North Dakota Geological Survey

An Examination of the Factors that Impact Oil Production from the Middle Member of the Bakken Formation in Mountrail County, North Dakota

By

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Introduction

Oil and gas production from North Dakota has increased dramatically since the successful development of the Bakken Formation in Mountrail County (See Fig. 1). Recent assessments of the technically recoverable oil in the Bakken Formation point to a significant undeveloped resource within the Williston Basin (Pollastro and others, 2008, Bohrer and others, 2008). Even though the presence of oil in the Bakken has been known since the earliest days of oil production, it has not been generally drilled as a primary target. Advances in horizontal drilling and well stimulation technologies coupled with rising prices for oil has dramatically increased drilling in the North Dakota portion of the basin.

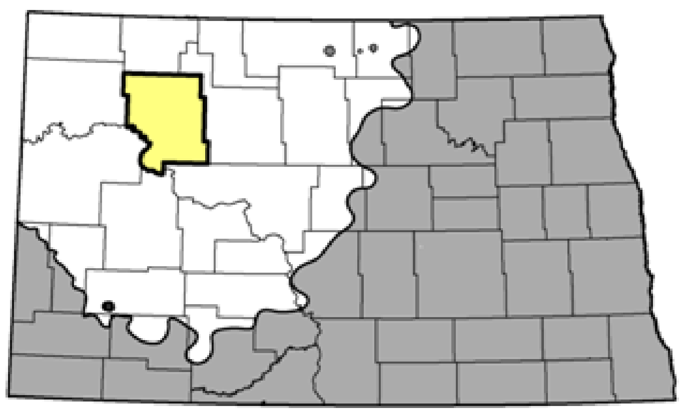


Figure 1. A map of North Dakota in which the extent of the Bakken Formation is shown in white and Mountrail County is highlighted in yellow.

Basin Centered Petroleum Accumulations

Conventional oil and gas reservoirs are localized accumulations of petroleum that consist of porous and permeable reservoir rocks overlain by impermeable cap rocks or seals that are folded, faulted or stratigraphically positioned so as to be capable of collecting (trapping) oil and gas. Oil and gas in conventional reservoirs originates in organic-rich source beds. The petroleum produced by these beds migrates, sometimes many miles, laterally and upwardly through water-filled pores before entering porous and permeable reservoir rocks within a trap.

The accumulation of oil and gas into conventional reservoirs is due, in large part, to differences in density that exist between oil, gas and water. Because petroleum is less dense than water, buoyancy drives petroleum upward through water-filled fractures and pores in the overlying rock until it encounters an impermeable seal or cap rock that forms a trap in which oil and gas accumulates. Reservoir pressures within these accumulations are usually close to the pressure exerted by a water column that is equal to the depth of the reservoir. The change in pressure with increasing depth is referred to as the "hydrostatic" gradient and can be used to estimate the reservoir pressure for most conventional fields in the Williston Basin.

In conventional reservoirs, trapped oil and gas "floats" on underlying water-saturated rocks across fairly sharp oil or gas/water contacts. Mapping out these oil/water contacts is the traditional method by which oil field boundaries are established. Together with the geometry and total pore volume that is present in the reservoir, reasonably good estimates of the total volume of oil in a conventional field can be made from these field boundaries.

The Lodgepole oilfields near Dickinson, North Dakota are excellent examples of conventional petroleum reservoirs. Chemical "fingerprints" of the oil in these fields indicates that the underlying Bakken Formation served as the source of the petroleum produced from these mounds. The fields contain permeable rocks that are surrounded by impermeable rocks. The original pressures within the fields were close to hydrostatic and there is a well defined oil-water interface. These features are typical of conventional reservoirs and are the only examples of conventional reservoirs that are producing Bakken generated oil (Pers. Comm., Price, 1993).

Unlike conventional reservoirs, "continuous" or "basin centered" petroleum accumulations do not form through buoyancy. Instead, oil and gas is injected into a reservoir that usually includes the source rock and the rocks close to the source. This frequently results in abnormally high formation pressures in the reservoir and the formation of a petroleum accumulation surrounded by water-saturated rock. In many respects, the rocks surrounding continuous-type accumulations are much like cap rocks or seals found overlying conventional reservoirs. In both cases, the migration of petroleum by buoyancy must be stopped before petroleum can accumulate. In order to do this some force must be present that counteracts buoyancy. The surface tension that exists between droplets of oil and the water that is present in the subsurface is one such force. Surface tensions exist whenever immiscible fluids, such as oil and water, are in contact.

The force associated with the surface tension between water and either oil or gas increases as the size of the pore throat that the oil or gas is moving through decreases. In other words, small pore throats tend to prevent buoyancy in the same way that surface tension prevents a needle from sinking in a glass of water. In general, small pore throats are associated with rocks containing small crystals and/or mineral grains such as shale, siltstone and finely crystalline or chalky limestone and dolostone.

Even though the sealing rock may be porous, surface tension between migrating oil or gas and water originally present in the seal prevents oil in the reservoir from moving through the small pore throats that make up the seal. Consequently, finer grained rocks block the migration of oil or gas until there is enough pressure on the petroleum to overcome the restraining surface tension and force the oil and gas into the pore space of the rock next to the source. In this way over-pressured oil "charges" a reservoir that acts both as reservoir and seal. The accumulation acts a bit like a balloon in that the original water in the pore space surrounding the source rock is pushed outward by the petroleum generated in the source rocks, with the surface tension between the petroleum and water acting as the skin of the balloon. One consequence of this is that fluid pressures within these reservoirs are substantially higher than would be expected if hydrostatic conditions prevailed.

After oil generation begins, available pore space in the source and surrounding rock fills with oil or gas as petroleum is forced into the space previously occupied by water. If the rock that the oil is being forced into is permeable or heavily fractured the oil may migrate through buoyancy and end up in a conventional reservoir. If however, there is no buoyant route for oil to escape from the source beds then this oil must displace water originally present in the rocks above, below or within the source.

The absence of a true petroleum/water interface in continuous petroleum accumulations makes it difficult to define field boundaries or estimate the total volume of oil or gas that may be present. Continuous petroleum accumulations typically cover very large areas so that wells drilled into them are almost never truly "dry". However, because the petroleum-bearing rocks have little permeability, economic success frequently depends on the presence of naturally occurring fractures or the creation of new fractures formed by injecting highly pressurized water (hydrofracing) into the reservoir after drilling. In either case, fractures substantially enhance oil flow from these rocks.

Petroleum within the Bakken is properly considered a continuous petroleum accumulation for the following reasons:

1) The Bakken is a regionally extensive, organic-rich source rock;
2) The Bakken has a burial history that has resulted in temperatures sufficient to convert organic matter into petroleum;

3) The overlying and underlying rocks are sufficiently thick, widespread and impermeable so as to isolate the accumulation;
4) There are overlying and/or underlying rocks that are sufficiently permeable and porous to accumulate economic quantities of oil or gas. (i.e. Bakken Petroleum System which includes the middle member of the Bakken Formation, Three Forks Formation, and the Lodgepole Formation; Price and LeFever, 1994); and,
5) Abnormally high formation pressures indicate that petroleum has been injected into these rocks and that the "charge" has not escaped through permeable zones, fractures or faults.

Petroleum accumulations, such as the Bakken, cover large areas with poorly defined margins. Economically productive areas or "sweetspots" are often restricted to localized geologic settings. The combination of very large regions containing this type of accumulation coupled with spotty areas of marginally higher permeabilities and fractures makes the determination of the size of the economic resource difficult. Nevertheless, virtually every study that has focused on the Bakken Petroleum System has concluded that the resource is enormous with total in place volumes of oil that are in the range of 10s to 100s of billions of barrels. By conventional standards this resource is not only enormous but the reason for its existence is also profoundly different than the mechanisms that govern conventional oil and gas accumulations.

History of Bakken Oil Production

Dow (1974) and Williams (1974) recognized the Bakken as a tremendous oil source within the Williston Basin. These papers suggest that the Bakken was capable of generating 10 billion barrels of oil (BBbls). Webster (1982, 1984) analyzed additional samples and concluded that the Bakken may have produced approximately 92 BBbls of oil. Schmoker and Hester (1983) estimated that the Bakken was capable of generating a total of 132 BBbls of oil in North Dakota and Montana. Price (2000, unpublished) estimated that the Bakken was probably capable of generating 413 BBbls of oil. Various numerical methods place the total amount of oil generated by the Bakken to be between 32 BBbls and 300 BBbls of oil respectively (Price and others, 1984; Meissner and Banks, 2000; Flannery and Kraus, 2006 and Flannery, 2006). In 2008, the United States Geological Survey (USGS) used a standardized assessment regime that concluded that the Bakken Petroleum System in the entire Williston Basin contains an undiscovered 3.65 BBbls of oil, 1.85 trillion cubic feet of natural gas, and 148 million barrels of natural gas liquids that are technically recoverable with current technologies (Pollastro and others, 2008). The North Dakota Department of Mineral Resources (Bohrer and others, 2008) estimates that there are 2.3 BBbls of oil in place (OIP) within the North Dakota portion of the Williston Basin.

Oil and gas production from the Bakken Formation provides an excellent case study of the successful development of a significant natural resource through the application of ever more sophisticated drilling and stimulation technologies. The history of Bakken development spans almost 60 years and is witness to several important advances in drilling, completion and stimulation techniques. Each of these advances has significantly increased the productive acreage and value of the formation. Probably the most conspicuous advance came with the development of tools that allows precise directional drilling and the modern horizontal well bore. The significance of this is that horizontal well bores open up much larger sections of an oil-bearing formation and by virtue of increasing the collection capacity of a single well allows for larger volumes of oil to be produced. This is especially important when attempting to produce oil from formations such as the Bakken and Three Forks in which oil naturally seeps into the well bore at very slow rates. However, horizontal s alone are frequently inadequate to allow for enough oil to be produced at rates that justify the cost of drilling and completing a well, a problem that is often overcome by increasing the natural seepage of oil by inducing fractures in the rock. This is done by pumping a water and sand slurry into the formation at pressures high enough to cause the oil-bearing rock to fracture (hydrofracing). The increased flow of oil through the network of fractures can substantially increase oil production. Hydrofracing has been used to stimulate well production since the earliest days of Bakken production. However, over time and the introduction of horizontal drilling the size of these stimulation efforts has increased dramatically. The reason for this is that larger hydrofracs produce more fractures and result in a substantial increased well productivity. More recently, very large fracture stimulation efforts have been joined by stimulation efforts that include multiple stages of hydrofracing. In the staged hydrofracture method, sections of the horizontal well bore are isolated and individually stimulated on a section by section basis. This allows for better control and yields in a more uniform distribution of fractures along the horizontal well bore.

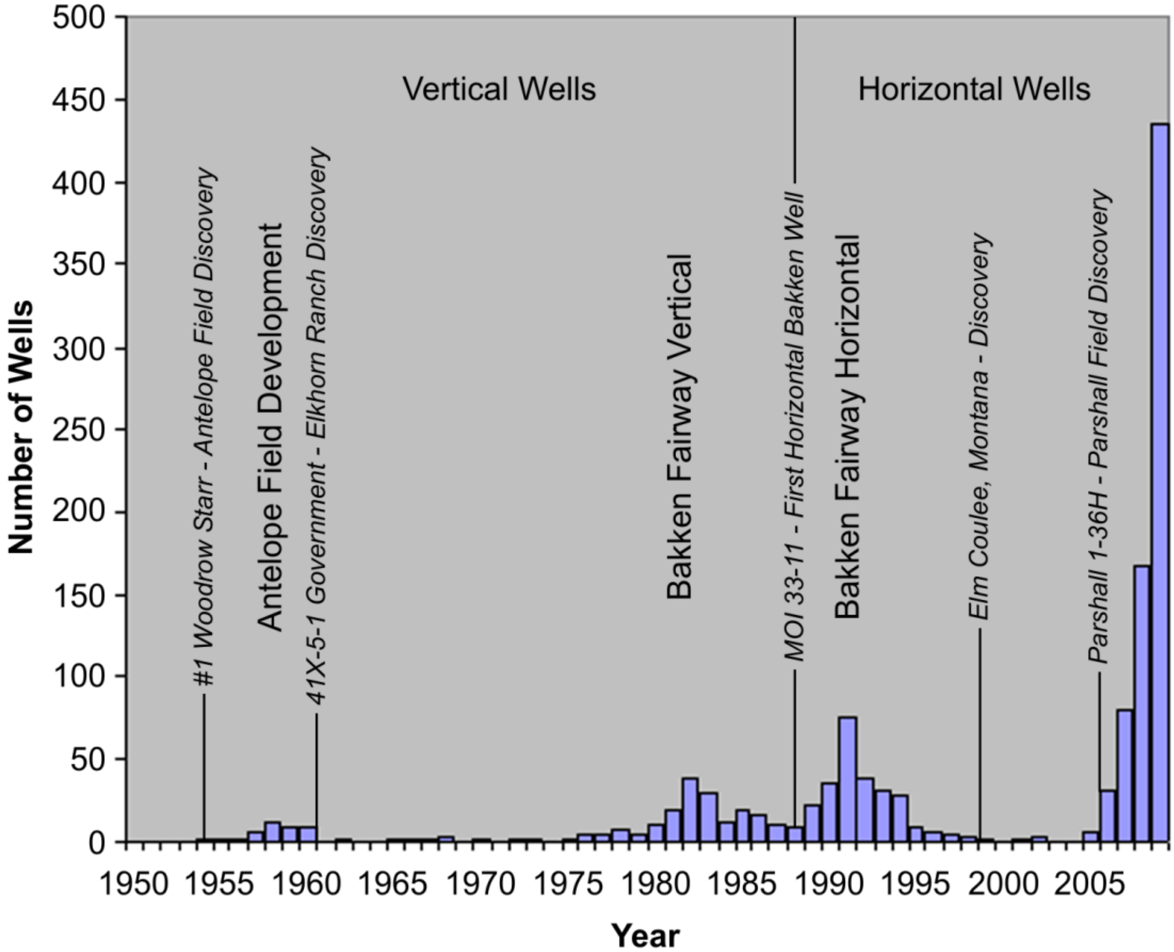


Figure 2. Historic distribution of Bakken tests, significant discoveries and technologic advances in the Williston Basin.

Antelope Field

Oil production from the Bakken was first established on the Antelope Anticline in 1953 when Stanolind Oil and Gas Corp. drilled and completed the #1 Woodrow Starr (SWSE Sec. 21, T152N, R.94W). The well was drilled to a total depth of 12,460 feet, plugged back and cased to 10,675 feet. The well was perforated between the depths of 10,528 to 10,556 feet and stimulated with 4,900 pounds of sand and 120 bbls of crude oil. The well came on line on December 6, 1953 with an initial production (IP) of 536 barrels per day of 44° API gravity oil and 770 cubic feet of gas per barrel. Casing problems in the #1 Woodrow Starr forced the well to be plugged and abandoned after 55 months of production during which 279,254 barrels of oil and 108 barrels of water were produced. The majority of the wells in Antelope Field were drilled during the 1950's and 1960's (Fig. 3). A total of 44 wells were drilled during that time with an average IP of 217 barrels of oil per day with one outstanding well producing 890 barrels per day (LeFever, 1991).

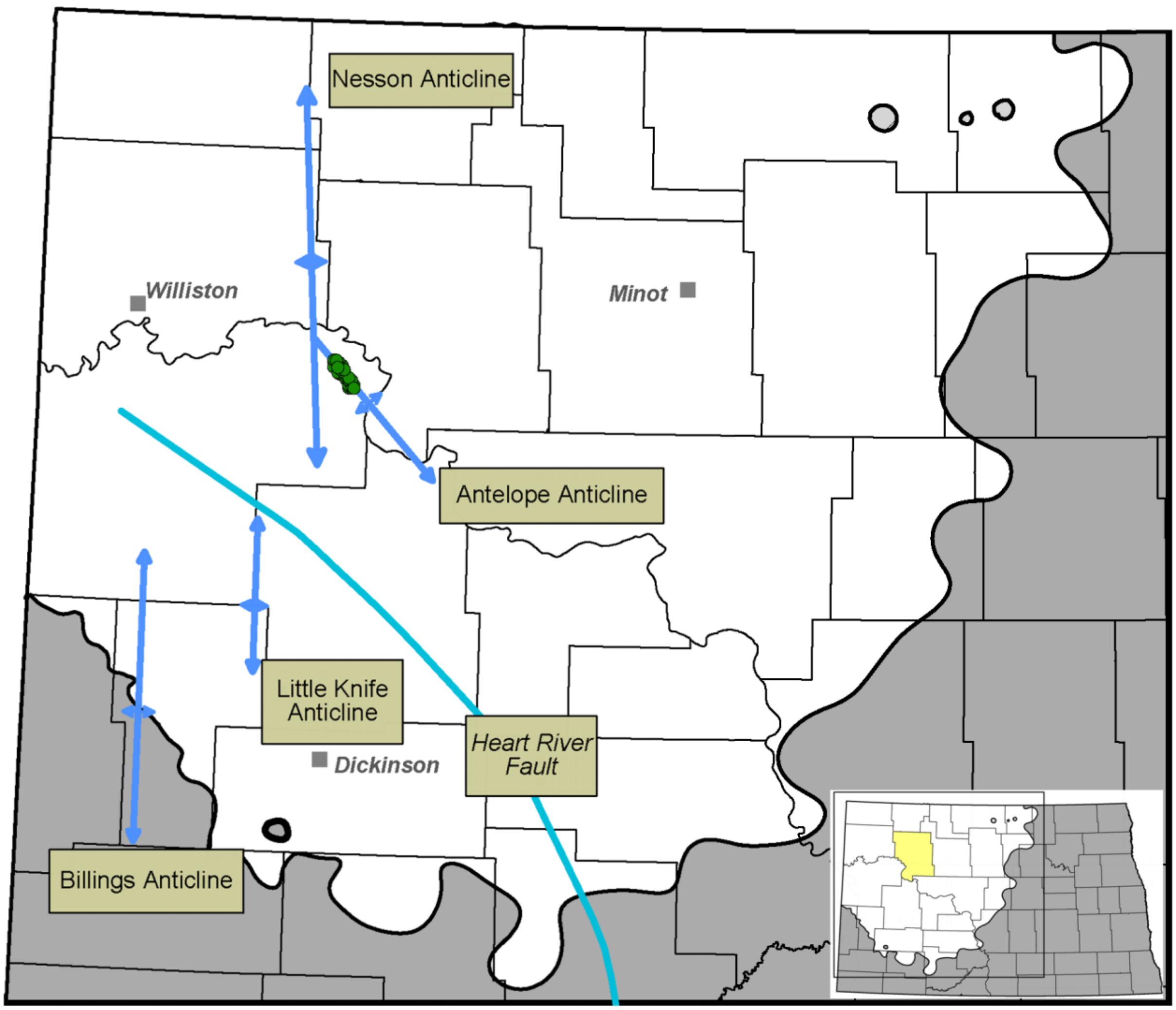


Figure 3. Bakken/Sanish producing wells drilled between 1953 and 1960 in the Antelope Field, McKenzie County. This map, as well as those to follow, includes an overlay of the regional structures in the Williston Basin. The heavy rectangle on the small map outlines the location of the following maps. Mountrail County is shown in yellow and the portions of North Dakota in which the Bakken Formation is absent are presented in gray.

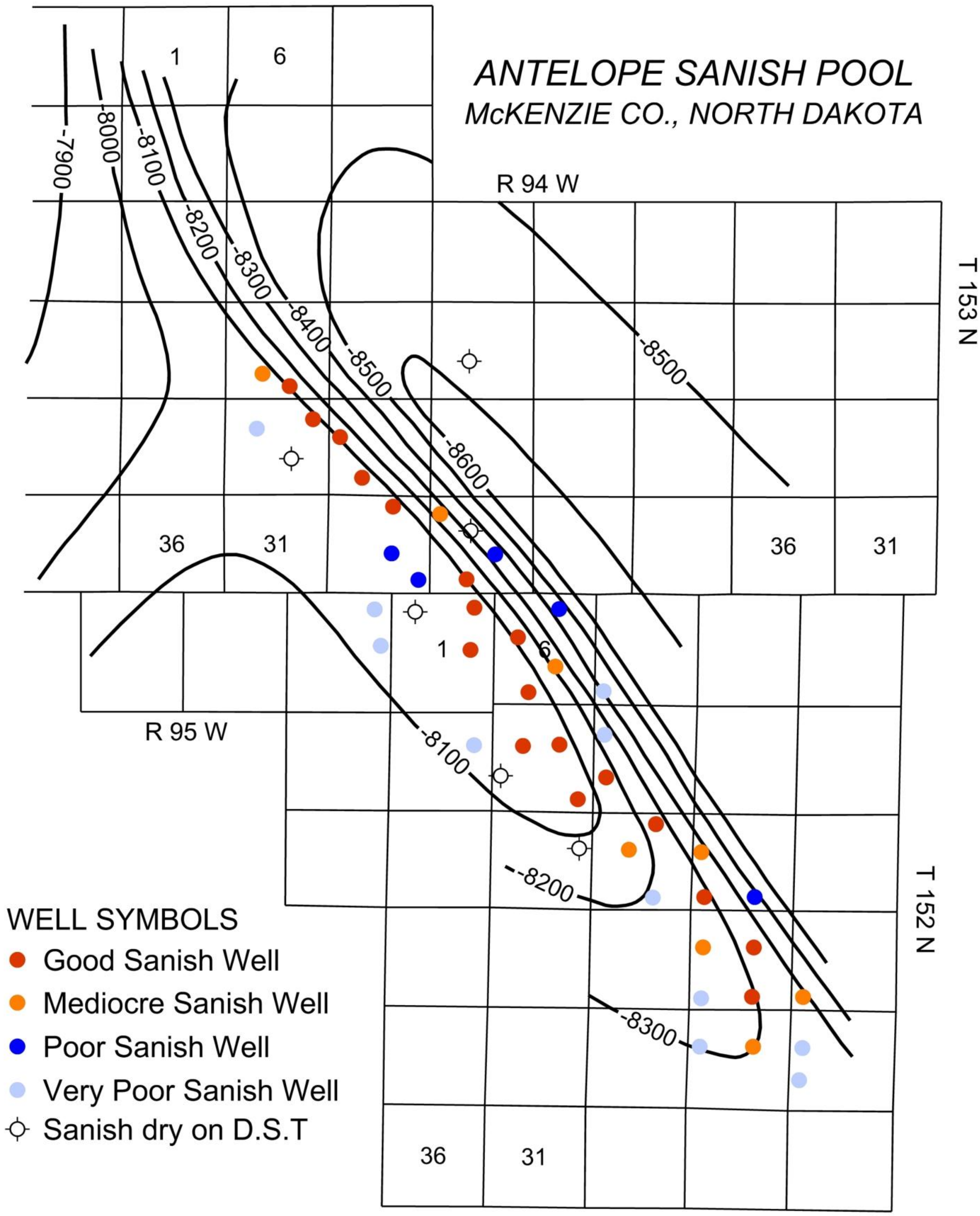

ANTELOPE SANISH POOL
McKENZIE CO., NORTH DAKOTA
R 94 W
R 95 W
T 153 N
T 152 N
1
6
36
31
-7900
-8000
-8100
-8200
-8300
-8400
-8500
-8600
WELL SYMBOLS
Good Sanish Well
Mediocre Sanish Well
Poor Sanish Well
Very Poor Sanish Well
Sanish dry on D.S.T

Figure 4. Structure map of Antelope Field with wells and relative production indicated (modified from Murray, 1968).

The success of wells drilled in the Antelope Field depended upon naturally formed fracture networks in the Bakken and Three Forks (Sanish) Formations to supply enough oil to the to be economic. Murray (1968) found that production from the Bakken/Sanish Pool in the Antelope Field is strongly influenced by tectonic fractures. These fractures probably opened through tensile failure along the most tightly flexed portion of the steeply dipping northeastern limb of the Antelope Anticline (Fig. 4). The presence of fracturing appears to have allowed for the otherwise “tight” reservoir rock in this field to yield oil and gas at commercial rates. Original formation pressures in this field were significantly above the typical near hydrostatic pressures present in other reservoirs in this field and in the Williston Basin in general. Meissner (1978) considered oil maturation and subsequent source rock compaction to be the primary cause of the abnormally high pressures generally found in the Bakken.

Oil production from vertical wells in the Antelope Field is restricted to localized geologic conditions that resulted in natural fracture systems. The recognition that structurally related fracture systems are a necessary component of a successful Bakken well became the dominant exploration model until the mid-1990s.

Early Vertical Bakken Discoveries

Between 1960 and 1975 production outside of the Antelope Field was established in a few wells (Fig. 5). Of particular significance was the discovery of the Bakken/Three Forks Pool in the Elkhorn Ranch Field on the eastern flank of the Billings Anticline. This discovery was made in 1961 after Shell Oil drilled the Government 41X-5-1 well in Billings County (NENE Sec. 5, T143N, R101W). The well was drilled to a total depth of 13,018 ft and was plugged back to a depth of 10,738 ft. A drill stem test that covered 109 feet of the lower Lodgepole, Bakken and Three Forks Formations recovered gas and heavily oil cut mud with shut in pressures of about 6,600 pounds per square inch (psi). The well was perforated in the upper Bakken shale between 10,682 and 10,692 ft depth and in the upper Three Forks between 10,705 and 10,715 ft depth. 4,000 gallons of acid were used to stimulate the well. The initial production rate was reported to be 136 barrels of 43.4 ^{o} API gravity oil with a gas to oil ratio (GOR) of 1230 cubic feet of gas per barrel of oil. Seven months later the well was hydrofraced with 20,000 gallons of acid and 9,000 pounds of sand. Production following stimulation was reported to be 48 bbls/d. The well was abandoned in August of 1964 after producing 57,840 bbls. of oil.

The "Bakken Fairway"

The second phase of Bakken activity occurred in the late 1970's along the depositional limit of the Bakken Formation. Along this trend, only the upper Bakken is present. Drilling was concentrated where the Bakken thinned over structural features. Enhanced fracturing of the shale was expected in these settings based on the idea that fracture density increased as the thickness of the upper Bakken shale decreased (Sperr, 1991).

At least 26 fields have been established along this trend that extends from the Estes/Mondak area to Little Knife (Fig. 7). In addition, most of the fields have multiple pays associated with these structures.

The "Bakken Fairway" Horizontal Drilling

Drilling methods changed significantly in 1987 after Meridian Oil, Inc. drilled the first horizontal Bakken well. Meridian drilled and completed a vertical well in March 1986 for 217 BOPD. (#21-11 MOI-Elkhorn; NWSE Sec. 11, T143N, R102W). This well established the presence of a fracture trend that was exploited with the first horizontal well into the Bakken. A 2,600 ft. long lateral was drilled from the vertical well into an 8-foot-thick section of the upper Bakken shale. Initial production from the completed lateral was 258 BOPD and 299 MCF of gas (LeFever, 1991). Horizontal drilling continued along a northwest-southeast trending strip of land that is referred to as the "Bakken Fairway" (Fig.7 and Fig. 8). The "Fairway" is some 200 miles long and 30 miles wide and lies along the updip feather edge of the upper shale. Horizontal drilling along the Bakken Fairway peaked in 1992 before slowing late in the 1990s and essentially ending by 2000 (Lefever, 2000).

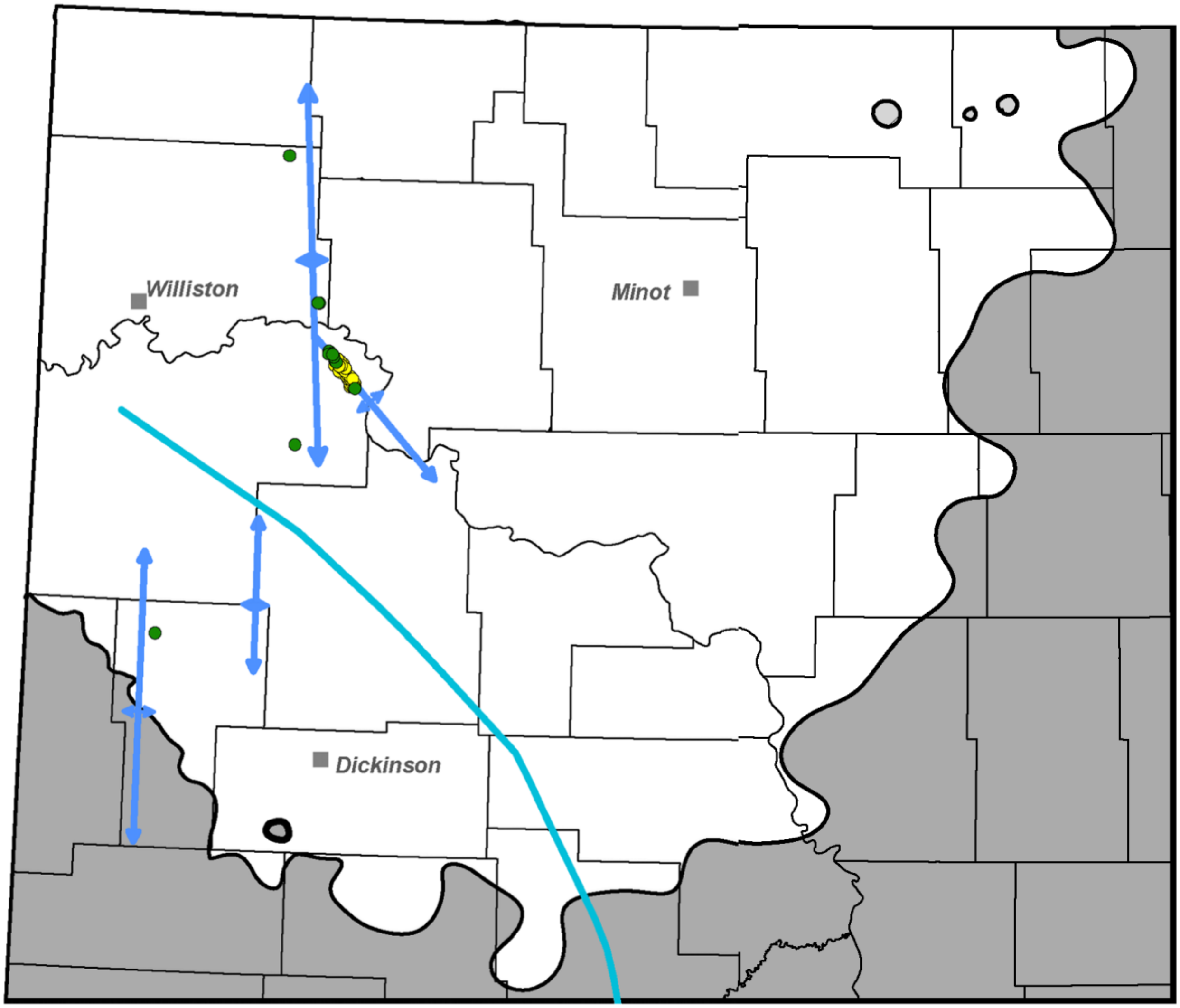


Figure 5. Bakken producers drilled between 1961 and 1975 (green circles) proving that Bakken production is possible outside of the Antelope Field. Wells drilled before 1961 are in yellow.

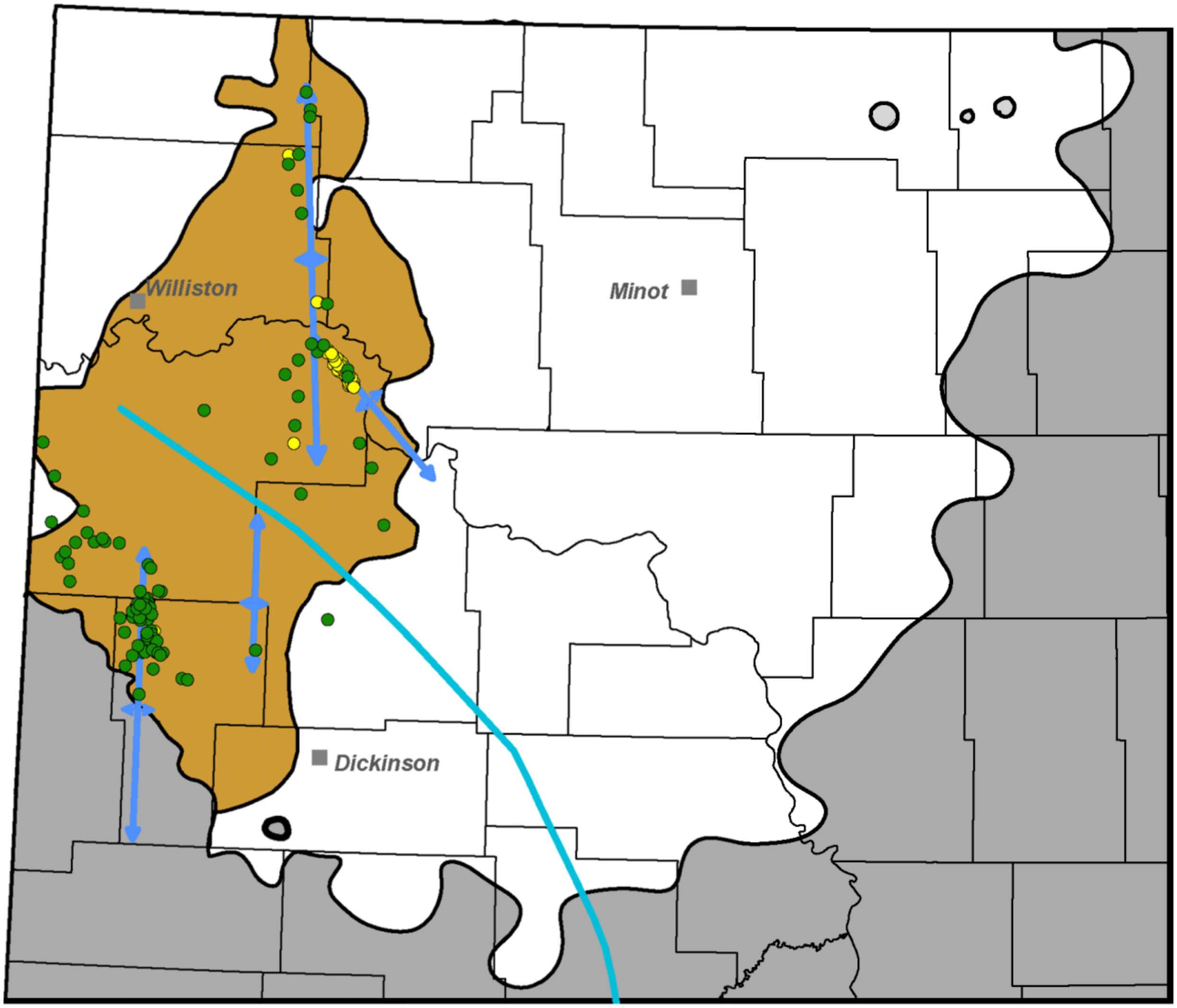


Figure 6. Vertical Bakken producing wells that were drilled from 1976 to 1985 are shown as green circles. Wells drilled before 1976 are in yellow. Most of the production was found in the "Bakken Fairway " near the southwestern limit of the Bakken Formation. On this map and the ones that follow, the portion of the Bakken that is considered "mature" on the basis of RockEval® data is shaded in light blue (See Nordeng and LeFever, 2009).

