Clay Minerals, (2011) **46**, 1–24

The 2010 George Brown Lecture

Earth's energy "Golden Zone": a synthesis from mineralogical research

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(*Received 2 September 2010; revised 12 November 2010; Editor: John Adams*)

ABSTRACT: The impact of diagenetic processes on petroleum entrapment and recovery efficiency has focused the vast majority of the world's conventional oil and gas resources into relatively narrow thermal intervals, which we call Earth's energy "Golden Zone". Two key mineralogical research breakthroughs, mainly from the North Sea, underpinned this discovery. The first is the fundamental particle theory of clay mineralogy, which showed the importance of dissolution/precipitation mechanisms in the formation of diagenetic illitic clays with increasing depth and temperature. The second is the surface area precipitation-rate-controlled models for the formation of diagenetic cements, primarily quartz, in reservoirs. Understanding the impacts of these geological processes on permeability evolution, porosity loss, overpressure development, and fluid migration in the subsurface, lead to the realization that exploration and production risks are exponential functions of reservoir temperature. Global compilations of oil/gas reserves relative to reservoir temperature, including the US Gulf Coast, have verified the "Golden Zone" concept, as well as stimulated further research to determine in greater detail the geological/mineralogical controls on petroleum migration and entrapment efficiency within the Earth's sedimentary basins.

KEYWORDS: global energy resources, petroleum geology, hydrocarbon migration, clay mineral diagenesis, fundamental particles, quartz cementation, porosity, permeability, basin analysis, North Sea, US Gulf Coast, oil and gas reserves, exploration risks, temperature, overpressure.

Energy in the form of large oil and gas accumulations in sedimentary basins has been the most important natural resource used by our society over the last century. This energy forms a key basis for our high-yield agricultural production, the infrastructure that provides our water, housing, transportation, medical care, educational and other services, as well as our impressive research establishments. Civilization as we know it today would not be possible without this energy. In this George Brown Lecture, we will review advances in mineralogical research, some of which began here at the Macaulay Institute in the early 1980s, in the area of clay mineralogy and sedimentary diagenesis. These diagenetic processes, which occur with increasing depth and temperature in sedimentary basins, have played a major role in the formation of our valuable oil and gas energy accumulations. The petroleum industry refers to them as conventional oil and gas resources, which stand at ~2 trillion

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DOI: 10.1180/claymin.2011.046.1.1

barrels of oil and 12 thousand trillion cubic feet of gas, mainly to distinguish them from unconventional resources such as heavy oil sands, shale gas, etc. The most remarkable of these 'conventional' oil and gas accumulations are the giant fields, each containing >500 million barrels, of which the North Sea is well endowed. Research has since shown that not only in the North Sea, but also in most of the world's petroleum producing sedimentary basins, these giant accumulations occur predominantly in a relatively thin, 60ºC, thermal interval that we refer to as the "Golden Zone" for exploration. The story of its discovery and verification is the main theme of this paper.

The research findings form the basis of a paradigm shift in exploration thinking and risk management that transforms perceived geological complexity into a global pattern of elegant simplicity (Buller *et al*., 2005). These findings, which are not without controversy, have provided new perspectives on the geological controls responsible for the creation of giant high-value oil and gas energy accumulations, which constitute the majority of conventional petroleum resources. More importantly, they make possible the prolific *rate* of energy production which maintains our very existence. That rate, in terms of daily oil production, stands at >80 million barrels *per day*, and for gas ~50 million barrels of oil equivalent (~300 billion cubic feet per day). If that amount of high-value fluid energy were to be sourced from sustainable agriculture, it would require the arable land of more than 3 planet Earths. A general understanding of the geology of the Golden Zone (GZ) and its formation is particularly important, therefore, as we approach the limits of production capacity, as foreseen by the pioneering work of Hubbert (1969) and further by Campbell & Laherrere (1998) as well as Deffreys (2004).

CLAY MINERAL DIAGENESIS AND THE GOLDEN ZONE

Over the last 20 years mineralogical models for sedimentary diagenesis have been developed for predicting the impact of clay mineral and quartz cementation on porosity/permeability evolution in sedimentary basins (Bjørkum & Nadeau, 1996, 1998; Bjørkum *et al.*, 1998a,b; Nadeau, 1998, 1999a,b; Nadeau *et al.*, 1984a,b, 1985, 2002, 2005; Nadeau & Bain, 1986; Oelkers *et al.*, 1998; Walderhaug, 1994, 1996). These models indicate that precipitation of diagenetic clay minerals at temperatures >60ºC leads to very low permeability shales/mudstones, creating an important component in the geological containers which hold many of our giant petroleum accumulations. The precipitated diagenetic clay, in the form of nanometre scale layer silicate particles, makes the sealing rock units much more effective at capturing and storing oil and gas which have been expelled from organic-rich source rocks at higher temperatures, generally >120ºC. It also helps to preserve the oil, isolating it from the effects of bacterial and thermal degradation (Nadeau *et al*., 2005b). This model for clay diagenesis was mainly advanced by workers at the Macaulay Institute, and is referred to as the 'Fundamental Particle' model, or FP model (McHardy *et al.*, 1982; Nadeau *et al.*, 1984a,b).

That research challenged the prevailing view that clay mineral diagenesis occurred via a solid-state transformation (SST) mechanism (Hower *et al.*, 1976; Altaner & Ylagan, 1997). The FP model proposed that diagenetic clay minerals precipitated within the pore space of sediments, and also created a new paradigm, interparticle diffraction, for the interpretation of 1-dimensional X-ray diffraction (XRD) characteristics of interstratified clay minerals (Nadeau *et al.*, 1984c). This paradigm, based on the FP model, advanced conventional interpretation methods and formed a basis for 3-dimensional crystal structure calculation of these clay mineral assemblages (e.g. Reynolds, 1992; Drits *et al.*, 1998, 2002), as well as models for crystal growth (Eberl *et al.*, 1998, 2000, 2002). Discussions on the origins of these clay minerals are still ongoing, and a clear consensus has yet to emerge on the reality as well as the implications of the FP model and related interparticle diffraction theory (e.g. McCarty *et al.*, 2008; Eberl *et al.*, in press).

Early workers in clay mineral diagenesis were quick to apply their findings in the petroleum industry. Comprehensive studies by Weaver (1960) and mechanistic models by Burst (1969) considered the impact of clay diagenetic processes on petroleum migration. These early studies were often based on the SST layer-by-layer mechanisms, whereby smectite layers collapse to form illite layers. Some considered that smectite dehydration resulted in fluid expulsion, causing fluid overpressure in sedimentary basins. Others also applied this approach with success in the US Gulf Coast, including Reynolds & Hower (1970) and Perry & Hower (1970).

The SST model, although consistent with the XRD observations at that time, was misleading in terms of the diagenetic mechanism and pathways for this very important mineral reaction, as well as its petrophysical consequences. For example, it also suggested that as smectite layers formed illite layers the hydraulic conductivity surface area of the affected lithologies was reduced, which further implied that the reaction would tend to *increase*, rather than decrease, the permeability of these sedimentary rocks.

The reaction is now understood to occur by dissolution and precipitation mechanisms, along several reaction pathways (Fig. 1), including:

1. smectite + K-feldspar = illite + quartz + water + exchangeable cations;
2. kaolinite + K-feldspar = illite + quartz + water.

Reaction 1 is more dominant on the US Gulf Coast, whereas reaction 2 is more common in the North Sea (eg. Bjørlykke, 1986; Ehrenberg & Nadeau 1989; Nadeau *et al.*, 2002a,b; Thyberg *et al.*, 2010). The onset of the reaction occurs at 60ºC, or ~2 km depth of burial for normal geothermal gradients, although the presence of carbonate minerals may increase the stability of the clay reactants to approximately 80ºC (Nadeau & Reynolds, 1981a; Nadeau, *et al.*, 2005). The precipitation of illite in the pore space of fine grained shales and mudstones greatly reduces the hydraulic conductivity, or permeability, of these rocks, most probably by several orders of magnitude (Nadeau *et al.*, 1985, 2002; Schneider *et al.*, 2003; Fig. 1). This greatly increases the susceptibility of subsurface formations to the development of overpressure, first as a result of shallow, mechanical compaction and porosity loss processes. As pressure insensitive chemical cementation at temperatures >60ºC increases, the probability of high reservoir overpressure in most fault segmented sedimentary basins increases exponentially (Bjørkum & Nadeau, 1998; Nadeau *et al.*, 2005b).

