COLORADO SCHOOL OF MINES

COLORADO SCHOOL OF MINES

MUDTOC

SPRING 2023 SPONSOR MEETING & FIELD TRIP

APRIL 27-29, 2023 • BEN PARKER STUDENT CENTER • BALLROOMS D & E

MUDTOC CONSORTIUM

SPRING 2023 SPONSOR MEETING

Meeting: Thursday, April 27, 2023

– Via ZOOM Invite & In-Person CSM Student Center Ballrooms D&E

Southern Denver Basin Field Trip: Friday, April 28 – Saturday, April 29, 2023

– Transportation from Mines' campus and lunches provided.

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

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

MUDTOC Consortium Sponsors – Spring 2023

Antero Resources

Civitas Resources

Chevron

Coterra Energy

EOG Resources

Fundare Resources

GMT

Halliburton

Helis Oil/Boomtown Oil/North Silo Resources LLC

Occidental Petroleum Corp.

Red Willow Production Company

TGS

Supporting Companies

Enverus

GeoMark

IHS

MJ Systems

Platte River Associates

Schlumberger

MUDTOC Research Faculty

Dr. Steve Sonnenberg, CSM – Principal Investigator

Chris Matson, PhD Student, Research Coordinator

Meeting Agenda

1:30 – 2:35 PM	**Geothermal Studies**

2:40 – 3:00 PM:	**BREAK**

3:00 – 3:45 PM:	**Permian Basin**

3:50 - 4:05 PM	**New Student Introductions**

Field Trip Agenda

Southern Denver Basin Field Trip - Florence, Cañon City and Pueblo Areas

Friday, April 28 – Saturday, April 29, 2023

Featuring world-class outcrops of the Dakota, Graneros, Greenhorn, Carlile (Juana Lopez & Codell), Fort Hays, Niobrara and Pierre (Sharron Springs) formations

Schedule

DAY 1

Friday, April 28, 2023

8:00 AM	Meet at Berthoud Hall loading area @ 8:00 AM
Stop 1	Turkey Creek
Stop 2	Sharon Springs
Stop 3	Rockafellow Park: Greenhorn, Carlile, Juana Lopez, Codell, Niobrara
Stop 4	Tepee Buttes, Boone, CO area
End	Evening at Hampton Inn Pueblo (1-719-543-6500).

DAY 2

Saturday, April 29, 2023

8:00 AM	Meet at Hampton Inn @ 8:00 AM
Stop 5	Lake Pueblo State Park (Lake Pueblo). Graneros-Greenhorn outcrops Railroad cut showing Bridge Creek & Hartland Shale Members.
Stop 6	Pueblo Nature Center Codell, Fort Hays, Niobrara C chalk and marl
Stop 7	Liberty Point: Codell, Carlile, Fort Hays
End	Return to Berthoud Hall ~5:00 PM

Note: Transportation from Mines' campus and lunches provided. Participants are responsible for accommodation, other meals, and all other necessities. Vans with collect at Hampton Inn, 4790 Eagleridge Cir, Pueblo, CO 81008, (719) 543-6500. Please contact matson@mines.edu if you have any accessibility concerns.

Origin and Stratigraphy of Enigmatic Sandstones of the Cretaceous Western Interior Seaway: the Late Turonian Wall Creek-Turner System, Powder River Basin, WY

Patrick Sullivan, PhD. Student, Department of Geology and Geological 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. One such unit, the Wall Creek-Turner system, consisting of the upper Turonian Wall Creek Member of the Frontier Formation and the coeval Turner Sandy Member of the Carlile Shale, is the most productive reservoirs of the Powder River Basin in Wyoming, yielding 65% of gas and over 50% of the basin's oil production in the past decade.

Despite the economic importance and decades-long publication history on the Wall Creek Turner System, the unit remains poorly understood due to a lack of regional studies on shelf-isolated sand bodies and documentation of sedimentary processes within the system. This uncertainty hinders paleogeographic reconstructions, causing maps of the Late Turonian system to look significantly different based on which depositional model for the system is used and precludes a basin-wide predictive framework for reservoir quality.