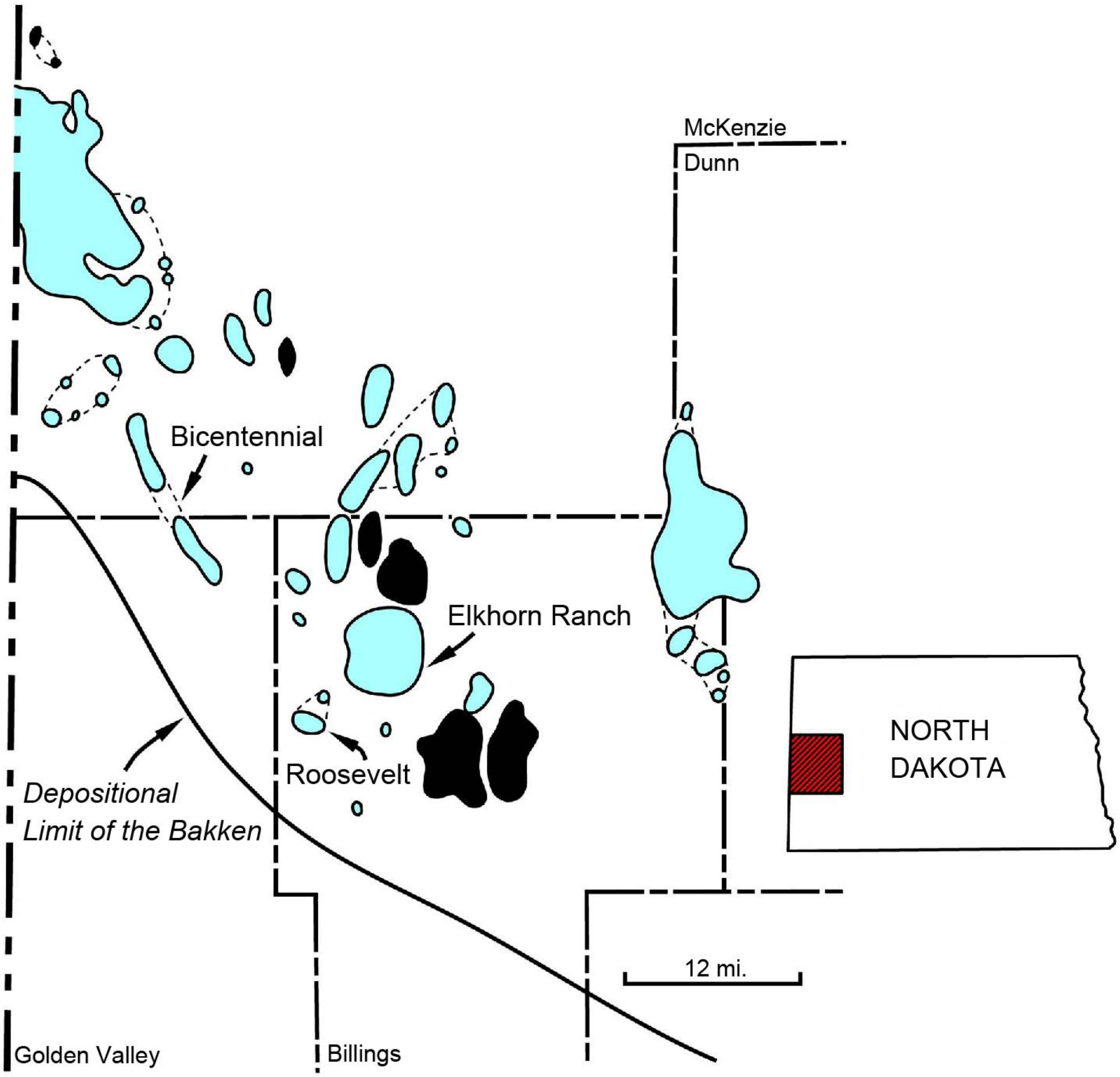


Figure 7. Map of western North Dakota showing the location of the “Bakken Fairway”. Fields in light blue contain wells with significant Bakken production. The fields in black do not contain any significant Bakken production (Modified from LeFever, 1991).

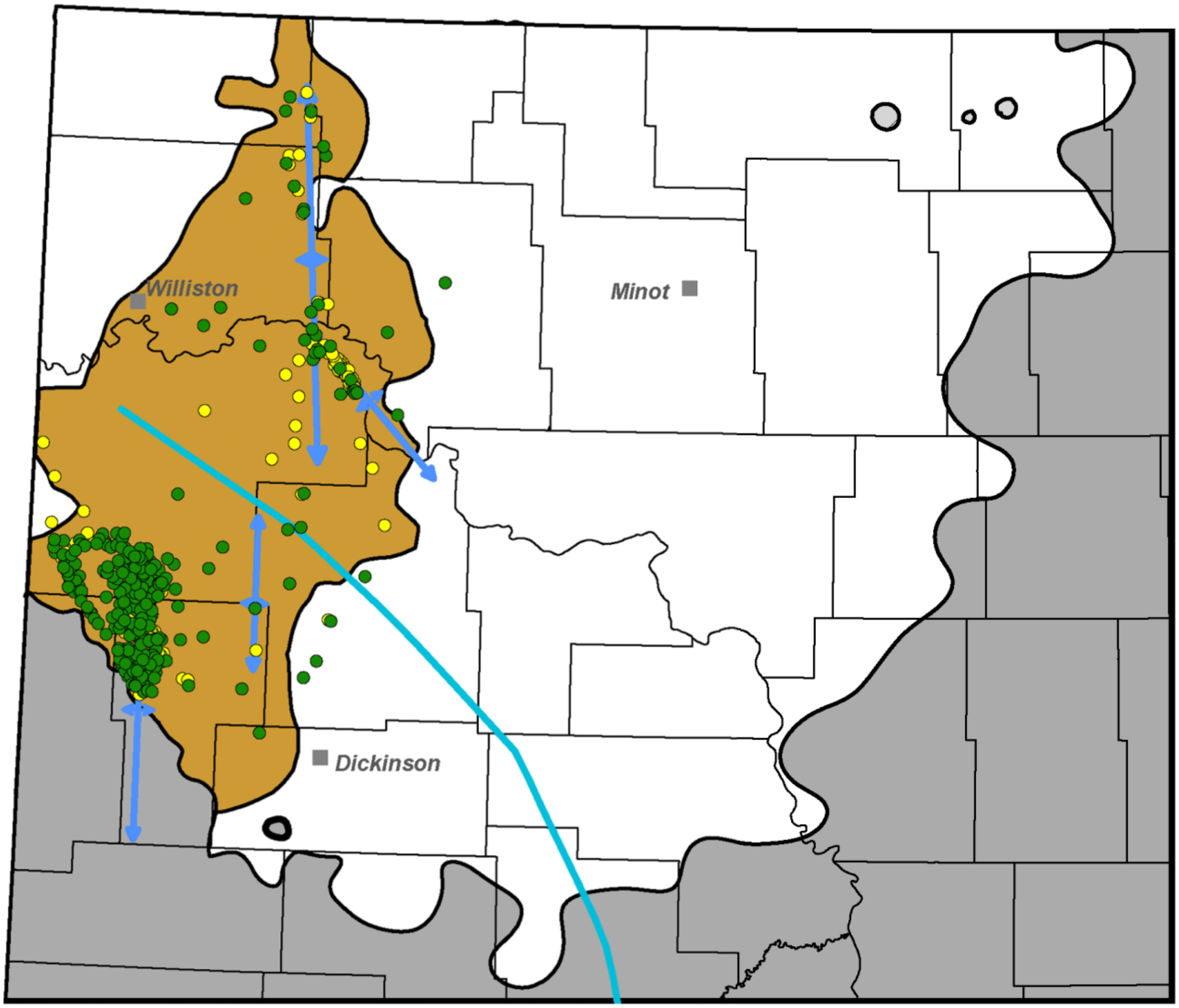


Figure 8. Bakken producers drilled between 1986 and 1995 (green circles). Wells drilled before 1986 are in yellow. Many of the wells drilled during this time are horizontal wells.

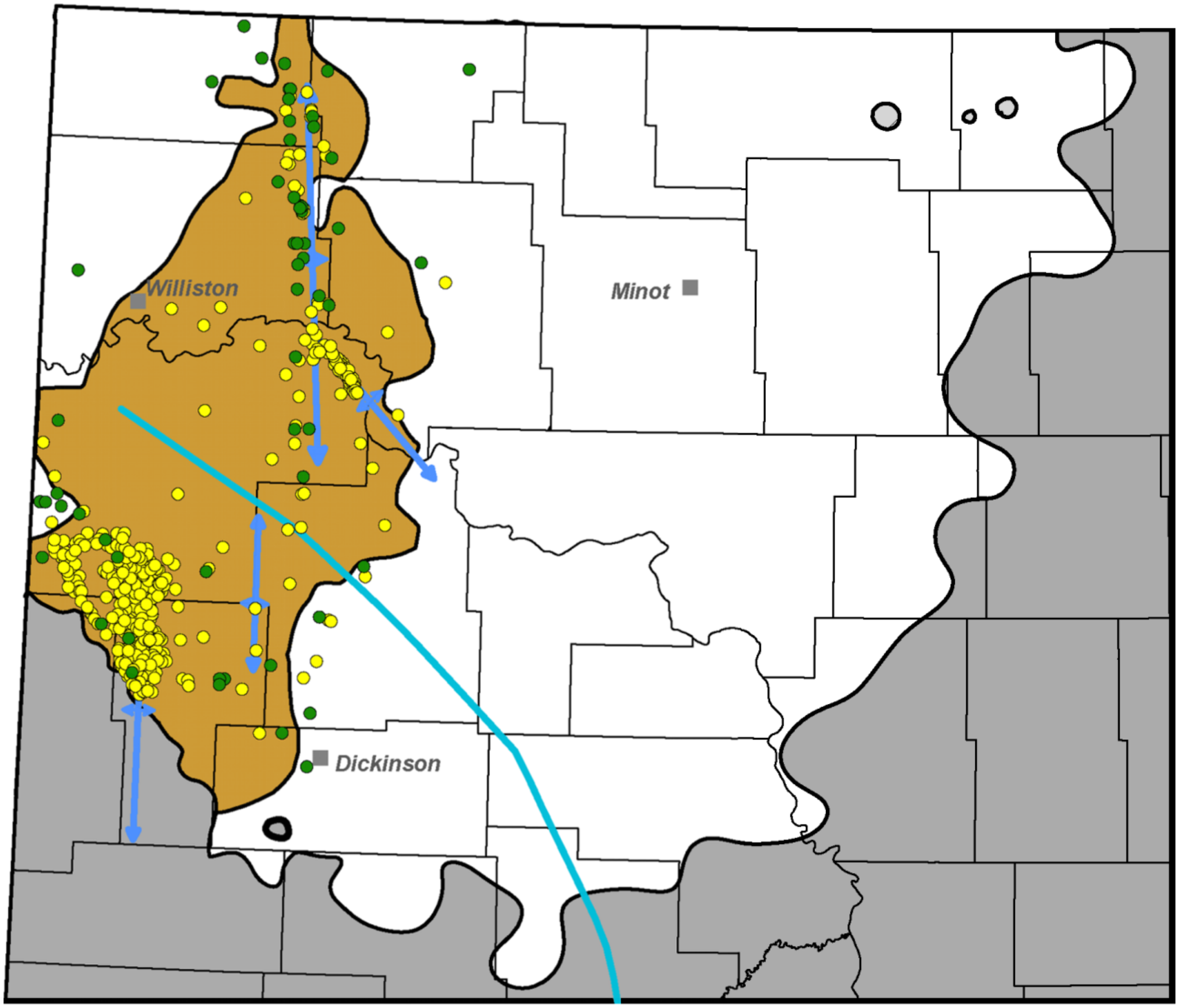


Figure 9. Bakken producing wells drilled between 1996 and 2005 (green circles). Wells drilled before 1996 are in yellow).

Elm Coulee

Elm Coulee Field developed after oil was first produced from the middle member of the Bakken Formation in 1996. This production was established in the Kelly/Prospector #2-33 Albin FLB following an unsuccessful test of the deeper Birdbear (Nisku) Formation. Subsequent investigations by Dick Findley found significant porosity in the middle member of the Bakken (Brown, 2006). Porosity maps outlined a northwest-southeast trending stratigraphic interval containing an unusually thick dolomitized carbonate shoal complex within the middle member of the Bakken Formation. Horizontal wells through the shoal complex in 2000 resulted in the discovery of the giant Elm Coulee Field in eastern Montana. As with the previous Bakken producing fields, production at Elm Coulee depends on fracturing but in this case the productive fractures are found in the middle member of the formation. Since its discovery, more than 600 horizontal wells have been drilled in the 450-square-mile field from which more than 90 MBbls of oil have been recovered. The productive portions of the reservoir contains between 3 and 9 percent porosity with an average permeability of 0.04 md. A pressure gradient in the Bakken of 0.53 psi/ft indicates that the reservoir is overpressured. Stimulation of the lateral is routine and includes various sand-, gel- and water-fracturing methods. Initial production from these wells ranges between 200 and 1900 BOPD (Sonnenberg and Pramudito, 2009).

Parshall Field

Michael Johnson noted that wireline logs of the Bakken Formation in Mountrail County resembled those from Elm Coulee. Even though the shales in the Bakken appeared incapable of generating oil, free oil recovered in DSTs and some minor production lead Johnson to pursue a Bakken play in Mountrail County (Durham, 2009). In 2005, EOG Resources demonstrated with the #1-24H Nelson-Farms (SESE Sec. 24, T156N, R92W) that horizontal drilling coupled with large scale hydraulic fracture stimulation of the middle Bakken Formation could successfully tap significant oil reserves along the eastern side of the Williston Basin in Mountrail County (Fig. 10). In the following year, EOG Resources drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD. Subsequent horizontal drilling in the Parshall Field coupled with staged fracture stimulation has resulted in several wells with IPs in excess of 1,000 BOPD. Currently the field is producing an average of about a million barrels of oil per month from 119 wells (see Fig. 12). This discovery has focused significant attention on the oil potential of the Bakken Formation in the Williston Basin. The discovery also raises an important question regarding the interpretation of conventional measures of organic maturity in exploration.

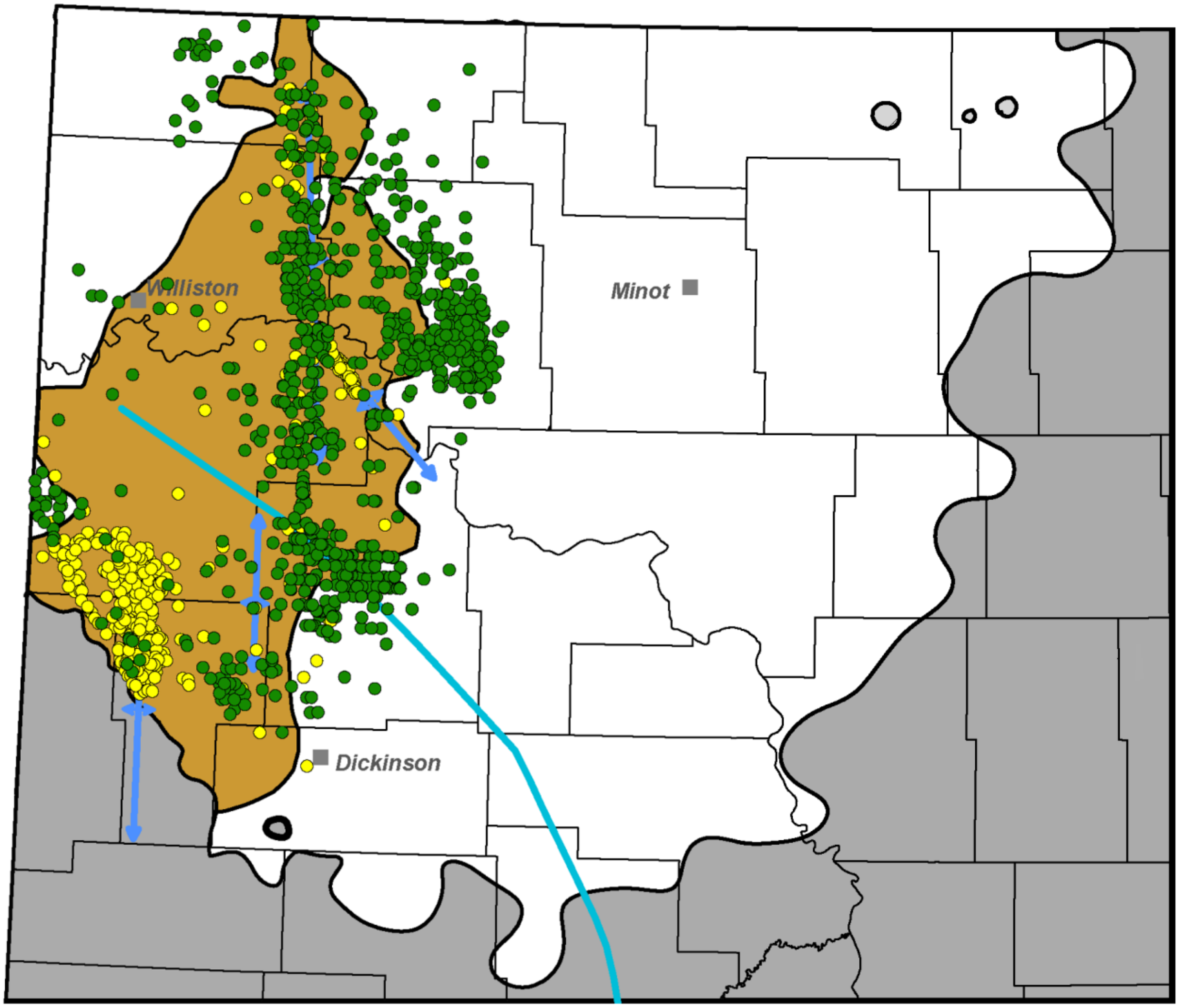


Figure 10 . Bakken producers drilled since 2005 in green. Wells drilled before 2005 are in yellow.

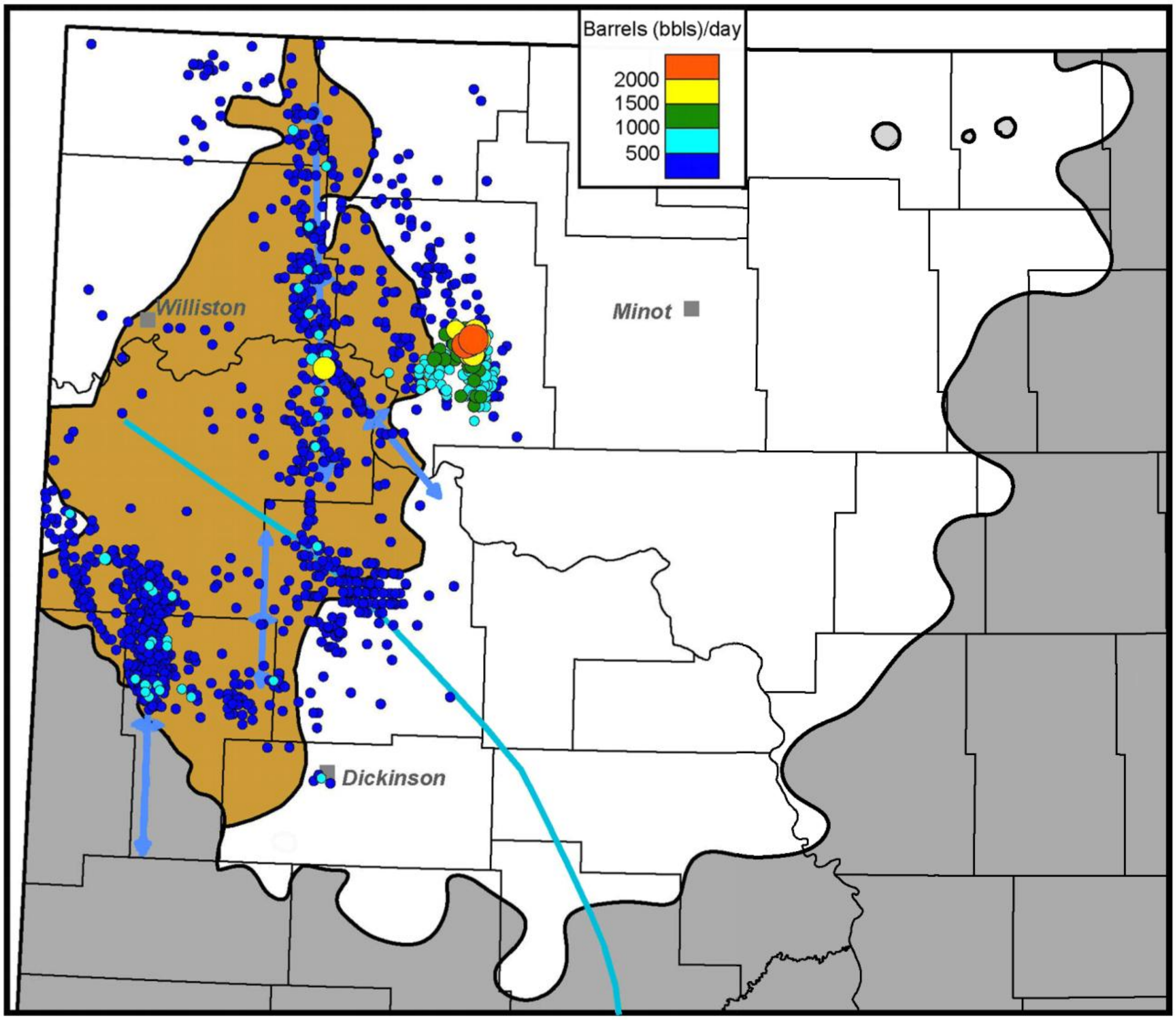


Figure 11. A map of Bakken producers. The initial production rates are scaled to the size and color of the circle. The initial production rate shown here is the average daily production rate obtained from no fewer than 60 days and no more than 90 days of production. The Parshall Field is located where the cluster of large orange circles (1000+ BOPD) are plotted in eastern Mountrail County.

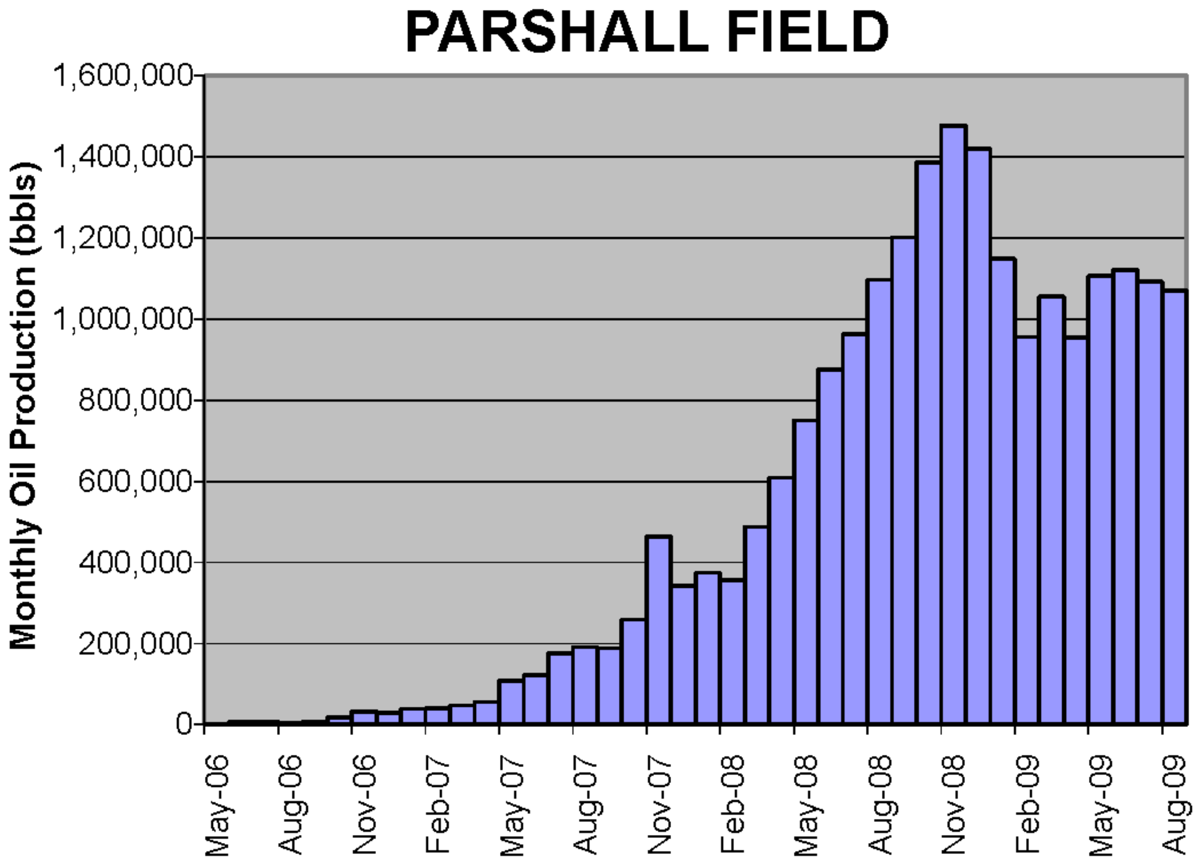


Figure 12. Monthly oil production from the Parshall Field, Mountrail County, North Dakota. Data is from the North Dakota Industrial Commission (NDIC).

Geologic History of the Bakken Source System in North Dakota

The Bakken Source System consists of the Three Forks, Bakken and lower Lodgepole Formations. These rocks were deposited over roughly 10 million years during the Late Devonian and Early Mississippian periods. At this time, North Dakota was situated in the tropics, very near the equator along the margin of an ancient sea that covered what would eventually become North America. During this time, what was to become the Williston Basin, was part of a tectonically active trough-like depression known as the Elk Point Basin. The Elk Point Basin more or less followed the trend of this ancient seacoast (See Fig. 13). The interaction of fluctuating sea-levels with differential subsidence resulted in variations in seawater circulation and water depth within the Williston Basin that are reflected in the various lithologies found in the Three Forks, Bakken and lower Lodgepole Formations.

The Three Forks Formation (Upper Devonian) includes sediments deposited in a broad epeiric sea that extended well into the interior of North America along the coast of a Late Devonian landmass (Fig. 13). The formation consists of clean and argillaceous micrite and dolomicrite containing varying amounts of silt, sand, and anhydrite. These sediments were deposited during periods of fluctuating sea-levels within a gradually subsiding sub-basin, which covers Mountrail, Dunn and Eastern McKenzie counties (Fig. 14).

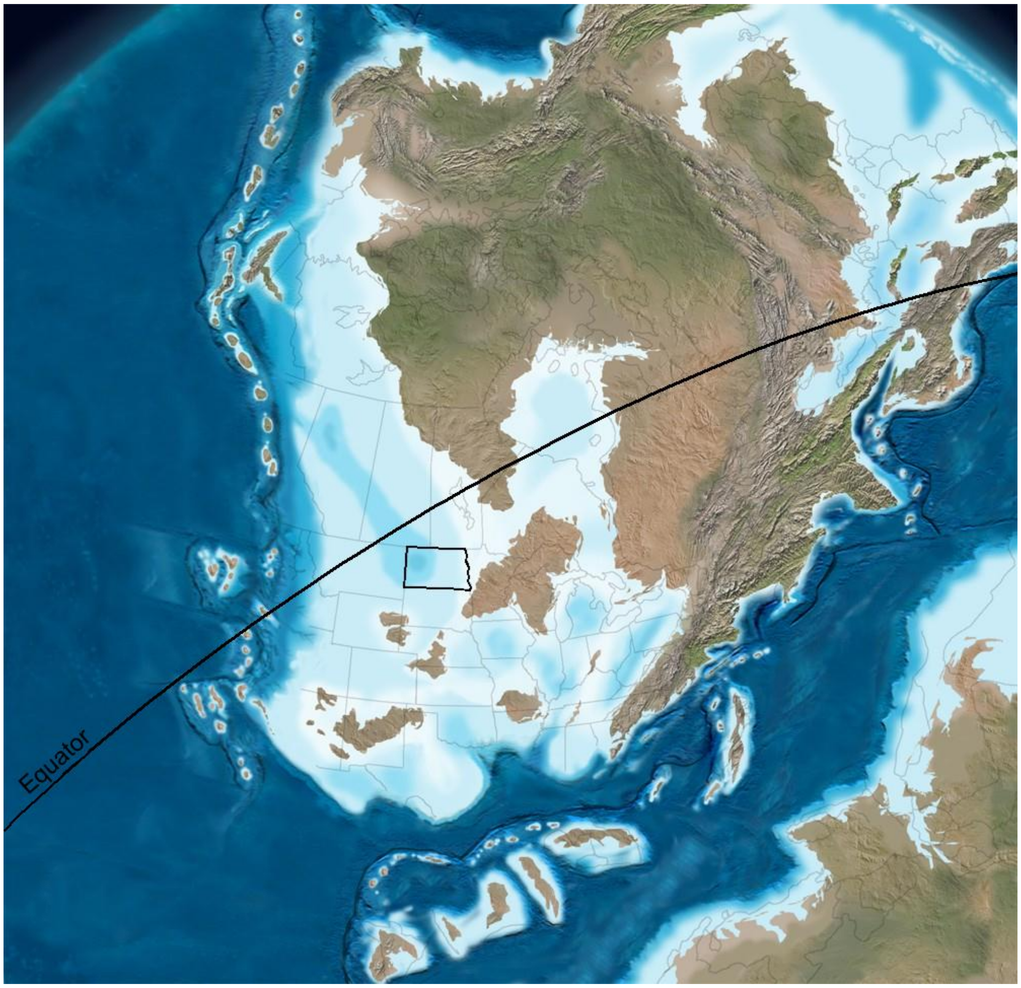


Figure 13. Paleogeographic reconstruction of North America during the Late Devonian showing the position of North Dakota outlined in black. The equator in this image runs diagonally from the lower left to upper right and passes almost through North Dakota. The depth of seawater in this illustration is suggested by shades of blue in which deep waters are dark blue and shallower waters are shown as lighter shades of blue. The general distribution of land masses and highlands are also shown in shades of green and brown (Blakey, 2005).

System	Formation	Informal Units	
Mississippian	Lodgepole		"False Bakken"
	Bakken	upper	upper shale
		middle	lithofacies 5
			lithofacies 4
Devonian			lithofacies 3
			central basin facies
			lithofacies 2
			lithofacies 1
		lower	lower shale
			lower silt — "sanish sand"
	Three Forks		unit 6
			unit 5
			unit 4
			unit 3
			unit 2
			unit 1

Figure 14. Detailed stratigraphic nomenclature for the Bakken Source System (Christopher, 1961; LeFever, 2008; Murphy and others, 2009).

