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**MINES**  
MUDTOC

**SPRING 2024 SPONSOR MEETING & CORE WORKSHOP**

**APRIL 25, 26 • BEN PARKER STUDENT CENTER • BALLROOMS D & E**

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# MUDTOC CONSORTIUM

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## SPRING SPONSOR MEETING

**Meeting:** Thursday, April 25<sup>th</sup>; Friday April 26<sup>th</sup>

– Via ZOOM Invite & In-Person CSM Student Center

Core Workshop in Green Center

**Website:** <http://mudtoc.mines.edu>

**(Includes member access to Archival Consortia Information:  
Bakken, Niobrara & Vaca Muerta)**



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## **MUDTOC Research Faculty**

**Dr. Steve Sonnenberg, CSM – Principal Investigator**

**Patrick Sullivan, PhD Candidate, Research Coordinator**

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## **Facies framework and depositional processes of the Wall Creek-Turner system, Powder River Basin, WY.**

Patrick Sullivan, PhD. Candidate, Department of Geology and Geologic Engineering, CSM

### **Abstract**

Relatively thin, laterally extensive sandstones bounded by marine shales are common features in Late Cretaceous strata of the U.S. Western Interior and are responsible for the majority of recent unconventional hydrocarbon production and development in the region. The nature of the formation and depositional processes represented within these basin-isolated sand bodies has been the subject of much debate. One such unit is the Upper Turonian Wall Creek-Turner system in eastern Wyoming, consisting of the Wall Creek Member of the Frontier Formation and the coeval Turner Sandy Member of the Carlile Shale, which is one of the most productive reservoirs of the Powder River Basin. Paleogeographic reconstructions of this system vary because regional studies of the Wall Creek-Turner system are sparse, and most analyses of the units derive regional interpretations of depositional environment based on a single outcrop belt or oil and gas field. As such, the nature of regional stratigraphic relationships, facies characteristics, and depositional environments represented in the system remain largely unresolved.

This work incorporates detailed sedimentological and ichnological descriptions of 19 outcrop and 41 cored sections of the Wall Creek-Turner system across the 150-mile-wide Powder River Basin in order to characterize and quantify the depositional environments documented by the unit. Eleven facies associations with 28 subordinate facies and distinct ichnological trends were identified in outcrop and core, documenting a range of shallow marine and offshore processes with varying degrees of deltaic influence. To the west, the unit contains facies associated with a mixed-process deltaic system displaying evidence of rapid sedimentation rates under predominately wave and tidal influence with significant modification by storm waves. To the south, evidence of deltaic influence wanes alongside an increase in deposition and modification by offshore processes including storm waves and sediment gravity flows under moderate to rapid sedimentation rates. To the east, the unit displays a range of increasingly non-deltaic marine processes under variable sedimentation rates and modification by storm waves and bottom currents. This study illustrates the value of establishing regional facies frameworks when studying basin-isolated sandstones, and can be applied to many enigmatic sandstones of the U.S. Western Interior and beyond to generate more comprehensive depositional reconstructions.

## **Muddy Sandstone Enhanced Oil Recovery (Carbon Capture Utilization and Sequestration), Bell Creek Field, Montana**

**Drew Stump**, MS Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

Bell Creek Oil Field is located in southwestern Montana within the Powder River Basin and is a major oil producer that is currently going through enhanced oil recovery (EOR). The field was discovered in 1967 and the Muddy Sandstone is the primary producing reservoir. This reservoir has produced 147 million barrels of oil throughout its lifetime with the help of water flooding and carbon dioxide injection. Major carbon dioxide injection began in 2012 which caused a notable increase in oil production. In conjunction with the carbon dioxide injection, a 4D seismic survey was collected over part of the field to show where the carbon dioxide was migrating to within the formation. This study includes detailed core analysis, log interpretation, and petrography to understand the differing injectability of each area throughout the field

