone (Krampert, 1947).

The Upper Jurassic Morrison Formation is a nonmarine varicolored shale, sandstone, conglomerate, and lacustrine limestone (Thomas, 1965).

Jurassic rocks in the Big Horn Basin are only minor producers of oil and gas from sandstones of the Sundance and Morrison Formations where stratigraphy and structures allow for accumulation (Thomas, 1965). The source was thought to have originated from fossiliferous shale beds within the section, but the lack of significant accumulations indicates that some if not most of the hydrocarbons were derived from older or younger sources by secondary migration through faults or fractures of tightly folded anticlines (Keefer, 1969).

Cretaceous

The Cretaceous System in the Big Horn Basin is divided into the Lower Cretaceous Cloverly, Thermopolis, and Mowry Formations (Kewanee Oil Company, 1961), and Upper Cretaceous Frontier, Cody, and Mesaverde Formations (Krampert, 1947).

The Lower Cretaceous Cloverly Formation contains the Lakota Sandstone, Fuson Shale, and Dakota Sandstone. The Lakota is sandstone with a conglomeratic base that marks the Cretaceous-Jurassic boundary (Keefer, 1969). The Fuson Shale is dominantly variegated shale (Krampert, 1947). The Dakota Sandstone or "Rusty Beds" is sandstone the fines-upward into siltstone (Krampert, 1947).

The Thermopolis contains distinct facies: lower middle, and upper. The lower facies is dark marine shale (Krampert, 1947). The middle facies is the Muddy Sandstone, which consists of fine- to coarse-grained sandstone interbedded with gray to black shale and siltstone (Keefer, 1969). The upper facies is dark marine shale (Krampert, 1947).

The Mowry Shale consists of approximately 200 feet of siliceous shale with streaks quartzitic sandstone (Krampert, 1947).

The Frontier Formation is a variable sequence of interbedded sandstone and shale of both marine and nonmarine origin. The Frontier contains gray to black shale; and gray, fine- to medium-grained, massive to thin-bedded sandstone (Rieke and Kirr, 1984). The sandstones are high volume producers of oil and gas (Thomas, 1965).

The Cody Shale is late Coniacian through early Campanian dark colored, marine shale. It is variable in thickness, but exceeds 2700 feet in the Hamilton Dome area (Krampert, 1947).

The Mesaverde Formation is Campanian in age and ranges from 900 to 1,500 feet thick in the Hamilton Dome area (Krampert, 1947). The Mesaverde contains light- to dark-gray sandstone interbedded with shale, siltstone, and coal (Krampert, 1947). Small volumes of gas have been produced in the Mesaverde Sandstones (Thomas, 1965).

Recent

In the Hamilton dome area, the surface formations are the Cody Shale and the Thermopolis Shale (Figures 33 and 35) (Chapman, 1989). The surface is often littered by a thin veneer of terrace gravels that consist of igneous boulders, sandstones, and clay.

Lithologies, Pressures, and Mechanisms (Table 7)

The pressure-depth data analyzed for the Big Horn Basin is specific to the Hamilton Dome Field in T. 44 N., Rgs. 97-98 W. of Hot Springs County, Wyoming. The Hamilton Dome Field is the fourth largest field in the Big Horn Basin (Stone, 1967) and

Table 7

Big Horn Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	Upper Cretaceous – Chugwater Fm.	shales	structure &/or stratigraphic	• hydraulic connectivity • steady-state ground water flow
lower under	Red Peak Mbr. of Chugwater Fm. – Precambrian	carbonate	structure	• hydrodynamic flow • unloading/rock dilation • differential hydrocarbon migration versus groundwater flow • depletion of hydrocarbons

Bally Classification: 222 – Perisutural basins on rigid lithosphere associated with formation of compressional megastructure; Dominated by block faulting

Klemme Classification: IIA – Continental multicycle basin; Craton margin – composite

(St. John et al., 1984)

produces primarily from the Chugwater (Triassic), Phosphoria (Permian), Tensleep (Pennsylvanian), Madison (Mississippian), and Bighorn (Ordovician) Formations (WGA, 1957). The pressure-depth plot identifies two pressure regimes: an upper normal and a middle underpressured. This type of distribution classifies the Hamilton Dome as a "Recessed-Tiered" pressure system.

The upper normal pressure regime begins at the surface (Upper Cretaceous) and extends to an approximate depth of 1,600 feet. This interval contains the Upper Cretaceous Cody Shale through the Triassic Chugwater (top of Red Peak Member). The dominant lithology is shale. This interval is not a primary petroleum-producing objective at Hamilton Dome, but does produce hydrocarbons elsewhere in the basin (Thomas, 1965). The lithologies and pressures for this regime point towards hydraulic connectivity as the primary pressure-generating mechanism.

The lower underpressured interval encompasses strata from the Triassic Red Peak Member of the Chugwater Formation through the Precambrian basement. This interval is dominated by carbonate beds (limestone and dolomite) with interbedded shales. This interval contains most producing reservoirs found in the Big Horn Basin. The trapping mechanisms in the underpressured interval rely on the buoyancy difference between the hydrocarbons and water. Most accumulations occur on faulted anticlines or simple anticlinal folds. Suspected mechanisms for the underpressured reservoirs include hydrodynamic flow, unloading/rock dilation, and differential hydrocarbon migration versus groundwater flow.

Alberta Basin

Geologic Setting

The Alberta Basin is located in the western provinces of Canada and the state of Montana in the U.S. (Figure 30). It sits on a stable Precambrian platform and is bounded on the west and southwest by the Rocky Mountains, on the northeast by the Canadian Precambrian shield, and on the north by the Tathlina High (Bachu, 1999). The Alberta Basin is separated from the Williston Basin by the Bow Island Arch (Bachu, 1999).

Sedimentation began in the Alberta Basin during the late Proterozoic following rifting of the North American craton (Bachu, 1999). Deposition occurred on a passive margin beginning in the Middle Cambrian and continued to the Mesozoic resulting in a section dominated by shallow-water carbonates, evaporites, and shale (Bachu, 1999). The formation and reactivation of the Peace River Arch during the Devonian, influenced clastic deposition and reef development (Bachu, 1999). As a result of continued subsidence, the Peace River Arch became an elongate island or peninsula, which aided in the development of a yolk-shaped fringing reef until it was submerged by the end of the Devonian (Clark et al., 1968).

Subsidence continued into the Mississippian and was accompanied by normal faulting that formed parallel to the Peace River arch (Clark et al., 1968). However, the subsidence was interrupted by periodic uplifts, resulting in emergence and erosion at the end of the Mississippian, Permian, Triassic, Jurassic, and Paleocene (Clark et al., 1968). All periods of erosion were brief until the Jurassic, and the latter (Paleocene) uplift continues today (Clark et al., 1968). Subsidence was greatest on the south and west and

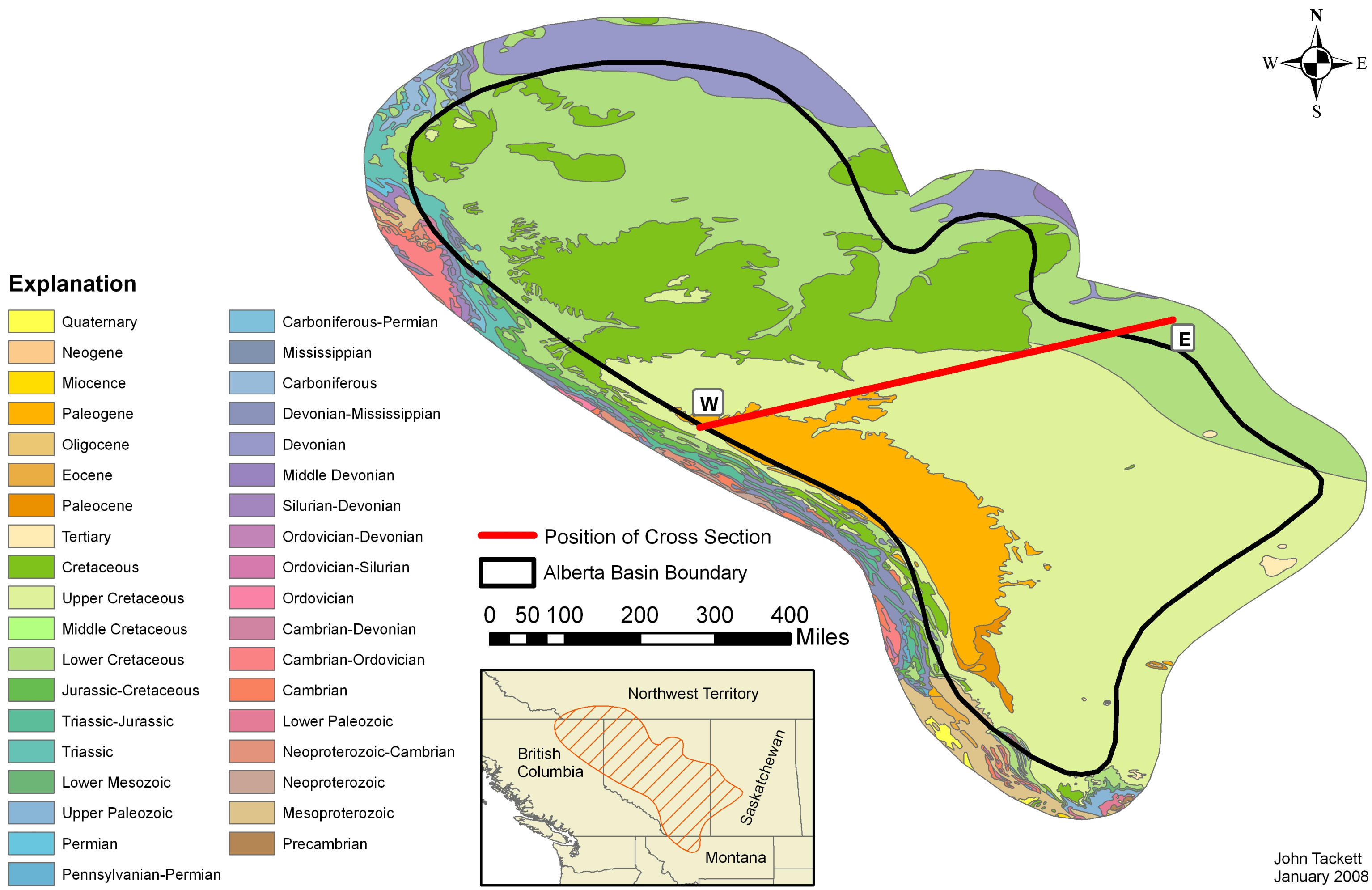

Figure 30. Generalized geologic map of the Alberta Basin showing the location of the cross section. The map shows the surface geology of the basin and 60 miles beyond. The data used for the map was adapted from the Geological Survey of Canada and United States Geological Survey.

uplift and erosion were greatest on the north and east, resulting in southwestward tilting and the development of shallow angular unconformities (Clark et al., 1968). Minor folding associated with the renewed movements on normal basement faults occurred, but it was not until the Laramide Orogeny that strong folding and thrust faulting (Clark et al., 1968) created conditions for foreland-basin development (Bachu, 1999).

Regional uplift and tilting during the Early Cretaceous resulted in widespread erosion (Clark et al., 1968). This erosion exposed Jurassic rocks in the southwest, Devonian rocks in the northeast, and produced hill-and-valley topography (Clark et al., 1968). A clastic wedge deposit advanced from the southwest consisting of coarse clastic material (Clark et al., 1968). Finer sediment followed filling valleys, and ultimately burring the hills and plateaus (Clark et al., 1968). Regional subsidence continued along with the advancement of the Early Cretaceous Sea, which would transgress the entire area (Clark et al., 1968). Marine and lagoonal deposition occurred throughout the Early Cretaceous and well into the Late Cretaceous (Clark et al., 1968). The sea receded in the Late Cretaceous and deposition of continental sands and muds began that continued into the Paleocene (Clark et al., 1968).

The Laramide Orogeny ended the depositional cycle and compressive orogenic forces created a belt of gentle folding that transition into the unfolded plains of Alberta (Clark et al., 1968).

<u>Pressures</u>

The pressure distribution in the Alberta Basin, and the exemplar Gold Creek Field, Peace River area, is classified into the “Recessed – Tiered System”. A generalized pressure-depth profile for this area has three parts: an upper normally pressured interval, a middle underpressured interval, and a deep normally pressured interval (Figure 31). The upper normally pressured regime extends from the surface to the top of the Upper Cretaceous Dunvegan Formation. The underpressured interval includes the Upper Cretaceous Dunvegan Formation and the Spirit River Formation of the Fort St. John Group. The deep normally pressured interval extends from the Lower Cretaceous Bluesky Formation to the Pre-Devonian.

Stratigraphy

Devonian

The Devonian rocks of the Peace River Area in the Alberta Basin include Middle and Upper Devonian carbonates (Figure 32). The Middle Devonian contains the Elk Point Group, which is dominated by carbonates with minor anhydrite and clastic intervals (Clark et al., 1968). The Middle Devonian and Upper Devonian rocks are separated by an unconformity at the base of the Watt Mountain Shale (Clark et al., 1968). Above the Watt Mountain are carbonate rocks of the Otter Park Formation (Clark et al., 1968). The Fort Simpson and its equivalent, the Leduc, lie above the Watt Mountain. The Fort Simpson is dominated by shale, while the Leduc is a carbonate reef system (Clark et al., 1968). The Winterburn and Wabamun are interbedded carbonates, shales, and siltstones (Clark et al., 1968). The Devonian rocks in the Peace River area contain commercial quantities of oil and gas, primarily in the Otter Park, Leduc, Winterburn, and Wabamun in reef structures and folds (Clark et al., 1968).

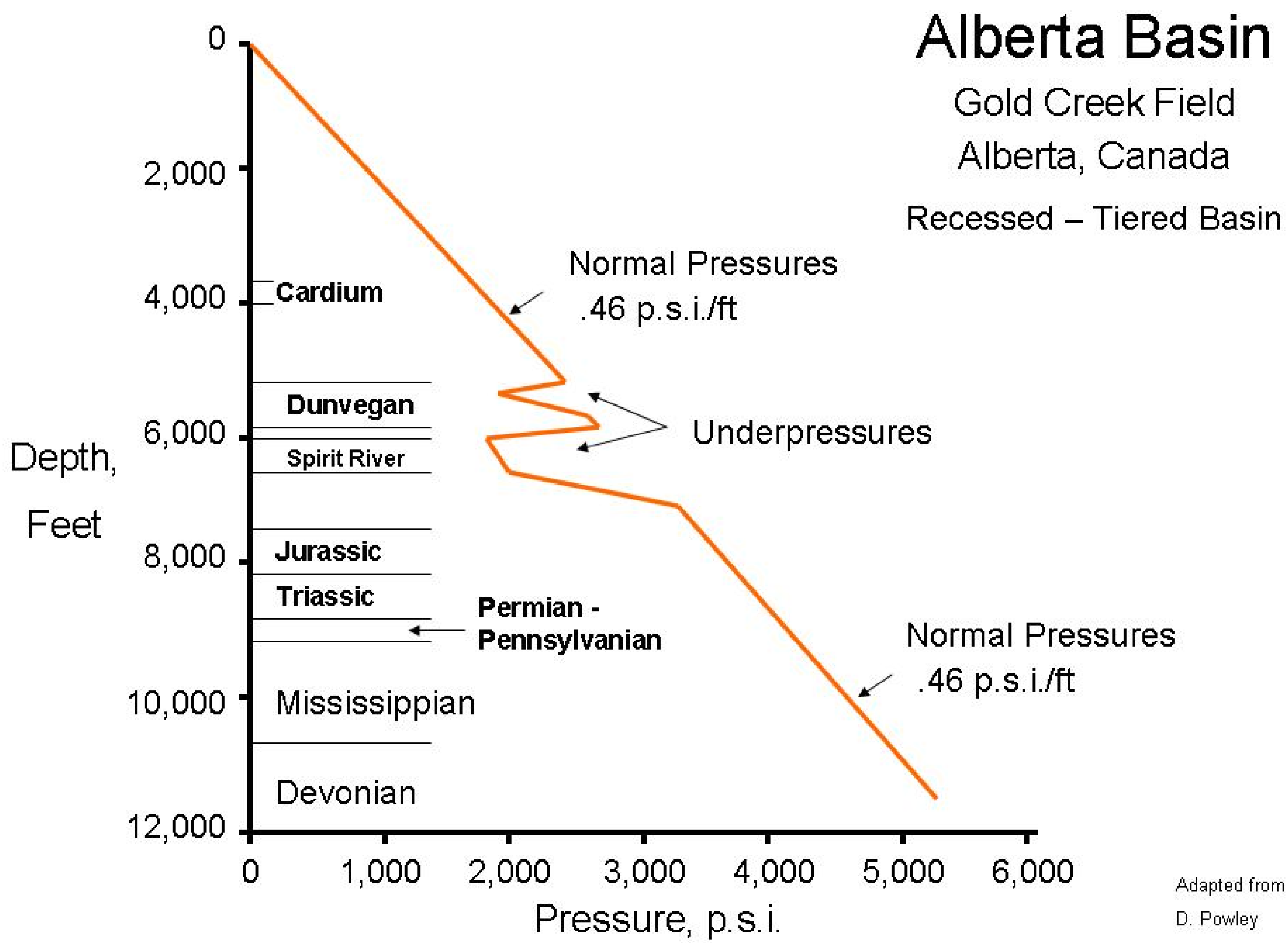

Figure 31. Pressure-depth profile from the Gold Creek Field, Alberta Basin (adapted from D. Powley).

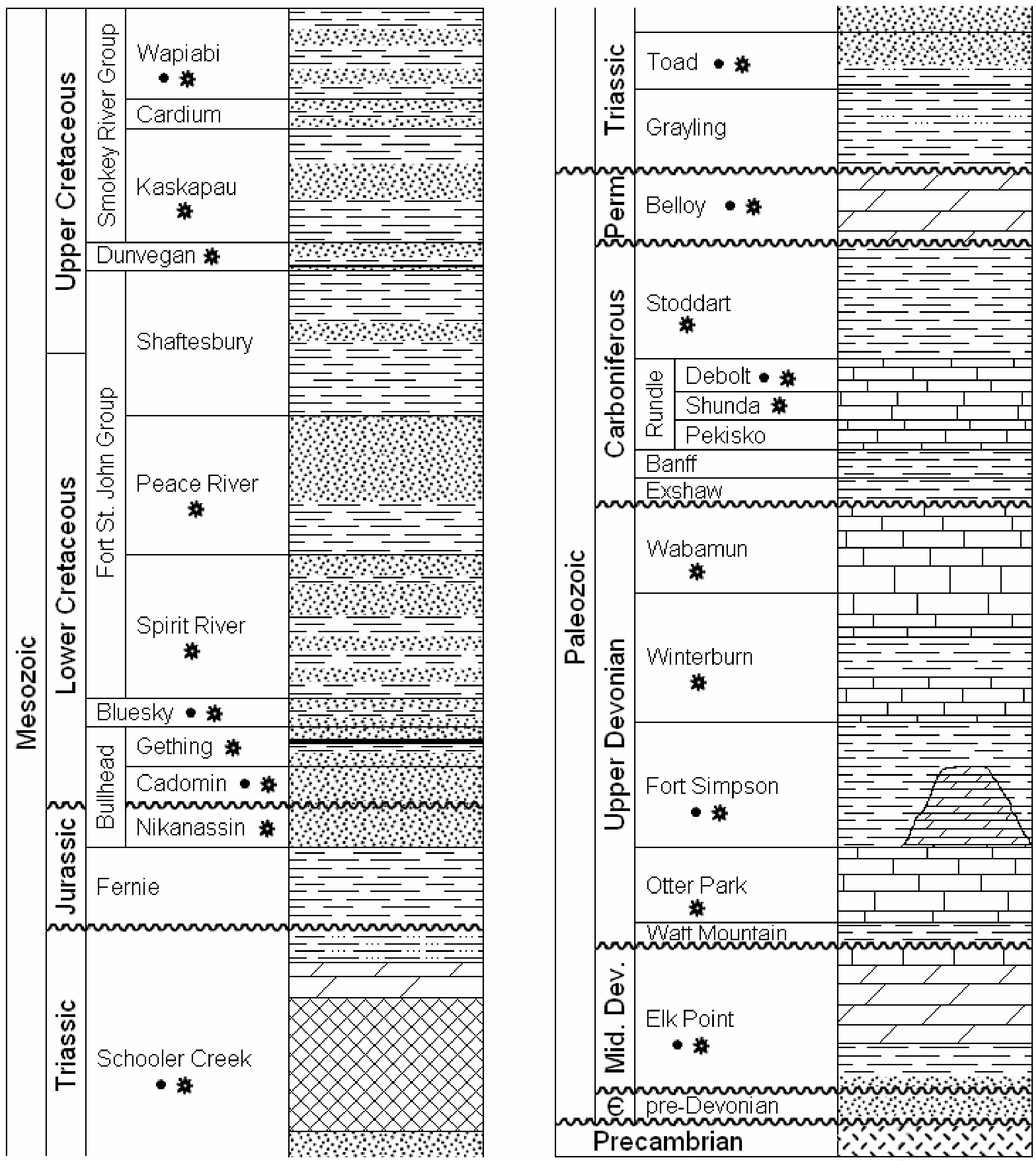

Figure 32. Generalized stratigraphic column, Peace River Area, Alberta Basin (adapted from Alberta Study Group, 1954, Clark et al., 1968, Gleddie, 1954, Hunt, 1959, Lackie, 1958, and Macauly, 1958). Petroleum-producing formations are marked (Clark et al., 1989).

Mississippian

The Mississippian strata in the Peace River area are divided into six formations. The earliest is the Exshaw Formation, which is dark brownish-black, bituminous, fissile, spore-bearing shale with beds of light gray, fine-grained, calcareous, quartzose siltstone and light gray, cryptocrystalline and finely granular, silty limestone (Macauley, 1958). The overlying Banff Formation is generally composed of brown bituminous shale, but contains bioclastic limestones (Macauley, 1958). The Pekisko Formation is light yellowish brown, coarsely bioclastic, cherty limestone, which grades northward into two limestone units, divided by a dark gray shale (Macauley, 1958). The Shunda Formation is dominantly light gray and yellowish brown, argillaceous or clean bioclastic limestones, with interbedded dark gray shales (Macauley, 1958). The Debolt Formation is divided into upper and lower members; the lower Debolt is cherty, massive bioclastic limestone, in part coarsely crinoidal, while the upper Debolt is composed of very finely crystalline to dense, massive dolomite, with numerous thin interbeds of finely crystalline anhydrite (Macauley, 1958). The limestone and dolomite beds in the Shunda and Debolt are reservoirs (Clark et al., 1968).

Mississippian – Pennsylvanian

The Stoddart Formation spans the Mississippian – Pennsylvanian boundary in the Peace River area of the Alberta Basin. The Stoddart Formation has a maximum thickness of 2,165 feet and is usually divided into two units, an upper and a lower. The lower unit is composed of dark gray to greenish shales, with minor brightly colored variegated shales, and numerous massive quartzose sandstones (Macauley, 1958). The upper unit contains light brown, finely crystalline and microcrystalline, non-vugular, sandy, and cherty dolomites (Macauley, 1958). The massive sandstone beds in the upper unit contain accumulations of oil and gas that are trapped as a result of facies changes and stratigraphic pinchouts.