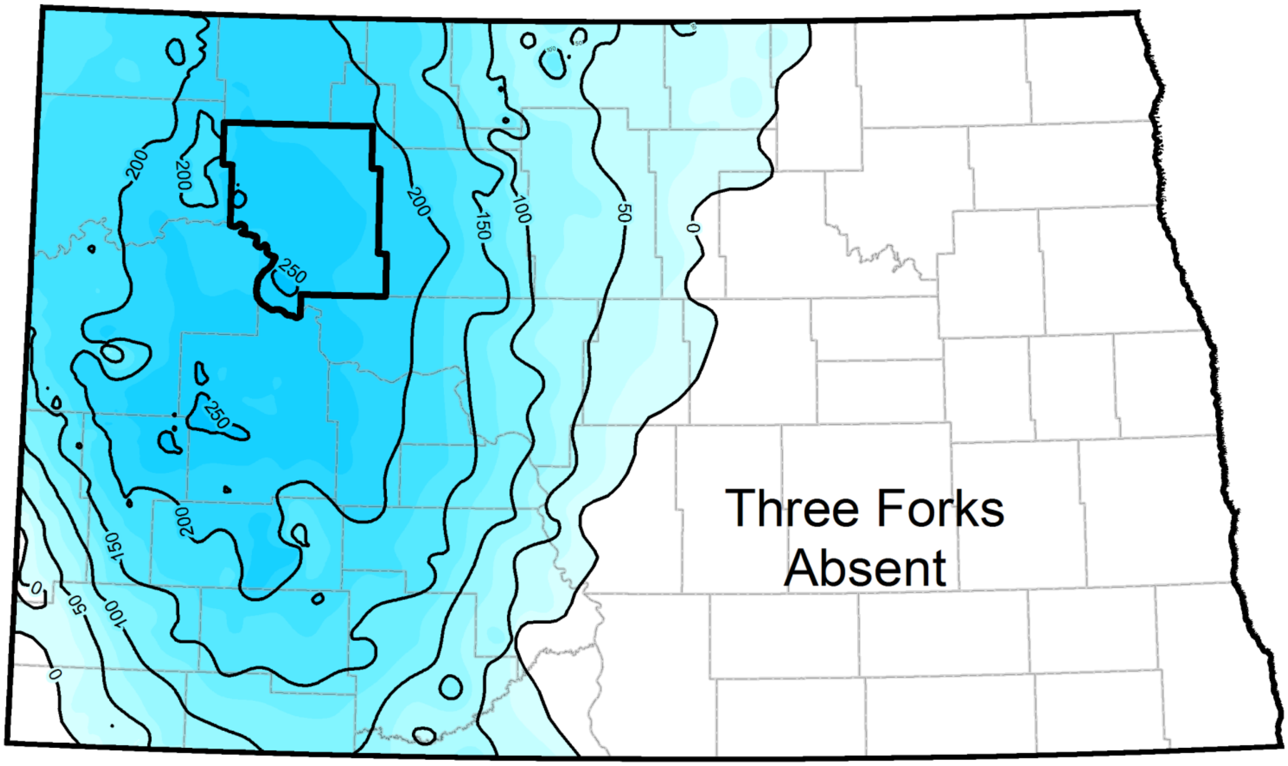


Figure 15. Isopach map of the Three Forks Formation in North Dakota. Mountrail County is outlined by the heavy line.

The Three Forks conformably overlies the Birdbear Formation and is conformably overlain by the lower Bakken member in the central portion of the basin. Along the margins of the basin, the formation is unconformably overlain by a progression of younger strata that include the middle and upper members of the Bakken Formation and the Lodgepole Formation.

The lower portion of the Three Forks Formation consists of massive, faintly bedded to brecciated rocks containing locally abundant anhydrite in the form of nodules and vug-filling cement. These features suggest deposition and/or early diagenesis in an arid, restricted shallow marine or sabkha environment in which a combination of evaporation and poor mixing with normal marine waters elevated the salinity of the waters from which the lower portion of the Three Forks were deposited.

Sediments deposited later in Three Forks time do not contain anhydrite suggesting that the climate became more humid and/or normal open marine waters once again circulated through the Williston Basin. The upper Three Forks differs from the lower portion in the frequency and detail of primary sedimentary structures. In general, the upper half of the Three Forks (above Unit 3) consists of thin layers of reddish or greenish clay-sized material alternating with thin layers of light tan silt to very fine-sand sized material. Sometimes these layers contain ripple cross-laminations. Intraformational breccias are common and suggest that several episodes of subaerial exposure occurred locally during deposition. Near the end of Three Forks time, sea level dropped enough for the formation to experience widespread erosion. This resulted in an unconformity between the Three Forks and the overlying Bakken Formation that can be traced along the margins of the basin. Closer to the center of the basin, erosion is difficult to document because the contact between the Three Forks and Bakken Formations appears conformable.

Deposition of the Bakken Formation began when rising global sea-levels drove shorelines landward further isolating the Williston Basin from terrigenous sediment sources. In addition, the basin subsided at a rate that outstripped the rate of infilling by sediment transported into the basin and sediment generated by carbonate producing organisms within the basin (Lineback and Davidson, 1982). Increasing water depths and continued subsidence of the Williston Basin in North Dakota formed a depression centered in western Mountrail County (Fig. 16) in which bottom water circulation from the open ocean diminished to the point that an oxygen-stratified water column formed (Webster, 1984; Smith and Bustin, 1997; 2000). Oxygenated surface waters together with equatorial inputs of solar energy generated massive amounts of organic matter in the upper part of the water column. This organic matter or some fraction of it filtered down into the oxygen deficient or anoxic bottom waters and accumulated as organic-rich sediments that gave rise to the organic-rich shale that make the upper and lower members of the Bakken Formation world-class source beds.

The Bakken Formation consists of an upper and lower organic-rich shale separated by a mixed carbonate-clastic middle member. Occasionally, organic-rich beds are present near the base of the Lodgepole Formation (“False Bakken”) and within the middle member and the underlying Three Forks Formation. The middle member of the Bakken contains a variety of rock types including heavily cemented limestone, and mixtures of siltstone, silt and mud-sized dolostone, and fine-grained sandstones.

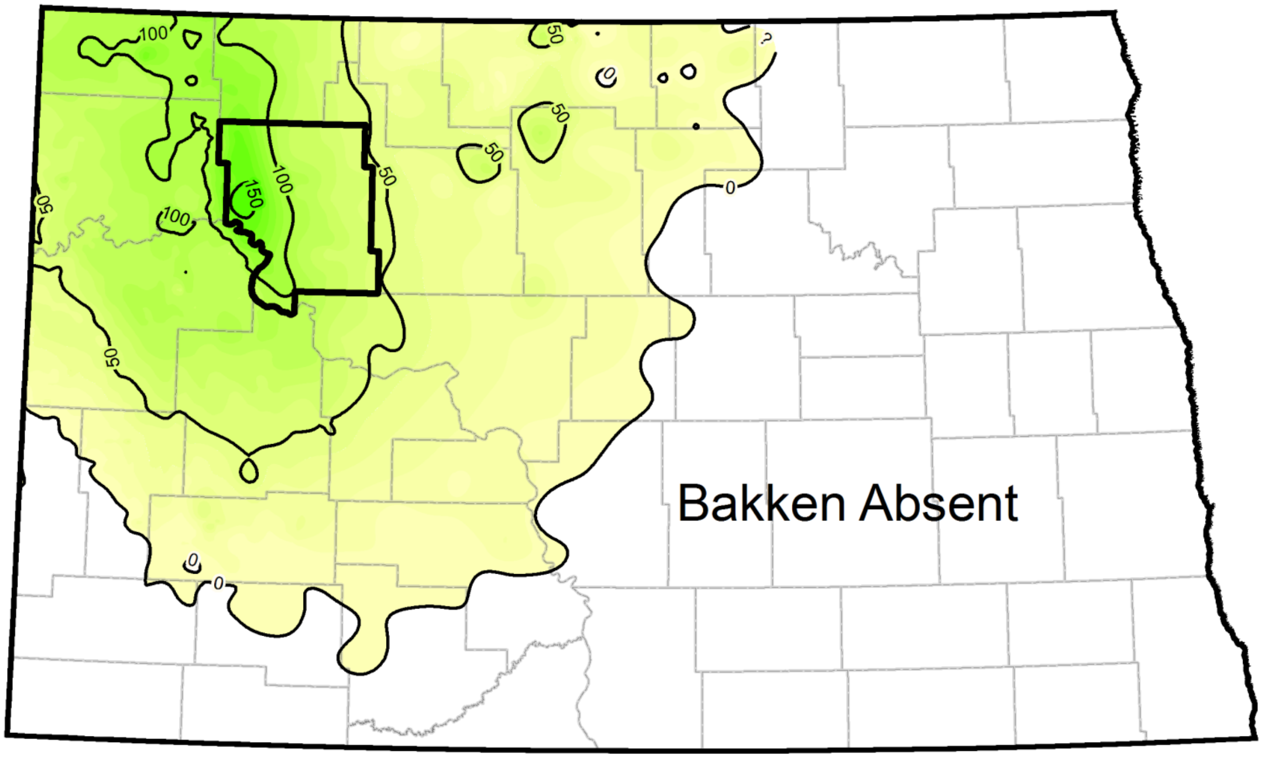


Figure 16. Isopach of the Bakken Formation illustrating the maximum extent of the formation in North Dakota. The depocenter of the formation is suggested by the thickest accumulation of Bakken rocks in the western part of Mountrail County, North Dakota (heavy black outline).

The Bakken Formation records the interaction of basin subsidence and at least two episodes of rising sea level. Following deposition of the intertidal Three Forks Formation, rising sea levels and tectonic subsidence within the Williston Basin created an oxygen-stratified water column (Webster, 1984; Smith and Bustin, 1997; 2000). Large amounts of organic-rich hemipelagic mud accumulated throughout the deeper parts of the basin forming the lower Bakken shale.

The middle member of the Bakken Formation is relatively lean with respect to organic carbon. This suggests that the end of lower Bakken shale deposition came as falling sea-levels and the return of well oxygenated bottom waters formed a mixed clastic-carbonate assemblage of lithologies. Textures and trace fossils suggest that sea levels within the Williston Basin initially fell during middle Bakken time (Smith and Bustin, 1997; 2000). This resulted in a generally upward shoaling succession of fine-grained to mud-sized clastic and carbonate sediments that in the deeper parts of the basin is capped by a clean, fine-grained cross-stratified sandstone or grainstone. This sandstone unit, or “clean gamma-ray” bench

(Lithofacies 3) on logs appears to mark a sea level lowstand that preceded the second phase of rising sea-levels that completed the deposition of the Bakken Formation (See Appendix II for detailed descriptions). Rising sea levels during the waning stages of middle Bakken deposition produced a succession of generally fining upward clastic and carbonate sediments. The apparent return of oxygen stratification and possible sediment starvation within the Williston Basin resulted in a second phase of organic-rich, hemipelagic mud accumulation that forms the upper Bakken shale.

The return of oxygenated bottom waters to the Williston Basin marks the end of Bakken deposition and the beginning of normal marine carbonate sedimentation that buried the Bakken Formation beneath a series of shallow marine platform deposits of the Lodgepole Formation.

Source Rock Maturation

Meissner in a landmark paper published in 1978 analyzed the petroleum potential of the Bakken Formation. He recognized several significant factors related to the accumulation of oil in Bakken and adjacent formations. One of these was the recognition that the resistivity of the Bakken Shale increased sharply in those portions of the Bakken that were at temperatures in excess of 160^{o} F (71^{o} C). He attributed the change in resistivity to the expulsion of electrically conductive water by electrically insulating oil during oil generation. Meissner assumed that this oil was generated in place and that the organic "maturity" of the formation could be gauged by the resistivity of the Bakken shales. He used this resistivity-based "maturity" to map the expected distribution of oil within the Bakken. Meissner also recognized that the elevated resistivities seemed to correspond with very high formation pressures. He argued that abnormally high pressures are an expected product when oil is generated in rock with little permeability. He also noted that in some Bakken wells the original formation pressures were close to the lithostatic pressure exerted on the formation by the weight of the overlying rock. Citing basic mechanical properties, Meissner argued that these pressures could be capable of spontaneously generating fractures within the Bakken and adjacent formations. Meissner proposed a pore scale model of oil generation from kerogen that would explain the change in rock resistivity he observed. One of the interesting elements of this model is the expectation that an oil generating shale would lose porosity during the conversion of kerogen to oil.

Oil Generation Rates

Producing petroleum from kerogen requires sufficient time and temperatures to accommodate the chemical reactions that are involved in this transformation. These reactions are very complex and involve a variety of individual organic compounds and reaction pathways. Consequently, most attempts at predicting oil generation rates make use of very simplified models.

The Lopatin (1971) method evaluates source rock maturity through the calculation of the so-called Time-Temperature Index (TTI). The TTI is probably the simplest way to incorporate the burial history of a basin with temperature and time to evaluate the petroleum generating potential of a basin. The method assumes that for every 10^{o} C rise in temperature the rate of oil generation doubles and that this "rate" accumulates with time (Wood, 1988). In this way, source rocks that have experienced maturation at lower temperatures over extended time periods could be expected to have the same generation potential as a source rock that matures at higher temperatures for shorter periods of time. Even though the method, at best, is limited to rough estimates of oil generation potential it does provide a means of determining oil generation potential from archived rock type and depth data obtained from drilling. The following map is an update of Nordeng's (2008) TTI map. The updated map incorporates Gosnold's (Pers. Comm., 2009) suggestion that the pre-glacial surface temperature in North Dakota was on average closer to 15^{o} C rather than the 4^{o}C used in the original map. The TTI map presented here (Fig. 17) suggests that oil generation is possible further to the east than was originally proposed and that the central part of the basin (i.e. McKenzie County) is probably super-mature. The updated TTI map shows that rapid oil generation (TTI~ 65) is possible along the western border of Mountrail County in relatively close proximity to the Bakken production in Mountrail and Dunn Counties.

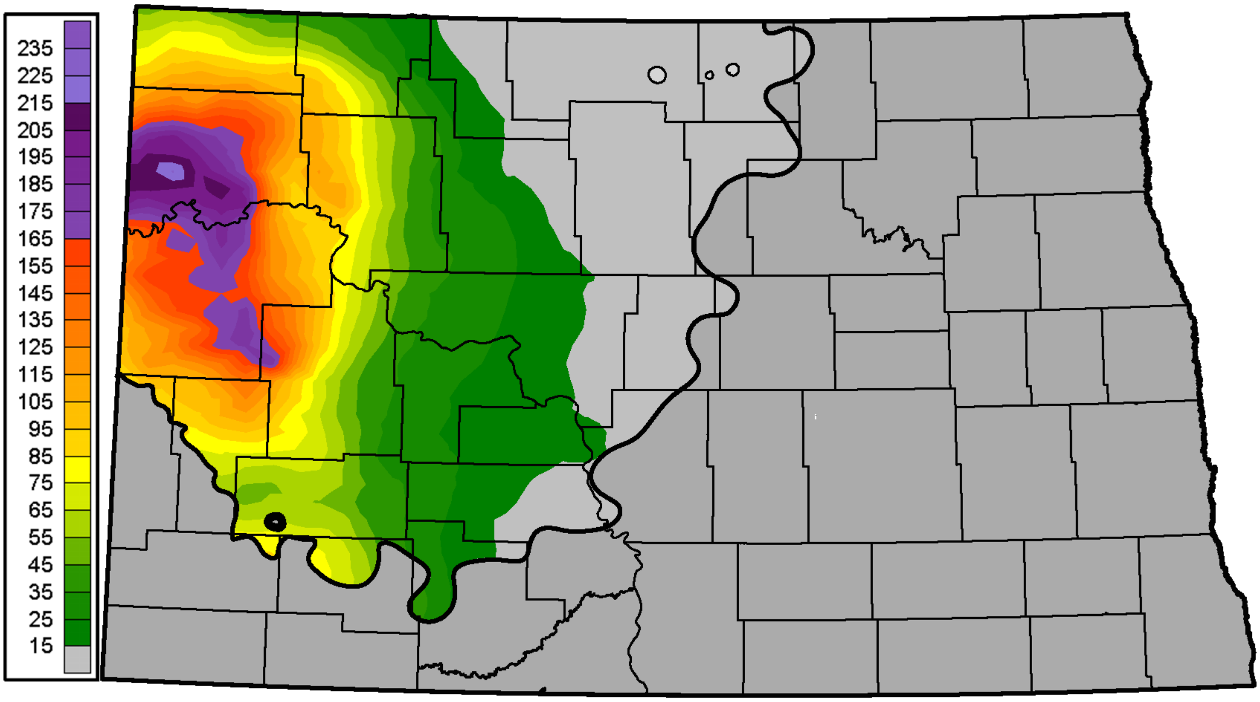


Figure 17. A TTI map using the Lopatin (1971) method. The map is constructed with the same data as was used in the North Dakota Geological Survey's Geological Investigation No 61 except that, a 15^{o} C surface temperature is used in place of the original 4^{o} C surface temperature. The onset of oil generation is usually associated with a TTI of 15, intense oil generation with a TTI of ~65 and the end of oil generation with a TTI of > ~165.

Most analytical solutions to the question of reaction kinetics in source rocks recognize that these reactions are sensitive to temperature and time. Most chemical reaction rates vary with temperature according to the Arrhenius equation as follows:

$$K = A\, e^{-E/RT}$$

Where:

K = reaction rate (M/T)
A= "frequency factor" which is related to the number of collisions that occur per unit time.
E = Activation energy which is the energy barrier that must be exceeded for a reaction to occur
R = Gas constant
T = Temperature (K)

In the case of a constant reaction temperature, the amount of material that has reacted is given by multiplying the instantaneous reaction rate by time. Geologic systems rarely allow such simplifications, so in these systems the instantaneous rate is integrated with respect to the change in temperature caused by subsidence and the time over which subsidence occurred. Fortunately, Wood (1988) solves this integral.

To illustrate the impact that reaction kinetics has on oil generation let's consider a simple model in which an initially flat lying source bed is allowed to "tilt" so that each point on the source bed subsides at a different rate. If we also assume that the temperature at 11,000 ft. is 140^{o} C, the surface temperature is constant at 4^{o}C and the temperatures between the surface and 11,000 feet varies according depth. Assume that the kerogen is uniform , has an activation energy of 204 kj/mol and a pre-exponential factor (A) of 1X10^{27} interactions per million years. The Arrhenius equation predicts that a unit mass of kerogen will decrease along the black sigmoidal line in Figure 18 with the relative rate of oil generation following the lavender line. This diagram shows that differential subsidence of a homogeneous source bed should reach a critical depth/temperature that corresponds with a rapid decrease in source rock kerogen and the simultaneously generation of a "pulse" of oil. At depths above this critical region temperatures are too low to rapidly transform kerogen into oil and at depths below this region the amount of reactive kerogen is essentially gone.

The theoretical concepts presented above are consistent with Meissner's notions concerning oil generation within the Bakken Formation. However, it's unclear whether the generation of a petroleum "pulse" during burial and the repercussions of this process are fully appreciated. One significant implication is that the generation rates suggested in Figure 18 are operating today. Therefore if this model is correct then oil generation within shallower portions of the Bakken must be geologically "young".

To test the idea that oil generation within the Bakken is largely restricted to a critical temperature/depth region requires an independent measure of oil generating potential. The RockEval® method is one popular solution to this end. The RockEval® method is essentially an artificial maturation experiment in which pyrolysis provides data sensitive to the kinetics of the organic matter present in the sample tested.

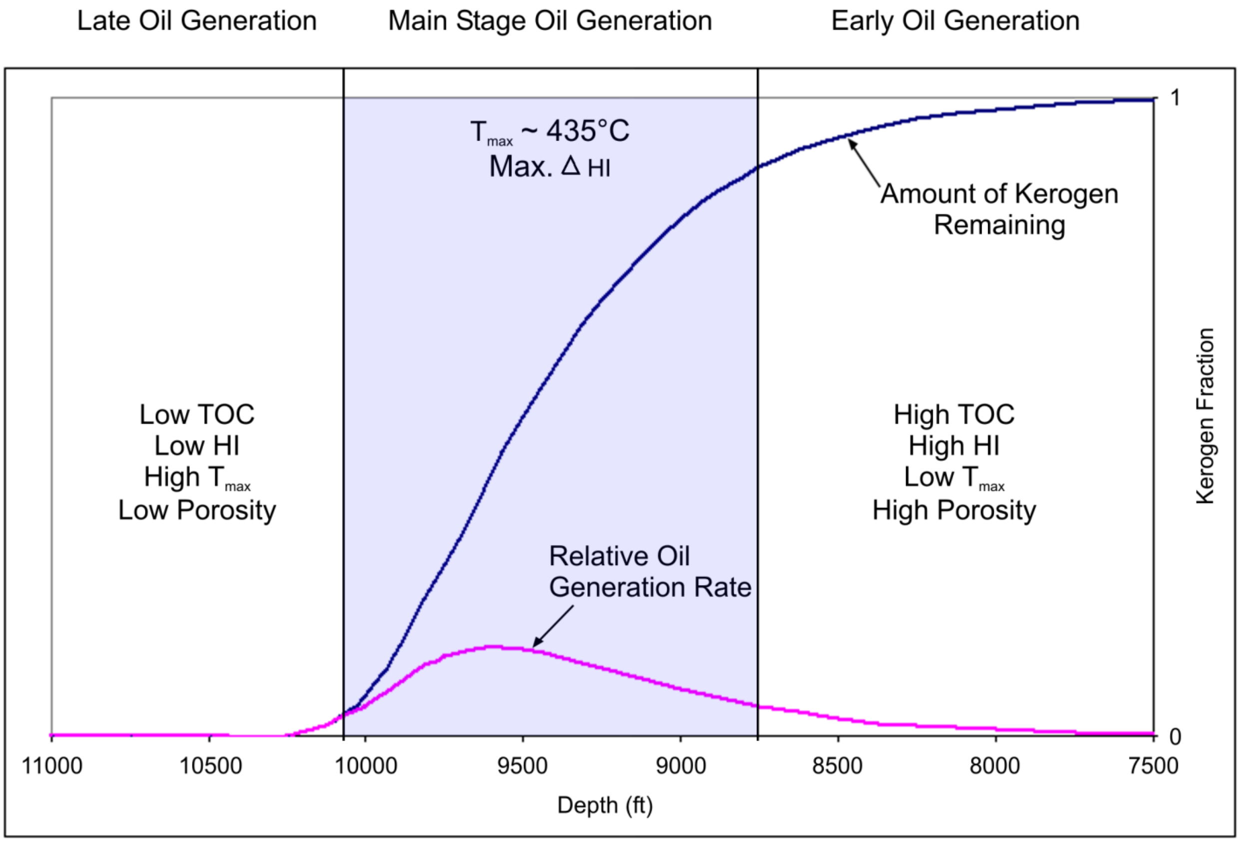


Figure 18. A schematic diagram illustrating the decline in the reactive kerogen content (dark line) and the relative rate of oil generation (lavender line) for a source bed that is tilted over the course of 360 million years to a maximum depth of 11,000 ft. The kerogen in the source rock has an activation energy of 204 kJ/mole and a "frequency" factor (A) of 1 X 10^{27} interactions per million years. The temperature at 11,000 feet is assumed to be 140 ^{o}C and at the surface 4^{o}C. Temperatures between these extremes are assumed to be linearly proportional to depth.

RockEval® Analysis

RockEval® analysis involves placing small samples (~0.1g) into an oven containing an inert (helium) atmosphere. The sample is heated through a standardized set of temperatures and heating rates during which thermally vaporized hydrocarbons and carbon dioxide are measured. The mass of three components are obtained during a typical RockEval® pyrolysis. These include the mass of free hydrocarbons (S_1), mass of potential or "crackable" hydrocarbons (S_2) and the mass of organically bound oxygen (S_3). Additionally, the temperature (T_{max}) that generates the maximum amount of crackable (S_2) hydrocarbons provides an important measure of the kerogen's level of thermal maturity.

S_1 provides direct evidence of past hydrocarbon generation whereas S_2 provides a measure of the remaining hydrocarbon generation potential of the sample. Unfortunately, the hydrocarbon mass in S_1 is frequently in error because samples lose hydrocarbons during transport and storage or are contaminated during drilling and handling. Because of the uncertainty in the values of S_1, these data are not discussed further here. The values for S_2 and S_3 are not as susceptible to these problems, primarily because the organic matter involved (kerogen) is stable under near surface conditions and is less susceptible to contamination.

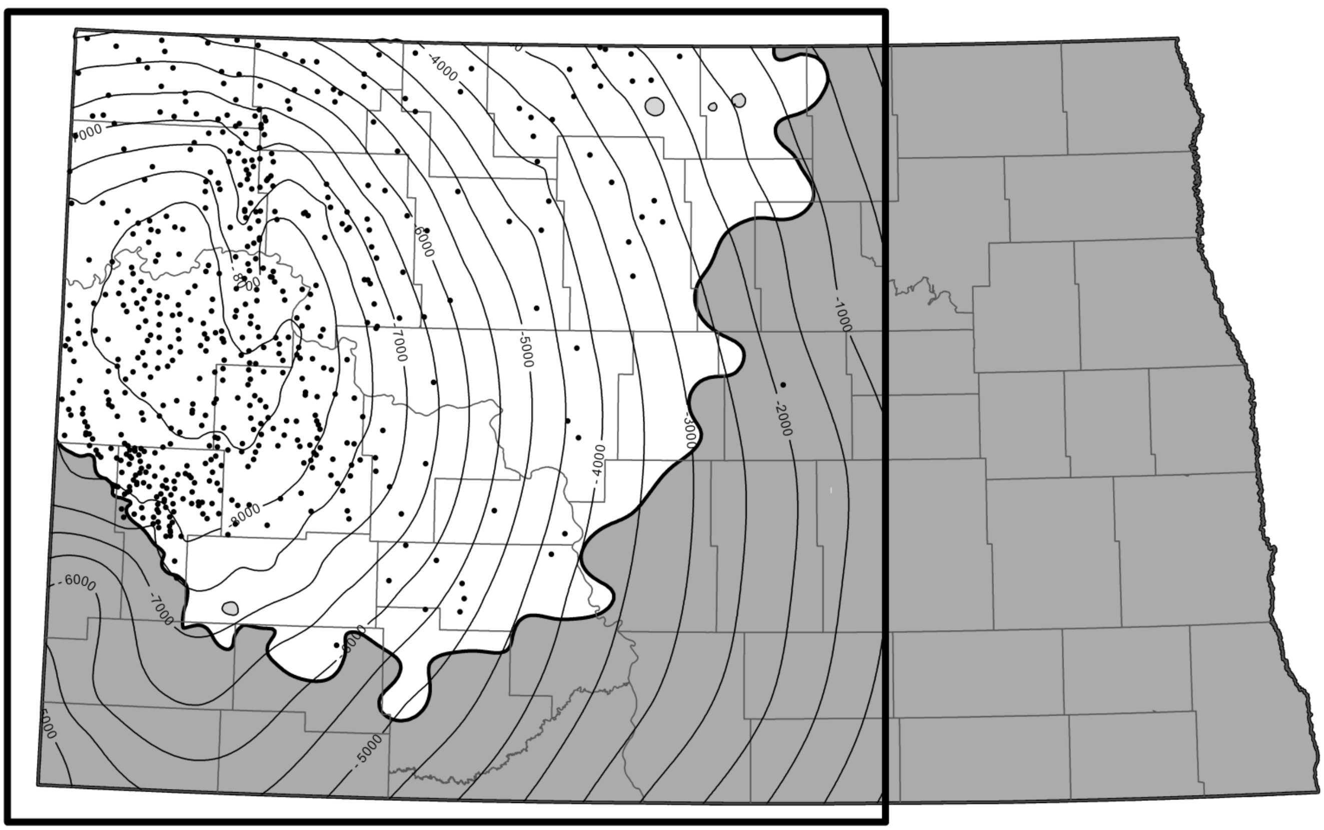


Figure 19. Location map showing the wells from which samples of the Bakken Formation have been analyzed by the RockEval® method. The contour lines represent the surface of the Bakken Formation or where absent, the Three Forks Formation. The outlined area is the part of North Dakota that is presented as detail maps.

RockEval® data has been collected by a number of workers in the Williston Basin. Many of these data are available through the USGS and the North Dakota Geological Survey (NDGS). In this report, the RockEval® data has been filtered to include only the analyses from the upper Bakken shale. An average value is used for each location in which there is more than one analysis available. The map in Figure 19 presents the distribution of RockEval® data used herein.

The S_2 and S_3 values along with the weight percent of total organic carbon (TOC) are useful tools for evaluating the original source of the organic matter that is preserved as kerogen in a source rock. It is common practice to normalize S_2 and S_3 to the total organic carbon content of the sample through the calculation of Hydrogen and Oxygen Indices as follows (HI and OI respectively):

HI = 100 X S2 (HC in mg/g) / weight % Total Organic Carbon

OI = 100 X S3 (CO_2 in mg/g) / weight % Total Organic Carbon

The HI value represents the amount of carbon within a sample that is capable of being thermally converted into hydrocarbons. High hydrogen indices are an indication that a source rock has the potential to generate hydrocarbons. The Oxygen Index (OI) is an estimate of the amount of organically bound oxygen that is present within a source rock. A cross-plot of the hydrogen index against the oxygen index is frequently used to determine whether a particular kerogen is prone to generating gas (Type III), oil and or gas (Type II), or oil (Type I). In the case of the kerogen within the upper Bakken shale the HI vs OI plot suggests that the kerogen is oil prone Type I and/or Type II kerogen (Fig. 20).

Changes in RockEval® parameters with increasing organic maturity

If the original kerogen within the Bakken Formation is assumed to be homogeneous then regional variations in the HI should be expected to reflect variations in the rate of oil generation (See Fig. 21). The plot of HI versus depth for the data in this report shows that the average HI index of the upper Bakken is roughly constant between 5,000' and approximately 8,500' depth (Fig. 22). Beyond 8500' HI decreases significantly with increasing depth. This is consistent with the idea that oil generation within the Bakken consumes the kerogen bound organic carbon that measured is by the HI.

The depression in the HI in the upper Bakken (see Figs. 22, 23, and 24) suggests that kerogen maturity roughly coincides with the regional structural depression that is mapped on the top of the Bakken Formation (see Fig. 19). If the change in HI is caused by oil generation then the first derivative of the HI surface would locate where and how rapidly, in a relative sense, the Bakken Formation is currently generating oil. The HI slope (first derivative) map (Figure 25) shows that the largest lateral changes in HI roughly rim the deepest portions of the basin. On either side of this “rim” the change in HI is much less. Furthermore, the pattern of HI slope and T_{max} contours are remarkably similar. Superimposition of the T_{max} map with the HI slope map shows that the largest changes in HI correspond with T_{max} values of between 435° and 440° C (Fig. 26). T_{max} values near 435°C are considered significant because this is a critical temperature that has been associated with maximum oil generation rates from Type I and Type II kerogens. If this is so then the correspondence of T_{max} values near 435°C with the highest rates of change (slope) in the HI index would support the idea that there is restricted zone of oil generation within the Bakken that rims the basin. Therefore, this “rim” and the inferred zone of oil generation would lie between slow rates of oil generation in less thermally mature kerogen from slow rates of oil generation in thermally mature though partially exhausted kerogen.

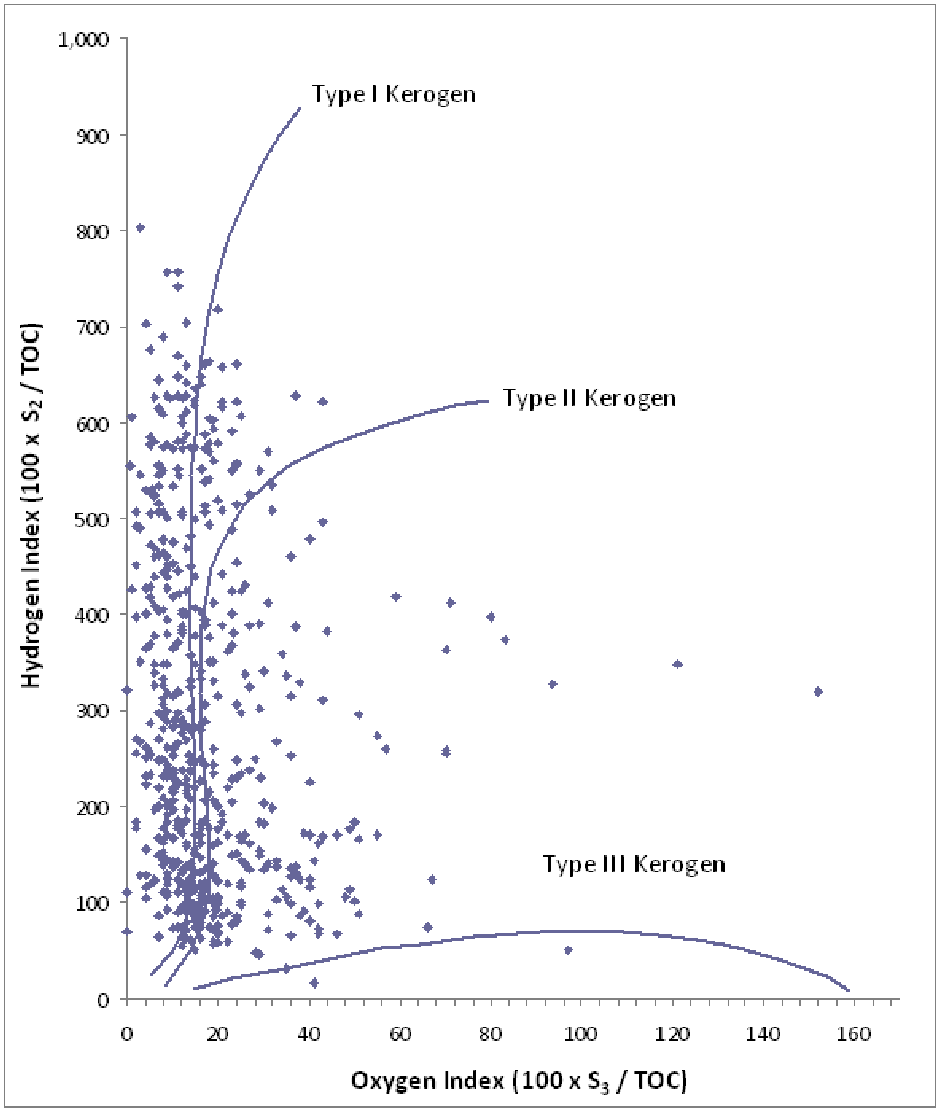


Figure 20. A modified Van Krevelen diagram showing one method of determining kerogen type using RockEval® data. This diagram suggests that kerogen within the Bakken Formation is oil prone Type I or Type II. The labeled lines reflect the change in OI and HI that is followed for different kerogen types during maturation. Maturation drives the OI and HI values towards zero along the lines for each kerogen type.