The objective of this study is to characterize the facies distribution, provenance and chronostratigraphic relationships of the Wall Creek-Turner system across the Powder River Basin. Detailed descriptions of over 40 cores and 20 outcrops tied to well logs across the nearly 150-mile-wide basin, in tandem with newly acquired CA-IDTIMS U-Pb geochronology data on ash beds and LA-ICPMS analysis on detrital zircons, will resolve long-standing uncertainties surrounding the paleogeographic evolution of the Turonian Western Interior Seaway and provide insight into the distribution and depositional controls of productive shelf-isolated sandstone reservoirs in the western U.S.

Reservoir Characterization of the Shannon Sandstone, Southwestern Powder River Basin, Wyoming

Rebekah Parks, MS Student, Department of Geology and Geological Engineering, CSM

Abstract

The Upper Cretaceous (early Campanian) Shannon Sandstone Member of the Cody Shale is an unconventional stratigraphic play in the southwestern part of the Powder River Basin in Wyoming, USA. Despite decades of petroleum exploration and analysis, varying interpretations of the Shannon Sandstone depositional environment remain. These include a shelf sand ridge complex, prograding shoreface, or incised valley fill. The Shannon Sandstone near Pine Tree Field is less well studied than the nearby Hartzog Draw and Jepson Holler Draw Fields. To address this, this study includes detailed analysis of nine cored wells and 27 wells with core associated reservoir property data across these fields in Johnson and Campbell Counties and subsurface analysis across the area.

Key outcomes of this detailed geologic reservoir characterization study include evidence that the Shannon is a heterolithic shelf current dominated marine sand with occasional tidal and wave influence, identification of the highest quality reservoir facies where fluid flow is mappable at a field level, and insight into the potential for future development in the area. A core to field scale study facilitates the understanding of lateral changes within the Shannon. This increased understanding of the depositional environment has broad implications for the geologic evolution of the basin as a whole.

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

The Lower Cretaceous Muddy Sandstone in Bell Creek Field is currently going through enhanced oil recovery (CO_2 injection). The Muddy Sandstone is divided into two separate intervals with the lower being the Bell Creek Sandstone member and the upper being the Valley Fill member. They are divided by a low-stand surface of erosion (LSE) that is present throughout the entire Bell Creek Field. The Bell Creek Sandstone is the main producing interval of the Muddy Sandstone and the Valley Fill member acts as the lateral and vertical seals.

An incised valley has eroded away most of the barrier island sequence, traverses through Bell Creek Field and has divided up the field into compartments. This erosion has created compartmentalization within the field restricting the lateral flow of fluids within the field. There are many depositional and structural heterogeneities throughout the Muddy Sandstone that create different flow compartments. A lot of these heterogeneities are a result from depositional setting and structural framework of the field on a large and small scale. Reservoir characterization of the separate areas of the field reservoir will help determine the best areas to inject carbon dioxide for future enhanced oil recovery within Bell Creek Field.

The Geological Reservoir Characterization and Assessment of Reservoir Deliverability for Unconventional Niobrara and Codell Reservoir Targets within the Hereford Field Area, Weld County, Colorado

Chad Taylor, M.Sc. Student, Department of Geology and Geological Engineering, CSM

Abstract

The Hereford Field lies in the north-central Colorado portion of the Denver Basin, approximately sixty miles northeast of the prolific Wattenberg Field. Hereford gained notoriety in 2009 when the 18-stage Niobrara completion of the EOG Resources Jake #2-01H averaged more than 49 MBO during the first three months of production. Such a large volume of oil production in a short period proved that chalk lithofacies within the Niobrara Formation had significant potential as a viable unconventional resource play in the Denver Basin.

Drilling and completion methodologies employed in the Hereford Field have quickly evolved since the completion of the Jake well in 2009. The post-2015 redevelopment operations incorporate cemented pad-drilled laterals (XRL and SRL) utilizing high-volume plug and perf completions, mirroring designs employed in the contemporary generation of unconventional Niobrara and Codell wells drilled and completed with great success in the Wattenberg Field.