Pennsylvanian – Permian

Sedimentary rocks above the Stoddart and below the Triassic are called the Belloy Formation (Clark et al., 1968). This section is dominantly bedded, dense dolomites and chert (Macauley, 1958).

Triassic

The Triassic is represented by the Grayling and Toad Formations and the Schooler Creek Group. The Grayling Formation consists of 600-1,000 feet of marine, soft, laminated, friable, dark gray shale, with beds of hard ripple-marked sandstone (Hunt and Radcliffe, 1959). The Toad Formation is marine, dark gray, brown, or black, slaty shales; dark shaly, thin-bedded, calcareous siltstones; and some massive, hard siltstones and thin lenticular dark limestones (Hunt and Radcliffe, 1959). The Schooler Creek Group is composed of interbedded massive anhydrites, redbeds, evaporitic dolomites, salt, and calcareous sandstones (Hunt and Radcliffe, 1959).

Jurassic

The Jurassic system in the Peace River Area contains of the Fernie Group and the Nikanassin Formation of the Bullhead Group. The Fernie Group is subdivided into four units; from oldest to youngest, Nordegg, Poker Chip Shale, Rock Creek, and an unnamed member (Lackie, 1958). Overall the dominant lithology of the Fernie Group is dark marine shale with sandstone and minor amounts of chert and limestone (Lackie, 1958). The Nikanassin Formation is composed mainly of fine- to medium grained sandstones that interfinger with black shale partings (Lackie, 1958).

Cretaceous

The Cretaceous rocks are divided into five major divisions; the Bullhead Group, Bluesky Formation, Fort St. John Group, Dunvegan Formation, and Smokey River Group.

The Bullhead Group, Lower Cretaceous, consists of the Cadomin and Gething Formations which lie unconformably on the Jurassic Nikanassin Formation. The Cadomin Formation, which is an oil and gas producer, is continental conglomeratic sandstone (Clark et al., 1968). The Gething Formation consists of nonmarine sandstones and shales, prominent coal seams and minor conglomerate beds (Alberta Study Group, 1954).

The Lower Cretaceous Bluesky Formation has become one of the main objectives of oil and gas wells drilled in the Peace River Area (Alberta Study Group, 1954). The Bluesky is argillaceous to shaly, glauconitic, poorly cemented sandstone with interbedded shale (Alberta Study Group, 1954).

Overlying the Bluesky Formation is the Fort St. John Group, which contains a lower Spirit River, middle Peace River, and upper Shaftesbury Formations. The Lower Cretaceous Spirit River Formation is characterized by dark gray shale, alternating shale and sandstone with numerous thin coals and calcareous and glauconitic sandstones (Alberta Study Group, 1954). The Peace River Formation consists of dark gray shale, massive fine- to very fine-grained sandstone, and poorly sorted sandstone containing pebbles and granules of quartz sand and chert (Alberta Study Group, 1954). The Upper and Lower Cretaceous Shaftesbury Formation is marine dark, sandy to silty shale with sandstone lenses (Gleddie, 1954).

The Upper Cretaceous Dunvegan Formation overlies the Fort St. John Group. This gas-producing interval consists of lenticular sandstone, shale, and locally developed coal beds (Gleddie, 1954).

The Upper Cretaceous Smokey River Group represents shallow subsurface and surface strata. The Smokey River includes the Kaskapau, Cardium and Wapiabi Formations. The basal Kaskapau Formation transitions from marine shale, silty shale, and sandstone in the lower portion back into a marine shale in the upper portion (Gleddie, 1954). The Cardium Formation consists of two prominent sandstone beds divided by shale; the lower sandstone is fine-grained and well-sorted, while the upper sandstone bed is medium- to coarse-grained, conglomeratic, glauconitic, sub-angular, and interbedded with silty shales (Gleddie, 1954). The Wapiabi Formation produces oil and gas from sandstone bodies bounded by dark gray marine shales.

Lithologies, Pressures, and Mechanisms (Table 8)

The pressure-depth data analyzed for the Alberta Basin are specific to the Gold Creek Field, Peace River Area, Alberta, Canada. The Gold Creek Field is one of the major fields, with reserves greater than 100 billion cubic feet and produces primarily

Table 8

Alberta Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent – Kaskapau	shale & sandstone	stratigraphic & structure	• hydraulic connectivity • steady-state ground water flow
middle under	Dunvegan – Spirit River	sandstone	structure	• hydrodynamic flow • unloading/rock dilation • differential hydrocarbon migration vs. groundwater flow
deep normal	Bluesky – Devonian	carbonate & shale	structure & stratigraphy	• hydraulic connectivity • steady-state ground water flow

Bally Classification: 221 – Perisutural basins on rigid lithosphere associated with formation of compressional megastructure; Ramp with buried grabens, but with little or no block faulting
Klemme Classification: IIA – Continental multicycle basin; Craton margin – composite

(St. John et al., 1984)

from the Late Devonian Wabamun and Winterburn Formations (Clark et al., 1968). The pressure-depth data identifies three pressure regimes: an upper normal, a middle underpressured, and a deep normal. This type of distribution classifies the PDP into the "Recessed-Tiered" pressure system.

The upper normally pressure regime extends from the surface (Upper Cretaceous) to approximately 5,200 feet and contains the Smokey River Group and Dunvegan Formation. The interval is dominated by marine shale with sandstone reservoirs. In the Gold Creek Field this interval is not a primary petroleum objective, but in other areas, produces hydrocarbons from a combination stratigraphic and structural trap (Clark et al., 1968). The fluid pressures in this interval support hydraulic connectivity and/or steady-state ground water flow as pressure mechanisms.

The lower underpressured regime encompasses strata from the Dunvegan Formation to the Spirit River Formation of the Fort St. John Group. This interval is dominated by massive sandstone beds that can be regionally traced. Trapping mechanisms are related to structures and facies changes. Suspected mechanisms for the underpressured reservoirs in this regime are one of or any combination of hydrodynamic flow, unloading/rock dilation, differential hydrocarbon migration versus groundwater flow (Bachu, 1999, Michael and Bachu, 2001).

The deep normal pressured regime contains strata from the Lower Cretaceous Bluesky Formation to Devonian strata. The lithologies in this regime are predominantly carbonates (limestone and dolomite) with interbedded shales and sandstones. From the pressure-depth data and surface geology, the aversion to normal pressure in this regime is most likely related to the groundwater flow (Bachu, 1999). The spatial distribution of these units on the flanks of the basin creates the necessary hydraulic connectivity to the surface for hydrodynamic flow. This is supported by the complex present and past flow of formation waters through the highly-permeable, paleokarsted strata of this interval and the resultant extensive drainage network seen in the Alberta Basin cross section (Figure 33); (Bachu, 1999). This is further supported by the trapping of hydrocarbons that are associated with water and buoyancy trapped.

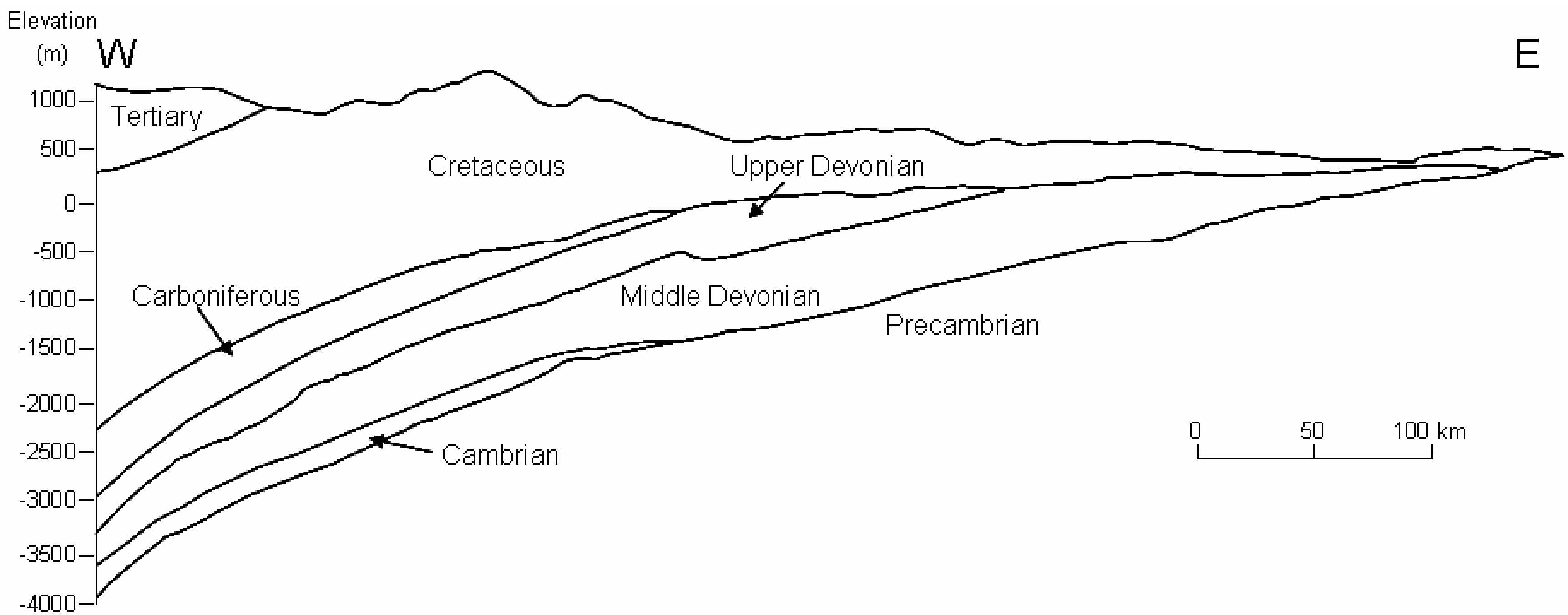

Figure 33. Geologic cross section (W-E) across central Alberta Basin, Alberta, Canada (adapted from Bachu, 1999).

CHAPTER V

LEDGED-TIERED BASINS

This section reviews three ledged-tiered basins. It examines the geologic history, stratigraphy, pressure measurements, and pressure mechanisms and the relationship between pressure types and lithologies. Graphical data supporting each evaluation is provided.

Anadarko Basin

Geologic Setting

The Anadarko Basin lies within five states: Kansas, Colorado, Texas, and Oklahoma; and is an elongated, west-northwest trending basin (Figure 34). It is bound to the south by the Wichita Mountains uplift and to the east by the Nemaha Ridge and Arbuckle Uplift.

The Anadarko contains some 35,000 feet of sedimentary rock in its deeper southern portion and 6,000 feet of sedimentary section on the shallower northern shelf (Breeze, 1970). Sedimentation rate curves for the Anadarko Basin infer relatively rapid sedimentation through the Cambrian to Ordovician, followed by relatively slow sedimentation from the Silurian to Early Mississippian, and finally extremely rapid rates

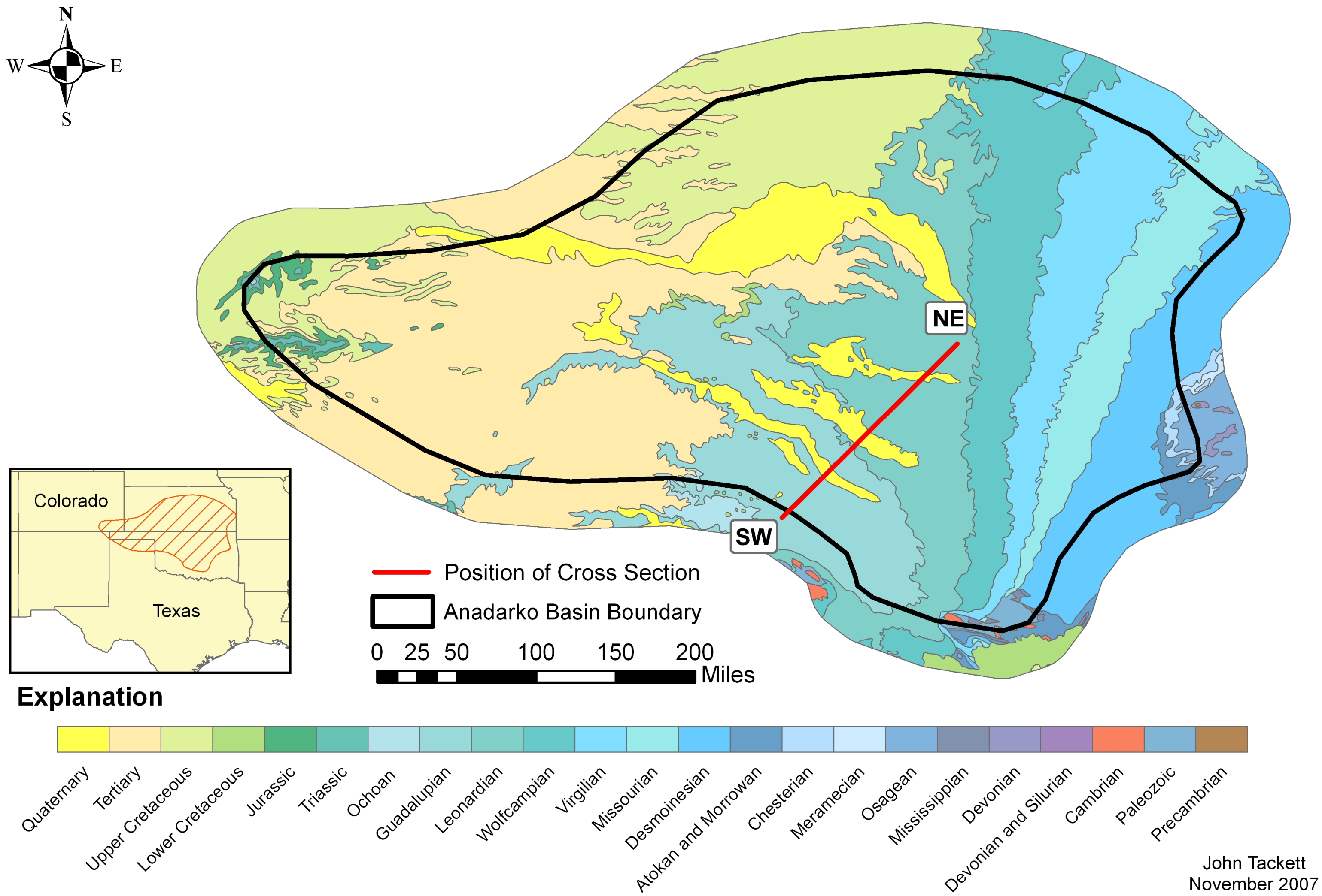

Figure 34. Generalized geologic map of the Anadarko Basin showing the location of the cross section. The map shows the surface geology of the Anadarko Basin and 30 miles beyond. The data used for the map was adapted from the USGS.

of sedimentation during the Pennsylvanian (Al-Shaieb, 1991). This rapid sedimentation coincides with the tectonic development of the Wichita Mountain uplift, which is bounded on the north by high-angle fault zones (Al-Shaieb, 1991). After the influx of sediment in the Pennsylvanian, the basin was filled from east to west (Al-Shaieb, 1991). It contains the sediments from five major sequences: Sauk, Tippecanoe, Kaskaskia, Absaroko, and Zuni (Adler et al., 1971).

The sedimentary column of the Anadarko Basin is dominated by shale, but contains sandstone and carbonate-rich intervals (Johnson, 1989) (Figure 35). The Anadarko Basin is a prolific producer of both oil and natural gas, primarily from Pennsylvanian sandstones and Lower Paleozoic carbonates. Production is from stratigraphic and structural traps that form more than 50 major fields and hundreds of minor ones (Lee and Deming, 2002).

Pressures

The Anadarko Basin is classified as a "Ledged - Tiered System". The general pressure-depth-profile for the Anadarko Basin has three parts: an upper normal pressured, a middle overpressured, and a deep normal pressured distribution (Figure 36).

The upper normal pressures occur from the surface, Permian, to the base of the Virgilian and includes the "Tonkawa" Sandstone.

The middle overpressures occur from the Upper Missourian to the Woodford Shale. It includes the "Marchand", the "Red Fork", the "Atoka", the "Morrow", the "Springer", the "Chester", the "Meramec", the "Osage", the "Woodford", and all lithologies between. This portion ranges in age from Missourian to Upper Devonian.

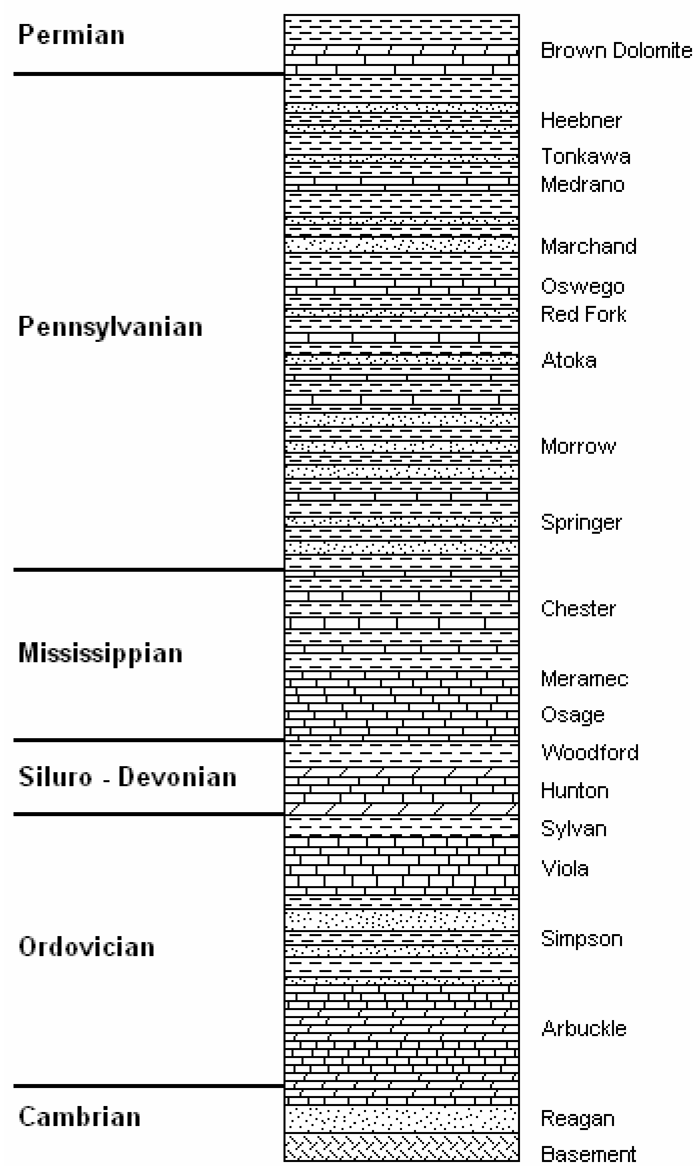

Figure 35. Generalized stratigraphic column of the Anadarko Basin (adapted from Al-Shaieb et al., 1999) No scale is intended.

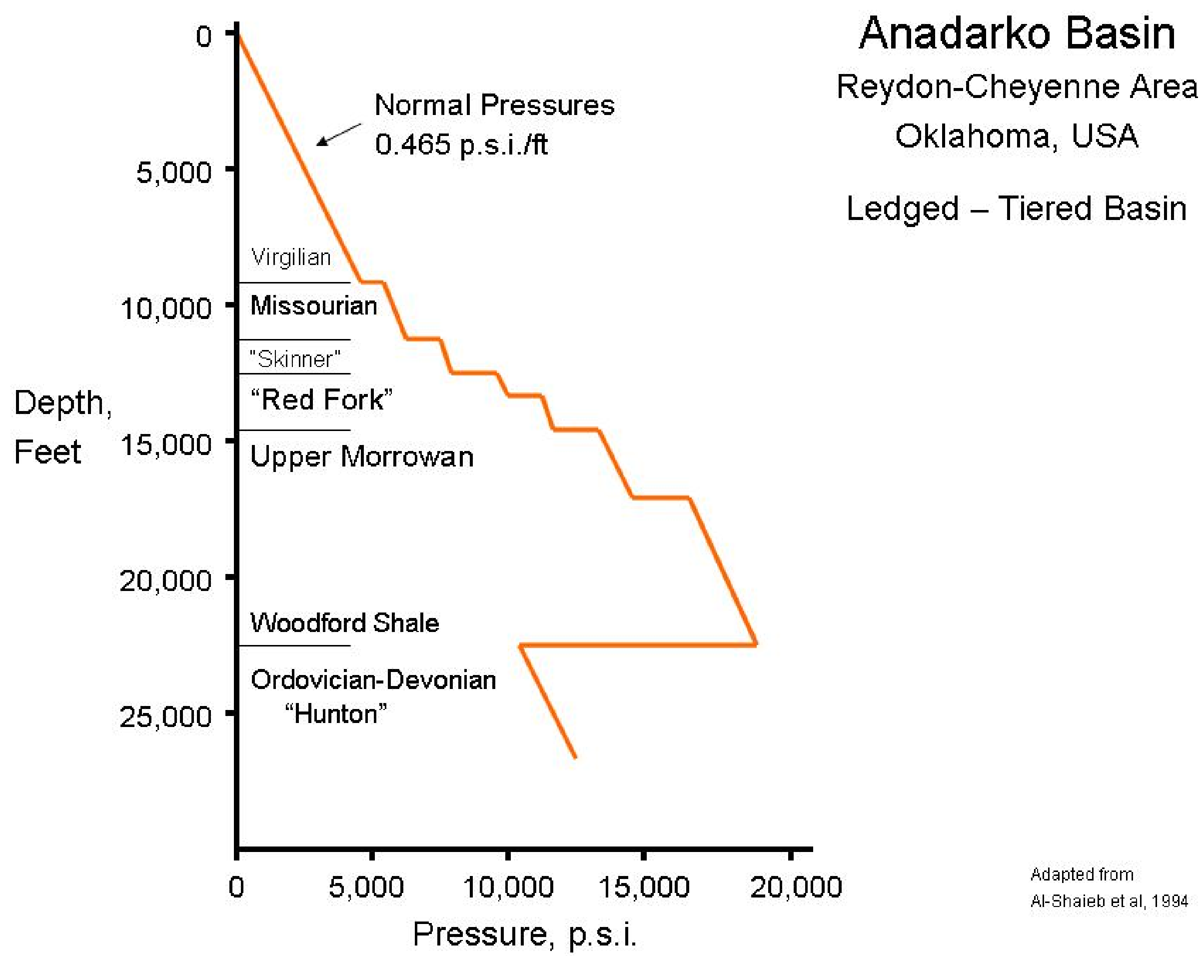

Figure 36. Pressure-depth profile from the Reydon-Cheyenne Area, Oklahoma in the Anadarko Basin (from Al-Shaieb et al., 1994). The Pennsylvanian (Morrowan) through Devonian Woodford Shale interval is highly overpressured.

