NEW STRATIGRAPHIC INTERPRETATIONS, GECHEMISTRY, AND
PETROPHYSICS OF THE LOWER MANCOS GROUP,
DOUGLAS CREEK ARCH,
NORTHWESTERN COLORADO, U.S.A.

by
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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements of the degree of Master of Science (Geology).

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ABSTRACT

A study of regional stratigraphy, geochemistry, and petrophysics of the interval between the Lower Mancos Shale and the Dakota Formations on the Douglas Creek Arch was conducted to investigate its resource potential as an unconventional gas accumulation. The purpose of this study was to test the hypothesis that the Lower Mancos Shale is a potential exploration target on the Douglas Creek Arch and evaluate various organic facies within this interval. Additionally, a comparison of the lower Mancos group of northwestern Colorado to previous studies of this unit across the state was performed.

To correlate separate, continuous, and mappable intervals in the Mancos B Shale to the Dakota formations, a study of well logs in this area was conducted. Within the stratigraphic interval thirteen key surfaces were identified: 1) Dakota Sandstone; 2) lower Tununk Shale; 3) Tununk Shale; 4) Frontier Sandstone; 5) Carlile Shale; 6) Niobrara 1; 7) Niobrara 2; 8) Niobrara 3; 9) Niobrara 4; 10) Niobrara 5; 11) Niobrara 6; 12) Niobrara 7; 13) Mancos Shale. Reservoir and source characteristics of each interval were investigated. The calcareous Niobrara Formation was identified on top of the Carlile Shale. To support the stratigraphic correlations and calcareous nature of the Niobrara Formation, an outcrop located in New Castle, Colorado was examined. Samples of the selected units were collected from the field. The petrology of the samples was analyzed.

The identified stratigraphic units were tied to the results of geochemical analysis performed on drill cuttings from existing boreholes. This allowed for the identification of intervals with moderate to high organic content. Formations in the study interval that may have source rock generative potential are: lower Tununk Shale, Tununk Shale, all the intervals within the Niobrara Formation, and part of the Mancos Shale. Additionally, a basic petrophysical study of the identified intervals within the lower Mancos group was conducted including the calculation of water saturations and porosities. In the final stage of the project, structure and isopach maps of the separate, continuous intervals of lower Mancos group were created. Based on the results, potential source rocks and reservoirs were identified. This study provides an opportunity for additional exploration targets in
the Piceance Basin to be developed, potentially supplying a significant amount of natural gas and oil to an increasingly demanding market place.
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CHAPTER 1

INTRODUCTION

Unconventional shale gas resources are garnering an ever-increasing share in the production of natural gas in the world. The percentage of the shale gas contribution is still relatively small, however, today’s energy market is constantly growing and very demanding. Natural gas is becoming a fuel of choice and becoming a bigger player. Accumulations of hydrocarbons in carbonate rocks can be very significant, for example, the vast carbonate reservoirs of the Middle East. The identification and evaluation of a new carbonate gas play in the Piceance Basin has the potential to supply new gas resources. Projections by the United States government and gas industry research organizations indicate that annual U.S. gas demand could increase by over 20% from the current 22 TCF to 27 TCF by the year 2030 (Curtis, 2007). Additionally, increasing prices allow more advanced methods of exploration to be developed. The first well in the U.S.A. specifically completed to obtain natural gas was operated in 1821 by William Hart in the state of New York; the first pipeline was built in 1891 (Natural Gas Supply Association, 2004). Substantial growth of the natural gas industry started in 1970s and, with the development of new technologies, is increasing significantly. There are several proven shale and carbonate hydrocarbon plays recognized within the Lower 48. The major ones include the Fort Worth Basin (Barnett Shale), Arkoma Basin (Hindsville Limestone), San Juan Basin (Lewis Shale), Illinois Basin (New Albany Shale), Denver Basin (Niobrara Formation), Michigan Basin (Antrim Shale), Appalachian Basin (Columbus Limestone), and Appalachian Basin (Ohio Shale), Williston Basin (Bakken Shale) (Curtis, 2002; Jordan Jr. and Wilson, 1994).

Improvement of natural gas exploration technology is possible with rising demand, increasing prices, and increasing environmental demands from governments. Individual consumers as well as exploration and development companies are interested in investments which could result in increasing production of natural gas. These reasons allow for unconventional gas resources to receive more attention. Shale gas systems are
usually unconventional, self sourced, and have continuous-type gas accumulations which
are thermogenic, biogenic or combined thermogenic/biogenic in origin. Production of
gas from these types of accumulations can be difficult and expensive. Typically, the
porosity of the reservoir rock is poor to fair and ranges between 6 to 14%. The
permeability of a shale reservoir rock is usually less than 0.1 md (Levorsen, 2001).

Due to the poor reservoir rock properties of shale and low porosity carbonates
(chalks), special completions and fracture stimulation are required to produce gas at
economic rates. Fracture stimulation increases the flow rate by many fold; the cost of
fracture stimulations may exceed the cost of drilling. This completion technology is
constantly improving and its cost is evolving. Carbonate reservoirs can have either
excellent or poor permeability depending on textures, fossil components, and diagenesis.
Poor permeability is common in low porosity dolomites, grainstones, boundstones, and
chalks; diagenesis can transform these rocks into porous rocks.

One of the biggest areas of unconventional plays in the United States is the Rocky
Mountain region. This area has estimated 318 TCF of proved and probable gas resource
(EIA, 2006). This represents 41% of proved and probable Lower 48 gas potential and
80% of these resources are unconventional (EIA, 2006). There are a few major
Cretaceous shale-plays in Colorado, including the Hilliard, Mancos, and Mowry
formations. The main carbonate play is the Niobrara Formation. The Mancos Shale is a
deep target in both the Uinta and Piceance basins with total depths of the wells reaching
16,000 feet (4876.8 m). The Niobrara Formation interfingers with the Mancos Shale and
has not been extensively explored in the Piceance Basin; however, it is a major producer
in the Denver Basin.

The undeveloped nature of the Niobrara Formation in the Piceance Basin allowed
this research to be undertaken. The stratigraphic, geochemical, and petrophysical study of
the interval between the Mancos B Shale and the Dakota Formation was studied.
Correlations of the subsurface data, study of the New Castle outcrop, Rock-Eval
pyrolysis, vitrinite reflectance, and basic petrophysical analysis of the lower Mancos
group were performed to provide answers regarding its petroleum potential.
1.1 Purpose and Scope

The purpose of this study is to test the hypothesis that the interval between the Mancos Shale to top of the Dakota interval is a potential exploration target on the Douglas Creek Arch (DCA) in the Piceance Basin, northwestern Colorado (Figure 1.1). A stratigraphic framework was developed by integrating organic geochemistry and previous correlations of equivalent units from the Denver to Uinta basins. Various subsurface techniques were incorporated to accomplish this purpose. Correlations of separate, continuous, and mappable intervals between the Mancos Shale and the top of the Dakota were completed using IHS Petra™ software. After determining key surfaces, potential reservoir and source intervals were analyzed. Geochemical analysis of existing well-bore cuttings along with the analysis of an outcrop were used to confirm stratigraphic correlations of the Mancos Shale-Dakota interval. Based on the correlations and geochemical data, potential reservoir and source rocks were identified. The third stage of the project concentrated on studying the relationship between geochemistry and petrophysics for wells with available geochemical data.

1.2 Study Area Location

The Bureau of Land Management (BLM) and EnCana Oil and Gas Company (USA) Inc. have an agreement in developing the Douglas Creek Arch Development Contract (DCADC), located on an anticlinorium which separates the Uinta and Piceance basins. This feature was created after the deposition of the Castlegate Sandstone in the Late Cretaceous through the Paleocene (Johnson and Finn, 1986). Within this contract a research study of the lower Mancos group was initiated. The DCADC area is located in northwestern Colorado across Rio Blanco and Garfield counties (Figure 1.1 a, b). It covers approximately 530,000 acres (214,483 ha). The DCADC extends from T 1 N to T 8 S and R 104 W to R 100 W measured from the 6th principle meridian. For the purpose of this study, the area was extended to include ten additional townships (Figure 1.1.b) and reached a size of about 890,000 acres (360,170 ha). The outcrop section described in
Figure 1.1 a) Regional map of Uinta-Piceance Basins; b) Outline of Douglas Creek Arch Development Contract (blue), Outline of Research Area (dashed line), Rio Blanco and Garfield counties boundary (red) Utah/Colorado state line (black), and township and range grid (Modified from Uinta-Piceance Assessment Team, 2003).
this project is located in the town of New Castle, Colorado along interstate I-70. The geographic coordinates of the outcrop are: N39°34’352", W107°28’82".

1.3 Previous work

There is a lot of information published about the Western Interior Cretaceous Seaway. The regional structure, paleogeography, sedimentation, biology, and eustacy were studied by many researchers (Berman et al., 1980; Dickinson et al., 1988; Franczyk et al., 1992; Haun and Kent, 1965; Johnson, 1988; Johnson and Finn, 1986; Kauffman, 1969, 1977, 1985; Kellog, 1977; Meissner, 1984; Molenaar and Wilson, 1990; Murray and Haun, 1974; Quigley, 1965; Stone, 1977; Tweto, 1980; Waechter and Johnson, 1985; Warner, 1961; Weimer, 1959). However, little information is available about the geochemistry of the lower Mancos group of the research area. Fisher (2007). This study amplifies the previous work. It is important to provide more information about the total organic content, thermal maturation, and organic matter type. The following sections review most of the important concepts previously published about the regional structure, geologic settings of the DCA, and sedimentation in the research area.

1.3.1 Previous Stratigraphic Correlations

The Mancos shale was first identified by Cross in 1899 (Warner, 1961). It was named for exposures in the Mancos Valley in the northwest San Juan Basin, Colorado (Warner, 1961). Publications which recognize the presence of the Niobrara on the DCA are limited (Longman et al., 1998; Molenaar and Wilson, 1990; Vincelette and Foster, 1992). Within the research area the Mancos Shale to Dakota interval was subdivided into the following formations using gamma ray and resistivity logs: Dakota, Lower Tununk, Tununk Shale, Frontier Sandstone, Carlile Shale, Niobrara 1, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, Niobrara 7, and Mancos Shale (Figure 1.2). The sharp difference in lithology on top on the Dakota Sandstone is visible on the well logs
and was previously identified by many researchers (Fisher, 2007; Franczyk et al., 1992; Haun, 1959; Haun and Kent, 1965; Johnson and Flores, 2003; Molenaar and Cobban, 1991; Moretti Jr. et al., 1992; Roberts and Kirschbaum, 1995; Uinta-Piceance Assessment Team, 2003; Weimer, 1984). The Dakota Group was deposited as shoreline deposits in the Cretaceous sea which transgressed across Colorado. Historically, various authors have subdivided the interval from the Mancos B Formation to the Dakota differently (Figure 1.2). This research will propose a new subdivision of this interval.

In the research area, the interval above the Frontier Formation is identified by many researchers as the Mancos Shale and was not broken into detailed units and its significant carbonate (chalk/marl) portion was recognized by a few researchers (Haskett, 1959; Longman et al., 1998; O'Boyle, 1955; Vincelette and Foster, 1992). Therefore, the Niobrara Formation was not recognized or evaluated for petroleum exploration within the research area. The Mancos Shale has been previously recognized on the DCA. The interval recognized above the Mancos Shale is the Mancos B, deposited in an offshore marine environment, and consists of claystone, siltstone, and fine sandstone (Kellog, 1977). This interval was subdivided into five intervals based on facies distribution (Kellog, 1977). The relationship between the upper Mancos and Mesaverde formations was studied by Warner (1961), but the study did not result in regional correlations of stratigraphic units within the Mancos shale.

The latest study of the research area was conducted by Fisher (2007). Fisher subdivided the Lower Mancos shale interval into separate units based on geochemistry and well log correlations. The units are, in ascending order, the Dakota Silt Equivalent, Tununk, Juana Lopez, Frontier Equivalent, Lower Blue Gate Shale, Niobrara Equivalent, and Upper Blue Gate Shale (Figure 1.2). Nomenclature used in his study was taken from Uinta Basin. The author suggests that additional detailed work is necessary to properly evaluate Lower Mancos shale on DCA, which required further structural, geochemical, and petrophysical analysis.
The study area is positioned near the western margin of the Western Interior Cretaceous Seaway. At its maximum extent the Western Interior Seaway (WIS) extended from Alaska to the Gulf of Mexico and was about 1,006 mi (1,620 km) wide (Figure 1.3). Pre-Cretaceous tectonic events formed a large structural basin (Roberts and Kirschbaum, 1995). The present-day Rocky Mountain region prior to the onset of Laramide deformation was part of a broad foreland basin within which marine facies were continuous for long distances (Dickinson et al., 1988). The northwest trending Western Interior Cretaceous basin is one of the largest foreland basins in the world (Weimer, 1984). During the Early Cretaceous, sediment supply was sourced from both sides of the basin with the thickest accumulation on the western side. During the Late Cretaceous, sediments were derived from the western margin and depositional environments ranged
from coastal plain and shoreline to marine shelf and deep water (Haun and Kent, 1965; Weimer, 1984).

During the Laramide orogeny, the Rocky Mountain foreland basin was partitioned. Partitioning took place in several steps. At the beginning of the orogeny, after the Park and Sawatch ranges were uplifted, the area of the Piceance Basin became a part of the structural and sedimentary basin which had its eastern border at the western flanks of the two ranges. The modern-day eastern margin of the basin is formed by the White River uplift which uplifted during Late Cretaceous and early Paleocene (Johnson and Flores, 2003). It is believed that the Sawatch and White River ranges are the only uplifts which do not have pre-Laramide expressions (Tweto, 1980). The western margin of the Piceance Basin is formed by DCA an anticlinorium sub-parallel to the Uncompahgre uplift on the south and Rangely anticline on the north (Murray and Haun, 1974). As a result of partitioning, the Piceance Basin region is an intermontane basin associated with the Sevier and Laramide orogenies formed during the late Early Cretaceous to late Eocene or Paleocene (Johnson, 1992; Waechter and Johnson, 1985). These two orogenies should be considered together because they grade into each other in space and time (Johnson, 1992).

The exact time of the Laramide orogeny is still controversial. There are at least four hypotheses as to when it began. According to Cross (1986), the initiation of Laramide tectonism occurred in the early Campanian about 84 Ma. Dickinson and others (1988) proposed the beginning of the Laramide deformation in the Maastrichtian about 71-66 Ma, and the systematic termination from north to south between early and late Eocene time. Franczyk et al. (1992) showed evidence that Laramide deformation started in the mid-Campanian about 75Ma when the gradual withdrawal of the Cretaceous sea from the Uinta basin region coincided with a decrease in subsidence rates in the areas closest to the Sevier thrust belt. During this time thin-skinned thrusting in the Sevier belt resulted in the formation of intermontane basins which had previously been part of the foreland basin. Sevier-style deformation took place until the late Paleocene 57 Ma (Franczyk et al., 1992). The full transition to Laramide-style paleogeography in the Uinta-Piceance area is characterized by the retreat of the Cretaceous seaway, the formation of the large Uinta and Piceance lacustrine basins, and surrounding uplifts.
According to Franczyk (1992) and Johnson (1988) the Laramide orogeny occurred between the late Maastrichtian and early Paleocene.

1.3.3 Tectonic History of the Douglas Creek Arch

The Douglas Creek Arch is a northwest trending anticline or a series of en-échelon anticlines which forms the western margin of the Piceance Basin and eastern margin of the Uinta Basin (Murray and Haun, 1974; Waechter and Johnson, 1985). There are many ideas related to the formation of the Douglas Creek Arch (Gries, 1983; Johnson and Finn, 1986; Ritzma, 1955). It has very complex history of uplift which can be observed in the sedimentary rock across the DCA (Johnson and Finn, 1986).

The DCA is thought to have a pre-Laramide tectonic origin (Stone, 1977; Waechter and Johnson, 1985). Pennsylvanian age fault blocks in the subsurface of the DCA have been identified and were still active in the Jurassic (Stone, 1977; Waechter and Johnson, 1985). Those fault blocks were most likely reactivated during the Laramide Orogeny and had a major influence on the formation of DCA (Stone, 1977; Waechter and Johnson, 1985). There is an ongoing debate about the precise timing of the uplift. Previously, researchers suggested that the movement on the arch started early in the Laramide orogeny or began even earlier and predated the uplifts of the Uinta and White River ranges (Gries, 1983; Johnson and Finn, 1986; Ritzma, 1955). According to Quigley (1965), the DCA is one of the older structures which influenced the deposition of the Mancos Shale. This conclusion is made based on the evidence of thinning of this formation over the arch.

However, more detailed analysis of the Paleocene and Eocene isopach and structure maps indicate asymmetrical development of the arch during the Paleocene (Johnson and Finn, 1986). The DCA became a positive structural feature when both the Uinta and Piceance basins began to subside. The asymmetrical flanks of the arch suggest that there was a significant difference in the subsidence history of the basins (Johnson and Finn, 1986). Based on the analyses of isopach maps, Johnson (1986) suggested that the movement on the arch could not start earlier than 77.5 Ma when the Castlegate
Figure 1.3 Paleogeographic maps of the Western Interior Seaway during the Cretaceous time (Blakey, 2006). Black rectangles represent location of the study area.
Sandstone was deposited. Johnson and Finn (1986) did not identify any significant thinning toward the arch on the isopach maps of the Mancos Shale to the Dakota. Therefore, for the purpose of this study the DCA uplift is considered to start with the deposition of the Castlegate Sandstone about 77.5 Ma.

1.3.4 Relative sea-level change and deposition

The Western Interior Cretaceous Basin of North America was a very complex foreland basin which was created as a result of accelerated plate spreading, convergence, and subduction along the Pacific coast of North America (Kauffman, 1985). The Circum-Boreal Sea and proto-Gulf of Mexico joined together in Late Albian time. The sea stayed connected for 30 Ma, until the late Middle Maastrichtian (Kauffman, 1985; Roberts and Kirschbaum, 1995).

The paleogeographic map of the Western Interior of Middle North America, for the Campanian interval (Figure 1.4 a) shows that the seaway started to develop after the Albian lowstand when the Muddy (Dakota) Sandstone was deposited. During the Cenomanian there was a general expansion of the seaway with a short regressive phase. One of the records for transgressive episodes of the Cenomanian age is the Mowry Shale and Tununk Shale, a detrital mudstone and siltstone interval. The regressive episode is further represented by sands of the Frontier Formation (Roberts and Kirschbaum, 1995).

During the early Turonian time period (Figure 1.4 b) the WIS had reached a maximum transgressive phase. According to Roberts and Kirschbaum (1995), the first highly calcareous muds (i.e. marlstone and chalks) were deposited over the eastern part of the seaway during this stage. Those calcareous muds are represented by the Greenhorn Formation. Toward the west of the seaway, calcareous muds grade into the gray muds and sandy muds of the Frontier Sandstone. Relatively rapid regression of the sea during Turonian stage resulted in the deposition of the sandier interval of the Frontier Sandstone. According to Roberts and Kirschbaum (1995), during the Coniacian and Santonian stages (Figure 1.4 c) there was a massive transgression of the sea interrupted by three small regressions. At the beginning of the Coniacian, the lower Niobrara formation (calcareous
mud) was deposited. Lime mud deposition occurred at the west, and detrital muds, which eventually replaced lime mud, were deposited in the southwestern region. The Coniacian and Santonian stages brought fluctuations of relative sea level which resulted in intertonguing of nonmarine and marine deposits.

The Campanian stage can be divided into two major parts in terms of sea level change. During the first part (Early Campanian) the WIS was in overall regression followed by transgression. At the beginning of the Campanian (Figure 1.4 d), carbonates were deposited in eastern Colorado and Texas. Elsewhere, pelagic muds such as the Pierre, Mancos, and Lewis shales were accumulated. During this stage in the western part of the WIS (present-day New Mexico, Utah, and Wyoming) significant coal beds were formed. During the second part (Late Campanian) the WIS was in its lowstand with shoreline farther to the east (Figure 1.3 e). There still was some marine deposition in the central part of the seaway resulting in the deposition of the Pierre Shale. However, the presence of the sandier member of this shale suggests that there were high fluctuations of sediment supply and that the shoreline was continuously moving towards the east. For the first time, predominantly terrestrial deposition took place in western Colorado. As a result of coastal plain environments, major peat accumulations were present. A good example of this is the Iles Formation and the lower part of the Williams Fork Formation of the Mesaverde Group (Roberts and Kirschbaum, 1995).