Niobrara and Codell reservoir quality within the Hereford Field appears regulated by the abundant fracturing associated with the adjacent E / NE trending paleo structure, the Morrill County High, which bounds the northern extent of the Hereford Field area. Fracture development and reservoir fluid dynamics appear linked to episodic reactivation of sheer-driven faults and the extensive layer-bound normal fault system formed during the deposition of the overlying Pierre Shale. Furthermore, the structural complexity combined with the area's complicated depositional and compactional histories has added an extra layer of reservoir heterogeneity observed in well-produced fluids throughout the Hereford field.

The Niobrara B (B2) Chalk lithofacies and the Codell Sandstone are the primary reservoir targets within the Hereford area. As of October 2020, cumulative production from all unconventional wells within the Hereford Field study area exceeded 13.3 MMBO, 18.6 BCF, and 12.7 MMBW.

This study incorporates both vertical and horizontal well petrophysical data, fluid/sample geochemistry, lateral formation image logs, petrographic analysis, and legacy well production data located throughout the greater Hereford Field area to facilitate an integrated interpretation of controlling properties that govern unconventional reservoir quality and deliverability in the Hereford Field.

Chemostratigraphy of the Greenhorn Formation in the Greater Wattenberg Area, Denver Basin, Colorado.

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

Abstract

The prominent, rhythmically bedded limestones and marls of the Upper Cretaceous Greenhorn Formation were deposited during the maximum aerial extent (T6 transgression of Kauffman) in the Western Interior Sea. These units are traced extensively throughout Central North America. High global sea levels and enhanced ocean connectivity due to increased tectonism and eruptions of Large Igneous Provinces occurred amid persistent global hothouse conditions. The result was a ~600 ka perturbation in the worldwide carbon cycle called Ocean Anoxic Event 2. However, marine sediments deposited during this interval were not uniformly anoxic, especially in the relatively shallow, epeiric ocean of the Western Interior Sea of North America. Sediment supply strongly controlled deposition, with the lime-rich units deposited during times of lowered precipitation, reducing runoff and starving the basin interior of sediment. The Greenhorn exhibits a high degree of facies variability and heterogeneity. The basal Lincoln Limestone Member is organic-rich (average TOC 2.77 wt%) with a higher argillaceous content (average 6.20 % Al) and is the least carbonate-rich (average 11.5 %). The middle Hartland Shale Member is the most lithologically variable unit with more well-developed carbonate-marl interbedding with little terrigenous sediment accumulation. The Hartland has the second highest organic matter content (average 2.12 wt% TOC), becoming less organic-rich towards the top of the unit. Argillaceous content is highly variable, and diagenetic carbonate is more prevalent in the middle of the Hartland interval. The upper Bridge Creek Limestone Member contains OAE 2 and has distinct upper and lower informal divisions based on facies presence and increasing facies variability upwards until the conspicuous, 0.5-2.0 ft interbedded lime-marlstone couples become dominant. The environment of deposition is dominantly pelagic throughout the Bridge Creek; however, more terrigenous-dominated facies in the lower informal unit suggest a shift from the latest transgressive interval to an aggregational to early progradational eustatic phase. The presence of wave- and current-ripple lamina associated with these facies implies that storm-driven currents may have effectively transported detrital material to these distal pelagic environments. The Bridge Creek Members is the least argillaceous (average 2.41% Al) and organically lean (1.21 wt% TOC) of the Greenhorn. The thin-bedded and organically lean Bridge Creek may also be a poor seal without the overlying Graneros Shale Formation despite the relatively high-quality source rock potential of the Greenhorn Limestone as a whole.

Integrating Full-Bore Formation Micro-Imager (FMI) Data for Niobrara & Codell Reservoir Characterization, Postle Area, Wattenberg Field, Colorado, USA

Eric Hillman, MS Student, Department of Geology and Geological Engineering, CSM

Abstract

Late Cretaceous Codell Sandstone of the Wattenberg field was derived from a major deltaic source and was deposited on the seafloor of the Western Interior Seaway (WIS) by waxing and waning shelf currents. Above the Codell Sandstone, the Niobrara Formation lithologies represent periods of fluctuating sea-level conditions resulting in depositing chalks, marls, sandstones, and shale cycles. The Wattenberg Field is located in the Denver-Julesburg (DJ) Basin in northeast Colorado, north of Denver across the axis of the Denver Basin, and covers approximately 81 townships.