The deep normal pressures start in the “Hunton” and extend into the “Arbuckle”. This includes the “Hunton”, the “Sylvan”, the “Viola”, the “Simpson”, and the “Arbuckle”. The strata in this section are Upper Cambrian to Siluro-Devonian.

Stratigraphy

Upper Cambrian

The basement in the Anadarko Basin is overlain by Upper Cambrian sedimentary rock. The Reagan sandstone rest unconformably on the basement and outcrops along the southern margin of the basin. The Reagan is a coarse-grained, arkosic, glauconitic sandstone and conglomerate (Huffman, 1959). Due to the irregularities of the basement surface the thickness of the Reagan sandstone ranges from 30 to 460 feet (Huffman, 1959).

Cambrian – Ordovician

Lying above the Reagan sandstone are the Timbered Hills and Arbuckle Groups, which are called “Arbuckle” in subsurface nomenclature. The Arbuckle reaches a maximum thickness of over 6700 feet of limestones and dolomites (Tulsa Geological Society). On the basis of lithologies and faunal content the Timbered Hills and Arbuckle Groups are divided into many different formations. In the late Cambrian they are Fort Sill limestone, Royer dolomite, Signal Mountain limestone, and Butterly dolomite and the McKenzie Hill, Cool Creek, Kindblade, and West Spring Creek in the Lower Ordovician (Huffman, 1959). In areas like the Texas panhandle, Wichita Uplift, Arbuckle uplift, Central Kansas uplift, and Nemaha ridge the Arbuckle Group rocks are thin or absent as a result of erosion.

Ordovician

The Arbuckle Group is overlain by the Simpson Group. The Simpson is subdivided into five formations consisting of limestone, dolomite, shale, and sandstone, each representing a parasequence with a basal sandstone or conglomerate (Huffman, 1959). These formations in ascending order are the Joins, Oil Creek, McLish, Tulip Creek, and Bromide. The Simpson thickness ranges from 2300 to 1200 feet in the Arbuckle Mountains and thins easterly. Simpson units are exposed on the south flank of the Ozark uplift and in the Arbuckle and Wichita uplifts.

Overlying the Simpson Group is the Viola Group. The Viola is split into two parts, a lower of Trenton age and an upper of Richmondian. This upper Richmondian age has been formally correlated to the Fernvale limestone of Tennessee and as such has been adopted as a formation in the Viola Group. The lower Viola Springs Formation is typically a dense, fine-grained, cherty limestone (Huffman, 1959). The Fernvale is a coarse-crystalline, fossiliferous limestone which rest unconformably on the Viola. The Viola Group is 800 to 400 feet thick on the southwestern flank of the Anadarko Basin and near the Arbuckle and Hunton anticlines. The Viola thins to the northeast and is eventually truncated (Tulsa Geological Society).

Above the Viola Group is the Upper Ordovician Sylvan Shale. The Sylvan is primarily dark green, fissile shale with intermittent sandy and dolomitic beds near the base (Huffman, 1959). The Sylvan has a thickness of 250 to 335 feet in the Arbuckle region and thins to the northeast where it is approximately 35 feet thick in the Ozark area of northeastern Oklahoma.

Ordovician – Devonian

The Ordovician-Devonian Hunton Group is subdivided into the Chimneyhill subgroup and Henryhouse, Haragan, Bois d'Arc, and Frisco Formations. The Chimneyhill Subgroup contains the Ordovician Keel Oolite, and the Silurian Cochrane and Clarita Formations. The Henryhouse is Silurian, whereas the Haragan, Bois d'Arc, and Frisco are Lower Devonian (Huffman, 1959). The Hunton Group is primarily limestone and dolomitic limestone sequences. The combined thickness of the Hunton Group exceeds 1000 feet near the Amarillo-Wichita uplift and thins northward and is finally truncated.

Devonian – Mississippian

Overlying the Hunton Group is the Woodford Shale. The Woodford is a sequence of black shales, thin chert beds, and a basal sandstone called the Misener (Oklahoma) or Sylamore (Arkansas). It has been correlated with the Chattanooga black shale of Tennessee and Arkansas (Huffman, 1959). The Woodford has a thickness of 300 to 400 feet near the Arbuckle Mountains and can be traced in the subsurface into the Chattanooga Shale of the Ozark uplift (Tulsa Geological Society).

Mississippian

Mississippian rocks outcrop both in the Arbuckle and Ozark Mountains and has a net thickness that exceeds 7000 feet in the Anadarko Basin (T. G. S.). The Mississippian rocks in the Anadarko Basin are primarily limestone and cherty, sandy carbonates. The thickness of the pre-Chesterian Mississippian rocks exceeds 2000 feet in the Anadarko Basin and decreases to the north and east (Adler et al., 1971). Chesterian rocks exceed 5000 feet thick in the Anadarko Basin and are mostly shale with interbedded limestone in the western portion of the basin and shale and sandstone in the eastern parts. The Mississippian (Chesterian) in the southeastern Anadarko Basin is dominantly shale and sandstone. This section is called the "Springer" and includes several important gas-producing reservoirs.

Morrowan (Pennsylvanian)

During the Morrowan, two entirely different depositional settings were at work in the Anadarko Basin: a southward-flowing fluvial system along the northwestern shelf and a northward prograding fluvial-deltaic complex associated with the Wichita uplift (Puckette et al., 1996). The shelf system consists of channel-fill reservoirs encased in shallow marine shales. The associated Wichita system rocks are primarily chert and/or arkosic arenites and conglomerate that were deposited by a complex of fluvial valley-fill and fan-deltaic environments (Puckette et al., 1996). The Morrowan section is dominantly shale, but contains lenticular sandstones (Adler et al., 1971). The Morrowan reaches exceeds a thickness of 4000 feet in the Anadarko Basin (Huffman, 1959). In the

Anadarko Basin, the Morrowan produces gas out of the numerous sandstone bodies (Tulsa Geological Society).

Atokan – Desmoinesian (Pennsylvanian)

The Atokan in the Anadarko Basin is limestone, shale, and carbonate conglomerates. The Atokan "Thirteen-Finger" limestone is an important marker on the northern shelf of the basin.

The Des Moinesian in the Anadarko Basin is divided into two primary parts: a lower clastic dominated Cherokee Group and an upper carbonate dominated Marmaton Group (Gibbons, 1964). The Cherokee Group is dominantly alternating clastics and carbonates, which include the oil and gas-producing Red Fork, Skinner, and Prue sandstones. Abundant channel fill, incised valley, deltaic distributary and sandstone of the fluvio-deltaic deposits of the Cherokee Group produce oil and gas from stratigraphic traps. Additional important sandstones represent alluvial fan, marine bars, and fan-deltaic deposits The Marmaton group is predominantly limestone to the west, north, and northeast, but grades into shale to the southeast (Gibbons, 1964). In some locations the Marmaton is cherty, dolomitic, or argillaceous limestone (Gibbons, 1964). Marmaton reservoirs are trapped by structural and stratigraphic mechanisms.

According to the Tulsa Geological Society possibly more that 75% of the total Pennsylvanian oil and gas production in Oklahoma comes from Atokan-Desmoinesian rocks

Missourian (Pennsylvanian)

Missourian rocks are primarily granite wash along the Wichita Mountain Uplift, and shale, sandstone, and carbonate in the central basin and along the northwestern shelf. Important oil and gas producing reservoirs include the Cleveland Sandstone and Cottage Grove Sandstone.

Virgil (Pennsylvanian)

Virgilian rocks are granite washes, along the Wichita Mountain Uplift, that the grade into limestone and shales northward (Gibbons, 1964). The Virgilian rocks include the Douglas, Shawnee, and Wabaunsee groups (Adler et al., 1971). Important oil and gas reservoirs in the Virgilian include the "Granite Wash" and the Tonkawa Sandstone.

Wolfcamp (Permian)

The Admire, Council Grove, and Chase Groups make up the Wolfcampian rocks (Adler et al., 1971). These groups consist of more than 1500 feet of cherty carbonate, mostly dolostone, separated by thin grey or red shales (Adler et al., 1971). The Chase and Council Grove Groups are the primary reservoirs in the giant Hugoton Gas Field in the Hugoton embayment.

Leonard (Permian)

The Leonardian contains the Wellington Formation, Hennessey Shale, and El Reno Group in Northwest Oklahoma; and the Wichita Formation in southwest Oklahoma (Adler et al., 1971). The Leonardian rocks are a mixture of red silty shale, silty fine-grained sandstone, siltstone, gypsum, anhydrite, and salt that reaches a maximum thickness of over 3000 feet thick and thins northward (Tulsa Geological Society).

Guadalupe (Permian)

The Guadalupian is dominated by "red beds" that grade into evaporites northward (Adler et al., 1971). The Guadalupian contains the Whitehorse Group, Taloga Formation, and Quatermaster Formation, which reach a combined thickness of 1000 feet in the Anadarko Basin.

Mesozoic

Mesozoic rocks are not well represented in the Anadarko Basin. The combined thickness of the Triassic and Jurassic strata is seldom more than a few hundred feet. Cretaceous rocks are scarce in the Anadarko Basin and are less than 100 feet thick.

Lithologies, Pressures, and Mechanisms (Table 9)

The pressure-depth data for the deep Anadarko Basin indicates that there are three pressure regimes, an upper normal, a middle overpressured, and a deep normal. This pressure distribution fits the model for a "Ledged-Tiered" pressure system.

The upper normally pressured regime encompasses strata from the Permian outcrops through the Pennsylvanian-Virgilian Series. The strata in this regime includes abundant clastic rocks, some that are coarse-grained, sandstones and conglomerates, evaporites and carbonates. Oil and gas production from this interval comes from the Cretaceous, Wolfcampian, and Virgilian (Adler et al., 1971). The pressures in the

Table 9

Anadarko Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent - Virgilian	coarse clastic	stratigraphic	• hydraulic connectivity • steady-state ground water flow
middle over	Missourian - Woodford Shale	alternating beds of shale, sandstone, & carbonate	structure & stratigraphic	• depositional, tectonic, and mechano-chemical diagenetic processes • gas generation and gas capillary seals
deep normal	Hunton Group – Arbuckle Group	carbonates	structure	• hydraulic connectivity • steady-state ground water flow

Bally Classification: 221 – Perisutural basins on rigid lithosphere associated with formation of compressional megastructure; Ramp with buried grabens, but with little or no block faulting
Klemme Classification: IIA – Continental multicycle basin; Craton margin – composite

(St. John et al., 1984)

normally pressured interval indicates that there must be some hydraulic connectivity with the surface. This hypothesis is further strengthened by the continuity between reservoirs and outcrops. Levorson (1967) states that sources for normal pressures are explained by the pressure exerted by the fluid column above the point of measurement.

The middle overpressured regime contains strata the range in age from the Pennsylvanian-Missourian Series to the Upper Devonian Woodford Shale. The lithologies for this interval are more clastic (shales and sandstones) dominated at the top and become carbonate dominated (limestones and dolomites) towards the base. Al-Shaieb et al. (1999) show that this interval is highly compartmentalized, and contains compartments that range in size from regional to local. Petroleum accumulations in the overpressured regime are mostly stratigraphic traps and water production is minimal. Al-Shaieb (1991) suggests depositional, tectonic, and mechano-chemical diagenetic processes were responsible for the formation and preservation of pressures in completely sealed reservoirs. Lee and Deming (2002) indicate that the generation and preservation of overpressures in the Anadarko Basin are enhanced by gas generation and capillary seals.

The deep normally pressured regime contains strata from the Lower Devonian Hunton Group to the Arbuckle carbonates. The lithologies in the deep normally pressured interval are predominantly carbonates (limestone and dolomite) with interbedded shales and sandstones. From the pressure-depth data, isopach maps, and surface geology the cause of the return back to normal pressures is most likely related to hydraulic connectivity and groundwater flow. The lateral continuity of strata can be seen in Figure37, which would allow for the necessary hydraulic connectivity with the surface. This is supported by the nature of oil and gas accumulations in the deep normally pressured interval, which rely on structural trapping mechanisms. This indicates that the traps are buoyancy driven and do not have a strong stratigraphic component.

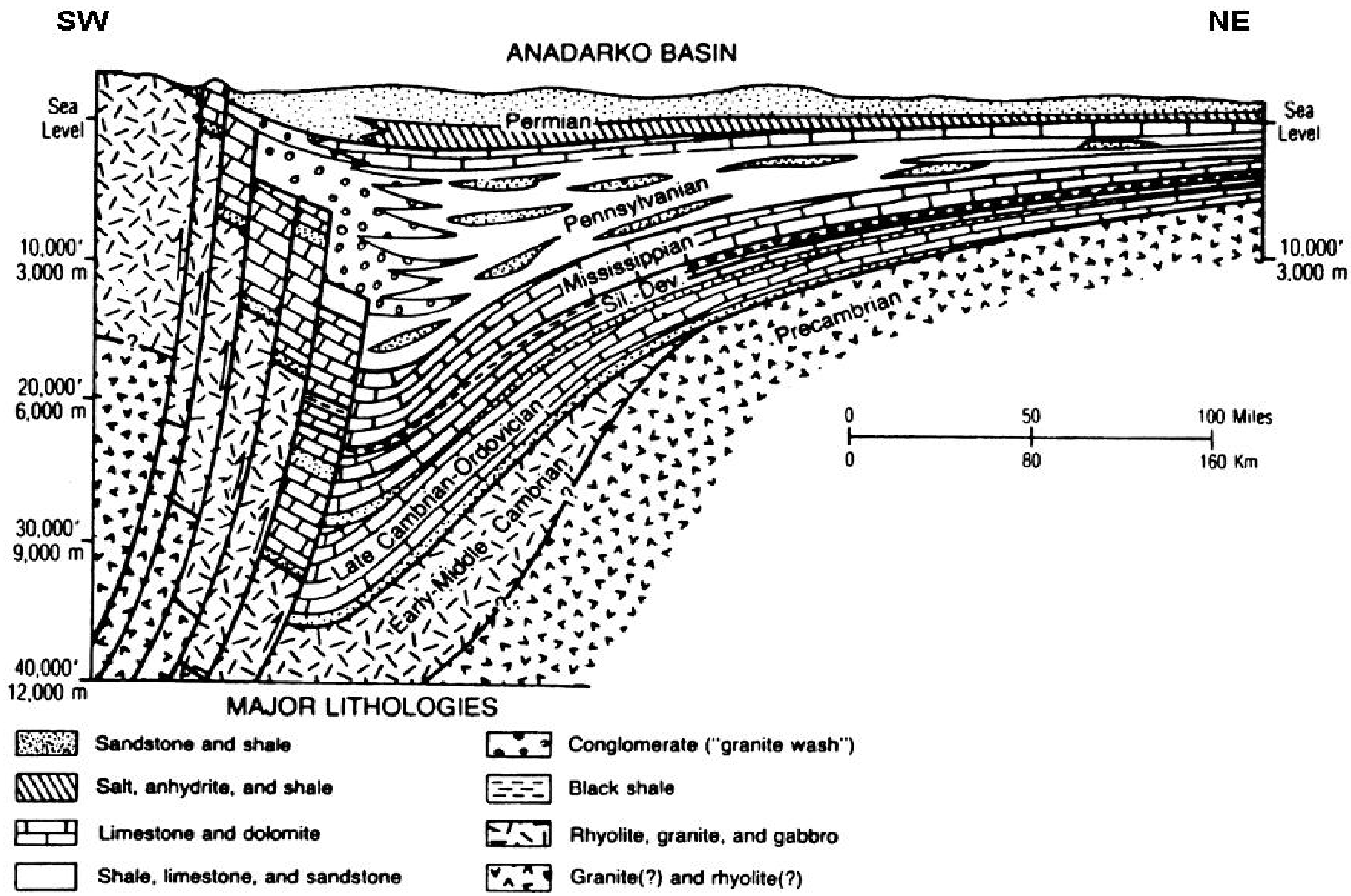

Figure 37. Generalized cross section (SW-NE) through the Anadarko Basin, U.S.A. (from Johnson, 1989).

Maturin Basin

Geologic Setting

The Eastern Venezuela Basin was renamed to the Maturin Basin in order to distinguish it from the old Eastern Venezuelan geosyncline (Murany, 1972). This Mesozoic and Cenozoic sedimentary basin lies in eastern Venezuela (Figure 38) encompassing an area of about 165,000 km^2 (64,000 mi^2) (Erlich and Barrett, 1992). The basin is bound by the Guayana shield to the south; the Venezuelan Andes, Cordillera de la Costa, and the Eastern Serrania del Interior to the north; the El Baul arch to the west, and the Atlantic to the east (Villaroel, 1993). The Maturin Basin is divided by the Anaco Fault Trend into two subbasins, the Guarico to the west and the Maturin to the east (Villaroel, 1993).

The Maturin Basin is asymmetrical in cross section with a long gentle southern limb and a steep northern limb (Hedberg, 1950). The basin was once thought to be a geosyncline, but new advances in geophysical methods and updated subsurface and outcrop correlations proved otherwise. The geodynamic history of the basin is very complex mostly because of it's location at a triple junction on the northwest corner of the South American craton (Roure et al., 2003). This complex tectonic history can be divided into four major episodes: a prerift phase during the Paleozoic, a rifting and drifting phase during the Jurassic and Early Cretaceous, a passive margin period during the Cretaceous-Paleogene, and a final oblique collision phase in the Neogene and Quaternary (Parnaud et al., 1995).

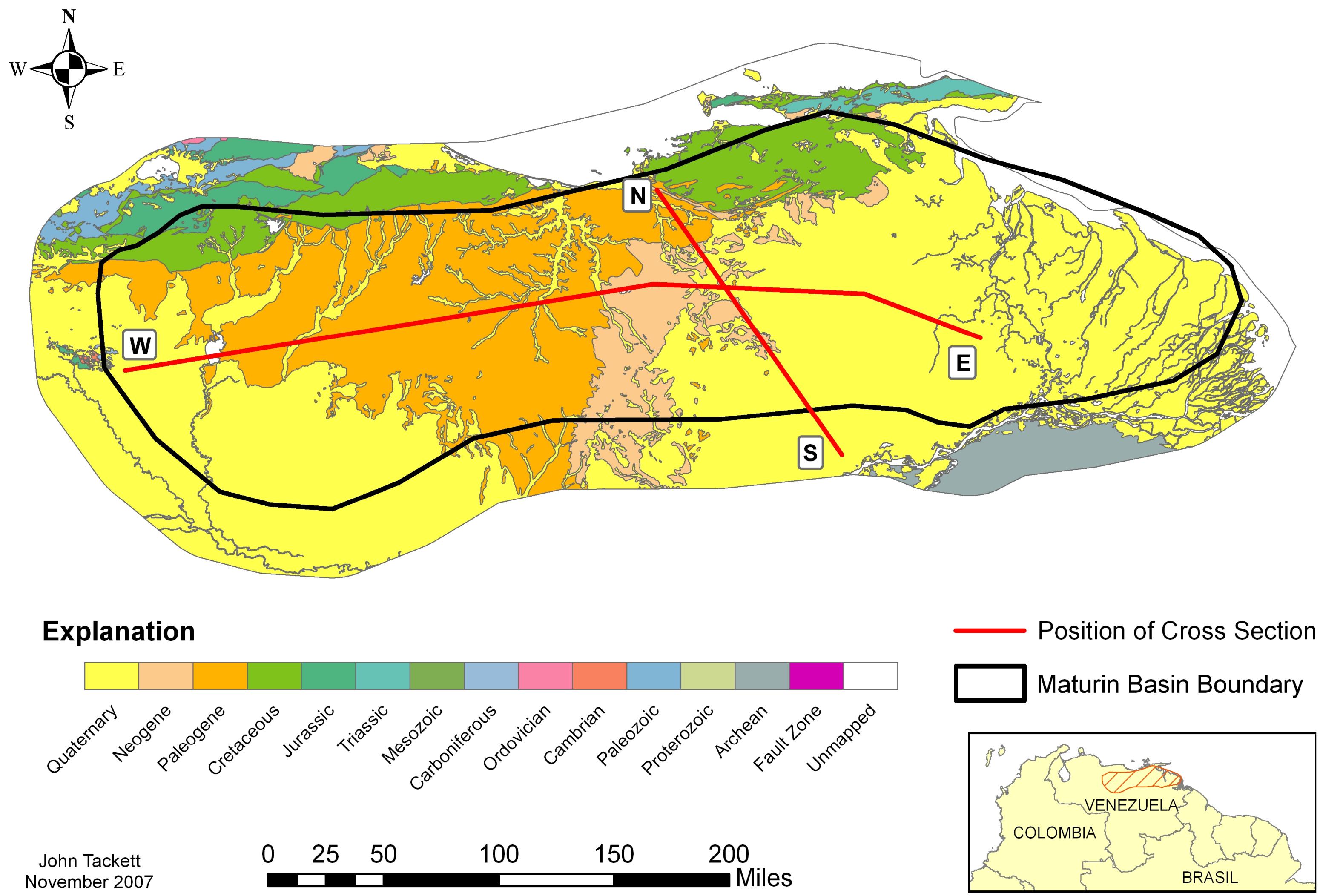

Figure 38. Generalized geologic map of the Maturin Basin showing the location of the cross section. The map shows the surface geology of the basin and 30 miles beyond. The data used for the map was adapted from the United States Geological Survey.

During the prerift phase, the Maturin Basin was subjected to transgressive periods followed by diastrophism associated with igneous activity (Renz et al., 1958). This activity can be identified in formations in the western portion of the basin (Parnaud et al., 1995). In other areas these units have undergone a certain degree of metamorphism and are considered part of the Pre-Cretaceous basement (Renz et al., 1958). During this phase the Guayana shield and El Baul swell were uplifted (Renz et al., 1958).

The rifting and drifting phase during the Late Jurassic through Early Cretaceous is characterized by grabens, the creation of oceanic crust in the Tethyan-Caribbean area, and a regional breakup unconformity (Parnaud et al., 1995). A lack of extensive crustal stretching supports that the initial breakup was by shearing rather than extension suggesting a somewhat different geohistory to that of a typical rifted passive margin (Erlich and Barrett, 1992).

The passive margin phase during the Cretaceous through Paleocene is characterized by three transgressive phases (Parnaud et al., 1995). These transgressive phases developed from north to south and are associated with Turonian, Paleocene-Early Eocene, and Oligocene eustatic sea-level change (Parnaud et al., 1995). During this period the northern margin of South America subsided enough to allow the accumulation of 3 to 4 km (12,000 ft) of marine clastic and carbonate rocks (Erlich and Barrett, 1992).

The oblique collision phase began when the South American plate collided with the Caribbean plate in the Early Eocene (Erlich and Barrett, 1992). This phase resulted in the formation of the Serrania del Interior and the transformation from a passive margin into a foreland basin (Parnaud et al., 1995). Deformation throughout northern Venezuela has continued to the present due to the continuing eastward motion of the Caribbean plate relative to the South American plate (Erlich and Barrett, 1992).

In the central Maturin Basin only the passive margin and collision phases can be recognized in wells and outcrops, while the pre-rift and rifting are interpreted from seismic data in localities to the east and west (Parnaud et al., 1995).

Locally, the pressure data reviewed is limited to the greater Anaco area in the Maturin Basin. The Anaco trend is the southernmost thrust-faulted anticline structure that consists of a southwest-trending fault whose upthrown northwest flank is folded into a series of northeast oriented, elongated domes (Villaroel, 1993).