Muddy Sandstone depths range between 4,300 to 4,600 feet across the field and has an average porosity of 28.5% with ranges between 6% to 35%, while permeability ranges from 0.1 mD to 13,000 mD. The Muddy Sandstone is divided into two separate sections, the Bell Creek Sandstone and the Valley Fill Sandstone. Both sections are divided by a low-stand erosional surface where above the surface is the Valley Fill Member and below is the Bell Creek member. Bell Creek field is divided into nine different injection units based on how the incised valley split up the field for the purpose of water flooding. Deposition of the Muddy Sandstone is a combination of an incised valley with tidal flats that make up the valley fill in the Valley Fill member. The Bell Creek Section is mostly quartz-arenite sandstone with excellent reservoir quality characteristics while the Valley Fill member is a mixture of reworked Bell Creek Sandstones, siltstones and shales. Stratigraphic pinchouts are the main trapping mechanism for the field and make it very desirable for oil and gas production. Understanding the depositional environments throughout the field will help to understand the compartmentalization of the field and where best to inject carbon dioxide for further increase in oil production.

Thin Section observations and XRD analysis show that the Bell Creek Sandstone has more pore space and is quartz dominated. The Valley Fill member is more clay dominated and the pore space is filled with clays and organic material. The areas with the best potential production for future production are those with the thickest amounts of foreshore deposits in the Bell Creek Sandstone such as areas four, five and six. These areas were historically the producing areas after waterflooding as well. They also have more area for carbon dioxide to move laterally compared to the areas on the eastern side of the field which are hindered by the Valley Fill. Further injection of carbon dioxide into the field should be focused on areas five, six, and eight based on porosity, OIP, and Bell Creek Sandstone thickness.

## **Enhancing Visual Core Descriptions in Mixed Fine-Grained Lithologies with Machine Learning: A Greenhorn Formation Case Study**

**Christopher C. Matson**, PhD Candidate, Department of Geology and Geological Engineering, CSM

### **Abstract**

The process of visual core description, essential in geological studies, is hindered by its manual and time-intensive nature. Variability in core descriptions also arises as geologists may emphasize different characteristics. This study introduces an innovative approach that combines dual-mode core imaging (white light and ultraviolet (UV) reflected light) with machine learning (ML) to automate and standardize the analysis of mixed compositional, fine-grained lithologies in cores from the Upper Cretaceous Greenhorn Formation in the Denver Basin. A Convolutional Neural Network (CNN) trained on high-resolution images under white light and UV from four annotated cores was developed to classify bulk mineralogic composition, grain size (notably foraminifera size and density), sedimentary structures, and facies boundaries. This model was then tested on unclassified cores from the same stratigraphic interval to assess its ability to automate core descriptions. The use of dual-mode imaging significantly improved the model's ability to distinguish geological features, particularly enabling the precise identification of bentonite facies and residual hydrocarbons through fluorescence signals under UV light.

Preliminary results show promising accuracy, achieving approximately 80-90% for clearly distinguishable facies such as the lighter-colored, carbonate-dominated "chalk" facies and the siliciclastic mudrock facies varying from light to dark gray in the Bridge Creek Member. However, identifying subtle differences within fine-grained siliciclastic rocks and marls, such as those in the Hartland Shale Member, presented challenges. The primary difficulties were differentiating closely related facies and accurately determining foraminifera density, attributed to the high variability in their visual appearance.

Future research will investigate advanced CNN architectures and enhanced data augmentation techniques to improve the precision of facies classification and the detection of subtle geological features. This includes better distinguishing grain-size variations and sedimentary structures, such as distinguishing between current and wave ripple laminae. The study will also consider expanding the training dataset to encompass a wider range of lithologies and depositional environments, including those found in the adjacent Graneros Shale and Carlile Shale formations. The success in identifying bentonite facies using the UV-enhanced dataset highlights the model's effective use of both imaging modes, showcasing a significant leap in applying ML to core description tasks, especially for features not easily observed under standard lighting.

This methodology demonstrates ML's potential to significantly aid core descriptions of fine-grained lithologies, offering a scalable, consistent, and efficient solution for sedimentological studies and hydrocarbon exploration. Employing dual-mode imaging markedly reduces manual analysis, facilitating rapid description of extensive core collections. This approach not only yields detailed digital records that enhance research integration but also aids in preserving the physical core archives for future investigations.