The Wattenberg field development and production started in 1970, with the majority of production coming from vertical drilling of the Lower Cretaceous J Sandstone. The Upper Cretaceous Niobrara and Codell formations became important producers in the 1980s. In addition, production in the Wattenberg is found in Dakota, D Sandstone, Greenhorn, Terry, and Hygiene. Continuous hydrocarbon accumulations is common throughout the field. The Wattenberg gas field is one of the largest natural gas fields in the United States, with resource estimates from the Niobrara being approximately 3-4 billion barrels equivalent (BBOE).

Faulting in the Wattenberg field is primarily basement-controlled, right lateral wrench fault zones with secondary faulting in between the wrench fault zones. Originally the basin axis was oriented north-south (N-S), but the Denver Basin axis was shifted because of the wrench fault zones that crosscut the Wattenberg field. The wrench fault zones of the Wattenberg Field can be associated with maximum compressional stress-oriented east-west (E-W) on a horizontal plane. The wrench fault zones will be a key driver of fracture formation, and potentially oil and gas migration within the Wattenberg field. In this study, detailed fracture characterization of the Codell and Niobrara Formations will be performed, which will help characterize both natural and induced fractures within these formations. Formation micro-resistivity image (FMI) log interpretation indicates a strong orientation preference created through hydraulic stimulation and can assume that the present-day stress orientation is not a result of reorientation due to production and stimulations. Interpretation of the image log data can establish the spatial geometry of the natural fractures within the wells and will help characterize the fractures that help produce hydrocarbons by hydraulic stimulation.

Reservoir Characterization and Quality of the Codell Sandstone, NE Silo Field Area

Matt Keator, MS Student, Department of Geology and Geologic Engineering, CSM

Abstract

The Turonian-aged Codell Sandstone member of the Carlile Shale Formation is a hydrocarbon bearing shaley sandstone that has been interpreted as a regressive, shelf sand deposit that has been reworked by storm waves in the Cretaceous Western Interior Seaway. The Codell Sandstone behaves as a low resistivity pay zone suppressed by the presence of clays and pyrite. Production out of the Codell Sandstone began in northeastern Colorado out of Wattenberg Field in the early 1980’s and has expanded north into southeast Wyoming. The Codell Sandstone is an unconventional tight sand reservoir that has been targeted in Silo Field approximately 20 miles northeast of Cheyenne, Wyoming within Laramie County and is the focus of this study. Structure maps indicate that the Codell Sandstone is approximately 7500 – 9000 feet TVD in the field, whereas isopach maps indicate a thickness of approximately 25 – 35 feet. The Codell Sandstone is 32 feet thick from a core taken from the Helis Cain 16-63-2-11-1CH well and was the targeted formation.

Geochemical analysis of produced oils from the Codell Sandstone and extracted hydrocarbons from the Niobrara C Marl and Greenhorn Limestone indicates a marine shale source from the Graneros Shale, Greenhorn Limestone, or Pierre Shale (Sharon Springs equivalent) formations. Core analysis from the Cain 16-63-2-11-1CH well indicated average permeability to air values of 0.019 millidarcies and average porosities of 12 – 13%. XRD analysis from core indicated clay percent by weight through the Codell interval in the Cain 16-63-2-11-1CH well to be between 16 – 20%. Porosity vs. permeability cross plots indicate a nano pore structure. A Modified Lorenz Plot was constructed along with cumulative storage capacity and cumulative flow capacity vs. depth plots. The Modified Lorenz Plot reveals seven distinct flow units. Flow units one and seven being “poor” while also showing no oil staining in the core under UV light. Flow units two through seven were considered “good” flow units and showed oil staining in the core. A cumulative storage capacity vs. depth plot showed consistent porosity through the section. Cumulative flow capacity vs. depth plot showed variable permeability that was affecting the quality of the flow units. Trace fossils include *Teichichnus*, *Planolites*, and *Skolithos*, indicating a mostly *Cuziana* ichnofacies. The *Cruziana* ichnofacies is consistent with a sublittoral zone of deposition between the fair-weather wave base and storm wave base.