It is important to consider separately overpressure in low-permeability shales and mudstones, which act as seals or aquitards in sedimentary basins, and unlike reservoirs, do not require lateral seals for overpressure development. Furthermore, we will not consider undercompaction in these lithologies, although it is an important phenomenon in the subsurface (e.g. Hedberg, 1974). It is often considered that there is significant fluid and mass balance transfer between shales and sandstones during deep diagenesis (e.g. Boles & Franks, 1979). Here we will accept the Knut Bjørlykke view of closed system diagenesis for burial environments, particularly those >60ºC (Bjørlykke & Jahren, 2010). In part this is due to the extremely low permeability of these units after clay diagenetic reactions, and also based on the numerous

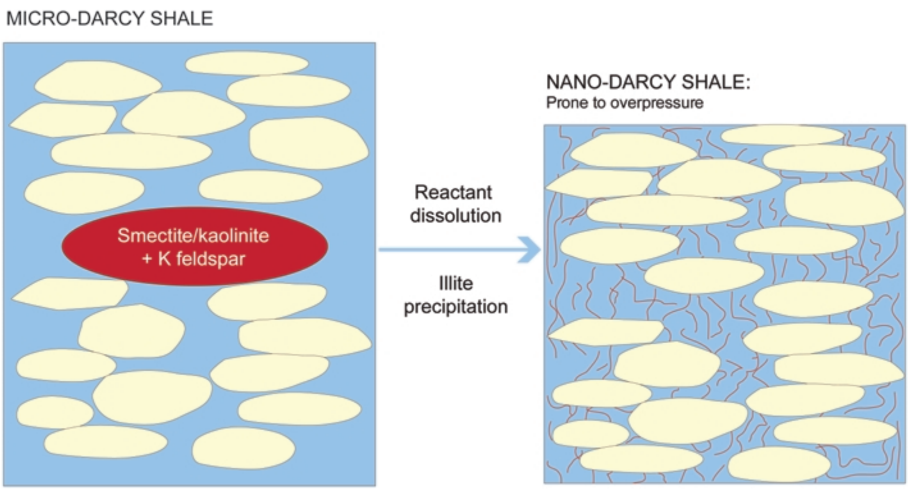

FIG. 1. Reaction pathways for precipitation of diagenetic illite in shales and mudstones. The reaction causes dramatic reductions in permeability, but has little effect on total porosity. The reaction commences at ~60ºC, but can be delayed to ~80ºC in the presence of carbonate mineral phases (after Buller *et al.*, 2005).

https://doi.org/10.1180/claymin.2011.046.1.1 Published online by Cambridge University Press

observations that dissolution components are not transported far (on the cm to m scale in sandstones) to subsequent precipitation sites in the subsurface. For example with respect to:

1. illite diagenesis (e.g. Chuhan *et al*., 2000);
2. quartz cementation (e.g. Walderhaug & Bjørkum, 2003);
3. carbonate cementation (e.g. Walderhaug & Bjørkum, 1998).

For this paper, therefore, we will focus on overpressure development in high-permeability reservoir sequences, mainly in sandstones that serve as aquifers in sedimentary basins, because these phenomena, in combination with very low-permeability shale aquitards (e.g. Bjørlykke *et al.*, 2010), have the greatest impact on the distribution of conventional oil and gas reserves in sedimentary basins.

It is also important to note here that early diagenetic smectite can form in sediments from the alteration of volcanic materials, mainly from amorphous glass components (Nadeau & Reynolds, 1981b). Such geological occurrences can also increase the susceptibility of these subsurface lithologies to overpressure and undercompaction, particularly during early stages of burial, such as in the North Sea Eocene Balder Formation (e.g. Marcussen *et al*., 2009).

CHEMICAL CEMENTATION, POROSITY LOSS AND OVERPRESSURE

The historical contributions of mineral diagenesis to the understanding of overpressure development has been impaired by early concepts of late-stage secondary porosity. These concepts propose that porosity actually *increases* with increasing depth and temperature for siliciclastic rocks (e.g. Schmidt & Macdonald, 1979a,b; Surdam *et al.*, 1984) as well as for carbonate rocks (e.g. Davies & Smith, 2006; Machel & Lonnee, 2002) despite the overwhelming lack of evidence for these processes to be of volumetric significance for oil and gas reservoirs (Bjørlykke, 1984; Giles *et al.*, 1992; Bjørkum & Nadeau, 1998; Ehrenberg & Nadeau, 2005; Darke *et al*., 2005; Ehrenberg *et al.*, 2008a,b; Esrafili-Dizaji & Rahimpour-Bonab, 2009). Similarly, misconceptions about the affect of oil arresting reservoir cementation (cf. Gluyas *et al*., 1993; Marchand *et al*., 2000, with Giles *et al*., 1992; Bjørkum & Nadeau, 1998; Aase *et al*., 1996; Taylor *et al*., 2010), as well as the material mass balance of cementation (cf. Gluyas & Coleman, 1992, with Bjørkum *et al*., 1998a) have also hindered a general understanding of this important geological process.

After methodically measuring the amounts of quartz cement in North Sea sandstone reservoirs as a function of burial history, quartz surface area and stylolite frequency, the kinetics as well as the material mass balance of this precipitation-rate-controlled reaction were established (Walderhaug, 1994, 1996; Aase *et al*., 1996; Bjørkum *et al.*, 1998a; Oelkers *et al.*, 1996, 1998, 2000; Walderhaug *et al.*, 2000, 2001, 2004). This research was mainly targeted at reservoir quality, porosity and permeability prediction. Over time, the implications for overpressure development, seal failure, hydrocarbon migration, and overall exploration risks ultimately came to supersede these initial research goals. This was evidenced by numerous exploration wells finding only residual hydrocarbon columns from former large oil and gas accumulations in good quality reservoirs whose seals had failed due to fluid overpressure at depths of ~4 km and temperatures >120ºC. It was soon realized that the exponential increase in cementational porosity loss rates was a major contributor to reservoir overpressure development and seal failure in low-permeability shales (Bjørkum, 1993, pers. comm.).

The quartz cementation reaction is a three step process involving:

1. the dissolution of silica at quartz, mica and illitic clay interfaces (stylolites);
2. silica transport by diffusion in the formation water to nearby quartz surfaces;
3. precipitation of silica on these surfaces (Fig. 2).

It is important to stress that the dissolution step is not pressure solution (Bjørkum, 1996), and that under typical reservoir conditions, precipitation is the slowest step, and therefore rate limiting (Bjørkum *et al.*, 1998a). The precipitation rate increases exponentially as a function of temperature and, unlike mechanical compaction, porosity loss by this process is not arrested by overpressure and reductions in effective stress (Bjørkum, 1996). Once overpressure is established in isolated pressure compartments, it will increase beyond the formation breakdown point, and reservoired fluids, including oil and gas, will migrate vertically *via* hydrofracturing (Hubbert & Willis, 1957; Lothe *et al.*, 2005) through anisotropic low-permeability

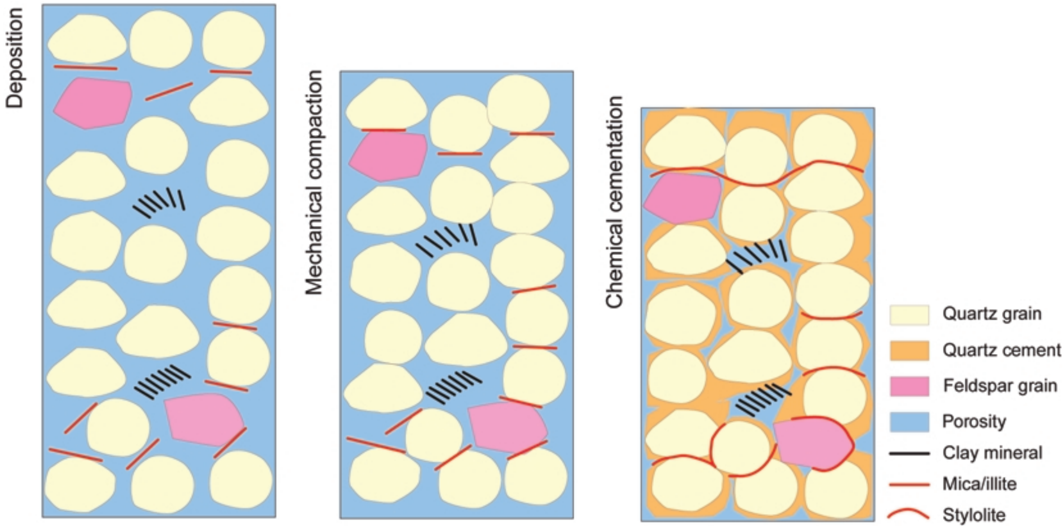

FIG. 2. Diagram of mechanical compaction which predominantly occurs at temperatures <60ºC, and chemical cementation processes which occur at temperatures >70ºC during burial (after Buller *et al.*, 2005).

lithologies, to shallower reservoir entrapment intervals. This last point is extremely important, as will be shown later with regards to overpressured systems. The process is also a function of available quartz surface area, such that finer grained sandstones tend to cement at faster rates. At high temperatures, very coarse grained sandstones can still persist with high porosity and relatively low amounts of quartz cement. The same is true for sandstones with clay coatings, including those with early diagenetic chlorite (e.g. Ehrenberg, 1993; Taylor *et al.*, 2010), which effectively inhibit silica cementation by greatly reducing the amount of available quartz surface area for precipitation.

In unusually clean sandstones with little or no mica and illitic clay, the lack of silica dissolution sites can preserve porosity from cementation to greater depths and temperatures (Walderhaug & Bjørkum, 2003). Also, in sandstones with biogenic and microcrystalline quartz phases, the resulting high-silica concentrations in formation waters, above that of quartz saturation, can locally inhibit the dissolution of silica at stylolites, and thus preserve porosity in these intervals (Aase *et al.*, 1996). These exceptional cases are generally very limited in total stratigraphic extent, with the vast majority of sediments following the more typical increasing cementation with increasing depth and temperature. As a result, the probability of overpressure in fault-segmented basins increases dramatically with increasing depth and temperature. In the North Sea this critical temperature of 120ºC is reached at approximately 4 km depth (Fig. 3). Around this depth, reservoirs typically show a rapid departure from more hydrostatic pressure condition, to very high degrees of overpressure, often approaching lithostatic gradients, and near the leak off pressure limit of the formations.

These reservoirs are often referred to as HPHT, or high-pressure high-temperature reservoirs (Fig. 3). For this lecture we will define HPHT subsurface environments as those >120ºC and >1.4 times hydrostatic pressure gradients (>1.4 g/cm^3 specific gravity (SG) gradient or about >12 pounds per gallon (ppg) drilling mud weights). These values are based on the analysis of reservoir temperature and pressure probability statistics from the Gulf of Mexico (Ehrenberg *et al.*, 2008b), as will be discussed later (Fig. 11a). The petroleum industry typically uses the higher values of 149ºC (300ºF) and ~15 ppg or 1.7 SG pressure gradients to define HPHT drilling environments.