## **CCUS Potential for the Niobrara A and B Intervals at Redtail Field, Weld County**

Chris Beliveau, M.Sc. Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

Carbon capture, utilization, and storage (CCUS) is the process of capturing carbon dioxide (CO<sub>2</sub>), injecting it into reservoirs to enhance oil and gas production, and safely and permanently storing it in the subsurface. This process has become more common in the oil and gas industry both as a technology to enhance production, and for companies to work towards carbon neutrality. While carbon capture, and storage (CCS) has sometimes garnered more attention, carbon capture, utilization, and storage (CCUS) is more attractive as it offers the additional economic incentive of increased hydrocarbon production as primary and secondary oil and gas recovery methods can still leave up to ~80% of oil in the reservoir. CCUS is used for enhanced oil recovery and can be a more effective technology for recovering additional hydrocarbons with the added benefit of safely sequestering CO<sub>2</sub> in the subsurface. CCUS is continuing to expand and has the potential to capture ~6GtCO<sub>2</sub> per year by 2050.

The Niobrara System was deposited in the Western Interior Cretaceous Seaway (WICS) during the Late Cretaceous by a series of sea level transgressions and regressions. Carbonate deposition in the WICS was controlled by cooler, oxygen-rich water from the north, mixing with warmer, oxygen-poor water from the south. In the Denver-Julesburg Basin, the carbonate-rich Niobrara A and B chalk beds exhibit favorable petrophysical properties for hydrocarbon production with increased resistivity and porosity. Consequently, they have both been extensively produced in recent years, and it is important to evaluate this reservoir as a potential CCUS target.

Core data from the Razor 25-2514H well in Redtail Field was evaluated to determine if the Niobrara A and B could be a viable CCUS target. Porosity and permeability measurements combined with production flow and injection treatments of CO<sub>2</sub> acting on the core plugs to replicate primary and EOR production were used to determine if the reservoir properties in the Niobrara A and B are favorable for CCUS. Results from the Redtail Field study area can then be applied to other fields in the Denver-Julesburg Basin leading to increased hydrocarbon recovery and the safe storage of CO<sub>2</sub>.

## **FMI and Facies Analysis of the Codell Sandstone in the Redtail Field, North-Central Denver Basin**

Sean Rascoe: MS Student, Department of Geology and Geologic Engineering, CSM

### **Abstract**

The middle Turonian (Upper Cretaceous) Codell Sandstone Member of the Carlile Shale is one of many petroleum producing sedimentary units within the Denver-Julesburg Basin. The Codell Sandstone is comprised of porous, very fine- to upper medium-grained silt and sandstones that can behave like a hybrid reservoir. The Codell Sandstone was deposited above and below the storm weather wave base along the western margin of the Western Interior Seaway. Storm events are recorded as discrete sequences of hummocky cross-stratified sands that grade vertically into planar to low-angle planar laminations often followed by a return to normal marine mudrock sedimentation.

Within this study, six cores penetrating the Codell Sandstone have been described and analyzed to identify storm sequences within the Redtail Field in north-central Colorado, USA. In total, 7 facies were determined from core aided by thin section analysis. and correlated across the field to determine storm deposited units within Redtail Field. A total of 4 storm units and 3 low energy units were identified and relative energy applied to quantify storm energy and strength.

A total of 222 strike and dip picks were obtained from the FMI log analysis which characterizes a primary SE paleocurrent from the low-angle planar laminated sandstone, rippled sandstone, and bed boundaries while the cross stratified sandstone shows to be more random.

Lorenz plots were made which characterize the Codell Sandstone at Redtail Field using porosity and permeability as a function of flow quality characteristics. Flow quality was applied to facies and the low-angle planar laminated and massive sandstone have the best quality flow characteristics whereas the bioturbated sandstone, rippled sandstone, and massive mudstone have the lowest quality flow characteristics. The lack of good flow characteristics of mud-rich facies indicate that they are barriers to hydrocarbon flow. The portion of the reservoir with the best flow characteristics is the middle to middle lower (4 to 8 feet) Codell Sandstone within storm unit 2 and 3.

