NDIC Contract No. G-51-098

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August 2021 Status Report

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Introduction:

This is the 3rd progress report with regards to the NDIC contract G-51-098 which is for a period of three years and aims to promote research and development critical to the oil and gas industry in the State of North Dakota. This contract will provide support to a minimum of 15 Ph.D. students over its duration and one-month of summer salary for 6 faculty members. In addition to these endeavors, the fund will promote the setup of the Drilling and Completion Labs (DRACOLA), donated to the DPE in Nov 2019.

The list of research areas worked on by the students and faculty through the current contract as proposed by the NDIC include:

1. Big Data Analytics/UAS/Data Mining
2. CO2-EOR
3. Sulfate Deposition
4. Machine Learning/Refracking
5. Real-time Leak Detection for Oil and Gas Pipelines in North Dakota
6. Oil and Gas Pipe Blockage Prevention and Detection Based on Operational Parameters
7. Prediction of Gas Hydrate to Improve North Dakota Oil and Gas Production Efficiency
8. Investigation of Multiphase Flow in Undulating Horizontal Wells to Enhance Bakken Oil Production
9. Light Hydrocarbon Injection to Enhance Bakken Tight Oil Recovery
10. Optimization of Multistage Fracturing in Horizontal Wells to Maximize Bakken Oil Recovery
11. Evaluation of Bakken Rock Properties Alternation Caused by CO2 Enhanced Oil Recovery
12. Feasibility Study of Water-Alternating-Gas Flooding in Bakken Reservoirs
13. Management and Treatment of Oil-Field Produced Water to Reduce Overall Cost, Bakken Case
14. Identification and Shut-off of Water Influx to Reduce Bakken Water Production
15. Frac-Hit Prediction, Prevention, and Mitigation for Bakken Pad Drilling and Stimulation
16. Study of Advanced Technologies to Reduce Gas Flaring in Bakken
17. Miscible EOR (CO2, rich gas) and Conformance Control in Miscible EOR
18. Reservoir Modeling and Simulation
19. Wettability Determination and Imbibition Experiments
20. CO2 Storage

21. Fluid Flow Mechanisms in Tight Formation
22. Saltwater Disposal and Its Optimization

PhD Program:

The DPE established its graduate program in 2016 and has been growing consistently since then. As of present, the Petroleum Engineering Ph.D. program is the largest in the College of Engineering and Mines (CEM) at UND and among top three largest in the country with close to 80 students. The reputation and prestige of the DPE continues to grow, as it is attracting more talent in terms of new graduates as well as experienced professional to the Ph.D. program. This mix of fresh talent and experience helps in facilitating world-class research.

The rapid growth in the petroleum engineering program is a result of the strong support of the industry and the State of North Dakota. The functioning of the department and direction of research projects are advised by a committee of 30 representatives from the state and industry known as the Industrial Advisory Committee (IAC). The IAC meets bi-annually to have open conversation on the syllabus of courses, functioning of the department, research directions as well as the expansion of the department in a sustainable fashion. The IAC not only provides research guidance to the Ph.D. students but also helps them build stronger industrial networks for their future growth and ensures the Ph.D. students help the economic growth of the local industry.

The continuation of the Ph.D. program at DPE contributes significantly towards the better understanding of crude oil and natural gas production in the State of North Dakota. The work done by the students of program also helps improve safety considerations as well as promotion of subsurface carbon-dioxide storage and geothermal resources in the state. The Ph.D. program directly supports the undergraduate program by providing the teaching assistance and mentoring roles. The Ph.D. students help the undergraduate students while working on their research topics defined by the NDIC. The program also provides a great resource in terms of human capital in higher education and research.

During the second year of this contract, the students who started their project during the previous contract were provided continued support to complete their projects. This has resulted in 2 Ph.D. completions by the second quarter of 2021. The Ph.D. students who defended their theses successfully and the topic of their projects are:

Omar Bilal Akash: Numerical Simulations of Hydraulic Fracturing Through Perforated Wellbores.

Dezhi Qiu: Hydraulic Fracture Propagation and Its Geometry Evolvement in Transversely Isotropic Formations.

The restrictions due to the COVID-19 pandemic have had a significant impact on the overall structure and deliverance of the program causing a shift in the modes of interaction between students and their advisors. Despite the interruption caused by the pandemic, over 20 new students have been admitted to the Ph.D. program in Spring of 2021. Majority of the new students are international and most of them are on-campus, as international travel opened up and UND re-opened the campus in the same manner we did before the pandemic. As of current, the pandemic has had minimal effect in the research output of the department. The university is reverting to regular instruction in Fall semester and will be a welcome boost to the program's overall performance in terms of participation in workshops and conferences.

In Table 1, the first 8 Ph.D. students are those who started their program prior to the starting date of this contract but working on the topics proposed by the NDIC. This Table also provides the title of the research projects of each student. The remaining Ph.D. students listed in Table 1 are those students who started their program since the beginning of the current NDIC contract. The total of 51 students working directly on the NDIC proposed topics (except 4) is much larger than the 15 students considered as part of this contract. This significant achievement could not happen without receiving the support of the NDIC through this contract. With the NDIC sponsoring and supporting the students, the visibility and reputation of the program has enhanced and this resulted in receiving so many high-quality applications which make the selection of them very difficult. In the next report, an update about the project proposals for some of these new students who will be working on the NDIC topics will be presented. At the end of this report, the list of publications (Appendix A) and conference attendance of students (Appendix B) since the last report are presented. There has a total of 73 research papers published since 2020 (with an increase of 14 entries since March 2021), which was not possible without the support of the NDIC. Despite travel restrictions, the overall attendance to workshops and conferences has increased to 53 since August 2020 (with an increase of 40 entries since March 2021), the department is still trying to improve workshops and conferences. Attendance. Appendix C provides the progress reports of each of the students mentioned in Table 1.

Table 1: List of current Ph.D. students conducting research on NDIC topics of interest.

No.	Name	Start Date	Project title	NDIC Research Area
1	Ailin Assady	August 2018	Evaluation of Gas EOR In Tight Oil Reservoirs	2
2	Abdulaziz Ellafi	August 2018	IOR/EOR Unconventional Applications to Enhance Oil Recovery from Rich Liquid Shale Reservoirs	2, 10, 13
3	Nidhal Badrouchi	January 2019	Evaluation of CO2 Enhanced Oil Recovery Performance in Unconventional Oil Reservoirs: Comparison between Middle Bakken and Three Forks	2
4	Ogochuckwo Ozotta	January 2019	Geomechanics analysis of CO2 on Bakken shales and potential for fault reactivation	2, 20
5	Matthew Dunlevy	January 2019	Scalable UAS solutions for Pipeline Leak Detection and Prevention with Big Data and Machine Learning	1, 5
6	Augustinus Zandy	January 2019	A Study of Stress Shadow Development Along the Multistage Hydraulic Fractures in Unconventional Plays: A Fracture Spacing Relationship with Stress Shadow	10
7	Nourelhouda Benouadah	May 2019	Numerical Simulations of Hydraulic fracture Behavior in TIV Medium	10
8	Jin Zhao	August 2019	EOR in Conventional and Unconventional Reservoirs Using Different Gases	2
9	Jerjes Porlles	January 2020	Geomechanical and reservoir modeling of unconventional formation using discrete fracture network - Williston Basin	10, 18, 21
10	Samuel Afari	January 2020	Gas flooding in unconventional reservoirs	17
11	Hamid Reza Rashidi Araghi	January 2020	Cuttings Transportation Modeling and Optimization in Deviated Wellbores	15,8

12	Chenyu Wu	January 2020	Evaluation of CO2 EOR in Bakken formation	2
13	Ruichong Ni	January 2020	Using MLR to Predict Sandstone Cores' Mechanics Properties change after DQ-TSRP01 Polymer Flooding	1, 18
14	Billel Sennaoui	January 2020	The effect of CO2 Injection - Enhance Oil Recovery in Bakken (Three Forks)	17
15	Xueling Song	January 2020	Refracture Treatment Design Based on Analysis of Stress Alteration During Reservoir Depletion	2,4
16	Abdelmalek Bellal	May 2020	Intelligent Oil and Gas Production from unconventional reservoirs	4
17	Joshua Kroschel	May 2020	Minimum Horizontal Stress Estimation Using Machine Learning Techniques	1,4
18	Kalyan Venugopal	May 2020	Data Driven approach to ND Salt Water Disposal Well Optimization	1,22
19	Prasad Pothana	May 2020	Stress dependent permeability and Porosity and their hysteresis, Three Forks formation	1, 11, 21
20	Mohamed Malki	May 2020	The Evaluation of Bakken rock properties alternation caused by CO2 EOR	11
21	Ghoulemellah Ifrene	May 2020	Geological Carbone Dioxide Storage in Deadwood Saline Formation, Williston Basin	20
22	Martin Leipzig	May 2020	Summary and comparison of Bakken CO2 EOR in the Williston Basin, North Dakota; as related to reservoir geological parameters.	2,17
23	Vibhas Pandey	May 2020	Fracture Growth in Layered Formations	10
24	Swati Sagar	Fall 2020	Gas based EOR in tight formation and prevention of scale deposition in Bakken wells	17, 15
25	Vasanth Gokapai	Fall 2020	Testing the applicability of Schmidt's Hammer method in replacing the traditional static value measurement methods and building a hydraulic fracturing model to check for the impacts of Schmidt's Hammer method on reservoir performance	15
26	Doina Irofoti	Fall 2020	Reservoir modeling and simulation of the Middle Three Forks formation	18

27	Ala Eddine Aoun	Fall 2020	Study of Advanced Technologies to Reduce Gas Flaring in Bakken	16
28	Abderraouf Chemmakh	Fall 2020	Assessing the multiphase flow in pipes, investigating and predicting the critical velocities of liquid unloading and sand transportation.	8
29	Stephanie Leipzig	Fall 2020	Advantages of injecting CO2 with oilfield-produced wastewater into non-hydrocarbon bearing reservoirs via deep-saltwater disposal wells	20,22
30	Prince Opoku Appau	Fall 2020	Surfactant-Assisted Enhanced Oil Recovery Process in Tight Reservoirs under Harsh Conditions: a Laboratory and Simulation Investigation	17,21
31	Tomiwa Oguntade	Fall 2020	Experimental and simulation study of surfactants flooding in high salinity and high temperature (HSHT) reservoir conditions	17,19,18
32	Francis Idachaba	Fall 2020	Real Time Leak Detection and Intervention Systems for Surface Pipelines under Heavy Snow Cover	4,5
33	Youcef Khetib	Fall 2020	Investigation of Multiphase flow performances in the undulating horizontal Bakken shale wells	8
34	Ahmed Merzoug	Fall 2020	Simulating Tip screen out using lattice formulation in Xsite	15
35	Ines Benomar	Spring 2021	Geologic Remote Sensing for Geothermal Exploration	1
36	Julio Figueroa	Spring 2021	Hydrothermal resources assessment and mapping using multivariable modeling in the Williston Basin.	1
37	Omar Bakelli	Spring 2021	The study of Barium Sulfate scale in the Williston Basin deposition mechanisms and mitigation technique	3
38	Mouna Benabid	Spring 2021	Optimization of Multistage Fracturing in Horizontal Wells to Maximize Bakken Oil Recovery	15

39	Usama Khand	Spring 2021	Analyze Multiphase Flow and Geomechanical Effects on Water Loss During Hydraulic-Fracturing Flowback Operation Using Mechanistic Model	15
40	Abes Abdelmalek	Spring 2021	Red River formation modeling and CO2 injection	18,20
41	Claudius Njie	Spring 2021	Application of Petroleomic/Geochemical Data for Selection and Optimization of Chemical Enhanced Oil Recovery Methods for Shale Oils in the Bakken Formation-North Dakota	1
42	Rasaki Salami	Spring 2021	ADVANCEMENT IN THE USE OF SEISMIC DATA IN UNCONVENTIONAL SHALE PLAY	1,18
43	Gisela Mora Cortez	Spring 2021	Multiphase flow modeling in tight oil reservoirs	9,18
44	Anis Larbi	Spring 2021	Wettability Determination and Imbibition Experiments	19
45	Aimene Aihar	Spring 2021	Shockwaves fishbone integrated solution for rock fracturing	
46	Oscar Suarez	Spring 2021	Frac-Hit Prediction, Prevention, and Mitigation for the Bakken Pad Drilling and Stimulation	15
47	Kenza Ait Larbi	Spring 2021	Autonomous Field Scale Fluid Sampling System for Measurement	1,4
48	Ahmed Ismail	May 2018	PDC rock-bit interaction Modeling	Drilling
49	Habib Ouadi	Fall 2020	Fishbone technology simulation using underbalanced coiled tubing drilling for unconventional reservoirs.	Drilling
50	Aimen Laalam	Spring 2021	Optimization of Oil Production through Appropriate Gas Lift Design	Gas Lift
51	Abdelhakim Khouissat	Spring 2021	New downhole motor design for microholes (Fishbones)	drilling

* NDIC Research Area column refers to the list of topics in page 1-2 of this report.

Drilling and Completion Labs (DRACOLA):

As part of the current NDIC contract, funding was granted for the setup and installation of the DRACOLA lab. The lab is located within the old Minnkota Power building in Grand Forks, ND. The Drill Lab / Research Facility is a 17,000 sq. Ft warehouse (Figure 1, left). The lab equipment was donated to the University of North Dakota Petroleum Engineering Department (UND DPE) by Terratek in October 2019 by its founder/CEO Sid Green. The DRACOLA lab is poised to be one of the leading labs for experimental field-scale drilling (Figure 1, right). The DRACOLA lab includes a wellbore pressure vessel, a full-scale drill rig and mud pumping capabilities for measuring the performance, wear, deviation and dynamics of full-size drill bits tested at overbalanced or underbalanced drilling conditions at simulated depth.

Figure 1: DRACOLA Facility (left) and arrival of equipment to the facility, Nov 2019 (right).

The DRACOLA lab at UND will play a crucial role in the development of research in drilling and completion for any drilling conditions worldwide. DRACOLA is the only test facility in the world with the capabilities to drill at real world conditions. The lab also will verify analytical modeling, field scale drilling, with costs one-tenth to one-hundredth of field tests, along with the reduced danger of hole fouling. DRACOLA offers low-cost and timely screening of novel drilling and completion techniques. The facility will provide industry services to optimize drilling operations, train hands on practical aspects of drilling operation and machinery to industry people, educate undergraduate students regarding practical side of drilling while they are taught in-class theories, and conduct research in the areas of industry needs by graduate level students.

As of August 2021, significant progress has been made in setting-up DRACOLA (see Figure 2). There is a four-member team working on the lab set-up (Mr. Harry Feilen, Mr. Lannie Fladeland, Mr. Doug Schmidt and Mr. Robert Jensen) along with several dedicated Ph.D. students from UND DPE. Some of the progress made since April 2021 are listed as follows:

- Mud tanks and prime pumps have been set and their assembly is finished.
- All valves on the mud tank side have been replaced or rebuilt.
- The rebuilt 1600HP triplex mud pump motors have been installed.
- Building modification have finished.
- The 5-ton overhead crane has been installed

- Floor cutout has been completed.
- The sample holder, cuttings screens, grating, rails and support beams have been placed.
- The top drive has been installed in the tower and some shake down has started.
- The electrical demand for the rig is being connected.
- A SCR motor control house is being connected to the grid and the support equipment motors.
- The drillers cabinet (drillers control room) is being wired and connected to the rig.
- The LabVIEW data system for operation and data collection has been purchased.
- The LabVIEW program is being written.
- Multiple partnerships with leading industry companies/experts continue to be fostered.
- Two fulltime classes, taught at the lab are continuing and have increased enrollment


(a) (b)


(c) (d)

Figure 2: **(a)** Floor cutout; **(b)** rails and support beams have been placed ; **(c)** sample holder moving **(d)** sample holder and cuttings screens have been placed

It is the estimated that the DRACOLA lab will be functional in September 2021. The lab will start providing facilities for research, industrial services and education immediately after an opening ceremony which is planned to be held on Oct 21.

Already, many undergraduate and graduate students have worked in the lab towards their project design and elective courses by helping in lab set up, maintenance of different equipment and doing calculations for different sections of the lab. This has been a great practical and hands on experiences for the students and we expect this to grow further when the lab is operational. The expectation is to upgrade the lab to the latest automated status of the current oil and gas industry.

It is important to add that the initial estimate of the lab was $1M by Mr. Sidney Green, who donated the equipment to us. However, the official appraisal performed by the UND Alumni was at $3.5M for the value of the equipment. However, we expect that the value of the lab once it is operational, from research and industry applications perspective to be over $40M.

In addition, Mr. Green donated a number of additional items, mainly 28 type of different full face and coring bits to us in early 2021 (see Figure 3). He valued them at $50,000, however, from practical side, they will offer much more value to the future work that we can do with the bits.

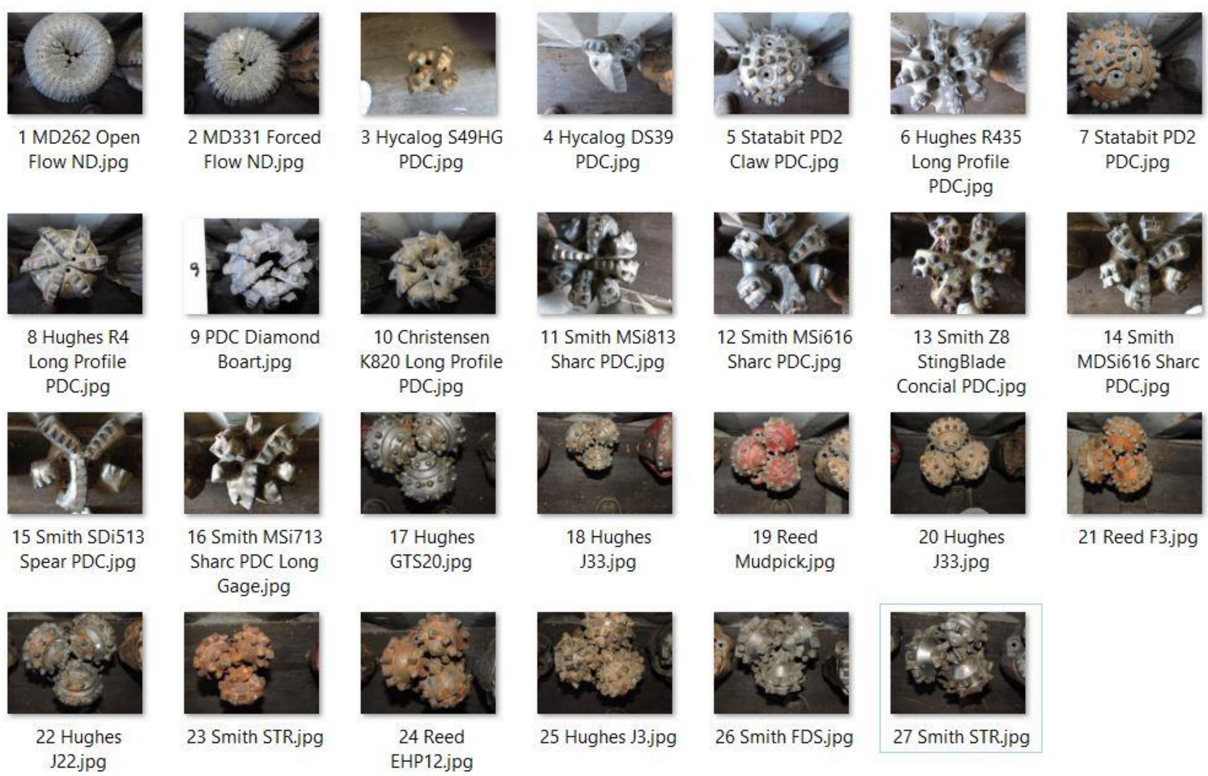

Figure 3: View of the bits donated to DRACOLA by Mr. Green in early 2021.

Industry Seminar:

In addition to the current report, as part of the requirements of the contract, and as per initial communication with the OGRC, we would like to organize a morning meeting on October 22, the day after the grand opening of the DRACOLA to invite the NDIC board to listen to the 1 min presentation competition of the Ph.D. students who will present briefly the areas of their research. If agreed by the NDIC, we also would like to announce the event to the industry in North Dakota to attend this seminar to provide their technical feedback about each project. This will help us to ensure that the projects will carry the industry applications and give us the opportunity to discuss the technical aspects of each project with the industry and request their support in terms of providing data. The meeting will be in person, however, we are planning to make it available remotely for those who cannot attend it.

Appendix A

Publications since 2020:

1. A. Abarghani, M. Ostadhassan, P. C. Hackley, A. E. Pomerantz, S. Nejati, (March,2020), 'A chemo-mechanical snapshot of in-situ conversion of kerogen to petroleum' Geochimica et Cosmochimica Acta, 273:37-50
2. A. Abarghani, T. Gentzis, B. Liu, S. Hohlbauch, D. Griffin, B. Bubach, M. Shokouhimehr, M. Ostadhassan, (April, 2020), 'Bacterial vs. thermal degradation of algal matter: Analysis from a physicochemical perspective', International Journal of Coal Geology: 103465.
3. A. Abarghani, T. Gentzis, M. Shokouhimehr, B. Liu, M. Ostadhassan, (February, 2020), 'Chemical heterogeneity of organic matter at nanoscale by AFM-based IR spectroscopy', Fuel 261:116454.
4. A. Abes, D. Irofti, G. Ifrene, S. Djemai, V. Rasouli, (June, 2021), 'The Impact of Geometric Attributes of Fractures On Fluid Flow Characteristics of Reservoir: A Case Study in Alrar Field, Algeria', 55th US Rock Mechanics / Geomechanics Symposium.A. Boualam, V. Rasouli, C. Dalkhaa, S. Djezzar, (July, 2020), 'Advanced Petrophysical Analysis and Water Saturation Prediction in Three Forks Reservoir, Williston Basin' SPLWA–750.
5. A. Boualam, V. Rasouli, C. Dalkhaa, S. Djezzar, (July, 2020), 'Stress-Dependence of the Permeability and Porosity of Thin Bed Reservoir, Three Forks, Williston Basin', 54thUS Rock Mechanics/Geomechanics Symposium held Golden. Colorado, USA.
6. A. Chemmakh, (To be published Sep 2021), 'Machine Learning Predictive Models to Estimate the UCS and Tensile Strength of Rocks in Bakken Field', SPE Annual Technical Conference and Exibition (ATCE 2021), Dubai, UAE.
7. A. Chemmakh, A. Merzoug, H. Ouadi, V. Rasouli, A. Ladmia, (Accepted to be published Oct 2021), 'Machine Learning predictive models to estimate the minimum miscibility pressure of CO2-Oil system', Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, UAE.
8. A. Fadairo, G. Adeyemi, T. Ogunkunle, K. Ling, V. Rasouli, E. Effiong, J. Ayoo, (February 2021), 'Study the suitability of neem seed oil for formulation of eco-friendly oil based drilling fluid', Petroleum Research (In press)
9. A. Fadairo, K. Ling, V. Rasouli, A. Adelakun, O. Tomomewo, (October 2020), 'An improved hydraulics model for aerated fluid underbalanced drilling in vertical wells', Upstream Oil and Gas Technology 5:100009.
10. A. Zandy, X. Wan, L. Jacobson, J. Hamling, N. Bosshart, V. Rasouli, (September, 2020), 'Understanding the Impact of Formation Properties on Stress Shadow in Multistage Hydraulic Fracturing Through Modeling and Simulation', AIChE Annual Meeting, Virtual.