1.4 Description of proposed research

Data used for this study were made available by EnCana Oil and Gas (USA) Inc. It consists of petrophysical well logs, cuttings, and geochemical data from boreholes previously drilled within DCADC. There are 617 wells within the research area which partially or fully penetrated the study interval (Figure 1.5). Most of these wells have raster (majority in the south part of the area) and/or digital logs. The digital logs are more desirable because they are easier to read and manipulate in the software packages allowing for quantitative petrophysical analyses.
Figure 1.4 Paleogeographic reconstruction maps of the Late Cretaceous Western Interior of Middle North America (Modified after Roberts and Kirschbaum, 1995). Black box represents location of the study area.
Six wells were sampled for geochemical analysis and one was sampled in the study by Fisher (2007). Five of them are located in the north-west part of DCADC: Hells Hole 6-14 (Sec 6, T2S, R104W); Hells Hole 19-1 (Sec. 19, T2S, R104W); Hells Hole 9131 (Sec.13, T2S, R104W); Hells Hole 18-9 (Sec.32, T5S, R102W); Taiga Mountain-Federal 6-22 (Sec. 22, T1N, R103W). The sixth well is located in the middle of the development contract area: South Baxter Pass Unit 2-20 (Sec. 20, T5S, R102W); the seventh well is located in the southern part of the research area: Ruby 8102-31M (Sec. 31, T8S, R102W) (Figure 1.5).

Stratigraphic correlations and petrophysical analysis were based on the study of gamma ray (GR) and resistivity logs. To establish the porosity of a rock, three different logs were used based on availability. Neutron porosity logs (NPHI), density porosity logs (DPHI), and bulk density log (RHOB) which is the density of the whole formation (solid and fluid) (Asquith and Krygowski, 2004; Levorsen, 2001; Selley, 1998).

In this study three methods were used to test the hypothesis that the Mancos Shale to Dakota interval can be a potential target on the DCA. The first of the methods was creating a stratigraphic framework which involved identifying key surfaces in this interval. Determining their geologic equivalents based on available regional information (Figure 1.2), and correlating identified intervals with intervals from the eastern part of the state. Correlations of the Upper Cretaceous strata between the basins are difficult because most of the sediments deposited in areas separating the basins have been eroded. Also, previously no detailed stratigraphic studies of the Mancos Shale to Dakota interval in this area have been published.

In the past, many authors concentrated on correlations of formations which underlie the Mancos Shale and the overlying Mancos B Shale. Generally, these marine intervals (Mancos Shale, Dakota, and Mancos B Shale) were grouped under the term Mancos Shale. The lower part of the Mancos Shale is identified as sandy marine shales which were deposited within the Western Interior sea (Molenaar and Cobban, 1991; O'Boyle, 1955). This interval in its central and upper parts is calcareous and is recognized as equivalent to the Niobrara formation of the eastern Colorado.

This study establishes a stratigraphic framework and correlates the Mancos Shale-Dakota interval starting in Park Mountain and Hells Hole areas and expands towards the
east. Correlations were completed using IHS Petra™ software. In the cross-section module of this software well-to-well correlations were performed using wells which fully penetrated the Mancos Shale-Dakota interval. Wire-line log correlations of subsurface units were followed by analysis of the New Castle outcrop which helped to ensure proper stratigraphic framework. The study of the outcrop concentrated on detailed lithologic descriptions followed by a hand-held GR measurement conducted by RS-125/230 Spectrometer. Rock samples from intervals identified in the outcrop were collected. For further analyses, petrographic thin sections of seventeen samples were made. Those were investigated for their faunal as well as petrological content.

The second method to test the hypothesis was analyzing the results of organic-geochemical tests from cutting samples collected on 30, 50, and 100-foot intervals from seven wells. The Taiga Mountain 6-22 and South Baxter Pass Unit 2-20 were sampled at U.S. Geologic Survey’s Core Research Center. The geochemical results were evaluated and used to ensure that previously interpreted stratigraphic intervals have been properly and uniformly recognized. Analyses performed include: RockEval pyrolysis, TOC, and vitrinite reflectance, and was done by Baseline Resolution Analytical Laboratories, Inc, Humble Geochemical Services, and Weatherford International Oil Field Services.

RockEval pyrolysis (thermal cracking) is defined as heating of organic matter in the absence of oxygen. Pulverized samples of whole rock are heated to 300°C and followed by programmed pyrolysis at 25°C/min to 550°C, each analysis takes approximately 20 minutes. During pyrolysis these parameters are obtained: S1 peak which is produced by free “hydrocarbons” thermally distilled from the rock; S2 peak produced by “hydrocarbons” pyrolyzed from kerogen; S3 peak produced by carbon dioxide pyrolyzed from kerogen; T_{max} which is the temperature at which maximum evolution of S2 “hydrocarbons” occurs; and production index (S1/(S1+S2)). Total organic content is measured on powdered rock sample with a LECO carbon analyzer. Samples are first acidified to remove carbonates and then heated to 100°C in the presence of oxygen. There might be some bitumen included in measurements but usually it is less than 10% of TOC.
Figure 1.5 DCADC study area showing 617 data base wells which penetrated the Dakota Group. Arrows point the locations of the wells: Hells Hole 6-14, Hells Hole 19-1, Ruby 8102-31M, Hells Hole 9131, South Baxter Pass, Unit 2-20, Taiga Mtn-Fed 6-22, and Hells Hole 18-9 which have geochemical data.
Vitrinite reflectance measures the thermal maturity of kerogen (an insoluble organic substance that upon heating produces bitumen and then hydrocarbons) as the percentage of incident light reflected by polished vitrinite fragments- reflectance ($R_o$). Usually 20 to 100 readings are necessary for each sample. Reflectance can be measured on isolated kerogen and on polished rocks, and is a standard analysis in maturity studies. Visual kerogen analysis is a description of the organic matter as observed under high magnification in transmitted and fluorescent light. The four types of macerals are: Type I- lacustrine, amorphous organic matter, oil prone; Type II- marine algae, plants lipids, pollen, spores, land plant cuticles and resins, oil and gas prone; Type III- woody and cellulosic material from land plants, gas prone; Type IV- charcoal, highly oxidized. In this study type II, mixed II/III, and type III were identified based on available data from the RockEval pyrolysis.

The vitrinite reflectance method is the most subjective of all and results from different laboratories can vary. Geochemical results and comparison to the Mancos-Dakota interval will identify which intervals are potential source rocks. (England, 1990; Peters, 1986; Selley, 1998; Tissot and Welte, 1984; Waples, 1985). Results of the geochemical analysis are compared between five wells in the north-south cross-section (Taiga Mountains-Federal 6-22, Hells Hole 9131, Hells Hole 18-9, South Baxter Pass Unit 2-20, and Ruby 8102).

The third method which helped to answer the question if the Mancos Shale-Dakota interval is a potential exploration target, is a petrophysical study. Parameters which are commonly used in evaluation of petroleum reservoirs are porosity, permeability, and water saturation. The first parameters which were evaluated in this study are total and effective porosities. Total porosity is a non-mineral space which can be occupied by fluids weather the pores are connected or not, it is measured in percentage. Effective porosity is the amount of space which is sufficiently interconnected to yield hydrocarbons. Porosity was established from analysis of available porosity logs (NPHI, DPHI, and RHOB). The next parameter which was evaluated is permeability. It is probably the most important single property of a reservoir rock. It permits the passage of a fluid through the interconnected pores of a rock and it is a measure of rock’s ability to transmit fluid. The unit of permeability measurement is named the Darcy after Henri
Darcy who experimented with the passage of liquids through porous media in 1856. The average permeability for the research area was established from available bottom hole pressure buildup surveys and well logs. Water saturation is the third factor which was analyzed. The water saturation and permeability are strictly related to the pore-size distribution (Archie, 1950). Water saturation is the fraction of water in a given pore space. It is measured in percentages and usually refers to effective water saturation if the pore space is effective porosity. Knowledge of the water saturation allows for an estimation of the percentage of hydrocarbons in a formation. It is very hard to predict the properties of a formation as a whole even if tested on the microscopic scale. Petrophysical analyses of each interval are helpful in estimating the hydrocarbon potential of the Mancos Shale-Dakota interval.

1.5 Summary

This research is an attempt to evaluate the exploration potential of the Mancos Shale-Dakota interval on the DCA. There is plenty of information related to tectonics, paleogeography, and sedimentation of the research area, however, not much information has been published about geochemistry. Additionally, the Mancos Shale-Dakota interval on the DCA was considered as a shaley interval (Mancos Shale) and was not tested for carbonate content. There is limited information about attempts to subdivide this interval. This research attempts to divide the Mancos-Dakota interval into smaller intervals based on regional information, log signatures, and geochemical data from wells drilled in the study area. In a previous effort to subdivide this interval, Fisher (2007) adapted terminology from the Uinta Basin. In this research, an attempt to correlate identified intervals form the DCA with previously recognized units from the eastern side of the State of Colorado as well as the Uinta Basin is made. To assure that subsurface correlation is correct there was an attempt to tie information from the outcrops. To make sure that lithologies of this interval were properly identified, the petrology of samples collected in the outcrop was studied. In the final stage of this project the author tried to tie geochemistry of identified intervals, for tested wells, to petrophysical information. Based
on the results of this study, maps of the identified units were made and possible source rock and reservoirs were identified.
 CHAPTER 2

STRATIGRAPHY AND CORRELATIONS

There are not many previous detailed stratigraphic studies published about the Mancos-Dakota interval of the DCA which acknowledge the calcareous character of the formation. Sediments of this interval overlay the Albian/Cenomanian Dakota Sandstone and underlie the Campanian Mancos “B” shale. These Upper Cretaceous rocks of northwestern Colorado vary in detail but overall are similar to the Cretaceous rocks of the Rocky Mountain province (O’Boyle, 1955). Sediments represented in the Mancos-Dakota interval were deposited in complexly intertwining marine and non-marine settings related to the fluctuations of the WIS (Berman et al., 1980). In the research area, the thickness of the section ranges from approximately 2,600 ft (792.5 m) in the northern part to 1,900 ft (590 m) in the southern part of the research area. This change of sediment thickness illustrates a significant thinning of the whole section onto the Uncompahgre Uplift. In this study, the researcher subdivided the thick Mancos-Dakota section into twelve intervals. The intervals overlie the Dakota Sandstone and in ascending order are: lower Tununk Shale, Tununk Shale, Frontier Sandstone, Carlile Shale, Niobrara 1, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, Niobrara 7, and Mancos Shale.

2.1 Methods of stratigraphic correlations

Stratigraphic correlations were conducted using IHS Petra™ software. Well-to-well correlations started in the northwest part of the research area where Hells Hole Field is located (Figure 2.1). Formations initially identified based on the regional information were: Dakota Sandstone, lower Tununk Shale, Upper Tununk Shale, Frontier Sandstone,
Figure 2.1 Location map of the north-south and west-east cross-sections. Circle shows approximate location of the Hells Hole Field. Numbers illustrate key wells. Star represents location of the type log for this study.
Carlile Shale, Niobrara Group, and Mancos Shale (Figure 2.2). Nine cross-sections, two north-south (A-A’ and B-B’) and six west-east (C-C’, D-D’, E-E’, F-F’, G-G’, H-H’, I-I’), were constructed to correlate formations across the whole field in example wells (Figure 2.1). From the example wells, correlations were expanded out to the rest of the study area. After studying the New Castle outcrop (discussed in chapter 3) and receiving results of geochemical analysis (discussed in chapter 4), the Niobrara Formation was further subdivided into seven intervals. These subdivisions were identified based on slight geochemical changes of the sediments within the interval, variations of the log signatures, and study published by Vincelette and Foster (1992). The Niobrara was divided into: Niobrara 1, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7 (Figure 2.2).

2.2. Identified intervals

In this section identified formations will be discussed in ascending order. For each interval detailed gamma ray and resistivity log signatures from the 8-32-4-103 Federal (Figure 2.2) well (Sec.32, T4S, R 103W) will be described. Important log character trends, used to correlate formations, are shown on the logs by arrows. To show interval geometries recognized during this study, cross-sections across the DCADC were established.

Cross-sections designed to correlate formation across the DCADC are also used to illustrate interval geometries. Appendix A contains a list of wells used in the cross-sections. Appendix B contains list of tops for wells used in the cross-sections. Appendix C lists formation tops for each of the 617 wells used for correlations in this study.

2.2.1 Dakota Sandstone

The Dakota Sandstone is widely deposited across the basin and is an important correlative surface. Northwesterly trending, nearshore marine and nonmarine, Dakota
Figure 2.2 The 8-32-4-103- Federal well type log for DCADC type log. The type log displays Gamma Ray and Resistivity curves used for correlation across the research area. Age associations, sea-level curve (modified after Berman et al. (1980)), and correlations are also displayed.
Sandstone (Albian/Early Cenomanian) was deposited in a high energy environment associated with rising of the WIS at this time (Franczyk et al., 1992; Molenaar and Cobban, 1991). This formation consists of resistant sandstone and conglomeratic sandstones with good to moderate sorting. In many Dakota beds, grain size increases upward (Molenaar and Wilson, 1990). The top of Dakota Sandstone defines the base of the study interval. The top of this formation is easy to recognize because there is a large decrease in GR. It is created as a response to lower amount of radioactive materials in

Figure 2.3 The 8-32-4-103 Federal well. Type log showing tops of Dakota, lower Tununk, Tununk, Frontier, Carlile, and Niobrara 1 formations.
sandstone (Figure 2.3.). There is also significant increase in response on resistivity log which is a result of pore fluids presence within this sandstone. The Dakota Sandstone is a known gas producer in the research area.

2.2.2 Lower Tununk Shale

There is significant controversy about the presence of the Mowry Shale in the research area. Some researchers suggest that the Mowry Shale is not present or is remnant in this region (Fisher, 2007). Additionally, it was classified as a part of the Dakota Sandstone and recognized as Dakota Silt (Moretti Jr. et al., 1992). According to Anderson (2009) and Molenaar and Cobban (1991), the Mowry is present only in the northern part of the study area and due facies change becomes more sandy on the south. Interval previously recognized as the Mowry Shale in this research will be called the lower Tununk Shale. According to O’Boyle (1955), this interval is in gradational contact with the Dakota Sandstone, however, Molenaar and Wilson (1990) suggested that there is sharp but conformable contact between the two. There also is controversy related to the age of this interval. It is either Cenomanian in age (Franczyk et al., 1992) or Turonian (Anderson, 2009). The Cenomanian age was established based on the presence of Neogastroplites and Metengonoceras fauna, which Cobban and Kennedy (1989) were able to correlate (Franczyk et al., 1992). The deposition of the lower Tununk Shale took place during the first marine transgression of the WIS. The lower Tununk Shale consists of hard dark-gray, organic-rich marine shale which grade upward into siliceous shale. Within the formation gray limestone and bentonites were identified (Molenaar and Wilson, 1990; O’Boyle, 1955).

In some areas, the lower Tununk Shale is more siliceous (silt) which is indicated by decrease on the GR logs. The top of the lower Tununk Shale is relatively distinct and was identified on the top of a fining upwards sequence (Figure 2.3). The GR signature indicates an increase of radioactive material within this formation (Figure 2.3). There is a significant increase of GR at the base of this interval which may indicate dark shale or bentonite. Above this increase, GR decreases which indicates a coarsening upwards and a
Figure 2.4 Cross-section A-A’ (north-south), from the west side of the study area, showing regional correlations. Well’s names and locations are shown in the Appendix A.
siliceous nature of the formation. In the top part of the lower Tununk Shale there is gradational change of sediments (higher shale content) which may show intertonguing of the lower Tununk Shale with overlying Tununk Shale. The thickness of this interval ranges between about 43 and 211 ft (13 and 64 m). It thickens towards the south and east of the research area (Figures 2.4 and 2.5).

The lower Tununk Shale is important for the regional stratigraphy. It is believed that the top of this formation marks the division between the lower and upper Cretaceous. Additionally, many researchers recognized a regional unconformity on top of this interval, which separates it from an overlying shale unit (Franczyk et al., 1992; Molenaar and Cobban, 1991; Molenaar and Wilson, 1990).

2.2.3 Tununk Shale

The interval overlying the lower Tununk Shale, identified during this project, is the Tununk shale. Previous classifications of this unit in the research area by Fisher (2007), and Franczyk et al (1992) have identified it as the Juana Lopez Formation and the basal shale member of the Frontier Formation, respectively. Molenaar and Wilson (1990) also referred that the marine shale unit which overlies the Mowry Shale as the Tununk Shale Member of the Frontier Formation. The Tununk Shale overlies an unconformity above the Mowry Shale (Franczyk et al., 1992). The Tununk Shale is of early to middle Turonian in age.

An increase of the GR signature above the lower Tununk Shale illustrates the Tununk Shale (Figure 2.3). In the upper part, the GR gradually decreases which suggests coarsening upward of the sequence. The top of the Tununk Shale was picked at the base of the Frontier Sandstone (Figure 2.3). The thickness of this formation ranges from approximately 115 ft (35 m) to 193 ft (58 m) and is thicker in the central and south-east part of the research area (Figures 2.5 and 2.6). The Tununk Shale is evaluated for its source capacity potential across the Uinta and Piceance basins (Anderson and Harris, 2006; Uinta-Piceance Assessment Team, 2003). It is considered a potential source rock within the research area.
Figure 2.5 Cross-section B-B’ (north-south), from the east side of the study area, showing regional correlations. Well’s names and locations can be found in the Appendix A.
2.2.4 Frontier Sandstone

The Frontier Sandstone is Turonian in age and conformably overlies the Tununk Shale. It is equivalent to the Ferron Sandstone of Utah and the Codell Sandstone of eastern Colorado. In northwestern Colorado, Frontier Sandstone is thin-bedded and shaly with ripple marks being common (O’Boyle, 1955). It has significant calcareous cement content which results in very low porosity and permeability. The deposition of the Frontier Sandstone probably took place during regression, when both marine sandstone and nonmarine sandstones were deposited.

The signature of GR above the Tununk Shale shows a gradual coarsening upward sequence which is topped with a sandstone about 20 ft (6 m) thick (Figure 2.3). Above this sandstone, GR increases which suggests an increase of radioactive material and a fining upward sequence is identified. This illustrates a gradual transition into shaly sediments deposited most likely during the Turonian transgression of the WIS. In this study the top of the fining upward sequence defines the top of the Frontier Sandstone. The thickness of the whole formation ranges from 40 to 166 ft (12 to 50 m) (Figures 2.6 and 2.7). This interval seems to be relatively uniform in thickness across the study area. The thickest sediments are in the northeast part of the area. Poor porosity, permeability, and high clay content result in low reservoir potential of this formation. Shows of gas have been identified in the Frontier Sandstone in the study area; however there is no significant production (O’Boyle, 1955). Sandstones from the Frontier Formation are significant reservoirs in Wyoming (Weimer, 1984).

2.2.5. Carlile Shale

The Carlile Shale was not previously identified in the research area. It was considered a part of the of the Lower Mancos Shale and not shown as a separate unit. It was described by researchers in Wyoming, Kansas, and eastern Colorado as shale underlying the Niobrara Formation (Fox, 1954; Von Holdt, 1978; Weimer, 1984). This interval is composed of siltstone, shale, sandstone, and limestone. It was deposited under
Figure 2.6 Cross-section C-C’ (west-east), from the north side of the study area showing regional correlations. Well’s names and locations are shown in the Appendix A.
marine conditions. The depositional model used to best describe sedimentation of the Carlile Shale is shelf, slope, and basin. Eustatic changes of the WIS and tectonic movement result in the presence of the unconformities within upper part of this unit (Weimer, 1984). The Carlile Shale is Upper Turonian in age.

The top of the Carlile Shale is picked on top of the fining upwards sequence characterized by gradual increase of gamma ray (Figure 2.3). This siltier interval is overlain by the Niobrara 1. On resistivity logs, this top is recognized at the base of shalier and more resistive interval. Generally, the signature of the resistivity log does not change within this interval. However, there is a noticeable increase in the middle of this interval on the east side of the study area. The Carlile Shale seems to be consistent in thickness across the majority of the study area. However, in the northeast it is significantly thicker in comparison to the southwest (Figure 6.6). The range of thicknesses for this interval is between 174 and 467 ft (53 and 142 m). The northeast to southwest thinning of the formation is illustrated on the cross sections (Figures 2.4, 2.5, and 6.6). The Carlile Shale is relatively thick in the research area but it is not rich in organic matter and is not considered a source rock (Chapter 4).