Pressures

The Maturin Basin is classified into the “Ledged - Tiered System”. The general pressure-depth-profile for this basin has three parts: an upper normal pressured, a middle overpressured, and a deep normal pressured distribution (Figure 39).

The upper normally pressured interval occurs from the surface to the base of the Moreno Member of the Oficina Formation (Figure 47) and is about 5,100 feet thick.

The middle overpressured interval occurs from the Naranja Member through the Colorado Member of the Oficina Formation and is about 4,500 feet thick.

The deep normal pressures occur from the top of the Merecure Formation to depth. Deeper intervals have not been tested or postulated as possible reservoirs.

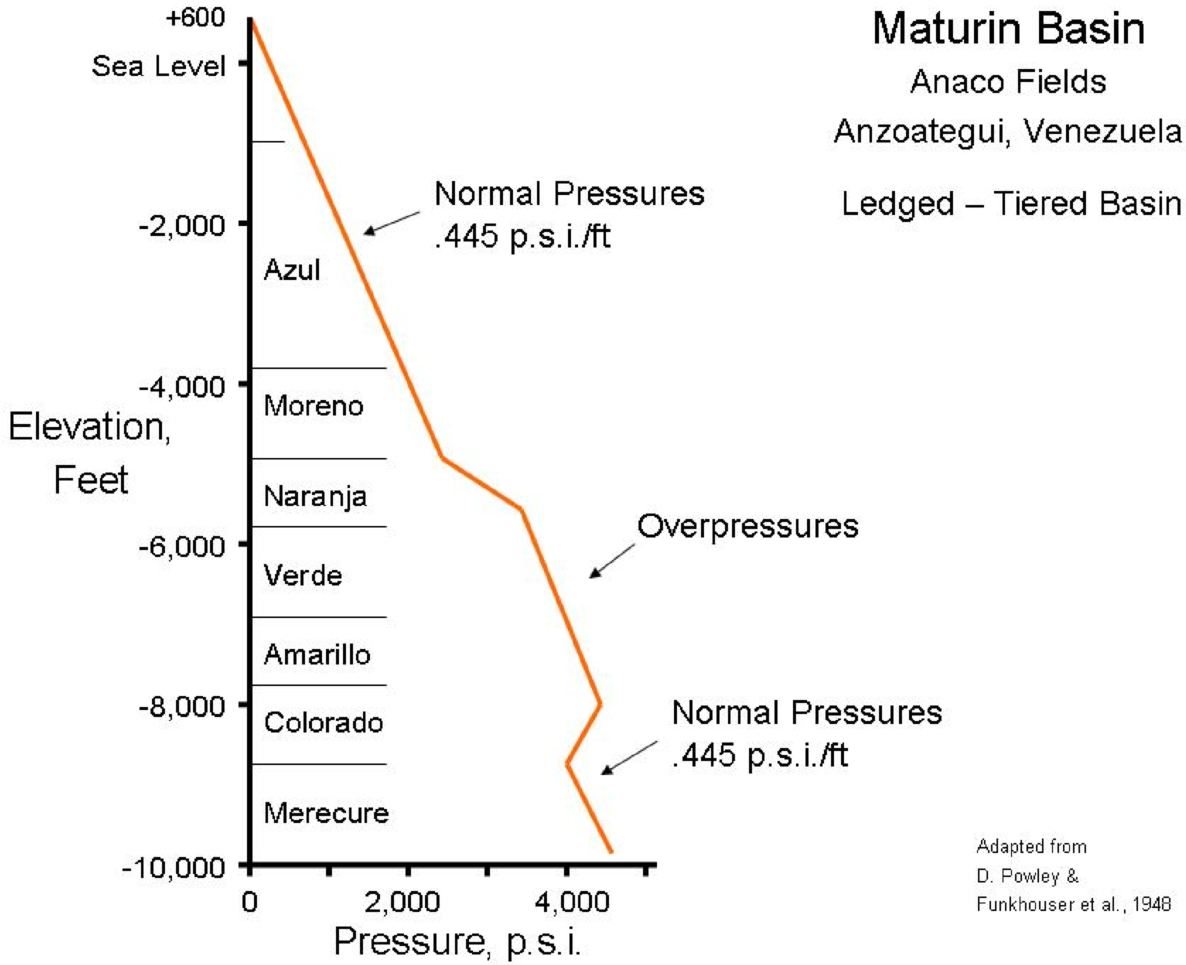

Figure 39. Pressure-depth profile from the Greater Anaco Area, Maturin Basin (adapted from D. Powley, Funkhouser et al., 1948). Overpressure coincide with the shale-rich Oficina Formation.

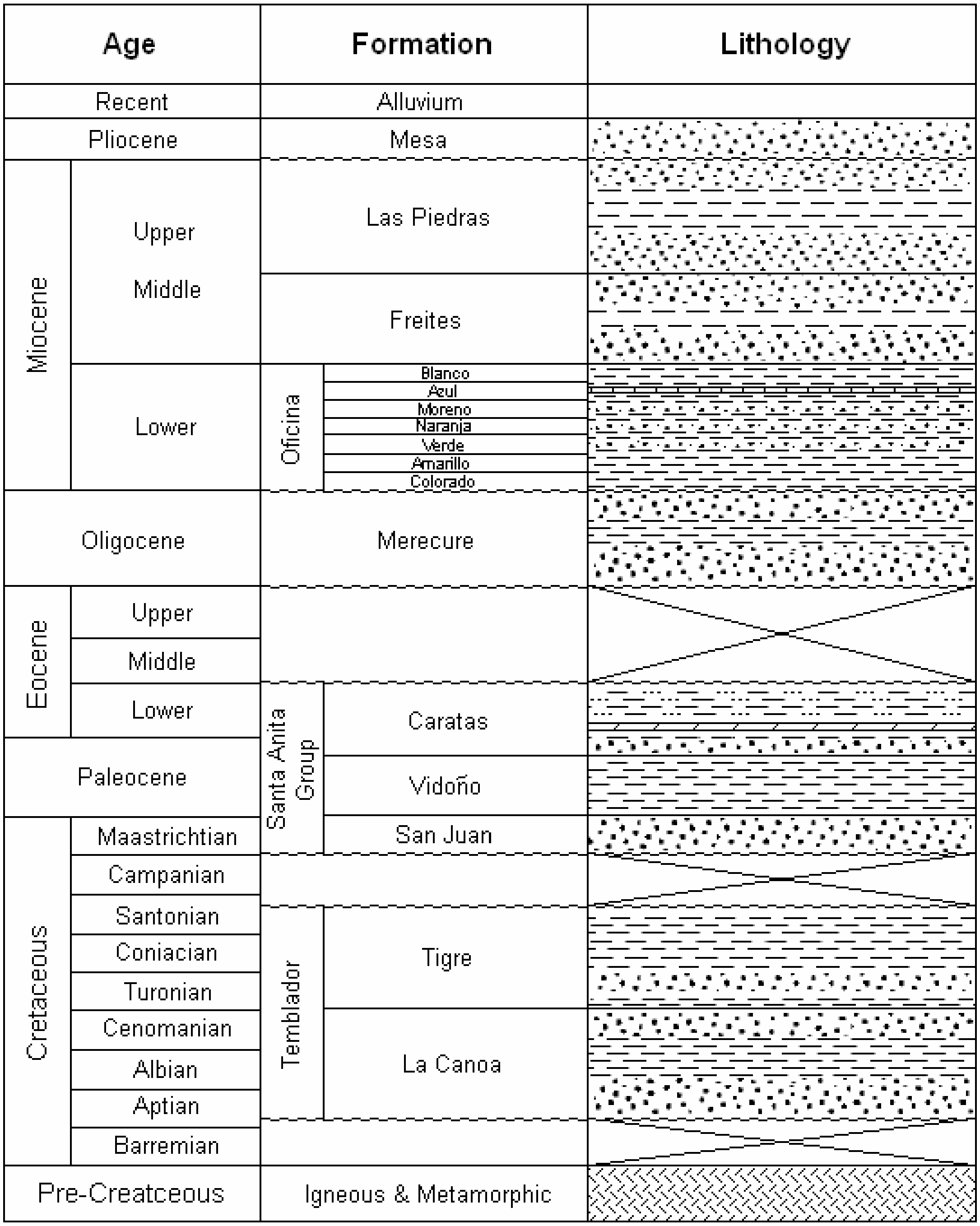

Figure 40. Generalized stratigraphic column of the Anaco field area, Maturin Basin, Venezuela (adapted from Erlich and Barrett, 1992, Murany, 1972, and Renz et al., 1958). No scale is intended.

Stratigraphy

Pre-Cretaceous

Pre-Cretaceous sedimentary rocks are only found in isolated areas in the western portion, Guarico subbasin, of the basin and are limited to the Cambrian sandstones of the Hato Viejo Formation and the Cambrian-Carboniferous sandstone and shale of the Carrizal (Erlich and Barrett, 1992). Where these rocks are encountered, data shows that they are at least 2,400 feet thick and are separated from the overlying strata by an angular unconformity (Erlich and Barrett, 1992). Rocks of the pre-Cretaceous age may have been more widespread prior to the initial rifting and erosion during the Middle to Late Jurassic (Erlich and Barrett, 1992).

Cretaceous

The Cretaceous in the Greater Anaco field area consists of the Temblador Group. The Temblador group is divided into an upper, Tigre, and a lower, La Canoa. The La Canoa Formation is lenticular continental sandstones with minor variegated shale intervals (Daal and Lander, 1993). The Tigre Formation is divided into three members, La Cruz, Infante, and Guavinita in chronostratigraphic order (Daal and Lander, 1993). The La Cruz Member is paralic to shallow marine sandstone and shale interbeds (Daal and Lander, 1993). The Infante Member is fossiliferous glauconitic limestones deposited in a marginal marine/platform environment (Daal and Lander, 1993). The overlying Guavinita member consists of glauconitic, calcareous, and kaolinitic sandstones, black shales, silty limestones, and dolomitic claystones (Daal and Lander, 1993).

Cretaceous (Maastrichtian) – Eocene (Lower)

The Maastrichtian-Lower Eocene age rocks are classified as the Santa Anita Group, which is divided into a lower, San Juan, a middle, Vidoño, and an upper, Caratas (Salvador and Leon, 1992). The San Juan Formation consists of quartz sandstones, which are excellent reservoirs for oil and gas (Salvador and Leon, 1992). The Vidoño Formation is composed of dark gray, glauconitic shale and includes arenaceous zones and occasional thin beds of glauconitic sandstone (Salvador and Leon, 1992). The Caratas Formation is a section of gray to greenish-gray, calcareous, glauconitic siltstones, fine-grained sandstones, and occasional dolomitic limestones (Salvador and Leon, 1992).

Oligocene

The Merecure Formation is characteristic of the Oligocene in the Greater Anaco area. The formation is massive to poorly bedded, fine- to coarse-grained, partly quartzitic sandstones, with laminae and thin beds of black carbonaceous shale, and gray claystones and siltstones (Mencher et al., 1953). The distribution of sand and shale in the Merecure seem to be erratic, but each comprises about 50 per cent of the total lithology (Funkhouser et al., 1948). Most shale and claystone beds/laminae are non-continuous and imply that the massive sandstone bodies have free communication with each other (Funkhouser et al., 1948). Hydrocarbon accumulations in the Merecure are associated with structures. Hydrocarbons in the Merecure system are a density separated sequence of gas, oil, water, where gas has not been found below oil nor has oil been found below water (Funkhouser et al., 1948).

Miocene

The Miocene of the Greater Anaco area consists of three formations, the Oficina, the Freites, and the Las Piedras. The Oficina Formation is lower Miocene in age, while the Freites and the Las Piedras are Middle to Upper Miocene in age.

The Oficina Formation contains the main producing sandstones, with average porosities of 18-20 per cent and permeabilities of 50 millidarcys, in the Greater Anaco area (Mencher et al., 1953). The sandstone bodies in the Oficina seem to pinch-out with distance and are separated from others by laterally continuous shales (Funkhouser et al., 1948). The lenticular sandstone reservoirs are related to domal structures, but sand pinch-outs are an important supplementary factor for accumulations (Funkhouser et al., 1948). For convenience in stratigraphy the Oficina has been divided into seven members (Mencher et al., 1953). These are, from oldest to youngest the following. The Colorado Member contains several fine-grained and coarse-grained sandstones, but is predominantly shale (Mencher et al., 1953). The Amarillo Member consists of dark gray shale and interlaminated sandstones (Mencher et al., 1953). The Verde Member consists of dark gray shales, interlaminated sandstone, thin fine- to medium-grained sandstone, and some thin limestones and lignitic shales (Mencher et al., 1953). The Naranja Member consists of gray fissile shales and interlaminated sandstones, and also lignites, limestones, and claystones (Mencher et al., 1953). The Moreno Member is characterized by dark gray fissile shales, but also includes some thin calcareous sandstones, limestones, lignites, and green claystones (Mencher et al., 1953). The Azul Member consists of interlaminated dark gray silty shale and fine-grained micaceous limestone, dark gray fissile shale, and fine-grained micaceous shaly sandstone (Mencher et al., 1953). The top of the Oficina is the Blanco Member, a sequence of gray carbonaceous and lignitic shales, sandstones, limestones, and lignites (Mencher et al., 1953).

The lower and middle Freites Formation varies in thickness from 0 to about 1,500 feet in the Greater Anaco area (Mencher et al., 1953). This formation is divided into three members, an Upper, Middle, and Lower. The Lower Member consists of fossiliferous, chert conglomerates, sandy limestone, sandstone and greenish gray shales (Mencher et al., 1953). The Middle Member is made up of gray and greenish gray shales and sandstones, and is fossiliferous at its base (Mencher et al., 1953). The Upper Member consist of interbedded and interlaminated gray or dark gray shales and sandstones, and a variegated mottled claystone at its base (Mencher et al., 1953).

The upper Miocene-Pliocene Las Piedras Formation consists of massive to thin-bedded sandstones and interlaminated siltstones and shales with lignites common (Mencher et al., 1953).

Pliocene – Pleistocene

The Pliocene-Pleistocene Mesa Formation is poorly represented in the Greater Anaco area (Mencher et al., 1953). The Mesa consists of poorly consolidated sandstones, gravel beds, and mottled, ferruginous, sandy claystones (Mencher et al., 1953) and is so named because it forms a widespread flat topographic feature throughout Eastern Venezuela that resembles a “mesa” (Funkhouser et al., 1948).

Lithologies, Pressures, and Mechanisms (Table 10)

The analysis of pressure-depth data for the Greater Anaco Fields suggests that there are three pressure regimes, an upper normal, a middle overpressured, and a deep normal. This pressure distribution fits the model for a "Ledged-Tiered" pressure system.

The upper normally pressured regime consists of strata from the present through the Moreno Member of the Oficina Formation. The lithologies in this regime tend to have more abundant clastic rocks, usually more coarse-grained (siltstones and sandstones), and some lignites. There is not an abundance of oil and gas production from this interval, but tests have shown that gas could be present in a few sandstone beds with in the upper Oficina Formation (Funkhouser et al., 1948). Gas shows seem to be related to stratigraphic traps and some compartmentalization (Funkhouser et al., 1948). The pressures for this regime imply that there must be some hydraulic connectivity with the surface or equal pressure release versus compaction. This is further supported by the outcropping of these units along the basin margin.

The overpressured regime contains strata from the Naranja Member of the Oficina Formation to the base of the Colorado Member of the Oficina Formation. The lithologies are dominated by sandstone bodies within laterally continuous shales (Funkhouser et al., 1948). Throughout the Greater Anaco area this interval of overpressures is on average 8 per cent sandstone and 92 per cent shale (Funkhouser et al., 1948). Studies identify this interval to be highly compartmentalized. Oil and gas reservoirs are related to domal structures, where sandstone pinch-outs are an important supplementary factor (Funkhouser et al., 1948). This interval is the dominant source for the production of oil and gas in the Greater Anaco area. Funkhouser et al. (1948) identified that the fluid

Table 10

Maturin Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent – Moreno Mbr.	Sandstone	stratigraphic	• hydraulic connectivity • steady-state ground water flow
middle over	Naranja Mbr. – Colorado Mbr.	shale with sandstone lenses	structure & stratigraphic	• disequilibrium compaction • gas generation
deep normal	Merecure Fm. – pre-Cretaceous	Sandstone	structure	• hydraulic connectivity • steady-state ground water flow

Bally Classification: 221 – Perisutural basins on rigid lithosphere associated with formation of compressional megastructure; Ramp with buried grabens, but with little or no block faulting
Klemme Classification: IICa – Continental multicycle basin; Crustal collision zone – convergent plate margin; closed

(St. John et al., 1984)

pressures were generated by disequilibrium compaction, where fluids were expelled from the shales due to compaction and compression and were forced into already saturated sandstone bodies. It must also be noticed that the overpressures in this regime correspond to zones of hydrocarbon bearing rocks, so hydrocarbon generation should be noted as a plausible mechanism. This mechanism is further supported buy the occurrence of several gas blowouts (Funkhouser et al., 1948).

The deep normal pressured regime contains strata from the Oligocene Merecure Formation to the pre-Cretaceous basement. This regime is dominated by sandstone with interlaminated shale. From the pressure-depth data, surface geology, and sparse subsurface data the cause of the aversion back to normal pressures in this regime is most likely related to the groundwater flow. The outcropping (Figures 41 & 42) of these units on the northern flanks of the Maturin basin would allow for the necessary hydraulic connectivity to the surface. This is supported by the formation of buoyancy driven oil and gas accumulations on structural traps.

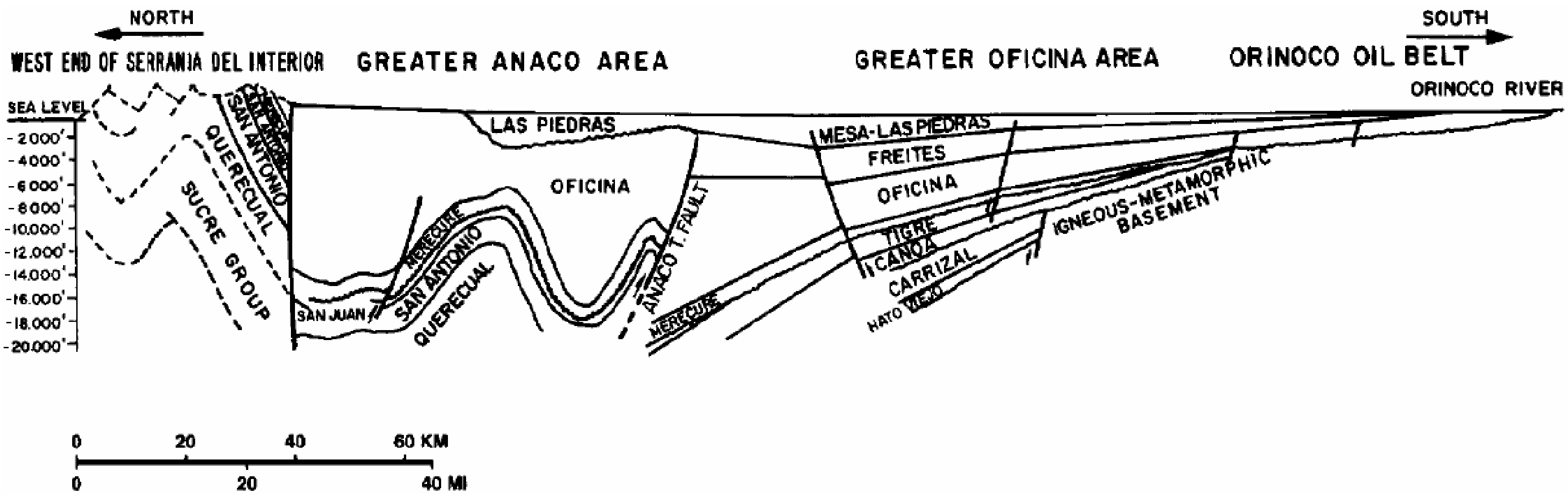

Figure 41. Geologic cross section (N-S) through the central portion of the Maturin Basin, Venezuela (adapted from Villaroel, 1993).

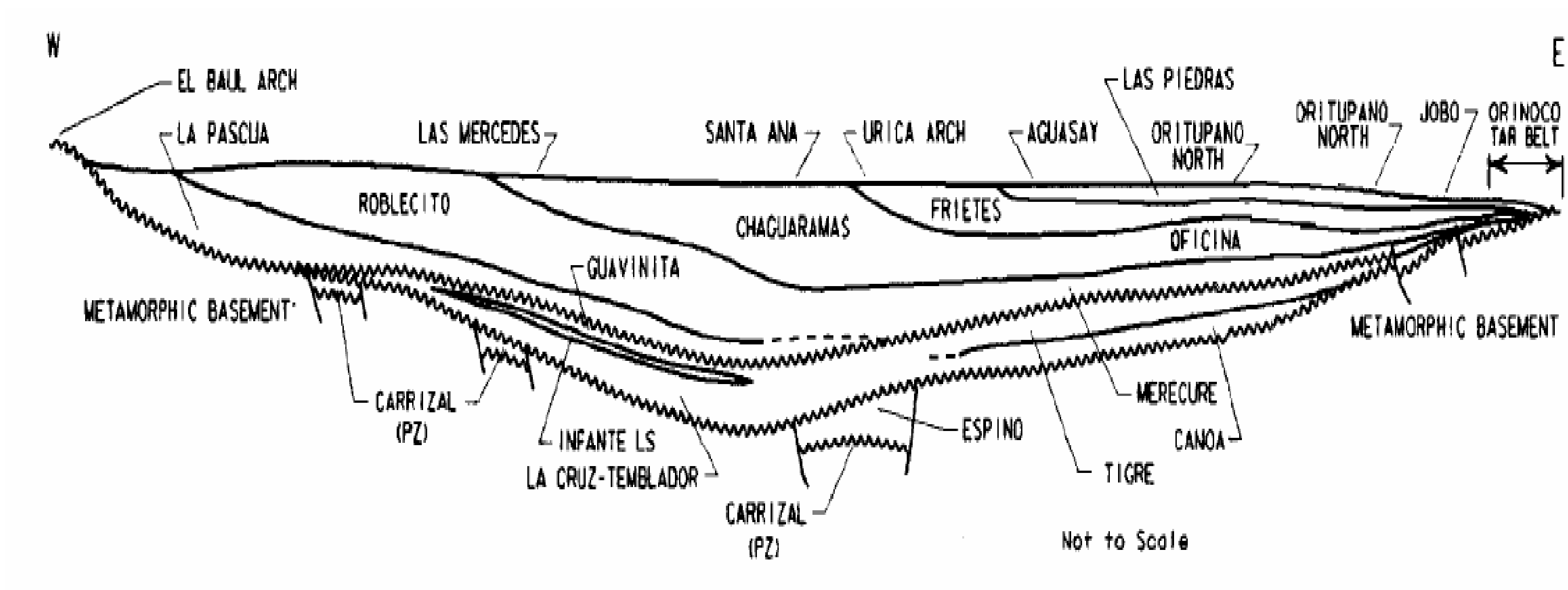

Figure 42. Geologic cross section (W-E) through the Maturin Basin, Venezuela (from Erlich and Barrett, 1992).