11. A. Assady and H.Jabbari (December, 2020), 'Assessment of Permeability Hysteresis during Stress Loading/Unloading in Unconventional Reservoirs', Rock Mechanics and Rock Engineering (In review).
12. A.G. Almetwally, H. Jabbari, (April, 2020), 'Experimental investigation of 3D printed rock samples replicas', Journal of Natural Gas Science and Engineering 76: 103192
13. A.G. Almetwally, H. Jabbari, (April, 2020), 'Finite-difference simulation of coreflooding based on a reconstructed CT scan; modeling transient oscillating and pulse decay permeability experiment', Journal of Petroleum Science and Engineering: 107260.
14. F. Badrouchi, R. Rasouli, (January 2021), 'Simulation of settling velocity and motion of particles in drilling operation', Jour. Of Pet. Sci. and Eng.. 196:107971.
15. B. Jia, B, L. Jin, B. Mibeck, J. Sorensen, (March, 2020), 'An Integrated Approach of Measuring Permeability of naturally Fractured Shale', Journal of Petroleum Science and Engineering, 186.
16. C. Feng, Z. Yang, Z. Feng, Y. Zhong, K. Ling, (July, 2020), 'A novel method to estimate resistivity index of tight sandstone reservoirs using nuclear magnetic resonance logs', Journal of Natural Gas Science & Engineering.
17. C. Feng, Z. Yang, Z. Feng, Y. Zhong, K. Ling, (2020), 'A novel method to estimate resistivity index of tight sandstone reservoirs using nuclear magnetic resonance logs', Journal of Natural Gas Science & Engineering.
18. C. Li, H. Pu, X. Zhong, Y. Li, J.X. Zhao, (May, 2020), 'Interfacial interactions between Bakken crude oil and injected gases at reservoir temperature: A molecular dynamics simulation study', Fuel 276: 118058
19. F. Badrouchi, V. Rasouli, (October, 2020), 'Simulation of Settling Velocity and Motion of Particles in Drilling Operation', Journal of Pet. Sci. and Eng.: 196: 107971. DOI: 10.1016/j.petrol.2020.107971
20. G. Adeyami, A. Fadairo, T. Ogunkunle, A. Oladepo, A. Alozie, R. Vamegh, L. Kegang, O. Oredeko, (August, 2020), 'A Model for Predicting Elemental Sulphur Induced Permeability Damage in a Fractured Sour Gas Reservoir', Presented at the SPE Nigeria Annual International Conference and Exhibition, Virtual.
21. G. Han, G. Ma, Y. Gao, H. Zhang, K. Ling. 2021. A new transient model to simulate and optimize liquid unloading with coiled tubing conveyed gas lift, Journal of Petroleum Science and Engineering, 108394
22. G. Liu, L. Zeng, H. Li, M. Ostadhassan, M. Rabiei (May, 2020), 'Natural fractures in metamorphic basement reservoirs in the Liaohe Basin, China', Marine and Petroleum Geology 119

23. H. Fu, Lu. Yang, H. Liang, S. Wang, K. Ling, (October 2020), 'Diagnosis of the single leakage in the fluid pipeline through experimental study and CFD simulation', Jour. Of Pet. Sci. and Engg. 193:107437.

24. H. Fu, S. Wang, K. Ling, 'Detection of two-point leakages in a pipeline based on lab investigation and numerical simulation', Journal of Petroleum Science and Engineering (in review).

25. H. Lee, A. Abarghani, B. Liu, M. Shokouhimehr, M. Ostadhassan, (June, 2020), 'Molecular weight variations of kerogen during maturation with MALDI-TOF-MS', Fuel 269: 117452

26. H. Zhao, W. Li, H. Pu, K. Yang, (May, 2020), 'Formation Applicability Analysis of Stimulated Reservoir Volume Fracturing and Case Analysis', Petroleum

27. J. Zhao, L. Jin, NW. Bosshart, C. Wu,Y. Yu, K. Ling, Experimental and Simulation Study of CO2 EOR and Associated Storage in a Naturally Fractured Reservoir. 2021 AIChE Annual Meeting (Under Review)

28. K. Balaji, M. Rabiei (2021), 'Carbon Dioxide Pipeline Route Optimization for Carbon Capture, Utilization, and Storage: A case study for North-Central USA', Sustainable Energy Technology and Assessment (In review).

29. K. Balaji, M. Rabiei (October, 2020), 'Effect of terrain, environment and infrastructure on potential CO2 pipeline corridors: a case-study from North-Central USA', Energy, Ecology, and Environment, doi: 10.1007/s40974-020-00194-y

30. M. Alamooti, J. Porlles, N. Fry, et al., (October, 2021), 'Mandaree, North Dakota : A case study on oil and gas well conversion to geothermal district heating systems for rural communities. In Decarbonizing existing oil and gas fields via EGS and direct use', 2021 Geothermal Rising Conference, San Diego CA.

31. M. Atique, X. Song, C. Yang, (Accepted), 'Pitch Angle & Decalage Effect in Biplane Blade Design for Wind Turbines', IMECE2021. N. Badrouchi, F. Badrouchi, OS Tomomewo, H Pu (June, 2020), 'Experimental investigation of CO2-EOR viability in tight formations: Mountrail County Case Study'. 54th US Rock Mechanics/Geomechanics Symposium, 2020.

32. N. Benouadah, N. Djabelkhir, X. Song, V. Rasouli, B. Damjanac, (February, 2021), 'Simulation of Competition Between Transverse Notches Versus Axial Fractures in Open Hole Completion Hydraulic Fracturing', Rock Mechanics and Rock Engineering, doi: https://doi.org/10.1007/s00603-021-02378-2

33. O. Ozotta, O., Ostadhassan, M., Liu, K., Liu, B., Kolawole, O., & Hadavimoghaddam, F. (November, 2021) Reassessment of CO2 Sequestration Tight Reservoirs and Associated Formations. JPSE 109071 0920−4105 https://doi.org/10.1016/j.petrol.2021.109071

34. O. Ozotta, O., Ostadhassan, M., Rasouli, V., Pu, H., Malki, M.L., Dawodu, O.V. and Kolawole, O., (June, 2021). Homogenization Models to Determine the Change in Elastic Properties Due to CO2 Injection. ARMA 55th US Rock Mechanics/Geomechanics Symposium

35. O. Ozotta, O., Ostadhassan, M., Liu, K., Lee, H., Pu, H., Kolawole, O., & Malki, M. L. (March, 2021). Time−dependent impact of CO2−shale interaction on CO2 storage potential. 15th international conference on greenhouse gas control technologies.

36. O. Ozotta, O., Liu, K., Gentzis, T., Carvajal−Ortiz, H., Liu, B., Rafieepour, S., & Ostadhassan, M. (March, 2021) Pore Structure Alteration of Organic−Rich Shale with Sc−CO2 Exposure: the Bakken Formation. Energy & Fuels 35(6), 5074−5089 https://dx.doi.org/10.1021/acs.energyfuels.0c03763

37. O. Ozotta, P.J. Gerla, (January 2021), Mapping Groundwater Seepage in a Fen Using Thermal Imaging', Geosciences 11, 29. https://doi.org/10.3390/geosciences11010029

38. O. S. Guan, R. Gholami, A. Raza, M. Rabiei, N. Fakhari, V. Rasouli, O. Nabinezhad (March, 2020), 'A nano-particle based approach to improve filtration control of water based muds under high pressure high temperature conditions', Petroleum 6(1).

39. R. Ashena, A. Elmgerbi, V. Rasouli, A. Ghalambor, M. Rabiei, A. Bahrami, (January, 2020), 'Severe wellbore instability in a complex lithology formation necessitating casing while drilling and continuous circulation system', Jour. Petr. Exp. Prod. Tech. 10: 1511–1532.

40. R. Gholami, A. Raza, M. Rabiei, N. Fakhari, P. Balasubramaniam, V. Rasouli, R. Nagarajan, (January, 2020), 'An approach to improve wellbore stability in active shale formations using nanomaterials' Petroleum.

41. R. O. Salami, A. Lafram, D. Lecerf , A. Asnaashari, (January, 2021), 'Extending subsurface imaging beyond OBN coverage using multiple: A case study in Deepwater Nigeria', SEG Interpretation Focus Africa (paper accepted)

42. S Hu, W Huang, H Yao, K Ling, (2020). A correction method based on geometric factor for resistivity log response of thinly laminated sand reservoirs: A case of study, Interpretation, https://doi.org/10.1190/int-2020-0080.1

43. S. Djezzar, A. Boualam, (July, 2020), 'Fractures Characterization and their Impact on the Productivity of Hamra Quartzites Reservoir, Haoud-Berkaoui area, Oued-Mya Basin, Algeria', 54th US Rock Mechanics/Geomechanics Symposium, Colorado School of Mines, Golden, USA.

44. S. Djezzar, V. Rasouli, A. Boualam, M. Rabiei, (February, 2020), An integrated workflow for multiscale fracture analysis in reservoir analog. Arab J Geosci 13:161.

45. S. Khadraoui, M. Hachemi, A. Allal, M. Rabiei, A. Arabi, M. Khodja, S. E. I. Lebouachera, N. Drouiche (July, 2020), 'Numerical and experimental investigation of hydraulic fracture using the synthesized PMMA', Polym. Bull

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Appendix B

Conferences/Workshops attended since August 2020:

1. Abes, A. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
2. Abes, A., D. Irofti, G.E.H. Ifrene, V. Rasouli, S. Djemai. The Impact of Geometric Attributes of Fractures on Fluid Flow Characteristics of Reservoir: A Case Study in Alrar Field, Algeria. 55th American Rock Mechanics Association Synposium, Texas, USA.
3. Adebimpe, A.I. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
4. Afari, S. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
5. Afari, S., May 2021: Williston Basin Petroleum Conference Annual. Participated.
6. Ait Larbi, K. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
7. Ait Larbi, K. May 2021: Williston Basin Petroleum Conference. Participated
8. Allam, L. July 2021: Geothermal Energy: Solutions for a Zero-Emissions Sustainable Energy Future, online.
9. Allam, L. July 2021: NExT Fundamentals of Data Analytics by Schlumberger, on campus.
10. Aoun, A. May 2021: Williston Basin Petroleum Conference, online.
11. Assady, A., Swati, S., Bellal, A. June 2021: ARMA 55th US Rock Mechanics/Geomechanics Symposium. Oral Presentation
12. Bakelli, O. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
13. Bakelli, O. July 2021: NExT Fundamentals of Data Analytics class in campus, Schlumberger.
14. Bakelli, O. May 2021: Williston Basin Petroleum Conference, online.
15. Balaji, K. November 2020: ESRI Spatial Data Science: The New Frontier in Analytics. Participated.
16. Benabid, M., Ellafi, A., December 2020: SPE University of Belgrade Online Webinar Series. Oral Presentation.
17. Benouadah, N., May 2021: Williston Basin Petroleum Conference Annual. Participated.
18. Chemmakh, A. May 2021: Williston Basin Petroleum Conference.
19. Ellafi, A., November 2020: SPE University of Oklahoma Online Webinar Series. Oral Presentation.
20. Ellafi, A., October 2020: SPE Annual Technical Conference and Exhibition. Oral Presentation.
21. Ellafi, A., September 2020: Canada Unconventional Resources SPE Conference. Oral Presentations.

22. Ifrene, G. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
23. Ifrene, G. June 2021: ARMA 55th US Rock Mechanics/Geomechanics Symposium. Poster Presentation
24. Ifrene, G. May 2021: Williston Basin Petroleum Conference, online.
25. Ifrene. G. July 2021: NExT Fundamentals of Data Analytics class in campus, Schlumberger.
26. Irofti, D. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
27. Irofti, D. June 2021: ARMA 55th US Rock Mechanics/Geomechanics Symposium. Poster Presentation
28. Irofti, D. May 2021: Williston Basin Petroleum Conference, Participated.
29. Laalam, A. May 2021: Williston Basin Petroleum Conference, Participated.
30. Mellal, I. July 2021: NExT Fundamentals of Data Analytics by Schlumberger, on campus.
31. Merzoug, A. May 2021: Williston Basin Petroleum Conference, Participated.
32. Mouedden, N. April 2021: NSI Technologies StimPlan™ Version 8 User Online Course.
33. Mouedden, N. July 2021: NExT Fundamentals of Data Analytics class in campus, Schlumberger.
34. Mouedden, N. May 2021: Williston Basin Petroleum Conference, online.
35. Ouadi, H. May 2021: Williston Basin Petroleum Conference, Participated.
36. Ozotta, O. Hazards in Hindsight: Lessons for the Future. AEG 63rd Annual Meeting. Poster presentation.
37. Ozotta, O. June 2021: ARMA 55th US Rock Mechanics/Geomechanics Symposium. Poster Presentation
38. Ozotta, O. March 2021: GHGT 15th International Virtual Conference on Greenhouse Gas Control Technologies. Poster presentation
39. Ozotta, O. October 2020. Geological Society of America Connects Online. Oral presentation
40. Ozotta, O. October 2020. Geothermal Rising Annual Meeting and Exhibition. Participated.
41. Ozotta, O. September 2020: Navigating the unknown. NABG 39th Annual Technical Conference. Poster presentation.
42. Pandey, V. J., October 27 – 29, 2029. Attended the SPE Annual Technical Conference and Exhibition (Virtual) and chaired session #38 on "Fracture Geometry and Fracture Driven Interactions".

43. Pandey, V.J.: Society of Petroleum Engineers (SPE) 2020 Outstanding Technical Reviewer Award. List published in the November issue of SPE Production & Operations and the December issue of JPT.
44. Porlles, J., July 2021: NExT Fundamentals of Data Analytics class in campus, Schlumberger. Participated
45. Porlles, J., May 2021: Williston Basin Petroleum Conference Annual. Participated.
46. Porlles, J., October 2020: 2020 Geothermal Rising Conference Annual Meeting & Expo. Oral presentation.
47. Salami R July 2021: NExT Fundamentals of Data Analytics class Online, Schlumberger.
48. Song, X. August 2021: 5th Annual Refrac Wells 2021. Oral Presentation.
49. Song, X. August 2021: North American Liquids-Rich Basins 2021. Participated.
50. Venugopal, K, July 2021: SPE Data Science Convention, Houston, TX, Participated.
51. Venugopal, K, July 2021: URTeC, Houston, TX, Participated and Presented a theater presentation on Accelerating AI adoption for energy companies for Schlumberger
52. Venugopal, K. March 2021: Machine Learning in Oil and Gas Conference, Houston, TX, USA, Panel discussion: Machine Learning case studies and practical insight in the brave new world of Covid-19.
53. Zandy, A. November 2020: AIChE Annual Meeting. Oral Presentation.

Appendix C – Student Research Reports

Evaluation of Gas Based EOR in Tight Oil Reservoirs

Ailin Assady
Ph.D. student, Department of Petroleum Engineering, UND

Problem Statement

Although CO_2/Gas EOR in tight oil reservoir is a relatively new concept, it has been widely applied in unconventional reservoir and investigated comprehensively both in literature and pilot test, recently. Enhancing oil recovery in shale reservoir with small pore size distribution is a challenging topic and can be exacerbated when heterogeneity add to this condition. Many scenarios have been applied and simulated since last 50 years ago, but still there are several different aspects that need to be considered. CO_2 injection is currently one of the most popular EOR (Enhanced Oil Recovery) methods in the world, as its MMP (Minimum Miscibility Pressure) with oil is lower than other common injected gases. Besides, CO_2 injection due to small size of molecules comparing to pore-size in shale reservoir proved to be the most efficient method, so far. But predicting oil recovery by modeling shale reservoir in conventional simulator is not accurate due to neglecting various effective parameters such as: sharp variation of permeability, porosity, changing capillary pressure etc. Better understanding of heterogeneity can help us to compare different injection scenarios more accurately leading to improved reservoir management and economy. Therefore, real effect of CO_2/gas injection with different scenarios requires more investigation.

Progress to Date – Results & Discussion:

Experimental Rock Characterization: Description of rock structures and characterizing rock to understand permeability, geomechanics, storage capacity, and fluids transport. The measurement of permeability of Bakken rock samples is very challenging due to their extremely low permeability. In this study, we determined a number of Bakken core samples (Well#24779) permeability using oscillating-pulse and pulse-decay methods. Also, the elastic moduli (i.e. Young's modulus, Poisson's ratio) of these core plugs were estimated through the measurement of seismic velocities (V_p and V_s); Table 1 and Fig. 1. Accurate characterization of Bakken core samples can enhance our knowledge of fluid flow and CO_2-EOR potentials in the Williston Basin, ND.

Permeability Hysteresis: Permeability hysteresis and damage over the tight formation, Bakken, Williston Basin, ND is investigated thoroughly. Permeability is determined under different confining pressure and pore pressure for two different pore size Middle Bakken core samples using pulse decay method. Based on laboratory measurements, we illustrated the influence of stress loading/unloading and effect of pore pressure, stress range on permeability damage for Middle-Bakken core samples. This approach can help us to get a better insight into the impact of mentioned parameters on permeability hysteresis path and permeability evolution under different effective stress condition.

Table 1. Measured Middle Bakken core sample elastic moduli

Confining Pressure(psi)	Vp(m/s)	Vs(m/s)	E(Gpa)	Poison Ratio
826.7151051	5476	3012	63.01	0.245
1551.903794	5476	3276	67.01	0.205
2277.092482	5811	3295	68.44	0.264
3002.281171	5811	3295	68.26	0.265
3727.46986	5811	3353	68.88	0.261
4467.162322	5811	3353	69.57	0.256
5917.539699	5811	3383	70.86	0.246

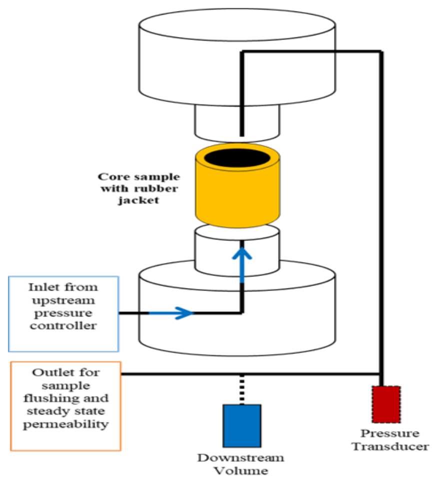


Figure 1. Schematic of the utilized permeability measurement

Digital Rock Analysis: While in conventional reservoirs the concept of Darcy flow is a reasonable assumption in simulating fluid flow, this is not applicable in unconventional reservoirs. In ultra-small pores of shale formations, fluid flow may violate one or more assumptions required for *Darcy flow* [*Kurtoglu*, 2013]. In those nanopores, turbulent flow may develop and cause deviation from the conventional models. Development of more accurate models to improve our knowledge of complex flow through nano-/micro-scale pores of shales is necessary considering the unique features of unconventional reservoirs.

Micro-CT scan of Bakken shale core sample was applied in visualizing the microscopic pores, and rock properties e.g. porosity, and pore size distribution, etc. were determined; Fig. 2. This work compares the pore-scale heterogeneities of different tight samples using digital rock analysis and help in investigating the impact of permeability heterogeneity in a huff-n-puff case study in the Middle Bakken Formation.