2.3 Niobrara Formation

The Niobrara Formation in the research area was previously considered by many as a shale interval in the lower Mancos. The Niobrara Formation was described in the Rangely Field (Piceance Basin) and Buck Peak Fields (Sand Wash Basin) where significant amounts of oil were produced. Most of this production comes from fractured lower Mancos Niobrara equivalent. Rangely Field is considered as the largest Niobrara field in northwestern Colorado (Vincelette and Foster, 1992). In their paper Vincelette and Foster (1992) discuss the field and present a Niobrara type log from the northeast part of the study area (2-1 Government La Gloria, Sec.2, T1N, R 101W). On this log, zonation and lithology of the Niobrara Formation from the Rangely area is shown. Similarly, as in this study, the Niobrara Formation was subdivided into seven intervals. The Niobrara Formation is Coniacian and Santonian in age.
Figure 2.7 Cross-section D-D’ (west-east), from the northern side of the study area, showing regional correlations. Names and locations of the wells shown in the Appendix A.
Vincelette and Foster (1992) divided the Niobrara into two main types of facies: the lower Puerto Chiquito and the upper Buck Peak. The first facies is composed of dark-gray, calcareous, organic-rich marine shale or marl with abundant Coccolith and Inoceramus. The lower facies are more brittle and composed of silty and sandy units interfingering with the calcareous shale (Vincelette and Foster, 1992). Intervals identified in the present study which create the upper facies (Buck Peak) are: the Niobrara 7, Niobrara 6, and Niobrara 5. The Puerto Chiquito facies as used by Vincelette and Foster is an equivalent to: Niobrara 3, Niobrara 2, and Niobrara 1 used in this report. The

![Figure 2.8 The 8-32-4-103- Federal well. The type log showing tops of Carlile, Niobrara 1-7, and Mancos Shale formations.](image-url)
Niobrara 4 is a transitional interval in-between two main facies types (Figure 2.8) It contains wide spectrum of lithologies such as: chalks, marls, shales, and sandstone (Longman et al., 1998). The whole Niobrara Formation was identified as a potential source rock (Meissner, 1984). Separate Niobrara intervals will be discussed in the following sections.

2.3.1 Niobrara 1

Niobrara 1 is lowest unit within the Niobrara Formation. It was named Lower Niobrara by Vincelette and Foster (1992). This interval sharply and most likely unconformably overlies the Carlile. There is a regional unconformity above the Carlile Shale in the eastern part of Colorado, Kansas, and Wyoming (Weimer, 1984). The lower part the Niobrara 1 is composed of interlaminated, very thin, tight sandstone, siltstone, and slightly calcareous shale (Vincelette and Foster, 1992). In the upper part, this interval is composed of hard, very calcareous shale. It is characterized by an increase of the total organic carbon from average 0.99% for the Carlile Shale to average 1.53% for the Niobrara 1 interval. The geochemistry of this interval will be closer discussed in chapter 4.

The Niobrara 1 top is picked where the GR reading slightly decreases which may suggest the top of the calcareous shale (Figure 2.8). This pick was also based on the readings of the resistivity log. There is an easy to distinguish increase of the resistivity at the base of this unit which gradually decreases to the top. The top of Niobrara 1 was picked at the point where resistivity log flattens again. This interval thickness ranges from about 44 ft (13 m) to about 131 ft (39 m). There is a noticeable thinning of the thickness toward the west and south (Figures 2.4 and 2.9). The Niobrara 1 may have a slight to modest source capacity within the research area. According to Haskett (1959), in the Tow Creek area there was oil present within this unit (1959).
2.3.2 Niobrara 2

The Niobrara 2 conformably overlies Niobrara 1. It was named “R” for Rangely Bench by Vincelette and Foster (1992). In the lower, part the Niobrara 2 is composed of very calcareous shale which is overlain by thin siltstone. Above the siltstone, in the middle of this interval, thick bentonitic clay exists and underlies very calcareous shale. In the upper part, this unit is composed of soft, non-calcareous shale (Vincelette and Foster, 1992). The average total organic carbon in the Niobrara 2 interval calculated in this study is approximately 1.37% which makes it leaner than the Niobrara 1.

Within the Niobrara 2 interval there is not much change of the GR and resistivity logs. A very slight increase of the GR at the top of this interval suggests presence of higher amount of radioactive components (Figure 2.8). This increase most likely indicates existence of shale within the upper part of the Niobrara 2. There are two visible changes on the resistivity log. The first, very small increase in the middle of this interval suggests the existence of the bentonitic clay recognized by Vincelette and Foster (1992). The second increase of the resistivity log is located in the uppermost part of the Niobrara 2 and may be an indication of non-calcareous shale. The thickness of this interval ranges between 43 and 244 ft (13 and 74 m). It is relatively consistent across the study area; however, there is a thickening of the interval in the central part of the area. This thickening forms a north-south trend across the whole DCADC (Figures 2.4 and 2.9). The isopach map is for this interval is shown and discussed in the chapter 6. The Niobrara 2 might have slight source capacity. There has been no indication of hydrocarbons within this interval.

2.3.3 Niobrara 3

The Niobrara 3 interval overlies the Niobrara 2. It is named “Lower S” by Vincelette and Foster (1992). In the lower part of this unit lithology mostly consists of sandy clay with mica flakes and thin rippled sandstones. In the middle part of the Niobrara 3 there are interbedded sandstone, siltstone, and shale which transition to calcareous shale. The
Figure 2.9 Cross-section E-E’ (west-east), from the middle part of the study area, showing regional correlations. Names and locations of the wells are presented in the Appendix A.
calcareous shale is interbedded by thin sandstone and siltstone. The upper part of this interval consists of tight calcareous sandstone with interlaminated siltstone and shale (Vincelette and Foster, 1992). The average total organic carbon in the Niobrara 3 is approximately 1.26%. The TOC of this interval is in the same range as the Niobrara 2.

The top of the Niobrara 3 is identified on the top of a coarsening upward sequence which consists of interlaminated siltstone, sandstone, and shale. There is also a significant increase of the resistivity in this part of the interval marked by sharp drop at the top (Figure 2.8). In the lower part of the Niobrara 3, siltier units are present which is illustrated on the GR log by a noticeable decrease in the reading. Along with this GR spike, there is a resistivity increase which might suggest the presence of hydrocarbons but also cement (tight streak). The thickness of this interval varies from about 78 to 252 ft (24 to 77 m). It is thicker in the north and especially the northeast part of the study area. In the south it is consistent in thickness, ranging from 120-140 ft (36-43 m) (Figures 2.4 and 2.10). Even though both, Niobrara 2 and Niobrara 3 have slight potential of source capacity, based on the geochemical analysis, the Niobrara 3 seems to be more promising than the Niobrara 2. This interval is considered one of the two biggest producers of the Niobrara oil in Rangely and Buck Peak fields (Vincelette and Foster, 1992).

2.3.4 Niobrara 4

The Niobrara 4 sharply overlies the Niobrara 3. Vincelette and Foster (1992) named this interval “S”. The lower part of it was classified as the upper part of the Puerto Chiquito Facies. The upper part of the interval was classified between Buck Peak facies and Puerto Chiquito facies. At the base, it is composed of siltstone overlain by interlaminated tight sandstone, siltstone, and silty shale. The upper part the Niobrara 4 is composed of about 110 ft (33 m) thick, moderately calcareous shale overlain by non-calcareous shale (Vincelette and Foster, 1992). The average total organic carbon for this interval is approximately 1.63% which makes it richer than the Niobrara 1, 2, and 3.

Both, GR and resistivity logs stay constant within this interval. The first change appears on the top of the Niobrara 4 where GR significantly increases above a slight
Figure 2.10 Cross-section F-F’ (west-east), from the middle part of the study area, showing regional correlations. Names and locations of the wells are shown in the Appendix A.
decrease (Figure 2.8). There also is an evident increase of the resistivity. This change in signatures of both logs suggests an alternation of lithology. The top of this interval was picked on the top of this small swallowing upward sequence. The thickness of the Niobrara 4 varies from approximately 20 ft (6 m) to about 306 ft (93 m) (Figure 2.11). This interval thins significantly towards the south of the research area. The thickest sediments are in the northeast part of the area. The Niobrara 4 is considered among the intervals with higher total organic content and might be a possible source rock.

2.3.5 Niobrara 5

The Niobrara 5 interval is composed of very calcareous shale with abundant Coccoliths and overlies a very thin layer of soft calcareous shale (Vincelette and Foster, 1992). This interval conformably overlies lower Niobrara 4. Vincelette and Foster (1992) classified it as the lowest unit within the Buck Peak Facies. It is a lower part of “T” (Tow Creek Bench) in their study. The Niobrara 5 is the first interval which is classified as being rich in total organic carbon in the Niobrara Formation. The average total organic carbon for this interval is approximately 1.67% which makes it the richest among previously discussed Niobrara intervals.

Similarly, as in the Niobrara 4, the upper part of the Niobrara 5 shows significant change of well log readings in comparison to the rest of the interval. The top of the Niobrara 5 is picked where GR increases above slight decrease (Figure 2.7). There also is an increase on the resistivity log. The thickness of this interval ranges between 60 ft (18 m) and 303 ft (93 m). This interval thins towards the Uncompahgre Uplift and to the east side of the research area (Figure 2.4 and 2.12). It has modest to good source rock capacity. Previously, oil was identified within this interval. The Niobrara 5 (lower Tow Creek Bench), together with the Niobrara 3 (“Lower S”) and Niobrara 6 is considered one of the two biggest producers of the Niobrara oil in Rangely and Buck Peak fields (Vincelette and Foster, 1992).
Figure 2.11 Cross-section G-G’ (west-east), from the south part of the study area, showing regional correlations. Names and locations of the wells shown in the Appendix A.
2.3.6 Niobrara 6

The Niobrara 6 interval is classified as upper part of the “T” Tow Creek Bench by Vincelette and Foster (1992). In the lower part this interval is composed of calcareous shale which is overlain by approximately 60ft (18m) of slightly silty calcareous shale. In the upper part it consists of shale with abundant Coccoliths above which is Coccolithic limestone (Vincelette and Foster, 1992). This limestone is overlain by very calcareous shale with locally abundant Coccoliths (Vincelette and Foster, 1992). The Niobrara 6 is considered as an interval with higher total organic content. The average total organic carbon for this interval is approximately 1.73%.

This interval was identified where GR significantly dropped and resistivity log noticeably increased (Figure 2.8). Within the Niobrara 6, the signature of the logs changes a few times. In the lower part, there is a decrease of the GR which illustrates the siltier nature of the shale. Above, the reading increases showing change into shale with abundant Coccoliths, and decreases again presenting Coccolithic limestone. In the top of this interval, the GR increases again which illustrates presence of shalier sediments. The resistivity log decreases significantly on the level Coccolithic limestone and increases where very calcareous shale is present (Figure 2.8). The thickness of the Niobrara 6 ranges from 95 to 372 ft (28 to 113 m) (Figure 2.12). The Niobrara 6, together with Tununk Shale, Niobrara 5, and Niobrara 7, is considered the richest interval in organic content in the study area. It has modest to good source rock capacity. There was a large amount of oil recovered from this interval in Rangely and Buck Peak fields (Vincelette and Foster, 1992).

2.3.7 Niobrara 7

The Niobrara 7 is classified as Niobrara by Vincelette and Foster (1992). It is a thick interval composed of shale. In the lower part it is calcareous shale overlain by very calcareous shale with Coccoliths. In the middle the Niobrara 7 consists of shale, calcareous shale, very calcareous shale with abundant Coccoliths. The upper part is
Figure 2.12 Cross-section H-H' (west-east), from the south part of the study area, showing regional correlations. Names and locations of wells are shown in the Appendix A.
composed of calcareous shale, shale, very thin bed of sandstone, very calcareous shale with abundant *Coccoliths* (Vincelette and Foster, 1992). The total organic carbon within the Niobrara 7 on average is about 1.74%.

The top of the Niobrara 7 was identified on the base of coarsening upward sequence of the Mancos Shale above last shaly unit within this interval (Figure 2.8). The slight changes of the GR within the Niobrara 7 illustrate changing lithologies. There are two significant high readings and two significant low readings on the resistivity log. The low illustrate shalier parts of the interval and the highs show more calcareous parts. The thickness of the Niobrara 7 ranges between 143 ft (47 m) and 353 ft (108 m). The thickness of this interval varies across the study area. There is a significant thinning towards the south and southeast (Figure 2.4 and 2.13). In this study the Niobrara 7 is considered as a potential source rock.

2.3.8 Mancos Shale

The term Mancos Shale has been broadly used by many researchers before. It was used to describe the thick shaly interval above either the Frontier Sandstone or above the Dakota Sandstone. In this study Mancos Shale is a formation which overlies the Niobrara 7 interval and underlies the Mancos B. The Mancos Shale is composed of silty, carbonaceous, non- calcareous to calcareous shale. In the middle and upper part is it composed of interbedded silty and shaly beds (Kellog, 1977; Vincelette and Foster, 1992). This interval is not as rich in organic carbon as the Niobrara 7; however, the average TOC for the Mancos Shale is approximately 1.32%.

The top of the Mancos Shale was identified based on very significant decrease of the GR log and increase of the resistivity log. This pick is very distinct across the whole research area. The signature of the GR suggests a large decrease of the radioactive material which suggests presence of siltstones within overlying Mancos B. The thickness of the Mancos Shale varies considerably (Figure 2.4 and 2.5). It is approximately 1323 ft (3403 m) in the north part of the study area and about 208 ft (63 m) in the south. The Mancos Shale is not considered as a potential source rock, however, it might have slight
Figure 2.13 Cross-section I-I’ (west-east), from the south part of the study area, showing regional correlations.
to modest source rock potential.

2.4 Summary

In this section all identified stratigraphic units were described. There are seven formations identified: Dakota Sandstone, lower Tununk Shale, Tununk Shale, Frontier Sandstone, Carlile Shale, Niobrara Formation, and Mancos Shale. Within the Niobrara Formation there were seven different interval identified based on the well log and geochemical information. Those intervals are: Niobrara 1, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7. The thickness of the whole Mancos group thins towards the south and is relatively consistent from west to east.
CHAPTER 3

OUTCROP STUDY

Previous research conducted by L.L. Von Holdt 1978 of the New Castle, Colorado outcrop located along Interstate I-70 (N39°34’352”, W107°28’820”) indicated the presence of a Niobrara section (Figure 3.1). That research concentrated on the Storm King Mountain Shale Member (Late Turonian-Coniacian) of the Carlile Shale (Kauffman, 1969, 1977; Kellog, 1977) and only described part of the outcrop. “The Storm King Mountain shales record the transition from a non-calcareous, organic-rich shale to open marine pelagic limestone (Von Holdt, 1978).” In her study Von Holdt (1978) established contacts between Juana Lopez and Storm King Mountain Members of the Carlile Shale. She also picked the contact between the Carlile Shale and the Niobrara Formation. The previous study agrees with the assumption made for this research, before correlating the formations in the subsurface, that the Niobrara Formation is present farther west than previously thought (Longman et al., 1998; Molenaar and Cobban, 1991; Vincelette and Foster, 1992; Von Holdt, 1978). GR measurements of the outcrop were also obtained. This was done to obtain a GR curve which may be correlated with the GR logs from the subsurface of the DCADC area. To confirm lithologies identified in the outcrop, samples of rocks were collected and analyzed using a petrographic microscope. Additionally, six samples were selected for geochemical tests. The whole-rock geochemical analyses provided information about the content of major oxides within the formations. The results of these tests will be discussed in the following sections.

3.1 Lithology

The Frontier, Carlile, and Niobrara formations are exposed in the New Castle outcrop. This section is approximately 410 ft (125 m) thick (Plate 3.1). The lowermost formation present in this section is the Frontier Sandstone, which is also known as the
Codell Sandstone. It is approximately 47.5 ft (14.5 m) thick. In the lower part, this formation is composed of interbedded sandstone and siltstone. It is folded, burrowed and ripple laminated. In the middle part, the Frontier Sandstone is shalier. There is approximately 3 ft (0.9 m) thick shale overlain by a 2 in (5 cm) bentonite layer (Plate 3.1). This bentonite is overlain by interbedded sandstone and shale. These beds are rippled and folded between the 32 and 34 ft (9.7 and 10.3 m) intervals of this measured section. In the upper part, the Frontier Sandstone is sandier with very thin interbedded shale. At the 45 ft (13.7 m) marker, a 0.75 inch (1.9 cm) bentonite layer is present. Below this bentonite, the Frontier is folded and above it, it is ripple laminated. A thin-section photomicrograph of this interval is presented in the Figure 3.2. Based on the petrographic thin-section analyses, the Frontier Sandstone is very fine grained and fractured. It is composed of quartz, muscovite, calcite, pyrite, and fine-grained rock fragments.

The contact between the Frontier Sandstone and the Juana Lopez identified in this outcrop by Von Holdt (1978) is found 48 ft (14.6 m) from the beginning of the section. It is a sharp contact between the interbedded sandstone and shale of the Frontier Formation and the very fossiliferous calcarenite of the Juana Lopez (Figure 3.3). This member of the Carlile Shale is about 5 ft (1.5 m) thick. It is composed of fossiliferous calcarenite and interbedded with non-calcareous clay shale overlain by thinly laminated siltstone and shale of the Storm King Mountain Shale Member (Dane et al., 1966). Fossils identified in the Juana Lopez are abundant Inoceramus fragments which vary in size (Figure 3.3). Besides Inoceramus, quartz, calcite, pyrite, clay and rock fragments are identified in this thin-section (Figure 3.4).
The Storm King Mountain Shale Member is composed of siltstone, bentonite, and shale with very fossiliferous (*Inoceramus*), thin limestone intervals in the lowermost part (Figure 3.4). In the middle section, it is composed of shale and highly fossiliferous laminated limestone. Visible slickenlines are present in the shale at about 60 ft (31.7 m). In the upper part, the Storm King Mountain Shale Member consists primarily of very fine laminated, broken shale and calcareous shale. The thin section of this interval reveals presence of abundant *Inoceramus* (Figure 3.4). This interval is approximately 50 ft (15.2 m) thick of very fine laminated, broken and calcareous shale.
The contact between the Storm King Mountain Shale Member and the Niobrara Formation is identified at approximately 104 ft (20 m) from the bottom of the section. At the base of the Niobrara Formation there is an undulating scour surface which most likely indicates an unconformity at the base of this formation. The Niobrara Formation in the lowermost part is composed of pure chalk (Figure 3.4). Closer analysis of a sample from this interval under the microscope allows identifying planktic foraminifers with spars-filled chambers most likely deposited as deep-shelf chalks.
Scholle and Ulmer-Scholle (2003) (Figure 3.5). Scholle and Ulmer-Scholle (2003) show a picture of a the Greenhorn Limestone from Denver Basin which have the same lithology and biota. This interval was identified by Von Hold (1978) as the Fort Hays Limestone of the Niobrara Formation.

The Fort Hays Limestone is overlain by approximately 20 ft (6.1 m) of interbedded limestone and limy shale. Above these interbedded beds is a 62 ft (18.9 m) thick, thinly laminated, limy shale (Figure 3.6). This is overlain by interbedded beds of limestone and shaly limestone each between 3 ft (0.9 m) and 30 ft (9.1 m) in thickness.

Figure 3.4 Photomicrographs presenting the lithology of the Storm King Mountain Shale Member taken of sample 9. All of the photomicrographs show 200 µm scale. Photomicrograph a) and b) present large fragments of the *Inoceramus*. On all of the photomicrographs fractures along the shells are visible. They may be a result of calcite dissolution and create secondary porosity related to diagenesis. Photomicrographs c) and d) show broken *Inoceramus* fragments in the upper left corner. Additionally, incised clay material is present.
Above this interval another thick section of interbedded limestone and limy shale is present. This section seems to have slightly higher silica content. The reaction of the limy shale with the 3% hydrochloric acid was slow. Figure 3.7 presents pictures of this interval.

The limestone which has the top on 247 ft (75.2 m) is the last thick, clearly defined chalk in this section. It is overlain by 134 ft (40.8 m) of limy laminated shale of the Niobrara 3.
3.2 Whole-rock geochemistry of the outcrop samples

Six samples were selected for geochemical analyses. Basic tests measuring the content of the major oxides were performed. This Whole-Rock Analysis was performed by Acme Analytical Laboratories. Whole rock samples were provided for tests. The results of the test are presented in the Table 3.1.