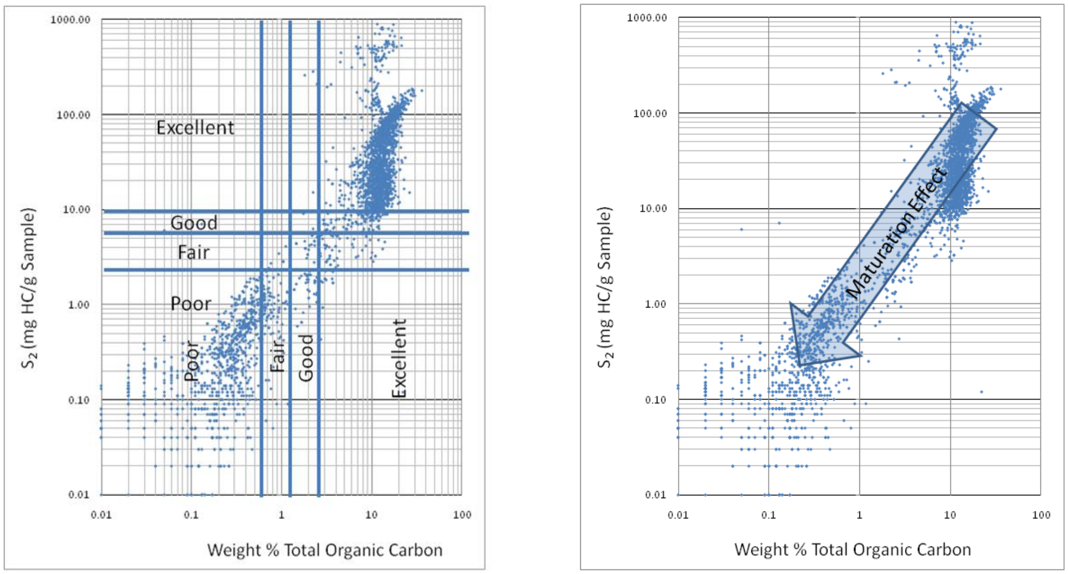


Figure 21. A plot of the mass of "crackable" hydrocarbons (S_2) versus the total organic content (TOC) of the sample. This diagram is partitioned with respect to the oil generation potential based on S_2 content and TOC content (Dembicki, 2009). The diagram suggests that the Bakken tends to have either excellent source rock potential or poor source rock potential. This could reflect regional variations in original kerogen quality or the variation could be due to an originally excellent kerogen being modified by oil generation so that it now plots in the "Poor" field (Maturation Effect).

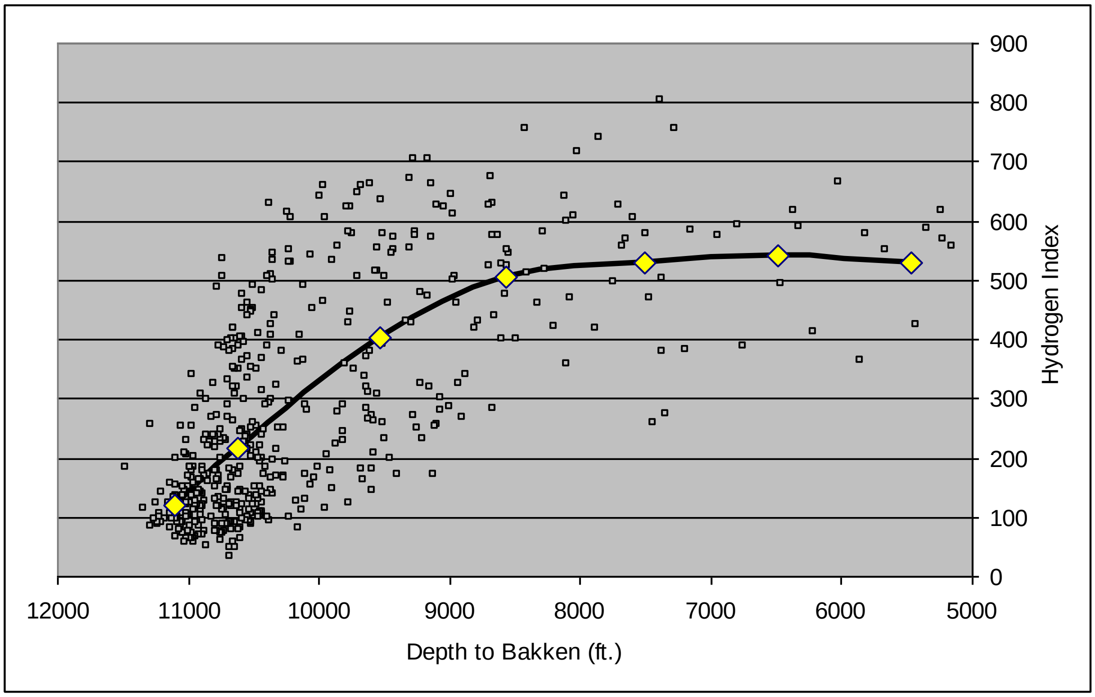


Figure 22. Hydrogen Index (squares) plotted against depth for 505 wells from which samples of the upper Bakken were analyzed using RockEval®. When the RockEval® data for the entire Williston Basin are grouped into 1,000' depth intervals and averaged (diamonds) the decrease in HI with increasing depth is readily apparent (heavy black line). This is the expected behavior of a more or less homogeneous kerogen (< ~8500') that is undergoing oil generation (>~8500').

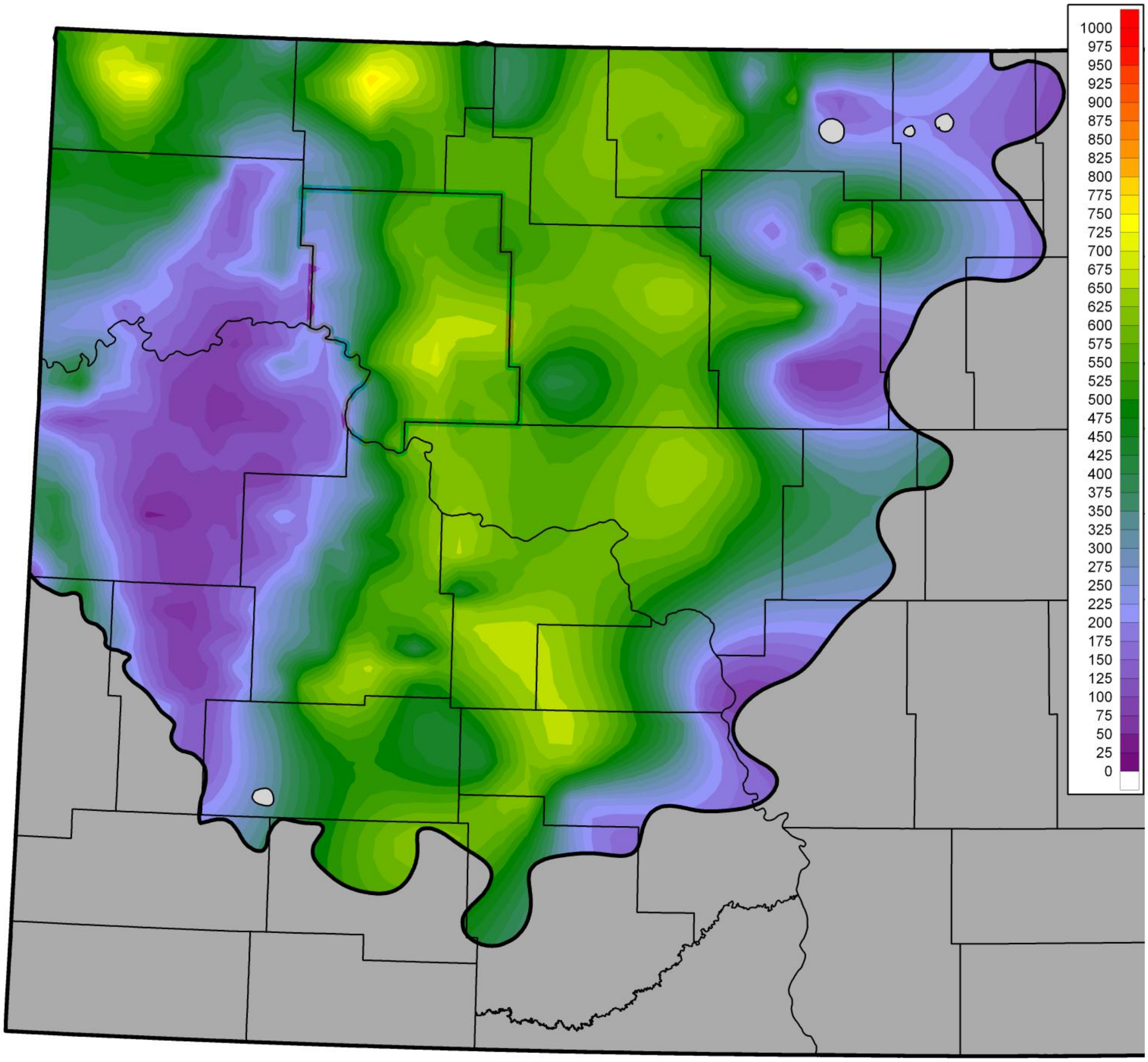


Figure 23. A map of the RockEval® determined HI for samples taken from the upper Bakken shale. Elevated hydrogen indices are presented as yellow and light green with the lower hydrogen indices shown as shades of purple and blue (modified from LeFever, 2008)

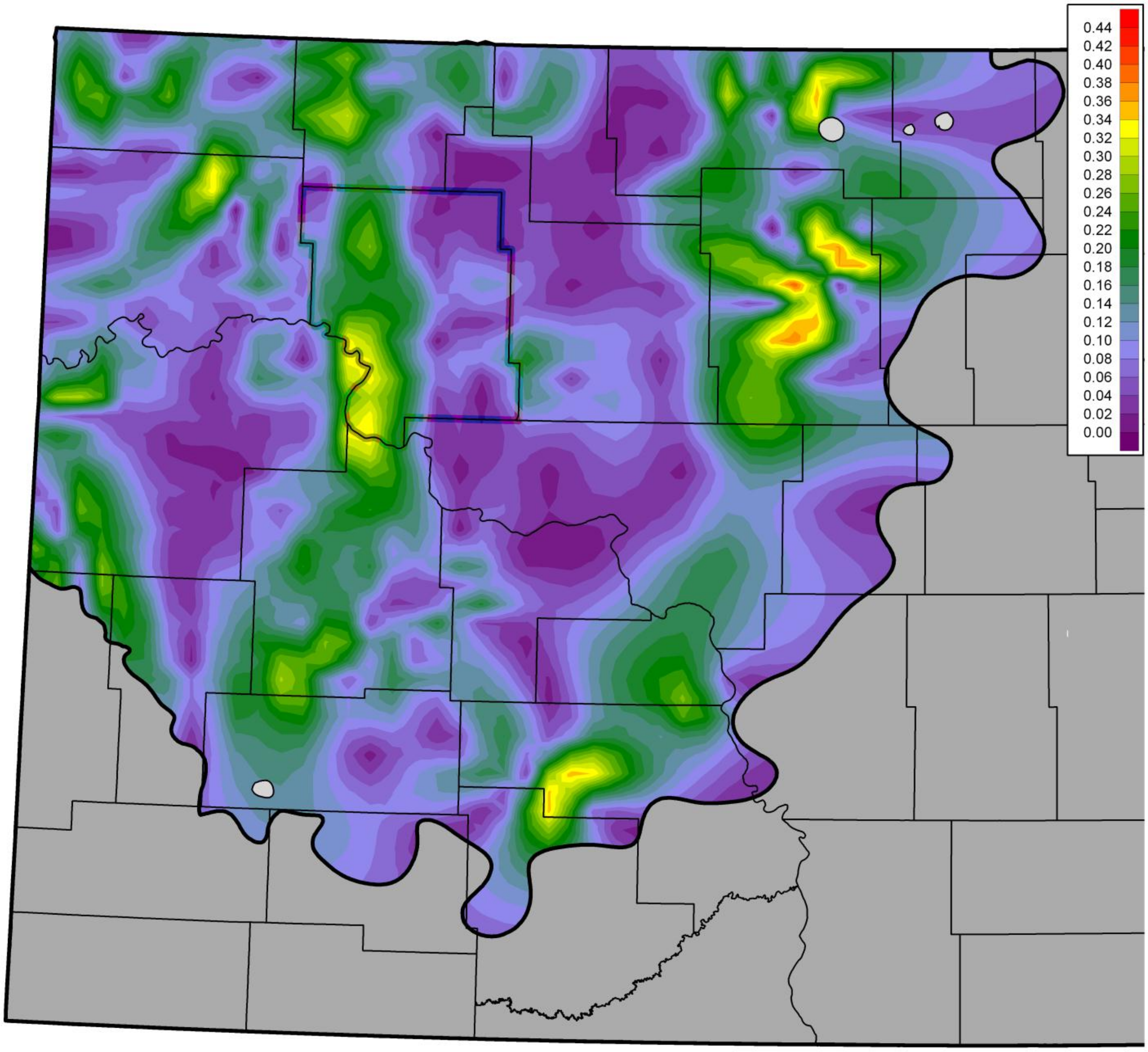


Figure 24. The 1st derivative or slope map of the HI in Figure 23. This map illustrates the lateral change in HI in which slow rates of change are presented as shades of blue and purple and rapid rates of change in shades of green, yellow and orange.

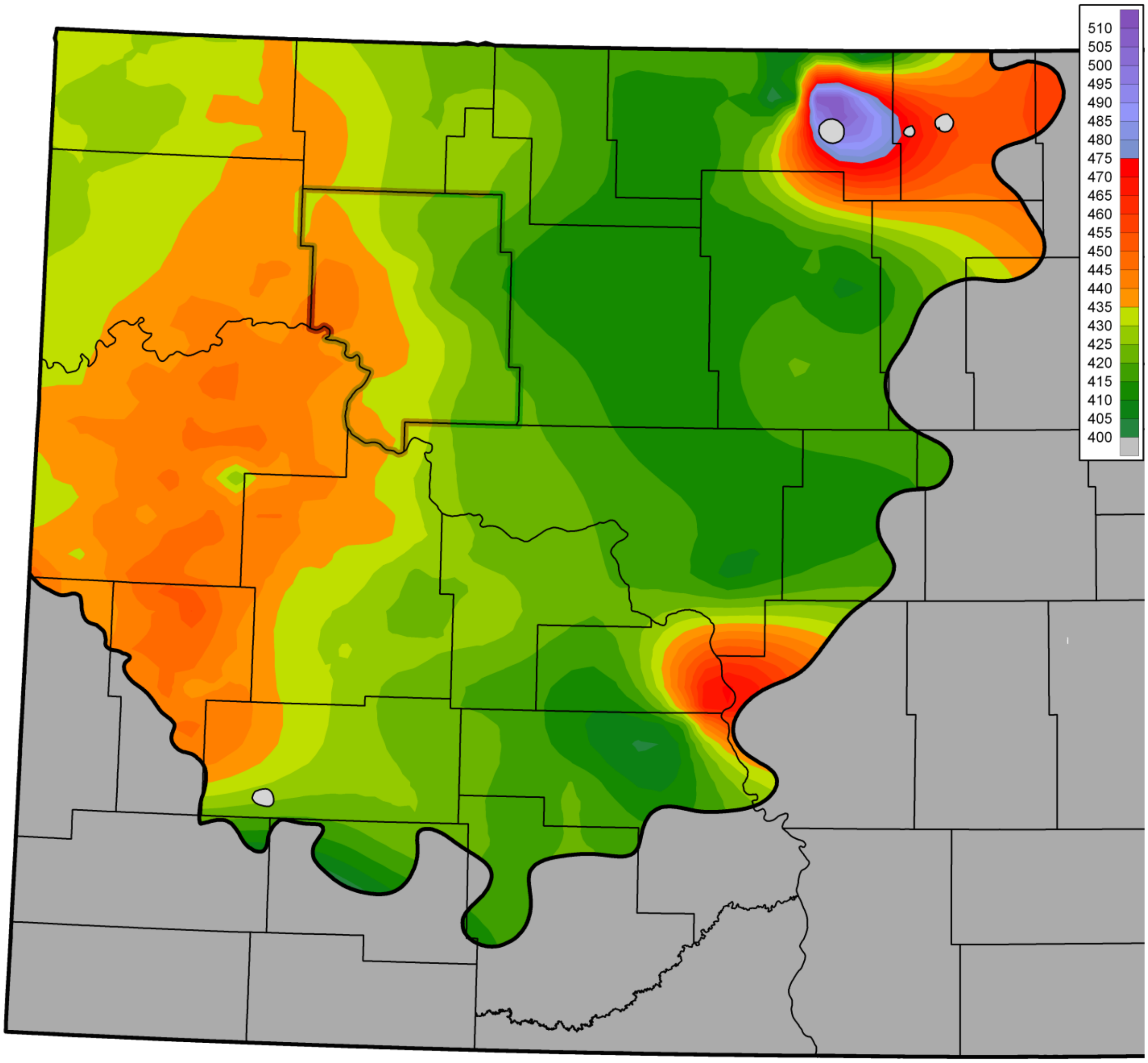


Figure 25. Map of the T_{max} values measured in the upper Bakken shale. Less mature kerogens are indicated by the lower values of T_{max} and are presented in shades of dark to light green which represent T_{max} values that range from 400° C to 435°C. Mature kerogens are represented by the contours presented as shades of orange (435° C to over 450°C) (modified from LeFever, 2008).

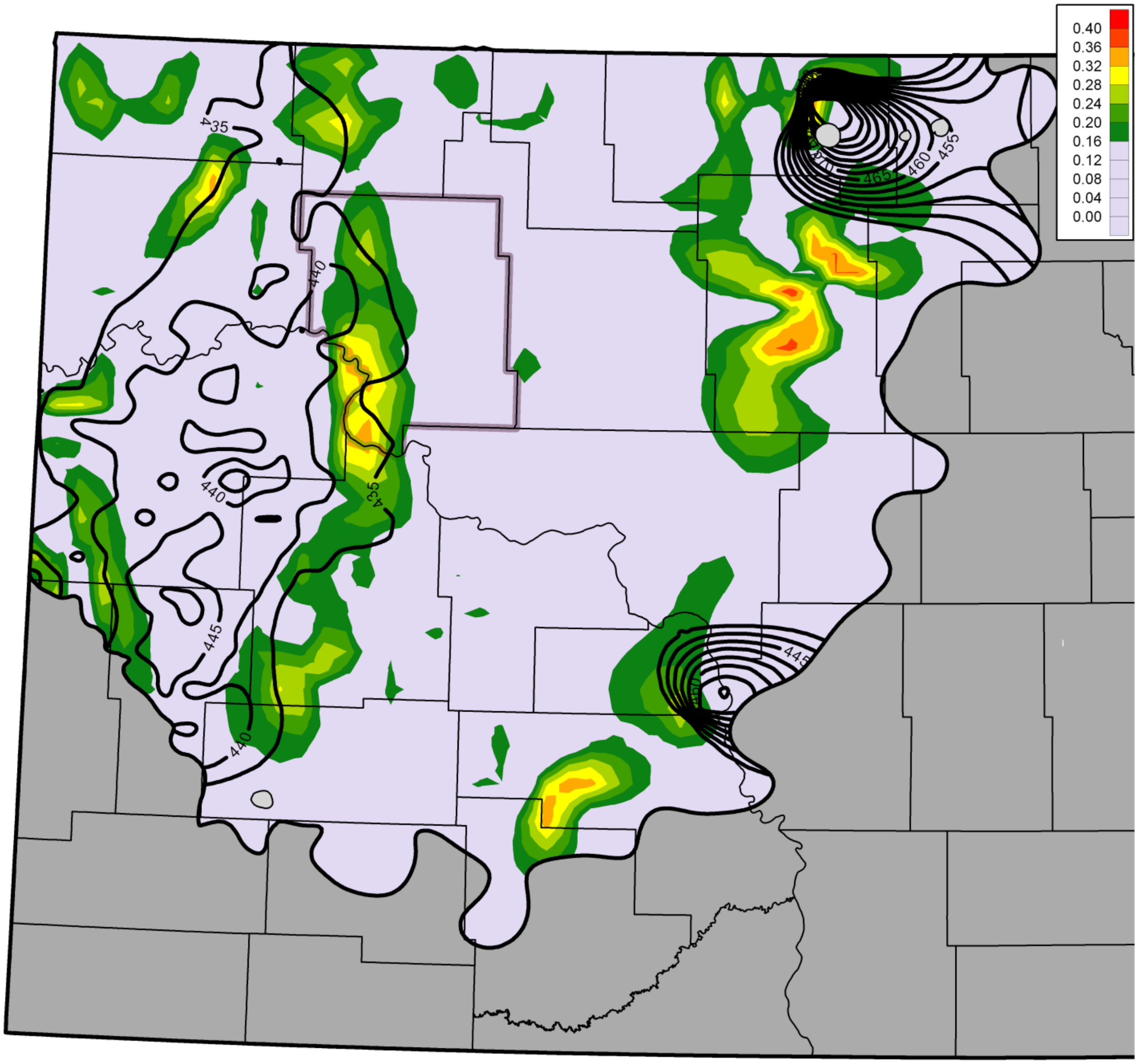


Figure 26. A composite map that includes contours (color filled) that show the location of the largest change in HI (>0.16) together with contour lines representing the T_{max} values for the upper Bakken shale that are >435° C.

Maturation and Compaction

One of the fundamental elements of Meissner's (1978) model involves changes in the texture of the Bakken source rocks during maturation. Figure 27 illustrates the main concepts involved. The source rocks within the Bakken source system contain on average about 11% kerogen. During maturation oil generation expels interstitial water. Because the rocks above and below the oil generating shales have very low permeabilities, high pressure is needed to expel the fluids. With time and oil generation, pore space within and adjacent to the Bakken source rocks become completely saturated with highly pressurized oil (Coskey and Leonard, 2009). At the same time the conversion of solid kerogen into moveable liquid petroleum results in compaction of the source beds.

This part of Meissner's model is consistent with porosity measurements obtained from 128 wells that have digital LAS logs on file with the NDIC. The wells were segregated on the basis of whether or not the wells surface location is greater or less than the 435^{o}C T_{max} contour in Figure 28. Wells within this contour interval are classed as "mature" (orange fill) whereas those wells outside the closed contour are considered "immature"(blue fill). Frequency diagrams constructed from porosity readings recorded by neutron and compensated density wireline logs (see Figure 29 and Table 1) indicate that within the upper Bakken, immature shales to contain, on average, 9% more porosity than mature shales. This result is consistent with Meissner's contention of a reduction in porosity caused by the conversion of kerogen into oil and gas. However, it is also possible that part of the porosity reduction may be caused by solid volume reductions caused by simple burial, clay mineral diagenesis or changes in log readings resulting from other forms of diagenesis.

Various lines of evidence substantiate the basic idea that oil production from the Bakken Source System is closely related to the kinetics of kerogen conversion (Price and LeFever, 1994). The kinetics are related to the subsidence and thermal history of the basin as well as the amount and specific kerogen types that are in the source rocks of the Bakken Formation. Current data suggests that there is an active oil generation zone that roughly rings the basin and that this zone is associated with decreasing shale porosities. The combination of oil generation and the loss of porosity provide the impetus to drive fluids from the source shales and into potential reservoirs such as the middle Bakken, Three Forks and possibly Lodgepole Formations.

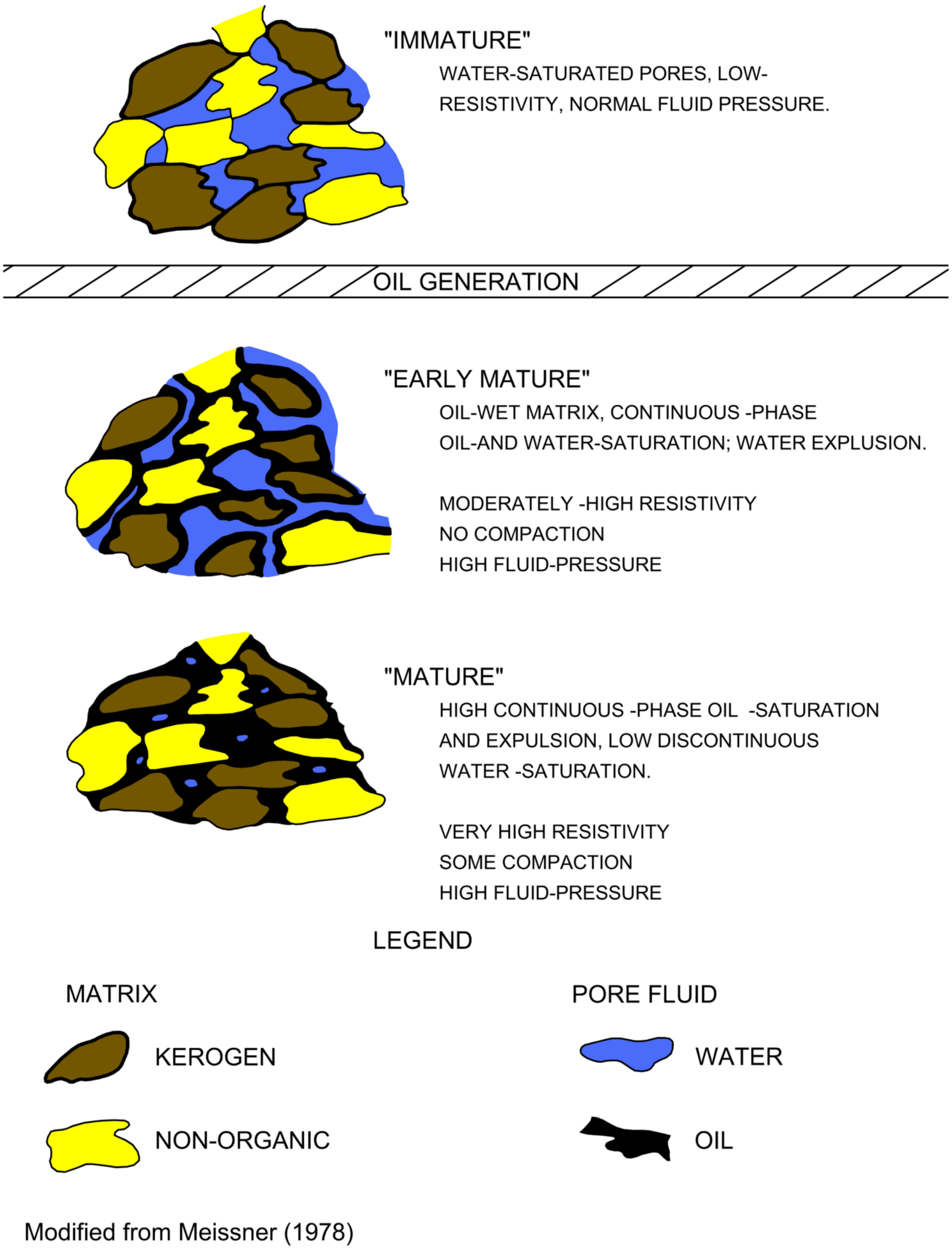


Figure 27. Schematic diagram illustrating the mechanism proposed by Meissner (1978) for maturation induced overpressures.

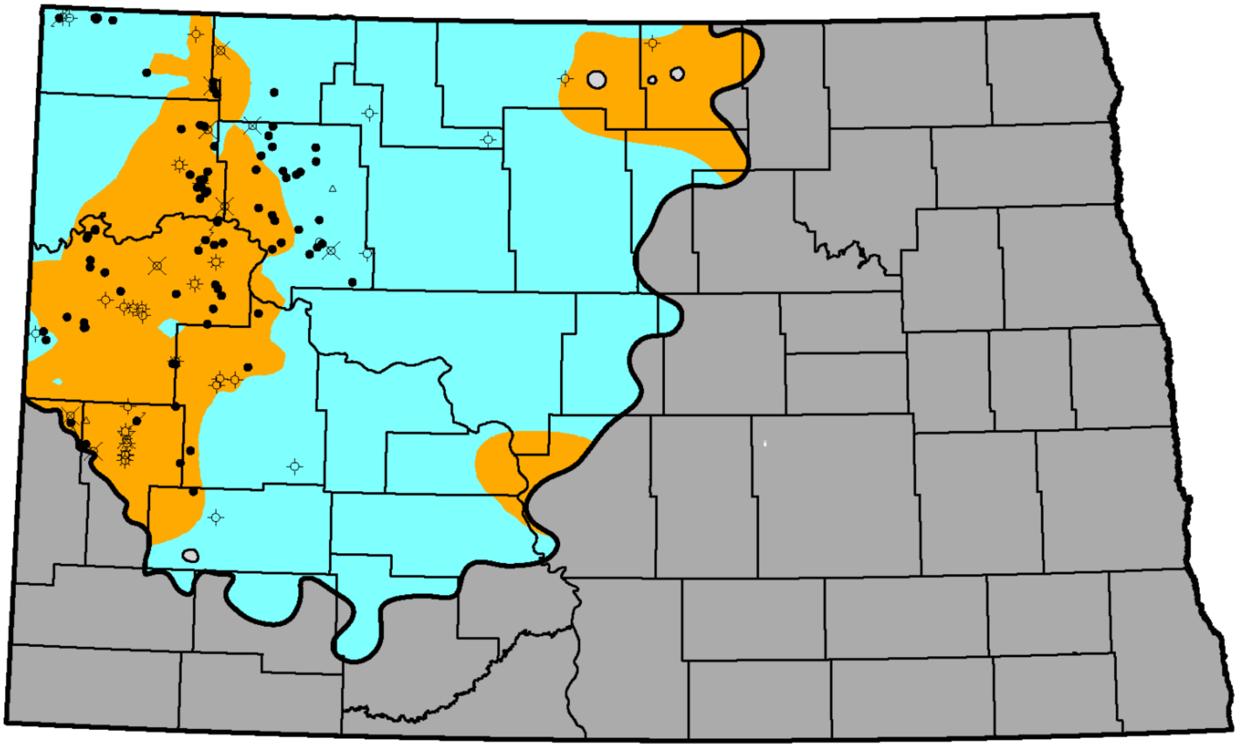
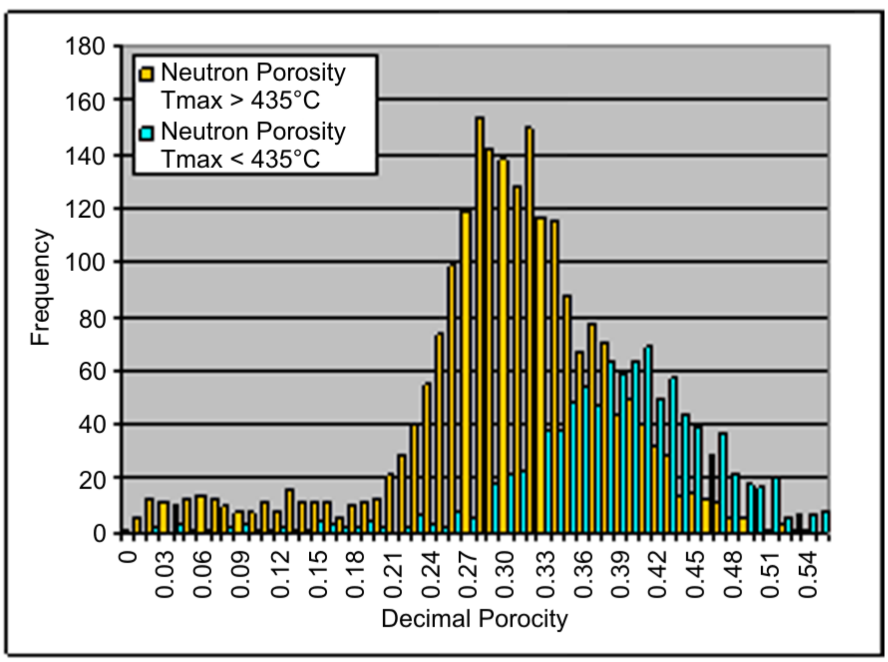
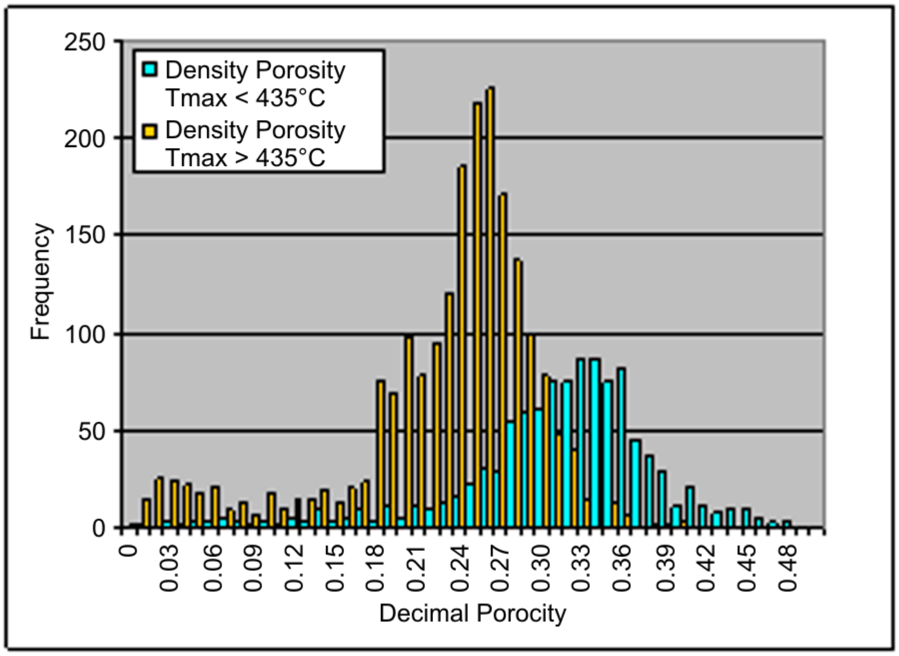


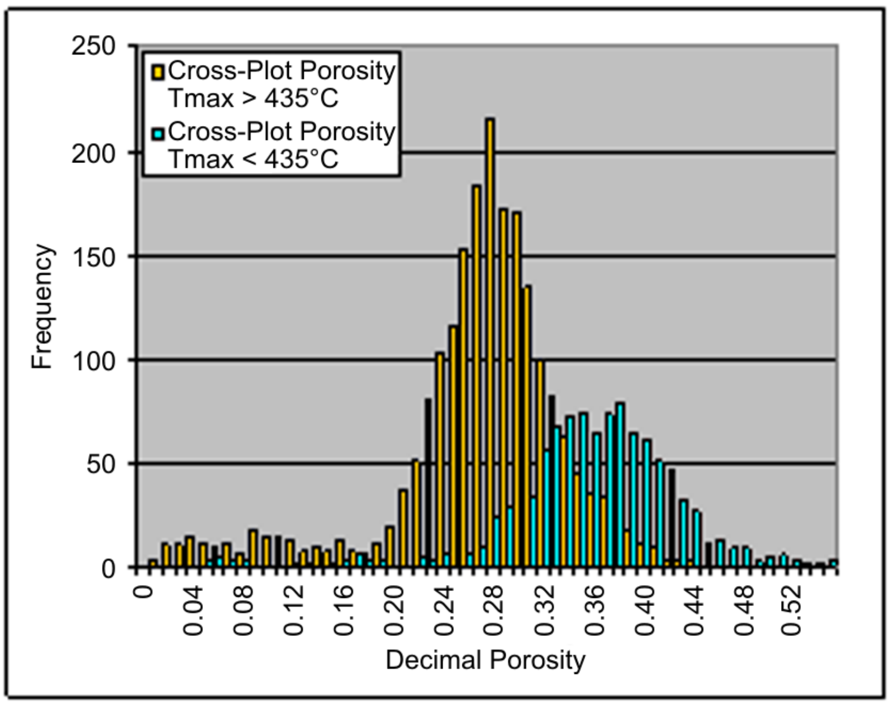
Figure 28. Location map with the distribution of LAS logs used to determine the porosity of the upper Bakken shale. The regions portrayed in gold are within in the 435°C T_{max} contour and are considered "mature" shales. Conversely, the region shown in light blue is considered "immature".