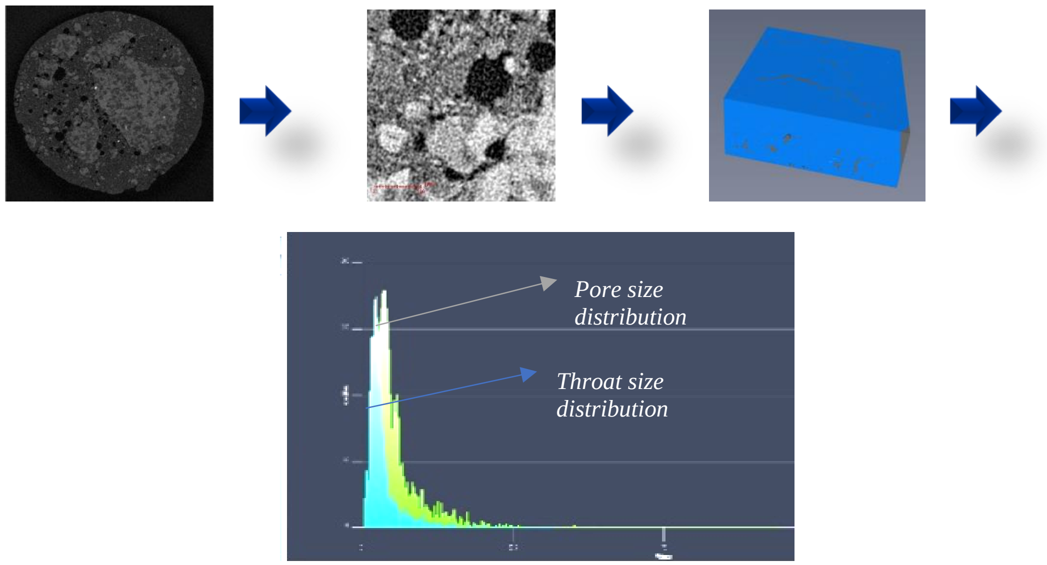
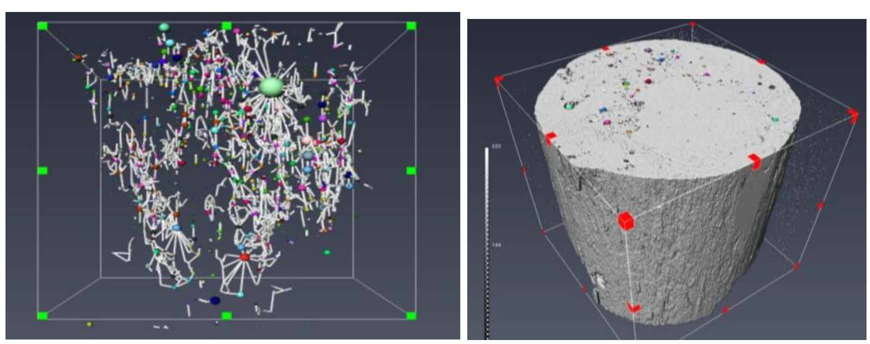


Figure 2. Procedure of DRP;1) Micro-CT 2) Preprocessing 3) Segmentation 4) Obtaining different rock properties



Left: Pore-network extarction. Right:3D view

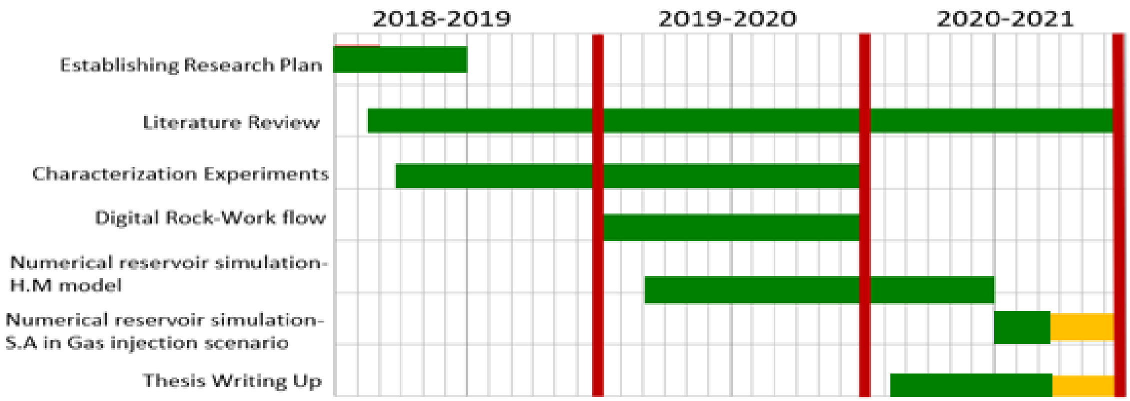
Numerical Simulation: Unlike conventional reservoirs, in a tight shale CO_2 is not sweeping oil out of the matrix. It needs to be in contact with in-situ fluid in a very slow process and after *molecular interactions* oil can be moved out into induced fractures and flow towards producing well. This means that CO_2 will need time to soak into rock matrix between injection and production for such a process to complete. This task will focus on evaluating CO_2-oil displacement in the Bakken Shale through several injection scenarios. We used CMG simulation software, to prepare the numerical reservoir model for a selected well section (#24779), and to run simulation scenarios for optimization in order to get a higher oil recovery factor.

Integrated development plan optimization: It is necessary to provide integrated optimization plans for future wells designed for EOR. Reservoir simulation will be performed to advice for optimal development planning, including:

- Optimization workflow for DualPOR/LGR models
- Comparison of several EOR schemes:
    - Patterns of producing and injection wells.
    - Continuous vs. cyclic CO_2

- Pure CO_2 vs. CO_2 mixed with other gasses.
- Homogeneous vs. heterogeneous reservoir model

Project Milestone and Timing:



Integrated Approach of Unconventional Reservoir Applications in Support of Improved Oil Recovery for Liquid-Rich Shale Reservoirs

Abdulaziz Ellafi
Ph.D. student, Department of Petroleum Engineering, UND

Problem Statement:

This research presents an integrated approach of unconventional reservoir applications to increase well/reservoir contact area (i.e., large stimulated reservoir volumes "SRVs") and produce efficiently more trapped oil in the pore matrix from liquid-rich shale reservoirs. In order to achieve research goals, understanding formation characterization and mechanisms of Enhanced Oil Recovery (EOR)/ Improved Oil Recovery (IOR) applications are the main aspects to explain the objective optimization workflow through comprehensive studies using lab experiments, data analysis, and software algorithm. Therefore, the research outcomes provide significant and vital information, assisting operators, academic researchers, and software developers in fully understanding models for fracture network characterization, fracture treatment effectiveness, assess new completion technologies, evaluate which formations are the most productive, and define dominant mechanisms of gas injection EOR. The research recommendations could be successful economically in field applications that might reduce the need for refracturing stimulation or infill drilling. In addition, the part of the research task may be used to develop a real-time analysis to apply an optimum pump schedule for the current and next treatment stages on a well. This point is a critical factor in the economic development of unconventional reservoirs since the well completion cost is a significant portion of the capital cost compared to other expenses, and heavily influences production rate or ultimate recovery.

Progress to Date – Results & Discussion:

HVFRs in High TDS Environment: In our research, enhanced the ability of anionic HVFRs in Bakken produced water conditions as water management option. The dilution technique is utilized to prepare the HVFR samples with up to 50% produced water to investigate the viscosity profile under a wide range of share rates and different dosages (0.25 to 8 gpt) for the anionic polymer (HVFRs) with molecular weight 18 to 26 million (g/mole). As can be seen in the **Figure 1**, the effect of the produced water is immediately shown in the viscosity profile. The 8gpt dosage is the only HVFRs load that is shown a stable viscosity measurement, where the viscosity is dropped at around 100 cp to 25cp at 66 s^{-1} shear rate and constant temperature of 70 ºF when the comparison is made based on the type of makeup fluids (i.e, 100 % freshwater and 50% & 50% freshwater and Bakken produced water, respectively). In addition, hydraulic fracturing simulation (2D/3D) proved that utilizing surfactant and HVFR as fracking fluid can enhance proppant transport (i.e. longer effective frac half-length) and fracture conductivity, which means larger SRVs and improved stimulated wells performance. The surfactant as additives modified the rheological properties of HVFRs with produced water by preventing degradation, reducing viscosity, expanding fluid viscoelasticity, and extending the flow behavior index (n') and flow consistency index (k') performance of the fracturing fluids to be able to carry proppant deeper up to secondary and tertiary fractures. The ultimate oil recovery results are depicted in **Figure 2**, where the oil recovery increased by 33% when the HVFR-PRS was used. This is a significant increase in EUR compared with Linear Gel and HVFR-PR due to extend and improve SRV region.

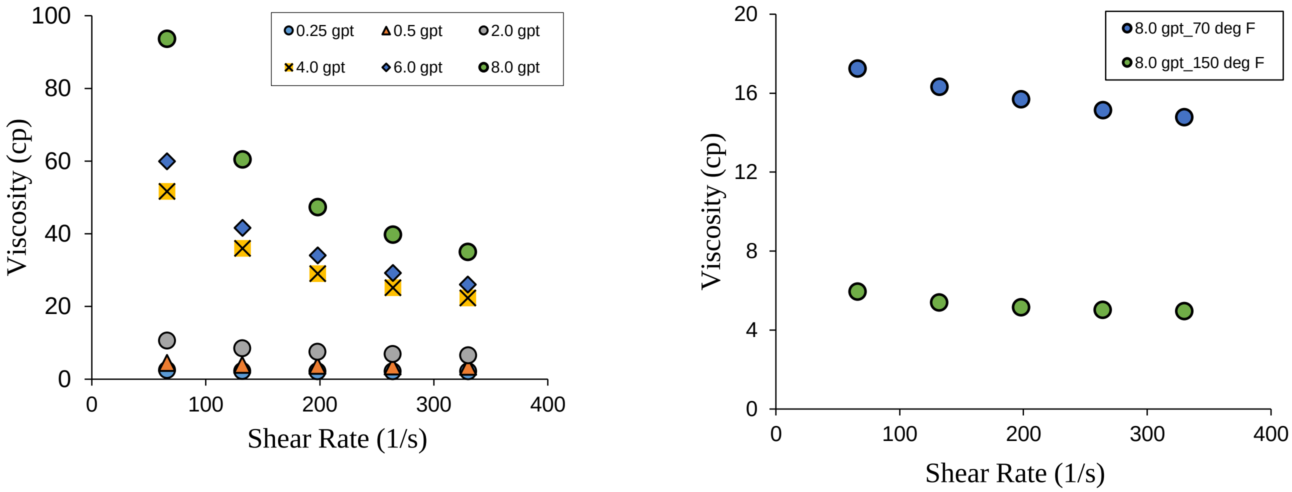


Figure 1. Viscosity Profile of HVFR Fracturing Fluid blend at 100% Bakken Tap Water at 70ºF (right) and 50% Bakken Produced Water at 70 ºF and 150 ºF

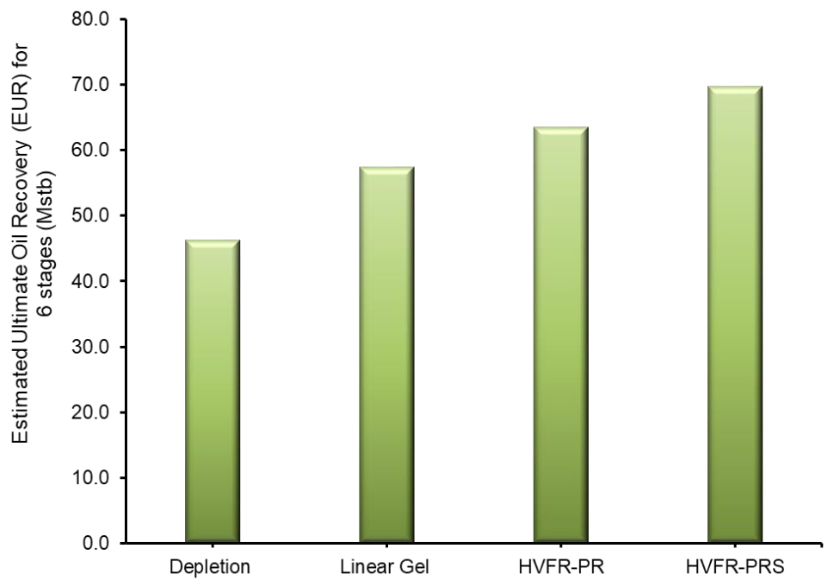


Figure 2. Forecasting production using different operation Scenarios "Depletion Vs. Re-fracturing Application

CO_2 Huff-n-Puff Protocol in Unconventional Reservoirs: The outcomes indicated on the effect of the reservoir temperature on the performance of the CO_2, where the recoverable oil increases as the temperature increase until reach the optimum depends on the injection pressure phase. On the other hand, high injection pressure yielded higher amount of produced oil, as shown in **Figure 3**. The wettability alteration was changed by CO_2-EOR as injection pressures increase and the wetting phase move from the oil wet toward the water wet system (See **Figure 4**). As overall outcomes from this research, the CO_2 huff-n-puff process has a good potential in the Lab and could be succeeded economically in field applications.

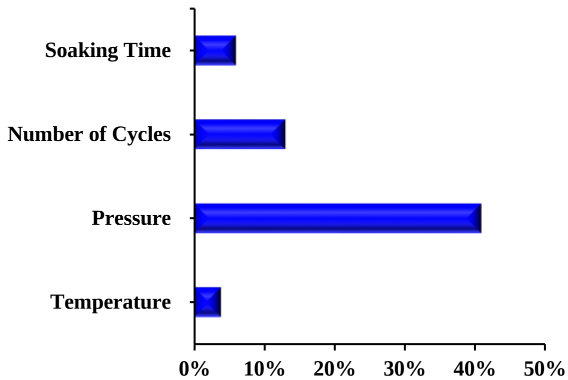


Figure 3. Oil recovery results under sensitivity analysis

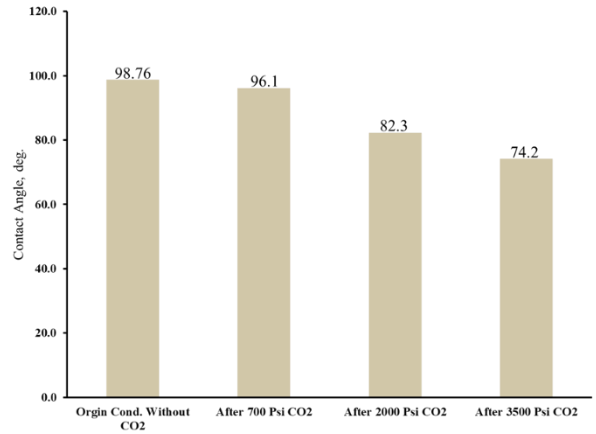


Figure 4. Contact angle measurements for the Middle Bakken Fm. at different conditions before and after applying CO_2-EOR

Assessment of Individual Fracture Stages: The same concept was used to analyze the pressure falloff data to determine the total fracture surface area for both natural fractures and hydraulic fractures on a stage-by-stage basis. The analysis outcomes provide the friction pressure losses and total fracture surface area. The analysis indicates (See **Figure 5**) that most of the fracturing fluid was leaked off through natural fracture surface area and resulted in the estimation of larger values compared to the hydraulic fracture calculated area. These phenomena might represent a secondary fracture set with a high fracture closure stress activated in neighbor stages that was not well developed in other sections.

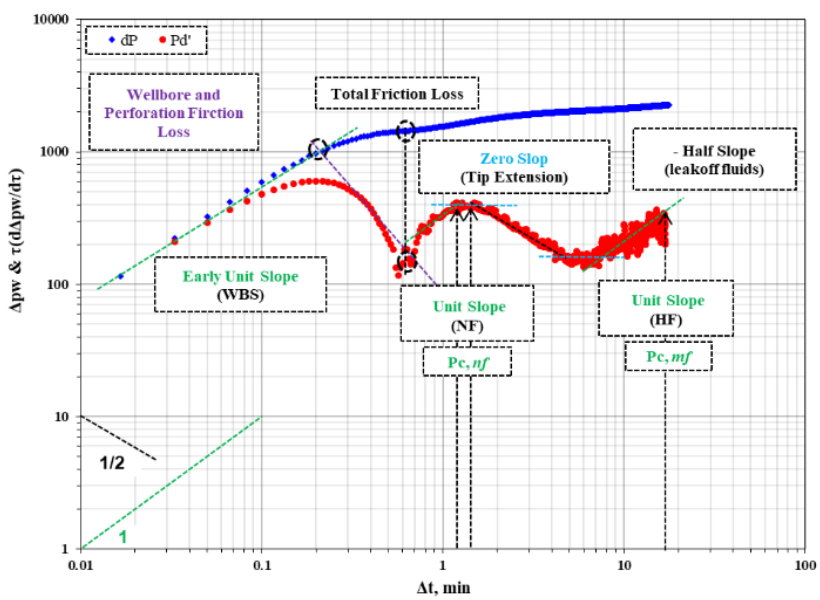
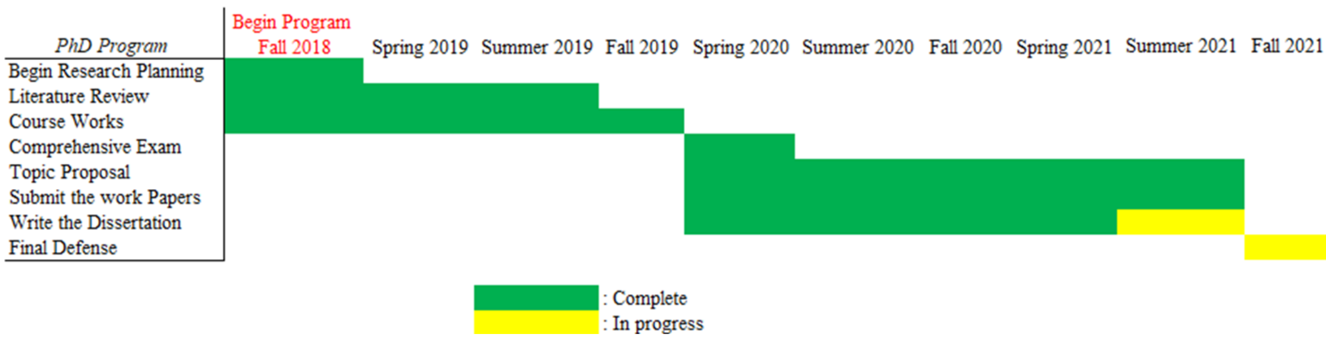


Figure 5. The diagnostic approach for the pressure falloff analysis for the main hydraulic fracture treatment.

We concluded that evaluating the performance of post-stimulation conditions on a stage-by-stage basis using indirect methods, such as pressure falloff data analysis, is the most promising technique for providing a wide range of information covering the mechanics of the hydraulic fracture, such as open, closed, and propped. This method may overcome limitations and weaknesses found in many of the proposed techniques reported in peer-reviewed journal articles, such as production data analysis and microseismic methods.

Project Milestone and Timing:



Evaluation of CO_2 Enhanced Oil Recovery Performance in Unconventional Oil Reservoirs: Comparison Between Middle Bakken and Three Forks

Nidhal Badrouchi
Ph.D. student, Department of Petroleum Engineering, UND

Problem Statement:

Significant efforts have been made to estimate the original oil in place (OOIP) in the Bakken petroleum system, and the results vary between 300-900 billion bbl. Yet, most of it is being left behind after the primary production. Currently, depletion drive is the main oil production mechanism for both the Middle Bakken and Three Forks, which recovers about 8% to 12 %of OOIP. The immense oil volume remaining in place is a strong motivation to investigate the application of improved and enhanced oil recovery (EOR) methods in Bakken.

In conventional reservoirs, different techniques were successfully implemented to improve the oil recovery, particularly CO_2 flooding has shown tremendous success during the past four decades. The poor reservoir quality in Bakken narrowed the selection of the appropriate enhanced oil recovery technique. Previous water injection pilot test in Bakken revealed that fluid injectivity is the main concern due to the nature of the very low permeability of the matrix. On the other hand, gas injection pilot tests revealed that injectivity is not a concern in Bakken, however, gas flooding in such densely fractured unconventional reservoirs might result in early breakthrough, resulting in poor performance. To mitigate that CO_2 can be injected at different cycles using the Huff-n-Puff (HnP) technique.

Previous pilot tests that used cyclic-CO_2 injection showed that it could be a promising technique to enhance the oil recovery in Bakken. However, no clear answer was provided. In term of improving the oil recovery, the reported results exposed the lack of understanding of CO_2 EOR mechanism in unconventional reservoirs. It also revealed that the earlier simulation studies were too optimistic, and the previous core-scale injection tests overestimated the CO_2 potential.

Progress to Date – Results & Discussion:

Optimization of CO_2 HnP Parameters: In CO_2 HnP, the injection pressure and soaking time have a significant impact on oil recovery in unconventional reservoirs. Thus, we studied the effect of injection pressure and soaking time on oil recovery in the Middle Bakken Member and the Three Forks Formation, and we have been able to optimize those parameters. Under typical reservoir conditions, the experimental results showed that:

- recovery in unconventional reservoirs using CO_2 Huff-n-Puff is a slow process compared to conventional reservoirs.
- The recovery process is even slower in the Middle Bakken than in the Three Forks and that could be related to the difference in permeability.
- For tight rocks, increasing the pressure above the minimum miscibility pressure results in recovering additional oil.

Evaluation of CO_2 EOR Performance: To evaluate the performance of CO_2 HnP in tight formations, we conducted a full parametric study in which we studied the effect of water presence, CO_2 injection scheme, sample size, CO_2 volume to exposed-rock-surface ratio.

When we compared the oil recovery using CO_2 flood or the Huff-n-Puff technique, we found that the latter is more promising for such reservoirs. Our results suggest that water presence in the fracture volume might have a negative impact on CO_2 EOR potential in both MB and TF samples.

Investigation of CO_2 EOR Side Effects: Gas injection side effects have been extensively studied in conventional reservoirs. The reported studies commonly state that asphaltene precipitation and deposition is the main disadvantage. Therefore, it can alter the petrophysical properties of the rock. However, asphaltene deposition kinetics widely vary based on reservoir conditions, crude oil characteristics, and the type of injected gas. On the other hand, gas injection side effects in ultra-tight formations were seldom reported, which motivated us to explore the possible side effects that can result from CO_2 Huff-n-Puff in Middle Bakken.

In our study, we noticed a porosity decrease after each CO_2 injection cycle. Beside pore plugging, that might occur as a result to CO_2 exposure, the pore structure damages might be caused by the alternative change of the effective stress induced by cyclic CO_2 injection.

Nuclear magnetic resonance (NMR) technique was used to detect the distribution of pore fluid in the cores before and after CO_2 injection. The shift of T_2 relaxation curve to the left after CO_2 injection (see **Figure 1**) is caused by a change of pore fluid distribution toward the smaller pore.