Sample number 3 from the Frontier Sandstone has the highest SiO$_2$ content. The high SiO$_2$ is accompanied by high Al$_2$O$_3$ (7.61%), Na$_2$O (1.10%), and K$_2$O (0.88%)
which suggest that there is a significant content of detrital material in this rock. The $\text{Al}_2\text{O}_3$ can be provided only from detrital materials. Additionally, the high content of zirconium (243 ppm) suggests a high detrital influx. The amount of $\text{Fe}_2\text{O}_3$ (1.92%) suggests that there may be some pyrite or siderite present. Low amounts of $\text{MgO}$ (0.645), $\text{CaO}$ (3.60%), $\text{MnO}$ (0.025), and strontium (209 ppm) show very scarce carbonate content in this rock. Total carbon in this sample is 0.83% showing a very low content of organic material. Low nickel (20 ppm) and relatively low sulfur to carbon ratio ($\text{S/C}$) may suggest that this rock was deposited in an oxic or dysoxic environment. It is difficult to adequately say how much oxygen was available during the deposition because cut-offs

Figure 3.7 Photomicrographs illustrating the lithology of the Niobrara 2, and Niobrara 3. Photomicrographs a) and b) show 50 µm scale. Photomicrographs c) and d) show slide 29 and 100 µm scale. The first photomicrograph presents foraminifers and calcite prisms. Under the crossed polarized light micro quartz and large calcitic fragment (upper right corner) are visible. Photomicrographs c) and d) show the same lithology however, the amount of pyrite is higher.
for nickel and sulfur are difficult to place.

Sample number 8 comes from the Juana Lopez member of the Carlile Shale. It has low SiO₂ (27.04%), Al₂O₃ (2.63%), Na₂O (0.41%), and K₂O (0.385%) contents which suggest that there is a very low influx of detrital material. High content of CaO (35.69%), MnO (0.02%), and Sr (936 ppm) illustrate high carbonate content. The total carbon content for this sample equals 8.07%. The low amount of MgO suggests the carbonate in this rock is composed primarily of calcite. The zirconium content of (141 ppm) is relatively low but still suggests a low influx of detrital material. The high amount of Fe₂O₃ (2.33%) suggests a higher amount of pyrite or siderite in this rock. Low nickel (20 ppm) and low S/C (0.016 ppm) ratio suggest that this rock was deposited in an oxic environment. Based on the observations made in the field and available geochemical data, this interval is classified as calcarenite.

Sample number 14 comes from the lowermost part of the Niobrara Formation (Fort Hays Limestone). This sample has very low SiO₂ content 9.93%. It also has very low Al₂O₃ (2.04%), Na₂O (0.15%), and K₂O (0.38%) which indicates very low detrital influx. The CaO content is 46.9%, MnO (0.075%), and strontium (1377 ppm) indicate very high carbonate content. The total carbon content in this rock is 10.34%. There also is low amount of MgO (0.56%) which suggests that this limestone is composed primarily of calcite. The zirconium (22 ppm) content is also very low which provides additional evidence that there is a very low detrital component in this rock. The low amount of Fe₂O₃ (1.14%) suggests low content of pyrite and siderite in this rock. The low nickel (22 ppm) and low S/C (0.018 ppm) ratio implies that the lowermost Niobrara Formation was most likely deposited in waters which were under oxygenated conditions.

Table 3.1 Results of the Whole-Rock geochemical analysis of the outcrop samples.

| Sample  | Weight | SiO₂ | Al₂O₃ | Fe₂O₃ | MgO | CaO | Na₂O | K₂O | LOI | H₂O | CaO | MgO | Na₂O | K₂O | Fe₂O₃ | MnO | Sr | Zr | Nb | Zr | TOTC | TOTC |
|---------|--------|------|-------|-------|-----|-----|------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| 8       | 0.74   | 38.70 | 7.60  | 1.92  | 0.04 | 3.04 | 1.10 | 0.38 | 0.28 | 0.33 | 0.02 | 0.004 | 0.01 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 |
| 14      | 0.12   | 27.04 | 5.60  | 2.32  | 0.33 | 35.69 | 0.41 | 0.38 | 0.37 | 0.11 | 0.02 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 |
| 22      | 0.08   | 35.72 | 9.94  | 2.57  | 0.04 | 32.45 | 0.08 | 1.79 | 0.35 | 0.19 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 |
| 15      | 0.09   | 23.47 | 9.53  | 2.32  | 0.33 | 33.06 | 0.79 | 1.31 | 0.33 | 0.13 | 0.01 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 |

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Sample 17 was collected from shaly limestone interval of the Niobrara Formation on 130 ft (39.6m) from the base of the section. The SiO₂ (21.27%) content of this sample is higher than in the Fort Hays Limestone, however it is still low. There also are increasing trends of Al₂O₃ (5.85%), Na₂O (0.21%) and K₂O (1.15%) which are consistent with increase of SiO₂. Those four oxides trending with each other may suggest that there is a small detrital influx in this rock. High CaO content of 35.55%, very high strontium (1600 ppm), and high MnO (0.08%) show that this rock is definitely calcareous. Slightly elevated MgO (1.18%) suggests that there may be very small portion of dolomite or that MgO is present in clay minerals. The total carbon content in this sample is still high and equals 8.00%. The zirconium content is still low (53 ppm) which is another suggestion that the detrital component in this rock is not very significant. The Fe₂O₃ content of 1.80% suggests slight pyrite and siderite constituent. Similar like in the previously discussed samples, nickel of 23 ppm and low S/C (0.013 ppm) imply that deposition of this rock took place in oxic or dysoxic environments.

Sample number 24 was collected from limestone interval of the Niobrara Formation 210 ft (64 m) from the base of the section. This sample contains 35.71% of SiO₂, 9.84% Al₂O₃, 0.68% of Na₂O, and 1.74% of K₂O. All of these percentages suggest that there is low influx of detrital material. Additionally, the zirconium content is slightly elevated in this sample (95 ppm) which suggests presence of detrital material. CaO content of 24.45%, MnO of 0.11%, and Sr of 701 ppm suggest lower carbonate content. The total carbon in this rock is 5.49%. Elevated MgO (1.675) implies suggests that there may be small portion of dolomite or that MgO is present in clay minerals. The Fe₂O₃ content of 2.37% suggests pyrite and siderite content is this rock. Nickel of 75 ppm and S/C ration of 0.044 ppm suggest that this rock may have been deposited under suboxic or anoxic conditions. All of the geochemical data suggest that this rock may have been improperly classified as a limestone. Additionally, the SiO₂ was not identified in the thin section. The presence of the detrital material in this rock implies that it should be classified as shaly limestone.

Sample 29 comes from the 4 ft (1.21 m) thick shaly limestone bed of the Niobrara Formation located 256 ft (78 m) from the base of the section. The geochemical results for this sample are similar to the result of sample 17. The SiO₂ content of this sample is
23.47% and is lower than in the sample 24. The Al₂O₃ (6.53%), Na₂O (0.29%) and K₂O (1.31%) contents track the SiO₂ result and indicate that there is small detrital influx in this rock. The amount of zirconium is the same for this rock as it was for sample 17 (53 ppm) and means that the detrital material is present in this sample. CaO content is 33.66%, MnO is 0.10%, and strontium is elevated to 1030 ppm which suggests that there is significant carbonate content. The MgO content is 1.33% which may suggest very small portion of dolomite or MgO in clay minerals. The total carbon content in this sample is still high and equals 8.42%. The Fe₂O₃ content of 2.33% suggests pyrite and siderite constituent. Ni of 39 ppm and S/C ration of 0.040 ppm suggest that this rock may have been deposited under suboxic or anoxic conditions.

3.3 Outcrop and subsurface GR comparison

Measuring of the outcrop section with the portable GR spectral scintillometer provided geochemical analysis (potassium, uranium, and thorium content) and allowed a direct tie to subsurface well log data (Figures 3.8 and 3.9). In spectra GR analyses of mudrocks, potassium is associated with clay minerals and potassium feldspar, uranium with organic matter and phosphates, and thorium with heavy minerals and volcanic ash (Bohacs, 1998).

The outcrop GR log can be correlated to the subsurface GR curve from the Federal 8-32-4-103 well which is a type log for this study. In the outcrop the measurements were collected every 2 ft (0.62 m) compared to 0.5 ft (0.15 m) in the subsurface. The time of measurements was 120 seconds which provided reliable result. In the New Castle outcrop the Frontier Sandstone, Carlile Shale and lower Niobrara formations are present. Therefore, GR for the respective interval from subsurface was selected for the correlation.

The comparison of two GR logs reveals similarities. The signatures of both curves can be easily followed and tops of the formations can be picked (Figure 3.8). The top of the Carlile Shale is picked where the GR gradually increases. The GR from the outcrop shows rapid decrease of the curve at the base of the Niobrara Formation. The same low
Figure 3.8 Comparison of the GR from the New Castle Outcrop to the curve from the Federal 8-32-4-103 well. Black lines illustrate corresponding intervals. Black dots represent the location of the samples for which thin sections were made and selected for geochemical tests.
reading of the GR can be seen on the log from the Federal 8-32-4-103 but it is preceded by a more gradual decrease. Above that point both curves show a very similar signature of slightly increasing and then decreasing readings. Additionally, both of the logs show rapid increase where the top of the Niobrara 2 is picked. Both of the curves illustrate

Figure 3.9 Comparison of spectral GR curves presenting potassium, uranium, and thorium.
decrease of the GR directly above the top of the Niobrara 2. It is followed by gradual increase of the curve representing the outcrop and more rapid increase on curve from subsurface. The interval for which the GR readings were analyzed is approximately 300 ft (91.4 m) thick in both the outcrop and subsurface. This supports the assumption that these rocks are equivalent and were deposited under similar conditions. However, the New Castle outcrop is approximately 70 mi (112 km) east from the DCA and due to facies changes the content of chalks may decrease. The assumption that these GR curves match is suspect to the distance between them.

Comparison of the potassium, uranium, and thorium curves shows that potassium and thorium are tracking each other (Figure 3.9). Both of those elements are associated with clays and suggest higher content of clay constituents in the same intervals. The uranium curve is very similar to the other two, however; in the upper part it shows more rapid increase of the uranium than potassium and thorium. This may suggest that this interval is slightly richer in organic matter. The curve illustrating thorium content seems higher values than the other two elements. This may be a result of high ash content which does not seem unusual given that many bentonite beds are seen in the outcrop.

3.4 Summary

The study of the New Castle outcrop allowed the Niobrara Formation to be identified in the western part of Colorado. The Niobrara Formation is approximately 308 ft (93.8 m) thick in this outcrop. Carbonate content was confirmed by the analyses of the thin sections prepared for this interval. Presence of the planktonic organisms (foraminifers) and fragments of Inoceramus were found during analyses with a standard petrographic microscope. Additional methods used to prove calcareous content within these strata, were geochemical analyses (whole-rock) of the samples. These analyses confirmed lithologies identified in the outcrop. GR measurements of the outcrop allowed for direct comparison to the subsurface from the DCADC. The comparison of both logs showed similarities of the log signatures and supports that rocks in both locations were deposited under similar conditions and most likely are equivalent.
Significant resemblance between the Niobrara 1 interval of the Niobrara Formation from the New Castle outcrop and sediments from the Denver Basin was identified based on the analyses of thin section. Additionally, similarities between the GR signatures from the outcrop and subsurface of the DCADC were noted. These similarities allow comparing the Niobrara Formation from the Denver Basin, the New Castle outcrop, and the DCADC. Appearance of the Niobrara Formation in the outcrop aided subsurface identification.
CHAPTER 4

GEOCHEMISTRY

This chapter of this research is dedicated to geochemical screening of the available samples from five wells from the study area. Originally, there were seven wells for which geochemical analysis were obtained. Those wells are: Hells Hole 6-14 (Sec 6, T2S, R104W); Hells Hole 19-1 (Sec. 19, T2S, R104W); Hells Hole 9131 (Sec.13, T2S, R104W); Hells Hole 18-9 (Sec.32, T5S, R102W); Taiga Mountain-Federal 6-22 (Sec. 22, T1N, R103W); South Baxter Pass Unit 2-20 (Sec. 20, T5S, R102W); Ruby 8102-31M (Sec. 31, T8S, R102W). However, for two wells Hells Hole 6-14 and Hells Hole 19-1, complete analyses were not available. Therefore these wells were excluded from the further investigations.

4.1 Screening methods

Screening methods used in this research are Rock-Eval pyrolysis, Total Organic Carbon (TOC), Vitrinite Reflectance (Ro), and Thermal Alteration Index (TAI). Total organic carbon is measured in weight percent (wt.%) and describes the quantity of organic carbon in a rock sample. TOC includes both insoluble kerogen and soluble bitumen. It was determined by direct combustion which is the most commonly used method used to measure TOC. TOC should not be treated as a clear indicator of petroleum potential (Peters and Cassa, 1994). The process of the Rock-Eval Pyrolysis is discussed in chapter 1. It is usually used to describe petroleum generative potential by providing information about the quantity, type and thermal maturity of the organic matter (Peters, 1986).

Most commonly types of the organic matter are classified by a van Krevelen or atomic H/C/ vs. O/C diagram (Figure 4.1a). On this diagram different types of kerogen (Types I, II, III, and IV) are shown. Different types of kerogen will be described in the
following section. In the van Krevelen diagram pathways describe the thermal maturation of the kerogen type where the most mature samples are in the lower left corner. The Rock-Eval method was used by Tissot et al. (1974) to derive the type of kerogen from H/C vs. O/C diagram (Peters, 1986). Data available in this study does not include atomic hydrogen, oxygen, and carbon. However, Tissot et al. (1974) proved that oxygen in the kerogen is proportional to the carbon dioxide derived during pyrolysis (S3) and that hydrogen content is proportional to the produced hydrocarbons (S2). Based on this conclusion, they identified that it is possible to describe the type of the organic matter by using a hydrogen index (HI) vs. oxygen index (OI) plot where HI is (S2/TOC) x 100 and OI is (S3/TOC) x 100 (Figure 4.1b). This method should be supported by microscopy, elemental analysis, or both (Peters, 1986). In most of the cases in this study, additional support is not available due to lack of the organic petrology measurements and elemental analysis. Geochemical parameters from pyrolysis can be classified and compared to describe the petroleum potential of the source rocks (Table 4.1) as well as the type of hydrocarbons generated (Table 4.2). Additionally, thermal maturity can be also estimated by using production index (PI) and T_max. Generally, PI and T_max values less than 0.1 and 435°C, respectively, represent immature organic matter. A T_max higher than 470°C represents wet-gas zone. PI of approximately 0.4 shows the bottom of the oil window (beginning of the wet-gas zone) and increases to 1.0 when hydrocarbon generative potential has been exhausted (Peters, 1986) (Table 4.3).

<table>
<thead>
<tr>
<th>Petroleum Potential</th>
<th>TOC (wt.%)</th>
<th>Organic Matter</th>
<th>Hydrocarbons (HC) (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Rock-Eval Pyrolysis</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>S1 (mg HC/g)</td>
<td>S2 (mg HC/g)</td>
</tr>
<tr>
<td>Poor</td>
<td>0-0.5</td>
<td>0-0.5</td>
<td>0-2.5</td>
</tr>
<tr>
<td>Fair</td>
<td>0.5-1</td>
<td>0.5-1</td>
<td>2.5-5</td>
</tr>
<tr>
<td>Good</td>
<td>1-2</td>
<td>1-2</td>
<td>5-10</td>
</tr>
<tr>
<td>Very Good</td>
<td>2-4</td>
<td>2-4</td>
<td>10-20</td>
</tr>
<tr>
<td>Excellent</td>
<td>&gt;4</td>
<td>&gt;4</td>
<td>&gt;20</td>
</tr>
</tbody>
</table>

Table 4.1 Basic geochemical parameters describing the petroleum potential of an immature source rock (Modified after Peters and Cassa 1994).
In this research traditional Roc-Eval pyrolysis is used to evaluate the source rock potential where the TOC of 1 wt.% indicates the good source rock. Some researchers do not agree with this classification. Lewan (1987) believes that 2.4-5.4 wt.% TOC is necessary for a continuous bitumen network to develop for argillaceous claystone.

Problems related to this method may include: small peaks which lead to unreliable production index, hydrogen and oxygen indices; heavy bitumens in S2 lead to bimodal S2 which may overestimate the source potential and lower $T_{\text{max}}$; high S3 is produced due to breakdown of liable carbonates; and mineral matrix retention of S2. There also are a few difficulties related to $T_{\text{max}}$. It is dependent on kerogen type, lowered by heavy bitumen, increased by recycled kerogen, increased by clay adsorption of S2 hydrocarbons, and small S2 peaks are unreliable. Rock-Eval pyrolysis should be verified by other analyses for example, kerogen elemental composition, vitrinite reflectance, and gas chromatography (Peters, 1986).

<table>
<thead>
<tr>
<th>Type</th>
<th>HI (mg HC/g C$_{\text{org}}$)*</th>
<th>S2/S3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>0-150</td>
<td>0-3</td>
</tr>
<tr>
<td>Gas and Oil</td>
<td>150-300</td>
<td>3-5</td>
</tr>
<tr>
<td>Oil</td>
<td>&gt;300</td>
<td>&gt;5</td>
</tr>
</tbody>
</table>

Vitrinite reflectance is another method used to measure thermal maturity of the organic matter. During this method kerogen (or whole rock) is impregnated with epoxy, mounted in a slide, and the slide is polished to a flat, shiny surface. Incident light reflected from vitrinite particles under oil immersion is measured in percentage. The subscript ‘o’ in $R_o$ refers to oil immersion” (Peters and Cassa, 1994). In this study $R_o$ is available for a few samples from two wells, HH 9131, and South Baxter Pass Unit 2-20. For the first well only a mean $R_o$ is reported for selected intervals. For the second well $R_{\text{min}}$ and $R_{\text{max}}$ values are also available. Those values represent a minimum and maximum
Figure 4.1 a) van Krevelen diagram showing maturity pathways, maceral groups, and types b) HI vs. OI diagram showing maturity pathways (Both modified after Peters 1986).
measured $R_o$. This method is very subjective because the interpretation of the reflectance is based on the experience of the analyst.

The thermal alteration index is an additional method which can be used to measure maturation. TAI is a numerical scale based on thermally induced color changes in spores and pollen. It is a scale from 1 to 4 often used to cover the color range from immature to overmature. TAI is determined in transmitted light with the naked eye. It can be estimated from amorphous kerogen when pollen is absent. This method is very subjective. Results from different laboratories often vary significantly (different scales/interpretations). Color can be influenced by thickness of the macerals. In this study TAI data is available for few samples from South Baxter Pass Unit 2-20 well.

<table>
<thead>
<tr>
<th>Maturation</th>
<th>PI [$S_1/(S_1+S_2)$]</th>
<th>$T_{\text{max}}$ (°C)</th>
<th>$R_o$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top oil window (birthline)</td>
<td>~0.1</td>
<td>~435-445</td>
<td>~0.6</td>
</tr>
<tr>
<td>Bottom oil window (deadline)</td>
<td>~0.4</td>
<td>~470</td>
<td>~1.4</td>
</tr>
</tbody>
</table>

4.2 Organic Matter Classification

There are two main types of organic matter in source rocks: kerogen and bitumen. Kerogen is insoluble whereas bitumen is soluble in organic solvents. Kerogen is organic matter composed of a mixture of organic chemical compounds that generates bitumen. Kerogen is classified in two manners: physical properties and compositional. In the physical classification there are five types: algal, amorphous, herbaceous, woody and coaly. The algal type is recognizable algal material of either marine or lacustrine origin. The amorphous type is largely sapropelic organic matter from plankton and other low forms of life. It can be of marine or lacustrine origin. It is a dominant kerogen in
carbonates. The herbaceous type is continental in origin, consists of pollen grains, spores, cuticles, leaf epidermis, and cellular structures of plants. The woody type is terrestrial in origin; it has an easy to recognize rectangular shape and woody structure. The coaly type (inertinite) is recycled plant material which has undergone natural carbonization such as charring, oxidation, moldering, and fungal attack.

The main types of kerogen in compositional classification are types I, II, III. This classification was proposed by Tissot et al. (1974). Type IV was proposed by Demaison et al. in 1983 (Peters and Cassa, 1994). This classification is based on van Krevelen's classification of coal, by its composition and maturity. Kerogen types are distinguished based on H/C and O/C ratios. This classification is good because it allows for compositional changes related to depth, temperature and pressure resulting in increasing maturity to be followed (Tissot et al., 1974).