Core descriptions of two other cores within Silo Field, the Cirque Berry Unit 13-9 and Cirque Child #30-9 showed a similar thickness of Codell, similar trace fossil ichnofacies, and similar sedimentary structures. The Berry Unit core in northwestern Silo Field is capped by the Sage Breaks Shale Formation, similarly to the Cain 16-63-2-11-1CH core. The Sage Breaks Shale is

absent in the Child #30-9 core in southwestern Silo Field. 20 thin sections were cut every two feet through the Sage Breaks Shale and Codell Sandstone section of the Cain 16-63-2-11-1CH core. While thin sections can be difficult to aid with facies separations in the Codell Sandstone, as composition is similar throughout, thin section and core descriptions helped to delineate six distinct facies within this section, three in the Sage Breaks and three within the Codell Sandstone based on varying sand/clay percentages, trace fossil assemblages, and sedimentary structures. Future work includes FESEM analysis based on interpreted facies in the Cain 16-63-2-11-1CH core.

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 lucrative sedimentary units within the Denver-Julesburg Basin. Unlike adjacent limestone and shale formations, the Codell Sandstone is comprised of more porous, very fine- to upper medium grained silt and sandstones that can behave more 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 cross-stratified laminations often followed by a return to normal marine mudrock sedimentation.

Within this study, six cores penetrating the Codell Sandstone will be described and analyzed to identify storm sequences within the Redtail Field in north-central Colorado, USA. Core descriptions and analysis will be compared to downhole Formation Microimager (FMI) image logs to correlate and describe these storm deposited units within Redtail Field.

A Geothermal Reservoir Characterization of the Deadwood Formation, Williston Basin

Gabrielle Bennett, MS Student, Department of Geology and Geologic 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 potentials. Research on the Deadwood Formation is mainly restricted to the subsurface, with the only outcrops exposed in the Black Hills of South Dakota. Despite decades of petroleum exploration and development in the Deadwood Formation, research shows that the conventional hydrocarbon reservoirs are not highly prospective. The reason may be related to low TOC values such as 0.04 to 0.8 wt. % values and maturity of source rocks in the Nesson Anticline area. 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 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. Research will be accomplished by combining traditional hydrocarbon reservoir characterization techniques such as FE- SEM analysis, well log based petrophysical analysis, core descriptions, XRD and XRF methods, along with geothermal exploration methods such as isotherm mapping and temperature modeling. 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.

Causes of Geothermal Temperature Anomalies in the Denver Basin: with Application to Petroleum and Geothermal Energy

Melia Eaton, MS Student, Department of Geology and Geologic Engineering, CSM

Abstract

Geothermal gradients and reservoir temperatures are critical data for petroleum and geothermal energy exploration. Hydrocarbon maturity and generation within a source rock is largely controlled by temperature, a function of the local geothermal gradient. Likewise, reservoir temperature is an important factor when determining potential geothermal energy resources - the hotter the reservoir, the better the geothermal energy potential.

The effect of subsurface temperature anomalies on hydrocarbon and geothermal energy resources is well known. The Wattenberg Field thermal anomaly exhibits a positive correlation between higher subsurface temperatures and hydrocarbon production. In producing Niobrara wells, high temperature anomalies coincide with higher oil gravity, higher gas-oil ratios, and better productivity. Within Peoria Field, anomalously high geothermal gradients coincide with productive areas of the Muddy "J" Sandstone. Similarly, productive areas of the Muddy "D" Sandstone within the Bennett Field coincide with anomalously high geothermal gradients. Geothermal exploration focuses on finding areas with high subsurface temperatures. Higher reservoir temperatures (>120°C) are required for utility-scale electrical power generation, but lower temperature reservoirs can only be used locally for direct use applications (e.g. district heating, greenhouses, fish farms).

While there has been significant research published about the importance of subsurface temperatures anomalies in sedimentary basins, there is a lack of research detailing why these anomalies occur. This project is focused on identifying the source of geothermal temperature anomalies and their effect on hydrocarbon and geothermal resources within the Denver Basin. If temperature anomalies within the Denver Basin can be explained, findings could be applied to sedimentary basins worldwide to assist in hydrocarbon and geothermal energy exploration.