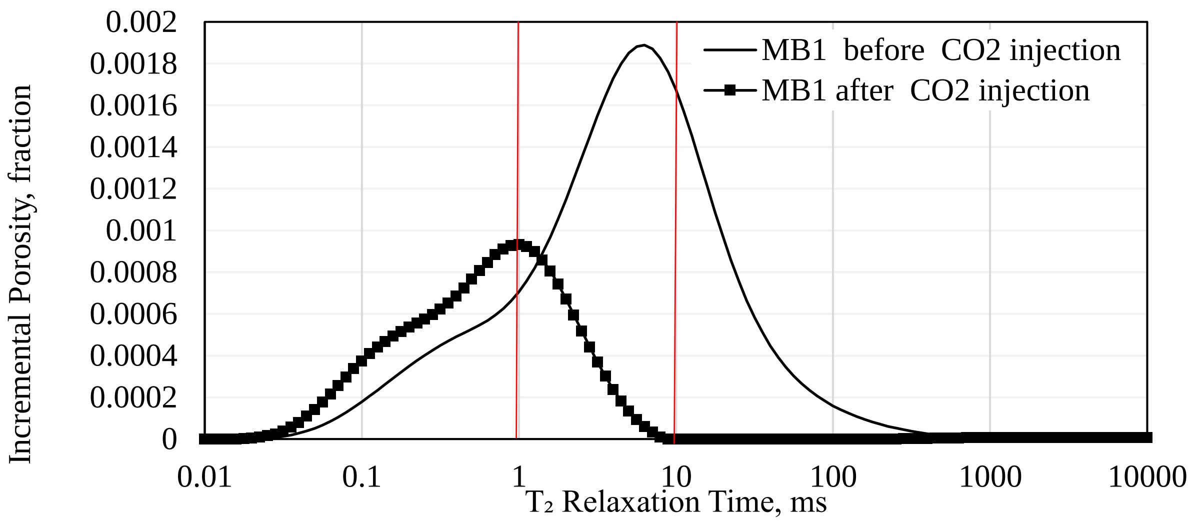
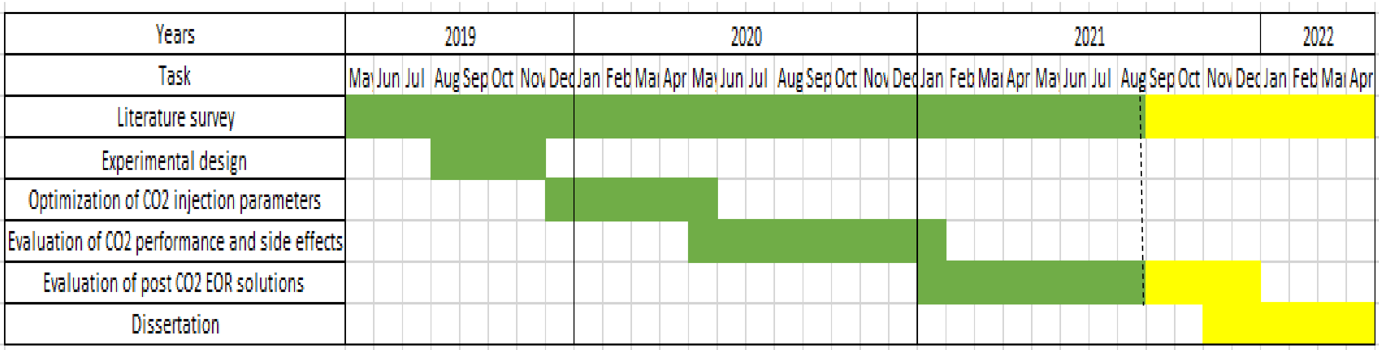


Figure 1. Incremental porosity Vs T2 Relaxation time of MB2 sample, straight black line: before CO_2 injection, black-squared line: after one CO_2 HnP cycle

Comparing CO_2 and Hydrocarbon Gas EOR Performance: To expand our understanding of gas EOR techniques and their viability to recover oil from MB and TF samples, in this section we compared the oil recovery factor after using cyclic CO_2 injection to successive injection of CO_2 and two different hydrocarbon gasses (ethane and propane). After performing three CO_2 HnP cycles, three successive HnP cycles, using CO_2, C2, and C3, respectively, were performed under similar conditions and the results were compared. The injection order is set based on the molecular weight selectivity of each gas. The results of these experiments show more oil can be recovered that by combining different gases. Following CO_2 injection by ethane and then propane injection can help overcome the narrow molecular weight selectivity of CO_2 and mobilize heavier hydrocarbons.

Project Milestone and Timeline:



Impact of CO_2 Storage on the Geomechanical and Geophysical Properties of Unconventional Reservoir and its Potential for Fault Reactivation

Ogochukwu Ozotta
Ph.D. student, Department of Petroleum Engineering, UND

Problem Statement:

Microfractures are generated in shale when CO_2 is injected into shale reservoir, causing swelling of shale matrix. CO_2 adsorption also weakens the mechanical properties of the shale. Mineral dissolution might influence diffusion properties by producing secondary pores and cracks in shale, which enhances the porosity and permeability. CO_2 in different phase state also caused a reduction in the uniaxial compressive strength test and Young's modulus. As pore pressure increases in the reservoir, the effective normal stresses on the fault's plane decrease, and may reactivate fault in the basin. This research aims to:

- Study CO_2 storage effect on rock matrix
- Pore structures of the shale reservoir in reaction to CO_2 storage.

This research will provide the mechanical information of the Bakken cores in reaction to load, water, and CO_2 exposure, and to ascertain if CO_2 storage will reactivate faults in the Williston Basin. This information will be used to determine the volume of CO_2 for storage and enhanced oil recovery, and capacity and integrity of each of the Bakken Formation member in North Dakota. If the mechanical and chemical properties are changing, how much of the changing is associated with the absorption of organic matter and how much of it is related to changes in the pore structures.

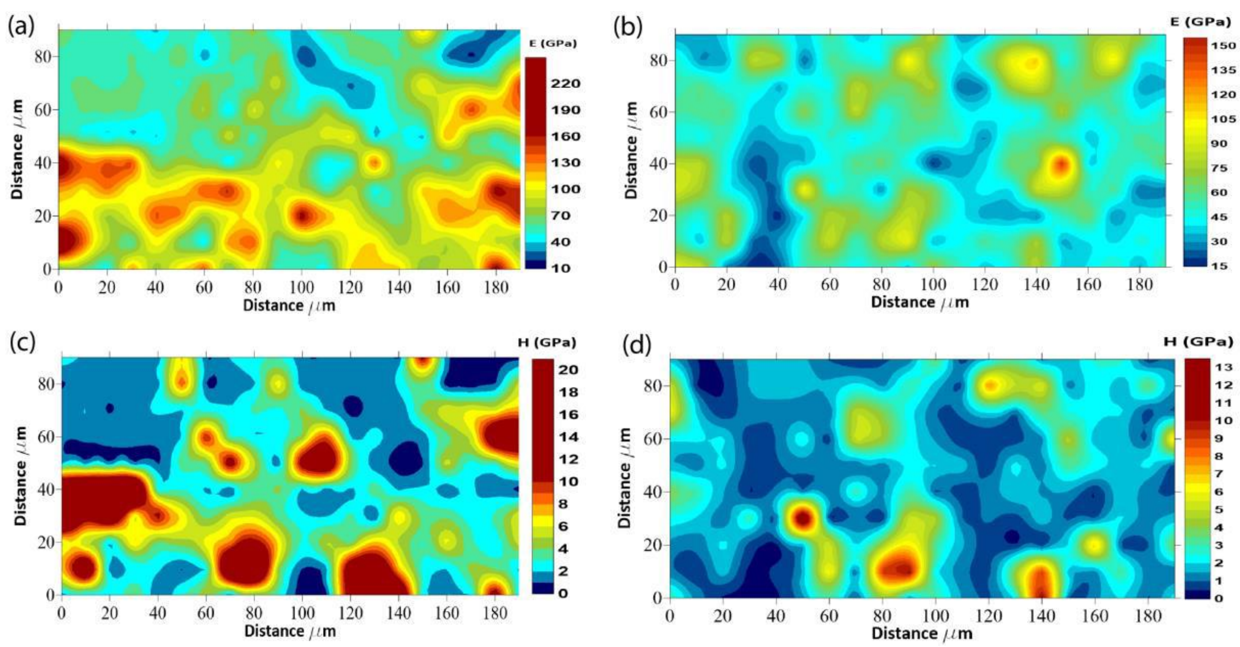
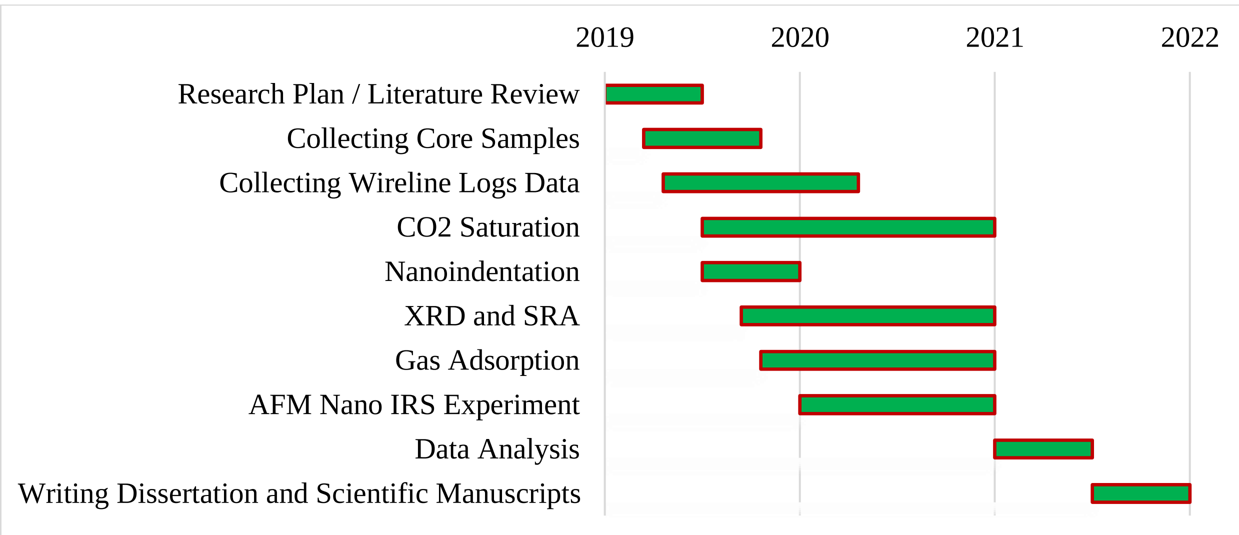


Figure 2. Mapping of elastic modulus of tested area in middle Bakken for (a) pre-CO2 saturation, and (b) post-CO2 saturation; with the mapping of hardness of tested area in the MBS for (c) pre-CO2 saturation, and (d) post-CO2 (d) saturation

Progress to Date:

- Literature review on the impact of CO_2 saturation on the geomechanical properties of shale reservoir.
- Built a geological model of the field with all the formation properties.
- Saturation of core samples with CO_2
- Carried out nanoindentation test on shale reservoir of the Bakken Formation
- Source Rock Analysis
- Field Emission Scanning Electron Microscopy (FESEM) characterization of the shale reservoir.
- Carried out gas adsorption to understand pore structure on the caprocks
- Nanoindentation changes on the shale reservoir
- Nano Atomic Force Microscopy (AFM) on caprocks parallel and perpendicular to bedding plan for anisotropy.
- Carry out triaxial test and velocity test to measure the elastic modulus, p-wave and s-wave on core plugs.

Project Milestone and Timeline:



Next action:

- Data analysis
- Manuscripts

Publications:

- Ozotta, O., Ostadhassan, M., Rasouli, V., Pu, H., Malki, M. L., Dawodu, O.V.& Kolawole, O. (2021). Homogenization models to determine the change in elastic properties due to CO2 injection. American Rock Mechanics Association.

- Ozotta, O., Ostadhassan, M., Liu, K., Lee, H., Pu, H., Kolawole, O., & Malki, M. L. (2021). Time−dependent impact of CO_2−shale interaction on CO_2 storage potential. 15th international conference on greenhouse gas control technologies.

- Ozotta, O., Ostadhassan, M., Liu, K., Liu, B., Kolawole, O., & Hadavimoghaddam, F. (2021) Reassessment of CO2 Sequestration Tight Reservoirs and Associated Formations. JPSE 109071 0920−4105 https://doi.org/10.1016/j.petrol.2021.109071

- Ozotta, O., Liu, K., Gentzis, T., Carvajal−Ortiz, H., Liu, B., Rafieepour, S., & Ostadhassan, M. (2021) Pore Structure Alteration of Organic−Rich Shale with Sc−CO2 Exposure: the Bakken Formation. Energy & Fuels 35(6), 5074−5089 https://dx.doi.org/10.1021/acs.energyfuels.0c03763

- Ozotta, O., Ostadhassan, M., Liu, K., Lee, H., & Onwumelu, C. (2020). Pore Structure Analysis from CO_2 Saturation using Gas Adsorption. In *SPE/AAPG/SEG Unconventional Resources Technology Conference*. Unconventional Resources Technology Conference.

- Ozotta, O. and Ostadhassan, M. (2019) Geomechanical Analysis of CO_2 Sequestration in the Bakken Formation, AAPG Annual Convention and Exhibition

UAS-Based Artificial Intelligence Solutions to Monitor and Reduce the Negative Impacts of Frontier Climate on Oil and Gas Assets

Matt Dunlevy
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Problem Statement:

There is a general lack of scholarly treatment and understanding of the capabilities, and applications, of Unmanned Aircraft Systems (UAS) technologies in the oil and gas industry, and especially how they pertain uniquely to the state of North Dakota. Because of North Dakota's climate and topography along with its status as a leader in the production of oil, and because of its recognition as the premier place in the United States to execute UAS operations, research on the intersection of these concepts can compensate for that lack. This study, generously funded by the North Dakota Industrial Commission, aims to fill that void of scholarship by flying drones with various types of advanced sensors to demonstrate what UAS solutions best assist oil companies' winter maintenance and leak detection needs. The research will compare the efficacy of the sensors under varying conditions of snow compaction, temperature, and atmospheric conditions. The three major areas of consideration for the project are UAS airframes, UAS sensors, and UAS use-cases, and as they are tested and compared, the ultimate goal will be to put forth a spectrum of which drone packages are optimized for the most important oilfield missions in the winter.

Progress to Date

As it became clear that the previous direction of the project needed to be altered, much of the work since the last update has been logistical. The focus of the current work has been on enabling the comparison of thermal imagery, magnetic induction level, and subterranean radar signals of pipelines under varying conditions. To enable experimental setup for imaging, one of the largest oil pipeline operating company has in North Dakota has been contacted to see if they were willing to donate a section of pipeline to UND for this research and they generously agreed to donate the pipe (see Figure 1). The permissions required to conduct the research using aerial drones on UND properties has to be ironed out with the UND Committee for the Strategic Enhancement of Autonomous Systems Research (CSEASR). CSEASR has granted permission for this research as of of 2 Aug 21.

Figure 1. Donated pipeline for UND research from a North Dakota pipeline company

Thermal data has been primarily used to detect pipeline signatures, however, literature and previous tests indicate that snow compaction in North Dakota heavily impacts the thermal wavelengths of IR images and their ability to detect buried pipelines. In order to enhance the detection of buried pipelines under snow compaction, an improved object detection apparatus is required. Hence, a convolutional neural network (CNN) designed for object detection developed by MIT is currently being modified for use to detect these buried pipelines and anomalies associated with them. The CNN utilizes various identity blocks as well as instance segmentation techniques to identify the boundaries of entities. Images are currently being acquired to train this network and various image multiplication techniques will similarly be used. An extremely high-power computer was built to keep up with the graphics processing, and artificial intelligence training required of the UAS-acquired imagery.

A bailment agreement has been executed with Infrared Cameras Inc. (www.infraredcameras.com) and they have sent an Optical Gas Imager as well as a UAS IR sensor to compare with the FLIR XTR data. The FLIR Duo Pro R sensor and another unique mounting bracket seen in Figure 2 are en route for the research. The Duo Pro R is the only sensor able to do the temperature attenuation needed to research the actual absolute temperature differential of a pipe against what a UAS-mounted thermal sensor reads.

(a) (b)

Figure 2. (a) Newly acquired FLIR Duo Pro R with atmospheric attenuation. (b) Custom mounting bracket for FLIR sensor on a DJI Inspire 1 UAS

According to literature, magnetometers and ground penetrating radars are successful tools for detection of buried pipelines. Therefore it is essential to understand their behavior in North Dakta's climate. Communications with the only company that makes UAS magnetometers (www.geometrics.com) and the only company that makes UAS Ground Penetrating Radar (www.radarteam.se) have been established. Having received quotes from the companies, a decision was made to cancel the Ground Penetrating Radar (GPR) research due to the fact that they will not rent a GPR unit and they are cost prohibitive. Hence, the magnetometer is to be rented for a period of time to enable the detection of buried pipelines under varying conditions.

Next Steps:

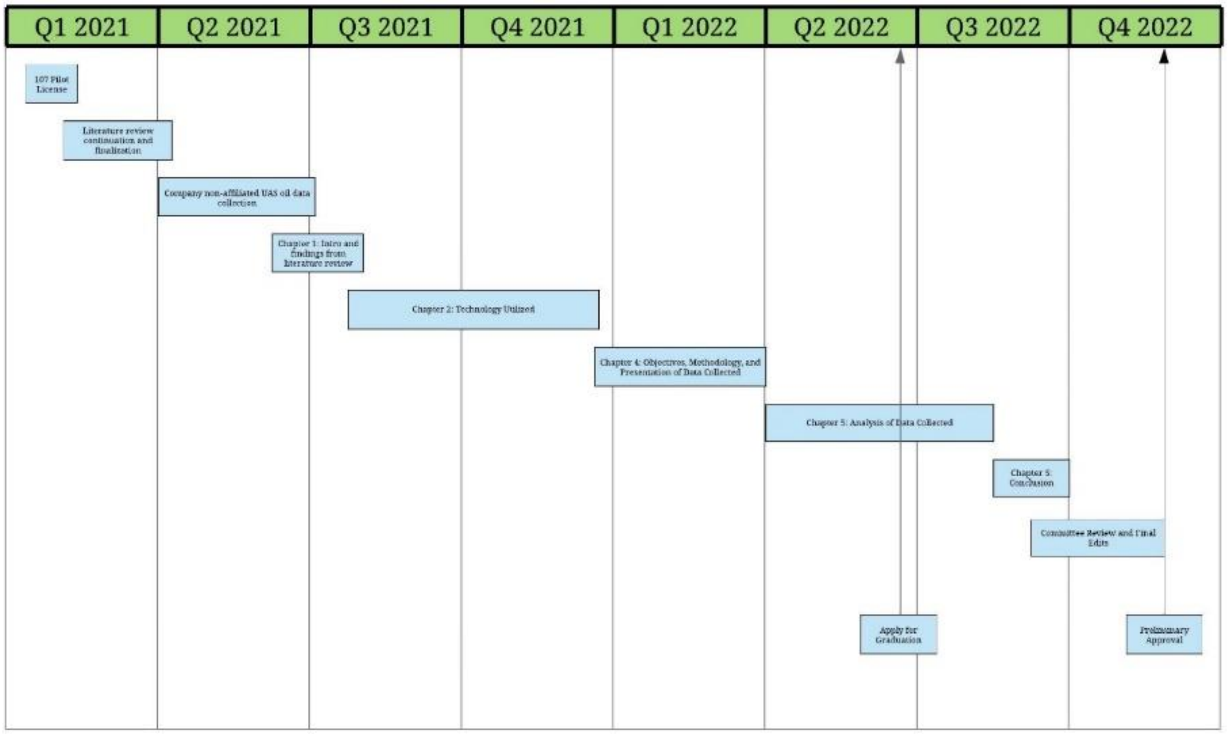
Now that parameters of the project are set and resources will arrive soon, a new literature review is being conducted with some of the references cited previously, among new references found from OnePetro specifically pertaining to the topic. The UND Petroleum Engineering Department has authorized the rental for a UAS magnetometer seen with a sample data set of a pipeline below in **Figure 3**.

Several oil companies mentioned in previous updates that owns the pipelines imaged in the thermal photos taken throughout the course of this research have been contacted, and the department will be receiving their pipeline schematics and history shortly. In addition to training the AI or new purpose of detecting buried pipelines, multiple types of required Geometrics magnetometer software known as “CSAZ,” “MagComp,” “MagPick,” and “MagMap” will be acquired. UND’s Research Institute for Autonomous Systems will be approached as a partner for the CONOPS to assist in the execution of some of the UAS missions and data analysis. The missions will commence as soon as the donated pipeline arrives at UND and is buried, and the sensors arrive from Geometrics and ICI.

(a) (b) (c)

Figure 3. (a) Geometrics MagArrow Magnetometer rental for pipeline flights. (b) MagArrow collecting aerial data from a DJI Matrice 600 UAS. (c) A pipeline dataset from the MagArrow displaying an oil pipeline

Project Milestone and Timeline:



Simulation of Hydraulic Fracturing Propagation in Transverse Isotropic (TI) Formations

Nourelhouda Benouadah
Ph.D. student, Department of Petroleum Engineering, UND

Problem Statement:

Multi-stage hydraulic fracturing is commonly used in stimulation of unconventional plays. A large number of these rocks exhibit transverse isotropy (TI) behavior due to fine scale layering, especially shales which are the most common hydraulically fractured rock type. In recent years, different studies and experiments have been conducted to understand the impact of anisotropy on the initiation and the propagation of hydraulic fractures. Some studies focused on the impact of stress anisotropy, others interested in studying the grain direction and orientation along the bedding plane causing the rock to be anisotropic. There are several studies which focus in the anisotropic parameters and the plane of elasticity and their impact on fracture propagation. However, most of hydraulic fracturing simulations have been modeled assuming isotropic medium. In this study, we will use analytical models and latice-based numerical simulations to investigate the most important parameters that control the initiation and propagation of natural fractures in TI medium. We will use the Bakken Formation Data in this study.

Progress to Date:

We studied analytically the effect of toughness anisotropy K_{IC} on the initiation pressure of a transverse and axial fractures and compared the energy needed to initiate each fracture type for different toughness anisotropy ratios $K_{C,3}/K_{C,1}$. Figure 2 shows a medium with transverse isotropic toughness.