A key geological factor controlling the occurrences of overpressured reservoir compartments is restricted lateral drainage, which is usually facilitated by lateral fault seals in sedimentary basins (Knipe *et al*, 1997; Buller *et al.*, 2005; Nadeau *et al.*, 2005b). Reservoirs lacking lateral seals will remain at normal hydrostatic pressure and high effective stresses, even at high temperatures. These

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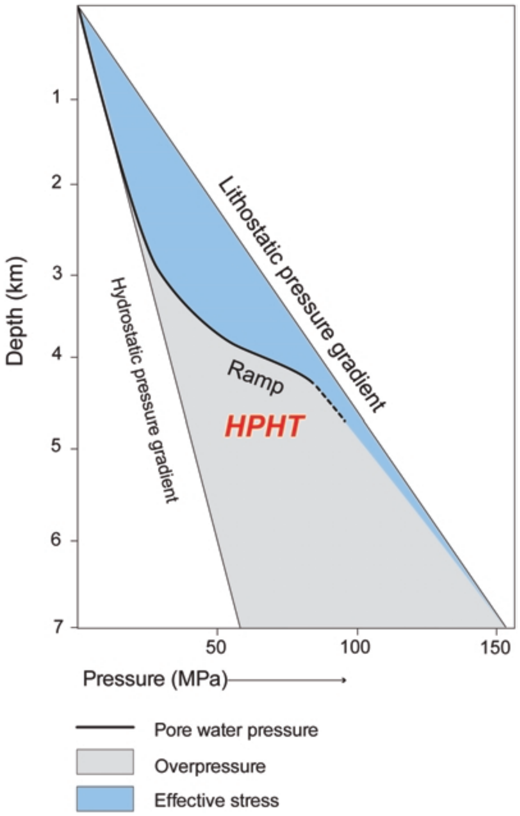

FIG. 3. Generalized depth plot of subsurface pressure regimes on the Norwegian continental shelf. Note that the overpressure pore pressure ramp marks the departure of pore fluid pressure from hydrostatic gradients to lithostatic gradients, with a rapid reduction in the overburden effective stress. This transition ramp marks the onset of high-pressure high-temperature (HPHT) conditions (after Buller *et al.*, 2005).

can be referred to as NPHT, or normal-pressure high-temperature reservoirs, and a notable example is the Smørbukk Field on the Mid-Norwegian Continental Shelf (e.g. Ehrenberg *et al.*, 1992). The oil and gas reservoirs of this giant field are at near normal hydrostatic pressure, despite having temperatures >150ºC. In these situations, reservoir porosity loss by chemical cementation causes hydrocarbon fluids to remigrate by conventional fill-spill migration to shallower reservoirs within the same or similar aged geological formations (e.g. Gussow, 1954), thus preserving the trap integrity. These conventional fill-spill remigration rates are typically one to two orders of magnitude slower than oil and gas remigration from HPHT expulsion zones, because they are driven by porosity loss only within the hydrocarbon-bearing reservoir intervals, rather than porosity loss within an entire HPHT pressure cell, of which typically >90% is saturated with predominantly incompressible formation water. Therefore, determining the impact of sub-surface faults on fluid flow, as well as stratigraphic units, are important components for evaluating overpressure, trap integrity, and the overall exploration potential of these drilling targets.

TEMPERATURE, OVERPRESSURE AND THE DISTRIBUTION OF OIL AND GAS IN SEDIMENTARY BASINS

Enlightened with this understanding of overpressure development, we have undertaken to examine the thermal structure of the Earth's sedimentary basins in order to map the GZ worldwide (Nadeau & Steen, 2007; Steen & Nadeau, 2007). This effort has focused on using high-quality reservoir temperature data, rather than the more numerous but less certain bottom hole temperature data (BHT data, e.g. Hermanrud *et al.*, 1990; for a US Gulf Coast comparison, cf. Nagihara & Smith, 2008, their fig. 2 with Ehrenberg *et al.*, 2008b, their fig. 2) as a basis for predicting the reservoir temperatures of exploration targets. This is very important, because the thermal gradients in sedimentary basins can vary widely, but generally fall between 30º±10ºC/km, which in turn mean that the thermo-chemical overpressure 'ramps' can occur at significantly different depths (Fig. 4).

From the perspective of the GZ concept, the distribution of hydrocarbons in sedimentary basins is the result of dynamic migration from mature source rock maturation areas, as well as remigration of hydrocarbons from overpressured reservoirs. These HPHT structures have completely or partially failed, remigrating most of their oil and gas to the optimal accumulation zone, which we call the GZ (Fig. 5). As basins subside, the GZ remains at a steady state with respect to temperature, with oil and gas entering continually younger geological reservoir intervals through this process of accumulation, overpressure and remigration (Fig. 6). This process can be relatively efficient geologically speaking, particularly in Tertiary delta settings such as the US Gulf Coast. In these settings, with their rapid rates of sedimentation, subsidence,

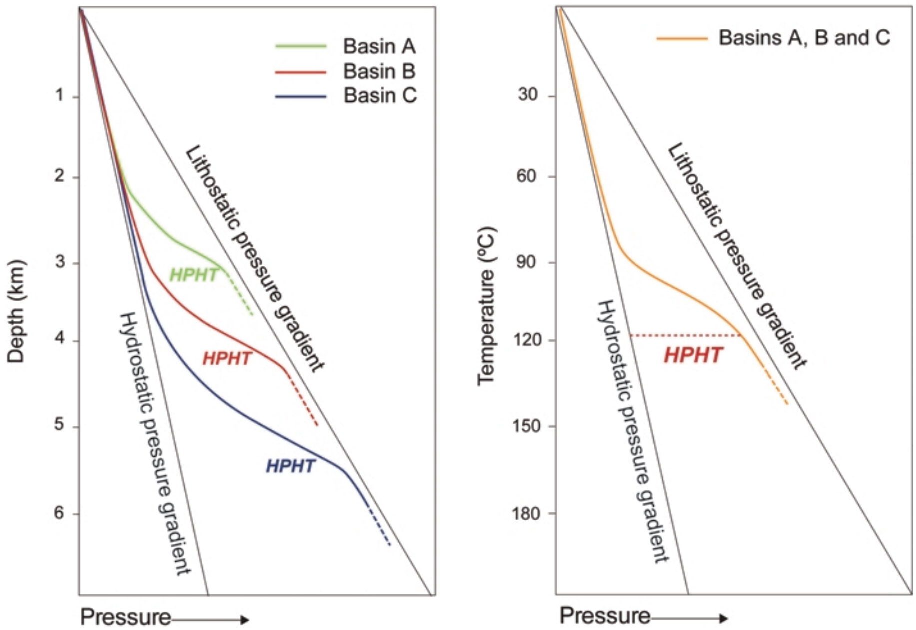

FIG. 4. Idealized pore fluid pressure trends in sedimentary basins, or basin segments, with different geothermal gradients. Note that the overpressure ramps and high-pressure high-temperature (HPHT) conditions occur at different depths, but coincide with the same approximate temperature intervals. The ramps start at about 80º to 90ºC, and reach hydraulic fracture pressure at ~120ºC (after Buller *et al*., 2005).

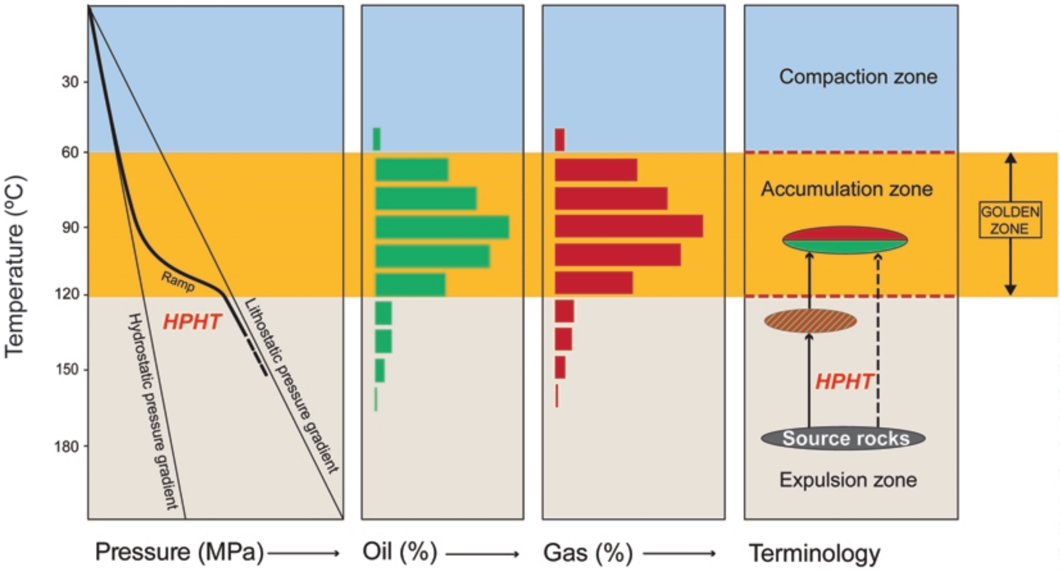

FIG. 5. A composite thermal zonation model for sedimentary basins: the compaction zone <60ºC; the optimum petroleum accumulation zone 60ºC to 120ºC also known as the Golden Zone; the high-pressure high-temperature (HPHT) fluid expulsion zone 120ºC to 200ºC; and the depleted zone >200ºC (after Buller *et al*., 2005).