## **Gas Occurrence and Petroleum System of Biogenic Gas Play in the eastern part of the Denver Basin**

**Wittaya Imurai**, MS Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

Natural gas is one of the most important energy resources around the world. This natural gas can be separated into two origins, which are the thermogenic origin and biogenic origin. Thermogenic gas is the most common reserve worldwide, which is 85 percent of conventional gas reserves worldwide. On the other hand, the rest of the natural gas reserves have a biogenic origin.

The petroleum system of biogenic play in the Eastern part of Denver Basin was proved. The produced gas in the Beecher Island field has a low carbon isotope ratio in the methane sample and also a very high ratio of dry gas. This aligns with maturity data from high TOC marl intervals in Niobrara formation and overlying shale from Sharon Springs Member.

For reservoir properties in this play, all of the biogenic gas accumulated in Niobrara "A" Chalk. This rock layer is composed of pellets and foraminifera. These pellets are the primary source of porosity in Niobrara A Chalk, as pellet grains and carbonate rock. Moreover, A Chalk from the Niobrara Formation also has a fracture as secondary porosity but is mainly filled with gypsum. So, the permeability of this reservoir is relatively low (0.1-1 mD.)

The structure in the Eastern part of the Denver Basin is a gentle dipping bed to the west direction. However, some areas have a small structure closure for biogenic gas to accumulate in structure high. All of these closures are expected to relate to the dissolution of underlying Permian salt. The great thickness of impermeability of the Sharon Springs shale layer that covers all of Niobrara Formation as a regional seal makes the structural trap type in the Eastern part of the Denver Basin a success.

As discussed above, most of the petroleum system elements of biogenic gas plays in the eastern part of the Denver Basin were analyzed and defined. However, it still has some room for improvement and an unknown factor that will help unlock petroleum potential in this area. One of them is the type of source rock analysis. As the origins of primary and secondary biogenic gas differ, knowing the type of biogenic gas will help geologists understand the subsurface conditions for bacteria that are associated with biogenic gas and also target biogenic gas potential areas that are associated with the limitation of source type and bacteria conditions.

## **Reservoir Characterization of the Deadwood Formation, Williston Basin**

Gabrielle Bennett: M.S. Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

Over the past few decades, the Cambro-Ordovician-aged Deadwood Formation in the Williston Basin has been studied by many researchers for the purpose of oil and gas exploration and alternative energy potential. Research on the Deadwood Formation is mainly restricted to the subsurface, with the only outcrop exposed in the Black Hills of South Dakota. Despite decades of petroleum exploration and development in the Deadwood Formation, research shows that the Deadwood Formation's conventional hydrocarbon reservoirs are not as lucrative as previously understood. Consequently, researchers are now focused on using these basal siliciclastic sands for emerging renewable energy sectors such as carbon capture, utilization, and storage (CCUS) and sedimentary geothermal energy resources.

Geothermal exploration in the Deadwood Formation is already underway in the northern part of the Williston Basin in southern Saskatchewan by the company called DEEP Earth Energy Production Corporation and various other researchers. This study is focused on determining the geographic extent of geothermal prospectivity in the Deadwood Formation near the North Dakota/ Saskatchewan border. The research will be accomplished by combining traditional hydrocarbon reservoir characterization techniques such as FE- SEM analysis; well log-based petrophysical analysis, core descriptions, XRF methods, and geothermal exploration methods such as isotherm mapping. The key outcome of this detailed reservoir characterization research will be to improve the understanding the geothermal potential of this rock unit within the specific study area, along with identifying key reservoirs for various geothermal energy development. Achieving these goals will help to advance and encourage geothermal energy development in basal siliciclastic reservoirs within sedimentary basins that lack significant heat flow from active volcanism.