Kerogen type I contains liptinite (exinite) macerals which include: alginate, amorphous organic matter, lacustrine algae (Botryococcus) and land plant resins. The relationship between principal maceral groups, liptinite, vitrinite, and inertinite, and van Krevelen diagram are presented in figure 4.1. This kerogen type derives primarily from lacustrine algae, formed in anoxic lakes and several other unusual marine environments. It is formed mainly from proteins and lipids. Kerogen type I has H/C ratios larger than 1.25 and O/C ratios smaller than 0.15. It produces liquid hydrocarbons, mostly normal and branched paraffins, with some naphthenes and aromatics.

Type II kerogen can be divided into Type II and Type II-S depending on the sulfur content. It consists of several types of maceral which include: exinite, cutinite, resinite, and liptinite. This kerogen type derives primarily from marine phytoplankton associated with preservation in a reducing environment. Kerogen type II is produced from lipids. It has H/C ratio smaller than 1.25 and O/C ratio in the range between 0.03 and 0.18. It tends to produce both oil and gas. A variety of moderate-length chemical compounds, mostly naphthenes and aromatics, are produced from this type of kerogen. When it is associated with sulfur it is classified as type II-S kerogen. Kerogen high in sulfur cracks at lower temperatures than normal type II kerogen.

Type III kerogen is subdivided into two types as well. Type III-A and Type III-B. Type III-A consists mainly of vitrinite maceral group and includes Desmocollinite,
Telecollonite, and Telinite maceral types. This kerogen type is derived from terrestrial plant matter that is lacking in lipids or waxy matter. It forms from cellulose, lignin, terpenes and phenolic compounds in the plant. It tends to be thick, resembling wood or coal. Kerogen type III-A has a H/C ratio smaller than 1, and O/C index ratio between 0.03 and 0.3. It contains high percentage of polycyclic aromatic hydrocarbons, oxygenated functional groups and some paraffin waxes. The low hydrogen content can be explained by the extensive ring and aromatic systems. From this type of kerogen mainly coal and gas are produced. Type III-B kerogen is similar to type III-A but it contains high lipid terrestrial organic matter that can generate waxy oils from the oils and waxes contained in spores and leaf coatings.

Type IV kerogen is composed of residual organic matter that either was recycled from older sediments by erosion, deeply altered by subaerial weathering, combustion, or biological oxidation in swamps and soils prior to redepocion. It contains mostly decomposed organic matter in the form of polycyclic aromatic hydrocarbons. Kerogen type IV has a low H/C ratio which is smaller than 0.5. This type does not produce any hydrocarbons. It is an termed inrtinite.

Kerogen with a high H/C atomic ratio produces oil while heated. The kerogen type, the level of thermal maturity, and the character of expelled products can be

<table>
<thead>
<tr>
<th>Kerogen Type</th>
<th>HI (mg HC/g TOC)</th>
<th>S2/S3</th>
<th>Atomic H/C</th>
<th>Expelled products</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>&gt;600</td>
<td>&gt;15</td>
<td>&gt;1.5</td>
<td>Oil</td>
</tr>
<tr>
<td>II</td>
<td>300-600</td>
<td>10-15</td>
<td>1.2-1.5</td>
<td>Oil</td>
</tr>
<tr>
<td>II/III</td>
<td>200-300</td>
<td>5-10</td>
<td>1.0-1.2</td>
<td>Mixed oil and gas</td>
</tr>
<tr>
<td>III</td>
<td>50-200</td>
<td>1-5</td>
<td>0.7-1.0</td>
<td>Gas</td>
</tr>
<tr>
<td>IV</td>
<td>&lt;50</td>
<td>&lt;1</td>
<td>&lt;0.7</td>
<td>None</td>
</tr>
</tbody>
</table>

Table 4.4 Geochemical parameters from Rock-Eval Pyrolysis describing kerogen type and expelled products (Modified after Peters and Cassa 1994).
described based on the Rock-Eval Pyrolysis (Table 4.4 and 4.5) vitrinite reflectance and thermal alteration index measurements.

4.3 Environment of deposition and alteration of the organic matter

In this chapter the terms marine and terrigenous will apply to organic matter derived from marine and land plants respectively. The difference between the depositional environment of the source rock and origin of the organic matter will be specified. Kerogen types are deposited in both marine and non-marine environments of deposition. Type I kerogen is formed from algal precursors and is deposited in lacustrine source rocks. Type II is derived from marine algal, pollen, spores, leaf waxes, and fossils resins but it is found in the rocks which formed in marine, reducing conditions. Type III kerogen is derived from terrestrial woody and coaly material but is found in the source rocks deposited under marine, oxidizing conditions. Finally, type IV kerogen comes from reworked organic debris highly oxidized material and is found in the rocks deposited under marine, oxidizing conditions.

<table>
<thead>
<tr>
<th>Stage of Thermal Maturity for Oil</th>
<th>$R_o$ (%)</th>
<th>$T_{max}$ (°C)</th>
<th>TAI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Immature</td>
<td>0.2-0.6</td>
<td>&lt;435</td>
<td>1.5-2.6</td>
</tr>
<tr>
<td>Mature</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Early</td>
<td>0.6-0.65</td>
<td>435-445</td>
<td>2.6-2.7</td>
</tr>
<tr>
<td>Peak</td>
<td>0.65-0.9</td>
<td>445-450</td>
<td>2.7-2.9</td>
</tr>
<tr>
<td>Late</td>
<td>0.9-1.35</td>
<td>459-470</td>
<td>2.9-3.3</td>
</tr>
<tr>
<td>Postmature</td>
<td>&gt;1.35</td>
<td>&gt;470</td>
<td>&gt;3.3</td>
</tr>
</tbody>
</table>
There are three major types of organic matter alterations: diagenesis, catagenesis, and metagenesis. Diagenesis is an initial alteration of the organic matter. It is a low temperature chemical and microbial transformation of the organic matter into kerogen. It usually occurs during shallow burial, generally less than a few hundred meters, but can sometimes reach about 2000m (about 6,060 ft). It is characterized by a small increase in temperature and pressure. During this phase, conversion of organic matter to kerogen (predominantly due to bacterial metabolism), generation of biogenic gas, and initial expulsion of liquids through compaction takes place. During this stage of burial, porosity and permeability start to decrease.

The second phase of the organic matter alteration is catagenesis. It is a thermal alteration stage during which kerogen passes though its principle phase of bitumen generation. Those changes of kerogen are irreversible and take place in the temperature range of approximately 50° to 200°C (122° - 392° F) and pressure between 300 to 1500 bars. This stage can be divided into an oil zone, which corresponds to oil window, and a wet gas zone. During the oil zone, liquid oil generation is accompanied by gas formation. During the wet gas zone, light hydrocarbons are generated through cracking. The wet gas window corresponds to the interval from the top of the wet gas zone to the base of the dry gas zone (Peters and Cassa, 1994). This phase is the main phase of secondary porosity creation.

The third alteration of the organic matter is metagenesis which corresponds to the dry gas zone. It is an intensive thermal alteration of kerogen, bitumen, and petroleum. During this stage kerogen is structurally rearranged (due to thermal activity) and releases small amounts of methane. Metagenesis of bitumen and petroleum leads to the formation of methane and pyrobitumen as end products. During this phase porosity and permeability begin to decrease again. These alterations take place at relatively hot temperatures (>200°C) and high pressure. Metagenesis immediately precedes metamorphism.
4.4 Geochemistry of the rock within the research area

Results of the geochemical analysis for five selected are presented in the following sections. Geochemical parameters derived from Rock-Eval pyrolysis and vitrinite reflectance descriptions are illustrated by a series of graphs for each well. Data from every well will be discussed separately and then compared with available geochemical results from all the wells. At the end of this chapter the possible source rocks will be identified. Analysis for Taiga Mountain 6-22, South Baxter Pass 2-20, Ruby 8102-31M were performed by Baseline Resolution, Incorporated. Hells Hole 9131 was analyzed by Humble Geochemical Services (Fisher, 2007) and analysis for Hells Hole 18-9 was performed by Weatherford Laboratories. Formation tops for wells with geochemical analysis are presented in Appendix E.

4.4.1 Taiga Mountain 6-22 well

Taiga Mountain 6-22 was sampled at approximately 100 ft (~30 m) intervals. The results for 34 samples are available for this well. Sampling on such large intervals might have a significant negative influence on the interpretation of geochemistry from this well. In some cases there is only one sample tested for the various formations (Tununk, Frontier, Niobrara 1, 2, and 4) and therefore this sample has to be treated as representative for that interval.

Total organic carbon values in this well range between 0.67 (Frontier Sandstone) and 2.25 wt.% (Niobrara 7). These values do not significantly increase with depth (Figure 4.2 a). The TOC vs. depth graph may help in the interpretations of the lithology in the Niobrara Formation. Samples from this formation which have higher TOC values are most likely form shaly intervals and the ones with lower TOC values may be from chalks. On the plot of TOC vs. HI there is a noticeable trend showing simultaneous increase of total organic carbon and hydrogen index (Figure 4.2 b). The highest measured HI in this well was 220 mg HC/g C$_{org}$ (Niobrara 7) and the lowest was 59 mg HC/g C$_{org}$ (Carlile Shale). There is a significantly different trend on the plot of TOC vs. OI. Total organic
carbon values decrease with the increase of the oxygen index values (Figure 4.2 c). When S2 versus TOC is plotted, there is a very obvious linear trend showing an increasing amount of generated hydrocarbons per gram of rock with increasing weight percent of total organic carbon (Figure 4.2 d).

All the TOC values from this well are larger than 0.5 wt.% which suggests that the rocks should not be affected by adsorption of pyrolyzate by the mineral matrix (Peters, 1986). According to Langford and Blanc-Valleron (1990), it is possible to calculate the x-intercept (calculated by solving for x when y=0 in the regression equation). A positive intercept indicates the threshold amount of organic material that must be present before enough hydrocarbons can be detected during pyrolysis (Figure 4.3 a) (Langdorf and Blanc-Valleron, 1990). The x-intercept value approximates the amount of hydrocarbons liberated by pyrolysis which were absorbed by the rock matrix (Langdorf and Blanc-Valleron, 1990). Clay-rich rocks are generally more influenced by...
adsorption. Rocks which are rich in illite, montmorillonite, calcite, and kaolinite minerals have the highest adsorption, decreasing in that order (Peters, 1986). The calculated rock-matrix adsorption for samples from Taiga Mountain 6-22 well is 0.53% (Figure 4.3 a) and b). The existence of large adsorption might result in reduced S2 and HI values as well as an increase in T_{max} and OI measurements.

The S2 vs. TOC diagram can be used to measure the adsorption of hydrocarbons by the rock providing a correction for HI. This plot also gives an indication of the petroleum potential and the kerogen type which is present (Langdorf and Blanc-Valleron, 1990). This graph is a useful tool to compare the sets of S2 vs. TOC graphs and will be used in the summary of this chapter to compare the potential of rocks from different wells.

Samples plotted on this graph have a linear regression which has a high degree of correlation. The R^2 is of 92% indicates a good correlation. This indicated that the group of samples is very consistent. The S2 vs. TOC diagram for Taiga Mountain 6-22 well shows that all the formations except the lower Tununk Shale, Carlile Shale, and Frontier Sandstone, have TOC values higher than 1 wt.% which suggest good generative potential based on the TOC values.

Drawing horizontal lines at S2=2.5 and S2=5 mg HC/g rock on Figure 4.2 d shows that Niobrara 1, 4, 5, 6 and Niobrara 7 have fair to good generative potential based on the S2 values. Additionally, the two deepest samples from the Mancos Shale and the samples from Tununk Shale formation are very close to this boundary. All other samples are located below 2.5 mg HC/g rock and have poor generative potential.

Looking at the HI vs. S2 graphs (Figure 4.3 c) allows for the type of hydrocarbons that can be generated from the sediments to be determined. Again, drawing a horizontal line at 150 mg HC/g C_{org} on Figure 4.3 c shows that the Tununk, Niobrara 1, 4, 5, 6, and Niobrara 7 intervals have potential to generate mixed gas and oil while other formations fall below this value suggesting gas generation based on the HI values.

While looking at S2/S3 (Appendix F) values for the Taiga Mountain 6-22 well the Tununk Shale (av.7.5), Niobrara 1 (av. 7.2), Niobrara 2 (av. 5.1), Niobrara 4 (av. 10.2), Niobrara 5 (av. 6.0), Niobrara 6 (av. 7.2), Niobrara 7 (av. 9.7), and the few deepest samples of Mancos Shale (av. 6.0) are oil prone. The lower Tununk Shale (av. 4.3) and
Niobrara 3 (av.3.1) can generate mixed gas and oil. The S1 values are relatively small which suggests that not many of hydrocarbons were already generated. There were no maturity tests (vitrinite reflectance) performed for this well. However, there were five samples tested for closely located Hell Hole 9131 (Fisher, 2007), all of them were immature (Figure 4.7 c). However, the top of the Mancos Shale in the Taiga Mountain 6-22 well is located 1582 ft (482 m) deeper than the HH 9131 well allowing for the maturity of the rocks in the 6-22 well to potentially be higher. It is difficult to estimate how much more mature these rocks are because it is unknown how long it this depth relationship has occurred. For the purpose of this study, the assumption that the rocks in this well are immature is made.

Figure 4.3 A) and b) Graphs showing regression equation of S2 vs. TOC plots for all of the samples; c) HI vs. S2 graph, and d) HI vs. OI graph with pseudo van Krevelen diagram showing kerogen types.
The majority of the sediments from the Taiga Mountain 6-22 well plot as type III kerogen. However, Niobrara 6 and Niobrara 5 seems to be on the border between type II and type III kerogen (Figure 4.2.d and 4.3 d). Therefore samples from those two formations have mixed kerogen type. Mixed kerogen types are generally known to produce oil and gas. It is difficult to predict what type of hydrocarbons would be generated from the source rocks from this well. Based on the analysis of production index (PI) and T$_{max}$, the samples fall into the oil generation window (Figure 4.4 b). Due to the lack of maturity information from this well, this analysis cannot be confirmed. If it is assumed that maturity values are similar or higher to those from the HH 9131 well, around 0.5%, these rocks are immature. However, T$_{max}$ temperatures increase with depth, which suggest an increase of maturity. Samples fall between 435 and 455°C which suggests that they are in early mature to mature stage based on the T$_{max}$ values. This may suggest that the rocks from this well may be productive, however it is difficult to predict without the actual maturity tests (Figure 4.4 a).

Among the formations tested, seven are potential source rocks. The Tununk, Niobrara 1, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7 all have TOC values higher than 1.3 wt.%. The HI values range from 150 to 300 mg HC/g C$_{org}$.

There also are relatively low oxygen index values, about 20 mg CO$_2$/g C$_{org}$, and S2/S3 results are higher than 7 with the exception of the Niobrara 6 which is 6. All of the
<table>
<thead>
<tr>
<th>TMD (ft)</th>
<th>HYDROGEN INDEX</th>
<th>ORGANIC RICENESS</th>
<th>HYDROCARBON POTENTIAL</th>
<th>MATURITY</th>
<th>NORMALIZED OIL CONTENT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas Flood</td>
<td>Mixed</td>
<td>Oil Flood</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>(S2/TOC)100</td>
<td>TOC %Wi</td>
<td>S2 mg/g</td>
<td>TMAX</td>
<td>(S1/TOC)100</td>
</tr>
<tr>
<td>0</td>
<td>200</td>
<td>400</td>
<td>600</td>
<td>0</td>
<td>2</td>
</tr>
</tbody>
</table>

Figure 4.5 Geochemical logs for Taiga Mountain 6-22 well. Summary was provided by Baseline.
mentioned formations have type III kerogen except Niobrara 5 and Niobrara 6 which have mixed type II and III kerogen. This assumption is made based on analyses of the S2 vs. TOC and HI vs. OI graphs. All this information suggests that these six intervals have the potential to produce oil and mixed, oil and gas. Figure 4.5 presents summarized geochemical log for this well.

4.4.2 Hells Hole 9131 well

Hells Hole 9131 was sampled at 30 ft (9.1 m) intervals. The results for 84 samples are available for this well (Fisher, 2007). The sample interval, 30 ft (9.1 m), provides reliable data and allows accurate conclusions to be made. In this well total organic carbon values are between 0.72 (Niobrara 1) and 2.33 wt.% (Tununk). There is no significant increase of TOC with depth (Figure 4.6 a), however it still can be used to try predict lithologies of the Niobrara Formation. On the graph representing the TOC vs. HI relationship, even though the samples are more widely scattered, there is a noticeable linear trend (Figure 4.6 b). Total organic carbon readings increase with the increase of the hydrogen index. In this well the Niobrara 5 formation has the highest measured hydrogen index, 396 HC/g C_\text{org}. The lowest HI was found in the Carlile Shale, 91 HC/g C_\text{org}. While looking at the TOC vs. OI plot, a less obvious linear trend, reversed to the one on the TOC vs. HI graph, can be observed (Figure 4.6 c). The Dakota Sandstone, lower Tununk Shale, and Frontier Sandstone are scattered farther away from the main cluster. There is a decrease of total organic carbon values with the increase of the oxygen index. Similarly as in the Taiga Mountain 6-22 well, when S2 vs. TOC results for the Hells Hole 9131 are plotted, there is an obvious linear regression trend showing an increasing amount of generated hydrocarbons per gram of rock with increasing weight percent of total organic carbon (Figure 4.6 d).

The calculation of the x-intercept for all the samples from this well gives the result of 0.64% (Figure 4.7 a and b). This suggests that there is higher overall clay content in the rocks from this well than in the samples from the Taiga Mountain 6-22.
This kind of adsorption should not have a significant influence on the S2, HI, OI, and $T_{\text{max}}$ measurements.

Similarly to Taiga Mountain 6-22, this well also shows a linear regression trend on the S2 vs. TOC graph. The $R^2$ value in this well is 89% which shows that the fit of the trend line is excellent. Total organic carbon information from this diagram shows that all the formations, except the Dakota Sandstone, lower Tununk Shale and Niobrara 1, have TOC values higher than 1 wt.%. This means that they should be considered as good potential source rocks.

The generative potential of the source rock, based on S2 values, can be again estimated by drawing a horizontal lines at S2=2.5 and S2=5 mg HC/g rock on Figure 4.5 d or 4.7 c. The line which would be drawn on 2.5 mg HC/g rock cuts through the cluster of samples and shows that the Niobrara 2, Niobrara 4, deeper samples from Niobrara 5 and Niobrara 6 fall into the fair to good range. The line drawn on the S2=5 mg HC/g rock

Figure 4.6 a) Graph illustrating relationship between TOC and depth; b) Plot of TOC vs. HI; c) Plot of TOC vs. OI; d) S2 vs. TOC diagram with lines representing estimated boundaries separate kerogen types.
value, shows that samples from Tununk, Niobrara 7 and shallower samples from the
Niobrara 5, Niobrara 6 fall into the good source rock generative potential based on the S2
results (Figure 4.6 d).

The type of hydrocarbons which can be generated from the rock from this well
may be identified by analyzing HI vs. S2 plot. Drawing a horizontal line at 150 mg HC/g
C_{org} on Figure 4.5 c shows that majority of the samples plots within the mix of gas and oil
generation. Formations plotting between 150-300 mg HC/g C_{org} are: Mancos Shale,
Niobrara 2, Niobrara 3, and Niobrara 4. The Niobrara 5, Niobrara 6 and Tununk Shale
plot on the border between gas and oil and oil generation. The majority of the Niobrara 5
falls above 300 mg HC/g C_{org} line which means that it may be generating oil (Figure 4.7
c).

Analyzing the S2/S3 (Appendix G) data, shows that three shallower samples of
the Niobrara 3 (av.4.3) formation may produce mixed gas and oil. The other formations
are oil prone based on the S2/S3 results: the Dakota (av. 4.3), Tununk Shale (av. 3.6),
Carlile (av. 4.5), Niobrara 1 (av.7.3), Niobrara 2 (av.1.1), Niobrara 3 (av. 6.3), Niobrara 4
(av.11.2), Niobrara 5 (av. 18.8), Niobrara 6 (av. 17.9), Niobrara 7 (av. 17.4), Mancos
(av.10). Similar to the Taiga Mountain well, the values characterizing the S1 peak are
low which suggest that small amount of hydrocarbons was expelled.

There were five samples tested for maturity by vitrinite reflectance (Fisher, 2007).
All of the results show that the rocks are immature ranging between 0.44 and 0.5%
(Figure 4.8 c). The samples from the Tununk Shale, and Niobrara 1 were tested for
maturity and had the lowest TOC contents among the samples from those formations.
The sample from the Niobrara 5 had the second lowest TOC reading. The two last
formations tested were the Niobrara 7 and Mancos Shale. These had second highest and
highest TOC content respectively.