Sedimentary Geothermal Play Types of the Texas Gulf Coast: Applications to Electrical Power Generation

Eric Stautberg, PhD Candidate, Department of Geology and Geologic Engineering, CSM

Abstract

Sedimentary basin geothermal is an emerging energy sector with the potential to provide renewable, dispatchable, baseload electricity to residential, commercial, and industrial markets above sedimentary basins. The Texas Gulf Coast contains the necessary reservoir temperatures required for electrical power generation (>250^{o} F), and Texas is the largest consumer of electricity in the United States. Identifying and characterizing the major geothermal play types in this basin will help to reduce the exploration and development risks associated with these geothermal resources and encourage geothermal energy development in this region.

Previously, the main sedimentary geothermal play type identified on the Texas Gulf Coast are the Paleogene geopressured-geothermal sandstones of the Wilcox, Vicksburg, and Frio formations. However, Cretaceous and Jurassic formations in south and east Texas have the necessary reservoir properties to be used for electrical power generation but have not yet been investigated thoroughly. Additionally, salt diapirs across the Gulf Coast are a potential source of geothermal energy because of their high thermal conductivity, but this concept has yet to be evaluated for a resource potential.

Preliminary results show that south Texas is optimal for sedimentary geothermal exploration. Eocene Wilcox geopressured-geothermal sandstones are in relatively close proximity to multiple salt diapirs and Cretaceous formations with reservoir temperatures greater than 250^{o} F. A data set of 3,407 wells with digital log suites and 1,590 wells with bottom hole temperature (BHT) measurements demonstrates that the Wilcox, Georgetown, Edwards, Glen Rose, Pearsall, and Sligo formations are the shallowest reservoirs across the research area that contain temperatures capable of electrical power generation.

Six potential sedimentary geothermal play types exist within these formations: 1) Paleocene and Eocene geopressured-geothermal deltaic and marine sandstones, 2) Aptian and Albian shelf-margin carbonates, 3) Aptian and Albian platform interior carbonate shoals, 4) Maastrichtian deltaic and marine sandstones, 5) reservoirs of varying age located on the flanks of salt diapirs, and 6) repurposing existing oil and gas fields within these formations for geothermal energy. Further reservoir characterization and reservoir modeling of geothermal reservoirs within each play type will start to answer some of the key questions required to reduce the exploration and development risk associated with these resources. Identifying what geothermal play types exist in this basin is the first step towards developing renewable, dispatchable, baseload geothermal electricity in markets above sedimentary basins, further supporting the transition to green energy resources.

Predicting Sedimentary Lithofacies and Mapping Carbonate Gravity Flows in the Wolfcamp A & B, Midland Basin, Texas, USA

Selena Neale, MS Student, Department of Geology and Geologic Engineering, CSM

Abstract

The A and B benches of the Wolfcamp Formation in Midland Basin, Tx consist of interbedded mudrocks and carbonate gravity flows. The complex, heterogeneous nature of these benches make the upper Wolfcamp Formation a challenge for oil and gas operators to drill and complete. Oil and gas operators can improve return on investment in wells they drill by better picking well targets, paths, and completion strategies by knowing how and where the Wolfcamp A and B's lithologies occur. This can be achieved through predicting sedimentary lithofacies from logged-while-drilling, wireline, and core-derived mineralogy data. Using core-derived mineralogy data, sedimentary lithofacies of siltstone, mudrock, carbonate, calcareous siltstone/mudrock, and silty/muddy carbonate are created in the Wolfcamp A and B benches of two vertical wells in Martin and Midland Counties in the central region of the Midland Basin.

The five sedimentary lithofacies labels and wireline features are the training and testing data for a multi-layer perceptron supervised machine learning algorithm, which produces a trained sedimentary lithofacies predicting model. Eight Wolfcamp A horizontal wells and sixteen Wolfcamp B horizontal wells with Logging While Drilling (LWD) gamma ray, Fracture ID Young's Modulus, Fracture ID Poisson's Ratio, and pseudo-wireline data were run through the trained model. The model then predicts sedimentary lithofacies along the entire length of the horizontal wells. These lithofacies are plotted in 2D map-view where similar facies packages and potential carbonate gravity flows are identified in wells targeting the same zones of the Wolfcamp A and B . Operators may then employ this process to create 2D maps of target formations to enhance completion economics and avoid hazardous drilling conditions.