## **Cause of Geothermal Temperature Anomalies in Wattenberg Field: Unraveling the Impact of Hydrothermal Fluid Movement in the Lyons Formation**

Melia Eaton: M.S. Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

The Wattenberg Field temperature anomaly solidified the field as the largest hydrocarbon producer in the Denver Basin and has spurred industry interest in using the field for geothermal energy and CCUS. While the presence and impact of the hot subsurface temperature anomaly is known, the cause of the anomaly is not. This study proposes that heat from northeastern Colorado Mineral Belt intrusions was conducted to reservoir rocks in the Greater Wattenberg Area via the subsurface circulation and migration of hydrothermal fluids along field-wide fault zones. Using core description, XRF, thin section microscopy, and FESEM analysis, pervasive hydrothermal fluid-rock interaction was observed in the Permian Lyons Formation. The Lyons Formation is the host of various ore minerals that are found to have been emplaced and nucleated in-situ: 1) low temperature (125°C-175°C) sulfides pyrite, marcasite, sphalerite and galena; 2) intermediate temperature (125°C-225°C) sulfarsenides of the Co-Ni-As-S system, including gersdorffite, nickeline, and clinosafflorite; and, 3) the high temperature (>225°C) sulfide chalcopyrite. Ore mineral emplacement is accompanied by various intermediate temperature (>150°C-200°C) gangue mineral alteration types such as albitization, dedolomitization, and generation of Fe-Mg-metal-rich clays.

Spatial relationships between ore minerals of differing temperature regimes indicate that at least three episodes of hydrothermal mineralization occurred. By comparing the timing of northeastern CMB intrusions with the timing of dissolution-reprecipitation events in the Lyons, hydrothermal interaction is interpreted to have occurred in Wattenberg Field from the late Paleocene to late Miocene. Long-term heat conduction between hydrothermal fluids and the Greater Wattenberg Area sedimentary succession was facilitated by the high thermal conductivity of the Lyons Formation (3.56 Wm-1K-1) and maintained by the thick, insulating Mesozoic sedimentary succession – ultimately causing the Wattenberg Field temperature anomaly.

Hydrothermal fluid-rock alteration begets critical implications for CCUS and geothermal activity in Wattenberg Field. Operators should investigate potentially detrimental chemical reactions that could occur between sequestered gases, sulfides, and sulfarsenides. Geothermal system designs should account for potential dissolution and remobilization of cementing metals that could alter reservoir characteristics and release metals to the groundwater supply. Overall, understanding the distribution and impact of hydrothermal alteration will improve energy exploration strategies in the Greater Wattenberg Area.

## **Geothermal Mapping on the Texas Gulf Coast**

Eric Stautberg: PhD. Candidate, Department of Geology and Geological Engineering, CSM

### **Abstract**

Accurate formation temperature is a pivotal part of geothermal resource assessments in sedimentary basins. Bottom-hole temperature (BHT) measurements from well logs are an abundant data set in these basins but are also notoriously unreliable because of several reasons such as the vintage of the measurement, type of tool used, ambient surface temperature at the time of logging, thermal properties of the drilling mud, time since circulation (TSC), rate of penetration (ROP) while drilling, human error, and the thermal conductivity of the formation and formation fluids (oil, natural gas, or brine) where the temperature is measured. Consequently, BHT correction methods vary depending on the basin and available data. In south Texas, where oil and gas wells dominate the landscape, the Waples correction method is commonly used because it incorporates TSC data and ambient surface temperature to correct for the cooling effects of drilling mud on the formation while the well was being drilled.

A 12,500 square mile area in south Texas was designated for BHT correction and temperature-depth mapping because it contains most of the key sedimentary geothermal elements of the Texas Gulf Coast. These elements include: 1) the location of geopressured reservoirs in Paleogene formations, 2) the location of the Aptian and Albian shelf margins, 3) the type of transitional crust beneath the sedimentary section, 4) the location of salt diapirs, and 5) the shallowest depth to 250° F in Texas. To help identify geothermal play types in the Cretaceous strata of south Texas, BHT measurements from 826 wells north of the Aptian and Albian shelf margins were corrected for temperature-depth mapping. Of these 826 wells, 272 had TSC data and were subsequently corrected using the Waples BHT correction methodology. This method resulted in an average temperature increase of 19.63%, which aligned with temperature measurements from cement bond logs, drill stem tests (DSTs), and regional BHT correction studies completed by other researchers. This 19.63% increase was then applied to the remaining 554 wells that lacked the TSC data needed to properly correct BHTs for those wells.