A) Density porosity.



B) Neutron porosity.



C) Cross-plot porosity.

Figure 29. Frequency distributions that illustrate the difference in density porosity (A), neutron porosity (B) and cross-plot porosity (C) between mature and immature Bakken shale. The maturation cutoff in this case is based on the T_{max} map of Nordeng and LeFever's (2009).

Porosity Log	Sample Group	Mean	Variance	# Samples
Density	>435	0.22	.0049	2078
	<435	0.31	0.0052	1049
Neutron	>435	0.30	0.0079	2181
	<435	0.39	0.0100	1049
“Cross-Plot”	>435	0.26	0.0052	2078
	<435	0.35	0.0064	1049

Table 1. Summary statistics for the log-based porosity data used this study. All three sets of statistics indicate that there is a 9% difference in porosity between the mature and immature portions of the Bakken Shale.

Fractures – Rock Mechanics

One of the prevailing themes that have emerged over the course of Bakken exploration is the central role that natural fractures play in enhancing oil production. Murray (1968) and Meissner (1978) both recognized that production from the Bakken source system depends on processes that induce fracturing in the Bakken, Three Forks and possibly the Lodgepole Formations. Murray noted that in the Antelope Field, enhanced production is associated with the most intensely “bent” parts of the Antelope Anticline along the northeastern limb of the structure. He was able to show a relationship between higher rates of production and the degree of structural flexing indicated by a second derivative map of the structure drawn on the top of the Three Forks Formation. In this model the degree of enhanced permeability depends upon the density of tension fractures that are caused by structural flexure.

A second derivative map of the Williston Basin in western North Dakota is presented in Fig. 30. Areas in which tensile fractures could be expected are outlined by negative values that correspond to upwardly convex structural features. The most obvious of these features is the crest of the Nesson Anticline. However, this map indicates a number of other areas where structural flexures could enhance fracturing of susceptible rocks within the middle member of the Bakken and Three Forks Formations.

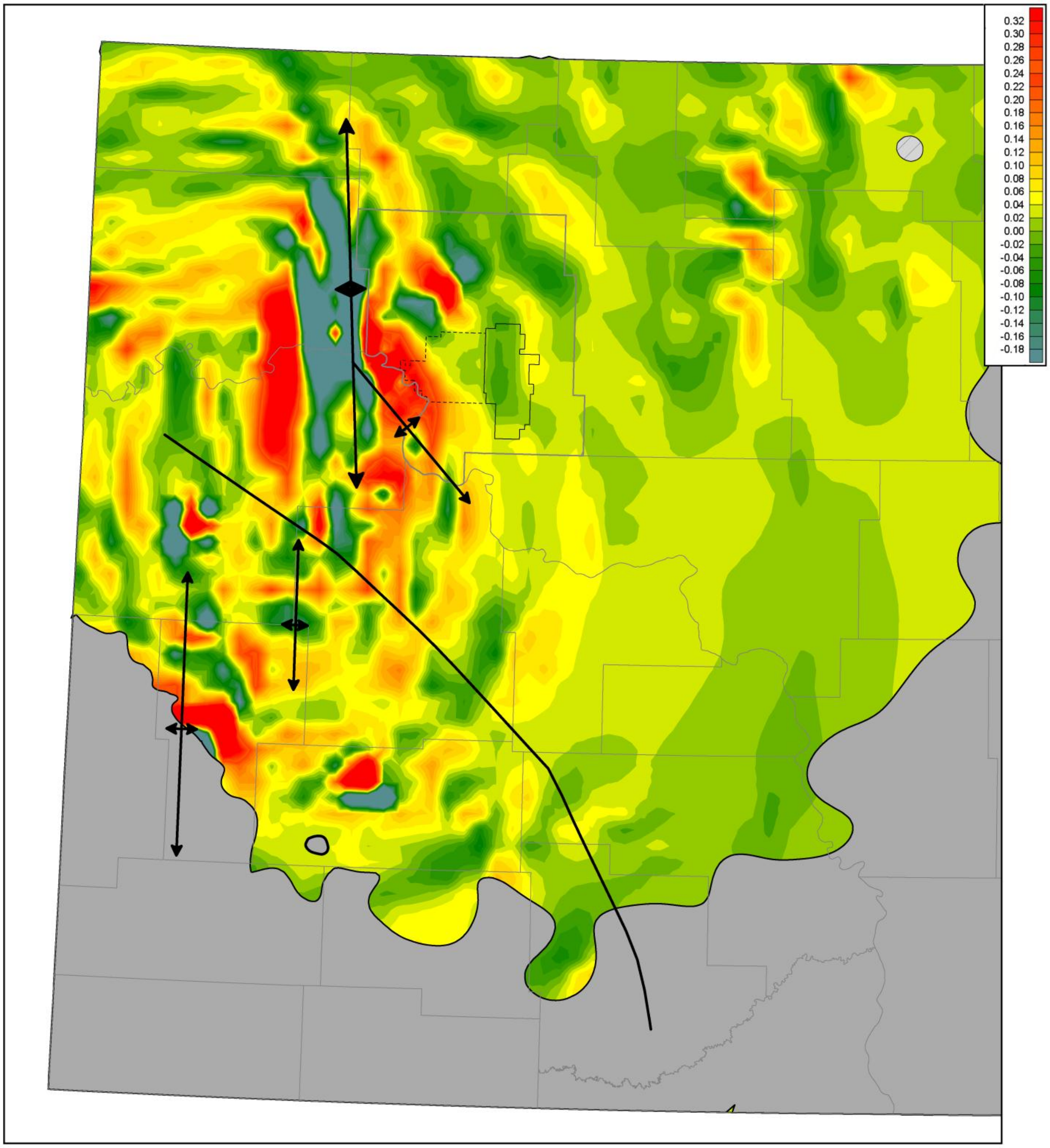


Figure 30 . A second derivative map of the structure on the Bakken Formation presented in Fig. 19. Negative values (greens, yellows, and blue) correspond to convex upward flexures (i.e. Nesson Anticline) whereas positive values (orange and red) correspond to concave upward flexures.

The Meissner model does not depend on structural flexures to induce fracturing. This model is based instead on the spontaneous formation of fractures caused by internal fluid pressures that build up during oil generation in rocks with very low permeabilities. The basic idea is that the loss of load-bearing kerogen and the production of hydrocarbons that cannot freely escape increases pore pressures beyond the confining stress imposed by the weight of the overlying rock column (lithostatic pressure). Significant overpressures are present in the Bakken/Sanish "pools" in the Antelope Field (see Figure 29).

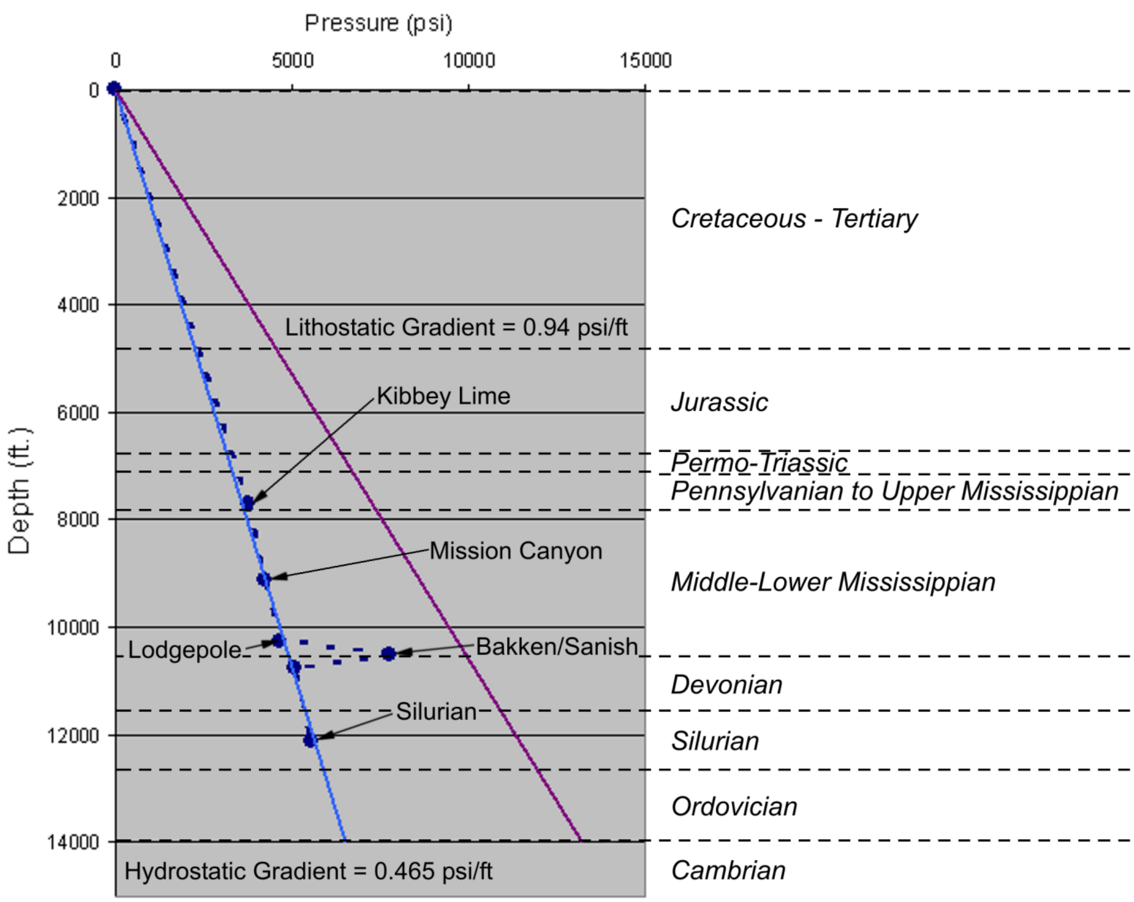


Figure 31. Pressure versus depth plot using Meissner's (1978) data from the Antelope Field, McKenzie County. The diagram shows that the formation pressures in the field are, with the exception of the Bakken/Sanish pool, close to a hydrostatic gradient of 0.465 psi/ft (solid blue line). The Bakken/Sanish pool, however, is significantly overpressured. The lithostatic pressure (purple line) assumes a lithostatic gradient of 0.94 psi/ft.

The presence of elevated pressures, when viewed in the context of basic rock mechanics, suggests that overpressure reservoir fracturing may play a pivotal role in forming an economic oil resource. Meissner illustrates this point graphically with Mohr's circles (See Figure 31). The Mohr's circle graphically describes the stress conditions under which a rock will fracture for a given rock strength. The diagram uses a coordinate system in which the abscissa is scaled in terms of stresses normal to a point within a rock (S) and an ordinate that represents tangential or shear stresses (τ). The mechanical response of a rock with a given tensile and shear strength to various stresses is provided by the rock's "failure envelope". The "envelope" defines the set of shear and normal stresses that will cause brittle rock to fracture. The failure envelope takes the form of a parabola and can be used to not only predict the stress conditions that result in failure, but also the type of rock failure that the stresses should produce for a given set of stress conditions. The mechanical behavior of a rock can be determined for a set of stresses by constructing a Mohrs' "stress circle" in which the diameter of the circle is given by the difference between the minimum (S3) and maximum (S1) principle stresses that are acting on the rock. The maximum principle stress is typically produced by the weight of the overlying rock column with the minimum stress lying at some orientation on the horizontal plane which is perpendicular to the principle normal stress. The center of a stress circle lies on the principle stress axis at the point that corresponds to the average of the maximum and minimum stresses ([S1-S3]/2). The mechanical response of a given rock to a specific set of stresses may be determined from these diagrams. Minimum and maximum principle stresses that produce stress circles that do not intersect the stress envelope are mechanically stable. However, rock fracturing is expected when the stress circle becomes tangent to the failure envelope. If the point of tangency is along the positive portion of the principal stress axis (+S) then the rock fails through shear. Conversely negative points of tangency (-S) indicate tensile failure. The difference between shear and tensile failure is that shear failure produces "closed" fractures whereas tensile failure forms "open" fractures that may contribute to porosity and enhance fluid migration (Fig. 33).

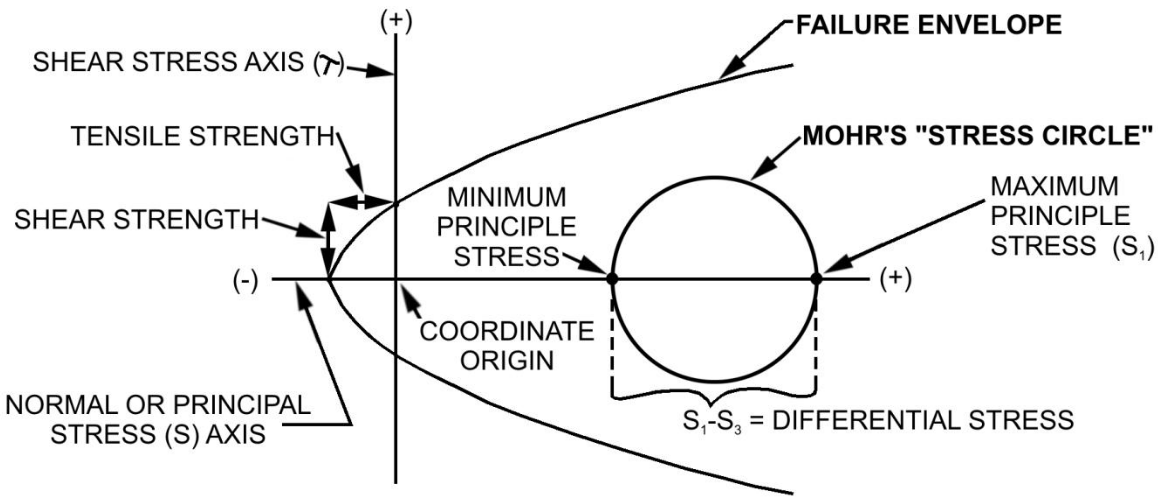


Figure 32. The basic elements used to construct a Mohr's circle that describes the mechanical behavior of a rock with a specific tensile and shear strength to various stress conditions expressed in terms of shear (τ) and principle (S) stresses. The stress circle illustrated here does not intersect the failure envelope. This indicates that the rock is mechanically stable because the stresses portrayed are insufficient to cause fracturing (From Meissner, 1978).

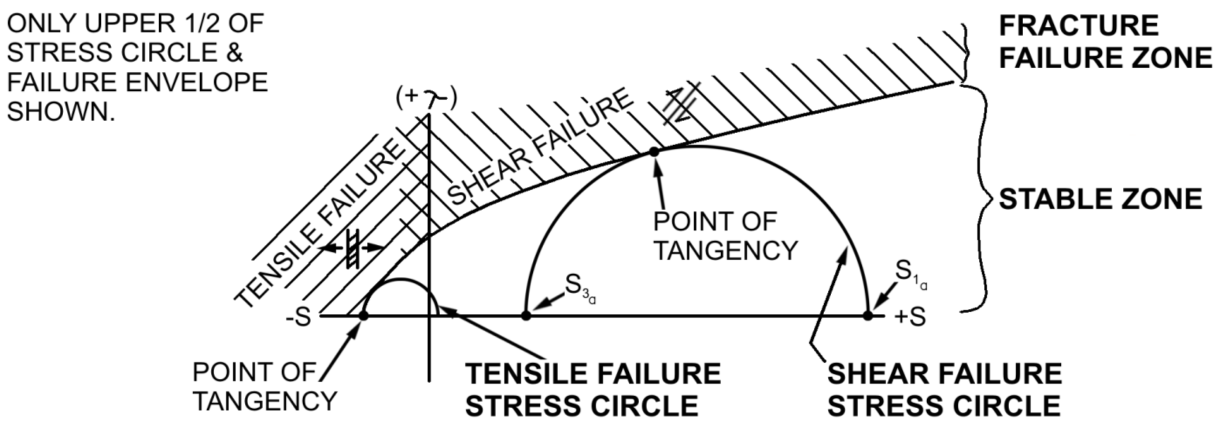


Figure 33. Two sets of stress conditions that result in rock failure are shown on the Mohr's diagram above. The stress circle on the left is tangent to the failure envelope within the tensile failure quadrant of the diagram. The stress circle to the right is tangent to the failure envelope in the shear failure quadrant. Tensile failure results in "open" fractures whereas shear failure produces "closed" fractures (From Meissner, 1978).

One of the important points that Meissner stressed was the influence that internal pore fluid pressure has on the stresses that are present in rock. He used the ideas developed by Hubbert and Rubey (1959) to emphasize that porous rock failure is strongly influenced by pressure induced pore fluid stresses. When pore pressures are included in a Mohr diagram, the stress circle must be modified. This modification results in a graphic representation of what is called the "effective" stress. The effective stress caused by fluid pressures (P) is found by shifting the total stress circle towards the origin (left) along on the principle stress axis (See Figure 34). Clearly, if "P" gets large enough the shift along the principle stress axis will bring the circle into contact with the failure envelope (See Figure 35). When this happens the rock described by the Mohr's circle may be expected to fracture. In this way elevated pore pressures may be responsible for the spontaneous fracturing of rock. Furthermore, if enough information concerning the mechanical strength of a specific rock exists then the conditions that result in the formation of open or closed fractures may be made (see Figure 36). This becomes increasingly important when considering that different rock types have different mechanical strengths. Differences in rock strength when coupled with the stress conditions in the subsurface may be used to predict what specific geologic conditions should be favorable for enhanced fracture formation and increased petroleum production.

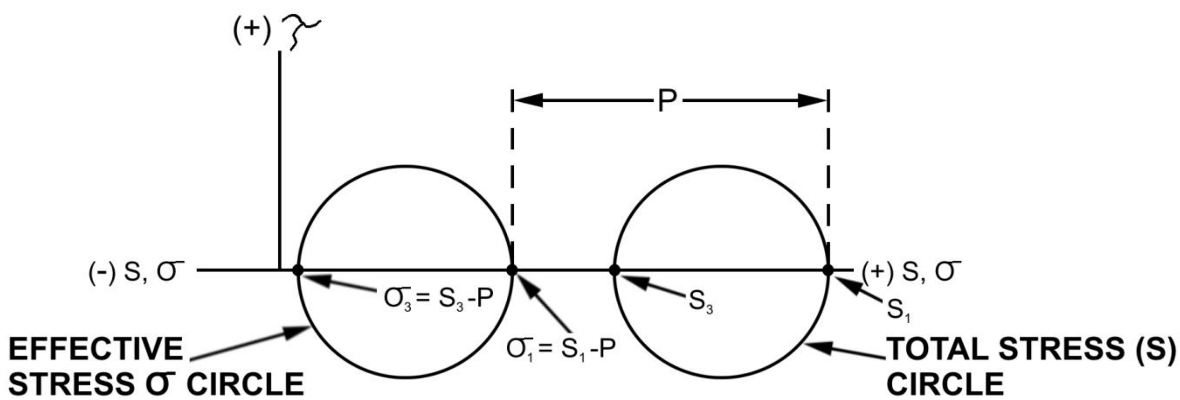


Figure 34. Increasing pore pressure (P) reduces the principle stresses in the diagram above. This reduction in principle stresses defines the "effective" minimum ($\sigma 3$ = S3-p) and maximum (σ 1 = S1-P) stresses that, graphically, moves the stress circle to the "left" (From Meissner, 1978).

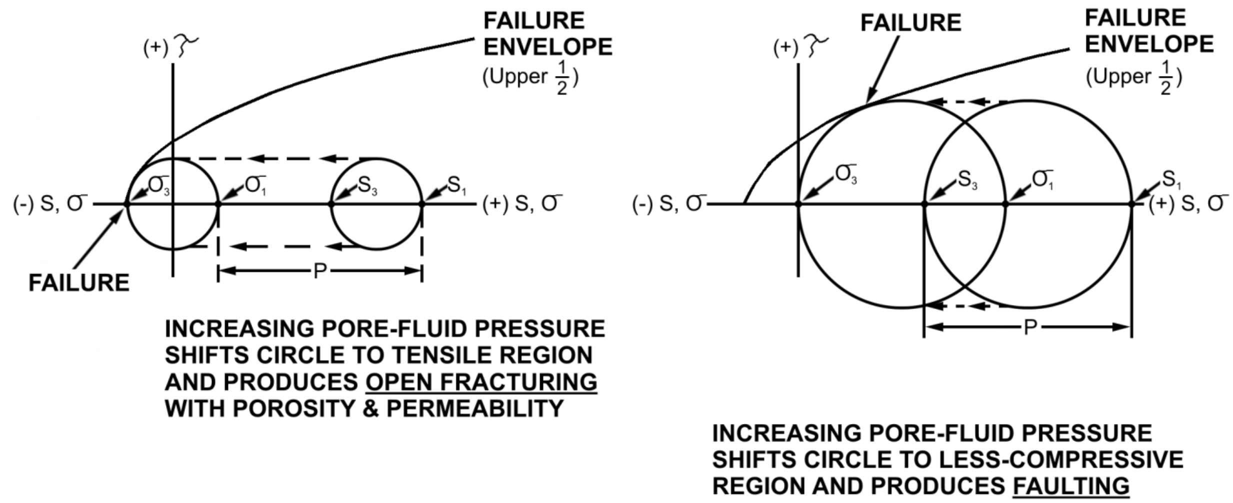


Figure 35. Diagrams illustrating the influence of increasing pore pressures that result in the formation of open tensile fractures (left) and closed shear fractures (right) (From Meissner, 1978).

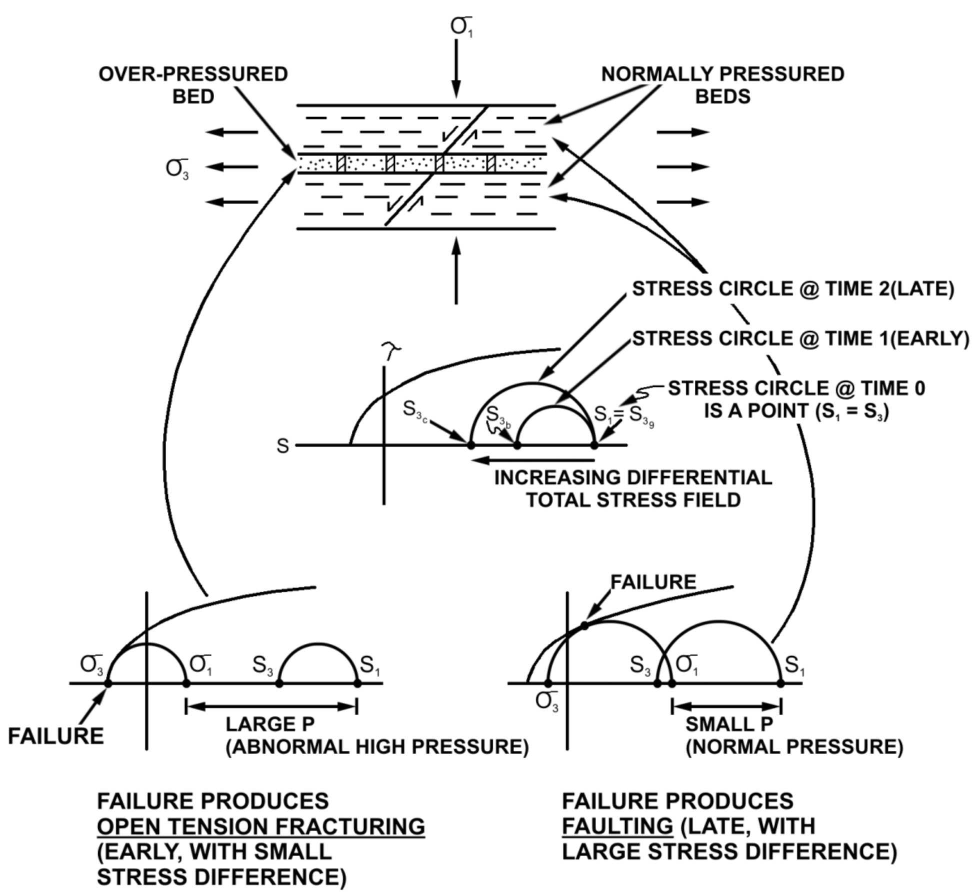


Figure 36. An illustration of the variation in the type of rock failure for an interbedded set of rocks that contain one over-pressured bed between two “normally” pressured beds (From Meissner, 1978).

The calculation of the so called “fracture” gradient makes use of an analytical solution to the basic ideas contained in the Mohr’s circle. The fracture gradient is the pressure at which a given rock may be expected to fail for a given set of stress conditions. The calculation uses Poisson’s ratio to describe the deformation (strain) of a rock in response to an imposed load (stress). The data needed to calculate Poisson’s ratio is obtained by compressing a specimen and measuring the amount of shortening that occurs parallel to the compression (transverse strain) and the amount of elongation (axial strain) that results along the axis perpendicular to the compression. The ratio between the transverse and axial strains as a function of loading is Poisson’s ratio. Table 2 includes a range of Poisson’s ratio that is found for common sedimentary rocks.

Table 2. Poisson’s ratio for common sedimentary rocks.

Rock Type	**Poisson’s Ratio**
Dolomite	0.09 – 0.20
Limestone	0.10 – 0.23
Sandstone	0.07 – 0.3
Shale	0.10 – 0.5

The fracture pressure of rock is calculated with Poisson’s ratio as follows:

$$\sigma_F = [\mu /(1- \mu)] (\sigma_L - \sigma_P) + \sigma_P$$

Where:

μ = Poisson’s ratio
σ_L = Lithostatic Pressure (psi)
σ_P = Pore Pressure (psi)
σ_F = Fracture Pressure (psi)

Using Meissner’s formation pressure data, and a presumed lithostatic gradient of 0.94 psi/ft, a Poisson’s Ratio of 0.15 yields a predicted fracture pressure that is less than 400 psi above the original Bakken/Sanish fluid pressure in the Antelope Field (see Figure 37). This suggests that shale-free dolomite, limestone and sandstones within the Bakken , Three Forks of lower Lodgepole Formations may spontaneously fracture when elevated pore pressures combine with local tensile stresses to form effective stresses that exceed the fracture pressure. The Parshall and Sanish fields in Mountrail County may be particularly important in illustrating the interaction of maturation induced pressures with relatively subtle structures to form reservoir conditions well suited to modern drilling and completion methods.

A study by Bingle-Davis (See Appendix I) of 425 thin sections taken from 14 cores of the middle member of the Bakken Formation show that for a given well there are significant differences between lithofacies in the length and frequency of microfractures. However, between wells there is no apparent relationship between lithofacies and either the fracture frequency or length. These results suggest that natural fracturing of the middle Bakken member is very heterogeneous and should therefore be evaluated on a well-by-well basis.

The factors that appear to contribute to the formation of fractures in the Bakken Source System are summarized as follows:

1) Convex upward structural flexure – second derivative map of structure - Antelope Model
2) Bed Thickness – Fracture Spacing – “Fairway” Model
3) Effective stress
    a) Pore pressure – Proximity in space and time to oil generation zone
    b) Maximum Principle Stress controlled through depth (lithostatic pressure)
    c) Minimum Principle Stress
4) Mechanical properties of the reservoir – Poisson’s ratio and other measures of rock strength.

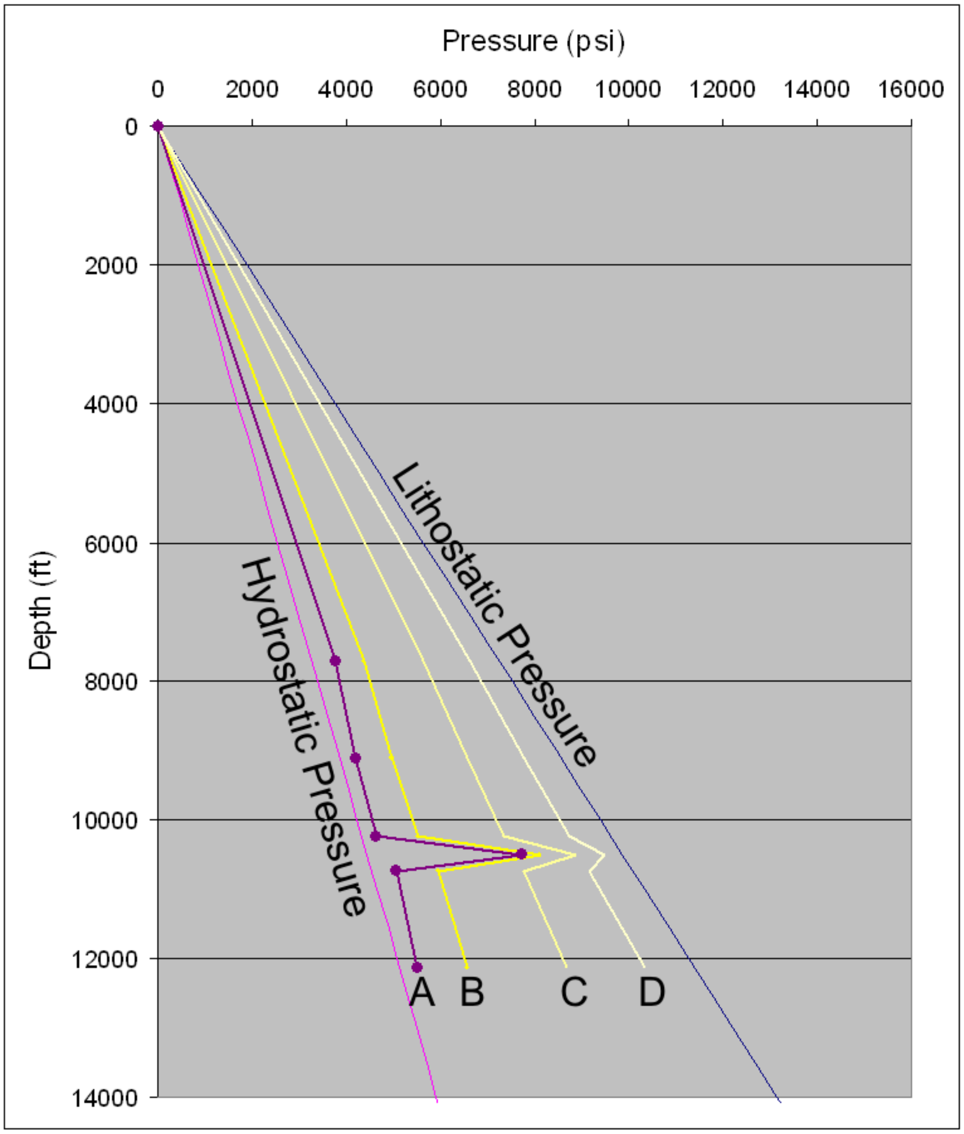


Figure 37. Pressure depth plot for the Antelope Field, McKenzie County, North Dakota. The line labeled hydrostatic represents the fluid pressure as a function of depth under an assumed hydrostatic gradient of 0.465 psi/ft. The line labeled lithostatic represents the maximum principle stress using a lithostatic gradient of 0.94 psi/ft. The pressures reported by Meissner (1978) are included on the line labeled "A". "Fracture" gradients calculated for the pore pressures present on line "A" are included along with 3 lines that represent the pressure needed to fracture rocks for different Poisson's ratios (B=0.15, C=0.30, D=0.45). Poisson's ratio ranges from 0.08 for a brittle dolomite to <0.50 for a plastic shale. The expected fracture pressure σ_F is calculated using Poisson's ratio (μ) and the effective stress that is present for a given pore fluid (σ_P) and and lithostatic (σ_L) pressure as follows: $\sigma_F = [\mu/(1-\mu)] * [\sigma_L - \sigma_F] + \sigma_F$.