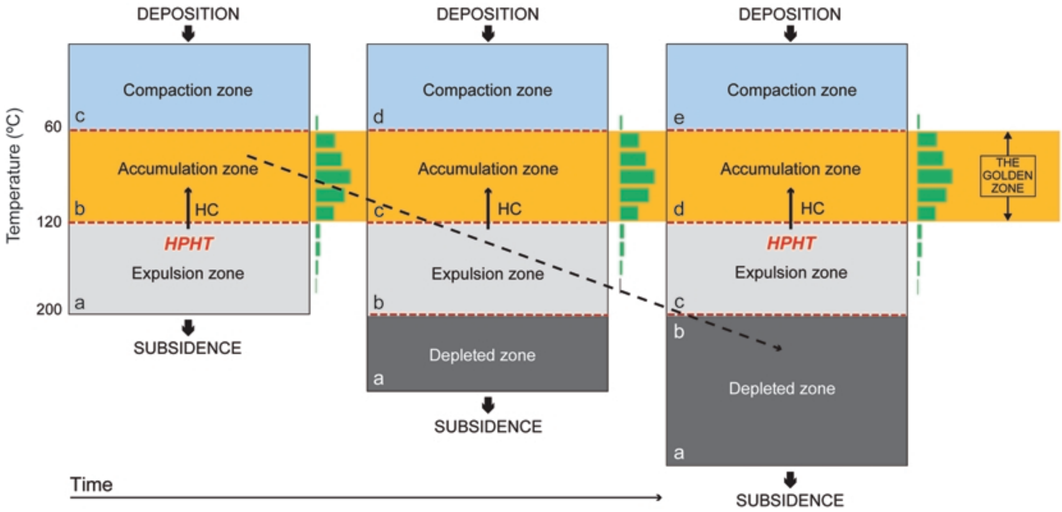

FIG. 6. Diagramatic representation of continuous deposition and basin subsidence showing the progressive evolution of thermal zonation and optimal petroleum accumulation and entrapment in sedimentary basins. As petroleum reservoir sequences (b) with geological lateral seals become more deeply buried and enter the HPHT (high-pressure high-temperature) expulsion zone, their hydrocarbons will remigrate vertically to create new reservoir intervals (c, d) such that the majority of oil and/or gas reserves will always be concentrated in the Golden Zone of 60ºC to 120ºC (after Buller *et al*., 2005).

accommodation and burial, earlier expelled oil phases can be combined with later expelled high-maturity gas, which vertically remigrate together through successive reservoir levels long after the hydrocarbon source rocks are over-mature and thermally depleted. The presence of younger reservoirs is facilitated by continual sea-level fluctuation cycles (e.g. Vail *et al.*, 1977) which conveniently provide successive regressive low-stand sandstone reservoir units, overlain by transgressive high-stand marine shales and mudstone sealing lithologies.

In the North Sea, the impact of these geological processes can be observed on the distribution of GZ giant fields in rotated fault block trap Jurassic reservoirs (Fig. 7). The occurrence of HPHT Jurassic in deeper environments is also observed, as well as the occurrence of younger Tertiary reservoirs such as the Frigg oil and gas field, over large HPHT Jurassic structures. The importance of faulting can also be seen in facilitating segmentation and the formation of pressure compartments between fault blocks. Because the Jurassic source rocks, such as the Kimmeridge and Draupne marine shales, occur in close association with the Jurassic Brent sandstone reservoirs (Fig. 7), it could be inferred that overpressure mainly results from hydrocarbon generation (e.g. Hunt, 1990). Although this thermally driven process certainly can contribute to overpressure generation, particularly in source rock lithologies, it is volumetrically insignificant when compared with cementation and compaction porosity loss at basin scale (e.g. Bjørkum & Nadeau, 1998; Darby *et al.*, 1998; see also below for US Gulf Coast).

We will now examine the scientific observations of the petroleum industry collected over the last century regarding the nature and distribution of hydrocarbon reserves in sedimentary basins in order to better evaluate the GZ concept. In an unprecedented search for energy, and after having acquired the drilling technology to reach GZ depths around the turn of the century (e.g. Hughes & Sharp, 1909) the industry invested trillions of dollars, drilled millions of wells, and discovered over 100,000 reservoirs containing the oil and gas reserves that we now rely on. These data have been summarized with respect to reservoir temperatures (Nadeau *et al.*, 2005b) and show the following (Table 1). Despite the fact that ~40% of all exploration wells are drilled to depths >120ºC isotherm (Nadeau *et al.*, 2005b), and that over 70% of the world's petroleum-producing basins are over-explored with respect to temperature (Nadeau

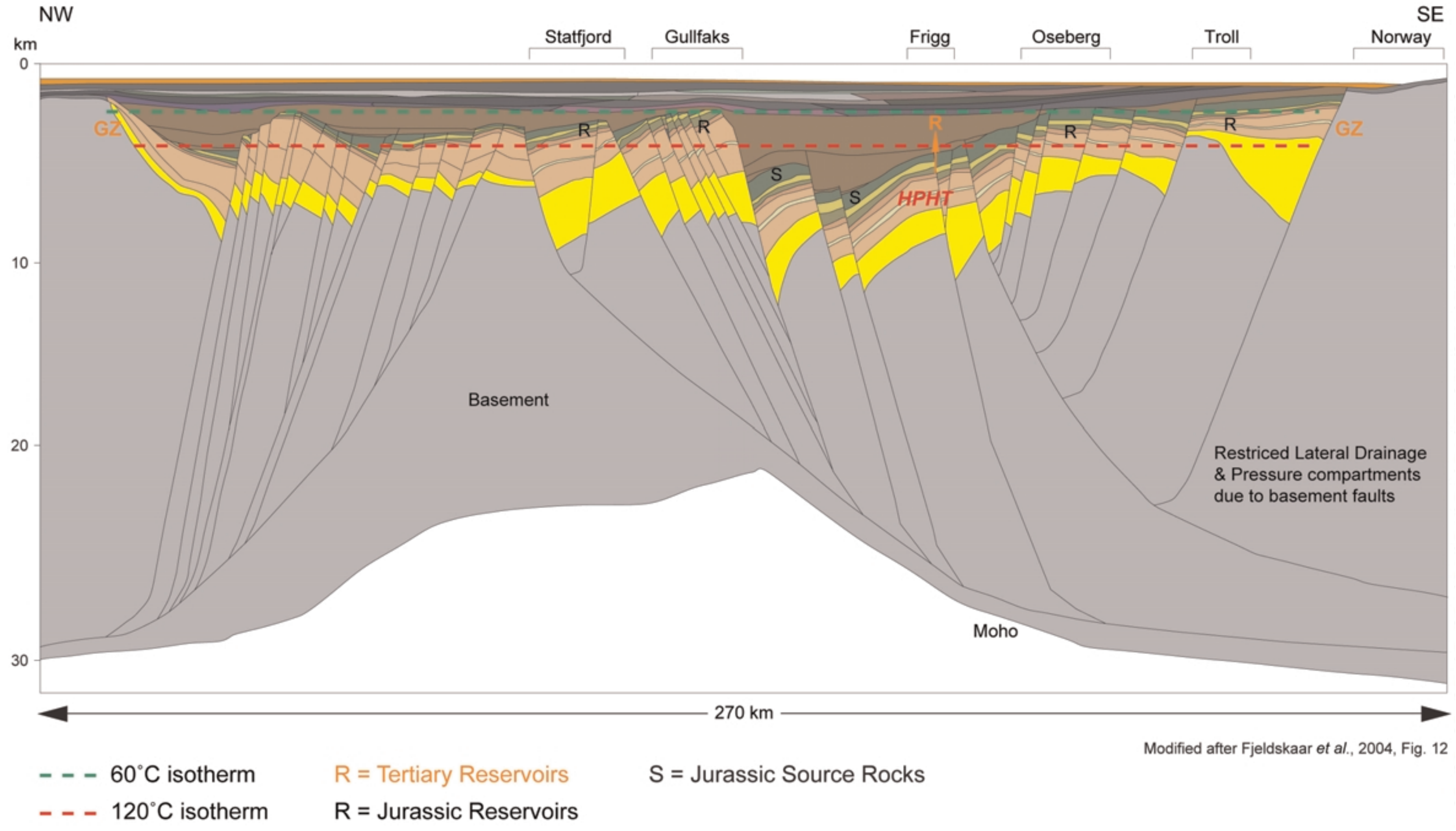

FIG. 7. Geological cross-section of the North Sea graben (modified after Fjeldskaar *et al.*, 2004) showing the giant Golden Zone oil and gas fields within the approximate 60ºC and 120ºC isotherms for this basin. Note the intense faulting caused by the partial rifting and thinning of continental crust from about 30 km thick to 20 km in the centre of the graben. Note also the large HPHT (high-pressure high- temperature) Jurassic structure underlying the younger Tertiary Frigg oil and gas field (projected from the south onto the line of section), which is shown charged from reservoirs and source rocks in a failed HPHT Jurassic fault block within the expulsion zone >120ºC.

TABLE 1. Distribution of global conventional petroleum reserves.

Reservoir temperature	Oil reserves (%)	Gas reserves (%)
<60ºC Compaction zone	12	40
60–120ºC Golden zone	85	50
>120ºC Expulsion zone	3	10

et al., 2006a,b; Nadeau, 2008), only 3% of the worlds conventional oil and ~10% of the worlds conventional gas reserves occur in reservoirs >120ºC. These statistics are significant, because not only do they show that most of the world's conventional oil and gas reserves occur within the GZ, but also that the expulsion of hydrocarbons from thermal regimes of ~120º to 200ºC normally associated with oil and gas generation into the shallower GZ reservoir entrapment levels is highly efficient. It also demonstrates the predominance of GZ type hydrocarbon migration for the accumulation of conventional oil and gas reservoirs, relative to other mechanisms such as fill-spill migration.