Corrected BHT measurements for all 826 wells were then used to calculate a temperature log from the surface to the total depth of each well. Using Petra cross section and mapping software, temperatures were correlated from well to well across the research area at 25° F increments from 250° F to 400° F. This methodology resulted in two important products for geothermal play type identification: 1) a high-resolution series of temperature-depth maps for play fairway identification and 2) a set of temperature logs that can be incorporated into petrophysical analysis for temperature-based reservoir characterization calculations.

## Potential for Enhanced Oil Recovery in Permian Wolfcamp and Elsewhere

Ozan Uzun: Ph.D. Candidate, Department of Petroleum Engineering, CSM

### Abstract

The Greater Permian Basin includes both conventional and unconventional oil production. While Permian's conventional oil production (via primary, secondary, and enhanced oil recovery) has been very successful over the last half a century, the average primary oil production from its unconventional resource is about 5%. Obviously, because of the enormous remaining oil in the Permian, there is a need for formulating robust and cost effective EOR methods for the Permian unconventional production (e.g., Wolfcamp). This research addresses this issue by providing insights into promising EOR mechanisms based on laboratory and field observations.

We have conducted wettability alteration measurements for a typical surfactant and a simple mutual solvent in the Wolfcamp using Drop Shape Analyzer (DSA) at reservoir temperature and pressure conditions. *We have used these results to explain whether wettability alteration or other mechanisms results in improved oil recovery for Wolfcamp shale reservoirs.* These results and the associated mechanisms are the basis for the favorable outcomes of three recent field EOR pilot tests.

Lab results indicate that temperature significantly affects water-oil contact angle, while pressure has a minor impact. Mutual solvents show minimal contact angle change under standard and reservoir conditions. *However, the effect of mutual solvents on improving oil recovery are based on a different mechanism that entails mass transfer due to mutual solubilization both in water and in the oil phase.* For surfactants, even small amounts of surfactants notably change contact angles on core surface and reduce IFT dramatically, especially in low salinity solutions. *Oil mobilization by surfactants is by wettability alteration and micelle formation at the oil-water interface.*

We present laboratory wettability alteration measurements using a very small concentration of a non-ionic surfactant and a mutual solvent for the Wolfcamp formation. The experimental results are used to explain why the use of low concentration surfactants and specific mutual solvents enhance oil recovery via the perceived wettability. As indicated earlier, these laboratory results shed light on why three recently reported field pilot tests have shown great promise for cost-effective EOR in unconventional shale reservoir.

## **Numerical Basin Modeling and Multi-resource Potential of the Alaska North Slope Basin**

Rand Gardner: Ph.D. Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

A 3D numerical basin model is being developed for the Alaska North Slope Basin. This basin covers approximately 170,000mi<sup>2</sup> including the Colville Basin, continental terraces of the Beaufort and US Chukchi Seas, and is bordered by the Brooks Range to the south. This basin is dense in hydrocarbon resources and wholly contains the National Petroleum Reserve of the United States and has a complex history consisting of four tectonostratigraphic sequences: (1) a Devonian and older basement complex that was part of a foreland basin along the northern margin of Laurentia. (2) A Mississippian to Triassic south-facing rifted passive margin. (3) A Jurassic to Lower Cretaceous north-facing passive margin that coincides with (4a) a foreland basin succession resulting from an arc-continent collision to the south. (4b) a Cenozoic succession filling the foreland basin and being deformed by tectonism from the northeast. Within this framework, twenty four units have been identified and are being mapped and modeled as distinct depositional episodes. The surfaces and lithologic inputs for the model are data being compiled from well logs, cores, and seismic data. The calibration data is being compiled from well bottom hole temperatures, drill stem tests, mud weight, and vitrinite reflectance measurements. Four key source rocks were identified that will be characterized and modeled: the Middle Triassic Shublik, Jurassic-Lower Cretaceous Kingak Shale, and the Cretaceous Pebble Shale and Hue Shale formations. The expected result is a calibrated 3D basin model of the Alaska North Slope Basin that predicts pressure, temperature, and maturity which will be used to assess the geothermal, CO<sub>2</sub> storage, and unconventional hydrocarbon potential of the basin.