Mountrail County

Introduction

The Williston Basin in north-central North Dakota is split into two smaller sub-basins by the north-south plunging Nesson Anticline. Mountrail County covers a large portion of the easternmost sub-basin (Fig. 38). The eastern flank of the Nesson Anticline and northeastern limb of the Antelope Anticline form the western boundary of this sub-basin in Mountrail County. The eastern flank of the sub-basin within Mountrail County dips to the west along a northwest-southeast trending strike that that cuts across the eastern border of Mountrail County. Structure contour maps in Figure 39 show that the deepest portion of the eastern sub-basin lies within the westernmost portion of Mountrail County or just to the south in McKenzie County.

Bakken Stratigraphy

A complete middle Bakken section (Fig. 40) consists of six lithofacies labeled (oldest to youngest), Lithofacies 1 (LF1), Lithofacies 2 (LF2), Central Basin Facies (CBF), Lithofacies 3 (LF3), Lithofacies 4 (LF4), and Lithofacies 5 (L5). Descriptions and core photographs of each lithofacies are included in Appendix II. Generally, thelower Bakken shale and the lower four lithofacies (LF1, LF2, CBF and LF3) appear to shoal upwards and include depositional environments ranging from an offshore, oxygen stratified environment (lower Bakken shale) through a series of shallower, normal marine (LF1, LF2, CBF) environments that culminate with near (shoal complex) shore, beach and bar deposits (LF3). The remaining lithofacies (LF4 and LF5) and the upper Bakken shale were deposited in progressively deeper waters that reached a maximum depth during upper Bakken time. The isopach maps of the upper, middle and lower members of the Bakken Formation suggest that during Bakken time, local structures were active. At least one isopach defined structure is evident (Fig. 41).

This structure appears to have formed a positive topographic feature along the southern margin of the Sanish Field. This local structure appears to locally control the southern extent of the carbonate and clastic sands in LF3 (Fig. 42). To the northeast of this structure the sand in LF3 is over 15 feet thick. The sand thins updip to the north and east before pinching out in the eastern part of the Parshall Field. Many of the wells drilled in the Sanish Field have the horizontal legs that target the sand in LF3. It is tempting to speculate that the stratigraphic pinchout of LF3 is in some way diagnostic of the productive limits of oil production in the Sanish Field. However, the exceptional production from those parts of the Parshall Field in which LF3 is absent argues against this idea.

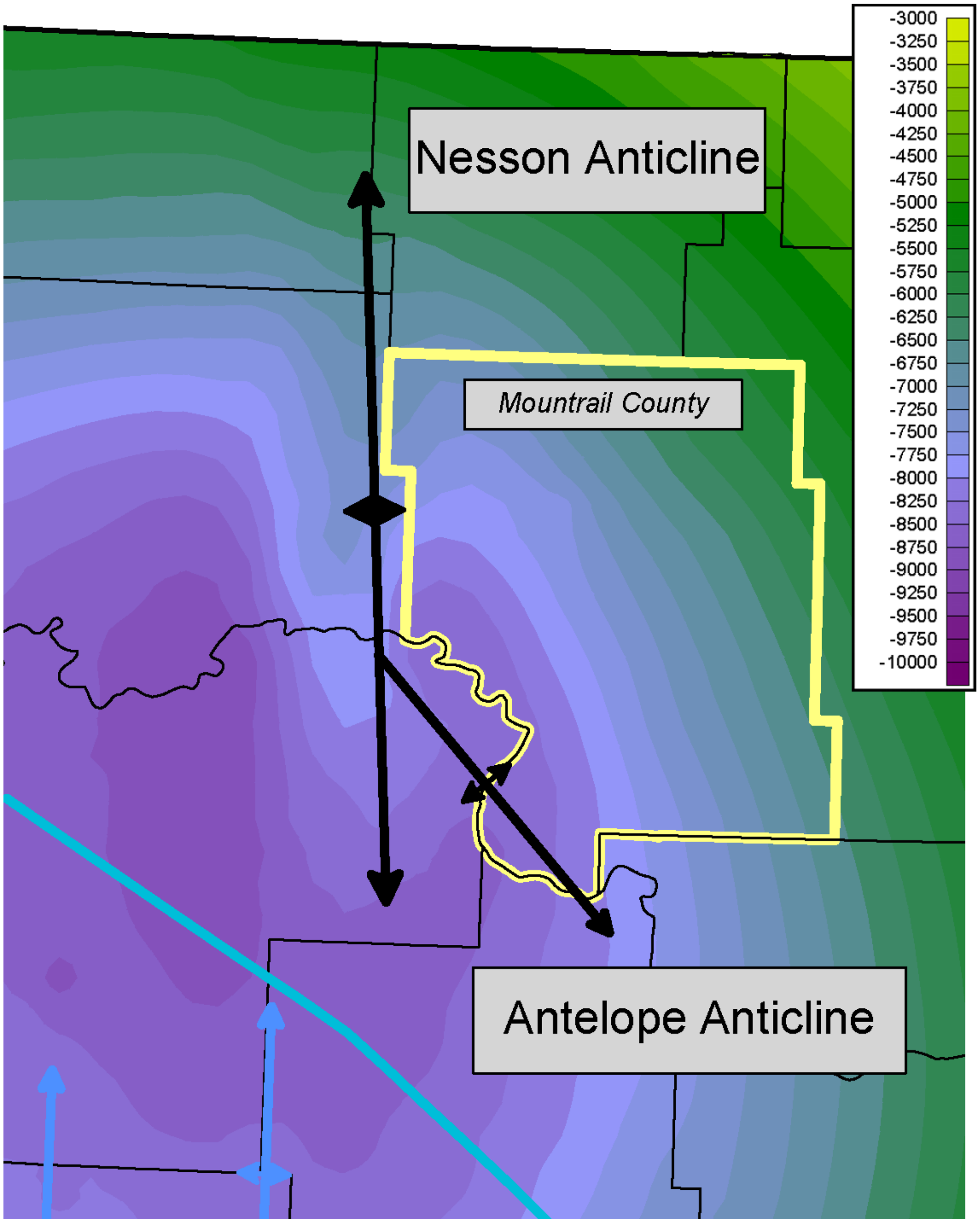
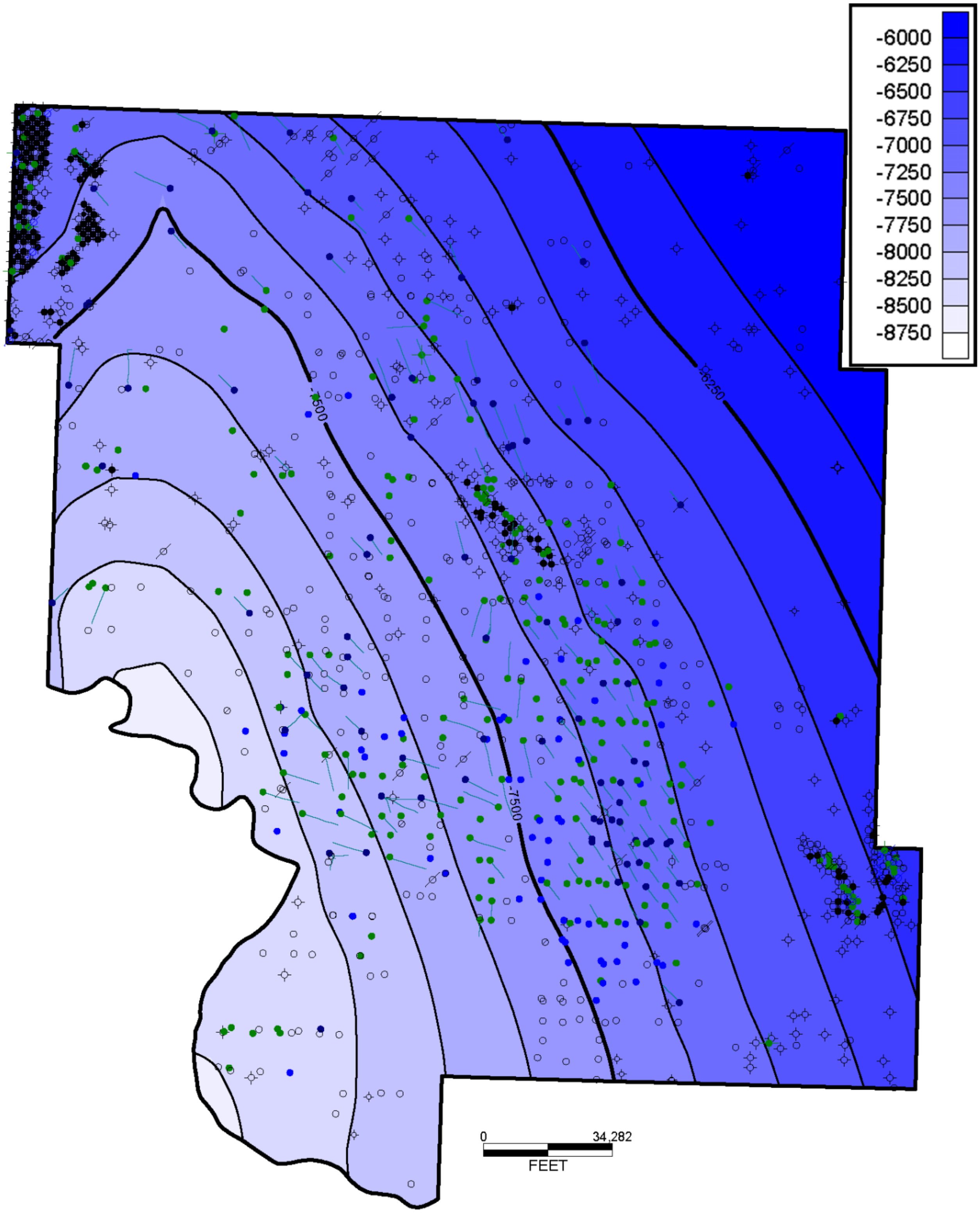
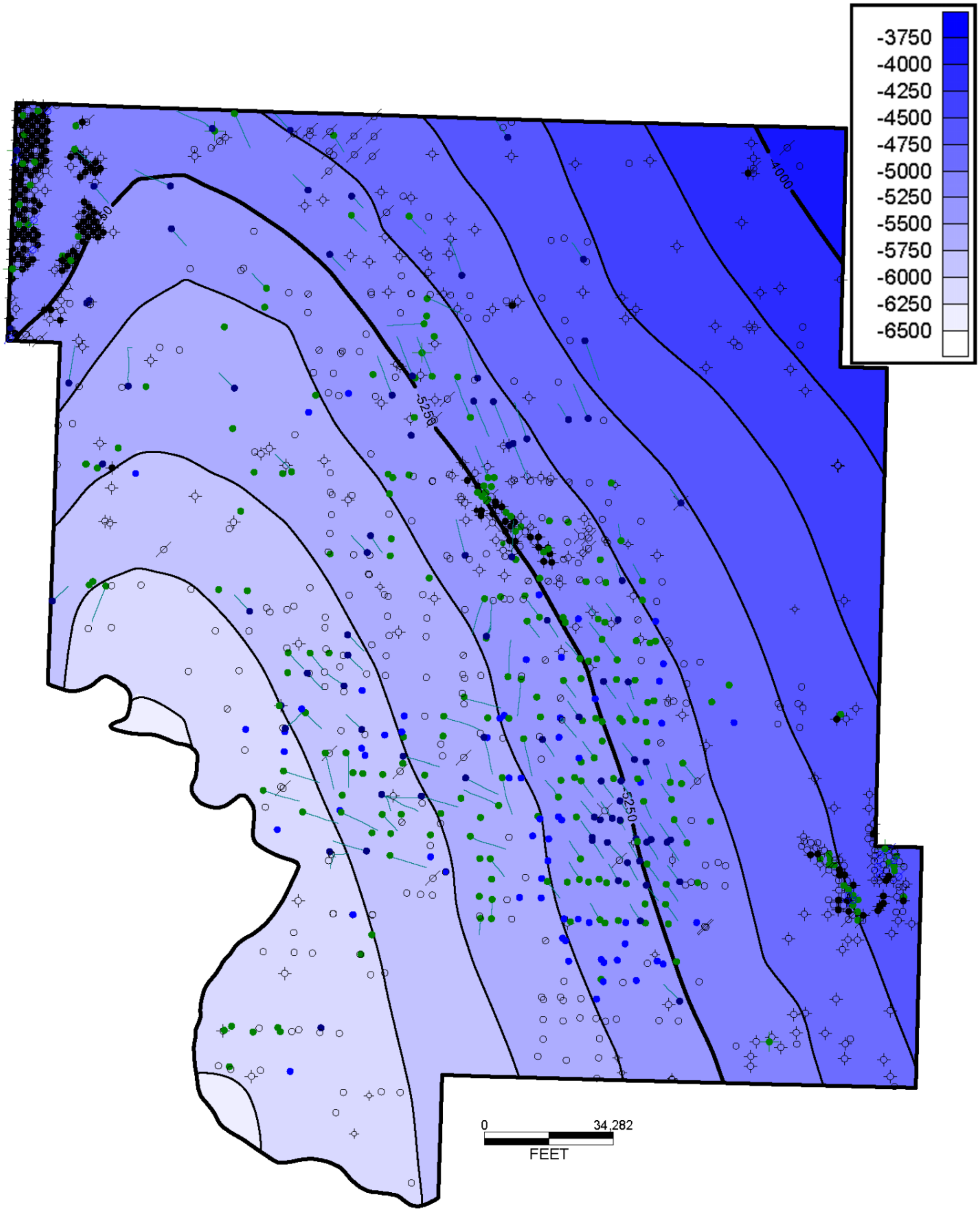


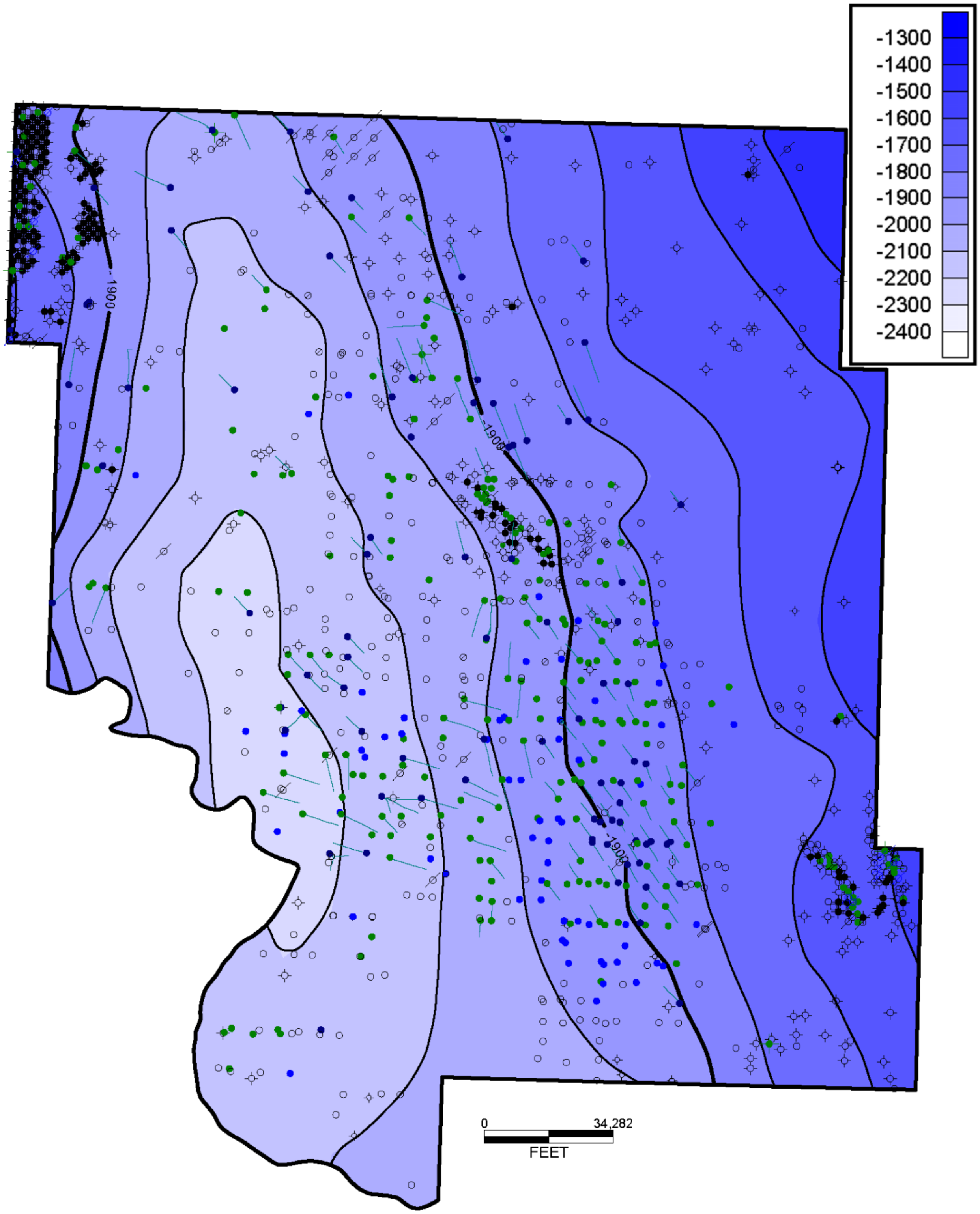
Figure 38. Structure contour map (datum = mean sea level) of the top of the Bakken Formation showing the location of the sub-basin that is found in Mountrail County (outlined in yellow). The overlay shows the location of the regional structures that form the western margin of the sub-basin.



39 A) Bakken Formation (Lower Mississippian).



39 B) Madison Formation (Mississippian).



39 C) Madison Formation (Mississippian).

Figure 39. Structure contour maps drawn on the top of the: A) Bakken Formation (Lower Mississippian); B) Madison Formation (Mississippian); and, C) Madison Formation (Mississippian).

Subsidence History and Local Structure

The subsidence history of the basin, summarized by the stratigraphy in the Deadwood Canyon Ranch indicates that the eastern sub-basin experienced rapid subsidence that began sometime before Bakken time and continued until the end of Madison time (Fig. 43). Relatively slow rates of subsidence continued from the end of Madison time until the early Cretaceous. Accelerated subsidence, beginning later in the Cretaceous, added almost 5,000 feet of section over, at most, 100 million years.

Various lines of evidence indicate that tectonic factors associated with the latter stage of basin subsidence may have played a role in modifying the stresses acting on the Bakken Formation in Mountrail County. Isopach maps of the three Bakken members in Figure 44 indicate that during Bakken time subsidence was not uniform in Mountrail County and that differential movement occurred along localized structures.

Fracture systems within the Bakken reservoir are another important consideration that impacts the local productivity of individual wells and may be important in controlling regional oil migration pathways. Fracture development in the Bakken may involve tectonic factors such as folding and faulting that, when coupled with elevated pore pressures, result in rock failure.

In the absence of elevated pore pressures, fracturing depends on tectonic factors that were in effect during the deformation that formed the basin. Murray (1968) demonstrated with structure data from the Antelope Field that tectonic fracture zones may be outlined by making a map of the 2nd derivative of a structure contour map. Murray (1968) used the elevation of the top of the Three Forks Formation to illustrate this point. Second derivative maps highlight structural features that could cause open tension fractures to form.

The second derivative of the Bakken structure contour map in Figure 30 shows that the greatest structural flexure in Mountrail County lies along the Nesson Anticline in the western portion of the county. The second derivative of the structure also shows that structural flexures similar in shape to the one in the Antelope Field are present along the eastern limb of the basin in Mountrail County. However, the degree of flexure is substantially less than what is found in the Antelope Field or along the crest of the Nesson Anticline. Within the Parshall Field and part of the Sanish Field there is a subtle north-south trending structural flexure that could contribute tensile stresses that assisted in forming fractures within the middle Bakken and possibly the upper part of the Three Forks Formation. These stresses, in the presence of sufficient pore pressure could result in open fractures, enhanced fluid transmissivity and an thus explain the extraordinary production that has been established in these two fields. However, the "flexure" is not at all prominent and may therefore be a coincidence with little impact on fracture development.

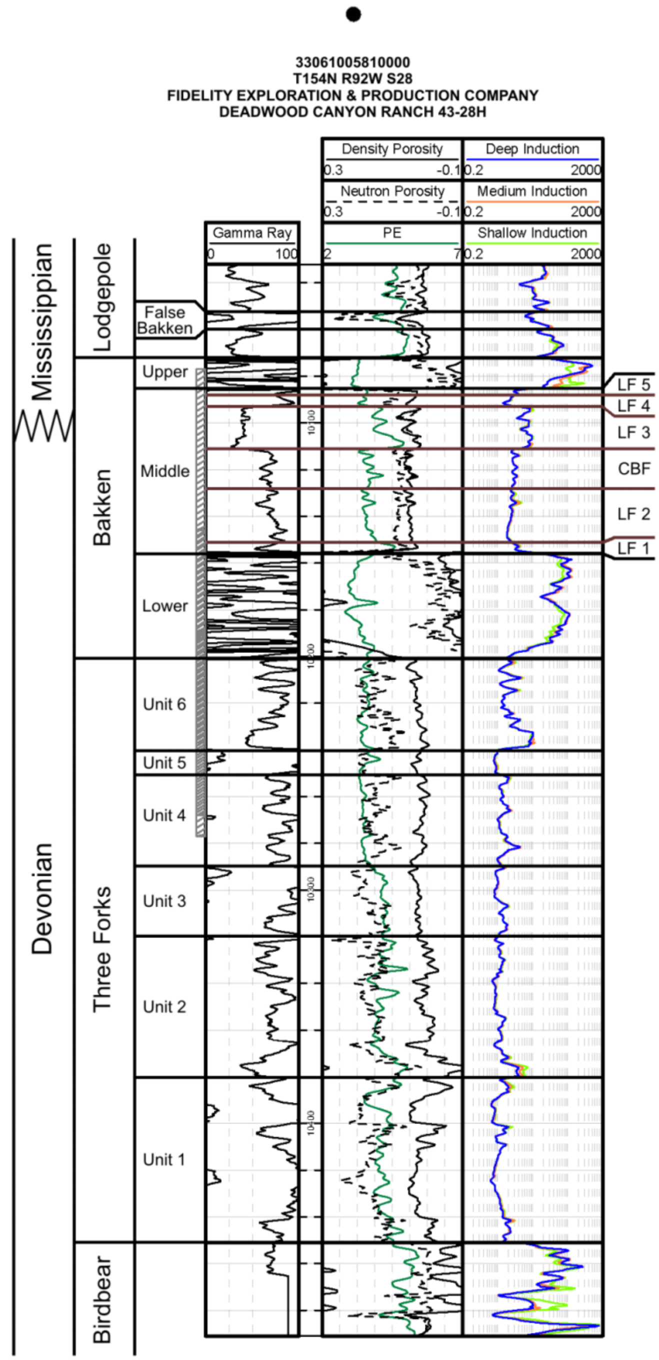


Figure 40. Typical section for the Bakken Formation in Mountrail County, North Dakota. Logs from the Deadwood Canyon Ranch #43-28H (NESE Sec. 28, T154N, R92W) shown here include the Gamma Ray, Neutron and Density porosity, Photoelectric (PE), and Induction logs. Subdivisions of the middle Bakken are from LeFever and others (1991) and subdivisions of the Three Forks Formation are from Christopher (1961).

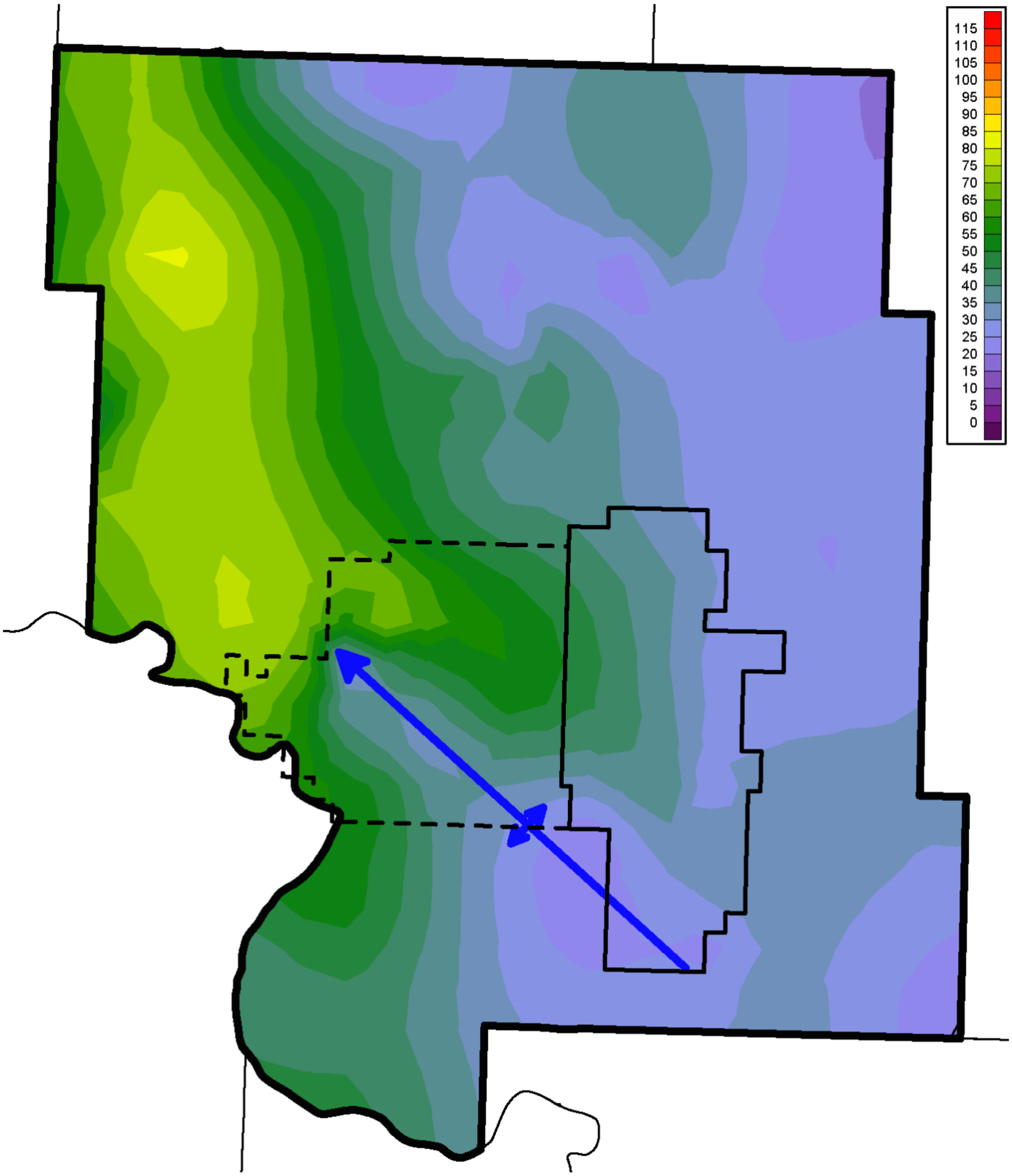


Figure 41. Coincident thinning in the isopach maps of the upper, middle (shown here) and lower members of the Bakken Formation indicate that a positive structural element, shown here as a plunging anticline, was active during Bakken time.

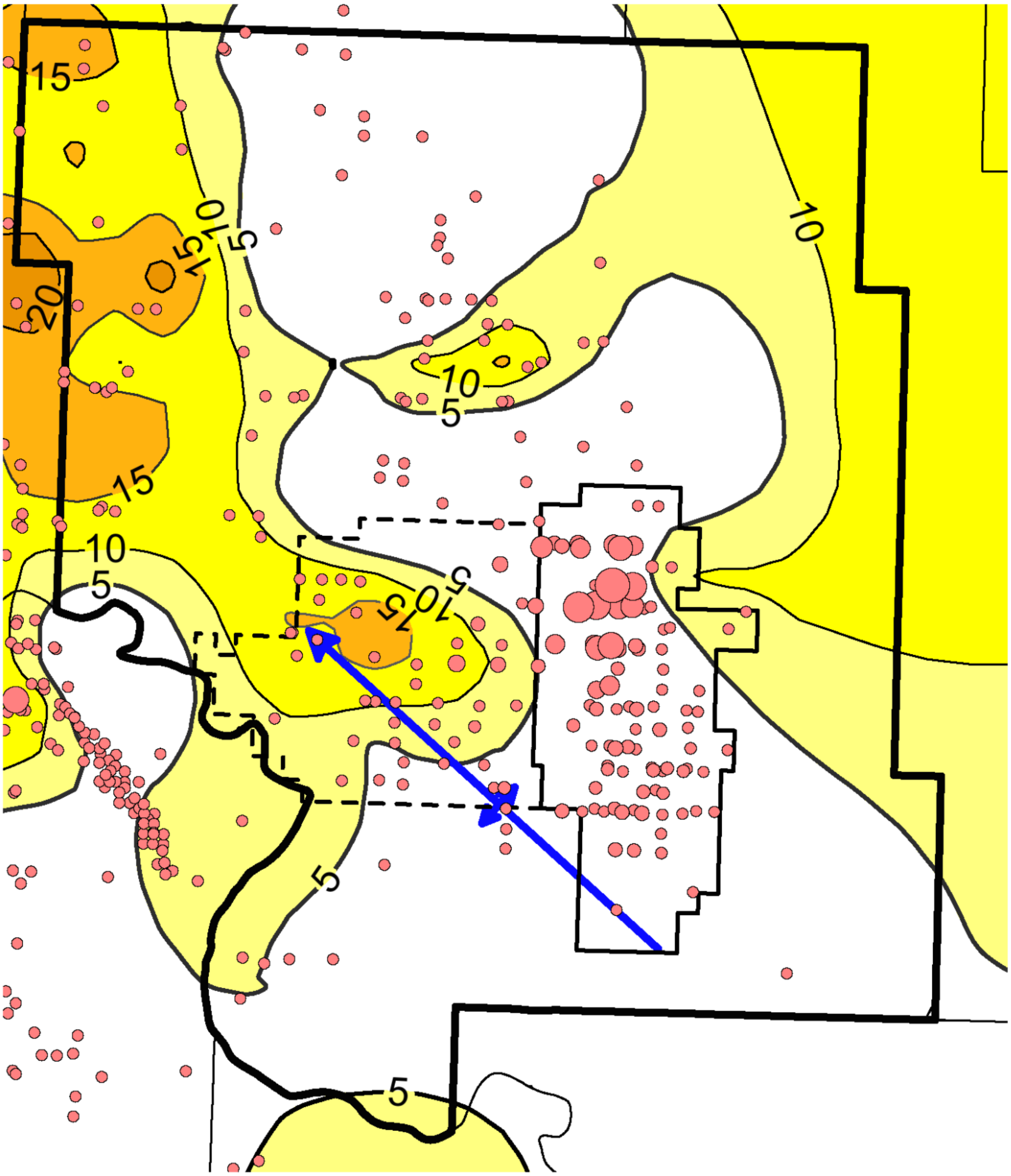


Figure 42. An isopach of Lithofacies 3 showing an updip pinchout of the unit. The shaded intervals are areas in which L3 is at least 5 feet thick. Each colored interval from light yellow to brown show an increase in L3 thickness using a contour interval of 5 ft. Production levels in the county are plotted as circles with the radius being proportional to the daily average of the first 60 days of production. The Parshall Field is outlined by the heavy solid line and the Sanish Field is outlined by the dashed line.