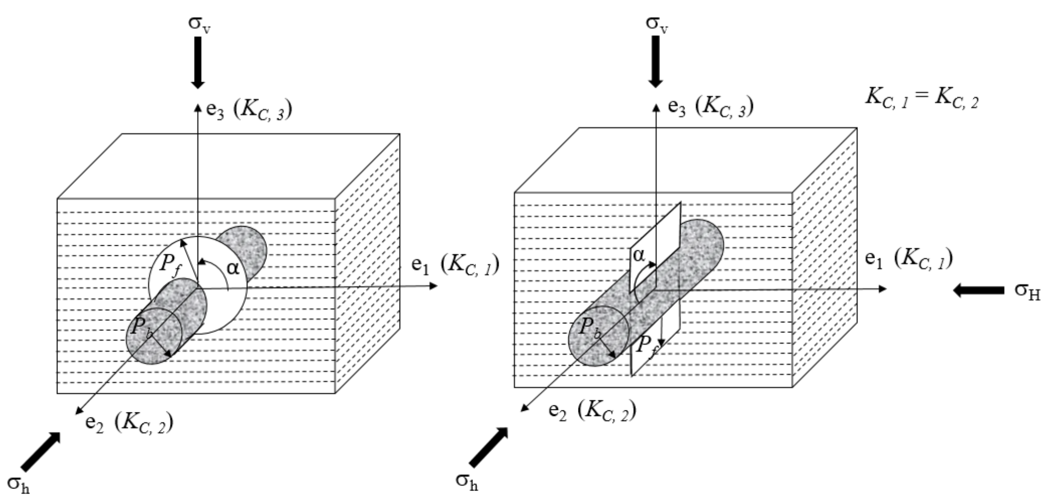


Figure 1. A medium with transverse isotropic toughness.

The pressure required to initiate a pre-existing crack of length L at the wellbore with a fracture toughness K_C is the minimum wellbore pressure that fulfils the condition $K_I/K_c = 1$. We used the following equation to calculate the initiation pressure (Benouadah et al. 2021):

$$K_I = \frac{2}{\sqrt{\pi}}\sqrt{L}\int_0^L (P_f - \sigma) f\left(\frac{x}{L}, \frac{L}{a}\right)\frac{dx}{\sqrt{L^2 - x^2}}$$

To implement the transverse isotropic toughness we used the following equation that shows the direction dependence of fracture toughness (Zia et al. 2018):

$$K_c = K_{c,3} \times \left(\sin^2\beta + \left(\frac{K_{c,1}}{K_{c,3}}\right)^4 \cos^2\beta\right)^{1/4}$$

$$\beta = \arctan\left(\left(\frac{K_{c,1}}{K_{c,3}}\right)^2 \tan(\alpha)\right)$$

Fracture initiation pressure curves for both fracture geometries (Axial and Transverse) under different $K_{C,3}/K_{C,1}$ ratios are plotted in Figure 2. As shown in the plot, when the ratio $K_{C,3}/K_{C,1}$ increases, the initiation pressures of both fracture geometries increase.

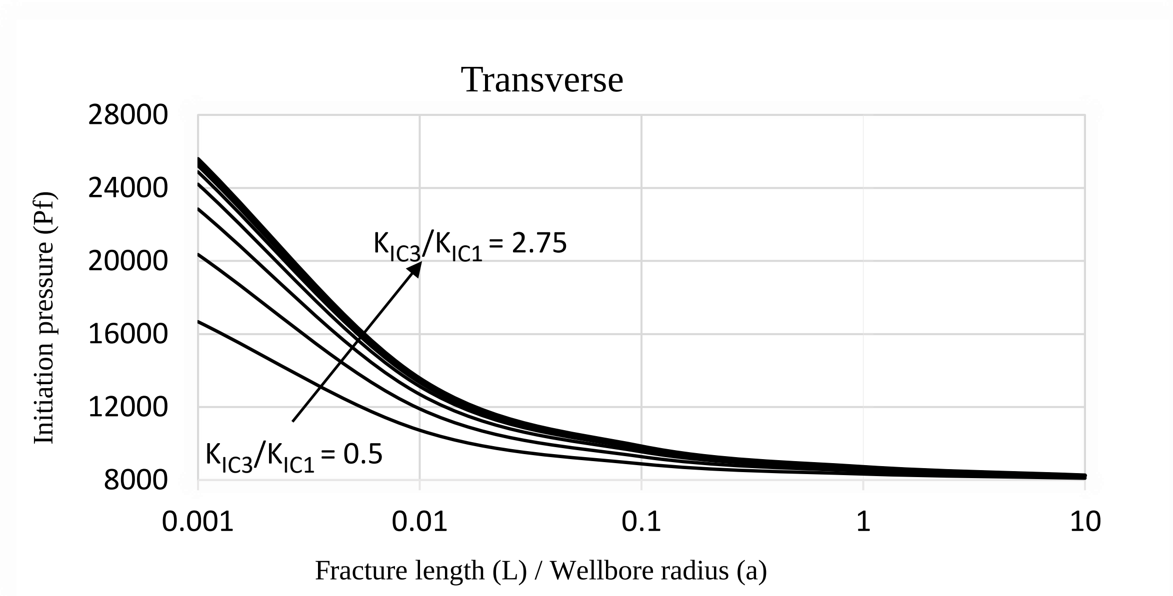


Figure 2. Fracture initiation pressures for transverse fracture in presence of different transverse anisotropic toughness.

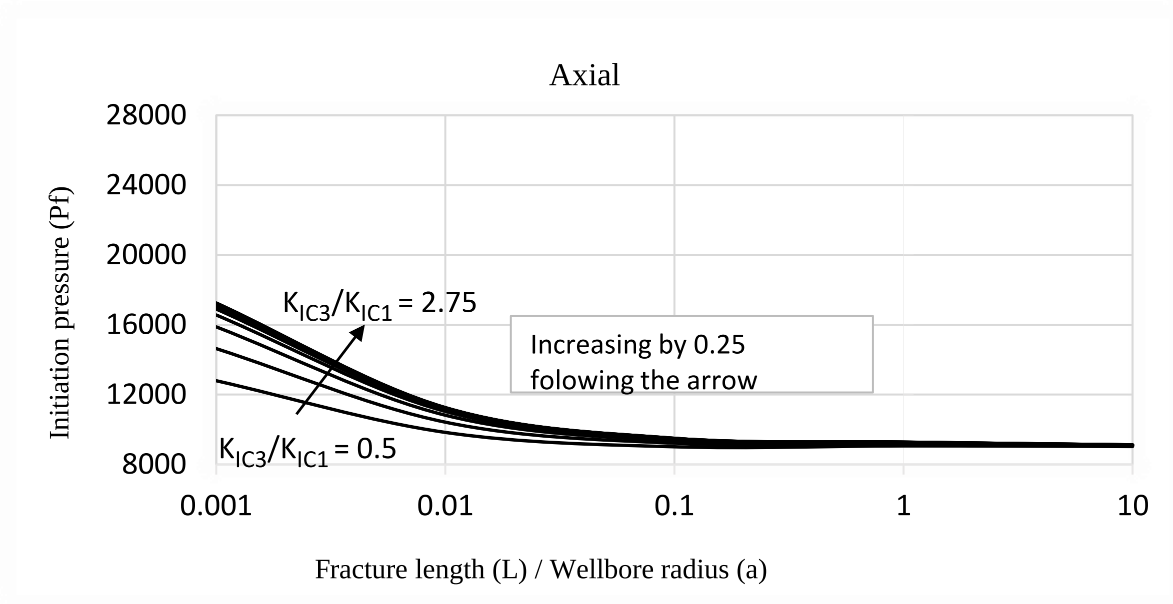


Figure 3. Fracture initiation pressures for axial fracture in presence of different transverse anisotropic toughness.

From **Figure 4** and **5**, it is seen that the cross over point moves to the right as the toughness anisotropy increases, this means larger notch length is needed to initiate transverse fracture.

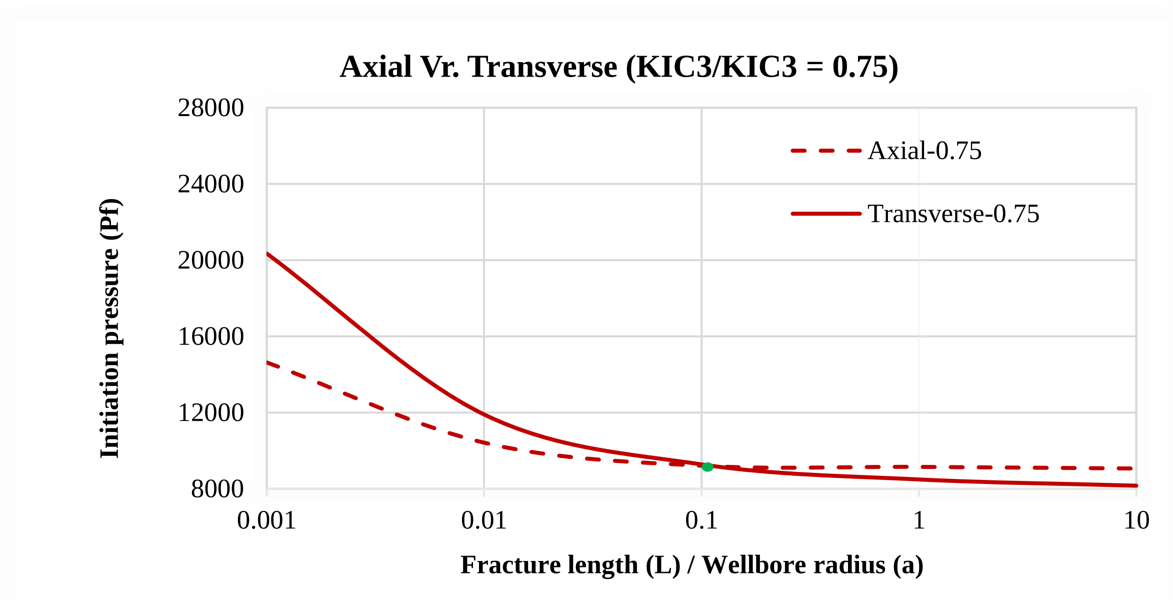


Figure 4. Fracture initiation pressures for both transverse and axial fractures for $K_{C,3}/ K_{C,1}$ =0.75.

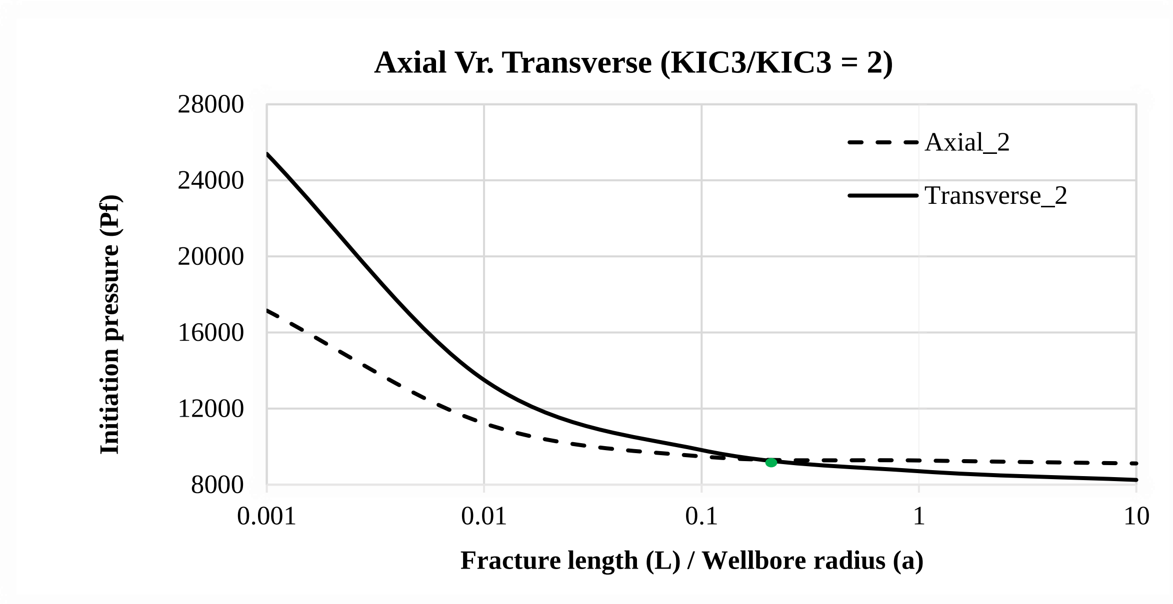


Figure 5. Fracture initiation pressures for both transverse and axial fractures for $K_{C,3}/\,K_{C,1}$ =2.

Next, we will run simulations to confirm the results using XSite, a new grain-based model software from the Itasca Consulting Company.

Project Milestone and Timeline:

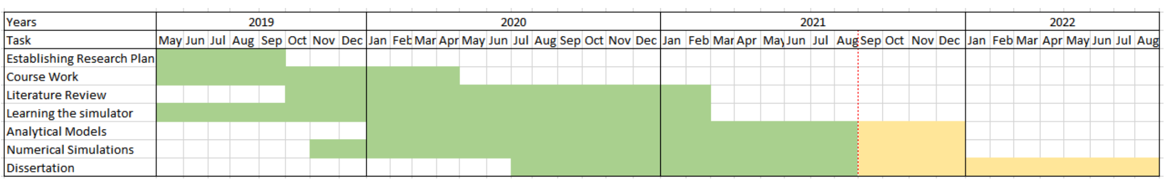


Figure 6. Project Milestones

References:

Benouadah N, Djabelkhir N, Song X, et al (2021) Simulation of Competition Between Transverse Notches Versus Axial Fractures in Open Hole Completion Hydraulic Fracturing. Rock Mech Rock Eng. https://doi.org/10.1007/s00603-021-02378-2

Zia H, Lecampion B, Zhang W (2018) Impact of the anisotropy of fracture toughness on the propagation of planar 3D hydraulic fracture. Int J Fract 211:103–123. https://doi.org/10.1007/s10704-018-0278-7

Enhanced Oil Recovery in Conventional and Unconventional Reservoirs Using Different Gases-DLM EOR and Storage

Jin Zhao
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Problem Statement:

Geologic storage of feedstock gas is an essential component of a petrochemical industry while a depleted conventional oil/gas reservoir may serve as a site for gas storage (Carter and others, 2017). According to the successful water flooding operations and their ability to trap oil and gas for millions of years, the Dickinson Lodgepole Mounds (DLM) in southwestern North Dakota have been identified as possible targets for natural gas EOR activities.

An important part of the study was investigated the possibility of storing feedstock gas in the Dickinson Lodgepole Mounds (DLM) and developing (preliminary) strategies to create this storage capacity through EOR. The proposed integrated simulation workflow may help operators optimize natural gas EOR activities in the mature conventional oil fields in North Dakota. The whole study would provide data to decision-makers intent on supporting the development of a Bakken gas storage hub and the petrochemical industry in the state. Since Bakken oil and gas production is one of the most important part of North Dakota's economy, the results of this study would benefit the local industry.

Progress to date:

Collected data for reservoirs in the DLM and select one representative field - Stadium Field, for a more detailed study (See Figure 1). The DLM are a reef structure which contains some of best wells in the history of North Dakota (See Figure 2). The Lodgepole Formation may a good source rock because it overlies the organic and oil-rich Bakken Formation even then it’s a tight, shaly limestone cap rock. However, compare to the average Lodgepole rock, the DLM contains a clean lime mud with higher porosity and substantially higher permeability (Burke and Diehl, 1993). The DLM have 44 wells are distributed inproducing from the ten individual fields at DLM. So far, the 44 wells in the DLM have produced 67 MMbbl of oil and injected 247 MMbbl of water, which show that the mounds are suitable for production and injection operations. Table 1 shows the ownership of the wells in the DLM.

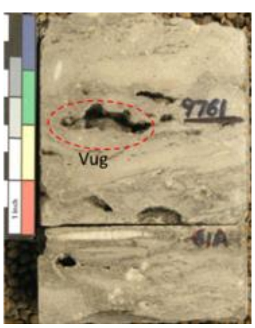


Figure 1. Images of cores collected from the DLM

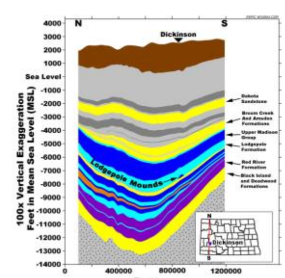


Figure 2. North-to-south cross section through North Dakota and the DLM.

Table 1. Ownership of wells in the DLM

Table 1. Ownership of Wells in the DLM			
No.	Company	Wells	Percentage
1	Scout Energy Management, LLC	32	72.73%
2	Armstrong Operating, Inc.	4	9.09%
3	White Rock Oil & Gas, LLC	4	9.09%
4	ConocoPhillips Company	1	2.27%
5	Core 54 Oil and Gas, LLC	1	2.27%
6	Denbury Onshore, LLC	1	2.27%
7	Wesco Operating, Inc.	1	2.27%
	Total	44	100%

Table2. Components in the EOS model

Table 2. Components in the EOS model			
No.	Component	No.	Component
1	CO_2	6	IC4 to NC4
2	N_2	7	IC5 to C7
3	CH_4	8	C8 to C12
4	C_2H_6	9	C13 to C19
5	C_3H_8	10	C20 to C30

Developed a reservoir simulation model to evaluate the gas storage potential in the DLM, here ethane and propane can easily interact with the remaining oil in the reservoir. According to the large size of DLM, Stadium filed was selected to conduct the simulate study Stadium Field has five wells and a remarkable production and injection records. So far, around 13 MMbbl of oil, 31 MMbbl of water, and 24 Bcf gas have been produced. In addition, 37 MMbbl of water has been injected in the field. Equation of state (EOS) regression and history matching will be performed to create a working simulation model for gas storage prediction. Figure 3 shows the distribution of essential porosity; Figure 4. Shows EOS model (GOR). Based on those, a simulation model was developed for the Stadium Field, as shown in Figure 5.

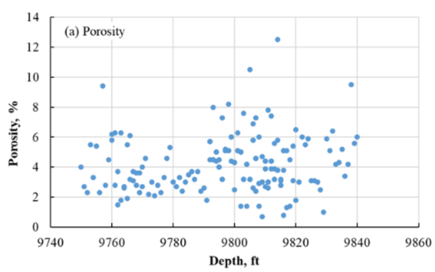


Figure 3. Distribution of porosity

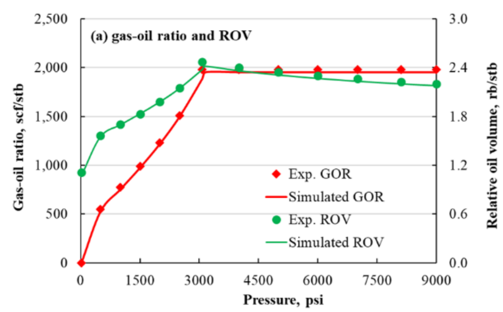


Figure 4. EOS Model

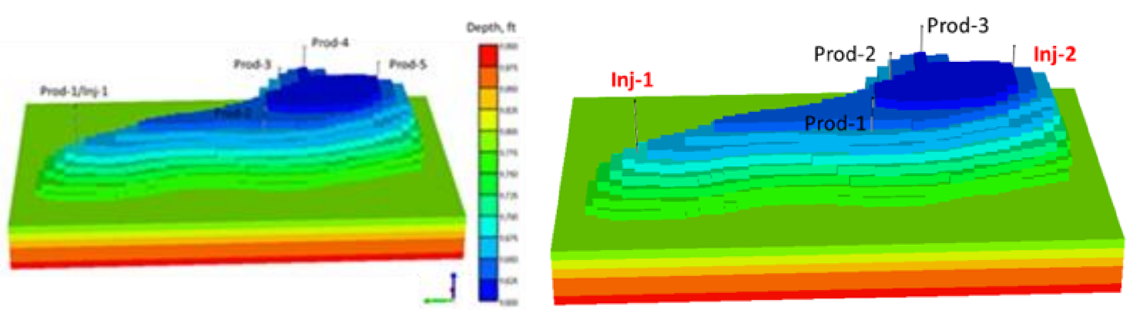
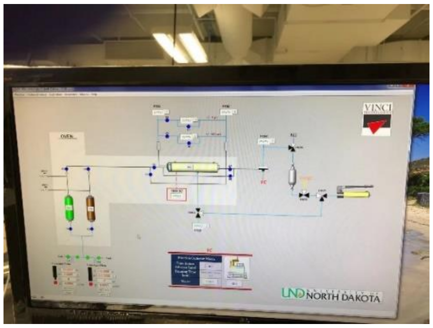


Figure 5. Simulation model of the Stadium Field

Conducting experiments to investigate EOR effects of different gases in the Stadium Field: C2 and C3 core flooding experiments have been conducted for DLM cores (See Figure 6 and 7 for the experiment setup).



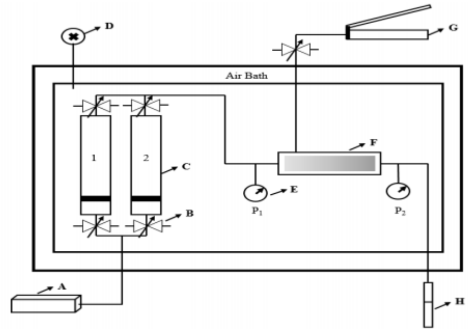


Figure 6. Image of the experimental setup

Figure 7. Schematic diagram of the experimental setup(Xun,2020)

Project Milestone and Timing:

Years	2019					2020												2021												2022											
Task	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
Established Research Plan																																									
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Experiment & Analysis Model																																									
Model & Journal Paper																																									
Dissertation																																									

Figure 8. Project Milestones

References:

Burke, R.B., and Diehl, P., 1993, Waulsortian mounds and Conoco's new Lodgepole well: North Dakota Geological Survey Newsletter, v. 20, no. 2.

Carter, K.M., Patchen, D.G., Moore, J.P., Fakhari, M., Daft, Jr. G.W., Solis, M., Dunst, B.J., Anthony, R.V., Schmid, K.W., Metz, K., and Dinterman, P., 2017, A geologic study to determine the potential to create an Appalachian storage hub for natural gas liquids: Final report for the Appalachian oil and natural gas research consortium, July 31, 2017.

Yu, W., Wu, K., Liu, M., Sepehrnoori, K., and Miao, J., 2018, Production forecasting for shale gas reservoirs with nanopores and complex fracture geometries using an innovative non-intrusive EDFM method: SPE-191666-MS, Presented at the SPE Annual Technical Conference and Exhibition. Dallas, Texas.

Zhong X. Surfactant-Nanoparticle Augmented Systems for Enhanced Oil Recovery: Formula Development and Evaluation.