## **Origin of Dolomite in the Late Devonian Upper Three Forks Formation, Fort Berthold Indian Reservation, North Dakota**

Lauren Bettinger, MS Student, Department of Geology and Geologic Engineering, CSM

### **Abstract**

Dolomite comprises many of the world's substantial carbonate hydrocarbon reservoirs, as the origin of dolomite and dolomitization process play an important role in reservoir quality. Deposited during the Late Devonian in a subtidal to intertidal environment, the dolomitic upper Three Forks Formation is an unconventional hydrocarbon reservoir of the Bakken Petroleum System in the Williston Basin. While the upper Three Forks is known to have a large presence of dolomite, there has been little research on the origin of the dolomite. Thin section petrography observations from previous work have suggested the presence of strictly diagenetic dolomite and strictly detrital dolomite. However, overlooking the possibility of a detrital origin for the dolomite overestimates the degree of dolomitization that occurred, which is an important factor that affects overall reservoir quality.

Five cores and their associated thin sections from wells on the Fort Berthold Indian Reservation in Dunn and McKenzie counties will be examined in detail for this study. Danks 17-44H, Hognose 152-94-18B-19H-TF, Henry Bad Gun 9C-3-1H, Pumpkin 148-93-14C, and Roberts Trust 1-13H-TF are the key wells for comparing whether dolomite formed in an authigenic, diagenetic, or detrital process. In addition to core descriptions, tools such as a cathodoluminescence (CL) microscope and a scanning electron microscope (SEM) will also be utilized for study of the thin sections, as dolomites are not as easily distinguished in basic thin section petrography. These resources will provide clearer evidence of overgrowths, dissolution, replacement, recrystallization, and cementation that may have affected the reservoir properties of the rock.

Based on thin section microscopy, core descriptions, CL petrography, and SEM analysis, this study aims to determine the origin of dolomite in the upper Three Forks, as well as recognize other minerals and diagenetic processes that are in play in the upper Three Forks Formation. Results from this study will provide more insight into this productive unit for future research and production. Furthermore, these findings will supplement data and observations to the ongoing discussion over the complex subject of dolomite. Better understanding of paragenesis will help to unlock the estimated 2.4 million barrels of oil and 2.9 billion cubic feet of gas that the latest USGS resource assessment suggests still technically recoverable from the Three Forks Formation.