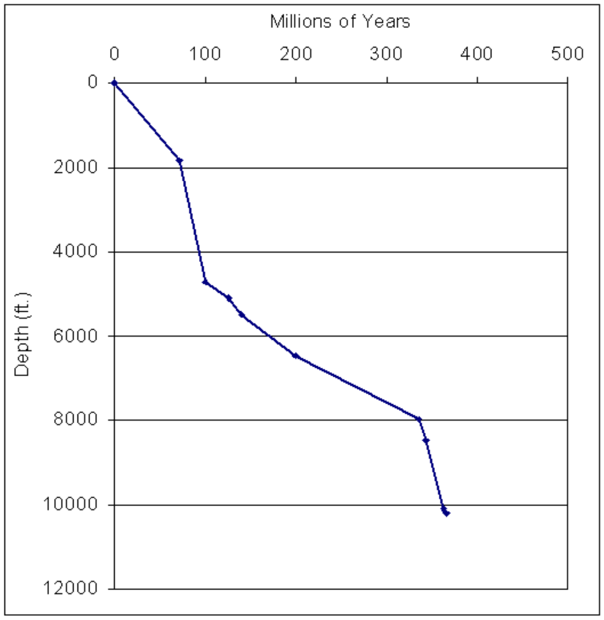
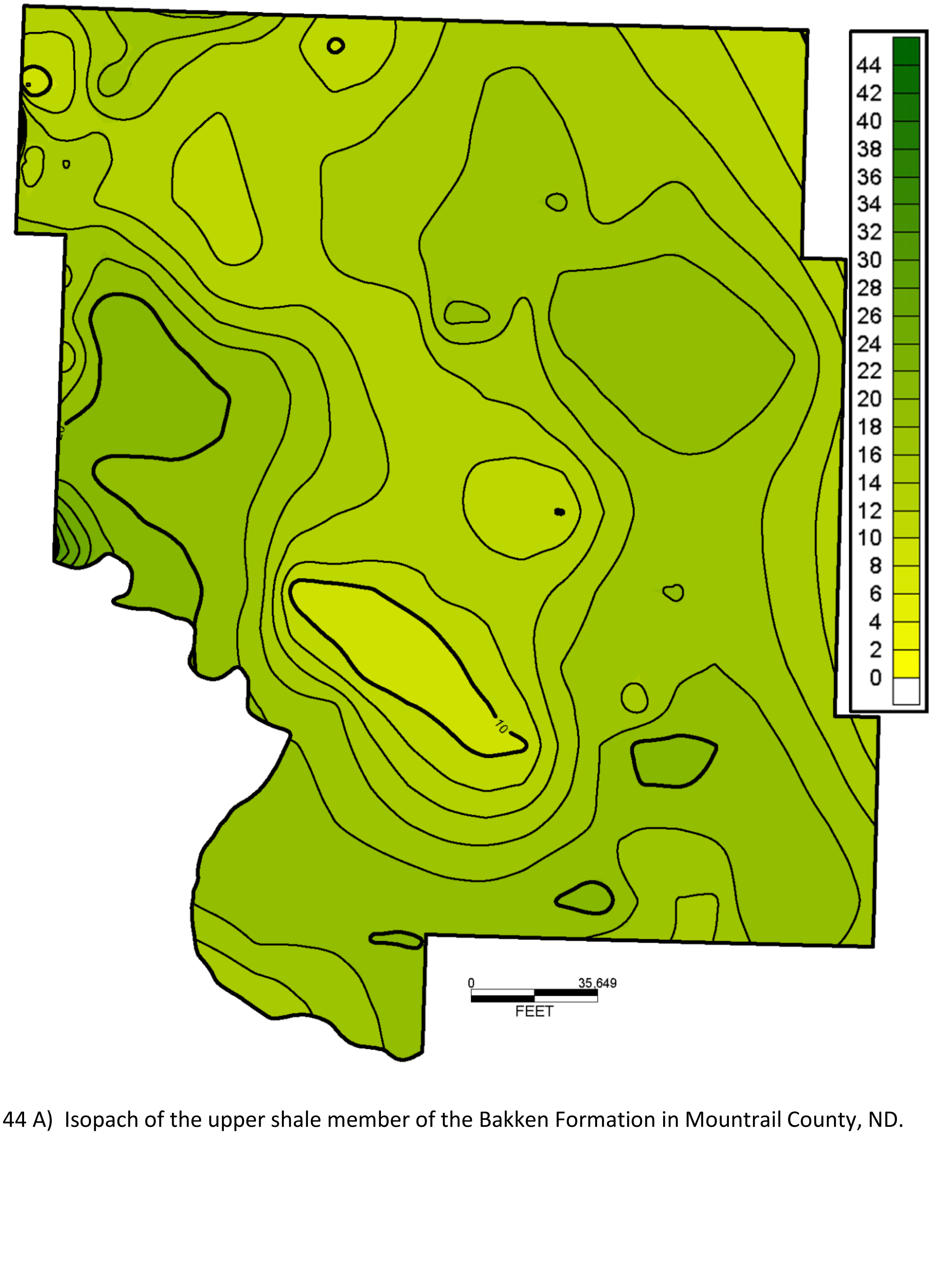
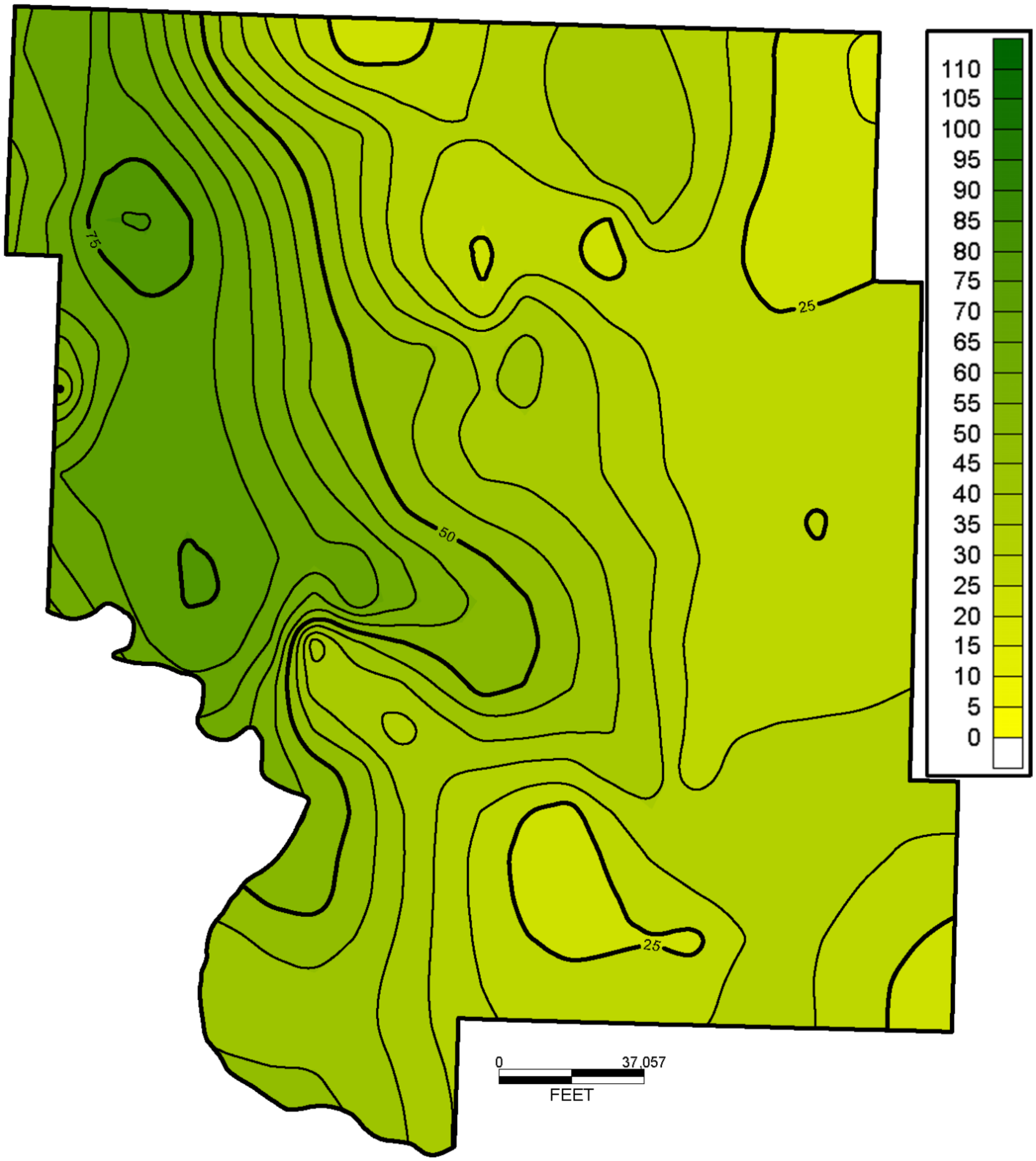


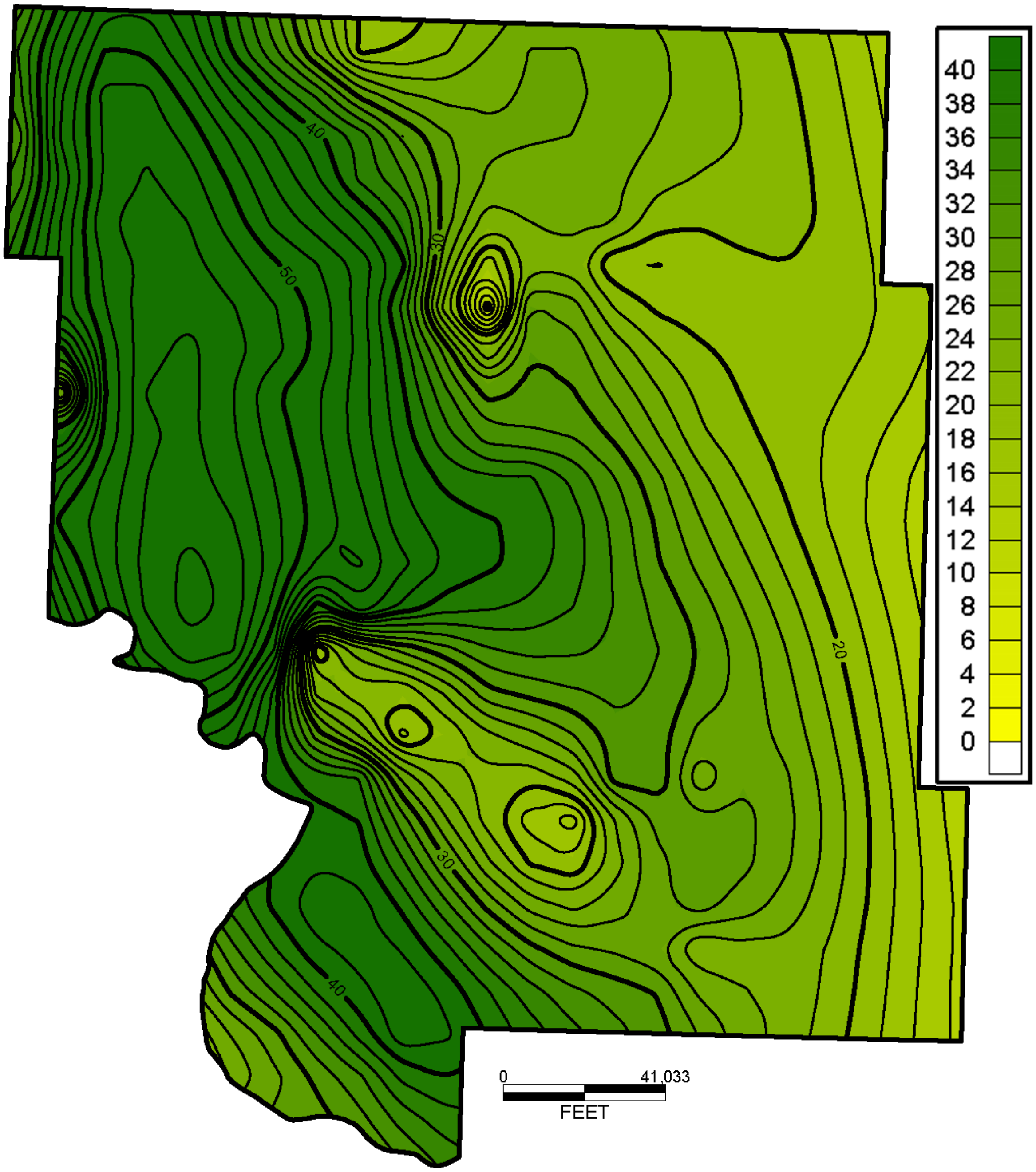
Figure 43. Subsidence history of the Fidelity Exploration & Production Co. #43-28H Deadwood Canyon Ranch well (NESE Sec. 28, T154N, R92E). This diagram illustrates the post Three Forks subsidence history of the Mountrail County sub-basin.



44 A) Isopach of the upper shale member of the Bakken Formation in Mountrail County, ND.



B) Isopach of the middle member of the Bakken Formation in Mountrail County, ND.



C) Isopach of the lower shale member of the Bakken Formation in Mountrail County, ND.

Figure 44. Isopachs of the upper (A), middle (B), and lower (C) members of the Bakken Formation. All three isopach maps suggest, by The coincidence of localized "thinning" trends on all three isopachs suggests that structural highs may have formed positive topographic features during Bakken time.

Proprietary seismic data reviewed by the North Dakota Geological Survey suggest that at least one of these structures is partially fault bounded (Fig. 45). This faulting appears to be basement related and has been episodically active up to at least the Late Cretaceous (Greenhorn time). Even though this faulting does not appear to involve displacement of more than 60 feet, the structures that are associated with the faulting appear to be reflected in the thickness variations within individual members of the Bakken and may be related to the local distribution of facies within the middle member.

Coincident thinning of the three members of the Bakken Formation and the overlying Lodgepole suggest that minor structural movements occurred throughout Bakken time and extended well into the Mississippian, if not longer.

The structures that are evident in eastern Mountrail County are very subtle. Probably the most conspicuous feature is illustrated by the cross-section in Figure 46 and the interpreted seismic section in Figure 45. Even though the vertical exaggeration used in cross-section is approximately 20X, the section clearly shows a slope break on the surface of the Bakken near the center of the Parshall field that overlaps the maximum flexure zone mapped on the 2nd derivative map of the Bakken structure (Fig. 30). This slope break can be traced on cross-sections to northwest and to the south. However, careful examination of other well based cross sections suggests that more than one slope break may be present. Unfortunately, the existence, magnitude and distribution of these slope breaks and associated structures are difficult to establish given the current coarse (640+ acre) well spacing and the level of precision that is possible when measuring structural tops from wireline logs. Supporting evidence for these structural features is present in an east-west seismic line that shows a similar feature in which there is an apparent “platform” to the east that breaks over into a more steeply westward dipping configuration (Figure 45). The seismic line shows that the slope break is downwardly continuous and seems to indicate the presence of basement faulting. The seismic line also shows what appears to be a thinning of the Prairie Evaporite along the footwall of the interpreted fault. The overlying Devonian, Mississippian and Jurassic reflectors suggest that these units have “collapsed” possibly in response to thinning in the Prairie. If salt dissolution in the Prairie is responsible for these depressions then some type of fracturing of the overlying section, including the Bakken, might be possible. The depression present in these deeper reflectors disappears in the shallower reflectors above Cretaceous-aged Dakota reflector. This indicates that whatever mechanism that was responsible for this structural displacement has probably been inactive since the Early Cretaceous.

Unlike the Antelope Field in McKenzie County, there is no significant structure that is clearly related to the extraordinary oil production from the Parshall Field. In part, the structures identified in eastern Mountrail County are small in comparison to the distance between the wells in which wireline logs have been run through the top of the Bakken Formation. However, these smaller structures may be quite evident if structure maps include tops within the Bakken Formation that are obtained from mud logs recorded as the horizontal legs are drilled.

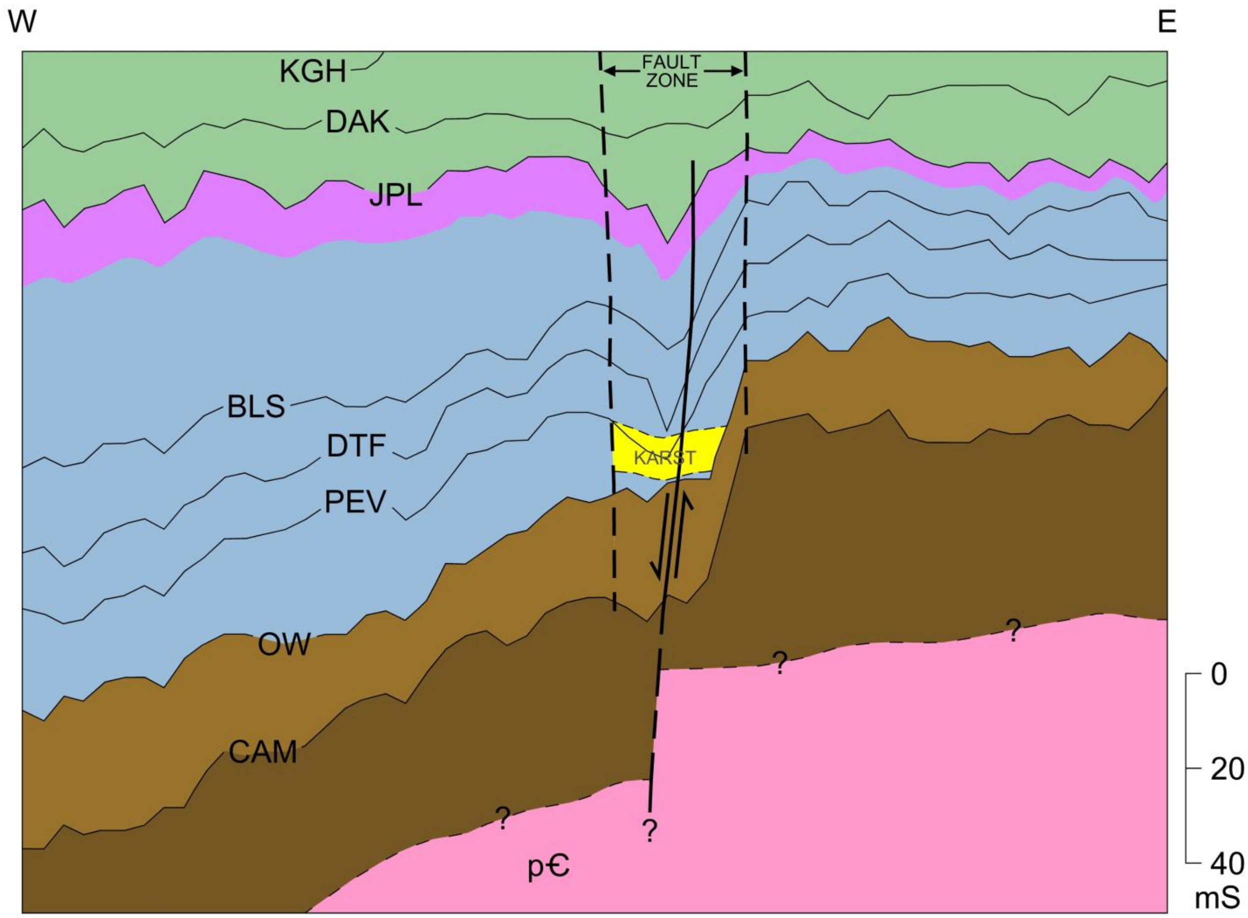


Figure 45. Interpreted seismic section showing the two way travel times for 7 reflectors in Mountrail County. The times are "hung" of the Greenhorn (KGH) reflector and show a prominent change in reflector dip along an east-west line in the eastern part of Mountrail County. The tops portrayed include reflectors on the Dakota Formation (DAK), Piper Limestone (JPL), Base of the Last Salt (BLS), Three Forks (DTF), Prairie Evaporite (PEV), Winnipeg (OW) and the "Cambrian" (CAM). The maximum 2 way travel time displacement across the fault is on the order of 20 msec which for a limestone (P-velocity ~ 6,000 ft/sec) translates to a physical displacement of about 60'. The structure on the Precambrian (pЄ) is inferred from the displacements apparent in the overlying section.

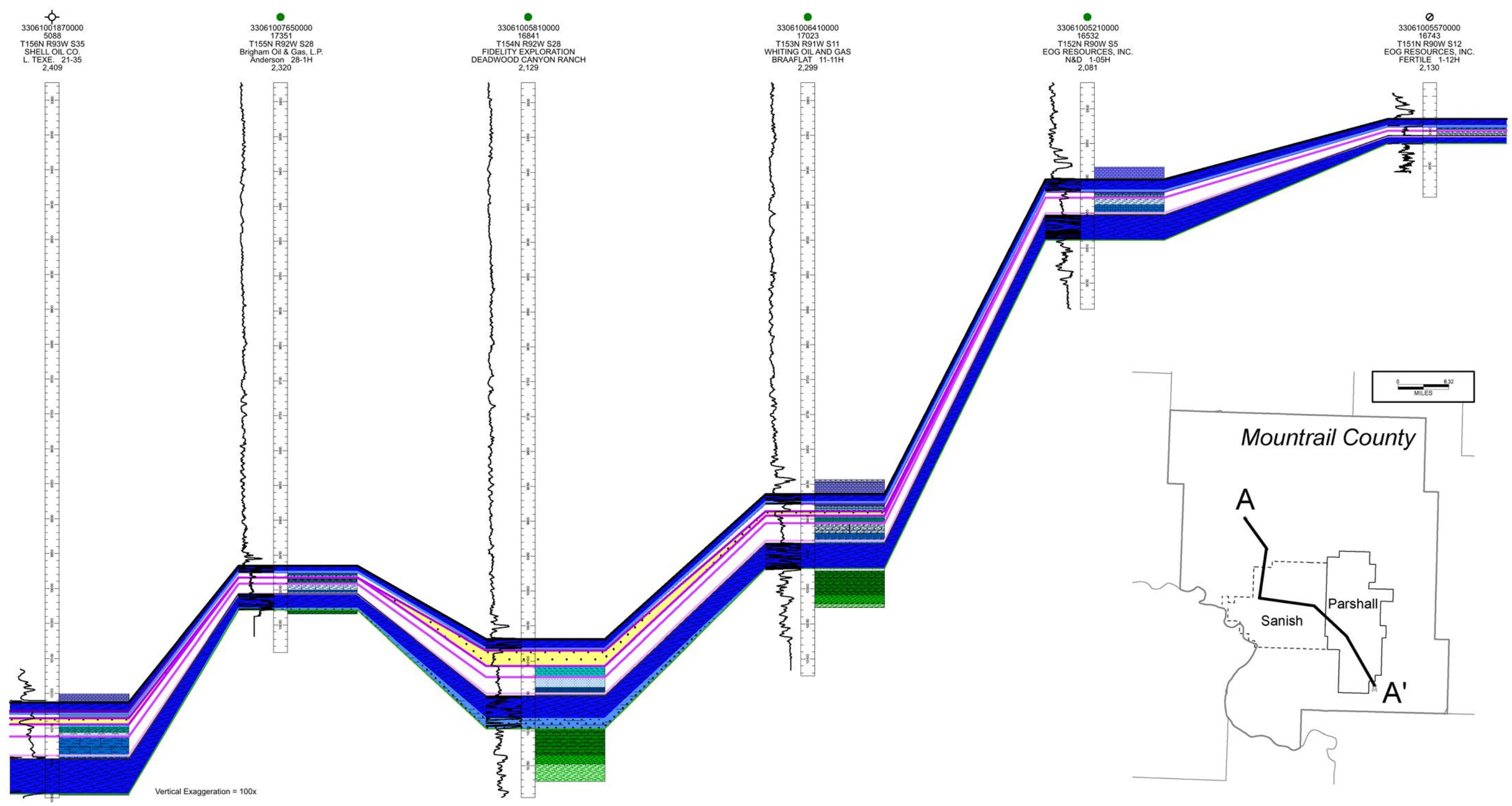


Figure 46. Structural cross-section A-A’ across the Sanish and Parshall Fields showing a depositional onlap of the sand body in lithofacies 3 and the slope break that exists along the eastern margin of the Parshall Field

Fractures and Lineaments

The surface of Mountrail County is covered by a variety of Pleistocene glacial deposits that range from ice edge collapse topographies in the northern part of the county to draped glacial deposits in the south. Beyond the border bounded by Lake Sakakawea, the surface consists of bedrock belonging to the Paleocene Sentinel Butte Formation (Clayton, 1980).

Lineaments mapped and analyzed in Mountrail County were evaluated against proprietary two-dimensional (2D) seismic data acquired in the mid-1980s. Unprocessed 2D wiggle trace plots were digitally converted and stratigraphically interpreted. Key structural features, such as sub-vertical basement faulting, formation thickening and thinning, and structures associated with collapse (i.e. paleokarsting) features were identified. These selected stratigraphic and structural interpretations served as a reference for the interpretation of successive 2D seismic lines existing in Mountrail County. Areas of structural development were delineated from cross-section to map view on the 2D seismic lines as structural zones. Faults identified within these zones were plotted with correlation occurring during the interpretation and mapping of each section. Basement faults and major structural discontinuities were the focus of the interpretive work. There likely exist numerous minor structures that can be interpreted from within the 2D seismic data. These features were not the focus of this work. The expression of basement faulting in the overlying Phanerozoic sedimentary rock sequence and linkage to potential surface expression as lineaments was the primary focus. Key lineament features present in the county were correlated with faults identified from the interpreted 2D seismic.

Lineament Mapping and Fault Identification Methodology

Individual lineaments were mapped onto 2D seismic line traces. Intersections of the individual lineament trace and the line of seismic were plotted on the map and transferred to a 2D seismic time horizon wiggle-trace section. Lineaments of similar character and relative density were grouped as lineament zones and plotted on the 2D seismic sections.

Individual faults, interpreted from discontinuities in the interpreted 2D seismic data, were identified and plotted on the respective 2D time horizon wiggle-trace section. Once all of these elements were plotted, they were evaluated with respect to their proximity to one another. This was done in order to evaluate the connection between structures interpreted at depth with overlying surface lineaments.

Zones of structural discontinuity were further interpreted and delineated from each of the stratigraphically interpreted 2D seismic sections. These zones were plotted on each 2D time horizon wiggle-trace section. Seventy-four sub-vertical, basement-rooted faults were identified from the available 2D seismic interpretive work. The faults are found to be relatable to 181 lineaments mapped at the surface in the county, and may be related to deeper basement structure. In the areas where 2D seismic data permits structural interpretations, the interpreted subsurface structures correlate well with surface lineaments.

Orientation of Faults

Faults mapped from 2D seismic in the study area are dominated by NW and NE orientations, consistent with the lineaments identified by Anderson (2008). Frequency and length based analysis of fault orientations both revealed three similar directional trends, two approximately orthogonal primary and secondary trends, and a tertiary trend located between the primary and secondary trends. A primary trend of N 50^{o} E (S 50^{o} W), a secondary trend of N 50^{o} W (S 50^{o} E), and a tertiary trend of N 75^{o} W (S 75^{o} E) were identified (Fig. 47).

Identification of Key Lineaments\Faults

Several key lineaments or lineament zones were revealed by the synthesis of the lineament mapping and 2D seismic interpretive work (Fig. 46). Fault traces were overlain with mapped lineaments and key lineaments were identified based on their relationships to interpreted faults (Table 3). As a result, 181 of the 3,485 mapped lineaments were found to be close proximity to and in good agreement with subsurface structural trends (Fig. 46) as evidenced by the inferred seismic faults. This includes lineaments where a fault was directly coincident as well as lineaments that were adjacent to a mapped lineament with a similar azimuth.

In addition, lineaments were identified that were found near or at the end of a fault and in similar orientation that had the potential to extend the mapped fault trace. Finally, lineaments that would tie two or more faults together (i.e. a bridging lineament) along a similar fault\lineament orientation were also identified. Each of these types of fault\lineament relationships provides further evidence linking basement sub-vertical faulting with surficial lineaments at the field and county scale. Details concerning the lineament study summarized here are included as Appendix III.

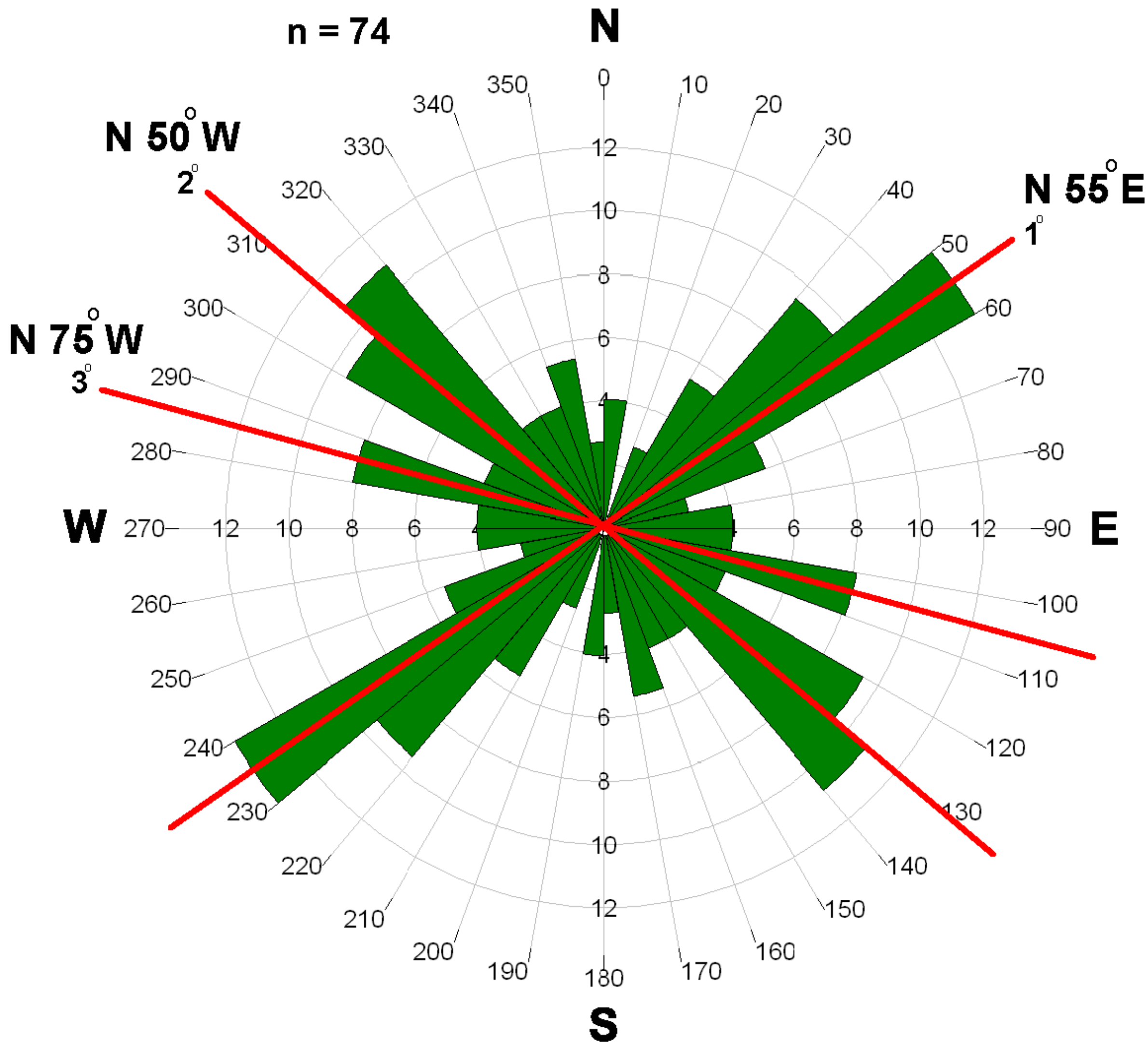


Figure 47. Rose diagram displaying dominant fault trace orientations (i.e. fault strike) from basement rooted faults interpreted from 2D seismic data in Mountrail County, North Dakota. Fault orientations are dominantly NE and NW, with a primary (1°) trend of N 55° E (S 55° W), a secondary (2°) trend of N 50° W (S 50° E), and a tertiary (3°) trend of N 75° W (S 75° E).