Potwar Basin

Geologic Setting

The Potwar basin (Figure 43) is located in the northern portion of Pakistan and includes the Potwar and Kohat Plateaus and Bannu Depression (Wandrey et al., 2004). The basin is bounded on the north by the Main Boundary Thrust Fault, on the west by the Kurram fault, on the south by the Surghar and Salt Ranges, and on the east by the Jehlum fault (Figure 44) (Wandrey et al., 2004).

The Potwar Basin and surrounding area acquired their primary structural and stratigraphic features from tectonic events that began in the Late Paleozoic and continues to the present (Wandrey et al., 2004). From the Permian through Middle Jurassic time, the Indian plate was located in the Southern Hemisphere as part of southern Gondwana (Wandrey et al., 2004). The Lower Permian tillites and other glacial deposits in the Kohat-Potwar plateaus are indicative of the cooler environment from this time (Wandrey et al., 2004). The northern Indian area was a shallow continental shelf on which carbonates, shales, and sandstones were deposited, which persisted through the Late Jurassic (Wandrey et al., 2004).

During the Early Cretaceous, the Indian plate drifted northward into warmer climates (Wandrey et al., 2004). Along the eastern portion of the Indian plate, the Rajmahal Trap volcanics were deposited in contrast to the northwestern margin where sequences of marine shales and limestones were formed (Wandrey et al., 2004). These Lower Cretaceous marine shales and limestones overlie a regional erosional surface, which can be seen at the top of the Samana Suk Formation (Wandrey et al., 2004).

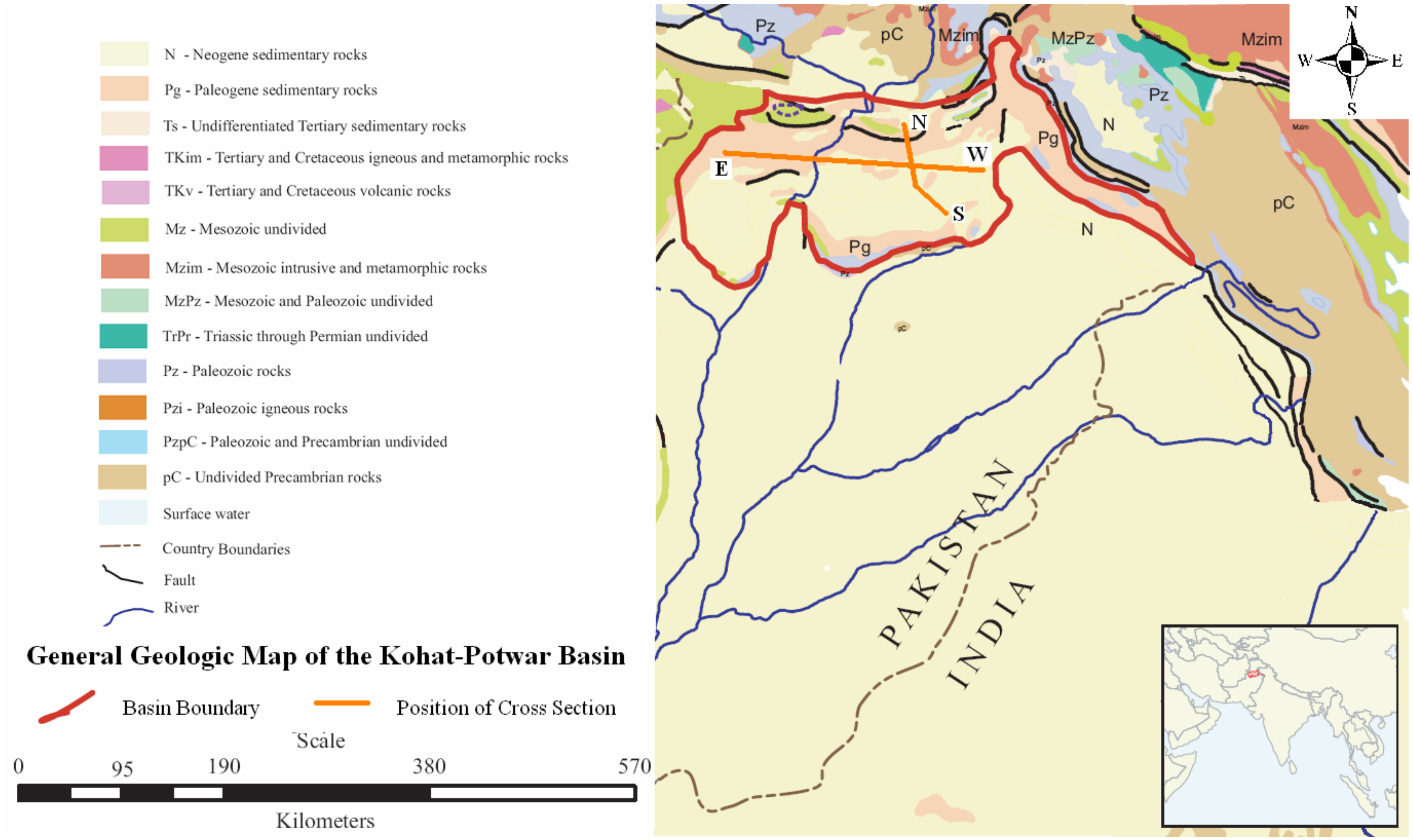

Figure 43. Generalized geologic map of the Potwar Basin showing the location of the cross section (adapted from Wandrey et al., 2004).

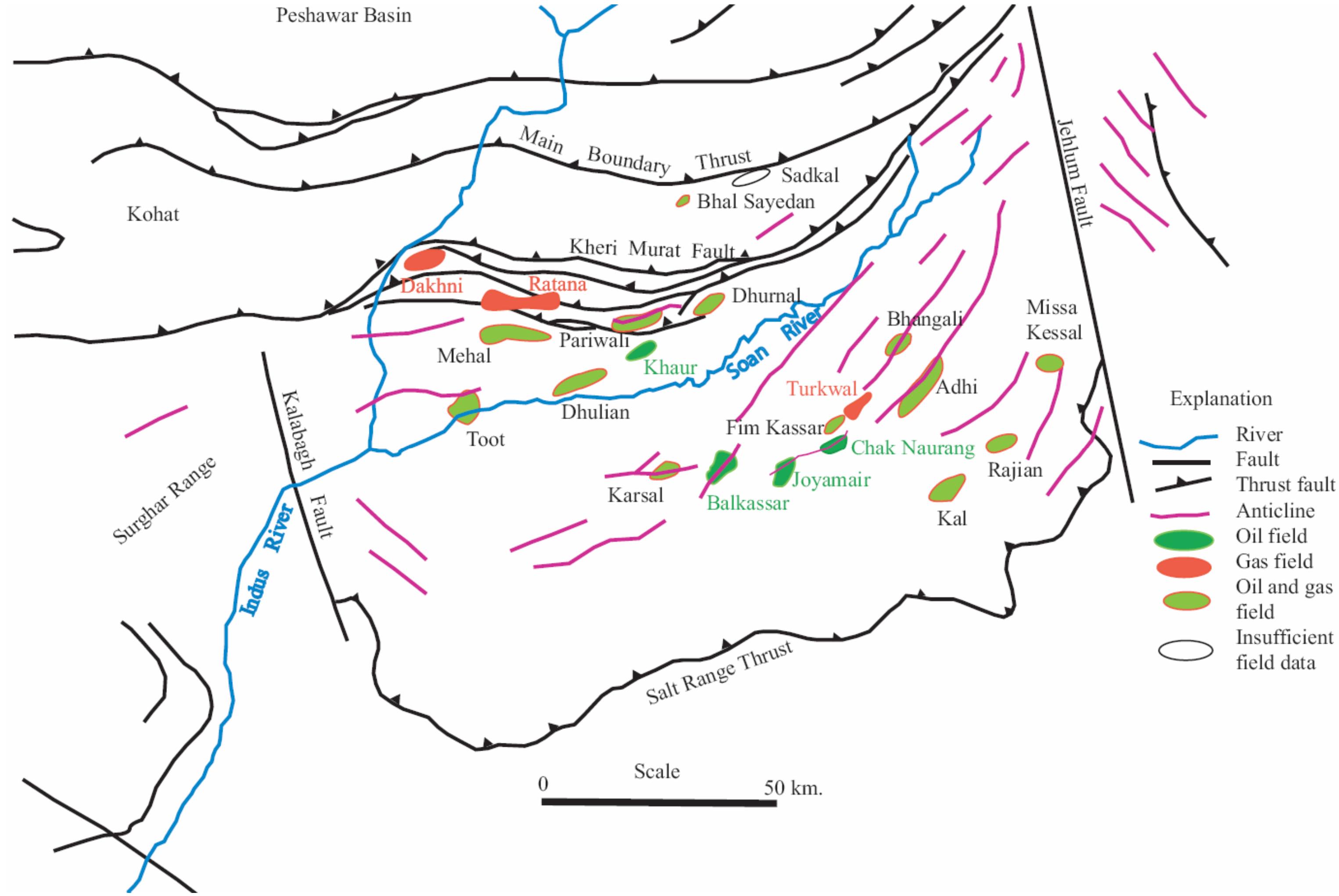

Figure 44. Generalized field and structure map of Kohat-Potwar area, Pakistan (from Wandrey, Law, and Shah, 2004).

Presently, carbonates from this time are recognized primarily on the eastern and western shelves, but it is likely that they existed over much of the northern shelf as well (Wandrey et al., 2004). This shelf environment persisted until the Late Cretaceous with the deposition of regressive sandstones (Wandrey et al., 2004).

The Indian plate continued to drift northward toward the Eurasian plate and the seafloor of the Bengal Basin began to form and flysch accumulated on all sides of the Indian plate during the Late Cretaceous (Wandrey et al., 2004). The Late Cretaceous was also a time of intense volcanism located in western India (Wandrey et al., 2004). The Indus basin, became floored with Deccan Trap basalts from the volcanic activity (Wandrey et al., 2004).

From the Late Cretaceous through Middle Paleocene, trap deposits and basal sandstones continued to accumulate on all portions of the plate except for the provenance of the south (Wandrey et al., 2004). Oblique convergence of the Indian plate with the Eurasian plate resulted in wrench faulting and the development of regional arches (Wandrey et al., 2004).

From the Eocene through the Middle Miocene, a carbonate platform built up on the shelves around much of the Indian plate (Wandrey et al., 2004). A newly forming trench, resulting from the subduction of the Indian plate beneath the Eurasian plate, began to fill with sediment from the rapidly rising Himalayan, Sulaiman-Kirthar, Sino-Burman, and Indo-Burman ranges and exceeded the carbonate buildup rates on the late Miocene platforms (Wandrey et al., 2004). The former shelf areas along the collision zones were either subducted or became emergent fluvial-deltaic environments (Wandrey et al., 2004). Detachment surfaces formed, as deep as the late Precambrian salts, as a result of the continued plate convergence (Wandrey et al., 2004).

Today, uplift of the Himalayas and subduction of the Indian plate continues and the growth rate of all depositional outlet deltas remain high (Wandrey et al., 2004).

In particular to the pressure-depth data from the Adhi field; the Potwar plateau is a foreland basin and part of the Himalayan foreland fold- and thrust-belt in northern Pakistan (Law et al., 1998). Law et al. (1998) states that “the structural deformation in the Potwar plateau is the result of the ongoing collision between the Eurasian and Indian plates that began in early to middle Eocene time”. The Potwar plateau is underlain by a low-dipping thrust fault that has allowed the entire sedimentary section to move southward along the decollement in the Precambrian Salt Range Formation where in the southern margin the Precambrian and younger sedimentary rock have been thrusted over Neogene rocks (Law et al., 1998). Differential folding of the sedimentary rocks relative to the underlying basement has produced tight, salt-cored anticlines separated by broad synclines (Law et al., 1998). The north flank of the area is defined by high dips and intense faulting and folding, whereas the south flank is characterized by less intense structural deformation (Law et al., 1998). Angular unconformities at the base of the Permian and Tertiary rocks suggest two periods of uplift and erosion (Law et al., 1998).

Pressures

The Potwar Basin is classified into the “Ledged - Tiered System”. The general pressure-depth-profile for the basin has three parts: an upper normal pressured, a middle overpressured, and a deep normal pressured distribution (Figure 45). The upper normally

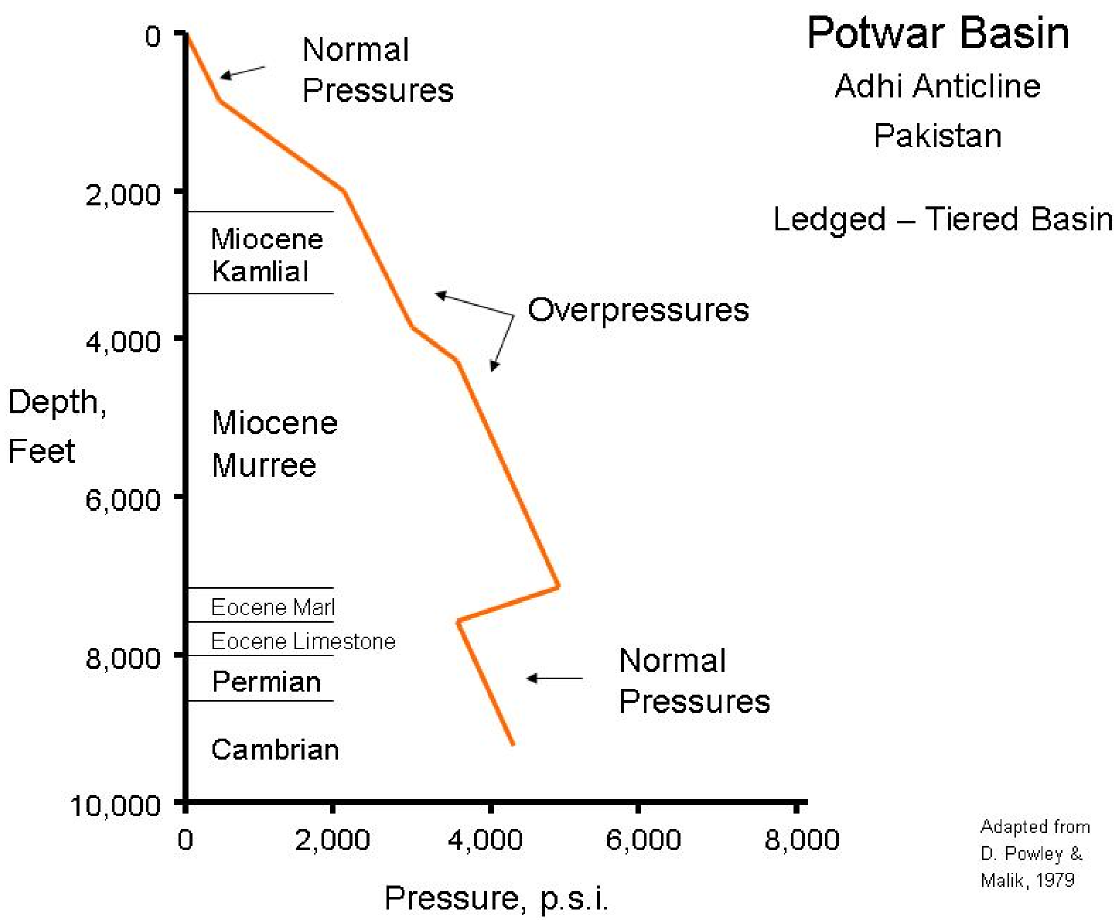

Figure 45. Pressure-depth profile from the Adhi Field, Potwar Basin (adapted from D. Powley, and Malik, 1979). Overpressuring is associated with Miocene shale dominated strata..

pressured interval occurs from the Pleistocene Soan Formation through the Pliocene Nagri Formation. These units can be identified on the stratigraphic columns for the Kohat-Potwar area and Adhi Field (Figures 46 & 47). The overpressured interval occurs from the Pliocene Chinji Formation through the Eocene-Paleocene carbonate rocks. The deep normally pressured interval occurs from the Permian Dandot Formation through the Precambrian Salt Range Formation.

Stratigraphy

Precambrian

Lying unconformably on Late Proterozoic metamorphic basement rocks are the oil-impregnated shales, sandstones, and interbedded carbonates and evaporites of the Salt Range Formation (Wandrey et al., 2004). The dominant lithology of the Salt Range Formation consists of thick carbonates and evaporites (Wandrey et al., 2004). Thickness of the formation varies from 50 to more than 1,000 meters. Dissolution of the evaporites is the probable cause for the variance. The Salt Range Formation is exposed along the Salt Range on the southern flank of the Potwar Plateau.

Cambrian

The Cambrian rocks consist of marine sandstone, shale, siltstone, and dolomite (Khan et al., 1986). One-hundred and fifty meters of marine shales and massive sandstones are represented by the Khewra Formation at the base of the Cambrian sequence (Wandrey et al., 2004). Above the Khewra are the glauconitic shoreface sandstones and siltstones of the Kussak (Wandrey et al., 2004). The overlying Jutana

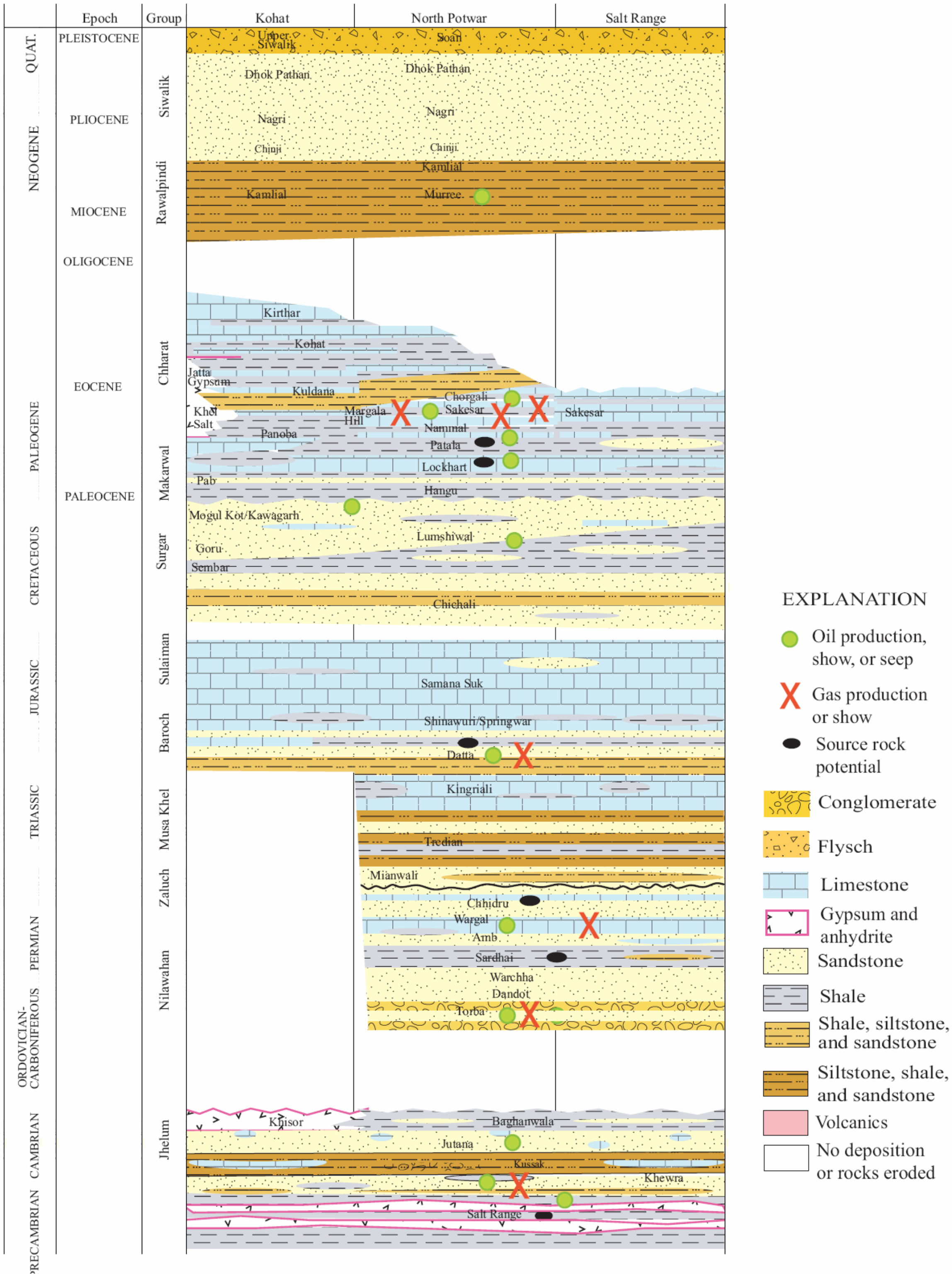

Figure 46. Generalized stratigraphic column of the Kohat-Potwar area (from Wandrey et al., 2004). No scale is intended.

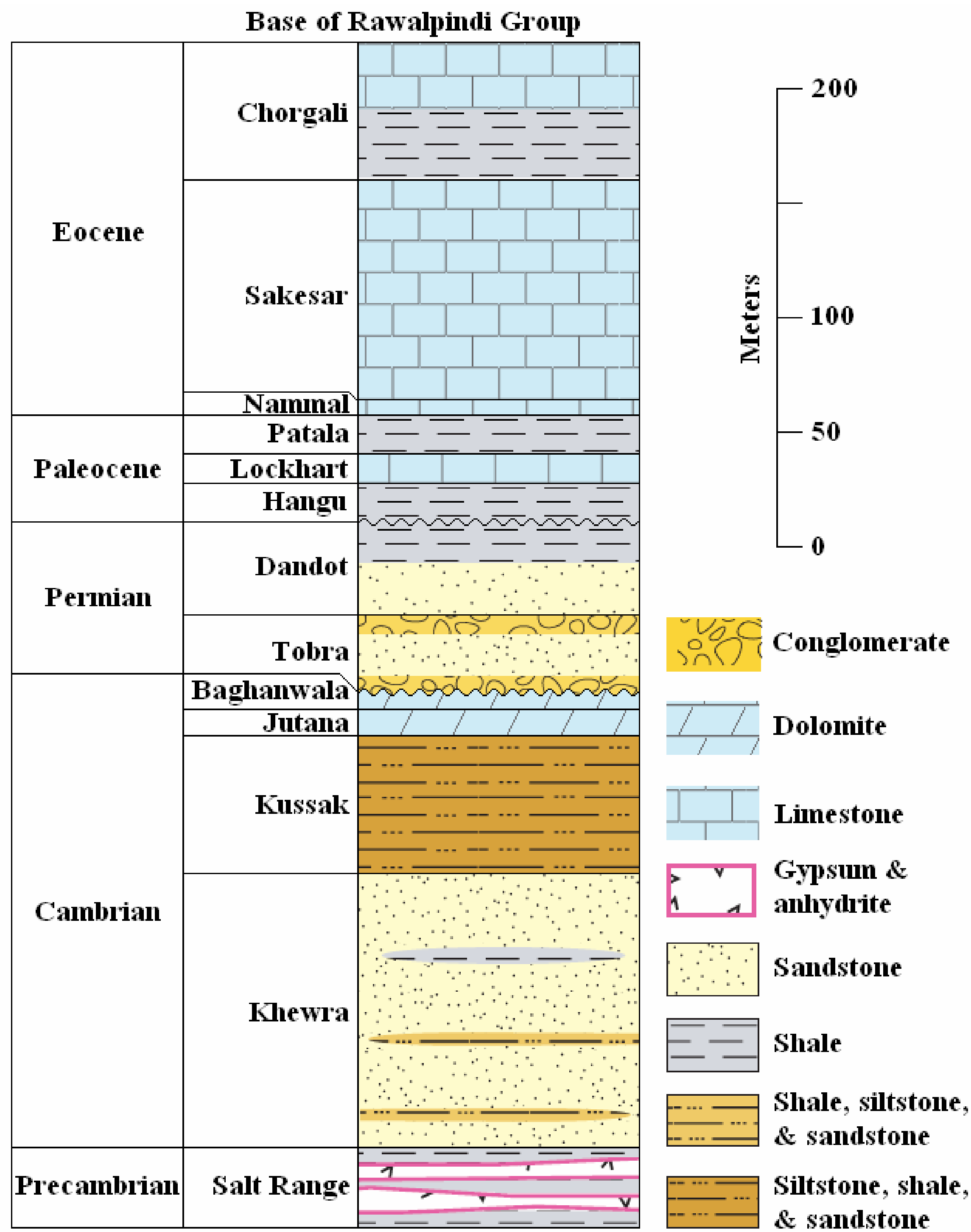

Figure 47. Generalized stratigraphic column from the Adhi Field, Potwar Plateau area, Pakistan (adapted from Khan et al., 1986).