## **CCS Potential in Lyons Formation in Redtail Area, Denver Basin**

**Rashed Alzahrani**, MS Student, Department of Geology and Geological Engineering, CSM

### **Abstract**

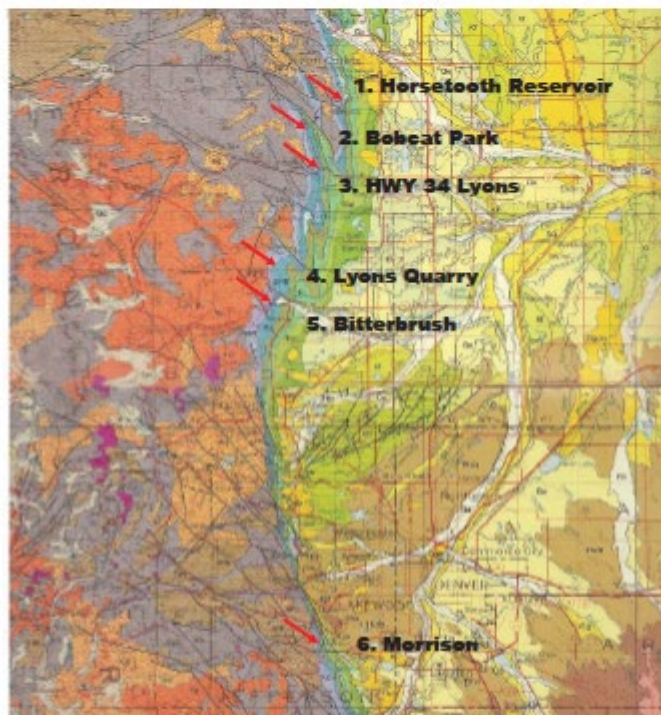
The Lyons Sandstone is a Permian aged formation, located in northeastern Colorado within the Denver Basin. It is exposed along the Front Range of Colorado and extends throughout the Denver Basin. The Lyons consists of quartz-rich sandstone, shale, and siltstone layers. The deposition of the Lyons Sandstone is predominantly influenced by wind processes in an eolian depositional environment. This results in the formation of variable thicknesses of cross bedded sandstone dune facies, along with dry and wet interdune facies. The Lyons also shows predominant high permeable and porous sandstone that is known to be an important hydrocarbon resource in the area. The unique textural characteristics of the Lyons Sandstone make it highly suitable for storing significant volumes of CO<sub>2</sub> within its subsurface pore spaces.

In order to assess the feasibility of CO<sub>2</sub> storage, the study will utilize diverse datasets from the Red-tail area. This includes petrophysical data from both vertical and horizontal wells, core samples, and fluid samples. The aim is to comprehensively characterize, evaluate, and assess the reservoir's potential for CO<sub>2</sub> storage.

## Spring Field Trip--April 26<sup>th</sup> Lyons Sandstone

### Lyons field trip stops

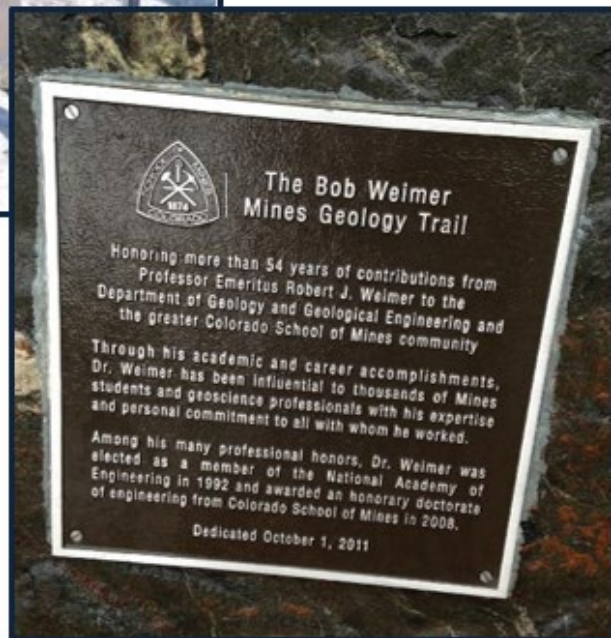
- Horsetooth Reservoir, South Bay campground, Horsetooth information Center
  - 7-7N-69W
- West Masonville/Bobcat Park: Stratigraphic overview of Fountain-Ingleside-Lyons (poor parking, drive-by)
- HWY 34 Roadcut: Thick Lyons with large dune foresets.
  - 12-5N-70W, west of Loveland
- Lyons Quarry
- South Lyons/Bitterbrush Trailhead
- Morrison Lyons/Elementary School: Fluvial Lyons



# BOB WEIMER MINES GEOLOGY TRAIL

## ACCESSIBILITY IMPROVEMENT CAMPAIGN

LEAD BY THE CSM AAPG STUDENT CHAPTER



**SEEKING FUNDS TO IMPROVE STUDENT ACCESS TO THE GEOLOGY TRAIL AND  
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**FOR MORE INFORMATION, PLEASE CONTACT STEVE SONNENBERG [SSONNENB@MINES.EDU](mailto:ssonnenb@mines.edu)**