Fill-spill hydrocarbon migration predicts that oil is more likely in shallow accumulations and gas in deeper accumulations, predominantly within the same stratigraphic intervals. This migration was described by Gussow (1954) for Western Canada, and has been recognized in other sedimentary basins which have reservoir sequences with mainly open lateral drainage. These include the Pliocene productive series in the Azeri segment of the South Caspian Basin (Narimanov, 1993), where biodegraded oils are found in reservoirs as shallow as 20 m. The world's first oil well is recorded to have been drilled near Baku in 1846, more than a decade before the famous 1859 Colonel Drake oil well in Titusville, Pennsylvania, to nearly the same depths. Similarly, lateral fill-spill migration within foreland basin settings is responsible for the occurrence of ~1.7 trillion barrels of in-place extra heavy oil in the Western Canadian oil sands deposits, as well as the about one trillion barrels in Eastern Venezuela (Roadifer, 1987). Unfortunately, most of this oil eluded entrapment at optimal GZ levels, partly due to the lack of lateral seals and effective confining faults at the basin scale (Nadeau *et al.*, 2005b, 2006). These heavy biodegraded oil reserves typically occur in shallow <60ºC compaction zone reservoirs. The oils are more viscous and require more energy to produce, e.g. in the form of steam assisted recovery, and also have lower reservoir recovery efficiencies, ~20% of in-place reserves, as compared with ~50% and higher for most GZ medium and light oil reservoirs.

At this point it is important to acknowledge that the GZ view for overpressure development is not shared by most basin modellers. The commonly held view by analysts, as implemented in these numerical simulation basin models, is that mechanical compaction disequilibrium is dominantly responsible for overpressure generation (e.g. Bethke *et al.*, 1988; Giles *et al.*, 1998), in combination with low permeability shale aquitards which are crucial components of overpressure (Bjørlykke *et al.*, 2010). These models rely on rapid sediment loading, as is common in geologically young deltas such as the US Gulf Coast, to generate and maintain overpressure. This 'paradigm' has been applied with varying success to other basins world-wide, including the North Sea (e.g. Vejbæk, 2008). Even these workers acknowledge, however, that this rock mechanics paradigm is mechanistically incorrect (Waples & Couples, 1998). Despite attempts to incorporate thermal porosity loss functions in basin simulators (e.g. Borge, 2002; Hermanrud *et al.*, 2005; Lothe *et al.*, 2005), most practitioners apply mechanical compaction porosity-effective stress analysis, as well as pressure transfer mechanisms to explain overpressure in sedimentary basins. Even in high geothermal gradient and partially uplifted basins such as the Baram province of Brunei, SE Asia, the occurrence of shallow overpressure is proposed to originate from mechanical compaction and lateral pressure transfer mechanisms at basin scale (Tingay *et al.*, 2009). The Baram province is characterized by variable and very high geothermal gradients, where 30% of the reservoirs have geothermal gradients in excess of 75ºC/km (Steen, pers. comm.). Certainly, thermo-chemical related porosity and permeability loss processes as described here would appear to be responsible for the generation of shallow and high levels of overpressure encountered in this and similar basin settings.

Petroleum systems modellers often consider that the GZ is simply a result of source rock maturation kinetics (i.e. the oil window, e.g. Radke *et al.*, 1997). The fact that the GZ oil and gas reservoir volume distributions apply equally well to basins such as the North Sea with relatively low rates of burial and heating, as well as to basins with extremely high rates of burial such as the US Gulf Coast (Nadeau *et al*., 2005b) does not support that view. The global energy reserves data are also inconsistent with that position. Around 97% of oil reserves and 90% of conventional gas reserves occur in reservoirs <120ºC (Table 1), despite the fact that most gas is thought to be generated in ~120º to 200ºC thermal regimes. In addition, fluid overpressure, from thermodynamic and experimental phase relationships, is shown to retard hydrocarbon generation and expulsion from source rocks to temperatures greater than the generally held value of 130ºC for peak oil, and even higher temperatures for gas (Carr, 1999; Carr *et al*., 2009). Others may call upon oil-to-gas cracking reactions (e.g. Waples, 2000) to explain the distribution. But as discussed above, HPHT conditions should increase the oil phase stability field, not reduce it (see also Bjørkum & Nadeau, 1998). Furthermore there are numerous examples of conventional NPHT or normal-pressure high-temperature oil reservoirs at temperatures >120ºC (Nadeau *et al*., 2005b), the Smørbukk Middle Jurassic Tilje oil reservoirs at temperatures of ~165ºC being a notable Norwegian example (Ehrenberg *et al*., 1992; Ehrenberg, 1993).

The fact that most oil reserves in carbonate reservoirs also are also found in the GZ (Darke *et al*., 2004) could call into question its diagenetic basis, because it is mainly derived from chemical reaction models for siliciclastic rocks. In fact, ~75% of global discovered carbonate reservoired oil *and* gas reserves occur within the narrow thermal interval of 80ºC to 120ºC. Comparison of porosity data for sandstone and carbonate reservoirs world-wide (Ehrenberg & Nadeau, 2005) show that the overall trends of porosity loss have similar depth relations, and that carbonate cementation at temperatures exceeding ~80ºC may be controlled by diagenetic reaction pathways in much the same manner as for sandstones and siliciclastic rocks (Nadeau *et al*., 2005a; Nadeau & Ehrenberg, 2006).

Here it is also important to note that a significant number of the Earth's sedimentary basins have undergone uplift and erosion. In these cases, the GZ reservoirs are uplifted (Fig. 8) and, dependent on the geothermal gradient, seal integrity, geological timing, and tectonic style, they can withstand up to ~1 km of uplift and erosion, and still remain prospective. Greater amounts of uplift often result in severe gas expansion, oil spillage/leakage, reduced effective stresses and ultimately trap failure (e.g. Doré & Jensen, 1996). The reduced basin temperatures deactivate source rock hydrocarbon generation and the expulsion zone (Fig. 8), which also has a negative impact on the exploration potential. The reservoir data in Table 1 include uplifted basins. From these, it can be deduced that uplifted basins are less prospective for oil and have a higher probability for gas, than basins which are at present-day maximum burial. Indeed, many of the world's first petroleum discoveries were made in such basins, where geological forces brought oil and gas reservoirs within reach of rudimentary drilling technology. The Appalachian foreland basin of the Eastern US is a notable example (Ziegler, 1918; Beaumont *et al*., 1987). The Norwegian Barents Sea, which contains about 3% of Norway's oil and gas reserves, has been uplifted and eroded by ~1.2 km, where the present-day GZ extends from ~0.5 to 2.5 km (Fig. 8, middle scenario).

In basins uplifted by ~2 km and more, the importance of pronounced diagenetic clay permeability reduction, and the retention of overpressure during and after tectonic uplift, may play a key role in the economic recovery of gas from mature source rock intervals in deactivated former HPHT expulsion zones. The importance of such onshore unconventional shale gas production in North America, including the Palaeozoic Barnett, Fayetteville, and Marcellus shales, is being felt world-wide (e.g. Jarvie *et al*., 2007; Kuuskraa, 2009). Diagenetic clay and its controls on rock properties, including the retention of overpressure after tectonic uplift and erosion, as observed for Jurassic and Cretaceous shales in the North Sea (Nadeau *et al*., 2002a,b) and in the Jurassic Opalinus clay intervals of the Molasse Basin, Western Europe (Marschall, *et al*., 2005; Mazurek *et al*., 2006), may be, therefore, important drivers in hydrocarbon recovery rates as well as recovery efficiency in these emerging global resource plays.

Glacial Pleistocene climate changes over the last million years have also influenced the distribution of global oil and gas reserves with respect to temperature, mainly in ice-free high latitude and arctic basins. Reductions in mean surface temperatures by up to ~25ºC lowers reservoir temperatures by ~15ºC to depths of 5 km after repeated Pleistocene glacial cycles (e.g. Makhous &

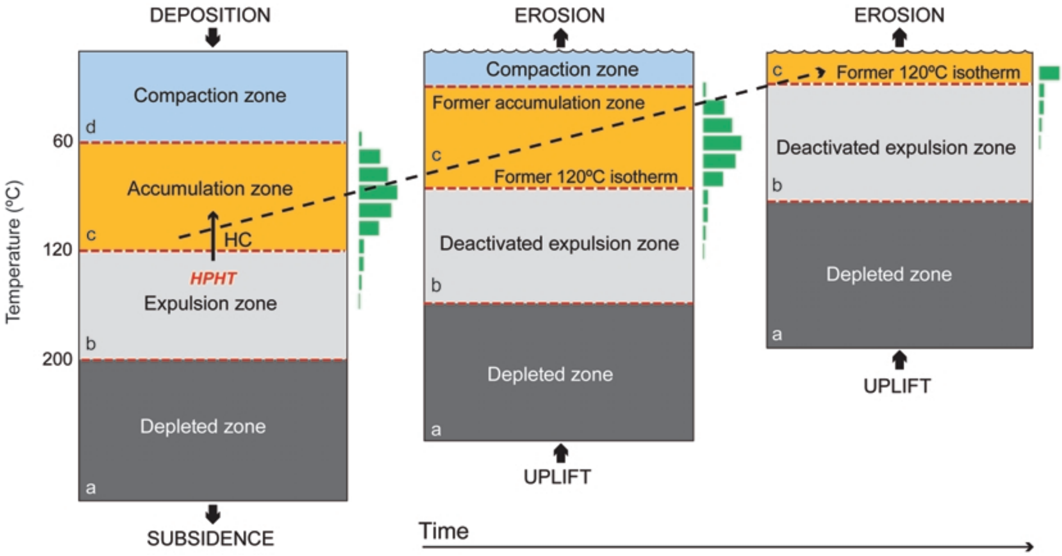

FIG. 8. Diagramatic representation of uplift and erosion of a sedimentary basin containing an optimal petroleum accumulation in the Golden Zone. As the zone enters shallower depths with lower fluid pressure, overburden confining stress and lower temperatures, the Golden Zone will become more gas dominated as fluids expand and oil is lost. In these basins the expulsion zone is deactivated by reduced temperatures such that oil and gas generation ceases. In severe cases the Golden Zone is destroyed by reduced confining pressure and surface processes (after Buller *et al*., 2005).