Evaluating Production Performance of Permian Basin Wells to Improve Hydrocarbon Recovery

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

Abstract

The Permian Basin is one of the most prolific oil and gas producing geologic basins in the United States. Permian Basin spans West Texas and Southeastern New Mexico. It has supplied more than 33.4 billion barrels of oil and 118 Tcf of natural gas during a 100-year period (EIA 2018). The ever-increasing water production and usage in the Permian Basin require produced water management by the operators. Classical waterflooding or gas flooding in unconventional reservoirs is not plausible because of the shale matrix's small pore size and low permeability. Therefore, creative approaches are needed to increase oil production without relying on large quantities of water injection to displace oil favorably. The practical alternative includes cyclic gas injection to increase oil production, or cyclic injection of wettability altering chemicals to clean the micro and macro fracture flow paths in the stimulated reservoir volume (e.g., solutions of ketones and ethoxylated alcohols).

I reviewed and organized the production data for the wells that have been drilled into the Wolfcamp Formation of the Delaware Basin from 2012 to 2020. I prepared bubble maps to identify the changes in cumulative oil, gas, and water production. The maps show the maturity of the basin where gas-prone wells are the majority in the North and North-Western part, and the South is more oil-prone. The wells drilled in Lea, Loving, and East-Reeves counties show the most oil production in one year of production. The gas production is highest at Culberson, North Reeves, and Loving counties. Furthermore, water production is large throughout the region regardless of the produced fluid type.

I performed production decline and Rate Transient Analyses (RTA) on several wells from the Delaware Basin to determine the stimulated formation permeability to determine stimulation effectiveness, the behavior of the flow types, and production of the individual wells in the region. The wells show diverse behaviors, where wells with the same linear flow period have significantly different cumulative production. This portion of the work will continue as a routine matter as new data become available.

Unconventional reservoirs are heterogeneous and show strong velocity anisotropy. Quantifying velocity anisotropy and geomechanical properties are important for reservoir characterization. Thus, I conducted experiments on selected cores from two wells in the Delaware basin to determine permeability, porosity, and pore compressibility. Siliceous mudstone samples show higher permeability values compared to calcareous silty mudstone facies. The mineralogical content was correlated to permeability. Furthermore, laboratory experiments indicated that the pore compressibility decreases with increasing quartz content.

Using data from four different wells, static and dynamic elastic properties, Young's Modulus (E), Bulk Modulus (K), and Poisson's Ratio (ν), were compared. The core data and log data were used to obtain a correlation between static and dynamic stiffness coefficients. The data also indicate that the wells in Delaware Basin exhibit vertical transverse isotropy (VTI).

In searching for the mechanism of huff-n-puff gas injection oil recovery in unconventional shale reservoirs, I came across convincing experimental results that indicate molecular diffusion is the main mechanism for improving oil recovery through micro-fracture-matrix interface.

Wettability is a crucial property of the interactions between the reservoir rock and the pore fluids which strongly affects the distribution of fluids in the reservoir pores and multiphase flow in porous in the reservoir. Consequently, I have conducted contact angle experiments on five different unconventional reservoir formations around the US and measured interfacial tension (IFT) between oil and brine from the formation.

I built a conceptual compositional dual-porosity reservoir model using CMG-GEM commercial reservoir modeling software in conjunction with the experiments. Next, I built a hydraulic fracturing model using Halliburton's GOHFER commercial software to simulate the actual hydraulic fracture propagation. The well completions and stimulation reports on actual well stimulation operations were used to build this model. This model provides conductivity and hydraulic fracture properties for each stage used in further reservoir simulation models. Finally, PVT reports from a Wolfcamp reservoir were used to build a fluid model for a reservoir using the CMG-Winprop module. Then, I used the production data from a well to get an idea about the reservoir production behavior. A sensitivity analysis will follow this effort to identify the parameters which impact the reservoir performance most. The ultimate goal is to combine geology, fluid flow theory, experimental observations, and reservoir simulation to evaluate production performance and improve Permian basin hydrocarbon recovery.