Formation consists of sandy carbonates and nearshore sandstones (Wandrey et al., 2004). The carbonates of the Baghanwala Formation mark the top of the Cambrian stratigraphic section. The Cambrian Khewra and Jutana have produced oil and gas in some fields (Wandrey et al., 2004). In the Adhi field the dominant lithology is the marine sandstone of the Khewra Formation. This sequence is terminated by an unconformity at the top of the Baghanwala Formation (Khan et al., 1986).

Permian

The Permian system is comprised of boulder beds, sandstone, clay, marl, and fossiliferous limestone (Khan et al., 1986). In the Adhi Field this sequence is made up of the Tobra and Dandot Formations. The Tobra contains tillite with polished and striated pebbles, which provide evidence for the Late Carboniferous-Early Permian glaciation (Khan et al., 1986). The overlying Dandot Formation is made up of alluvial or glacial coarse-grained sandstones and shales (Wandrey et al., 2004). Only a few fields have produced oil or gas from the Tobra Formation in the Potwar Plateau area (Wandrey et al., 2004).

Paleocene

The Paleocene rocks in the Potwar plateau consist of the Hangu, Lockhart, and Patala Formations. The Hangu is dominated by shales, which unconformably overlie the Permian Dandot Formation. The Lockhart Formation is predominantly shelf carbonates that have a transitional contact with the marine shales and minor carbonates of the Patala

Formation (Wandrey et al., 2004). In the Kohat-Potwar region oil production is from the Lockhart and Patala Formations (Wandrey et al., 2004).

Eocene

The Eocene system includes the Chharat Group and its formations, Nammal, Sakesar, and Chorgali. The Nammal Formation has a transitional contact to the underlying Paleocene Patala Formation and is characterized by shallow-marine to lagoonal shales and limestones (Wandrey et al., 2004). The Sakesar, or Margala Hill, is marine limestone and shale, which have produced oil or gas in eight fields in the Potwar Plateau (Wandrey et al., 2004). The uppermost unit is the marine shales and interbedded limestones of the Chorgali Formation (Wandrey et al., 2004).

Miocene

With Oligocene rocks missing over much of the Potwar basin, the Miocene Rawalpindi Group lies unconformably on top of the of the Eocene rocks. The Rawalpindi Group consists of the Murree and Kamlial Formations. The Murree is represented by alluvial sandstones and siltstones while the overlying Kamlial contains fluvial sandstones and clays (Wandrey et al., 2004). Wandrey (2004) states “the Murree Formation contains the youngest reported oil-producing reservoirs” in the Potwar Basin.

Pliocene

The fluvial sandstones and conglomerates of the Siwalik Group mark the top of the stratigraphic column for the Potwar Basin. In the Adhi Field and surrounding areas the Nagri Formation outcrops on the surface (Law et al., 1998).

Lithologies, Pressures, and Mechanisms (Table 11)

The analysis of pressure-depth data for the Adhi Field indicates three pressure regimes: an upper normal, a middle overpressured, and a deep normal. This pressure distribution fits the model for a "Ledged-Tiered" pressure system.

The upper normal pressured regime consists of strata from the present to an approximate seal lithology in the Chinji Formation of the Siwalik Group around a depth of 2,000 feet. The lithologies in this regime are dominated by fluvial clastic rocks, usually more coarse-grained (conglomerates and sandstones), and some shales. There is not a record of oil and gas production from this interval. The pressures for this regime imply that there must be some hydraulic connectivity with the surface or equal pressure release versus compaction. This is supported by the exposure of these units on the surface and the coarseness of the sediments incorporated in the strata.

The middle overpressured regime contains strata that range from the seal in the Chinji Formation to the unconformity at the base of the Hangu Formation. The dominant lithologies for this interval are siltstone, shale, and carbonate, with the uppermost portion being siltstone, and carbonate becoming more dominant in depth. Throughout the area this interval of overpressures can reach as high as lithostatic pressure. This interval is suspected to be highly compartmentalized, since there is a lack in a regular depth

Table 11

Potwar Basin

Pressure Regime	Age/Formation	Lithology	Trap	Pressure Mechanism
upper normal	recent – Chinji Fm.	sandstone & conglomerate	?	• hydraulic connectivity • steady-state ground water flow
middle over	Chinji Fm. – Hangu Fm.	siltstone, shale, & carbonate	structure & stratigraphic	• disequilibrium compaction • tectonic stress
deep normal or deep sub-over	pre-Hangu Fm. – Precambrian	sandstone	structure	• hydraulic connectivity • steady-state ground water flow or • tectonic stress • hydrocarbon generation

Bally Classification: 41 – Folded belt; related to A-subduction
Klemme Classification: IICb – Continental multicycle basin; Crustal collision zone – convergent plate margin; trough

(St. John et al., 1984)

to top of abnormal pressures (Law et al., 1998). Reservoirs for this regime are related to structures (Law and Spencer, 1998) and possible facies changes within sedimentary units. This interval is also the source for much of the oil and gas production in the Potwar Basin, containing 1/3 of the produced reservoirs (Wandrey et al., 2004). Law et al. (1988) identified that the pressures where generated primarily by disequilibrium compaction and secondarily by tectonic stresses.

The deep normally pressured regime contains strata from the Permian Hangu formation to the Cambrian rocks. The lithologies are dominantly sandstones with interbedded shales and minor evaporites and carbonates. From the pressure-depth data, surface geology, and sparse subsurface data the cause of the aversion back to normal pressures in this regime is most likely related to the groundwater flow. The outcropping (Figures 48 & 49) of these formations to the south along the Salt Range allows for the necessary hydraulic connectivity with the surface. This is supported by the formation of oil and gas accumulations being buoyancy driven structural traps (Law and Spencer, 1998). Law et al. (1998) indicates this interval contains abnormal pressures in other fields located in the Potwar Basin. While abnormal pressures do occur in this sequence of strata, the pressure gradients are not as high as they are in the overlying Miocene interval (Law et al., 1998). The pressures in this field return to normal gradient, which fits the "Ledged-Tiered" pressure system. Law et al. (1998) propose that tectonic compression and hydrocarbon generation are the probable causes for the abnormal pressures.

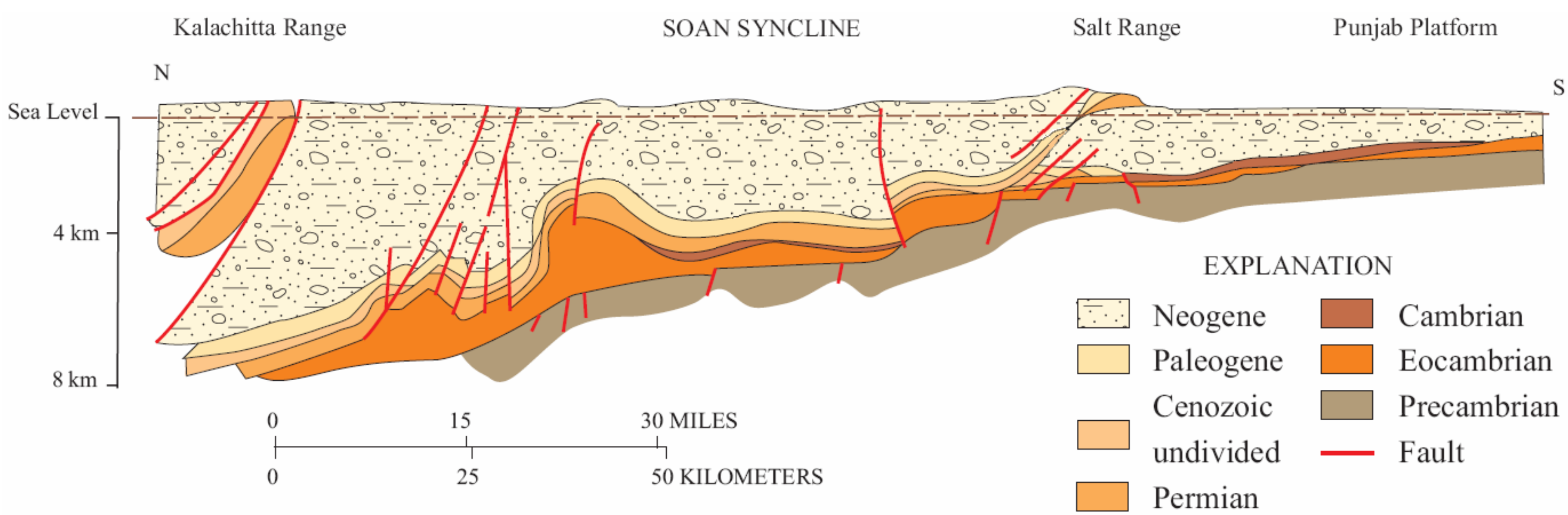

Figure 48. Geologic cross section (N-S) through the Potwar Plateau, Pakistan (from Wandrey et al., 2004).

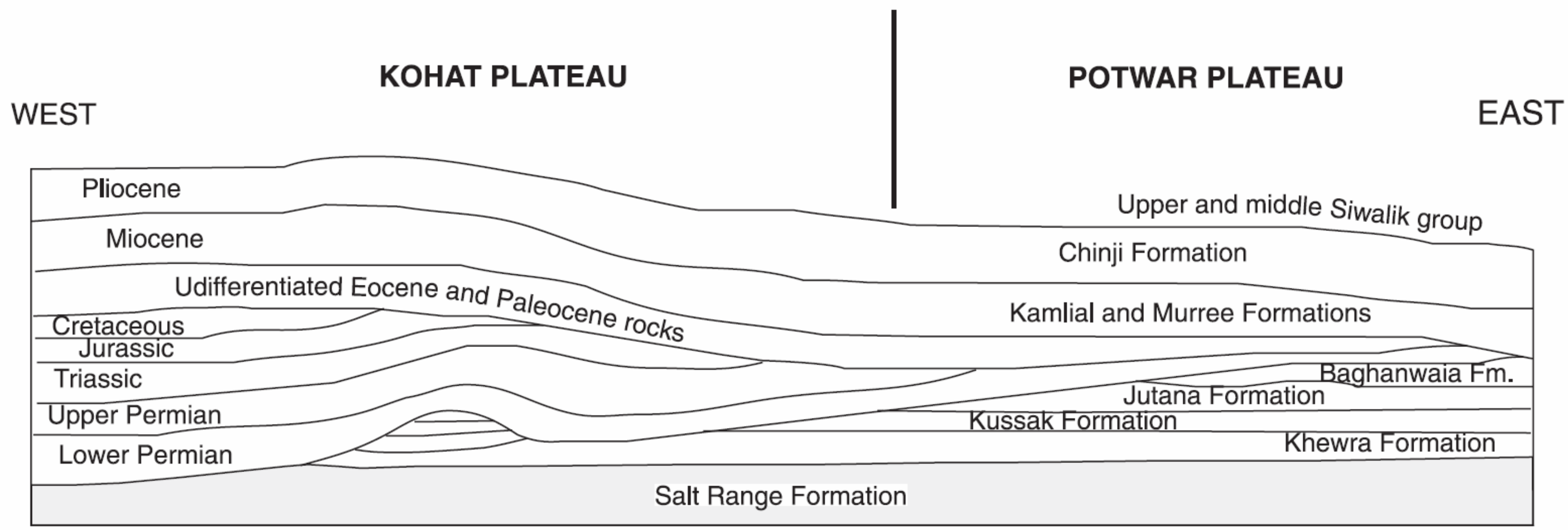

Figure 49. Geologic cross section (W-E) through the Kohat-Potwar Plateaus, Pakistan (from Law et al., 1998).

CHAPTER VI

CONCLUSION

Pressure distribution in basins can be predicted in some cases if the subsurface stratigraphy and the spatial distribution of reservoirs are known. The following provides insight on the prediction of fluid pressures from the basins studied. Conclusions are summarized according to the lithologic controls on subsurface fluid pressures and lithologies associated with pressure domains from the selected basins. These conclusions made it possible to characterize fluid pressures in tiered basins making the prediction possible.

Lithologic Controls

Sedimentary basins with tiered patterns or pressure distributions contain abnormal pressures. These abnormal pressures are either high or low and can be predicted by the lithology. Lithologies exercises two main controls on pressure. Lithologies can (1) provide the seal that contain the abnormally high or low pressures or (2) serve as the conduit or container where they may be found. The combination of sealing and conduit lithologies maintain an environment where either normal or abnormal fluid pressures are sustainable. These two factors control hydrocarbon development and production, and influence trapping mechanisms.

Seals are probably the single most important factor in the preservation and generation of subsurface fluid pressure. Hydrocarbons rely on seals for accumulations and pressure maintenance. In cases where abnormally high pressures are encountered, like those in the stepped- and ledged-tiered basins, seals must be able to hold pressures that approach lithostatic stresses and form isolated compartments that in some cases (senile basins) have maintained abnormally high pressures over large spans of geologic time. Abnormally low pressures, like those found in the recessed basins, occur in regions with extensive lateral continuity, but are sealed above and below by low permeable strata. Lithologies like shales, mudstones, chalk, evaporites, and other semi impermeable strata appear to form the best seals. Pressures seek equilibrium and over periods of geologic time no seal is completely impermeable. When seals are evident in sedimentary basins it must be remembered that they are transient features and represent a snap shot of seal history.

Reservoir generating and delineating can be related to pressures regimes. Abnormally high pressures, like those encountered in reservoirs in the stepped- and ledged-tiered basins often have smaller areas than underpressured or normally pressured reservoirs. These overpressured reservoirs can be highly lenticular bodies of sandstones or carbonates that vary laterally because of changes in lithofacies. Abnormally low pressures are generally found within laterally continuous, generally massive bodies that can be traced regionally in the subsurface. In the Sacramento Basin, studies have shown that the largest accumulations of hydrocarbons are associated with normally pressured reservoirs, not the abnormally high pressured area. This is further evidence supporting the contention that abnormally high pressures need enclosed multidimensional seals for generation and preservation.

Lithologies associated with the Tiered Basins

Stepped-Tiered Basins: (Table 12) Stepped-tiered basins have two pressure regimes, an upper normal and a lower overpressured. In the chosen stepped-tiered basins, Northern North Sea (Figure 50), Nile Delta (Figure 51), and Sacramento (Figure 52), the upper normal pressured regime occurs in the younger sediments and is dominated by coarse clastic material like sandstones. The lower overpressured regime, which exhibits the stepped appearance when profiled, is dominated by thick intervals of seal-forming shales and chalks, with isolated reservoirs dispersed through the section. These reservoirs tend to be sandstone or carbonate that lack lateral continuity. Overpressures are generated in these discontinuous reservoirs by processes such as disequilibrium compaction or hydrocarbon generation. Accumulations of hydrocarbons are found in both the normal and abnormally high pressure regimes, but the trapping mechanisms differ. In the upper normal regime, accumulations are associated with structure, stratigraphy, or combination traps, but the lower overpressured regime accumulations are found in combination traps (structure and stratigraphic).

Recessed-Tiered Basins: (Table 13) The selected recessed-tiered basins, Wind River (Figure 53), Big Horn (Figure 54), and Alberta (Figure 55), are characterized by normal and abnormally low pressures. In the Wind River and Alberta basins there are

Table 12

Stepped-Tiered Basins

Pressure Regime	Lithology	Trap	Pressure Mechanism
upper normal	shale and sandstone	stratigraphic	• equilibrium of pressure escape during compaction
lower over	shale, chalk, marl	structure & stratigraphic	• disequilibrium compaction • hydrocarbon generation • thermal cracking of oil

Basin	Bally Classification	Klemme Classification
Northern North Sea	1211	III A
Nile Delta	114	IV
Sacramento	332	III Bd
	311	V

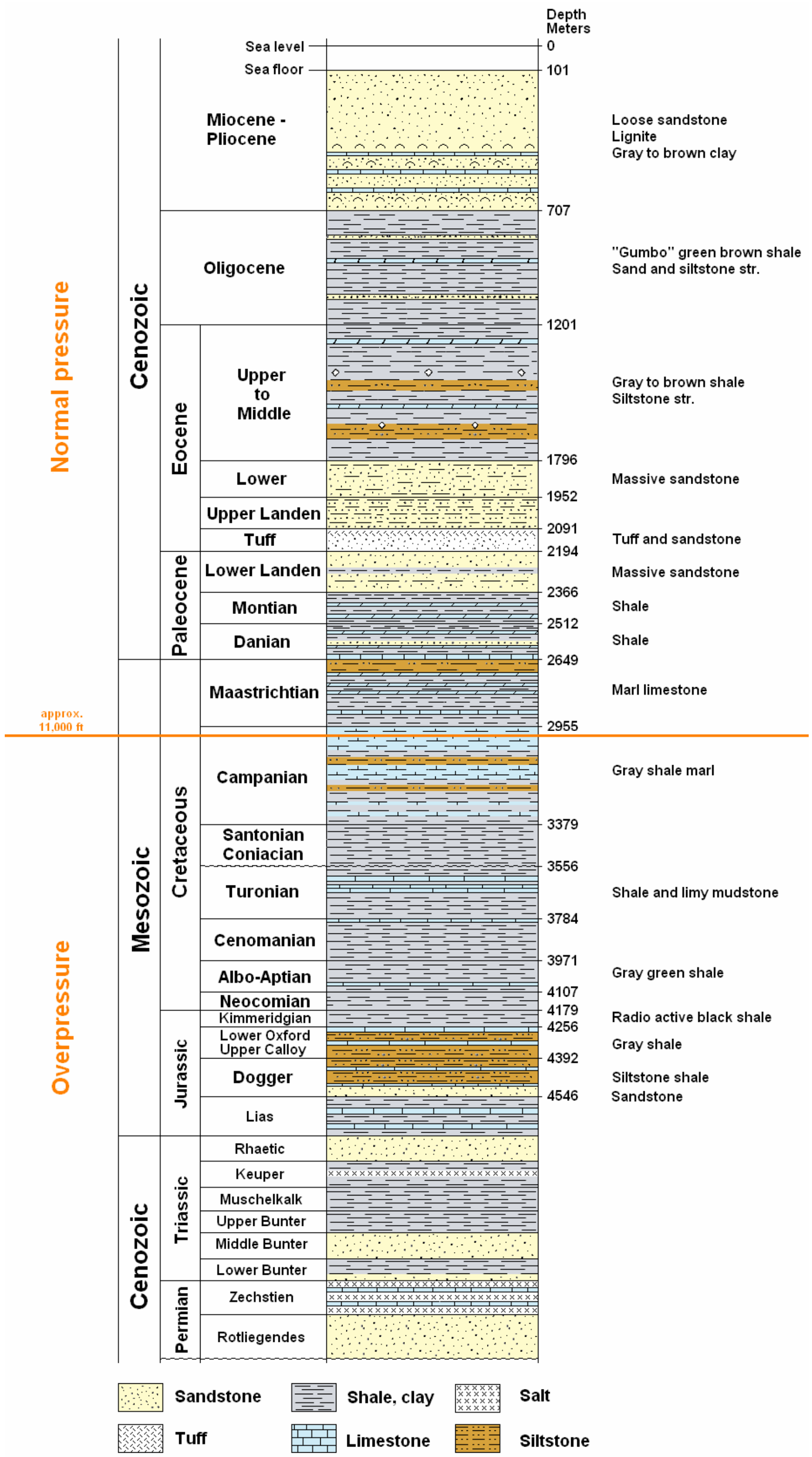

Figure 50. Stratigraphic column of the PDP for the Northern North Sea Basin, Frigg Field area. Lithologies and associated pressure regime from the PDP are shown.