Galushkin, 2005). Warm interglacial periods, such as our current climate, typically last ~10,000 y, which is much shorter than the ~100,000 y glacial periods. In these basins, therefore, our current interglacial climate has had little effect on conventional reservoir temperatures. As such, many of our high-latitude oil and gas reservoirs are still within thermal regimes established by Pleistocene glaciations. A notable example is West Siberia, thus far the only oil super province (>100 billion barrels conventional oil reserves) discovered outside of the Middle East. In this basin, the current 95ºC isotherm approximates the palaeo 120ºC isotherm at maximum burial and temperature (Nesterov *et al*., 1990) and, as predicted by the GZ concept, relatively minor amounts of oil and gas reserves are found deeper than this level. About 60% of the reservoir temperature reduction can be related to glacial climate change (Makhous & Galushkin, 2005); the remainder can be attributed to several hundred metres of uplift and erosion. Therefore, former HPHT overpressure conditions in high-latitude arctic basins can occur within currently lower thermal regimes that are today HPNT, or high-pressure normal-temperature environments.

THE US GULF COAST AND THE GOLDEN ZONE

When the GZ concept was first proposed based on North Sea research (Bjørkum & Nadeau, 1996) it was widely thought to be only locally valid. The North Sea oil province has predominantly Jurassic syn-rift sandstone reservoirs, with relatively low rates of sedimentation and burial. Younger post-rift Cretaceous and Palaeogene Tertiary accumulations are found mainly above deeper Jurassic HPHT compartments. In the late nineties, a concerted effort was made to compile reservoir data world wide to further evaluate the GZ concept. The US Gulf Coast was a focus area for this effort, in part because it is characterized by extremely high rates of sedimentation and burial, having predominantly very young Neogene Tertiary reservoirs (Fig. 9). It also has the largest and most comprehensive publicly available offshore reservoir database in the world (Ehrenberg *et al*., 2008b) and as such is unaffected by uplift and erosion, except for a few isolated occurrences such as certain reservoirs in the Perdido foldbelt. It was thought that in a basin so dominated by rapid burial and mechanical compaction, thermal

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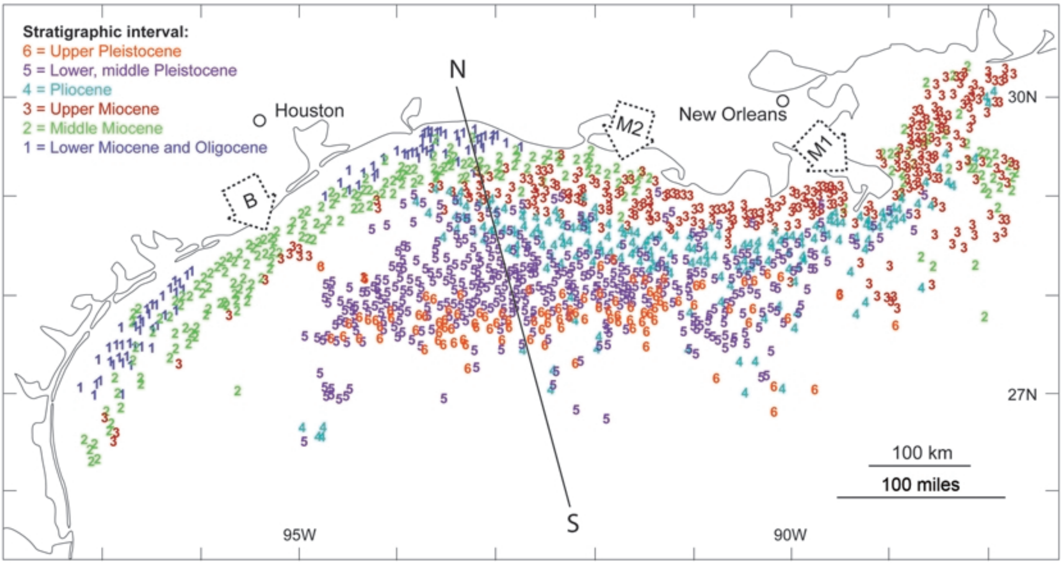

FIG. 9. Map showing the geological ages and spatial distribution of US Gulf Coast reservoirs (after Ehrenberg *et al*., 2008b). The pattern represents the reservoir ages which are predominantly within the Golden Zone across the basin, which is controlled mainly by the geothermal gradients and the sedimentary burial from the Mississippi River system arrows 'M1' present day and ~Miocene time and 'M2' mainly in Pleistocene time, and to a lesser extend the Brazos River system arrow 'B' along the Texas coast. The Golden Zone model is unique in its ability to explain this pattern of discovered reservoirs. The line N-S shows the approximate location of the geological cross section in Fig. 10.

chemical process would be only of minor importance. It was unexpected, therefore, to observe that ~90% of the oil and 80% of the gas reservoirs occur within the GZ (Nadeau *et al.*, 2005b), despite the relative exploration maturity of the shallow water shelf areas at that time.

The distinctive pattern of reservoir ages in Fig. 9 reflects this distribution, and the GZ concept is thus far the only oil and gas migration and accumulation model that can predict it. The US Gulf Coast, therefore, provides a rigorous validation of the GZ concept as well as its founding geological diagenetic process models. The reservoir age pattern reflects an overall decrease in age of offshore reservoirs, mainly from Miocene to Pleistocene in the outer shelf, and then back to Miocene and older reservoir plays in deep-water environments. This distribution is in response to:

1. generally decreasing geothermal gradients in deep-water environments;
2. sediment input variations through time, mainly from the Mississippi River and to a lesser extent the Brazos River systems (Fig. 9);
3. variable surface temperatures related to water depth (Fig. 10, see also Ehrenberg *et al*., 2008b, their fig. 3).

The GZ concept predicts that HPHT environments should dominate deeper than the 120ºC isotherm (Fig. 10). This can be compared with basin simulations based on mechanical compaction disequilibrium, which predict high-pressure environments in areas of rapid Pliocene-Pleistocene sedimentation loading rates (e.g. Summa *et al*., 1993, their fig. 8). Despite the high sedimentation rates, allochthonous salt tectonics and dynamic fluid migration, the thermal structure of the basin is generally well behaved with respect to reservoir temperature, play segment burial depth and water depth (Ehrenberg *et al*., 2008b, their fig. 2). It is important to remark here that although there is a general trend of decreasing geothermal gradients in deeper water environments, there are notable deep-water thermal anomalies of ~50% (Steen, pers. comm.) that should also be considered when making geological evaluations for exploration potential and overpressure prediction.

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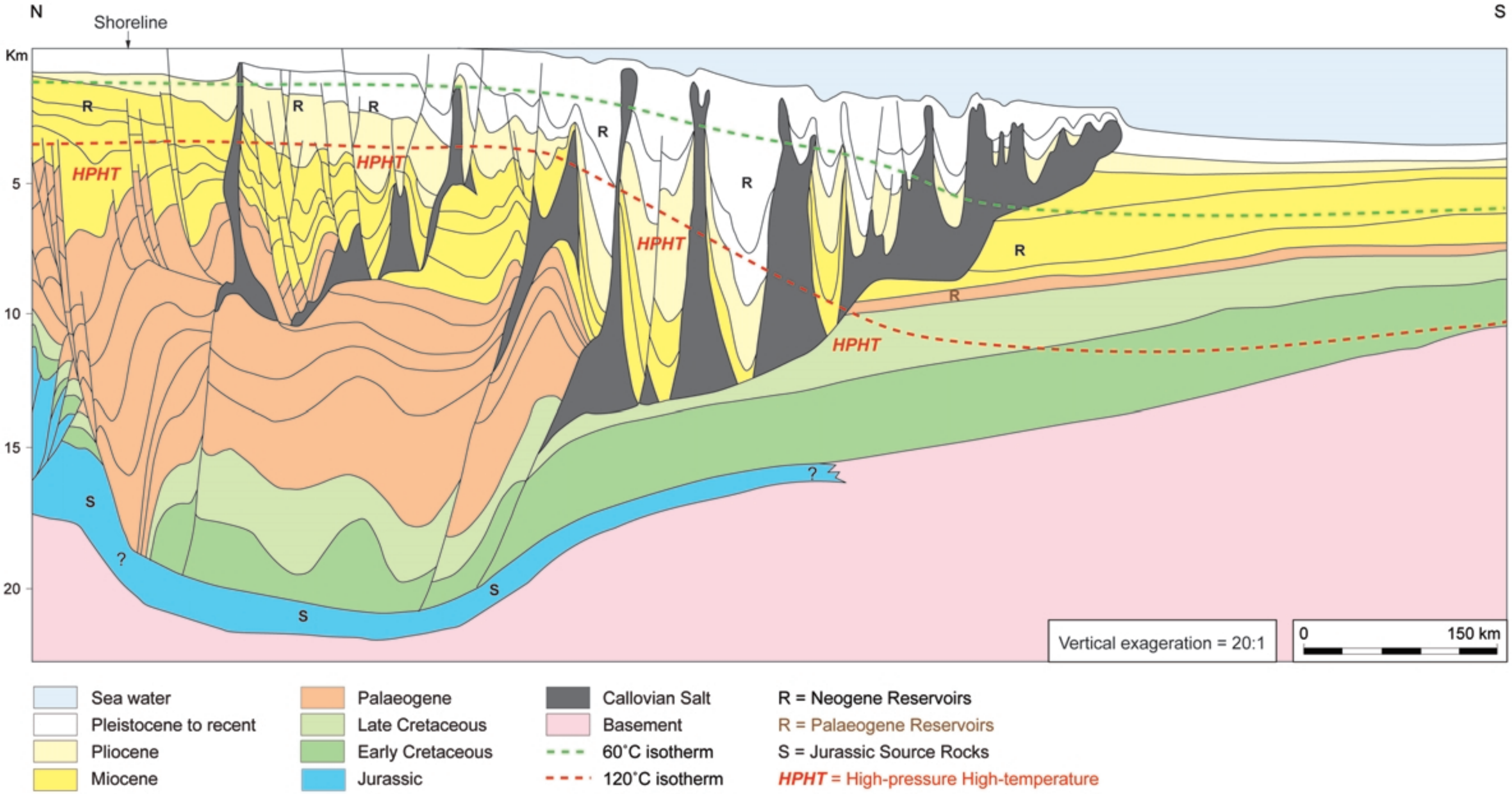