The main kerogen types present in this well are types II and III (Figures 4.6 d and
4.7d). Samples from the Niobrara 1, Niobrara 3, Niobrara 6, plot within type II kerogen.
Dakota Sandstone, lower Tununk Shale, Frontier Sandstone, Carlile Shale, and Mancos
Shale fall into type III kerogen. The Niobrara 2, Niobrara 5, and Niobrara 7 seem to have
mixed type II and III kerogen (Figures 4.6 d and 4.7 d). Type II kerogen is known to
produce oil. Type III kerogen produces gas while mixed type II and III produce gas and
oil. The maturity information for this well suggests that the samples are immature. However, there is a clear increase of maturity with depth in this well (Figure 4.8 c). Even though the results of the vitrinite reflectance are smaller than 0.6%, it is still possible that these rocks may generate oil with increasing burial depth and hence greater thermal maturation. Those rocks would be associated with a very early oil generation window.

This assumption is made based on the analysis of the diagram representing the relationship between depth and $T_{\text{max}}$. It shows a gradual increase of temperature with depth which suggests an increase in maturity (Figure 4.8 a). Most of the samples fall between 435 and 448°C which makes them range from early mature to mature. Additionally, a study of the production index versus $T_{\text{max}}$ shows that PI for the majority of the samples ranges between 0.07 and 0.18. Dakota Sandstone and lower Tununk Shale are close to 0.2. Therefore, most of the samples tested from this well fall into the very early oil generation window based on the PI and $T_{\text{max}}$ results (Figure 4.8b).

Figure 4.7 a) and b) Graphs showing regression equation of S2 vs. TOC plots for all of the samples; c) Plot showing the relationship of HI and S2; d) Diagram of HI vs. OI graph with van Krevelen diagram showing kerogen types for HH 9131 well.
Within the rocks tested for this well there are seven which may have good source rock capacity. Those formations are: Tununk Shale, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7. TOC values for these rocks are in the good range. The HI results suggest possible generation of mixed gas and oil and oil. All the oxygen index measurements are approximately 20 mg CO₂/g C орг. The Niobrara 3 is the only interval from the Niobrara Group tested in this well which has S2/S3 value of 6.3. The other Niobrara intervals have S2/S3 numbers higher than 10. The Tununk Shale is the lowest in S2/S3 values and it is 3.6. Based on S2 vs. TOC and HI vs. OI the major kerogen types are II and III which also indicates the possibility of the generation of mixed gas and oil. However, based on the PI values, the Tununk, Niobrara 5, and Niobrara 7 may not generate a large amount of hydrocarbons. Samples tested for maturity, turned out to show low results however, these rock may still produce hydrocarbons. Figure 4.9 presents summarized geochemical log for this well.

Figure 4.8 a) Plot presenting depth vs. T max relationship; b) Graph showing relationship between PI and T max; c) Plot showing depth vs. R o.
Figure 4.9 Geochemical logs for Hells Hole 9131 well. Summary provided by Humble Geochemical Services.
4.4.3 Hells Hole 18-9 well

Samples tested for the Hells Hole 18-9 well were collected every 30 ft (9.1m). There was a total of 79 samples tested by the Rock-Eval Pyrolysis for this well. Reliable conclusions can be made based on the sampling at this interval. Total organic carbon values identified from this well range from 0.89 (Mancos) to 2.09 wt.% (Niobrara 6). TOC values do not increase with depth and plot rather scattered on the Depth vs. TOC graph (Figure 4.10 a). This graph can be helpful in identification of the lithology of the Niobrara Formation. It is possible to identify linear trend which shows an increase of both total organic carbon and hydrogen index (Figure 4.10 b). The TOC vs. HI plot indicates that the Niobrara 7 interval has the highest hydrogen index value, 351 mg HC/g C<sub>org</sub>. The Carlile Shale was identified with the lowest value of 116 mg HC/g C<sub>org</sub>. The TOC vs. OI plot shows highly scattered results which do not present any specific trend. Total organic carbon values do not change in the relationship to the oxygen index (Figure 4.10 c). In comparison with the first two wells there is a significant linear regression trend on the S2 vs. TOC diagram. This trend also shows an increase of the amount of generated hydrocarbons per gram of rock with the increase of the weight percent of total organic carbon (Figure 4.10 d).

The x-intercept value for all of the samples is 0.60% which shows that clay contents for the rocks in this well is similar to those in the HH 9131. When calculated for only the lower Tununk Shale, Tununk Shale, Niobrara 2, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7 the result is lower, 0.50% (Figures 4.11 a and b). This suggests that mentioned rocks have smaller adsorption of liberated hydrocarbons than the rest of the rocks from this well. Again, this kind of adsorption should not have a significant influence on the S2, HI, OI, and T<sub>max</sub> measurements.

While analyzing the S2 vs. TOC diagram, it is easy to notice that all of the formations have total organic carbon of 1 wt.% or higher (Figure 4.10 d). All of the formations should be considered as potential source rock based on the TOC values. The technique previously used to analyze the generative potential of the source rocks based on the S2 values, can be applied again here. Drawing horizontal lines at S2=2.5 and S2=5 mg HC/g rock on Figure 4.10 d suggests to see that approximately half
of the samples have S2 higher than the other half. The lower Tununk Shale, Tununk Shale, Niobrara 5, Niobrara 6, and Niobrara 7 are in the good generative potential range. The Niobrara 1 and the Niobrara 4 are in the fair to good range. The remaining formations are in the poor to fair generation range based on the S2 values. HI vs. S2 plot shows a clear linear trend (Figure 4.11 c). The R² value is very similar to the one from the HH9131 well and is 80%. Horizontal line at 150 mg HC/g C$_{org}$ would show that only the Frontier Sandstone might generate gas.

All other formations fall between 150 and a little over 300 mg HC/g C$_{org}$. This suggests that the type of the hydrocarbons which might be generated by the rocks from the HH 18-9 well are mixed gas and oil.

S2/S3 analyses (Appendix H) suggest that all of the formations tested have potential to generate oil based on the S2/S3 values. The results applying to these parameters for the Carlile Shale, Niobrara 1, and Niobrara 2 may be unreliable due to
very small S3 values. These values may also influence the reliability of the oxygen index which is calculated based on the S3 peak. Therefore, the average values illustrating these parameters might not really be as high as 28, 30, and 54 respectively. The results or all other formations seem to be reliable and are as follows: lower Tununk Shale (av. 35.7), Tununk Shale (av.33.4), Frontier Sandstone (av.10.8), Niobrara 3 (av. 26.2), Niobrara 4 (av. 20.8), Niobrara 5 (av. 21.9), Niobrara 6 (av. 20.5), Niobrara 7 (av. 20.2), Mancos Shale (av. 11.7).

Figure 4.11 S2 vs. TOC results for all sample in the HH 18-9 well presented on a) and b) diagrams; c) Relationship between HI and S2 parameters; d) Plot of HI vs OI data with lines presenting types of kerogen in this well.

There are only $T_{\text{max}}$ maturity information available from this well. However, there were Ro test performed for the HH 9131 (Fisher, 2007). Close proximity of these wells and very similar depths (30.5ft - 9.2m offset) allow one to assume that maturity results from the HH 18-9 would be very similar. Based on this assumption, the rocks from HH
18-9 well will be referred to as immature with values of vitrinite reflectance ranging between 0.44 and 0.5% (Figure 4.8c).

Analysis of the diagram representing the relationship between depth and $T_{\text{max}}$ is very similar to the one from the HH 9131 well. It shows gradual increase of the temperature with depth which may suggest increase of maturity with depth (Figure 4.12a). In this well $T_{\text{max}}$ temperatures are slightly lower than in the two previously discussed wells. Samples fall between immature and mature zone based on the $T_{\text{max}}$ results.

Additionally, the study of the HI vs. OI graph shows that all of the samples fall in between kerogen type II and III (Figure 4.9d). The S2 vs. TOC plot shows that the lower Tununk Shale, Tununk Shale, Niobrara 1, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7 most likely have type II kerogen (Figures 4.10d and 4.11d). This suggests that hydrocarbons which may be generated from the source rocks in this well are oil and gas. PI vs. $T_{\text{max}}$ graph suggests that majority of the samples, fall into very early and early oil generation window based on the PI and $T_{\text{max}}$ values (Figure 4.12b). The PI values are much higher in this well than they were in the HH 9131. Based on the 435°C cutoff for a top of oil window, the Niobrara 5, Niobrara 6, and Niobrara 7 may not be mature enough to generate hydrocarbons (Figure 4.12b). This well is approximately one mile away from the HH 9131 and the top of the Mancos Shale is 103 ft (31 m) deeper. Based on this proximity, the assumption is made that the maturity is the same for both wells. The rocks in the HH 18-9 are considered immature.

Similarly to the previously discussed wells there are a few intervals which might be potential source rocks. In this well the lower Tununk Shale, Tununk Shale, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7 show higher source rock potential than the rest of the formations. The Niobrara 2 is the only formation of those mentioned that have TOC results around 1 wt.%. The other six have TOC values range between 1.5 and 2.09 wt.%. The hydrogen index results for these intervals are between 200 and 350 mg HC/g C$_{\text{org}}$ which suggests that these rocks may be mixed gas and oil, and oil prone. The oxygen index results range between 8 and 24 mg CO$_2$/g C$_{\text{org}}$. The OI results for the Niobrara 2 well might not be reliable due to small S3 peak values. The same concern applies to the S2/S3 values for this formation. The other six are oil prone based on the S2/S3 results. The major kerogen types are II and III which also
indicates possibility of generation of mixed gas and oil and oil. However, based on the PI and T_{max} values, the Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7 may not generate hydrocarbons. The lower Tununk and Tununk Shales as well as the Niobrara 2 are in the oil window. There were no maturity tests for this well but the assumption that similar values to those in the HH 9131 are present in this well, making these rocks immature, however, hydrocarbons may still be produced. Figure 4.13 presents summarized geochemical logs for the HH 18-9 well.

4.4.4 South Baxter Pass Unit 2-20 well

The South Baxter Pass Unit 2-20 well has results for 44 samples tested at approximately 50 ft (15.2 m) intervals. Mostly reliable conclusions can be made based on the sampling at this interval. Total organic carbon results range between 0.82 (lower Tununk Shale) and 2.73 wt.% (Tununk Shale). There is one sample from the lower Tununk Shale which has very high TOC value of 7.12 wt.%. This sample was the deepest within tested lower Tununk Shale rocks. TOC values again, do not increase with depth (Figure 4.14 a). Analysis of the TOC vs. HI plot shows that the Niobrara 7 has the highest hydrogen index, 262 mgHC/g C_{org} and the Carlile Shale the lowest, 73 mg HC/g C_{org}. There is a clear, linear trend showing simultaneous increase of the TOC and HI for all the formations, visible on this graph (Figure 4.14 b). The TOC vs. OI also shows a linear trend. This trend shows decrease of total organic carbon with increase of oxygen
Figure 4.13 Geochemical logs for Hells Hole 18-9 well. Summary provided by Baseline with the report.
index (Figures 4.14 c). The S2 vs. TOC graph, the same like in the previous wells, shows very significant linear regression trend. The $R^2$ value is 82%. There is an recognizable increase of the amount of generated hydrocarbons per gram of rock with the increase of the weight percent of total organic carbon (Figure 4.14 d).

The x-intercept value for all of the samples is 0.42% which shows that clay contents in the rocks from this well are the lowest of all the mentioned wells (Figure 4.15 a and b). This suggests these rocks have smaller adsorption of liberated hydrocarbons than the same formations in the different wells. Again, this kind of adsorption should not have significant influence on the S2, HI, OI, and $T_{\text{max}}$ measurements.

When taking a closer look at the S2 vs. TOC diagram shows that majority of the majority of the formation has TOC values higher than 1 wt.%. One sample from the lower Tununk Shale, Frontier Sandstone and two of the Carlile Shale have TOC values smaller than 1 wt.% (Figure 4.14 d). All of the formations, despite the mentioned exceptions, have good source rock potential based on the TOC values. Only one diagram was composed to present the linear regression equation for this well. This is because almost all of the formations may have source rock potential.

The first analysis of the generative potential of the rocks from this well is based on the S2 vs. TOC diagram. Again, if two lines are drawn, the first at $S=2.5$ and the second at $S=5$ $S_2=5 \text{ mg HC/g rock}$, it is easy to see that majority of the formations plot between the two boundaries (Figure 4.14 d). The Frontier Sandstone, Carlile Shale, Niobrara 1, Niobrara 2, Niobrara 3, and the majority of the lower Tununk Shale fall into poor source rock generative potential based on the S2 values. The remaining formations: Tununk shale, Niobrara 4, Niobrara 5, Niobrara 6, Niobrara 7 plot in the fair to good range. The extreme sample from the lower Tununk Shale has S2 value of 10.5 mg HC/g rock and very good source rock generative potential based on the S2 values.

On the HI vs. S2 diagram there also is a linear trend with a little scattered plot of the Niobrara 5 and one sample of the lower Tununk Shale (Figure 4.15 b). A horizontal line at 150 mg HC/g $C_{\text{org}}$ shows that the result split approximately in half. The Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 7, and deeper samples from the Mancos Shale have a potential of generating mixed gas and oil. Four of the formations plot on the border
between gas, and gas and oil generation. Those are: Tununk Shale, Niobrara 1, Niobrara 2, Niobrara 4, and shallower samples for the Mancos Shale. Gas may be generated from the lower Tununk Shale, Frontier Sandstone, and Carlile Shale.

Analysis of the S2/S3 data (Appendix I) shows that there are two formations which are gas prone. Those are Frontier Sandstone and Carlile Shale, averages 2.4 and 3.3 respectively. All other formations have potential to generate oil based on this analysis. The average values for those formations are: lower Tununk Shale (av.13.3), Tununk Shale (av. 10.8), the Niobrara 1 (av. 6.5), Niobrara 2 (av. 6.4), Niobrara 3 (av. 5.9), Niobrara 4 (av.8.2), Niobrara 5 (av. 8.8), Niobrara 6 (av.9.5), Niobrara 7 (av. 11.4), and Mancos Shale (av. 5.9). Again, the S1 peaks suggest that these rocks did not expel many hydrocarbons.

Figure 4.14 Results for the South Baxter Pass Unite 2-20 well; a) Depth vs. TOC plot; b) Relationship between TOC and HI; c) Plot of TOC vs. OI; d) Graph showing a relationship between S2 and TOC with lines presenting boundaries between different kerogen types.
All the above evaluations are performed based on the assumption that the source rocks are immature. However, there were maturity tests ($R_o$) performed on thirteen samples from this well. Vitrite reflectance results show that all of the tested samples were mature. The lowest values were recorded for the Mancos Shale (0.6%) and the highest for the Frontier Sandstone and lower Tununk Shale (0.94%) (Figure 4.16 c).

The study of a diagram representing relationship between depth and $T_{\text{max}}$ shows general increase of the temperature with depth (Figure 4.16 a). This also may suggest increase of maturity with depth. Samples fall between immature and mature stage based on the $T_{\text{max}}$ results. The “extreme” Mowry sample is most likely over mature based on these analyses.

Analysis of the HI vs. OI plot shows that most of the samples fall closely to type III kerogen (Figure 4.14 d and 4.15 c). Two of the formations (Niobrara 7 and Niobrara...
6) seem to have mixed type II and III kerogen. Kerogen types identified in this well suggest that mixed, gas and oil and gas may be generated from the source rocks. The PI vs. $T_{\text{max}}$ graph shows that all of the formations plot in the early oil to oil generation window (Figure 4.16 b). The maturity of the rocks in this well suggests generative potential.

The majority of the formations from this well show source rock capacity potential. All of the intervals have TOC values above 1 wt.%. The greater part of the Tununk Shale, Niobrara 6, and Niobrara 7 are approximately 2 wt.% which suggests good to very good source rock generative potential. The deepest sample form the lower Tununk Shale has TOC values of 7.12 wt.%.

Figure 4.16 Maturity and production information for the South Baxter Pass Unit well; a) Relationship between depth and $T_{\text{max}}$; b) Plot of PI vs. $T_{\text{max}}$; c) Graph showing increasing maturity with depth

Hydrogen index results for the formations in this well show that based on this parameter, the source rock might generate gas and mixed gas and oil. The hydrogen index values
range between 73 and 439 mg HC/g C\textsubscript{org}. The oxygen index results range between 5 and 51 mg CO\textsubscript{2}/g C\textsubscript{org}. The oxygen index of 5 mg CO\textsubscript{2}/g C\textsubscript{org} is from the Mowry sample scatters apart from the rest plot. Two of the formations have S2/S3 ratio which suggests gas generation (Frontier Sandstone, Carlile Shale). The results for the other formations imply oil generation based on S2/S values. The major types of kerogen are type III and mixed type II and III. This also indicates the possibility of generating gas and oil. Additionally, analysis of the PI vs. T\textsubscript{max} diagram supports this interpretation. The source rocks are mature and most likely will produce hydrocarbons. Figure 4.17 presents summarized geochemical logs for the South Baxter Pass Unit 2-20 well.

### 4.4.5 Ruby 8102-31M well

There were 81 samples tested from the Ruby 8102-31M well. Tests were performed on 30 ft (9.2m) sample intervals which provides suitable data for accurate conclusions. At the bottom of the tested interval there are controversial results which suggest that the Dakota Sandstone has very organic rich facies and the Tununk Shale is very lean. This may be a result of improper identification of the cuttings collected at the surface. In the bottom part of whole interval, the results are most likely shifted by approximately 100 ft (30 m). In this section all the data will be discussed without accounting for this assumption.

Total organic carbon results for this well ranges between 0.69 (Carlile Shale) and 4.39 wt.% (lower Tununk Shale) (Figure 4.18 a). Study of the TOC vs. HI plot presents that the Niobrara 3 has the highest hydrogen index of 598 mg HC/g C\textsubscript{org} and the Niobrara 2 has the lowest HI values of 59 mg HC/g C\textsubscript{org}. The majority of the formations plot linearly, however, there are some scattered samples from the Dakota, Mowry, Tununk, and Niobrara 3 intervals. All of the formations show an increase of the hydrogen index and total organic carbon (Figure 4.18 b). The TOC vs. OI plot shows a rather scattered plot. The Tununk Shale, Frontier Sandstone, and Carlile Shale have the lowest OI and TOC values. The rest of the formations show decreased TOC with increasing hydrogen index (Figure 4.18 c). There is an observable linear trend on the S2 vs. TOC diagram.
Figure 4.17 Geochemical logs for the South Baxter Pass Unit 2-20 well. Summary provided by Baseline with the report.
showing an increase of generated hydrocarbons with an increase of total organic carbon. Similar to previously discussed wells the $R^2$ value is of 80%. However, the Dakota Sandstone and lower Tununk Shale again plot differently than the rest of the formations showing high S2 and TOC values (Figure 4.18 d).

The clay content in the Ruby 8102-M 31 is the lowest from all described wells. The x-intercept value for all of the samples is 0.21% (Figure 4.19 a and b). This suggests that rocks in this well have the smallest adsorption of liberated hydrocarbons than the same formations in the different wells. The S2, HI, OI, and $T_{\text{max}}$ would not be affected.

A study of the S2 vs. TOC diagram shows that only the Tununk Shale, Frontier Sandstone, Carlile Shale, Niobrara 2, and one sample from the Niobrara 3 have total organic carbon values smaller than 1 wt.%. It is important to remember that the Tununk Shale and lower Tununk Shale would have the same values however, they were most likely improperly identified while cuttings were collected (Figure 4.18 d). Most of the formations have good source rock potential based on the TOC values.

Based on the S2 vs. TOC diagram samples for the Dakota Sandstone, lower Tununk Shale, Tununk Shale, Niobrara 1, Niobrara 3, and Niobrara 5 look the most promising to generate hydrocarbons based on the S2 values. The Niobrara 6, Niobrara 7, and Mancos Shale fall into fair to good generative potential based on this parameter. The remaining samples show poor generative potential.

On the HI vs. S2 plot there is a linear trend showing increasing hydrogen index with increasing S2 peak (Figure 4.19 b). This plot shows that the Dakota Sandstone, lower Tununk Shale, Tununk Shale, Niobrara 1, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, Niobrara 7, and Mancos Shale plot above 150 mg HC/g C$_{\text{org}}$ which suggests a potential for mixed, gas and oil generation. The rest of the formations may generate gas based on the hydrogen index values.