Optimization of Stimulated Wells in Unconventional Reservoirs

Jerjes Porlles
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Problem Statement:

Deep reservoirs, such as granite or limestone provide high temperature to develop an unconventional project. Some rock properties, such as natural fractures, matrix porosity, permeability, rock thermal conductivity, and so on. Also, working fluid (water and CO2) should be analyzed to determine the optimal unconventional reservoir model using data analysis, statistical, and process improvement tools to generate an enhanced geothermal system.

An Enhanced Geothermal System is used to produce energy from hot dry rock geothermal resources for use in power production. These rocks, such as granite, are dry and impermeable at depths ranging from 9,000 to 18,000 feet with temperatures above 150 °C. Two wells are drilled to create a circulation loop for cycling fluid through the enhanced geothermal system: injection and production. The thermal energy between these two wells is extracted by circulating fluid through fractures created by hydraulic fracturing; therefore, hydraulic fracturing is the key technology used to produce geothermal energy in this system.

The EGS technique is typically performed using a nearly vertical well in one stage without proppant. The oil and gas industry has accomplished radical improvements in stimulation performance in the past several years by using multiple stages, proppants, and horizontal, or deviated, wells. These technologies have not yet been adopted in EGS since the community has focused their attention on the concept of "shear stimulation," or injecting water to induce slip-on self-propping natural fractures; therefore, proppant is viewed as being unnecessary or ineffective. The use of packers to enable multiple stages is considered technically infeasible since EGS wells are completed open-hole to maximize connectivity to natural fractures, and reliable open-hole packers are not available at high temperatures.

Some formations in the Williston Basin have around 100°C to 160°C. This energy should be used to provide more energy to the North Dakota population, especially communities near oilfields into the Williston Basin. Deadwood Formation and Red River Formation, in the Williston Basin, are viable sites for the installation of Enhanced Geothermal System (EGS). EGS is possible there because temperatures in the formation surpass 150° C and the permeability is 0.1-38 mD. Also, fracture stimulation can be utilized to improve performance using Xsite, which is a powerful three-dimensional hydraulic fracturing numerical simulation program based on the Synthetic Rock Mass (SRM) and Lattice methods.

Progress to Date – Results & Discussion:

Since the research was initiated, it was developed a series of investigations related to Geothermal concepts.

1. Using Additive Manufacturing to design, fabricate Pipe Interventions Gadget (P.I.G.) for Removal of Scale Deposition from Geothermal Wells (Figure 1). This proposal's core focus is to advance the pigging device capability towards increasing the cleaning efficiency in geothermal pipelines.

   http://blogs.und.edu/uletter/2020/11/und-engineering-team-wins-geothermal-manufacturing-prize-advances-to-next-level/

   This research participated and won a Geothermal Prize which is led by DOE's Office of Energy Efficiency and Renewable Energy's Geothermal Technologies Office (GTO) and Advanced Manufacturing Office (AMO), and is administered by the National Renewable Energy Laboratory (NREL) in partnership with Oak Ridge National Laboratory (ORNL).

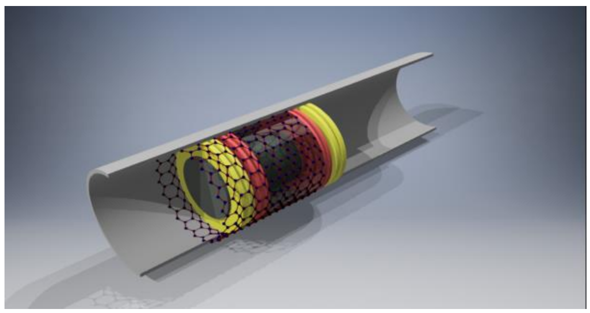


Figure 1.

2. It was developed a series of experiments at the Autolab to determine the Mechanical Permeability Prediction during Loading/Unloading with respect to Critical Stress in Unconventional Reservoirs. The purpose of the experiments is to fit models to the experimental data points during pressurization and depressurization for an unconventional rock sample using exponential and power-law models. Determine average permeability/porosity damage for each core sample, under different confining and pore pressure values. Effect of critical stress on geomechanical properties, Young's and Poisson. Currently, it was developed the experiments, collecting data, QA&QC, and data analysis.

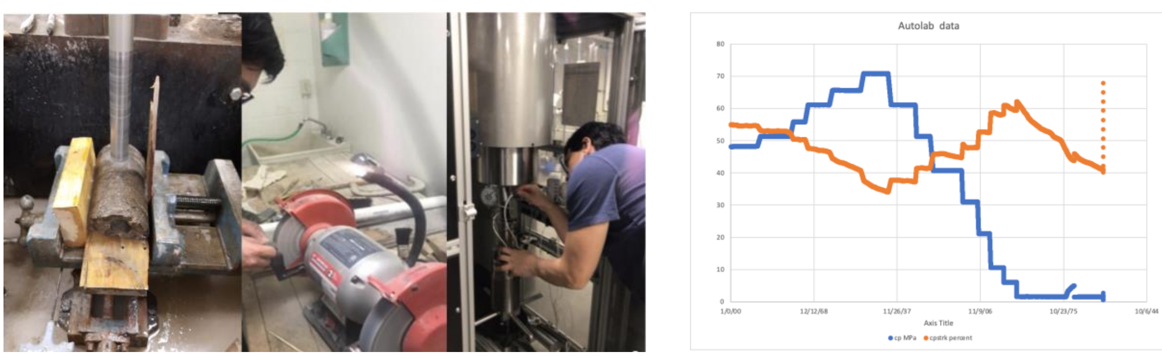


Figure 2.

3. It was collected pressure and injection flow rate data from Utah-Forge project to develop an analysis of well testing, minifrac, and falloff test to determine reservoir properties. This analysis will be used to model a hydraulic fracturing (**Figure3**).

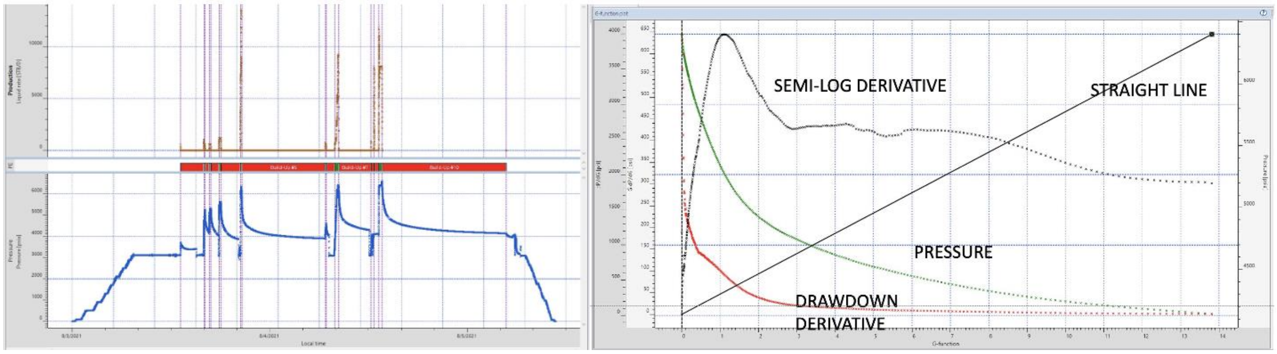


Figure 3.

4. Geothermal Design Challenge™. As a part of the literature review related to the Geothermal industry. It was developed an infographic that highlights the benefits of eight common uses of geothermal energy: agricultural drying, cooking, greenhouse heating, aquaculture, electricity generation, space heating, snow melting, and bathing and swimming. The infographic offers global context, breaking down each use as a percentage of the total geothermal market. A world map further illustrates the use of geothermal resources around the world.
https://www.energy.gov/eere/articles/department-energy-announces-winners-fall-2020-geothermal-design-challenge
This research participated and won the Fall 2020 Geothermal Design Challenge™ which is led by The U.S. Department of Energy's Geothermal Technologies Office. (Figure 4)

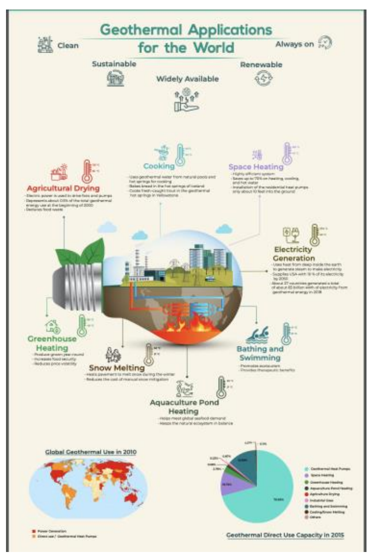
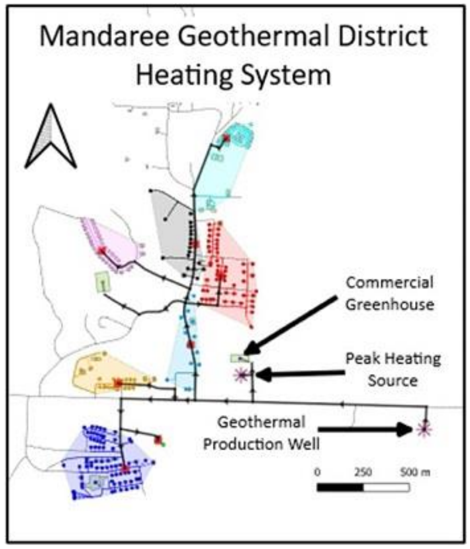


Figure 4.

5. Geothermal Collegiate Competition. The project is related to the direct use of Geothermal energy at the Mandaree community (North Dakota) using abandoned gas wells.
https://www.energy.gov/eere/geothermal/geothermal-collegiate-competition
This research participated and won the Geothermal Collegiate Competition which is led by the U.S. Department of Energy's (DOE) Geothermal Technologies Office. (Figure 5)



(Figure 5)

Project Milestone and Timing:

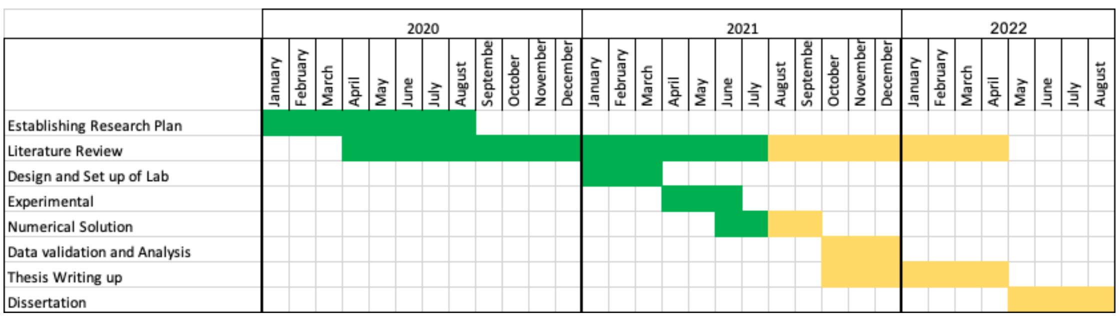


Figure 6.

Enhanced Oil Recovery by Hydrocarbon Gas Injection in Unconventional Reservoirs

Samuel A. Afari
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Problem Statement:

Unconventional reservoirs are known to hold significant quantities of hydrocarbon. However, owing to their extremely low permeabilities, they were unable to produce oil and gas in commercial quantities. Recent advances in hydraulic fracturing and horizontal drilling have changed this narrative. These technologies have more than doubled hydrocarbon production from unconventional reservoirs. Still, only a small percentage of the oil present in unconventional reservoirs (less than 10%) can be accessed using current technologies. After drilling and fracturing a well, oil production typically declines to less than 20% of the initial rate within one year. Current enhanced oil recovery techniques, that have been successful for conventional reservoirs, do not work for unconventional reservoirs. This warrants further research and development into enhanced oil recovery techniques that can improve oil recovery from these reservoirs.

Injection of gases into ultra-low permeability reservoirs to enhance oil recovery has shown promising results in many laboratory and field studies. In most of these studies, CO_2 has been used as the injection gas, because of its added environmental advantage. Only a few of these studies have considered hydrocarbon gases and their mixtures. Preliminary studies have shown that hydrocarbon gases may be better at enhancing oil recovery than CO_2 because of favorable properties such as lower viscosity, molecular weight, minimum miscibility pressure, etc. compared to CO_2. However, the mechanisms by which they enhance oil recovery and the factors that affect their performance remain elusive. The objectives of this research are:

- To investigate the performance of hydrocarbon gases (i.e. CH_4 and C_2H_8) and their mixtures in enhancing oil recovery in ultra-tight core samples and compare it with the performance of commonly used gases such as CO_2, N_2, and air.
- To investigate the underlying dominant mechanisms by which hydrocarbon gases and their mixtures enhance oil recovery.
- To investigate the various factors that affect the performance of hydrocarbon gases and their mixtures in enhancing oil recovery in ultra-tight core samples. These factors will include the effect of injection mode, injection pressure, surface area to volume ratio, and the presence of water saturation

Progress till Date - Results and Discussion:

Experimental: After cleaning, drying, and air evacuation, the core samples were saturated in oil in an accumulator at 2500 psi for two weeks. Owing to the low permeability of the middle Bakken core samples, only a minuscule amount of brine percolated the pore space. The Middle Bakken core samples have an average volume of 25cc and an average porosity of 3 %, which suggests the core samples have an average pore volume of 1 cc. After the first round of saturation, only 0.2 cc (average) of brine percolated the samples. This volume was too small for any meaningful estimations of oil recovery during core flooding. The core samples were then saturated again at 6500 psi for an additional one week. After this round of saturation, approximately 0.7 cc of brine was able to percolate the pore space. Next, a core sample was placed inside a core holder, and brine was injected at a constant pressure of 2500 psi. The rate of water production was noted with the corresponding pressure drops. This step enabled the calculations of absolute permeability. The calculated permeability of the core sample was 0.02 mD. Then, oil was injected through the core samples to displace brine. This step will enable the computation of relative permeability. Owing to the tight nature of the core sample, we expect that this process takes some time for the oil to breakthrough.

Numerical Simulation Modelling: A reservoir model of the Bakken and adjacent formations was constructed using CMG. The model (Figure 1) has a dimensions of 1500 ft x 6000ft x 150 ft with 31 x 30 x 5 grids. The fluid model has been described in the previous report. The well and production history have been modeled after the Deadwood-CR well in the Sanish Field. A history match was run to calibrate the reservoirs for correct, accurate reservoir properties. Figure 2 shows the history match results for the oil production rate. A base case production scenario was then run using to study the production performance without any injection. Gas injection using CO2 at the injection gas was simulated to study the performance of CO2 injection in the Bakken Formation. Then studies of different injection strategies were undertaken to study the optimum strategy and most important design parameters. The results are shown in *Figures 3 and 4*. The results indicate that CO2 injection is able to increase the recovery factor from 5.56% to 13.83% when operating parameters are optimized. When optimizing, the most important operating parameter is the production bottom hole pressure.

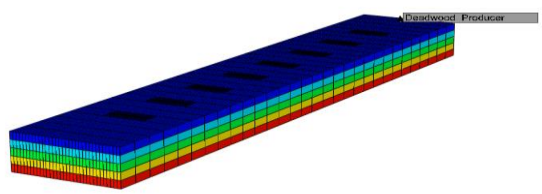

Figure 3. Reservoir Model of the Bakken and adjacent formations

Figure 4. History matched oil rate for the model.

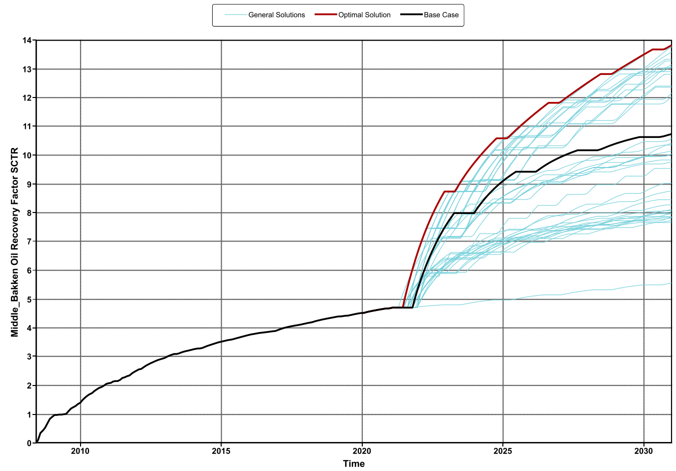

Figure 5. Recovery factors for various scenarios showing bases case, general solutions, and optimized case

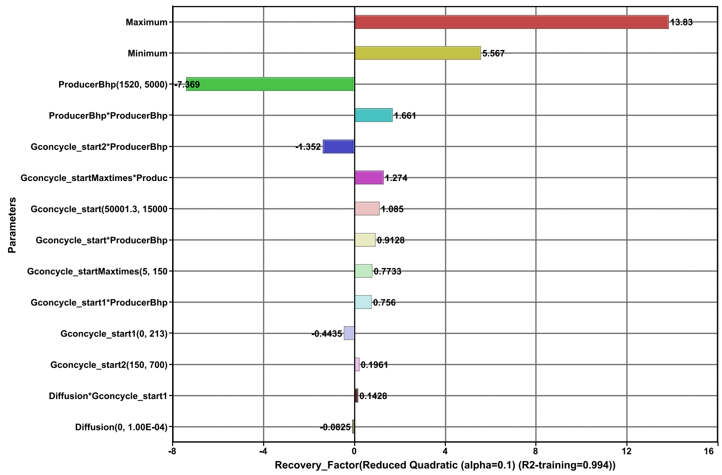

Figure 6. Tornado chart showing effects of various parameter

Project Milestone and Timeline:

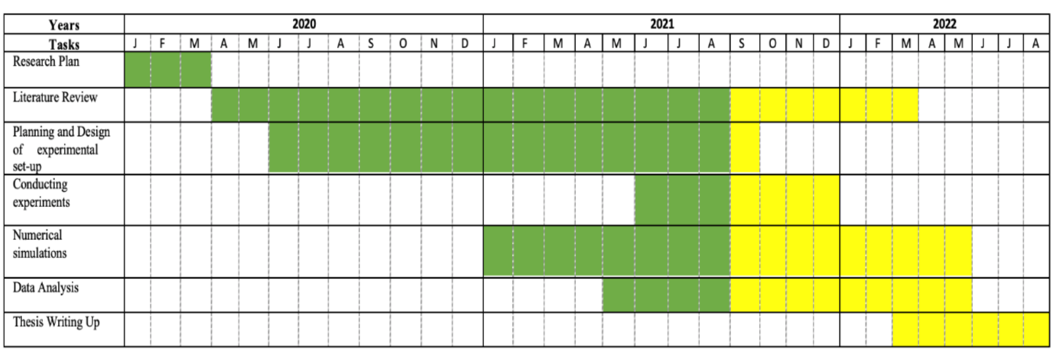

Figure 7. Project timeline

Cuttings Transportation Modeling and Optimization in Deviated Wellbores

Hamid Reza Rashidi Araghi
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Problem Statement:

Drilling long horizontal wells is common in development of unconventional reservoirs. Effective cuttings transportation for better hole cleaning during drilling operations can increase the rate of penetration (ROP) and mitigate various drilling associated problems such as high drag and torque and pipe sticking. Of the many functions that are performed by the drilling fluid, the most important is to transport cuttings from the bit up the annulus to the surface. If the cuttings cannot be removed from the wellbore, drilling cannot proceed for long. Transport is usually not a problem if the well is near vertical. However, considerable difficulties can occur when the well is being drilled directionally as cuttings may accumulate either in a stationary bed at hole angles above about 50° or in a moving, churning bed at lower hole angles. Drilling problems that may result include stuck pipe, lost circulation, and high torque end drag end poor cement job. The severity of such problems depends on the amount and location of cuttings. The objective of this research was to investigate the cuttings size, density, and fluid properties; coupled with wellbore deviation and circulation rate on hole cleaning efficiency.

In the early 1980s, experimental work was performed using different custom made flow loops [1–7]. These researchers focused on the particle settling velocity; however, they studied multiple particles movements in inclined wellbores resulting in an extensive literature on experimental and modeling work from which we modified some analytical models to study the rolling and lifting of particles. Clark and Bickham (1994), Ford (1993), Larsen et al. (1997), Luo et al. (1992), and Rasi (1994) developed some of the analytical models in this research topic. The model developed by Larsen et al. (1997) was able to predict cuttings bed height at sub-critical flow conditions, the rate less than what is required to prevent cuttings deposition in the annular space. Their model was based on empirical correlations derived from experimental data collected from a 35-ft long 5-in diameter flow loop. Luo et al. (1992) and Ford, (1993) previously formulated the sub-critical flow region mathematically, validating their models against experimental data. Some models were validated against experiments carried out at inclinations that allow cutting beds to form, i.e., inclinations higher than 50° [8-9]. Ford et al. (1990) developed a model available for different wellbore inclination. The results of their work showed that the flow regime and rheological properties of the fluid are the key parameters in hole cleaning.