Finally, I will evaluate the current machine learning models using data from hydraulic fracture treatments and the associated production data to arrive at an optimal hydraulic fracture design. To accomplish this, I collaborated with GOHFER software development team. We are building a workflow to be used in GOHFER to arrive at more accurate model interpretations using statistically quantified inputs from many treatments. To be able to accomplish this goal I first cross correlated the formation tops using digital logs from Ward County, TX. And then I created subsurface maps. The next step in this effort (the petrophysics analysis) is to create synthetic logs for the wells when they are not available. Afterwards, the created synthetic logs will be verified on the geologic model. This machine-learning process will include cycles of training and verification where the accuracy of the model will increase with each cycle.

The Occurrence of Biogenic Gas in the Denver Basin

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

Abstract

Biogenic or microbial gas is an alternative type of gas production from conventional resources. Global recoverable biogenic gas volume is around 8 - 15% of conventional petroleum reservoirs. These numbers might be small, but most biogenic gas fields are related to shallow targets, making the production well costs relatively low. Therefore, the Biogenic gas play type is an exciting play that needs to be studied in its occurrence and play accumulation.

Biogenic gas was previously defined as a gas from the immature thermogenic maturation of organic matter. However, many studies and research have been published about the occurrences of biogenic gas. There are two types of its occurrence. First is the primary microbial gas, which occurs from the organic matter in the rock layer. The second type of microbial gas originates from generated thermogenic hydrocarbons. The different types of biogenic gas occurrences can affect field understanding, especially the migration pathway of gas.

One of the most interesting gas fields known for biogenic gas is the Beecher Island field from Yuma County, Colorado. This field is part of the Denver Basin, which has both thermogenic and biogenic systems. This field was defined as a biogenic occurrence, but there still is doubt about which types of sources generate microbial gas. Therefore, this project will focus on the occurrences of biogenic gas in the Denver Basin by analyzing the produced gas characters and integrating them with the basin evolution to identify the play potential for biogenic gas play in the Denver Basin area.

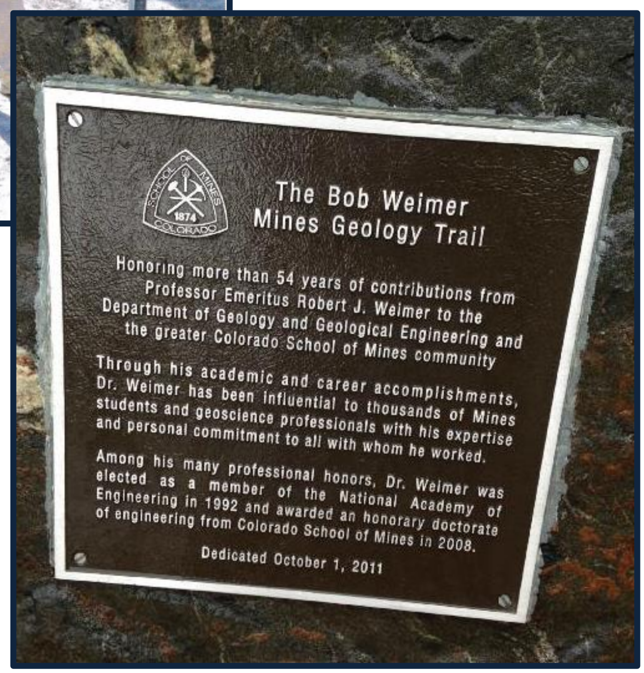
About Wittaya:

Wittaya Imurai, as known as Ken, is a first-year student for a Master's degree in Geology at Colorado School of Mines. He graduated with a bachelor's degree in geology from Chiang Mai University, Thailand. After graduation, he worked in the exploration and development field with Thai national oil and gas exploration, PTTEP, for seven years since 2015. With experience working Offshore Myanmar's petroleum system, he is interested in the biogenic gas play. He hopes that studying and being with the MUDTOC consortium will help him unlock the hidden potential of the biogenic gas play.

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 acknowledge the continued impact of Dr. Weimer on campus

FOR MORE INFORMATION, PLEASE CONTACT CHRIS MATSON: MATSON@MINES.EDU