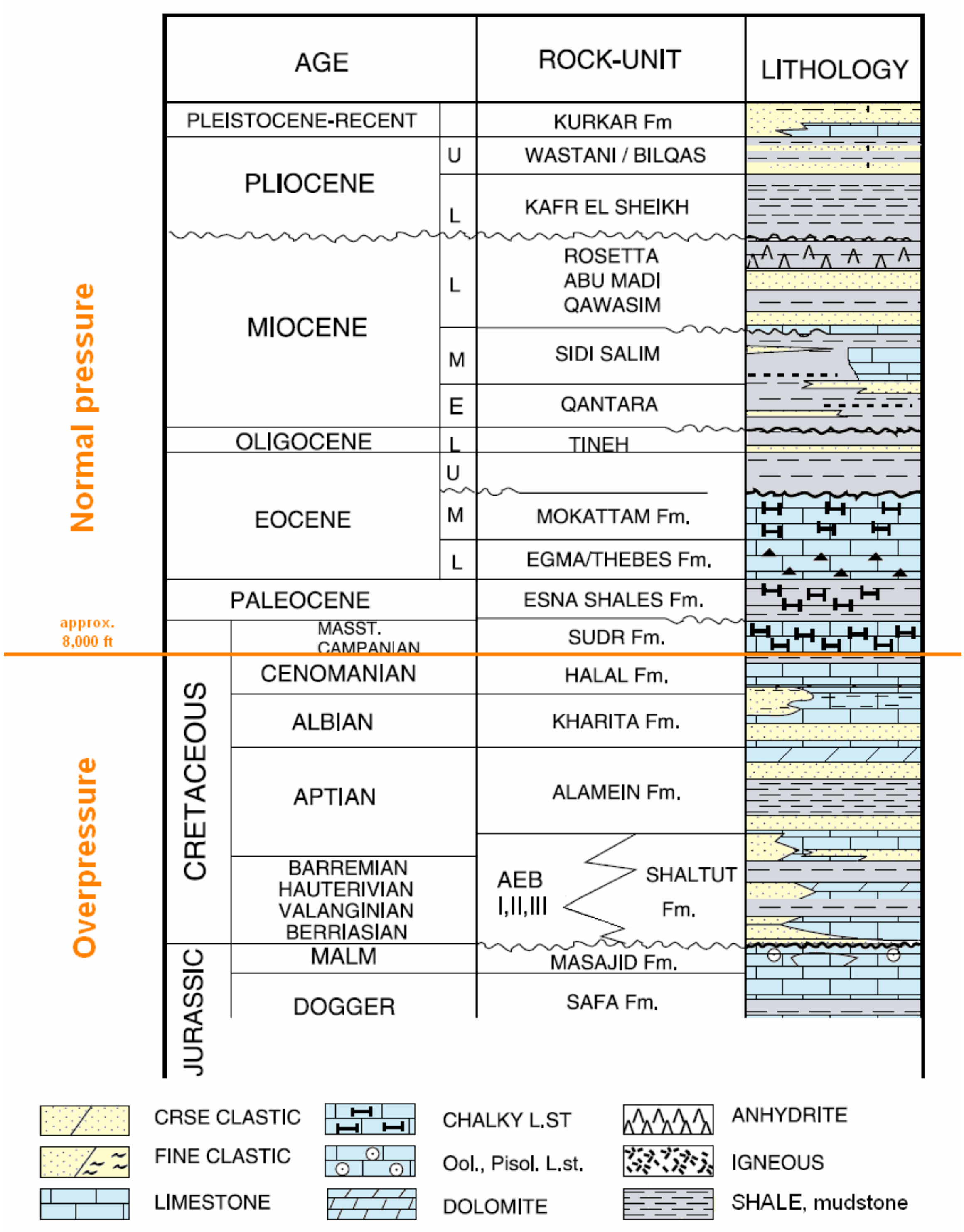

Figure 51. Stratigraphic column of the PDP for the Nile Delta Basin, Offshore Sinai area. Lithologies and associated pressure regime taken from the PDP are shown.

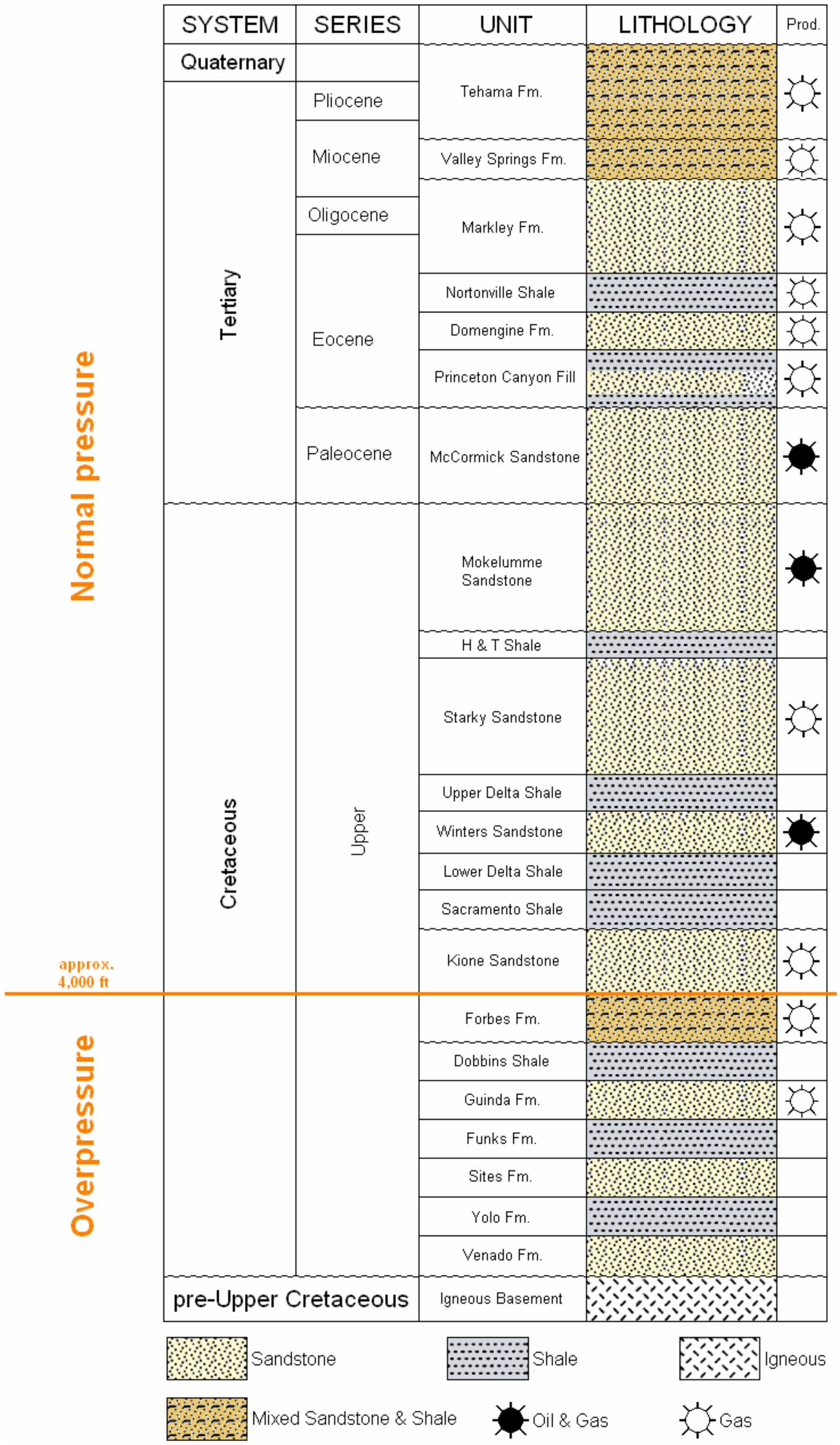

Figure 52. Stratigraphic column of the PDP for the Sacramento Basin, Willows-Beehive Bend area. Overpressures coincide with shale-rich formations.

Table 13

Recessed-Tiered Basins

Pressure Regime	Lithology	Trap	Pressure Mechanism
upper normal	alternating beds of shale & sandstone	structure &/or stratigraphic	• hydraulic connectivity • steady-state ground water flow
middle under	sandstone	structure & stratigraphic	• hydrodynamic flow • unloading/rock dilation • differential migration • depletion of hydrocarbons
deep normal	carbonates	structure	• hydraulic connectivity • steady-state ground water flow

Basin	Bally Classification	Klemme Classification
Wind River	222	II A
Big Horn	222	II A
Alberta	221	II A

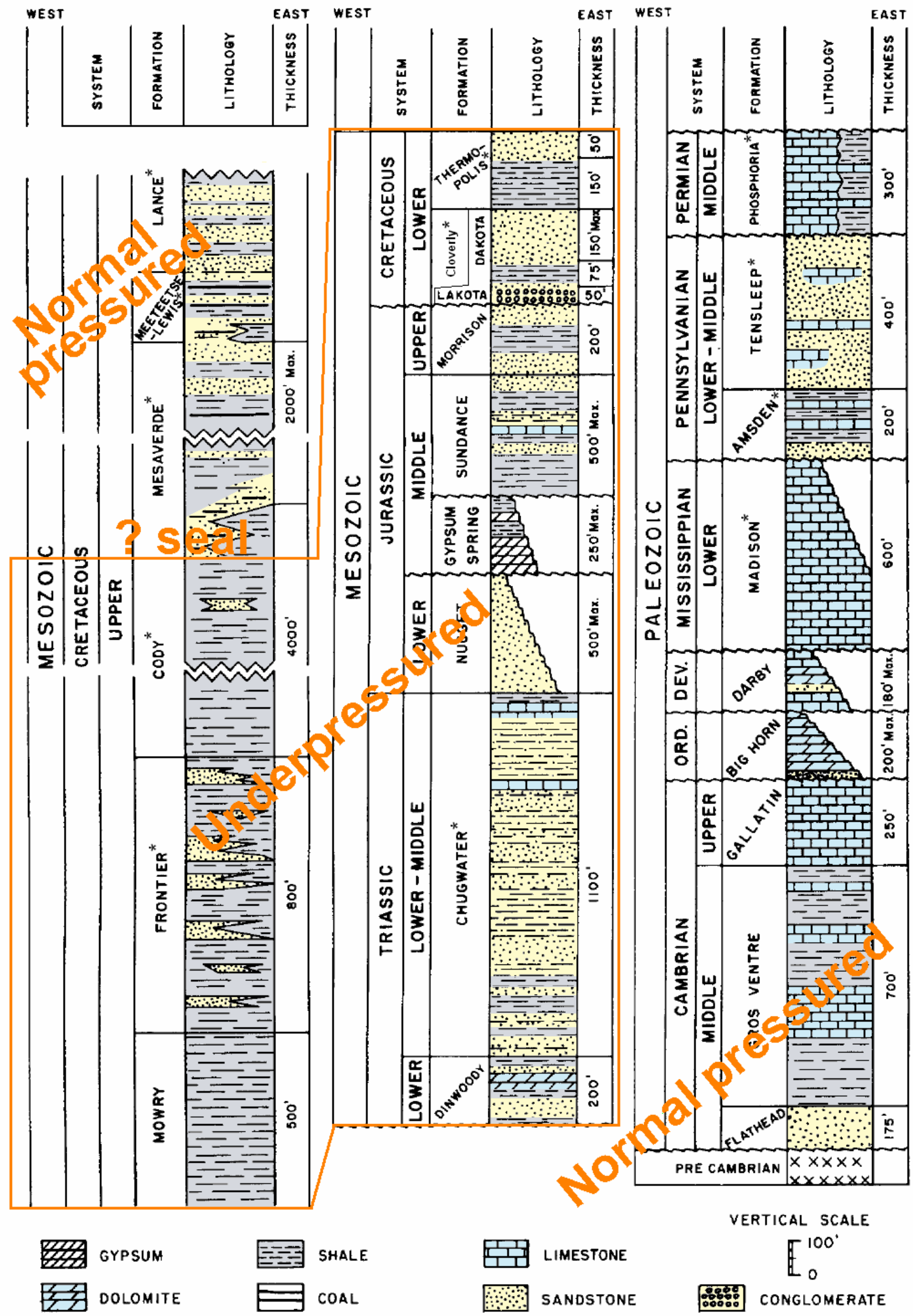

Figure 53. Stratigraphic column of the PDP for the Wind River Basin, Beaver Creek area. Overpressuring occurs in the shale-dominated interval.

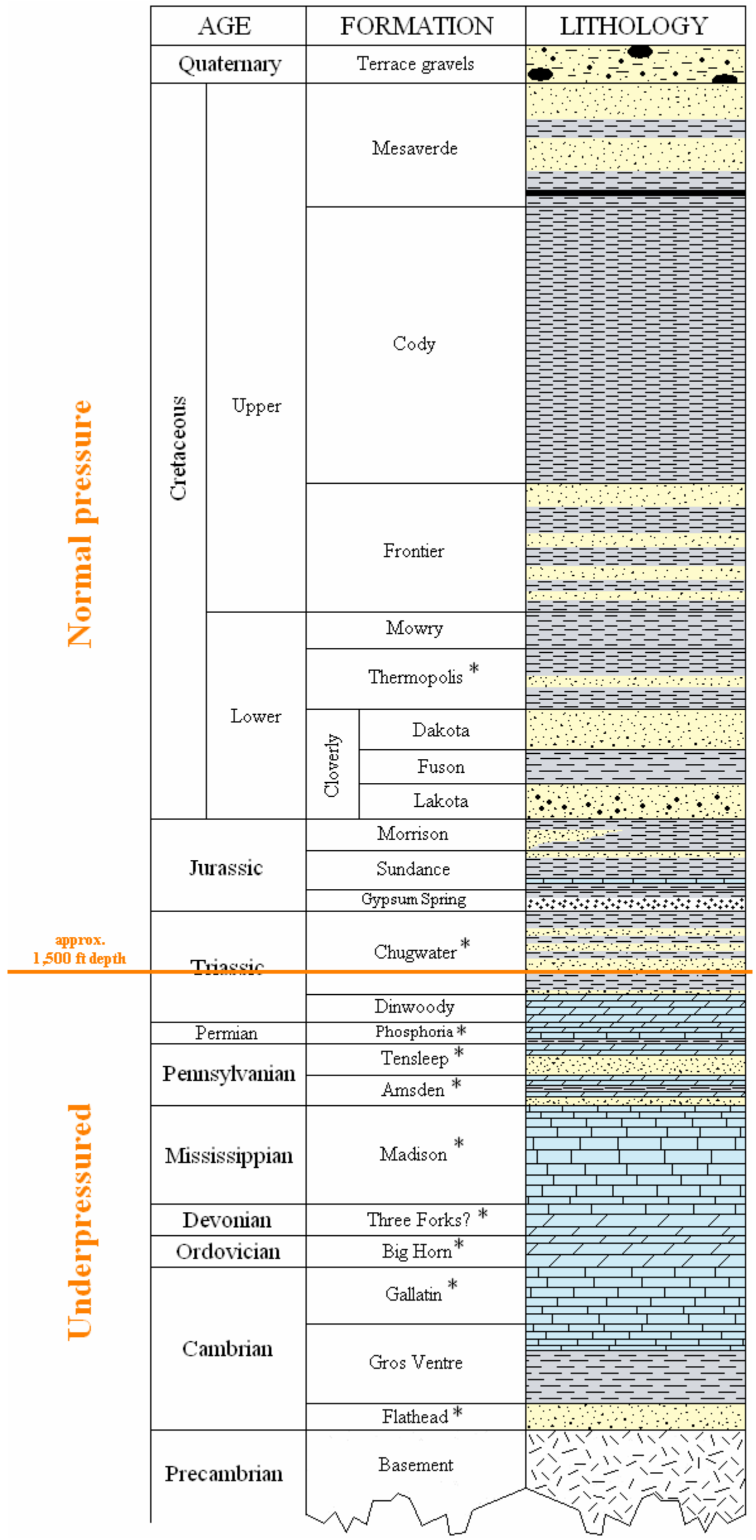

Figure 54. Stratigraphy associated with the PDP for the Big Horn Basin, Hamilton Dome area. Underpressures occur in the carbonate-dominated Paleozoic interval.

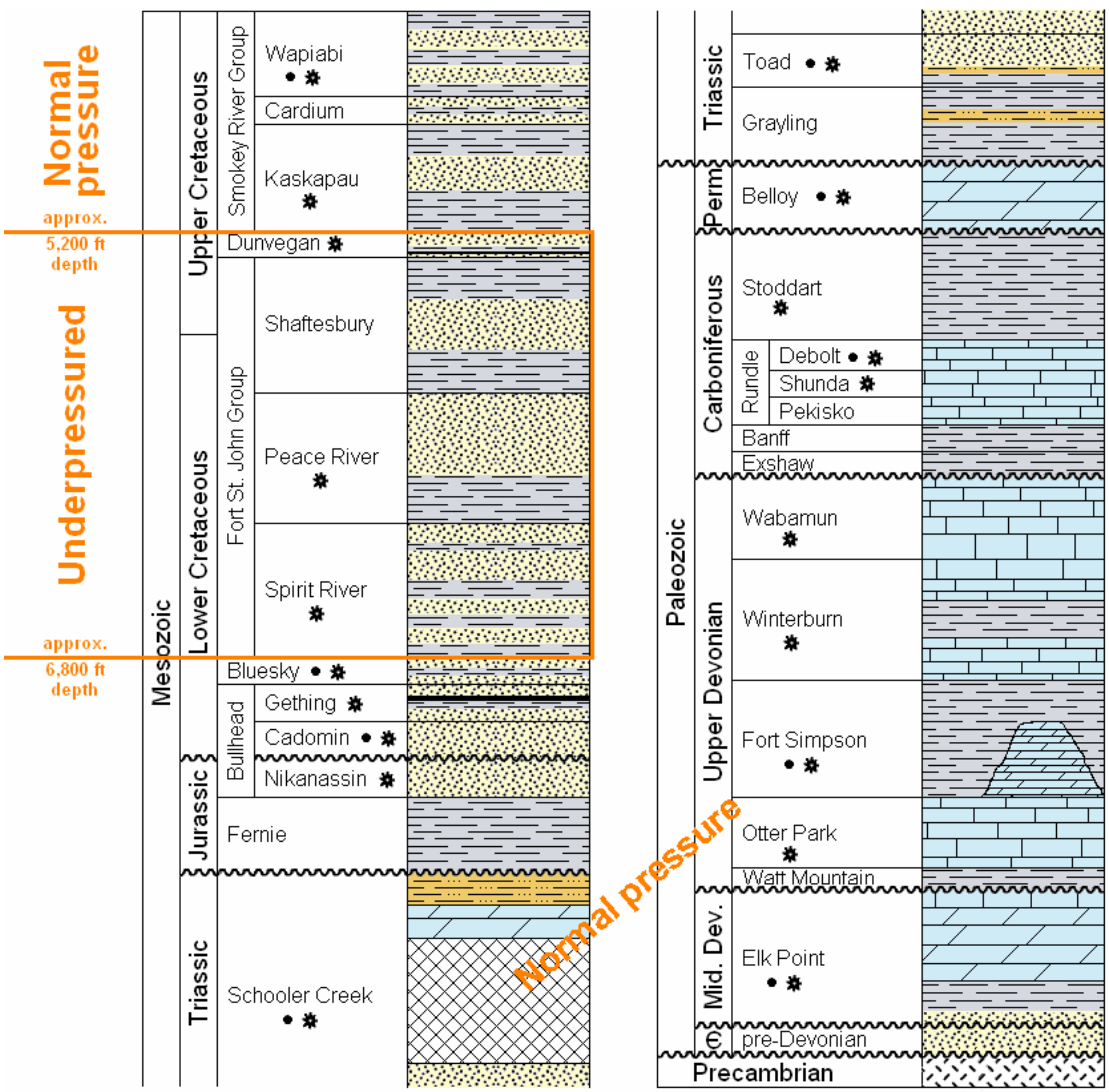

Figure 55. Stratigraphic column for the PDP for the Alberta Basin, Peace River area. Underpressure is restricted to the sandstone reservoirs of the Dunvegan and Fort St. John Group.

three regimes, an upper normal, middle underpressured, and a deep normal, but in the Big Horn basin there are only two regimes, an upper normal and a lower underpressured. In both cases, the upper normal regimes are dominated by shales with sandstone beds. The underpressured regimes are dominated by regionally deposited coarse-grained clastic material. In most cases the underpressured regime is generated by an active water drive that is able to move somewhat freely throughout the reservoirs in this interval. This is facilitated by the lateral continuity of the rock units. Accumulations of hydrocarbons in the underpressured regimes are found on structures that use the buoyancy difference between the hydrocarbons and water for trapping. A lower normal pressured regime can occur beneath the underpressured regime, as is the case for the Alberta and Wind River basins. In each of these two basins this lower normal pressured regime is dominated by carbonates that can be traced from the surface into the subsurface, providing extensive pore networks which maintain hydraulic connectivity with the surface recharge.

Ledged-Tiered Basins: (Table 14) In the ledged-tiered basins, Anadarko (Figure 56), Maturin (Figure 57), and Potwar (Figure 58), three distinct pressure regimes are recognized: an upper normal, a middle overpressured, and a deep normal. In these basins the upper normal regime is dominated by clastic material consisting of sandstones and carbonates. The middle overpressured regime is characterized by alternating beds of shales, forming the seals, and sandstones and carbonates, forming the reservoirs. The reservoirs in this regime are often laterally discontinuous, creating the compartmentation required to preserve and maintain the abnormally high pressures. The generation of the

Table 14

Ledged-Tiered Basins

Pressure Regime	Lithology	Trap	Pressure Mechanism
upper normal	coarse clastic	stratigraphic	• hydraulic connectivity • steady-state ground water flow
middle over	shale, interbeds of sandstone & carbonate	structure & stratigraphic	• stress-related (vertical and lateral) • hydrocarbon generation
deep normal	carbonates	structure	• hydraulic connectivity • steady-state ground water flow

Basin	Bally Classification	Klemme Classification
Anadarko	221	II A
Maturin	221	II Ca
Potwar	41	II Cb

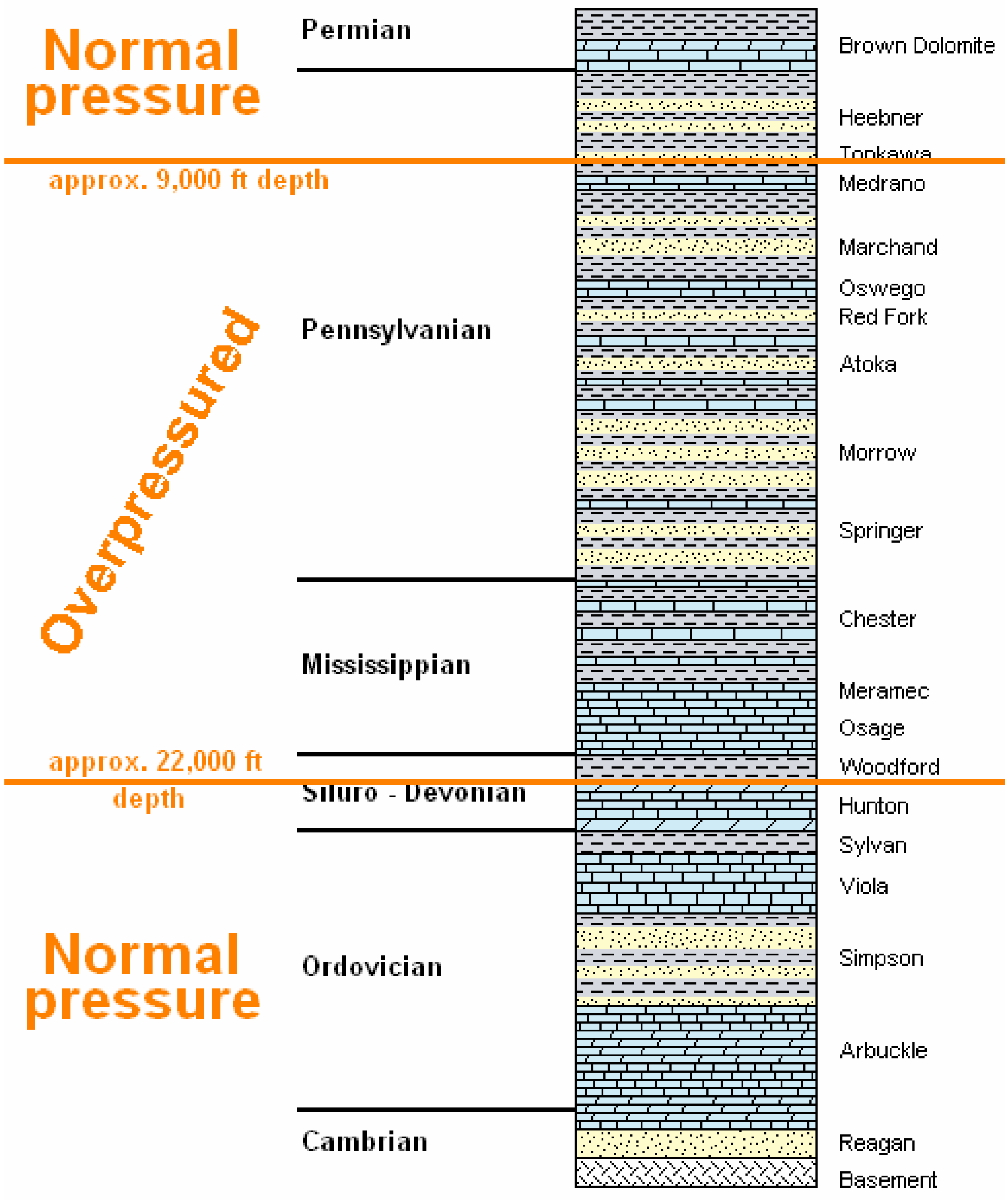

Figure 56. Stratigraphic column for the PDP form the deep Anadarko Basin, Reydon-Cheyenne area. Overpressure is restricted to shale-dominated Pennsylvanian strata, Mississippian carbonate, and the Woodford Shale.