Objectives:

- Hole cleaning efficiency by the change of wellbore deviation
- How fluid density and viscosity will impact on effective cutting transportation
- How cutting density, geometry and roundness will impact on cleaning efficiency
- How stabilizer will impact to increase on hole cleaning efficiency

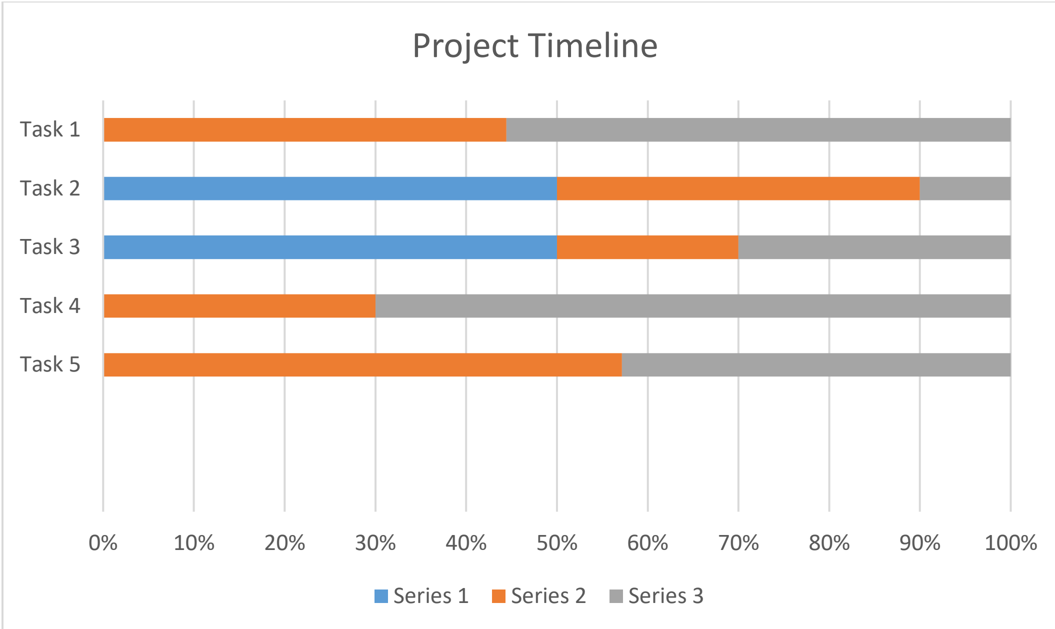
Methodology:

- Monitor and record various data during lab experiments, including pressure drops, flow rate, temperature and solid concentration.
- Use existing analytical models to optimize the parameters affecting cuttings transportation.
- Run numerical simulations using lab data to do sensitivity analysis of model parameters.
- Upscale the lab results to field scale through numerical simulations.
- The repose angle will be an important parameter in hole cleaning efficiency. This assumption was confirmed analytically and experimentally.
- The lift velocity is the limiting velocity needed to start cleaning a bed deposited at the wellbore. This value is not the optimum velocity for cleaning; however, it is the limit where the cuttings start to be transported out of the well.
- The cuttings transport model has been presented which uses fluid mechanical relationships developed for the various modes of particle transport: settling, lifting, and rolling. Each transport mechanism is dominant within a certain range of wellbore inclination range.
- The model provides a means of analyzing cuttings transport as a function of operating conditions (flow rate, penetration rate), mud properties (density, rheology), well configuration (angle, hole size, pipe size), and cuttings properties (density, size, repose angle, bed porosity).

Project Milestone and Timeline:

Time major milestone of the project Include the following tasks:

- Task 1: Literature
- Task 2: Slurry Loop Designed
- Task 3: Moved to New Drilling Lab
- Task 4: Experiment and Data Collection
- Task 5: Run numerical simulations



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Effects of Fractures on Carbon Dioxide EOR in the Bakken Formation: Laboratory Study

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Problem Statement:

Bakken Formation in the Williston Basin is one of the most productive unconventional reservoir in the US, which produces approximately one million barrels of oil per day (Hawthorne et al., 2017). Four units in the Bakken Formation mainly contribute to the proved-profitable production – the Upper Bakken Member, Middle Bakken Member, Lower Bakken Member and Three Forks Formation. The open natural fractures in the Bakken formation play a significant role in the hydrocarbon production, including the effects on reservoir permeability and porosity and then fluid migration. These fractures are resulted from multiple tectonic process and salt dissolution and induced collapse of overlying rock (Mullen et al., 2010). Beside natural fractures, hydraulic fracturing technique is also widely used in the Bakken Formation to produce trapped oil and gas due to extremely tight nature and ultralow permeability of the formation.

However, traditional EOR method (water flooding) is very challenging to be operated in the Bakken formation because of its tight matrix and complex and high-conductive fracture networks; so carbon dioxide flooding is considered as one of the applicable techniques to enhance oil recovery in the Bakken Formation. Many laboratory studies have demonstrated the effectiveness of carbon dioxide flooding on the EOR of unconventional reservoirs with concrete sample cores under low pressure and low temperature.

The proposed project is going to analyze the effects of fractures on CO_2 flooding in the Bakken Formation by testing fractured and concrete cores with similar size and properties.

Objectives:

- Design and develop the experiments under reservoir conditions.
- Investigate the performance of carbon dioxide flooding under high pressure and high temperature (approximately 6500 psi and 233 °F)
- Analyze how fractures affect the efficiency and results of carbon dioxide flooding in the Bakken Formation
- Investigate the difference between direct carbon dioxide flooding and Huff-n-Puff carbon dioxide flooding in the fractured unconventional reservoir

Methodology:

- Prepare fractured and concrete core samples in total of 25 and measure their size and properties.
- Use Core Flooding Experiment equipment to conduct three groups of contrast experiments under in-situ reservoir pressure and temperature. Further detailed experiment design is discussed in the Progress-to-date session.
- Compare experiment results to see the effects of fractures on carbon dioxide EOR.

Significance:

- Carbon dioxide flooding is one of the most important EOR method in the Bakken Formation due to ineffectiveness of traditional EOR method in the formation, the proximity of several large anthropogenic carbon dioxide sources and associated geological storage of carbon dioxide.
- There are thousands of fractures caused by natural geological process and hydraulic fracturing in the Bakken Formation.
- Experiment results may contribute to the understanding of the fracture effects on carbon dioxide flooding and optimization of carbon dioxide flooding design.

Progress to date – Experiments:

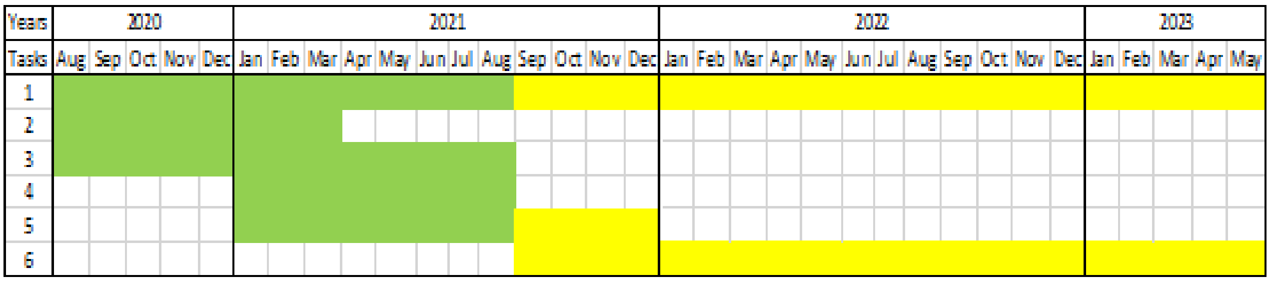
- 16 experiments are designed and completed until now. Different pressure and temperature conditions are considered. For temperature of 220 °F, the values of pressure used for core flooding experiment were 2650 psi (MMP), 4500 psi and 6500 psi. For temperature of 255 °F (reservoir condition), the values of pressure used for core flooding experiments were 3200 psi (MMP), 5000 psi and 6500 psi, which are slightly higher than those in temperature of 220 °F.
- Beside simple carbon dioxide flooding, water injection is also considered in the experiment due to the high-water saturation in Bakken Formation, ranged from 15% to 35%. The average TDS of water in Bakken formation is 244 g/L and most of them are NaCl. 300g NaCl were used for 1-liter purified water.
- Here are some results of core sample weight before and after core flooding experiments and design for different experiments.

Group	Core Sample No	Weight Before Experimemt (g)	Weight After Experiment (g)	Inj. Fluids	EOR Type
1	2-4	11.01	10.91	CO2+Water	Flooding
	18-1	13.99	13.85		
	C-1-1	32.31	31.89		
2	C-2-3	26.36	26.29	CO2+Water	Flooding
	C-3-1	30.02	30.01		
	6-1	33.22	33.28		
3	C-1-2	25.48	25.40	CO2+Water	Flooding
	C-2-1	30.42	30.38		
	N-1	29.61	29.55		
4	#5	67.60	67.25	CO2+Water	Huff-n-Puff
5	6	96.60	96.25	CO2+Water	Flooding
6	#12	93.61	93.44	CO2+Water	Huff-n-Puff
7	#2	78.48	78.32	Ethane+Water	Flooding
8	C4-1	41.52	25.25	CO2	Huff-n-Puff
	C3-2	26.39	26.22		
	C1-3	25.41	41.47		
9	#4	89.5	88.82	CO2	Flooding
10	F-9	87.21	85.9	CO2	Flooding
11	F-1-1	92.03	91.54	CO2	Huff-n-Puff
12	F-a	27.42	27.31	CO2	Flooding
	F-2-5	10.4	10.31		
13	F-3	77.53	77.31	CO2	Huff-n-Puff
14	F-5	70.26	69.92	CO2	Huff-n-Puff
15	F-2-1	88.17	88.03	CO2+Water	Flooding
16	F-4	92.44	91.96	CO2+Water	Huff-n-Puff

Project Milestone and Timeline:

Time major milestone of the project include the following tasks:

- Task 1: Literature review
- Task 2: Core samples preparation
- Task 3: Experiments design
- Task 4: Conduct core flooding experiments
- Task 5: Data collection, organization, and analysis
- Task 6: Thesis writing up



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Using Machine Learning methods to Predict Sandstone Cores' Mechanics Properties change after Polymer Flooding

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Problem Statement:

Recently, researches of clean energy become more and more popular. As a member of non-fossil energy, geothermal has advantages of clean and environmental protection. It is a practical way to use geothermal by changing abandoned oil wells to geothermal wells (Zhang et al., 2019). This method needs engineers to know target formations' mechanics properties. Thus, formulas which could predict how mechanics properties change after polymer flooding will be needed if engineers prepare to change polymer inject/produce wells into geothermal wells. This research's aim is to use Machine Learning methods to match cores' mechanics properties change value of before and after polymer flooding or other EOR methods.

Progress to Date:

Since I will arrive in UND at Fall 2021 semester, the research plan has to be changed. After the latest report, I mainly focused on three parts of work. First, continue oil displacement experiments in Daqing. Second, learn more machine learning methods and join in a research project in Beijing. Third, continue literature review which is about American oil fields especially Bakken oil field.

Oil Displacement Experiments: Following figure is one of experiments' results of surfactant flooding. These experiments simulated the recovery process which is water drive first, and then inject surfactant for 0.5 PV, and water drive at last.

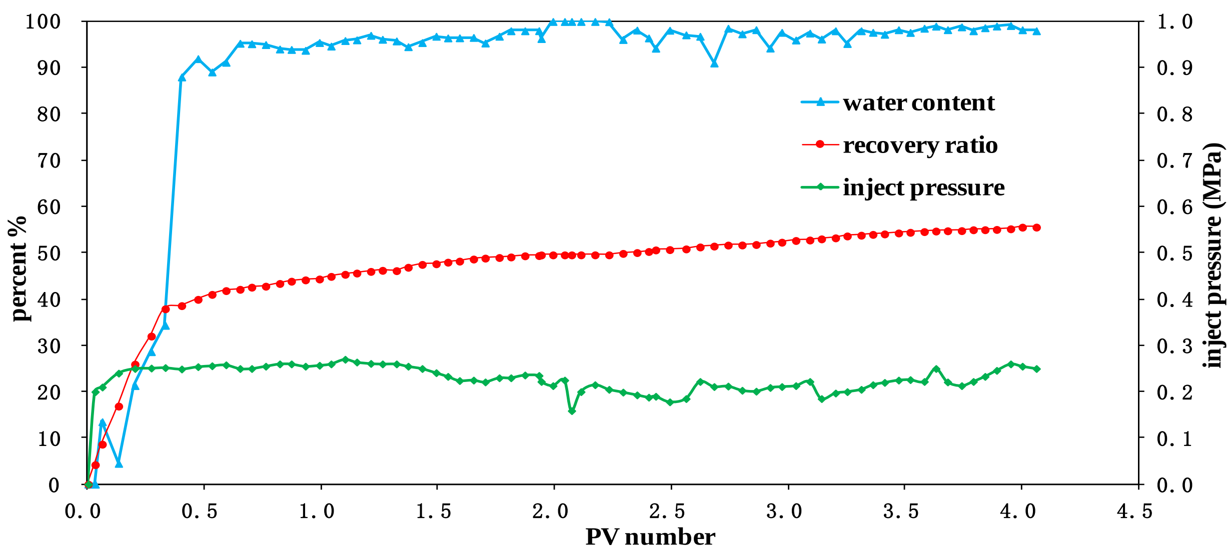

Figure 1. One of oil displacement experiments' results

By doing surfactant flooding experiments, the recovery ratio of surfactant could be getting, which is around 55%. What is more, those cores which finished these experiments will be stored and prepared for the triaxial compressive test. When all of these oil displacement experiments are done, triaxial compressive test will start and data will be collected. After that, machine learning methods will be used.

Those experiments' data maybe will not appear in my Ph. D dissertation. However, it could be a good practice and reference for my research in America.

Research Project in Beijing: This project contains two groups of experiments. The first group is to predict and evaluate the specific surface area of the formation through four parameters: asphalt content, clay content, siliceous content and calcareous content. In the second group, the total pore volume of the formation is proposed, predicted and evaluated by using three parameters: total organic carbon content, porosity and siliceous content. In both groups, 42 groups of data were randomly divided into two sets. One is the training set, which is used to train the constructed fuzzy neural network, including 34 groups of data; The other is the test set, which is used to test the accuracy of the trained fuzzy neural network in predicting new data, including 8 groups of data. The standardized specific surface area and total pore volume are divided into five grades for evaluation: very poor (0-0.2), poor (0.2-0.4), medium (0.4-0.6), good (0.6-0.8) and excellent (0.8-1).

Figure 2 shows the fuzzy neural network used to evaluate the specific surface area of the formation as an example.

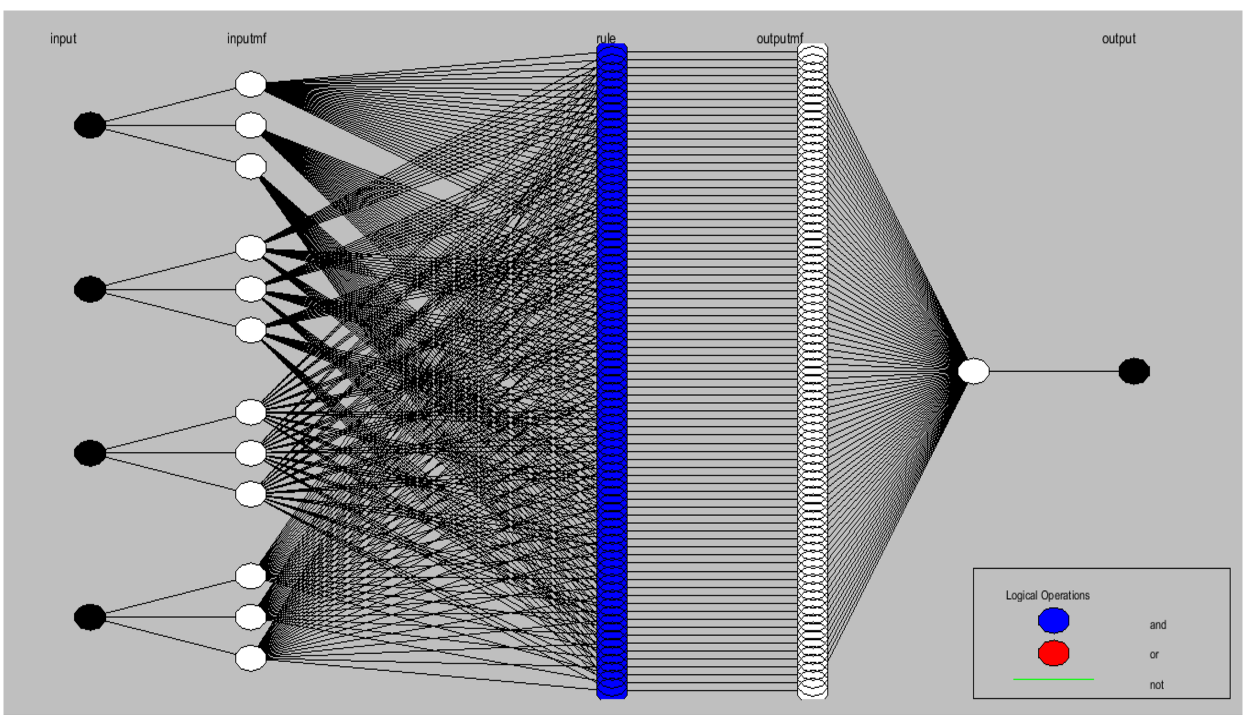

Figure 2. Fuzzy neural network

As shown in **Figure 2**, the second layer of the fuzzy neural network of this part has 12 nodes. Because in the debugging process, the fitting effect is the best when each variable is divided into three language variable values (i.e. "good, medium and poor"). Both the third and fourth layers have 81 nodes for calculation. In this research, both specific surface area and total pore volume's predict accuracy rate were 60+%, which is much higher than previous researches (around 50%).

Project Milestone and Timeline:

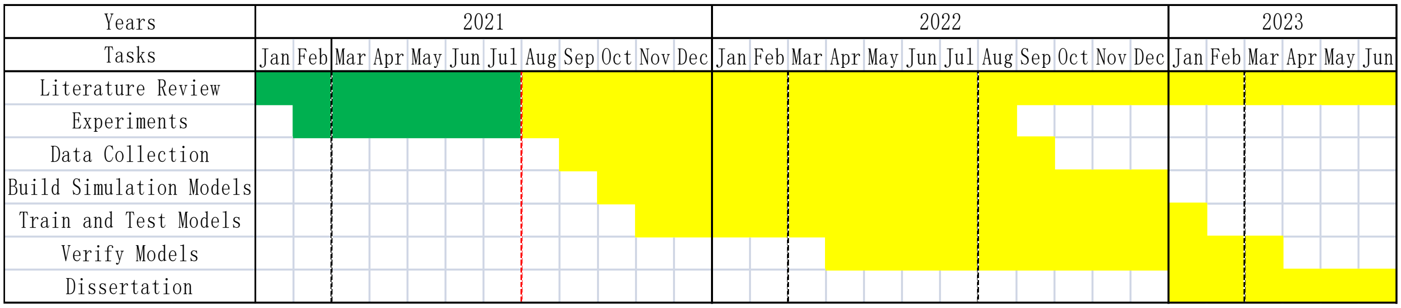

Figure 5. Project Milestones

The Effect of CO_2 Injection - Enhance Oil Recovery in Bakken

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Problem Statement:

Over the last decade, horizontal drilling and stimulation process have caused production from ultra-low shale oil reservoirs to increase rapidly. While initial rates are high in these reservoirs, their recovery factors are predicted to be very low. The enormous oil remaining in shale oil reservoirs stimulates our efforts to investigate the application of enhanced oil recovery methods. Unlike conventional reservoirs, water or gas flooding does not appear to be a viable secondary option because of the ultra-low matrix permeability of shale rocks (low injectivity) and the long payback period of gas and water flooding process. The cyclic process or huff-n-puff could be the alternative to improve the recovery of these reservoirs. The cyclic process is mainly a single well process. This technique is composed of three steps; 1. Injection phase- a gas is injected into producing well; 2. Soaking phase- the well is shut in and the fluid allowed to dissipate into the formation; 3. Production phase- the well is placed on production. There are many reasons make the cyclic gas injection process an effective and low-risk process. As mentioned, it is a single-well process; well-to-well connectivity is not required. The fracture system which includes hydraulic fractures and natural fractures complexity provides a large contact area for the injected gas to penetrate and diffuse into the low-permeability matrix. It also provides the pathways for both injected gas and produced oil. The payback period of the cyclic gas injection process is short compared with the other flooding process.

Objectives:

- Analyze the different factors that can affect the efficiency of CO2 injection into reservoir with ultra-low permeability.
- Get the best optimization (production curve with CO2 injection before and after) from the factors that can affect the efficiency.
- Simulate the production rate with changing the CO2 rate injection and time of shut-in and soak period, and compare the difference.
- Build a static model and see the effect of the rock properties and how that can affect our EOR process.
- Compare between large scale and core-scale results.

Methodology:

- Use Petrel to build a static model with all the petrophysic and rock proprieties logs.
- Use CMG to simulate the model with CO2 injection on different way.
- Use cores simple with same properties as the model and study how CO2 enhance oil recovery.
- Compare the results between the simulation and the experimental work and analyze the errors.
- Core –flooding and Huff-n-Puff methods.