Analysis of the S2/S3 data (Appendix J) suggests that all of the formations have a potential to generate oil based on S2/S3 values. Four of the formations have S2/S3 values smaller than 10, the Frontier Sandstone (av. 5.3), the Carlile Shale (av. 5.4), the Niobrara 2 (av. 5.4), Niobrara 7 (av.8.1). The Dakota Sandstone (av. 28.1), lower Tununk Shale (av.20.7%), Tununk Shale (av. 24.5), Niobrara 1 (av. 18.4), Niobrara 3 (av. 14.5), Niobrara 4 (av. 15.5), Niobrara 5 (av. 13.4), Niobrara 6 (av.10.7), and Mancos Shale (av.
all have very good potential to generate oil based on these parameters. Average S1 results imply that hydrocarbons were previously expelled from these rocks.

There were no maturity tests (other than $T_{\text{max}}$) performed for this well and the closest well with the vitrinite reflectance the South Baxter Pass Unit 2-20 is located approximately 28 miles away. The distance between two wells is too large to apply data from the SBPU 2-20 in relations to the Ruby 8102-M31 well.

Based on the depth vs. $T_{\text{max}}$ diagram, it is hard to say that there is an increase of temperature with depth. All of the samples plot rather randomly in the range between 435 and 449°C (Figure 4.20 a). $T_{\text{max}}$ results show that rock from this well are early mature to mature. The study of the HI vs. OI diagram suggests that there are kerogen types II, mixed type II and III, and type III present in the samples from this well (Figure 4.18 d and 4.19 d). These types of kerogen are oil, oil and gas, and gas prone, respectively. Based on the available data there is a possibility that these rocks may produce
hydrocarbons, however the lack of the maturity information does not allow to adequately assume the generation potential. Additionally PI vs. $T_{\text{max}}$ values show that all of the samples fall into the oil window (Figure 4.20 b).

The results of the geochemical analysis for this well are controversial due to most likely improper identification of samples at the time of collection. The results for the Dakota Sandstone, lower Tununk Shale, and Tununk Shale are most likely not correct. In all other wells the Tununk and lower Tununk Shale were possible source rocks and the Dakota seemed to have reservoir potential. However, in this well the results for the Tununk Shale are really low and for the Dakota Sandstone are very high. The assumption that the results are shifted down in made. Based on this, the high values identified for the Dakota Sandstone most likely should be identified with the Tununk and lower Tununk Shales. This would suggest that those two shales still have good generative
potential and should be considered as source rocks.

Along with these two shales, all of the intervals from the Niobrara Group, except the Niobrara 2, have TOC values higher than 1 wt.%. The Dakota Sandstone, lower Tununk Shale, Tununk Shale, Niobrara 1, and Niobrara 4 have TOC values above 1 wt.% which suggests good source rock generative potential based on this parameter. The Frontier Sandstone, Carlile Shale, and Niobrara 1 have relatively low HI values (~60 mg HC/g Corg) but they still may generate gas based on this parameter. All other formations fall into mixed gas and oil range based on the HI values. The oxygen index results for all of the formations are lower than 46 mg CO2/g Corg. All of the formations have a potential to generate oil based on the S2/S3 values (>3). Three different kerogen types identified in this well (II, mixed II and III, and III) also illustrates possibility of generating oil, mixed gas and oil, and oil. Additional analysis of the PI vs. T_max diagram supports this interpretation. There is no maturity information for these rocks but good results of the parameters tested during pyrolysis suggest that there may be some hydrocarbons generated from these rocks. Figure 4.21 presents summarized geochemical logs for the Ruby well.

4.5 Summary

In this chapter the results of the geochemical analyses were discussed and potential source rocks for each well were identified. Formations which most likely have
Figure 4.21 Geochemical logs for The Ruby well. Summary provided by Baseline with the report.
good source rock capacity showed similar values in all tested wells. In the Taiga Mountain 6-20 well all of the formations, except the Frontier, Carlile, and lower Tununk Shale have TOC values higher than 1 wt.%. The Niobrara 7 results are above 2 wt.%. In the HH 9131 well the Dakota Sandstone, lower Tununk Shale, Niobrara 1, and Niobrara 4 have TOCs lower than 1 wt.%. The Tununk Shale and Niobrara 7 have values above 2 wt.%. In the HH 18-9 all of the intervals have TOC results above 1 wt.% but below 2 wt.%, one sample from the Niobrara 6 has TOC above 2 wt.%. In the South Baxter Pass Unit 2-20 all of the formations have total organic carbon above 1 wt.%. The Tununk Shale has values above 2 wt.%. The Niobrara 5 and Niobrara 7 range between 1.9 to 2.28 and 1.57 to 2.11 wt.% respectively. In the Ruby 8102-31M the Niobrara 3, Niobrara 5, Niobrara 6, Niobrara 7, and Mancos Shale have results above 1 wt.%. The Niobrara 5 ranges from 1.28 to 2.16. The Niobrara 1 and Niobrara 4 have values about 2 wt.%. The Dakota Sandstone, lower Tununk Shale, and one sample from the Tununk Shale show results above 2 wt.% ranging between 2.38 and 4.39 wt.%. The Tununk Shale would most likely present more values with good total organic carbon but due to the most likely improper identification of samples during collection, those values were assigned to the lower Tununk Shale and Dakota Sandstone. Geochemical data is summarized in Table 4.6 where average values for all of the formations in all of the wells are presented. If look at the TOC values based on the classification by Lewan (1987) all of the rock except the Tununk Shale may be immature.

Among the formations which may produce mixed gas and oil based on the HI values are: lower Tununk Shale, Tununk Shale, Niobrara 1, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, and Niobrara 6. The lower Tununk Shale, Tununk Shale, Niobrara 5, and Niobrara 6 show the potential of producing oil in two HH 9131 and HH 18-9 wells. If the S2 results are looked at the same formations across the field show potential to generate hydrocarbons. In Taiga Mountain 6-22 well the Niobrara 4, Niobrara 6, and Niobrara 7 have values higher than 3mg HC/g rock. In the HH 9131 the Tununk Shale, Niobrara 1, Niobrara 2, Niobrara 5, Niobrara 6, and Niobrara 7 show values higher than 3 mg HC/g rock. In the HH 18-9 seven formations have generative potential based on the S2 values: Tununk Shale, lower Tununk Shale, Niobrara 1, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7. In the South Baxter Pass Unit 2-20 the Tununk Shale,
Niobrara 5, Niobrara 6, and Niobrara 7 show potential. In the Ruby 8102-31M well the Dakota Sandstone, Tununk Shale, lower Tununk Shale, whole Niobrara Group, and Mancos Shale have S2 values above 3 mg HC/g rock.

The major kerogen types in all of the wells are type II, mixed type II and III, and type III. From these kerogen types generation of oil, mixed gas and oil, and oil is possible. If PI vs. $T_{\text{max}}$ diagram is observed, all of the samples fall into oil window.

The Dakota Sandstone is a reservoir in the study area. Additionally, all of the intervals from the Niobrara Group have a potential to be a self sourcing reservoirs which may produce significant amount of hydrocarbons. It is difficult to predict where exactly the hydrocarbons generated from the lower Tununk and Tununk Shales may have migrated. There is a possibility that the lower, sandier part of the Frontier Sandstone is a reservoir as well.
Table 4.6 Average results for Rock-Eval Pyrolysis and available maturity data for each formation in all tested wells.

<table>
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<tr>
<th>Well Number</th>
<th>Formation Name</th>
<th>TOC %</th>
<th>$S_1$ mg/g</th>
<th>$S_2$ mg/g</th>
<th>Tmax °C</th>
<th>HI mgHC/g_Corg</th>
<th>OI mgCO2/g_Corg</th>
<th>PI</th>
<th>$S_2$/TOC</th>
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<td>1.52</td>
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CHAPTER 5

GEOCHEMISTRY AND PETROPHYSICS

In this chapter analyses of the basic petrophysical results and their relationship with geochemical data for five available wells are presented. All of the wells which have geochemical data were selected to be analyzed in this study. However, not all of the wells could be used because the log sets were limited. The decision to use one, representative well was made. The well selected for further study was Hells Hole 9131 well.

5.1 Methodology

Four logs were selected to provide a base for the analyses: GR, AT90, NPHI, and RHOB. The GR log measures the natural radioactivity in the formations, allows identifying lithologies, and can be used for correlations of the zones. AT90 is an Array Induction Two Foot Resistivity AT90 which measures deep resistivity of the formations. This log is used to determine hydrocarbon-bearing versus water bearing zones, indicate permeable zones, and determine porosity (Asquith and Krygowski, 2004). NPHI log is a neutron porosity log which measures hydrogen concentration in a formation. RHOB log is a bulk density log which shows the density of the entire formation, both solid and fluid part. This log is used to calculate density porosity helps to detect gas-bearing zones in conjunction with NPHI identify evaporite minerals, and determine porosity.

Mixed lithologies are present in the wells across the research area. Because of that three density porosity (DPHI) curves were calculated based on the RHOB log. There are four elements taken into the equation: RHOMA, RHOB, and RHOF. RHOMA is a bulk density of matrix rock and it is measured in g/cm$^3$. Different values were used to calculate each log. The first, DPHI curve is calculated for the matrix density of 2.65 g/cm$^3$, which is characteristic for sandstones, was used. The second DPHI curve is calculated based on the 2.68 g/cm$^3$ and characterizes shaly sand. For the third DPHI curve
a value of 2.71 g/cm$^3$ was used. Based on the DPHI logs three porosities for each formation were calculated (Table 5.1). In the DPHI equation as in IHS GeoPlus Petra$^{TM}$: 

$$\text{DPHI} = \frac{(\text{RHOMA} - \text{RHOB})}{(\text{RHOMA} - \text{RHOF})},$$

remaining two variables are RHOB- bulk density log and RHOF- density of the fluid which was set as constant and equaled 1 g/cm$^3$.

The next step taken was to calculate the average water saturation (Sw) for all of the formations. To accomplish this exercise, Sw curves had to be computed. SW was calculated based on the Archie’s equation in IHS Petra$^{TM}$ software: 

$$\text{Sw} = \frac{\text{Rw}}{(\text{RT}*(\text{PHI}**\text{M}))*((1.0/\text{N})}}.$$ 
Rw stands for resistivity of formation water and in this study it equals 0.05 (ohm). Rt is a resistivity of rock filled with hydrocarbons. In this equation RT is represented by the AT 90 log. PHI is porosity. In this equation DPHI log is used to calculate SW. The n and m are constants for cementation and saturation exponents, respectively. Their value is approximately 2. The SW was calculated for three different lithologies. There is not enough data available to calculate permeability for the formations across the research area.

5.2 Porosity and water saturation results

Porosity and water saturation values were calculated for the entire well. Next, the results were applied to the previously identified formations (Appendix K). Based on the values for the entire interval, average porosity and water saturation for three different lithologies were determined (Table 5.1). While looking at the average values for porosity calculated for sandstone, only one formation (Tununk Shale) shows porosity above 5 %. Two of the formations have porosity values below 5 % (Carlile Shale and Frontier Sandstone) based on the values calculated for the shaly sand. All of the formations show porosities higher than 5 % using limestone for matrix values. All of the formations are wet if only the average results for SW calculated for all three lithologies are taken into account. However, if all the logs presented in the Figure 5.1 are compared, it is clear that within all of the formations there are intervals which have lower SW. They correspond to the elevated porosities and gas shows.
5.3 Porosity and water saturation vs. gas shows and total organic carbon

Relationships between porosity, water saturation, and geochemistry can be seen on the Figure 5.1. Three DPHI and SW logs are plotted next to each other in order to show slight differences in values depending on the matrix density. The first curve (blue) shows results for sandstones (\( \rho_b=2.65 \text{ g/cm}^3 \)), second (red) is a curve, representing shaly sands (\( \rho_b=2.68 \text{ g/cm}^3 \)), and third (green) shows results for limestone (\( \rho_b=2.71 \text{ g/cm}^3 \)).

The upper part of the log shows porosity values for the Mancos Shale. Porosities in the upper part of this formation are somewhat higher than the ones in the lower part. The same trend is visible on the SW log where upper part is completely saturated with water. The lowermost Mancos Shale is less saturated; however, it is still wet. The changes of porosity correlate good with gas shows. The upper part of the Mancos Shale shows more distinct gas shows than the lower part. Comparing the Sw and gas shows curves indicates a relatively good correlation. However, one of the highest spikes on the gas shows curve seems to line up with 100% Sw which presents a mismatch. The TOC log is consistent

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<td>100</td>
<td>100</td>
<td>98.4</td>
</tr>
<tr>
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<td>4.6</td>
<td>6.2</td>
<td>99.9</td>
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<td>97.4</td>
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<tr>
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<td>69.2</td>
<td>54.5</td>
<td>48.3</td>
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<td>5.6</td>
<td>7.3</td>
<td>94.3</td>
<td>98.8</td>
<td>96.8</td>
</tr>
</tbody>
</table>

Table 5.1 Average values of porosities and water saturation for different formations and lithologies. Values calculated based on DPHI and SW logs.
Figure 5.1 Juxtaposition of GR, resistivity, DPHI (2.65 g/cm$^3$ blue, 2.68 g/cm$^3$ red, 2.71 g/cm$^3$ green), Sw (2.65 blue, 2.68 red, 2.71 green), gas shows log, and TOC geochemical log for the HH9131 well.
with DPHI, Sw, and gas show curves. The highest TOC content correlates with increased gas shows. At the base of the Mancos Shale there is a noticeable increase of porosity. It characterizes upper intervals of the Niobrara Formation.

The Niobrara 5, Niobrara 6, and Niobrara 7 seem to have very distinct increasing trend on all of the logs. The Sw curve shows the lowest saturations for the Niobrara 5, Niobrara 6, and Niobrara 7 respectively. This trend is also very significant on the gas shows curve. There is a rapid increase in the middle part of the Niobrara 7, to approximately 400 units. There is a gradual decrease of gas shows with depth reaching about 180 units at the bottom of the Niobrara 5. The boundary between the Niobrara 5 and the Niobrara 4 show another increase, to about 300 units, below which values rapidly decrease. The TOC curve seems to closely follow the gas curve showing a decrease from the Niobrara 7 to the Niobrara 5. The TOC values registered for these three intervals are among the highest for the whole lower Mancos Shale group and oscillate around 2%.

The underlying Niobrara 4 is characterized by decreasing porosities and very high Sw. The same trend can be followed on the gas shows and the TOC curves. If this interval is compared to the upper intervals of the Niobrara Formation it is not very promising but analyses of the whole log suggest that there may be some potential. The Niobrara 3 has very similar porosities as the Niobrara 4; however, the Sw values are much lower. There is a major decrease of the gas shows curve which corresponds to decreasing TOC results.

The porosities further decrease in the Niobrara 2. The Sw in the upper part of this interval shows that it is 100% saturated and that the saturation slightly drops in the lower part. The lower part of the Niobrara 2 shows an increase in gas shows which corresponds to the increase of the TOC in this part. The Niobrara 1 is characterized by the increasing porosities and decreasing Sw. The gas shows and TOC show lower values for this interval.

The Carlile Shale has very similar log signatures as the Niobrara 2. The DHIP log shows relatively low values, which correspond to the very high Sw. There also are no major gas shows which seem to match the TOC curve. The TOC values for this interval are approximately of 1%. Overlying Frontier Sandstone does not illustrate an improvement of porosities. This is related to high clay content in this formation. The Sw
log shows that the Frontier Sandstone is completely wet. There is not much activity shown by the gas shows curve which corresponds to the TOC log where the values do not show any increase.

It is harder to follow trend for the Tununk Shale due to lack of data. There is no information available from the RHOB log which could be used to calculate porosities and Sw. However, the analyses of the available peaks show that there is a significant increase of porosity in this formation. The Sw curve also suggests that the saturation is relatively low in the Tununk Shale. There is an increase on the gas shows curve which can be correlated with higher TOC values for this formation. Higher porosity results are also present in the lower Tununk Shale. This interval is also hard to interpret due to lack of available data. The top of the lower Tununk Shale shows lower saturation than the central and lower part of it. The upper part of this formation also shows significant gas shows reaching about 600 units. The TOC curve does not show any increase of data and all of the points are slightly smaller than 1%.

5.4 Summary

The analysis of logs and calculations of Sw and porosity for the Hells Hole 9131 well suggest that the quality of possible reservoirs is poor. There is very low total porosity and if the effective porosity is about 40 to 75% of the total porosity the values for this well are very low. Additionally, formations present in the HH 9131 are wet. These results are not optimistic; however, they provide important information about the trends existing in this interval. There are few zones within the lower Mancos Shale group which may be productive in different parts of the research area. The lower Tununk Shale, Tununk Shale, Niobrara 5, Niobrara 6, and Niobrara 7 have lower Sw and higher porosities. These two parameters correspond to elevated gas shows and TOC. These formations have very consistent GR, resistivity, RHOB, and geochemical results across the whole research area which allows assuming that these trends are present across the DCADC area.

Petrophysical analyses of the HH 9131 well give an idea about reservoir quality.
Very low effective porosities suggest that all the potential reservoirs have very low permeability and additional completion techniques may be necessary to produce hydrocarbons. The Lower Mancos Shale-Dakota interval should be considered as a potential target for unconventional exploration.
CHAPTER 6

MAPPING

Isopach maps were created for the twelve of the intervals identified during the stratigraphic correlations. Additionally, thirteen structural maps were constructed and reviewed. All of the structural maps are very similar and do not reveal significant structural changes across the whole research area. Therefore, only two of them will be presented in the following sections. The first one is on the top of the Dakota Sandstone and the second one is on the top of the lower Mancos Shale. There are no isopach maps created for the Dakota Sandstone. The reason for this is that this formation was recognized as the base of the lower Mancos group and strata below it was not studied. Maps will be presented in ascending order.

6.1 Methodology

All maps were created in IHS Petra™ software. To create maps several steps had to be followed. For the structural maps: a) all the formation tops had to be correlated across the whole study area; b) based on those tops, contour grids were generated; c) all the data was contoured and displayed. For the isopach maps: a) previously identified formation tops were used; b) based on those, thicknesses of the intervals (zones) were calculated; c) generation of grid from zones was performed; d) contours were generated from the zone data and displayed. All of the maps were checked for accuracy. Separate intervals were previously discussed in Chapter 2.
6.1.1 Generation of the grid and contour display

All of the twelve grids which were generated in GeoPlus Petra™ software from formation tops used a minimum curvature calculation method on a 1702 by 1702 ft (518 m) grid. Depth values used for creating structural maps were measured as feet sub-sea (SS). In creating isopach grids depth values in feet were used as well measured depth (MD). There were no trends or fault data included in the gridding process. The available data from existing wells was used to define the grid area. In some of the wells not all of the formations tops could be picked due to the lack of the log image or bad log quality.

Appropriate grids were selected to construct structural and isopach contours. Suitable contour intervals were picked based on the maximum and minimum sub-sea depth or zone thickness for the selected grid. Twenty foot contour intervals were set to assure readability and detail of the maps. Additionally, maps presented in the following section are color filled to allow easier visualization of the contours.

6.1.2 Accuracy control

Originally created grids had to be reviewed for accuracy. There were suspicious points (possible errors) visible on the maps. The possible errors were associated with presence of “bullseyes” which are concentric contours surrounding a wellbore. Very often they are a result of miscorrelations, lack of log information, and intersecting faults. A visual examination of miscontoured data points was followed by evaluation of correlated intervals. Eventual miscorrelations were fixed and contours were re-gridded. There was no attempt made to remove the bullseyes from the maps unless they were related to the miscorrelations. For example, if there was poor quality log, structural complexity or any non-geologic effect related to the specific well it would not be used.
6.2 Structural maps

Initially structural maps were created for all of the intervals. After visual analysis of those maps, major similarities were identified. All of the grids showed a central crest which illustrates the DCA and clearly pronounced flanks. The Dakota Sandstone grid (Figure 6.1) shows a wide structure which narrows to the north. All of the structural maps showed that the anticline is plunging towards the north and that the west flank is steeper than the east. Significant thinning of the whole lower Mancos group from the north to south (Figure 2.4 and 2.5) may also suggest plunging of the structure. This also suggests that there was more accommodation space to the north. The Douglas Creek Arch is shallower on the south side of the study area and relatively flat in the central part on the top of the crest. Overall the structure of the DCA does not change significantly.