FIG. 10. Generalized geological cross-section of the US Gulf Coast showing the complex relationships of stratigraphy and salt movement tectonics resulting from the very rapid sediment burial rates in this basin (modified after Peel *et al.*, 1995). The approximate locations of the 60ºC and 120ºC isotherms of the Golden Zone are also shown (Steen, pers. comm.), and demonstrate how the dominant reservoir play ages in Fig. 9 occur within the predicted optimal accumulation zone temperature interval. Note how the Golden Zone deepens and thickens to the south, in response to lower geothermal gradients and surface temperatures (see also Ehrenberg *et al.*, 2008b), such that older reservoirs re-enter the Golden Zone in deep water environments (see text).

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The GZ concept predicts that deep overpressure in sedimentary basins is mainly the result of thermo-chemical porosity and permeability reduction rates, which are exponential functions of temperature (Bjørkum & Nadeau, 1996, 1998). Although the amount of cement, and therefore the *amount* of porosity reduction, is the integral of thermal exposure over geological time, the *rate* of porosity reduction is *directly proportional to temperature*. For overpressure development, it is the *rate* of porosity loss and the seal permeability that dominates the fluid pressure calculations. Therefore, the North Sea provides a better geological 'laboratory' for quantifying the cementation process, because sufficient geological time had elapsed to form readily measurable amounts of quartz cement. The Gulf Coast, on the other hand, is extremely young, so although the rates of quartz cementation are extremely high, insufficient geological time has elapsed for most of the reservoir sequences to form readily measurable amounts of quartz cement (Ehrenberg *et al.*, 2008b, their table 4). It should be in theory, therefore, the best basin to test the GZ concept. Furthermore, overpressure is observed in mainly younger Neogene Tertiary rocks, whose organic matter has been greatly diluted by rapid clastic sediment input. This reduces the probability of hydrocarbon generation as the cause of overpressure. Here, the petroleum system's oil and gas discoveries are sourced predominantly by deeply buried Jurassic marine shales, which thermally matured long before most of the present-day reservoirs were deposited (Fig. 10; cf. McBride *et al.*, 1998).

To evaluate this hypothesis, the relationship of reservoir pressures *vs.* temperature and burial sedimentation rates were examined and compared (Fig. 11). Here it is important to recall that reservoir overpressure also requires restricted lateral drainage, meaning that the reservoirs have to be laterally sealed, as well as top sealed by low permeability shales. This is normally accomplished by the presence of fault-bounded pressure compartments in sedimentary basins (Nadeau *et al.*, 2005b). Even with this important proviso, the Gulf Coast data show that the median, P50, reservoir pressure probability is for normal or near hydrostatic pressures to occur at temperatures <60ºC, despite

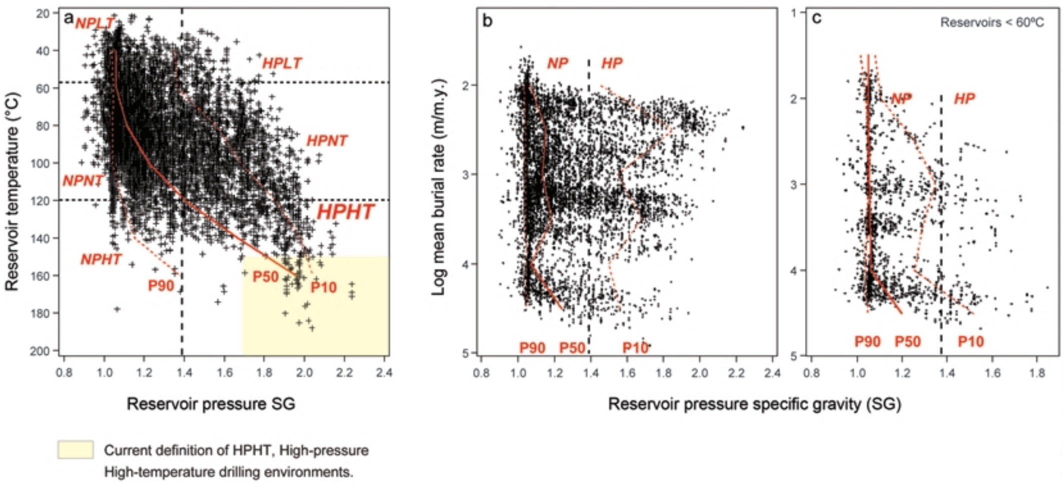

FIG. 11. US Gulf Coast reservoir data (n =11864) showing the distribution and probability statistics for temperature *vs.* pressure in specific gravity (SG) units (a) and burials rates (b and c). Note that the median P50 probability increases exponentially at temperatures >60ºC, such that at >120ºC the P50 is >1.4 SG and it enters the HPHT expulsion zone. Temperature *vs.* pressure is utilized rather than depth because thermal gradients in this basin vary widely, between 14ºC and 36ºC per kilometre (Ehrenberg *et al.*, 2008b). Note also the inverse logarithmic scale on the burial rate *vs.* pressure. The overpressure probability statistics show little to no relation to this indicator of mechanical compaction rates, with the exception of the P10 probability for reservoirs in the <60ºC zone (c) at burial rates >100 metres per million years (log scale >2, see text). The current industry definition of HPHT drilling environments is shown on (a) for comparison, in the yellow shaded area. Less than 1% of the discovered reservoirs fall into this current definition.

the extreme rates of porosity loss in this compaction zone. At >60ºC the probability of overpressure begins to increase, at first gradually and then more rapidly, such that at temperatures >120ºC, the P50 is increasing exponentially, with 50% of the reservoirs having pressures >1.4 times that of hydrostatic gradients. We use this gradient, therefore, to distinguish between normal and high-pressure environments.

Readers who are unfamiliar with temperature *vs.* pressure analysis of very large date sets should note that most of these reservoir observations are normally pressured, in spite of the extremely high rates of burial and sedimentation. That is why the calculated probability distributions are also included in Fig. 11. In fact, 79% or about four out of five GZ reservoirs are NPNT, as compared to 64% HPHT or about two out of three reservoirs in the expulsion zone (Table 2). This means that the risk of high-pressure reservoirs increases by a factor of three, or 300%, at temperatures >120ºC.

When we examine reservoir pressure *vs.* the mean sedimentation burial rates, we find that there is little if any relationship with the pressure probability distributions. The burial rate scale is inverse logarithmic in order to compare with the reservoir temperature (Fig. 11b,c). These are among the highest burial rates in the world, up to ~10,000 m/m.y. (log scale 4 to 5). By comparison, North Sea burial rates are orders of magnitude lower, generally 10 to 100 m/m.y. (log scale 1 to 2). The older, mainly Miocene, reservoirs at the top of Fig. 11b have, if anything, a higher probability of overpressure compared with the extremely young and rapidly buried Pleistocene reservoirs at the bottom. In fact the data show general repeating trends where the burial rate of any given reservoir age class required to reach the 120ºC isotherm is where high pressure is predominantly observed. Older reservoirs generally reach this isotherm at smaller burial rates than do the younger reservoirs, as can be observed in the P10 probability distribution (Fig. 11b). Thus the P10 actually shows an overall *decrease* in pressure with increasing burial rates.

TABLE 2. Distribution of reservoir overpressure: US Gulf Coast.

Reservoir temperature	Normal pressure	Overpressure SG >1.4
<60ºC Compaction zone	95% NPLT	5% HPLT
60–120ºC Golden zone	79% NPNT	21% HPNT
>120ºC Expulsion zone	36% NPHT	64% HPHT

The astute observer of Fig. 11a will also note that in the compaction zone at <60ºC there are a few HPLT reservoirs. The P5 probability is 1.4 SG, that is to say that 5% of the pressure observations are >1.4 times the hydrostatic pressure gradient (Table 2). There is a tendency for these observation to originate from reservoirs with burial rates >100 m/m.y. (log value >2, Fig. 11c) so here mechanical compaction disequilibrium is the most likely overpressure mechanism. This is not surprising, given the very large porosity reductions in this mechanical compaction zone, from about 40% to 25% porosity for sandstones and around >50% to <20% for shales (Giles *et al.*, 1998). These shallow reservoirs predominantly contain dry gas, formed from bacterial activity, which is referred to as biogenic gas, or exsolution gas from rising formation waters entering lower pressure regimes (Nadeau *et al.*, 2005b). The pressure data also demonstrate that some of these reservoirs have restricted lateral drainage, even at relatively shallow levels of burial. Nearly 95% of these reservoirs have normal or moderate overpressure, which indicates that shale permeabilities in this zone are relatively high, in the micro-Darcy range, or sufficient to facilitate the escape of compaction-driven formation water under mainly hydrostatic pressure conditions.