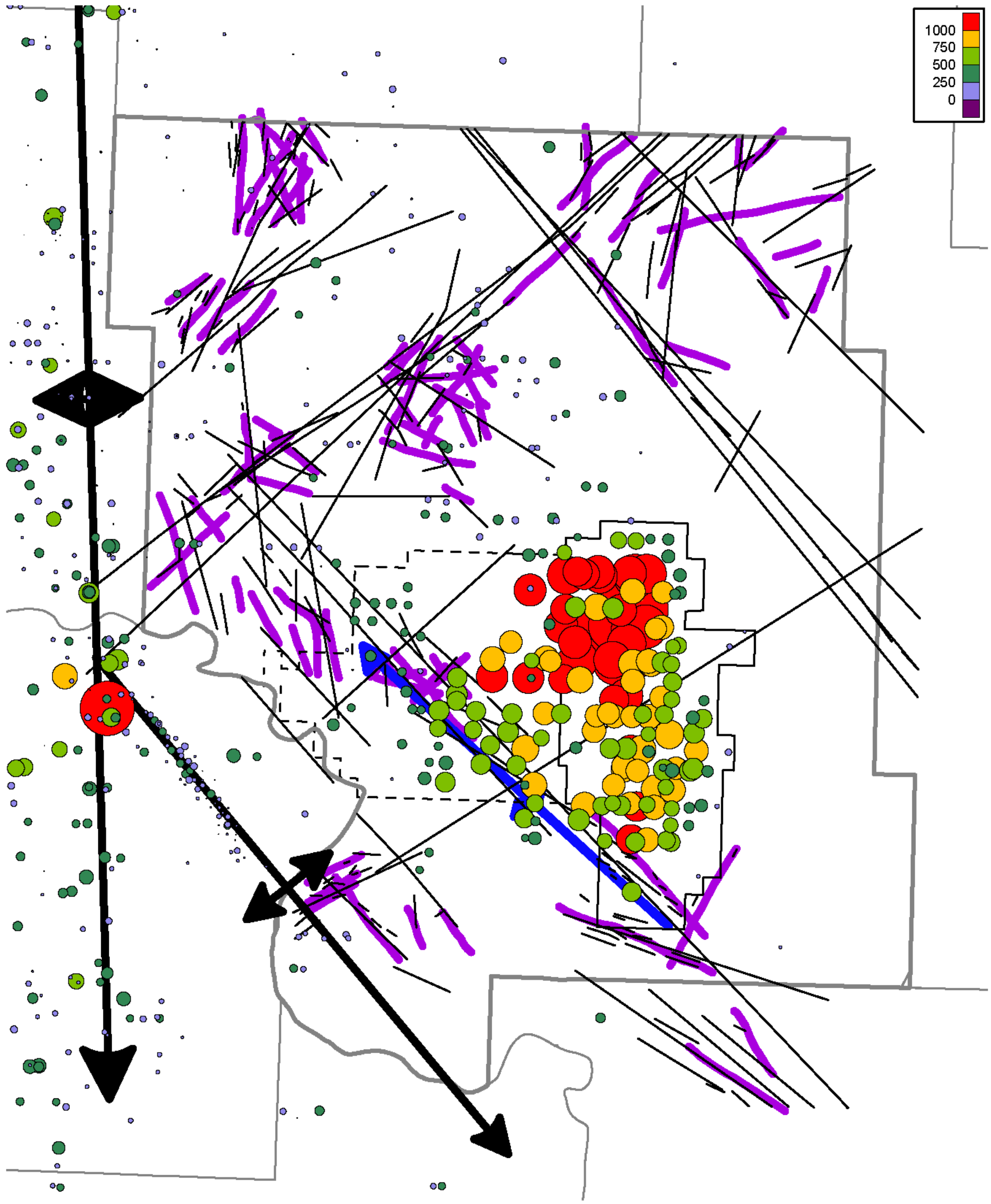


Figure 48. Key lineaments in black with faults interpreted from seismic sections in purple. The axis of the structure identified from the Bakken isopach maps is in dark blue and the Nesson and Antelope Anticlines are in black. The Sanish Field is outlined by the heavy dashed line. The Parshall field is outlined by a heavy black line. The color-filled circles show the location of Bakken/"Sanish" producers. The fill color and size of the circles are indexed to the average initial daily oil production from the first 60 to 90 days of production.

Fault/Lineament Relationship	No. of occurrences	% Occurrence	Description
Coincident	19	26	Faults with lineaments that lie directly upon one another.
Adjacent	44	59	Faults with lineaments that lie near the fault trace in similar (i.e. parallel) orientation.
Bridging	15	20	Faults where lineaments start or end near the end of the fault trace that tie two faults.
Extending	35	47	Faults where a lineament trace begins or ends at the end of a fault trace.

Table 3. Relationships of mapped faults in Mountrail County with surface lineament features.

Relationships to Horizontal Well Drilling and Current Well Production

The range of lineament orientations (i.e. N-NE & S-SW) and dominant directional lineament trends within that range, are consistent with drilling and completion trends (along N-NW oriented pathways) that may be more conducive to higher overall well production. This suggests that directional wells completed along NNW to S-SE orientations should effectively intersect a greater amount of structural discontinuities. Areas of higher overall rates of production tend to be correlative to areas of greater lineament density (both on and off anticline). This holds whether you are comparing production to lineaments per unit area, lineament line length per unit area, density of intersecting lineaments, or a combination of all three (Fig. 49).

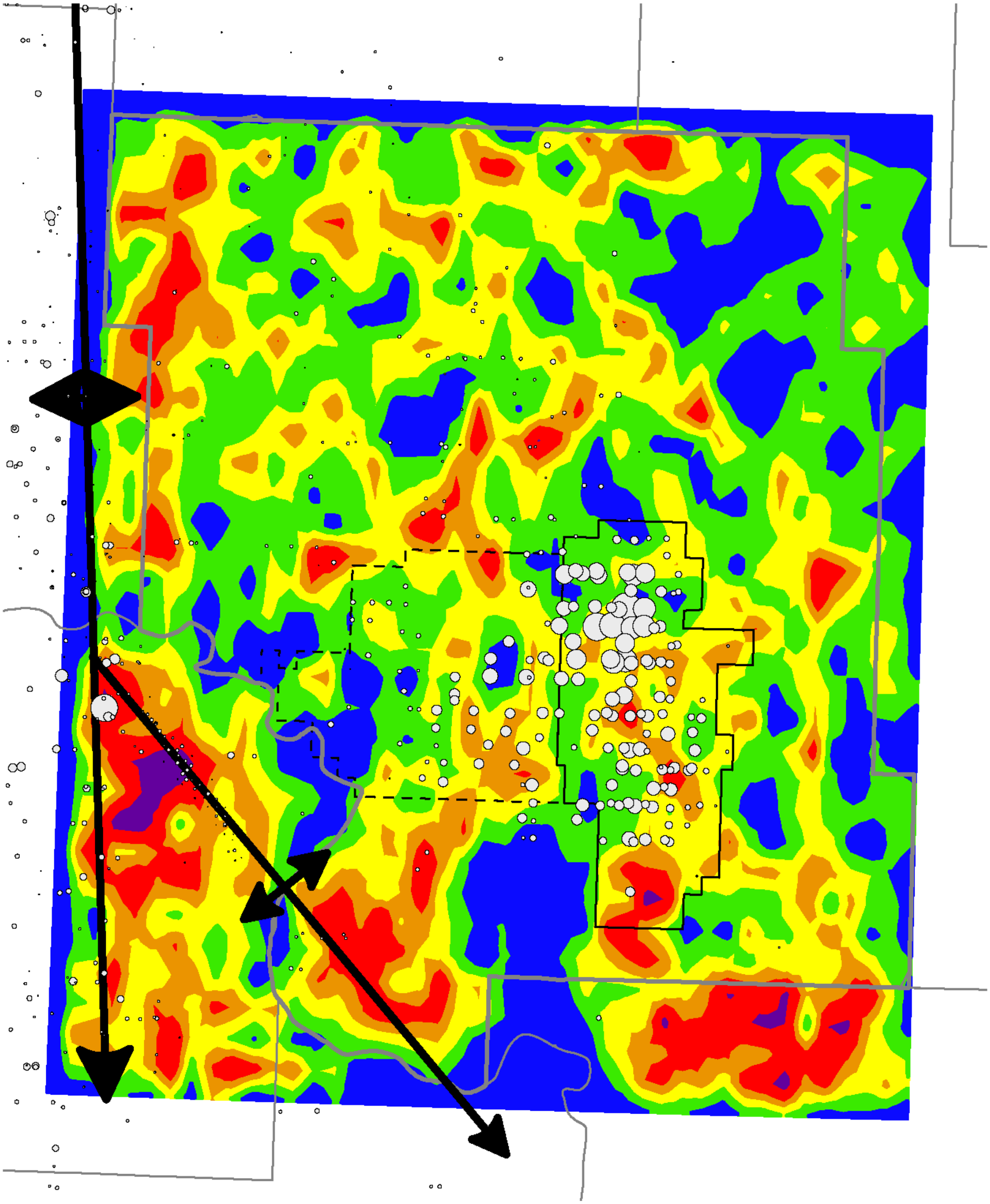


Figure 49. Lineament density map of Mountrail County overlain with daily average (based on first 60 to 90 days) production (radius of circle proportional to average daily production). Areas of greater relative lineament density are shown as "warmer" colors. Areas of relatively higher well production correlate with areas of greater relative lineament density.

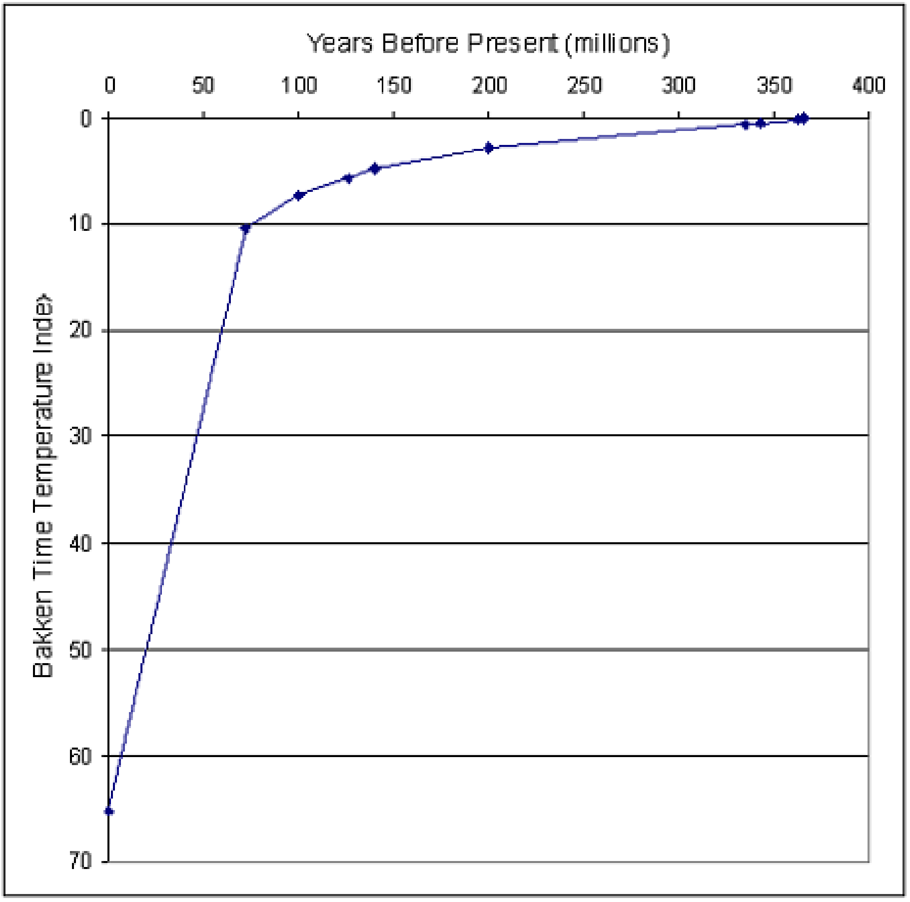


Figure 50. The TTI history of the Bakken Formation using a constant surface temperature of 15° C, a constant geothermal heat flow of 48 mW/$m^2$and the subsidence history for the Deadwood Canyon Ranch #43-28H. The diagram suggests that oil generation (TTI>15) within the Bakken Formation did not begin until after deposition of the Pierre Formation (72 mybp) and that oil generation rates may be near a maximum today (TTI ~65).

Relationship Between RockEval® Data and Oil Generation

The Time-Temperature Index (TTI) calculated for the subsidence history of the Deadwood Canyon Ranch 43-28H (Figs. 43 and 48) suggests that in Mountrail County oil generation began in the Bakken shales late in the Cretaceous. These results are in line with the level of maturation indicated by the T_{max} and Hydrogen Index (HI) slope maps presented in Figure 51.

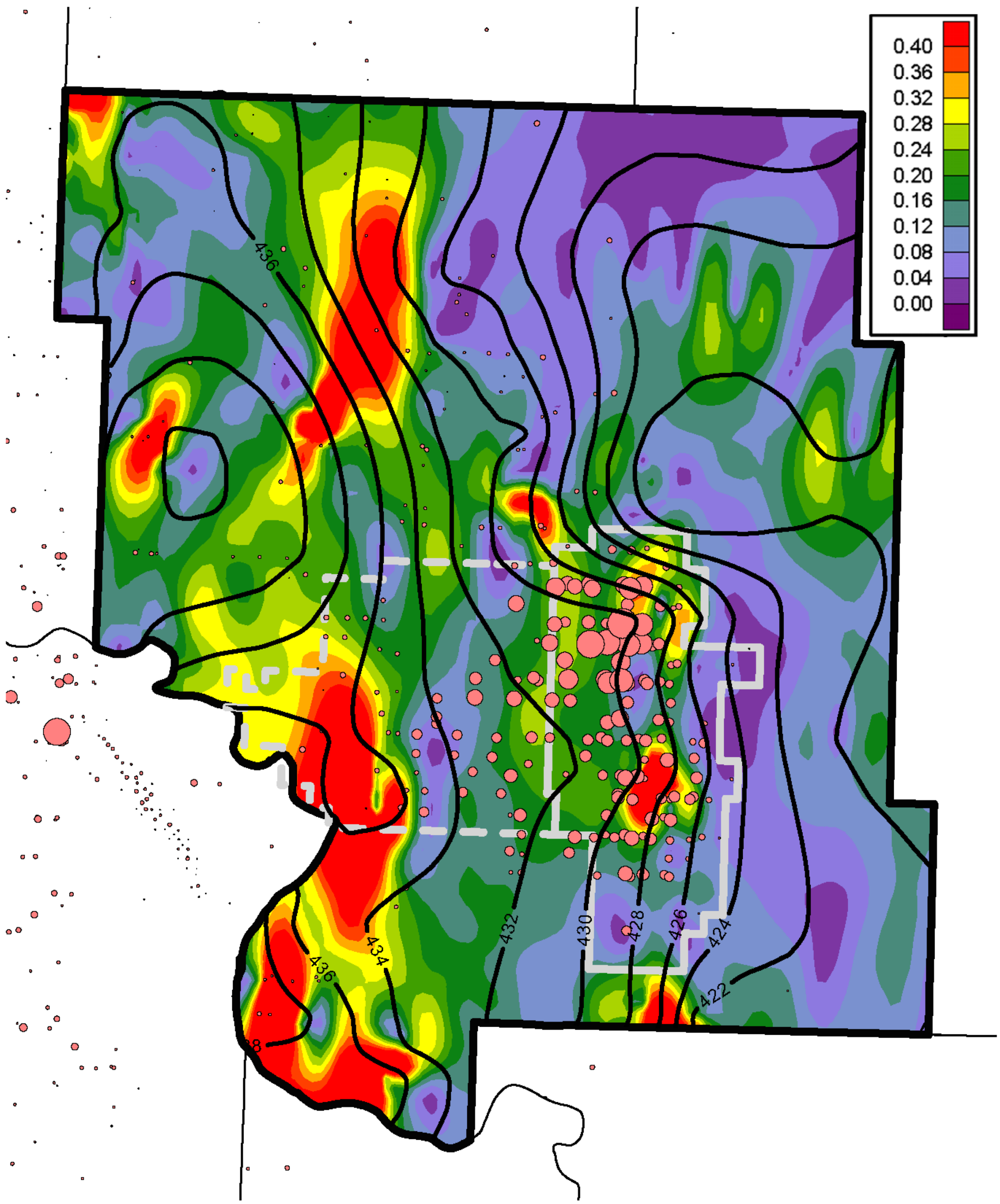


Figure 51. Detailed Hydrogen Index slope (color filled contours) and T_{max} (labeled black contours) map of the upper Bakken shale in Mountrail County, North Dakota. The diameters of the pink circles represent the relative initial production rates for the Bakken producers in the mapped area. The Parshall Field is outlined with a heavy solid black line and the Sanish Field is outlined by the heavy black dashed line.

The Hydrogen Index (HI) slope map (Fig. 51) suggests that peak oil generation or something close to peak oil generation may be occurring within the Parshall Field. However, T_{max} in the Parshall Field is well below the 435°C level that appears to coincide with the much more prominent Hydrogen Index slopes found in the western part of the Sanish Field. The somewhat high Hydrogen Index slopes in the Parshall area might reflect the presence of a kerogen that generates oil well below a T_{max} of 435°C and would therefore be consistent with a local source model that does not include migration. However, if oil generation is indicated by a high Hydrogen Index slope and T_{max} near 435°C then the presence of oil in the Parshall/Sanish Fields requires migration. The most likely source in this case would be from the areas in western Mountrail County that have large Hydrogen Index slopes and T_{max} values near 435°C. If oil generation is occurring in these areas then the oil present in the Sanish and Parshall Fields would have had to migrate up to 20 miles.

One of the outstanding questions concerning the source of the oil present in the Parshall and Sanish fields revolves around the issue of whether or not the oil is locally sourced or has migrated. Even though the Hydrogen Index slope and T_{max} map might be interpreted as outlining the regions in which oil is being generated this not meant to define the only areas in which oil generation in the Bakken is occurring. The TTI map indicates that oil generation in the Bakken shales is occurring throughout Mountrail County and Meissner's (1978) resistivity/maturation map shows that the shales are probably saturated with oil. The question is not if the Bakken has generated oil but rather what are the conditions that allow the generated oil to be produced.

There are at least three interacting components that appear to be related to the oil production in the Bakken Source System in Mountrail County. These include the tectonic stress environment, oil generation rates of the upper and lower Bakken shales and the reservoir properties of the middle Bakken and upper Three Forks Formations. The following observations may be useful in attempting to understand how these three components interact to generate "sweetspots" in Mountrail County.

If the oil generation rate is the only relevant consideration with regard to defining productive areas of Mountrail County then the HI Slope Map could be expected to coincide with the best production. This is currently not the case. In general, regions expected to be at the highest state of oil generation (largest change in HI) lie downdip of areas that are exceptionally productive. This is especially true when viewing the distribution of production in the Sanish and Parshall Fields relative to the HI Slope map. The implication is that either oil is being expelled from the shales and injected into adjacent reservoirs before peak generation rates are achieved or that the oil formed in the region of peak oil generation has migrated into rocks that are more capable of high levels of production.

In the Parshall Field, the HI Slope map suggests that there may be small areas in which the Bakken shale could be generating oil at a comparatively high rate. This coupled with a structural flexure within the field could contribute to a set of tectonic stresses that, when modified by locally high pore pressures, result in effective stresses that cause spontaneous fracturing or enhanced fracturing of pre-existing zones of weakness.

Recent oil generation within the Bakken coupled with very low permeabilities in the surrounding rocks could be expected to produce elevated pore pressures in the middle Bakken within the Parshall Field (Fig. 52). According to Meissner (1978) sufficient pressure could lead to spontaneous rock fracturing. Figure 53 shows an example of calcite filled fractures in a core of LF3 from the Sanish Field.

Pressures measured in the Parshall Field are nearly constant (average = 6337 psi). These pressures, when plotted against depth and overlain with various fracture gradients show that the current field pressures are insufficient to cause fracturing except in rocks with very low Poisson's ratios (<0.1). The presence of a single field wide pressure suggests there is pressure communication throughout the field (Fig. 52). Given that the matrix permeability of the Bakken is in the micro-darcy range, the most likely way that pressure is communicated through the reservoir would be through a pervasive fracture network. However, whether or not widespread pressure communication in the Parshall Field reflects natural fracture systems or artificially induced fractures remains an open question. The steep fracture gradient in the Parshall Field pressure data could represent a stable balance between tectonic stresses, pore pressures, and the various mechanical strengths related of the lithofacies in the middle Bakken.

Within Mountrail County, oil production from the "sweet spot" in the Parshall and Sanish Fields appears linked to a structural flexure that, under the influence of high pore pressures, results in significant fracturing and increased transmissivity. Pressures within this system could be created during oil generation and compaction from within the field or pressures could be transmitted updip from the region of presumed intense generation that lies to the west of these fields (see Fig. 54).

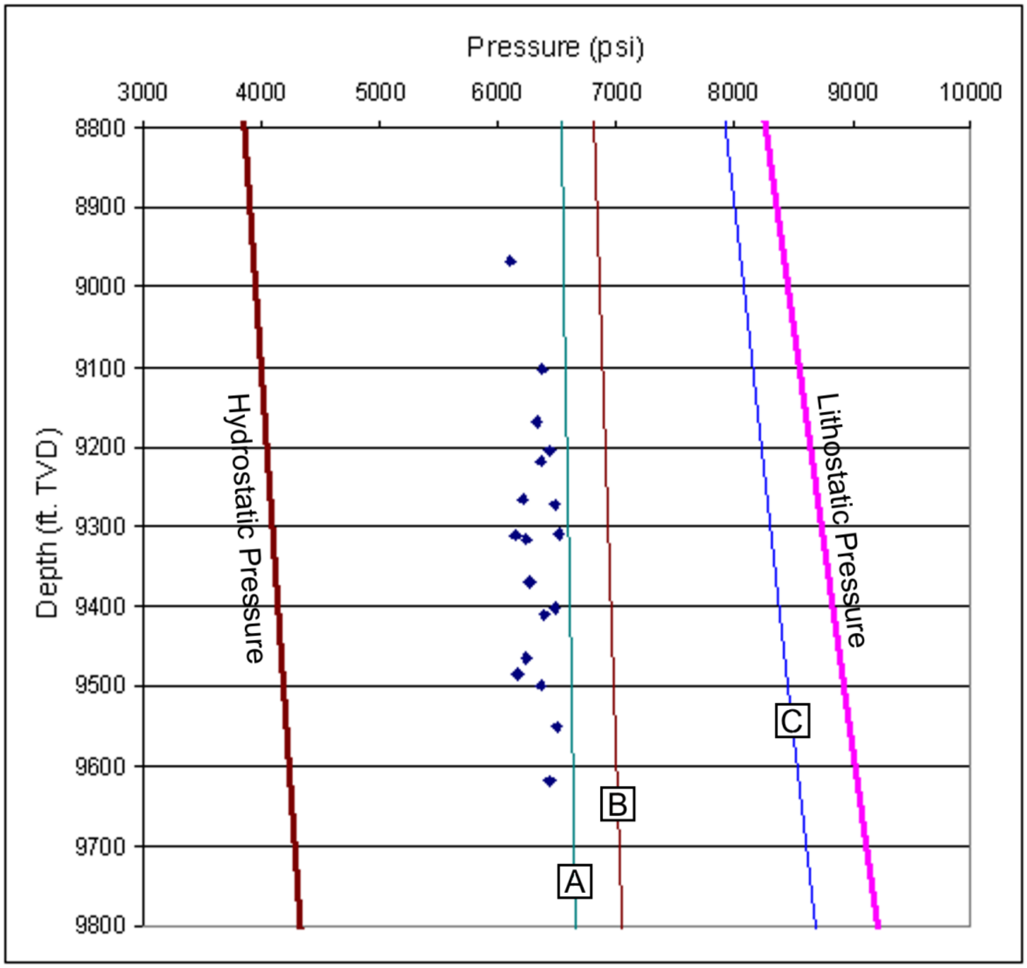


Figure 52. Pressure versus depth plot of pressures obtained from the Parshall Field contained in NDIC Case No. 10629 Exhibit E6. The pressure gradients reported on this exhibit are converted into pressures using the TVD of the top of the Bakken Formation as a depth reference. The heavy line on the left corresponds to a hydrostatic gradient of 0.465 psi/ft and the line on the right is the lithostatic pressure that corresponds to a gradient of 0.94 psi/ft. The labeled lines show the fracture gradients for rocks with a Poisson ratio of: 0.1 (A), 0.2 (B) and 0.45 (C).

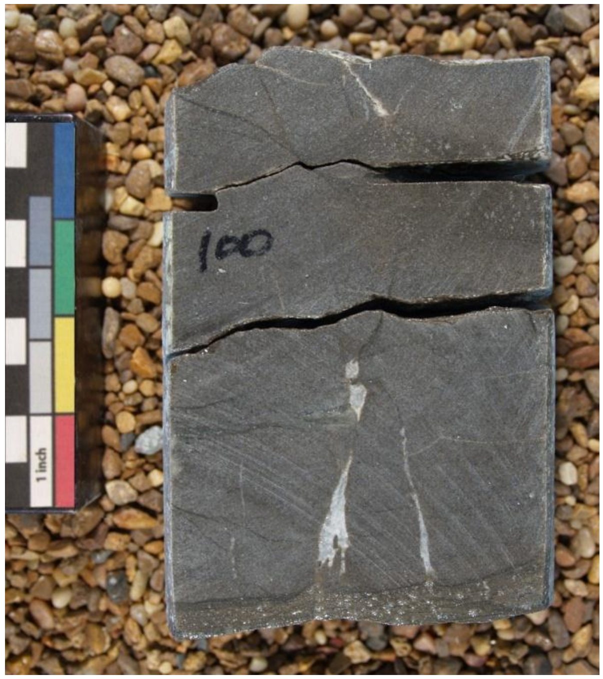


Figure 53. Core photo of calcite filled fractures in Lithofacies 3 in the Sanish Field. This core is from the Deadwood Canyon Ranch #43-28H (NESE Sec. 28, T154N, R92W) and was taken at a depth of 10,100 ft MD.

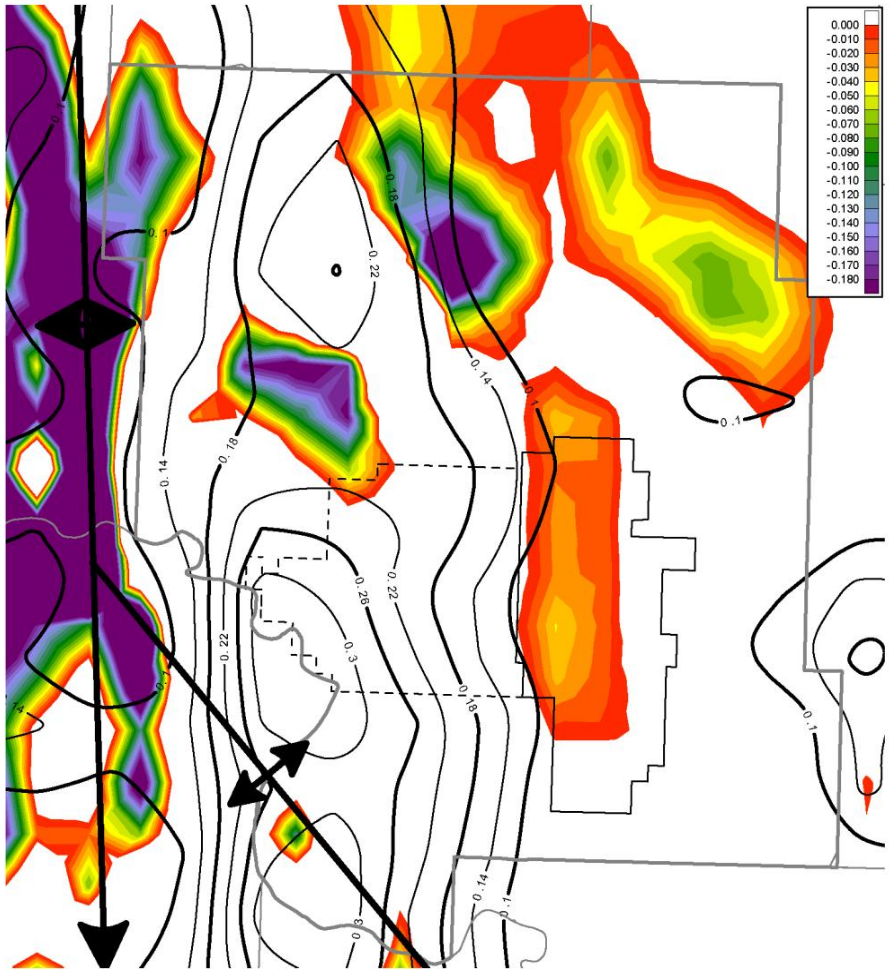


Fig. 54 A combination of the HI slope (closed contours) and 2nd derivative of the structure (color filled contours) on the Bakken Formation in Mountrail County. The 2nd derivative contours show the location of the crest of the Nesson anticline and various monoclinal (convex upward) slope breaks that follow the general structure of the basin. The contours on the HI slope are restricted to those that illustrate the inferred position of the oil window in Mountrail County.

Conclusions

Any exploration strategy in Mountrail County requires answering two basic questions. The first involves evaluating the oil generating history of the source rocks in the Bakken. The second question involves understanding how the generated oil gets into an appropriate reservoir.

There is little question as to the oil generating potential of the Bakken Formation. The shale members contain world class quantities of oil prone kerogen. The burial history of the Williston Basin in Mountrail County is consistent with the development of sufficient temperatures over adequate periods of time for significant oil generation to occur. The question is not whether the Bakken has generated oil but whether the generated oil has been expelled into a potential reservoir rock. The answer to this question involves two parts.

The first part involves the flow properties of oil, water and to a lesser degree gas within the potential reservoir rocks that lie adjacent to the Bakken shales. Almost without exception the rocks that lie above and below the Bakken Formation have low porosities and permeabilities in the microdarcy range. In order for large volumes of oil to be stored in these low porosity rocks, very large volumes of reservoir must be tapped. Furthermore, the very small pore throats responsible for the low permeabilities require elevated pressures to inject oil into the pore space of these rocks. The general presence of overpressures within the Bakken Formation is well documented. In order for injection to occur some pressure generating process must be operating at a sufficiently high rate to maintain a sufficient pressure level so that fluids are injected into the reservoir. Overpressures could be obtained by high rates of oil generation and/ or kerogen loss which results in compaction of the Bakken shales. In either case or some combination of the two, it is the rate of kerogen conversion that seems critical in causing overpressures in the Bakken.

The second part involves the need for a pervasive fracture system within the reservoirs that enhances the recovery of oil during production and may facilitate the injection of oil into the reservoir. At least three factors must be considered when attempting to understand the distribution of fractures within the reservoir rocks of the Bakken system in Mountrail County. The first involves the tectonic stress field that is responsible for the small structures, faults, flexures and associated surface lineaments that are the more obvious manifestations of these external stresses. The second important factor involves the internal stresses on the reservoir that caused by pore fluid overpressures. The third component is the reservoir itself. This includes pre-fracture strength of the rocks present in the reservoir, the vertical distribution of rocks strengths and the lateral continuity of these rock properties. Unfortunately the pre-fracture strength of the reservoir will likely remain unknown. Therefore, these factors must be estimated from analogous rocks found in similar subsurface settings. Probably the best analogs for the pre-fracture environment in the Bakken would be rocks with similar mineralogies and textures. These will, most likely, have been deposited under similar conditions and have similar burial histories. Combining the internal and external stresses operating on the reservoir with the distribution of reservoirs rock strengths should prove useful in defining fracture prone regions in Mountrail County and elsewhere in the basin.

Questions to Resolve

1. The question as to whether or not the oil in the Parshall Field is migrated or locally sourced is unresolved. Three lines of investigation seem warranted.
    a. RockEval® analysis of one or more sets of closely spaced core samples from the Parshall Field. If local sourcing is to be accepted then there must be intervals in the upper shale that are mature. A clear indicator of maturity would be the identification of subintervals within the upper or lower shale that have T_{max} values in the 435°C range.
    b. It may be useful to determine whether the kerogen in the Parshall Field contains more organic sulfur than is usually found in the Bakken shales. The presence of elevated organic sulfur compounds is frequently associated with oil generation at unusually low levels of thermal maturity.
    c. Petrographic analysis specifically keyed to the organic components of the upper shale may reveal local differences in kerogen composition within the Parshall Field that could account for oil generation in rocks with T_{max} well below 435°C.

- The scale and prevalence of natural fracturing in the middle member of the Bakken Formation in the Parshall and Sanish Fields is not well known. This suggests that additional reservoir quality studies are needed to determine the relative significance of depositional environments, diagenesis and structural history.
    - Depositional Environment
        - Detailed studies of the petrology and stratigraphy of Lithofacies 3 (LF3) keyed to the natural fractures in these rocks.
        - In the case of Sanish and Parshall fields, is LF3 associated with reservoir compartmentalization? This should be evident in the level of fluid communication in areas where LF3 is absent (Parshall) versus where LF3 is present (western Sanish).

- The influence of diagenesis needs to be addressed. Multiple episodes of cementation are evident in cores and thin section. The timing of this diagenesis and its affect on reservoir quality and reservoir communication is not clear from the work done to date. Fundamental work is needed to determine unravel the paragenesis of the Bakken Source System. Particular attention should be paid to the timing and number of fracturing episodes that are present in all three members of the Bakken Formation as well as the Lodgepole and Three Forks Formations. Work towards understanding the development/destruction of porosity within the various formations and members that make up the source system is also needed.
- Structural Details –
  - Current maps of the Bakken Structure are severely limited by the 640 acre well spacing and the tendency for many production wells to be drilled without wireline logs through the Bakken Formation. For this reason structural details derived from 2-D seismic are not currently verified by drilling and subtle structures possibly related to local fracturing are not evident. Evaluation of the seismic details and the construction of better structural maps of the Bakken could be made from mudlogs made during the drilling of the laterals in the Parshall and Sanish Fields. In most cases, mudlogs contain directional drilling data that would make it possible to locate where and at what elevation marker horizons intersected the wellbore. Additional data would significantly enhance the structural picture as well as provide data demonstrating structural offsets associated with the faults inferred from the 2-D seismic and surface lineament studies.
  - The relationship between surface lineaments and subsurface features cannot be demonstrated independently with the data at hand. In the absence of relevant statistics or field evidence to the contrary, the alignment of surface features with structures at depth is, at this time, an unexplained coincidence that may or may not have any underlying basis.
- Other producing areas, such as the Bailey and Fairway Fields, should be compared with the Sanish and Parshall Fields to determine whether there are any underlying similarities.

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