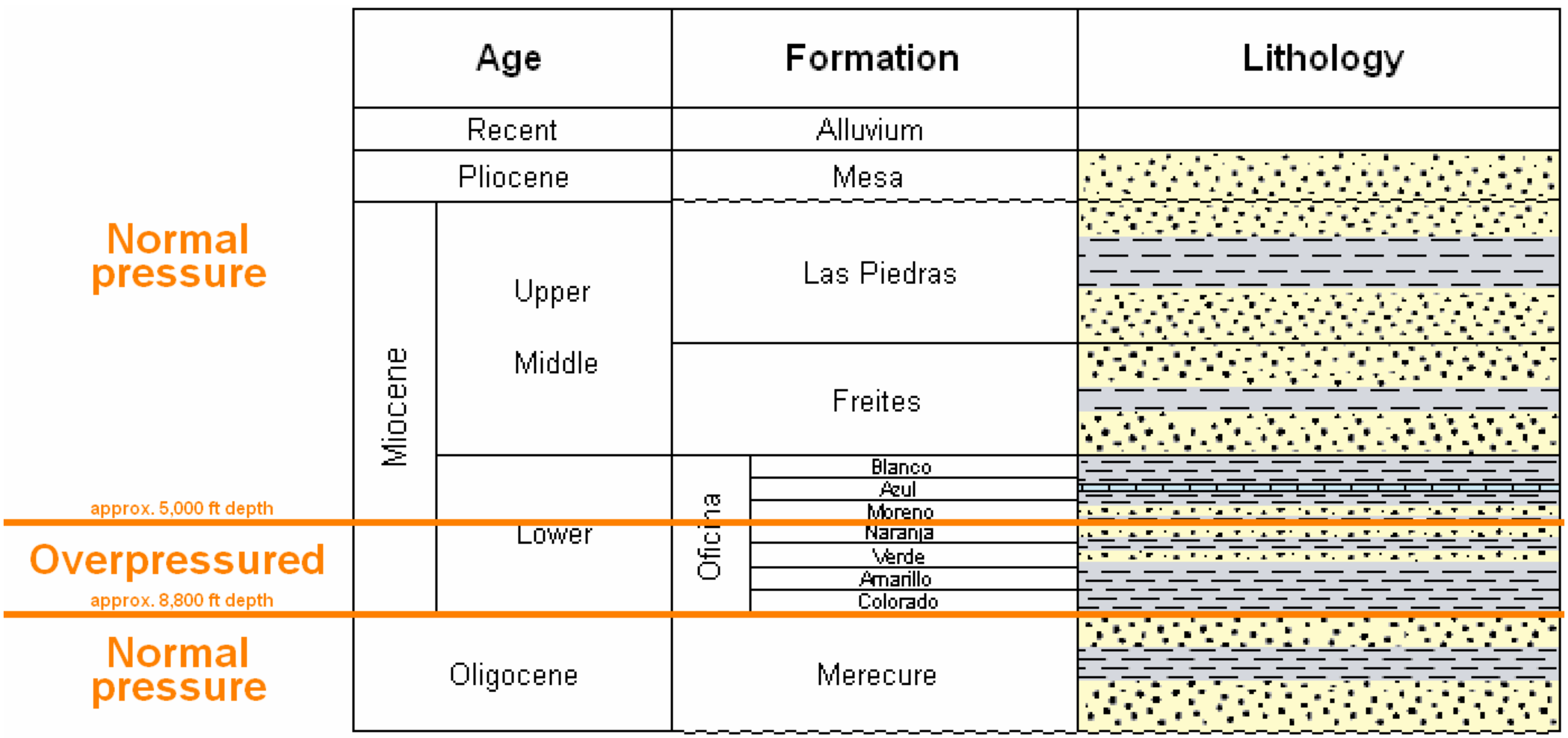

Figure 57. Stratigraphic column for the PDP form the Maturin Basin, Greater Anaco area. Overpressure is associated with the shale-dominated Miocene interval.

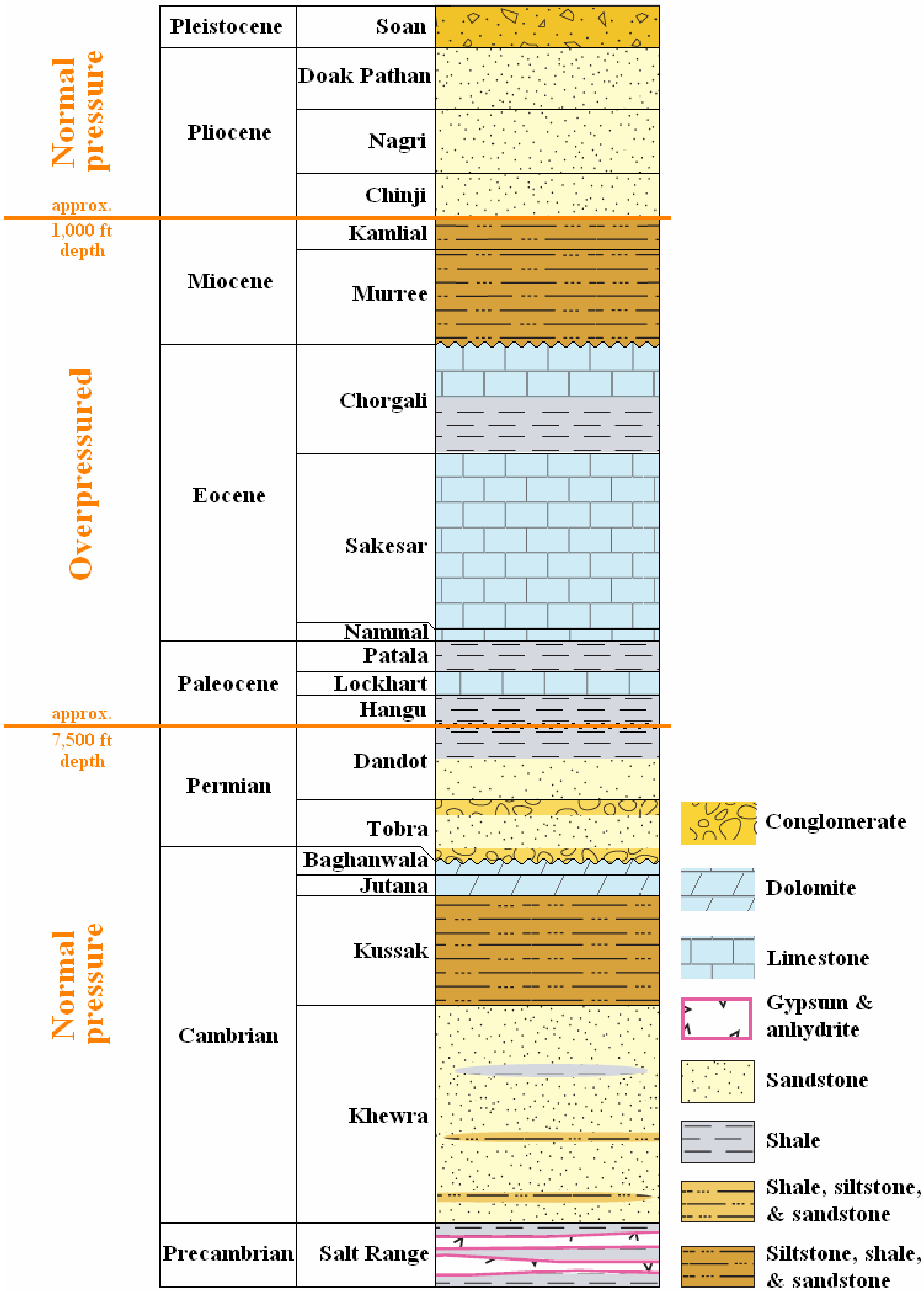

Figure 58. Stratigraphic column for the PDP form the Potwar Basin, Adhi area. Normal pressure occur in sandstone-dominated interval; overpressure in the shale-rich units.

abnormally high pressures are attributed to stress-related (both lateral and vertical) and hydrocarbon generation mechanisms. Below the overpressured regime is a deep normally pressured regime that is dominated by regionally deposited coarse-grained sandstones and carbonates. The return to normal pressures beneath the overpressures is the result of extensive reservoir continuity and the free communication these reservoirs maintain with the surface, by their outcropping on the basin margins.

Prediction of Pressure Distribution in Sedimentary Basins

Knowing the distribution of pore fluid pressures when prospecting or producing an area may help increase the efficiency of petroleum exploration and production. Data was examined from over 300 PDPs in more than 75 basins worldwide. Of the total, more than 65 could be distinguished into a tiered pressure distribution: 13 ledged-, 12 recessed-, 38 stepped-, and 2 multiple tiered basins (Table 15). From the data analyzed, conclusions regarding the lithologic controls of pressure distributions and correlations between pressures and lithologies in tiered basins was documented (previous section). In addition, a distinct set of characteristics was observed that could enhance the ability to predict pore fluid pressures in sedimentary basins. These characteristics observed selected basins are listed below.

Stepped-Tiered Basins:

- on or near plate margins
- active tectonism
- increased sedimentation after tectonic events
- relatively fault-free strata unconformably atop highly faulted
- thick sequences of relatively impermeable rock

Example: Graben filled system like that found in the North Sea

Table 15

BASIN	COUNTRY	TIERED CLASSIFICATION
ANADARKO	USA	LEDGED
EAST TEXAS SALT DOME	USA	LEDGED
GREEN RIVER	USA	LEDGED
HAWKES BAY	NEW ZEALAND	LEDGED
IRKUTSK	USSR	LEDGED
MATURIN	VENEZUELA	LEDGED
MICHIGAN	USA	LEDGED
PERMIAN	USA	LEDGED
POTWAR	PAKISTAN	LEDGED
SAN JUAN	USA	LEDGED
VIENNA	AUSTRIA	LEDGED
AL AZRAQ	JORDAN	RECESSED
ALBERTA	CANADA	RECESSED
ARKOMA	USA	RECESSED
BIG HORN	USA	RECESSED
DENVER	USA	RECESSED
HENRY MOUNTAINS	USA	RECESSED
POWDER RIVER	USA	RECESSED
UINTA	USA	RECESSED
WIND RIVER	USA	RECESSED
ARABIAN	MIDDLE EAST	STEPPED
BENGAL	BANGLADESH/BURMA/INDIA	STEPPED
BOHAI	CHINA	STEPPED
BOMBAY	INDIA	STEPPED
BRUNEI-SABAH	MALAYSIA	STEPPED
CAUCASAS NORTH	RUSSIA	STEPPED
COOK INLET	USA - ALASKA	STEPPED
DNEPR-DONETS	USSR	STEPPED
EEL RIVER	USA	STEPPED
GANGES	INDIA	STEPPED
GULF COAST	MEXICO/USA	STEPPED
GULF OF SUEZ	EGYPT	STEPPED
KRISHNA	INDIA	STEPPED
LOWER MAGDALENA	COLOMBIA	STEPPED
MEERVLAKTE	INDONESIA	STEPPED
MISSISSIPPI SALT DOME	USA	STEPPED
NAVARIN	USA - ALASKA/USSR	STEPPED
NILE DELTA	EGYPT	STEPPED
NORTHLAND	NEW ZEALAND	STEPPED
NORTH SLOPE	USA - ALASKA	STEPPED
NORTHERN NORTH SEA	NORWAY/U.K.	STEPPED
NUWUK	USA - ALASKA	STEPPED
ORINOCO DELTA	TRINIDAD/VENEZUELA	STEPPED
PAPUAN	PAPUA NEW GUINEA	STEPPED

Table 15 cont.

BASIN	COUNTRY	TIERED CLASSIFICATION
PO	ITALY	STEPPED
RED DESERT	USA	STEPPED
SACRAMENTO	USA	STEPPED
SARAWAK	MALAYSIA	STEPPED
SCOTIA SHELF	CANADA	STEPPED
SOUTH TEXAS SALT DOME	USA	STEPPED
SOUTHERN NORTH SEA	NETHERLANDS/U.K./DENMARK	STEPPED
TADZHIK	AFGHANISTAN/USSR	STEPPED
TRANSYLVANIAN	RUMANIA	STEPPED
WEST JAVA	INDONESIA	STEPPED
WILLISTON	CANADA/USA	STEPPED
DALHART	USA	multiple
BLACK SEA	RUMANIA/USSR/TURKEY	multiple

Table 15. Summary of Tiered Basins in which PDP data was analyzed.

Recessed-Tiered Basin:

- found on continental plate
- major sedimentation before major tectonic episode
- thick sequences of regionally deposited strata
- majority of strata can be traced from the surface into the subsurface
- majority of strata outcrops at basin margins

Example: Regionally uplifted strata of the Denver and Alberta basins

Ledged-Tiered Basin:

- found on continental plate
- significant increase in sedimentation after major tectonic episode
- strata found in the deepest portions of the basin outcrop at basin margins
- sedimentation after major tectonism in fills synform structure

Example: Permian Basin system of West Texas and New Mexico

Basins with tiered pressure systems are found to exhibit a relationship between pressure regimes and subsidence history. Basin with active subsidence, such as the U. S. Gulf Coast can be classified as a stepped-tiered system. Senile basins, like the Anadarko Basin, where subsidence stopped and uplifting has occurred, exhibit a fluid pressure profile classified as a ledged-tiered system. Finally, basins that have experienced significant amounts of uplift contain pressures that would be classified as a recessed-tiered system, i.e. Denver Basin.

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APPENDIX

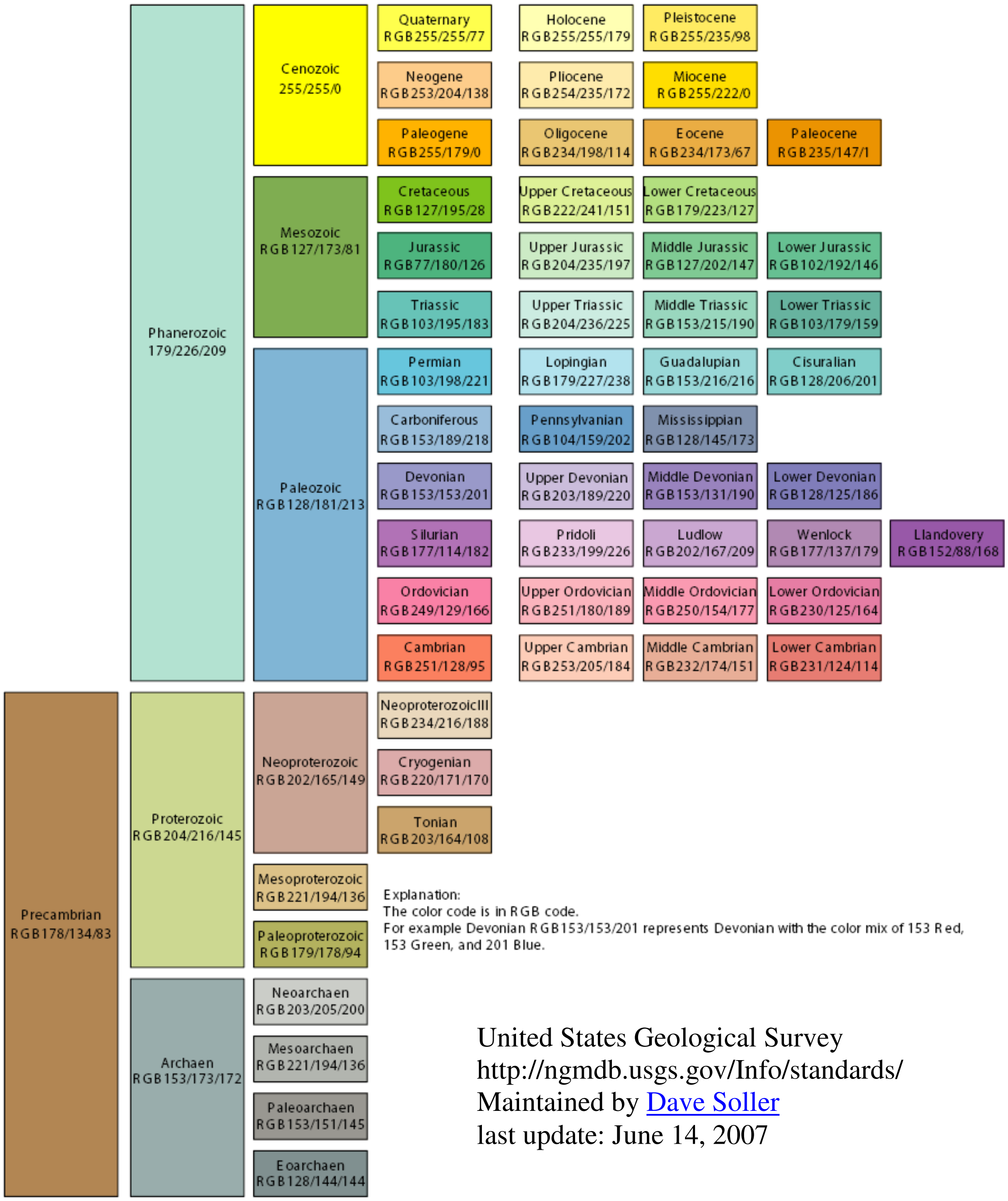
Appendix A-Explanation of Klemme Basin Classification (St. John et al., 1984)

I. Craton interior basin
II. Continental multicycle basins
    A. Craton margin – composite
    B. Craton/accreted margin – complex
    C. Crustal collision zone – convergent plate margin
        a. Closed
        b. Trough
        c. Open
III. Continental rifted basins
    A. Craton and accreted zone rift
    B. Rifted convergent margin – oceanic consumption
        a. Backarc
        b. Transform
        c. Median
    C. Rifted passive margin – divergence
        a. Parallel
        b. Transform
IV. Delta basins
    A. Synsedimentary
    B. Structural
V. Forearc basins

Appendix B-Explanation of Bally Basin Classification (St. John et al., 1984)

1. Basins located on the rigid lithosphere, not associated with formation of megasutures
    11. Related to formation of oceanic crust
        111. Rifts
        112. Oceanic transform fault associated basins
        113-OC. Oceanic abyssal plains
        114. 'Atlantic-type' passive margins (shelf, slope, & rise) which straddle continental and oceanic crust
            1141. Overlying earlier rift systems
            1142. Overlying earlier transform systems
            1143. Overlying earlier backarc basins of types 321 & 322
    12. Located on pre-Mesozoic continental lithosphere
        121. Cratonic basins
            1211. Located on earlier rifted grabens
            1212. Located on former backarc basins of type 321
2. Perisutural basins on rigid lithosphere associated with formation of compressional megasuture
    21-OC. Deep sea trench of moat on oceanic crust adjacent to B-subduction margin
    22. Foredeep and underlying platform sediments, or moat on continental crust adjacent to A-subduction
        221. Ramp with buried grabens, but with little or no block faulting
        222. Dominated by block faulting
    23. 'Chinese-type' basins associated with distal block faulting related to compressional or megasuture and without associated A-subduction margin
3. Episutural basins located and mostly contained in compressional megasuture
    31. Associated with B-subduction zone
        311. Forearc basin
        312. Circum-Pacific backarc basin
            3121-OC. Backarc basins floored by oceanic crust and associated with B-subduction
            3122. Backarc basins floored by continental or intermediate crust, associated with B-subduction
    32. Backarc basins, associated with continental collision and on concave side of A-subduction arc
        321. On continental crust of 'Pannonian-type' basin
        322. On transitional and oceanic crust of 'W Mediterranean-type' basins
    33. Basins related to episutural megashear systems
        331. 'Great basin-type' basin
        332. 'California-type' basin
4. Folded belt
    41. Related to A-subduction
    42. Related to B-subduction
5. Plateau basalts

Appendix C- United States Geological Survey color schematic for the mapping of stratigraphic units on geologic maps.



Explanation:
The color code is in RGB code.
For example Devonian RGB153/153/201 represents Devonian with the color mix of 153 Red, 153 Green, and 201 Blue.

United States Geological Survey
http://ngmdb.usgs.gov/Info/standards/
Maintained by Dave Soller
last update: June 14, 2007

VITA

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Master of Science

Thesis: LITHOLOGIC CONTROLS OF TIERED PRESSURE DISTRIBUTIONS IN SELECTED SEDIMENTARY BASINS

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Institution: Oklahoma State University Location: Stillwater, Oklahoma

Title of Study: LITHOLOGIC CONTROLS OF TIERED PRESSURE DISTRIBUTIONS IN SELECTED SEDIMENTARY BASINS

Pages in Study: 197 Candidate for the Degree of Master of Science

Major Field: Geology

Scope and Method of Study:

The purpose of this study was to examine the lithologic controls of tiered pressure distributions in selected basins worldwide. The study included more than 300 individual pressure-depth profiles for more than 75 sedimentary basins. From the total number of basins, nine were selected to study a more in depth view of the relationship pressures had with lithologies.

Findings and Conclusions:

Tiered systems contain distinct pressure domains or compartments whose distribution patterns are categorized as stepped, recessed, and ledged. Pressures in stepped basins increase with depth and form a staircase pattern of distinct pressure compartments. Recessed patterns are formed by a subnormally pressured interval, which is intercalated both above and below by normal pressures. Ledged patterns consist of an overpressured section with subjacent and superjacent normally pressured intervals.

Stepped pressures are representative of basins containing thick sections of seals with intervening hydrocarbon-bearing sandstone reservoirs with irregular subbasin relief. Recessed patterns result when underpressured hydrocarbon-bearing carbonate or sandstone reservoirs are sealed from normally pressured reservoirs above and below and have encountered some tectonic activity. Ledged patterns have three distinct pressure domains: (1) a shallow, normal pressured sandstone-rich interval, (2) a shale-dominated interval that contains overpressured and gas-filled sandstones, and (3) a deeper, normally pressured interval. This deeper normally pressured domain is dominated by carbonates or sandstones that are hydraulically connected to the surface, have active water drives, and contains gas that is buoyancy trapped above the water leg. Gas accumulations in abnormally overpressured and shallow, normal pressured intervals within tiered basins are dominantly stratigraphically trapped. In contrast, deep gas in sub-ledge, normally pressured intervals typically requires anticlinal folding or faulting to trap.

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