The GZ concept suggests that the discovered Gulf Coast oil and gas fluids have remigrated vertically several times to reach their current stratigraphic levels, given the very high sedimentation rates (Nadeau *et al.*, 2005b, 2006; Nadeau, 2008). The impact of this remigration can also be seen on the gas-to-oil ratio (GOR) of these reservoir fluids (Fig. 12, where shallow dry gas reservoirs have been excluded). The predominantly remigrated oil reservoirs (GOR <10 Mft^3/barrel) and the predominantly remigrated gas reservoirs (GOR >10 Mft^3/barrel) occur mainly in the GZ between 60ºC and 120ºC, forming a phase separation envelope over the HPHT expulsion zone, which predominantly consists of a relatively small number of partially failed traps with high GOR

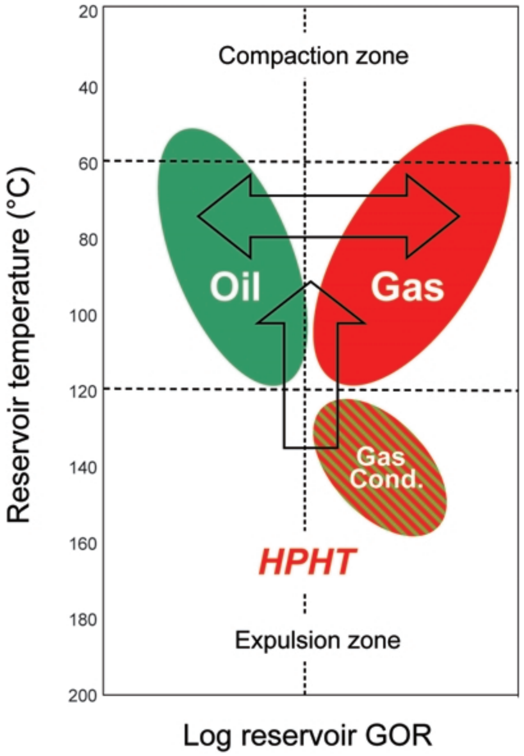

FIG. 12. Idealized petroleum vertical remigration and phase separation of conventional oil and gas reserves from the HPHT expulsion zone into the optimal accumulation Golden Zone. The HPHT expulsion zone is typically populated with smaller gas-condensate reservoir accumulations. This gas-to-oil ratio (GOR) remigration signature, which varies by several orders of magnitude, is present in most sedimentary basins, including the North Sea and the US Gulf Coast, where reservoir sequences have predominantly restricted or confined lateral drainage (see also Nadeau *et al*., 2005b). The separation between oil and gas occurs at ~10,000 ft^3/barrel, which is also the approximate GOR for this basin, and about twice the global average.

gas-condensate reservoirs. The likely reason for the high GOR critical gas-condensate HPHT reservoir fluids is that only liquids dissolved in the gas phase can exist in these dynamically charged and partially failing traps. Any liquid phase in the sub-surface HPHT reservoir is rapidly remigrated via the dynamic spill point at the gas/water contact established by the hydraulic fracture failure point, and then migrated to shallower reservoirs or leakage environments (Figs 5 and 12). Similar patterns are observed in most basins, including the North Sea, but with far fewer observational data points. In fact, one can speculate that if Gulf Coast exploration were to occur several million years from now, these oil and gas fluids would be discovered in reservoirs which have not yet been deposited. Such insights would not be provided by conventional Petroleum System concepts, namely critical moments (Magoon & Dow, 1994) which predict that only geological traps present at the time of source rock expulsion should contain these oil and gas fluids. Most basin analysis methods in use today still lack these important GZ processes and insights.

It should also be noted here that for deep water marine fan reservoir plays, the probability of overpressure, particularly within the GZ, is greater than that for the overall data set, which includes more laterally extensive shallow water progradational reservoirs (Nadeau *et al*., 2005b; Ehrenberg *et al*., 2008b). Therefore, drilling operations for these deep water targets should be prepared for HPNT or high-pressure normal-temperature conditions, which is probably also related to the higher shale to sand ratios in these depositional settings. This is particularly important, because some of the largest oil discoveries have been made in these drilling environments, where both mechanical compaction and chemical cementation processes contribute to overpressure risks.

IMPLICATIONS FOR THE BEHAVIOUR OF HPHT SYSTEMS

The predictive power of the GZ concept is unique with respect to its ability to quantify exploration risks, particularly for overpressure development and for HPHT environments. Therefore, understanding the geological processes responsible for the occurrence of HPHT reservoirs is vital in order to properly assess these risks as well as increase exploration efficiency.

An important aspect of the GZ concept deals with the behaviour of overpressured systems in the sub-surface. Mechanical compaction disequilibrium models typically assume that once overpressure is established, further porosity loss can only be facilitated by diffusive fluid migration through the sealing lithologies (e.g. Waples & Couples, 1998). This is due to the negative feedback caused by the inverse relationship between overpressure and effective stress (Fig. 3) which drives mechanical compaction. Sediment 'undercompaction' at

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shallow levels of burial is commonly attributed to this behaviour.

In contrast, the GZ concept has no such negative feedback. The porosity loss is controlled by, and an exponential function of, temperature. Once overpressure is established, it can increase through the fracture initiation (leak off) and formation breakdown points, to the fracture propagation pressure, so as to hydraulically fracture non-isotropic sealing lithologies (e.g. Hubbert & Willis, 1957; Bjørkum & Nadeau, 1998; Hermanrud *et al*., 2005). The resulting dynamic expulsion of fluids, including oil and gas, is the driving force which creates and maintains the GZ as a steady state distribution with respect to temperature. Therefore, the GZ concept also predicts that there are low probabilities, but finite risks particularly in HPHT environments, for encountering such fracture zones during exploration and production operations.

SUMMARY AND CONCLUSIONS

Thermo-chemical mineralogical processes have been established as the important controls of porosity and permeability evolution in sedimentary basins. These geological processes, when combined with petroleum system considerations, result in optimal entrapments for conventional oil and gas reservoirs in narrow thermal intervals, generally between 60º and 120ºC. Given typical basin thermal environments, this zone is between 1.5 to 3 km in thickness, averaging about 2 km, and controlled by surface temperatures, geothermal gradients, and the burial history.

In terms of entrapment efficiency and exploration risks, the GZ concept encourages a very selective, sub-surface geological approach, for assessments of the undiscovered potential, optimal basin segments, and play types (Nadeau *et al*., 2006a,b). In terms of global economic energy policies, the concept encourages effective resource conservation measures, and greatly increased energy efficiency to ensure that our remaining high-value conventional oil and gas resources are broadly available at moderate costs to facilitate economic growth within the limits of those supplies, and the Earth's environmental capacity to sequester atmospheric carbon. (Nadeau, in prep.).

Compilation of extensive reservoir, well, environmental and other geological information used to evaluate the GZ concept has resulted in basin as well as global analysis methods for the:

1. distribution of reservoir and rock property parameters;
2. occurrences of conventional oil and gas reserves with respect to depth, temperature and pressure, as well as;
3. geological processes and controls for 1. and 2.

These extensive data sets can also be applied to examine the impact and relationships of sea level, climatic, and tectonic cycles on the Earth's weathering, erosion and sedimentary systems, as well as the distribution of oil and gas reservoirs over geological time (e.g. Ehrenberg *et al*., 2009). For example, >90% of our Earth's conventional petroleum reserves are contained in rocks <200 Ma old. This can be related to the Wilson Supercontinent tectonic cycle (e.g. Wilson, 1966; Murphy & Nance, 1992) which increases the probability that petroleum systems older than 200 Ma are destroyed in plate tectonic collisions.

Because the diagenetic processes which create the GZ behave fundamentally differently to the typical rock mechanic models used to predict fluid pressure and migration in the sub-surface, the concept provides valuable insights with respect to many basin phenomena related to overpressure, which have previously defied accurate predictions. It is recommended, therefore, that burial and thermal modelling of these processes be included in basin evaluation methods to help predict and map geological exploration risks, including those related to the:

1. optimal geological intervals for oil and gas reservoir accumulation;
2. occurrences of fluid overpressure and related exploration risks.

ACKNOWLEDGMENTS

The author is indebted to many colleagues over the years spanning this research, including Jeff Wilson and Steve Hillier, The Macaulay Institute; Denny Eberl, Water Resources Branch, USGS; Per Arne Bjørkum, Dean of Natural Sciences, University of Stavanger; Tony Spencer, Olav Walderhaug, Tony Buller, Bill Maloney, Morten Rye-Larsen & Øyvind Steen, Statoil ASA; Steve Ehrenberg, Shell Professor of Carbonate Geoscience, Sultan Qaboos University; Prof. Andrew Hurst, Aberdeen University; Prof. Per Aagaard, The University of Oslo; Douglas McCarty, Chevron Energy Technology; Profs. Jim Aronson and Ed Meyer, Earth Sciences Department, Dartmouth College; and Prof.

Cindy Riediger, formerly of The University of Calgary, for many helpful discussions. Øyvind Steen is gratefully acknowledged for creating the Gulf Coast geothermal model and isotherms figure, as well as Steve Ehrenberg for generating the Gulf Coast reservoir pressure probability distribution figures. Statoil ASA is kindly thanked for supporting this research and permission to publish this lecture, and Prof. Quentin Fisher, The University of Leeds, for many constructive comments to the manuscript. The views and opinions expressed herein are those of the author, and do not necessarily reflect those of Statoil ASA or its operating groups.

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