Analysis of the Dakota Sandstone map suggests presence of two major northwest-southeast trending normal faults (red lines Figure 6.1). They were previously identified by Stone (1977) and named, the Garmesa and Douglas Creek normal faults. Fisher (2007) also acknowledged the presence of these faults across the research area. Based on the corresponding research by Levi Heintzelman (graduate student at CSM), of seismic of the north part of the study area, it is not clear whether the sediments of the Dakota Sandstone are cut by the Douglas Creek fault or just folded. This fault is, however, visible on the maps of shallower formations which are most likely cut by it. The Garmesa Fault most likely cuts sediments of the Dakota Sandstone. In this section both of the faults can be best seen on the structural map of the Mancos Shale (Figure 6.2). The north part of the study area is highly faulted. There are many northeast-southwest trending normal faults which were illustrated by Fisher (2007). They are concentrated in central and north part of the research area.

All of the similarities present on the structural maps suggest that the deformations post-dated the youngest interval mapped and that the arch was uplifted during or post Laramide Orogeny.
Figure 6.1 Top of the Dakota Sandstone structural contour map composed based on the sub-sea depth. The left side of the figure shows 250 ft contour interval. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah border.
Figure 6.2 Top of the Mancos Shale structural contour map composed based on the sub-sea depth. The left side of the figure shows 250 ft contour interval. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
6.3 Isopach Maps

There are twelve isopach maps computed for the lower Mancos-Dakota interval. The Dakota Sandstone is the only formation for which an isopach map was not created. This is because the stratigraphic correlations did not extend below the top of the Dakota. Each of the maps will be discussed in the following sections.

6.3.1 Lower Tununk Shale

The isopach map for the lower Tununk Shale illustrates significant thinning of the formation toward the north-east and north-west part of the study area (Figure 6.3). The thickness of the interval varies from approximately 211 ft (64 m) in the south to about 43 ft (13 m) in the north part. The average thickness of the formation is approximately 115 ft (35 m) across the research area. When the east to the west profile of the area is examined the thicknesses are relatively uniform. The average TOC results for this formation is about 1.80% (Chapter 4). There is an increase of the total organic carbon content from the north to the south of the area. In Taiga Mountain 6-22 well TOC is 0.86%. In Ruby well located at the south border of the DCADC TOC is 2.58% (Table 4.6). Analyses of the map and TOC suggest that the source of the sediment at the time of deposition of the lower Tununk Shale was at the south or southeast. This interval is thicker and most likely has higher source rock potential in the south part of the study area.

6.3.2 Tununk Shale

The map of the Tununk Shale shows relatively uniform thickness of this interval across the area (Figure 6.4). The average thickness of the Tununk Shale is 115 ft (35 m) across the whole DCADC. In the south-east corner, there is a significant increase to about 193 ft (58 m). By contrast, on the north and the north-east side the area there is a major
Figure 6.3 Isopach map of the Mowry Shale. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
Figure 6.4 Isopach map of the Tununk Shale. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
thinning. There also are few spots showing lower thicknesses within this interval in the north-central part of the area. A possible explanation for them is that sediments in this area are faulted. The TOC results for this formation average about 1.72% (Table 4.6). They also increase from the north to the south as in the lower Tununk Shale. However, the results for the Ruby well are most likely lower due to improper collection of the samples. The distribution of the sediments on the map suggests that the interval thickens dramatically into the Piceance basin. The Tununk Shale is fairly uniformly distributed across the area (100-140 ft thick) (30.5-42.7 m) which suggests that it may be an important source rock across the whole DCADC.

6.3.3 Frontier Sandstone

The isopach of this formation indicates that it is thicker to the north, central east and central west of the study area where it reaches approximately 166 ft (50 m) (Figure 6.5). In the south part the thickness decreases to approximately 40 ft (12 m). On average this interval is 83 ft (25 m) thick. The Frontier Sandstone is of marine origin and the likely source area is to the northwest and north. The difference in thicknesses at the northeast corner may be related to limited well control in this region. The northwest and southeast trending “belt” of thicker and thinner sediments may be explained by the presence of the Douglas Creek fault in this area.

The average TOC result for the Frontier Sandstone is 0.97% (Table 4.6). These results are higher in the Hells Hole Field area (1.23%), lower in the southern part of the study area (0.99%), and significantly lower in the north part of the area (0.69). The lower part of the Frontier Sandstone is sandier. It most likely has better reservoir quality than the upper part and may be a potential reservoir. There is high clay content within this formation which may lead to low permeabilities.
Figure 6.5 Isopach map of the Frontier Sandstone. Black lines illustrate “belt” of varying thicknesses along the Douglas Creek Fault. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
6.3.4 Carlile Shale

The isopach of the Carlile Shale illustrates that the thickness of this formation varies considerably across the study area (Figure 6.6). It is approximately 467 ft (142 m) in the northwest part of the research area and 174 ft (53 m) in the south and southwest. There is a similar trend across the central part of the area which was seen on the map illustrating the Frontier Sandstone. The thicknesses of the interval tend to vary along the Douglas Creek Fault. The Carlile Shale is the thickest in the north part of the research area. There are two spots on this map which look like bullseyes and are significantly thicker than the surrounding sediments. An explanation for these variations is the close proximity of northeast-northwest trending normal faults. The very thin section on the northeast side may not be properly identified due to the lack of control data.

The average TOC for this interval from all tested wells equals 0.99% (Table 4.6). These results do not significantly vary across the DCADC. Silt, shale, and very fine grained sands of the Carlile Shale should not be considered as a source rocks. This formation is not expected to have high permeabilities. However, this formation may be a potential reservoir target for unconventional exploration.

6.3.5 Niobrara 1

The distribution of the Niobrara 1 is rather uniform across the majority of the study area and can be seen on Figure 6.7. The Niobrara 1 is thicker in the northeast part of the area where it reaches 131 ft (39 m). In the southwest part it is thinner and only 44 ft (13 m). The Niobrara 1 is on average 84 ft (25 m) thick across the DCADC. Taking a closer look at the map suggests that the thicknesses are uniform from the west to the east. The thicker contours of the isopach on the east may be a result of a lack of control wells, therefore incorrect gridding.

The TOC data averages at 1.53% and is the third lowest among all of the Niobrara intervals (Table 46). This map suggests that there were higher rates of deposition of this formation in the north and northeast side of the research area.
Figure 6.6 Isopach map of the Carlile Shale. Black lines illustrate “belt” of varying thicknesses along the Douglas Creek Fault. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
Figure 6.7 Isopach map of the Niobrara 1 of the Niobrara Formation. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
6.3.6 Niobrara 2

The isopach of the Niobrara 2 interval does not show a uniform distribution of the interval (Figure 6.8). The maximum thickness is 244 ft (74 m); the thinnest is 43 ft (13 m). The average value for the whole the Niobrara 2 is approximately 138 ft (45 m). Sediments of this interval are not consistent in thickness from the west to the east of the area. The isopach seems to be thinner in the southeast and east part of the DCADC. The east thinning again can be explained by the lack of the well control in this area. Varying thickness of this isopach in the central part of the research area may be associated with the presence of the large amount of normal faults. The average TOC for the Niobrara 2 is 1.37% which makes it the second lowest of the tested wells. The Niobrara 2 may be considered a self sourcing reservoir with relatively poor source and reservoir qualities.

6.3.7 Niobrara 3

The Niobrara 3 isopach also does not illustrate a uniform distribution of the sediments (Figure 6.9). There is a general thickening trend visible towards the north of the research area. The Niobrara 3 is the thickest in the northeast section of the study area and reaches up to 252 ft (77 m). The thinnest spots in the southern side of the area are about 78 ft (24 m). Similar to the other isopachs of the Niobrara Formation the Niobrara 3 shows variation of the thicknesses in the locations which are most likely affected by the Douglas Creek, Garmesa, and smaller normal faults. The average thickness of this interval of the Niobrara Formation is approximately 154 ft (47 m) across the research area. The average TOC value for the Niobrara 3 is 1.26% which is the lowest within the whole Niobrara Formation. In tested wells, the TOC values increase from the north to the south of the DCADC. This increasing trend does not correlate with the increase of the thickness. This interval does not have great source rock potential; however, it may be self sourcing reservoir with poor reservoir qualities. It should be considered as a potential, unconventional exploration target.
Figure 6.8 Isopach map of the Niobrara 2. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
Figure 6.9 Isopach map of the Niobrara 3. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
6.3.8 Niobrara 4

The isopach of the Niobrara 4 shows that there is an overall thickening trend towards the north and northeast side of the research area (Figure 6.10). The thickness of this interval of the Niobrara Formation varies from 20 ft (6 m) in the south part to 306 ft (93 m) in the north part. The grid of the thickest area (northeast) may be influenced by low amount of control points and may not be real. In the central-north part of the area, the differences of the thickness are not major. In the southern side, the thickness varies along the Garmesa Fault. The average thickness on this isopach is 154 ft (46 m). The average TOC value calculated for this interval is 1.63% (Figure 4.22). The highest TOC values were identified in the southern part of the area; the lowest values in the Hells Hole Field. The Niobrara 4 has a low to moderate source rock generative potential and also may be a self sourcing reservoir.

6.3.9 Niobrara 5

On the isopach map of the Niobrara 5, there are three thin spots visible, in the south, northwest, and northeast (Figure 6.11). The lower contour values in northeast side again may be explained by the lack of the well control. The same idea is most likely an explanation for the thickening on the central-west side, just outside of the study area. The thinning in the south is consistent with a general thinning of the whole lower Mancos Shale-Dakota interval. Again, thickness changes occur along the Douglas Creek Fault. The thickness of the Niobrara 5 interval ranges from 60 to 306 ft (18 to 93 m). On average it is 176 ft (54m) which is the third thickest interval within the Niobrara Formation. The average TOC for the Niobrara 5 is 1.67%. The TOC results are not showing any variation from the north to the south of the study area. The Niobrara 5 formation is considered a possible source rock within the DCADC. It may also be a poor quality reservoir, and a target for unconventional exploration.
Figure 6.10 Isopach map of the Niobrara 4 interval of the Niobrara Formation. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
Figure 6.11 Isopach map of the Niobrara 5 interval of the Niobrara Formation. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
6.3.10 Niobrara 6

The isopach map of the Niobrara 6 shows that there is a variation in thickness of the interval across the research area (Figure 6.12). It has both northwest and northeast trends. In the northeast this interval is thinner but this grid is based on only six wells. In the south side of the DCADC the Niobrara 6 is significantly thinner. There are visible changes of the thickness along the Douglas Creek Fault in the central-north part of the area. This interval ranges between 95 and 372 ft (28 and 113 m). It is the second thickest interval of the Niobrara Formation. It is 200 ft (61 m) thick on average across the whole research area. The average TOC calculated for this interval is 1.73% (Table 4.6). It is relatively constant in four wells. In the Ruby well it has lower value. The Niobrara 6 has the second highest TOC average among the intervals of the Niobrara Formation. The thickness and geochemical results of the Niobrara 6 interval suggest that it may be a good source rock. Additionally, as other intervals of the Niobrara Formation, it may be a potential target for the unconventional exploration.

6.3.11 Niobrara 7

An isopach map of the Niobrara 7 shows that the distribution of the sediments is uniform across the majority of the research area (Figure 6.13). In the southeast part, there is a significant thinning suggesting slower rates of deposition or less accommodation space. Additionally, thinner spots along the Douglas Creek and Garmesa faults are present. This isopach is the thickest in the northwest side of the research area. The thickness of the Niobrara 7 ranges from 143 ft (47 m) to 353 ft (108 m). The average thickness of this interval across the whole research area is 244 ft (74 m). It is the thickest interval of the Niobrara Formation. The average measured TOC is 1.74%. This parameter stays relatively consistent across the whole area. It is lower in the Ruby well but this inconsistency should be attributed to improper collection of the samples during drilling. The Niobrara 7 is considered as a potential source rock and potential exploration target for unconventional exploration. It most likely has a poor reservoir quality due to low porosities.
Figure 6.12 Isopach map of the Niobrara 6 interval of the Niobrara Formation. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
Figure 6.13 Isopach map of the Niobrara 7 interval of the Niobrara Formation. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
6.3.12 Mancos Shale

The isopach map of the Mancos Shale shows general thinning to the south (Figure 6.14). This trend agrees with the overall thinning of the Mancos-Dakota interval onto the Uncompahgre Uplift. This suggests that the source of the sediment supply for this formation was most likely from the north or northwest of the research area. The thickness of the Mancos Shale in the north is approximately 1323 ft (403 m). In the south this formation is about 208 ft (63 m) thick. The average thickness for the whole Mancos Shale across the study area is 580 ft (176 m). Analyses of the TOC data show that the average TOC for this formation is 1.32%. This parameter does not vary significantly from the north to the south of the area. The Lower Mancos Shale may be a potential source rock. Hydrocarbons from this formation may migrate into the overlying silty/sandy Mancos B Shale or may stay in place making the Mancos Shale a self-sourcing reservoir.

6.4 Summary

Structural and isopach maps created in this research project do not allow for full interpretation of the regional relationships of the DCADC to the adjacent Uinta and Piceance basins. In many cases it is difficult to predict the direction of the sediment supply and describe larger, regional trends for each of the formations. These difficulties are a result of limiting the grid only to the available data from the study area. Additionally, the quality of the well logs, especially in the south and east part of area, is not very good. In these areas, well log suites are incomplete which provides further challenge. Lack of log information makes correlations across the area problematic and negatively influences process of grid generation. Significant number of wells located in the south and east part of the area are partially correlated and therefore, unused in the grid generation. These challenges influence the results; however, large amount of the wells available for correlations and their density allow to present reasonable results and interpretations.
Figure 6.14 Isopach map of the Mancos Shale. The red lines illustrate approximate location of faults. Brown line shows Colorado Utah.
Structural maps created for the formations identified within the research area illustrate the presence of the anticlinal structure of the DCA (Figure 6.1 and 6.2). This structure was created after all of the formations were deposited. On the structural map of the DCA, two major normal faults are visible, Douglas Creek and Garmesa faults. Additionally, there are many normal faults in the northwest and north part of the area. All of the structural features may be helpful in unconventional exploration. Highly faulted areas should be modeled for the development of the natural fractures. Fractures present in the area of the Hells Hole field will be further analyzed by Levi Heintzelman (in progress). Development of “sweet spots” may significantly increase and create secondary permeability. Normal faults, if they are sealing, can create structural traps. If the faults do not seal, they may be important hydrocarbons migration pathways, and the trends should be studied closer.

The isopach maps created for all of the formations show significant thicknesses of potential source rocks and reservoirs. The potential source rocks combined are over a 1000 ft (304 m) thick and may expel significant amounts of hydrocarbon depending on their TOC, HI, kerogen quality and maturity. The majority of the formations are thicker in the central and northern parts of the study area. Analyses of the Frontier Sandstone and Carlile Shale isopachs also suggest northern portion of the area to be more promising (Figure 6.5 and 6.6). This may suggest that the potential exploration should concentrate on those two areas of the DCADC.
CHAPTER 7

CONCLUSIONS AND FUTURE WORK

The data analyzed in this report show that the stratigraphic interval deposited between the Dakota Sandstone and the Mancos B Shale can be subdivided into the lower Tununk Shale, Tununk Shale, Frontier Sandstone, Carlile Shale, Niobrara Formation, and the Mancos Shale. Based on the published data, geochemical analyses, and well logs correlations, the Niobrara Formation was subdivided into seven intervals: Niobrara 1, Niobrara 2, Niobrara 3, Niobrara 4, Niobrara 5, Niobrara 6, and Niobrara 7. The interval overlying the Carlile Shale is the calcareous Niobrara Formation.

The Niobrara Formation was also examined in the outcrop located in New Castle, Colorado. This outcrop is approximately 70 mi (112 km) away from the DCADC and there may be a significant change of facies between the two areas. The calcareous content of the interval tested may decrease to the west. In the New Castle outcrop the Niobrara Formation is exposed in a 308 ft (93.8 m) long section. Lithologies from this location were analyzed with a petrographic microscope. These tests helped to identify the carbonate content. Petrographic thin-sections prepared for the Niobrara Formation show planktic organisms (foraminifers) and fragments of *Inoceramus*. Petrographic thin sections showing planktic foraminifers with spar-filled chambers were compared to photomicrographs from the Denver Basin. These observations allow for the Niobrara Formation to be present in the western part of the state and are in agreement with previous studies. Outcrop GR measurement of the strata provided a means to compare the outcrop readings to the subsurface data from the DCADC. GR readings of the outcrop strata for the Frontier Sandstone, Carlile Shale, and lower parts of the Niobrara Formation corresponded to equivalent subsurface readings. The confidence of the correlation of the outcrop and the subsurface log is inhibited by the distance between them. The presence of this formation in the outcrop supported subsurface identification.

Geochemical analyses provided evidence that the lower Tununk Shale, Tununk Shale, and the Niobrara Formation may have the potential to generate hydrocarbons. All
of these intervals should also be considered as potential self-sourcing reservoirs for the purpose of the unconventional exploration. Additionally, the lower part of the Frontier Sandstone may be a potential reservoir. All of the mentioned formations most likely have poor reservoir quality due low porosities and permeabilities. The variable sampling intervals used in this study may have resulted in inconsistent data.

Basic petrophysical analyses performed for the Hells Hole 9131 well showed important trends existing in this interval. The lower Tununk Shale, Tununk Shale, Niobrara 5, Niobrara 6, and Niobrara 7 have lower Sw and higher porosities. These parameters correspond to elevated gas shows on mud logs and measurements of TOC on cuttings. These formations have a characteristic and consistent GR, resistivity, RHOB, and geochemical values suggesting that they are present across the whole research area. Based on this consistency the Sw and porosity would be expected to follow the same trend across the DCADC. The trends strongly suggest that the lower Tununk Shale, Tununk Shale, and the Niobrara Formation may be capable of generating hydrocarbons.

Study of the maps created for all of the identified intervals reveals that the majority of them are thicker in the central and northern parts of the DCADC. Stratigraphic cross-sections and intervals isopach maps suggest the presence of many normal faults (isopach thins). If the faults do not seal, they may be important hydrocarbon migration pathways, and their trends should be closer studied. The Mancos-Dakota interval should be considered as potential target for future unconventional exploration.

7.1 Future work

The basic characteristics of the Mancos-Dakota interval are presented in this report. To have a more definitive answer about the petroleum system of this formation, an additional, more detailed study is necessary. The Rock-Eval pyrolysis may show better trends existing in the source rocks if the analyses are tested on smaller sample intervals, perhaps 5-10 ft (1.5-3 m). Atomic analyses of hydrogen, oxygen, and carbon may be helpful in the identification of organic matter types. To better evaluate the source rock, knowledge about TOC data and hydrogen content is necessary. The H/C ratio determines hydrogen content and allows an estimation of the amount of potential hydrocarbons.
expelled from the source rock (Dembicki Jr., 2009). The more hydrogen in the organic matter relative to carbon, the more hydrocarbons can be generated.

To better interpret the burial history of the region, additional information about kerogen is needed. Additional $R_o$ data and gas chromatography could aid in characterizing the kerogen. A higher sampling interval for the $R_o$ analyses from wells located in different part of the research area may provide better understanding of the burial history, maturity (source rock models), and time of generation. The gas chromatography analyzes parts of the pyrolyzed material which is responsible for generating S2 peak (Dembicki Jr., 2009). The information obtained during this test provides information about qualitative and quantitative chemistry of the thermal decomposition products of kerogen, which allows better prediction of kerogen type (Dembicki Jr., 2009).

Obtaining core data may be very helpful in better identification of environments of deposition. The Mancos-Dakota interval contains significant amounts of clay. To better understand clay content, XRD analyses may be acquired. XRD and additional sample analysis can further document the presence of Niobrara chalk/marl lithologies on the DCA. This interval looks very promising for future unconventional exploration and is a known producer in the Rangely Field (DCA) and Buck Peak Field (Sand Wash Basin).
LIST OF ACRONYMS

BLM- the Bureau of Land Management
DCA- Douglas Creek Arch
DCADC- Douglas Creek Arch Development Contract
DPhi- Density Porosity Log
GR- Gamma Ray Logs
HH- Hells Hole
HI- Hydrogen Index
md- Millidarcies
NPhi- Neutron Porosity Logs
OI- Oxygen Index
PI- Production Index
R_o- Vitrinite Reflectance
Rhob or \( \rho_b \)- Bulk Density Log
SBPU- South Baxter Pass Unit
TAI- Thermal Alteration Index
TCF- Trillion Cubic Feet
TOC- Total Organic Carbon
WIS- Western Interior Seaway
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