Results:

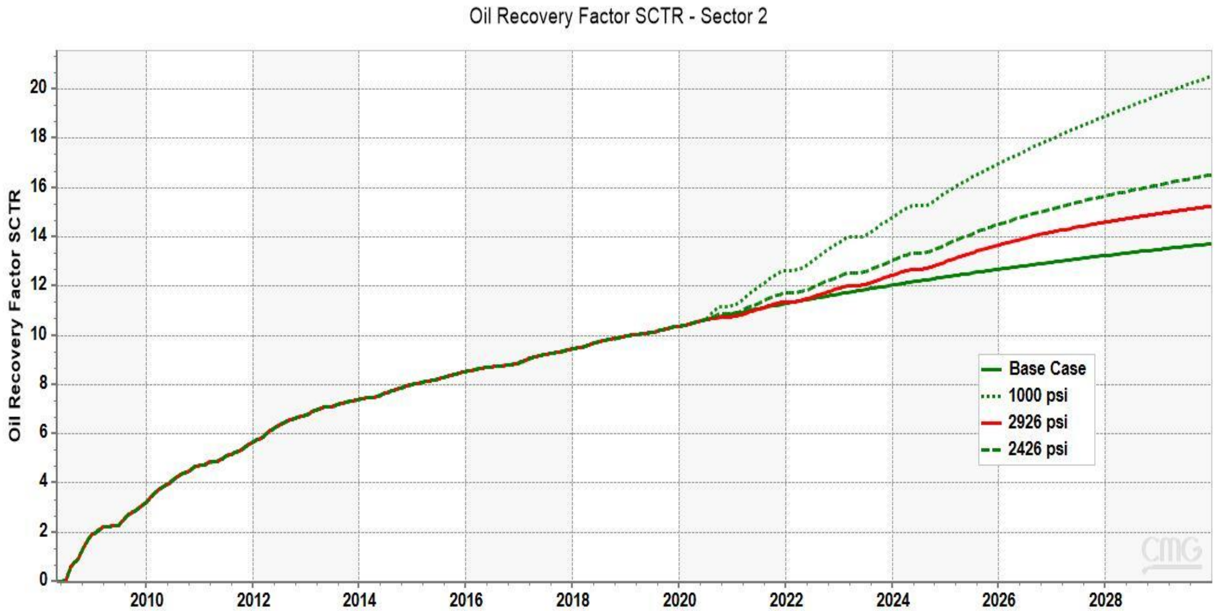


Figure 1. The recovery factory in different BHP in the production with 4 cycles of Huff-and-Puff, 60 days injection, 20 days soaking, 360 days production

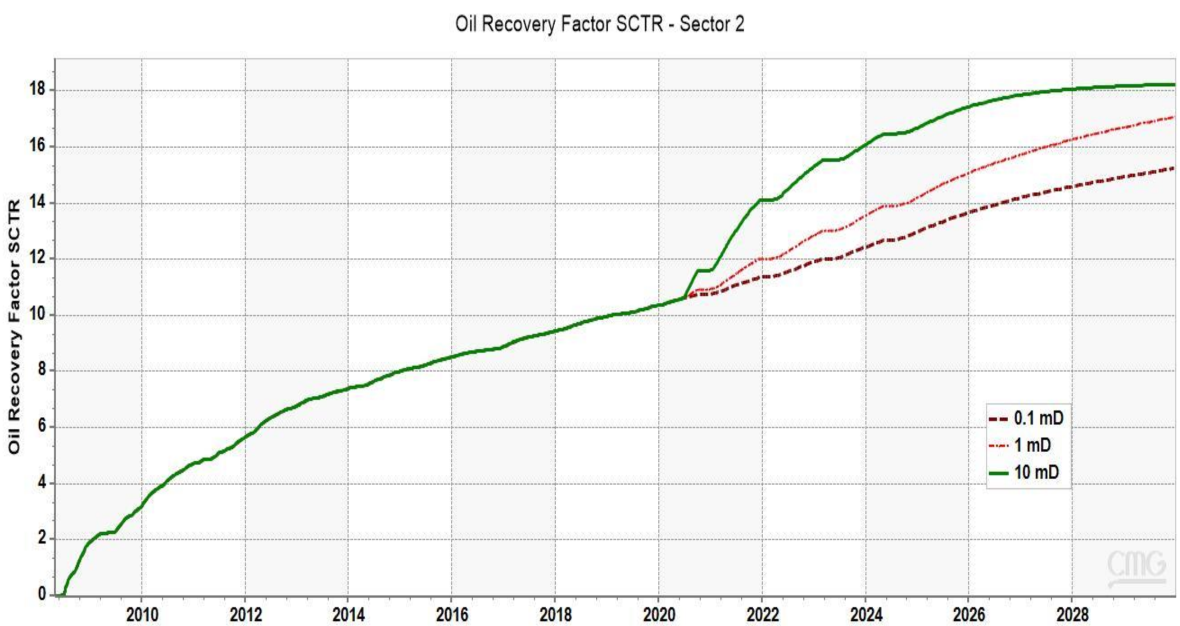


Figure 2. The recovery factory in different natural fracture permeability

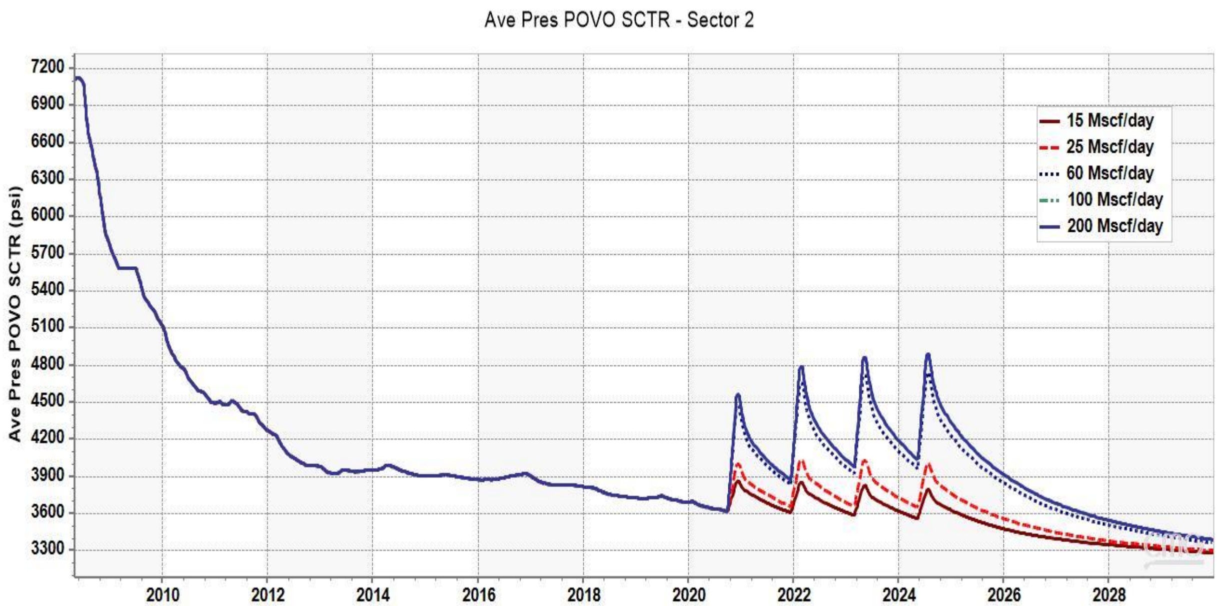
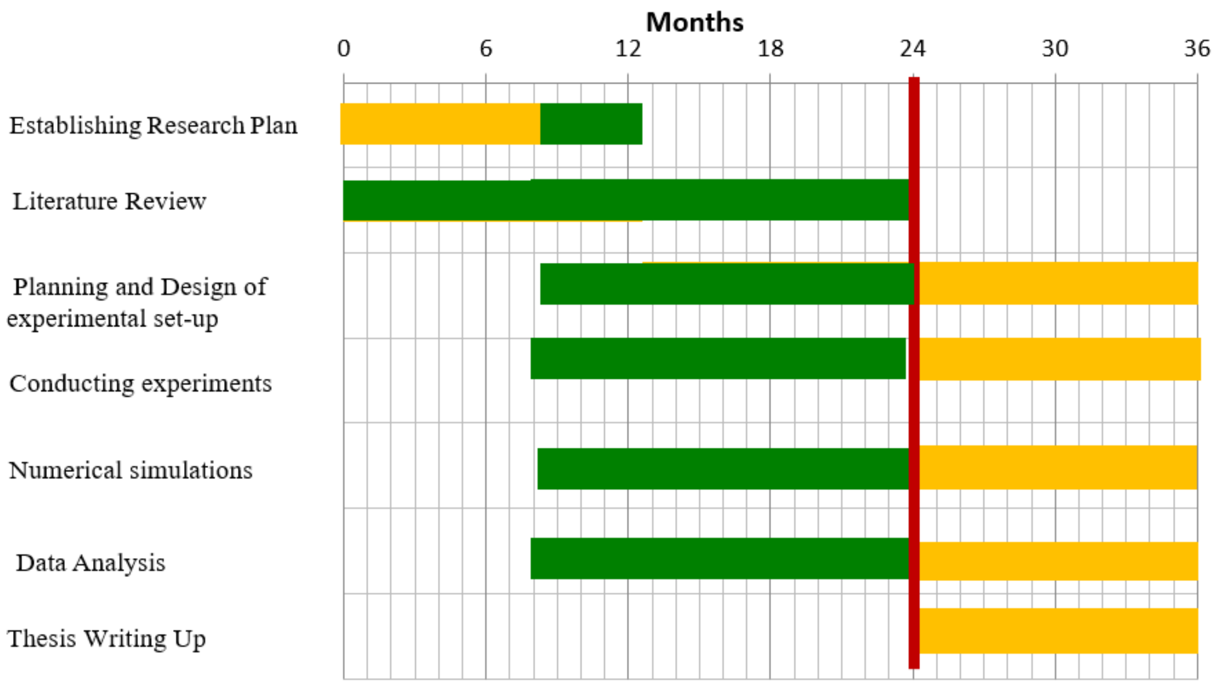


Figure 3. Effect of different CO2 injection rate on reservoir pressure

Project Milestone and Timeline:



Optimization of Primary and Enhanced Oil Recovery from Tight UCRs Through Re-fracturing

Xueling Song
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Problem Statement:

Unconventional reservoirs played an important role in oil and gas production in recent years. Drilling Horizontal well coupled with hydraulic fracturing treatment is the main method to exploit hydrocarbon from the unconventional reservoirs as it consists of shale, clay, and other formations with very low permeability. However, although hydraulic fracturing treatment increased oil production rates dramatically, it is not a long-term benefit as fractured wells in unconventional reservoirs lose most of the production rate in two to three years. Fast reservoir pressure depletion caused by oil production from deeply penetrating and well performed fractures makes the old well depleted. Refracturing, an operation to re-stimulate a well after an initial period of production, can open new fractures that have different fracture geometry and orientation from the initial fractures. Although the industry realized that refracturing is critical to increase reservoir EUR, there is big gap between the research and practice of re-fracturing. When and how is the best to re-stimulate the well? How would the new fracture look like under the stress shadow around the initial fractures and the effective stress change due to production? How to design the cluster spacing and fluid injection rate of re-stimulation? The objective of this study is to analyze the stress shadow induced by poroelastic effect and to design the refracturing treatment in order to increase the stimulated reservoir volume (SRV) in shale reservoirs.

Progress to Date – Results & Discussion:

Effect of stress change on fracture geometry: The non-uniform pore pressure distribution around the initial fractures after years of production results in stress change around the fracture. The stress change induced by reservoir depletion have big effect on fracture geometry, it will result in longer and curved fracture, which will enlarge the drainage area around wellbore. As figure 2 shows, the secondary fracture is longer than the initial fracture and curved in the low fluid pressure zone compared with figure 3 if the secondary fracture was stimulated before reservoir production. And the figure 4 demonstrates that the initial fracture has critical impact on the direction of the secondary fracture,

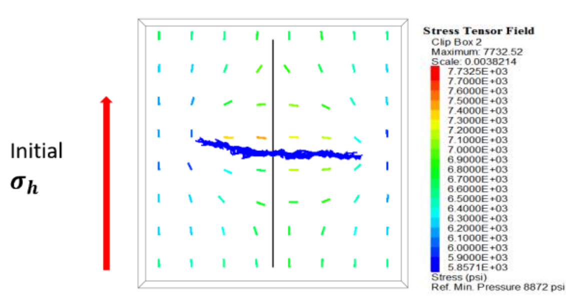


Figure 1. Minimum horizontal stress after reservoir depletion

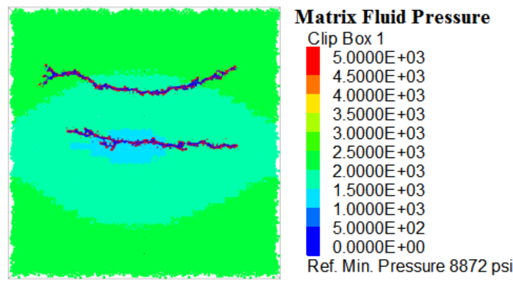


Figure 2. Secondary fracture configuration under depletion

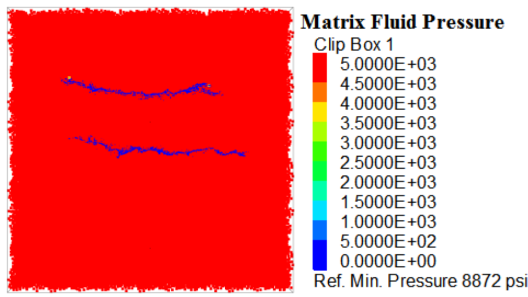


Figure 3. Secondary fracture configuration without depletion

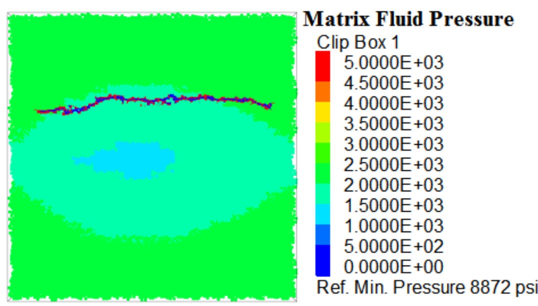
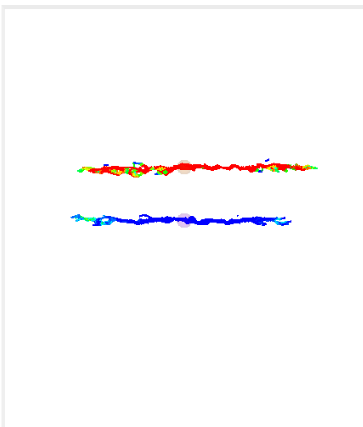


Figure 4. Fracture configuration under depletion without the initial fracture

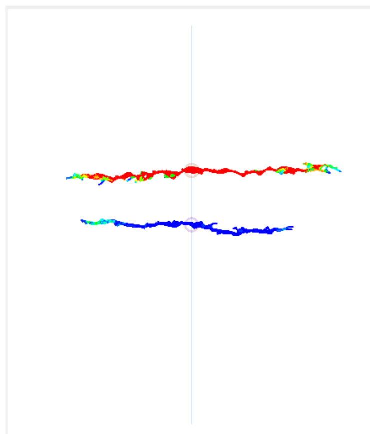
Effect of refracturing time & stress anisotropy: To study the effect of stress anisotropy and refracturing time on fracture geometry and production, the sensitivity analysis was designed as Table 1 shows. As the ratio of minimum and maximum horizontal increase, the far-field stress anisotropy becomes smaller, which results in longer and more curved secondary fracture after re-stimulation. And we can see apparent frac-hit when stress anisotropy is small and re-stimulate the well after 10 years of production, as Figure 5 shows, Figure 6 shows that refracturing earlier after the reservoir depletion is better to increase production, which make sure the reservoir still have enough energy to produce.

Table 1. Data of stress anisotropy sensitivity analysis

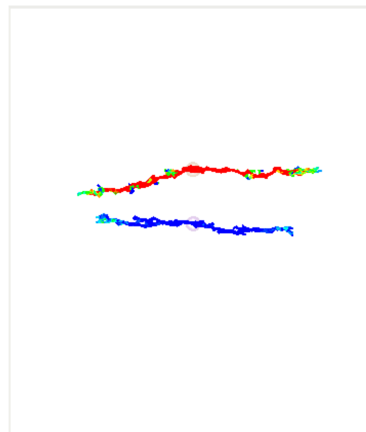
Scenario	σ_v/psi	σ_H/psi	σ_h/psi	$(\frac{\sigma_h}{\sigma_H})$
Case 1	11090	10536	8317	0.79
Case 2	11090	9981	8872	0.89
Case 3	11090	9527	9326	0.98



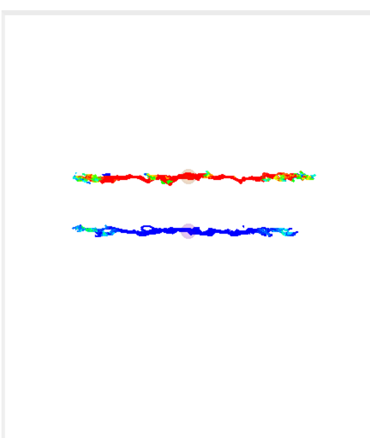
Case 1- refracturing time: 4 years later



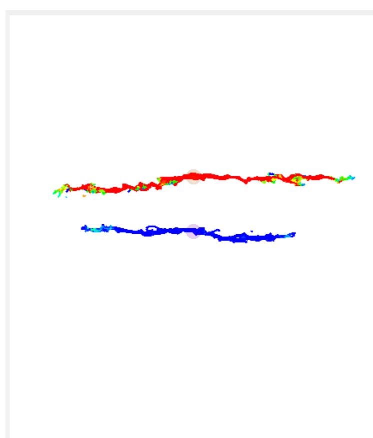
Case 2- refracturing time: 4 years later



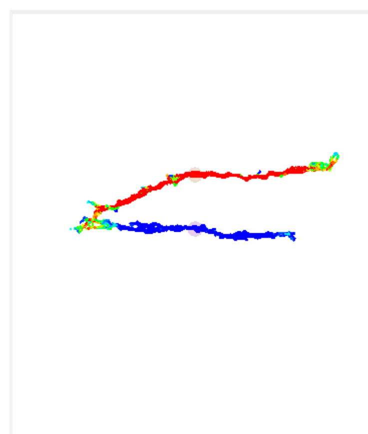
Case 3- refracturing time: 4 years later



Case 1- refracturing time: 10 years later



Case 2- refracturing time: 10 years later



Case 3- refracturing time: 10 years later

Figure 5. First and secondary fracture configuration under different stress anisotropy and refracturing time

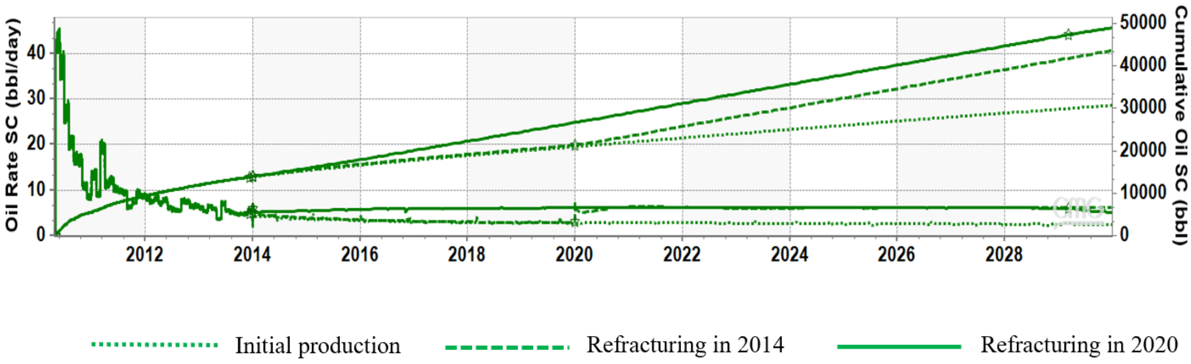


Figure 6. Oil production evaluation after refracturing

Project Milestone and Timing:

Year	2021												2022												2023							
Task	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Literature Review																																
Data collection																																
Single Well Model Design																																
Sensitivity Analysis																																
Analytical Solution																																
Well Pad Model Design																																
Economic evaluation																																
Dissertation																																

Minimum Horizontal Stress Estimation Using Multi-Variate OLS and Artificial Neural Network (ANN)

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Problem Statement:

Oil and gas extraction has become a large part of the North Dakota industry and economy. The oil and gas bearing formations underneath North Dakota are unconventional and need to be hydraulically fractured (frac or frac'd) to become economically viable. This process is complex and there is still much to be learned to make frac and drilling operations more efficient. One important characteristic in the frac and drilling design process is the minimum horizontal stress (S_h). Although there are numerous models and correlations that exist to estimate S_h, little has been done to investigate the degree to which inputs into the models affect the estimation of S_h.

The proposed project will use multi-variate OLS techniques to give an idea as to the extent to which unit changes in the independent variables affect S_h. The independent variables include dynamic Young's modulus, Poisson's ratio, and effective overburden stress. Along with investigating causality, the multi-variate OLS technique also offers a linear equation that can be used to estimate S_h. Next, the same multi-variate OLS technique will serve as a selection mechanism for inputs into an ANN based on causal investigation and statistical significance as opposed to simply correlation. Finally, the multi-variate OLS and ANN models will be verified using StimPlan software which will serve as a physics-based model for comparison. The methodology for constructing the multi-variate OLS models for this study is shown in **figure 1**.

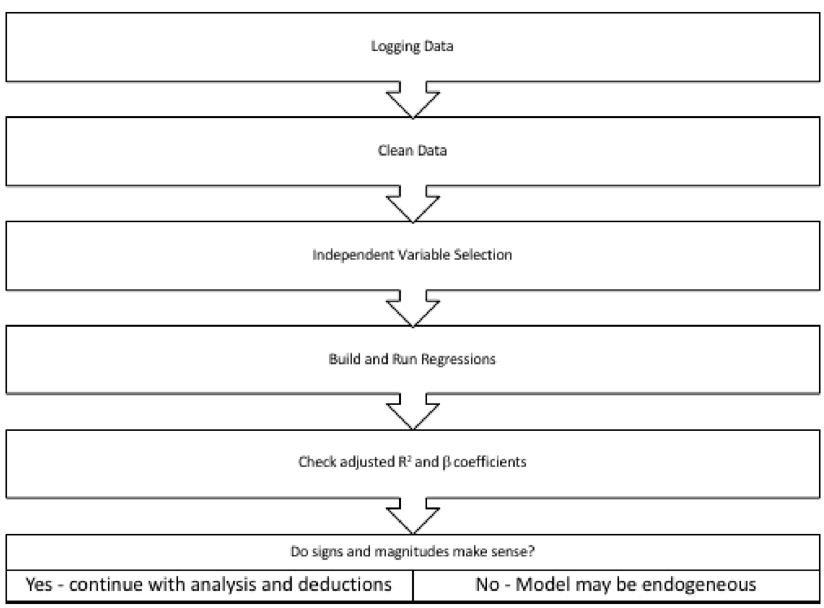

Figure 1. Methodology for constructing multi-variate OLS

Progress to Date: Results and Discussion:

Early Regression Results: After attempting to construct regressions estimating S_h, it was apparent that collinearity would be a problem as the traditional way of calculating Young's modulus (YME) and Poisson's ratio (PR) using well log data. Therefore, the dynamic measurements for dynamic vertical and horizontal YME and PR given in the data set were investigated to see the validity of the measurements using multivariate OLS so these may be used in place of the original calculations. The results for each regression are given below.

```
Call:
lm(formula = YME_H_DYN ~ VCLAY + RHOZ + DTCO + DTSM_FAST, data = data2)

Residuals:
     Min       1Q   Median       3Q      Max
-0.48748 -0.00749  0.01391  0.03123  0.34179

Coefficients:
              Estimate Std. Error  t value Pr(>|t|)
(Intercept) 14.8241590  0.8889346   16.676  < 2e-16 ***
VCLAY        0.0521742  0.0091164    5.723 1.23e-08 ***
RHOZ         4.1754932  0.2723964   15.329  < 2e-16 ***
DTCO        -0.0781443  0.0029604  -26.397  < 2e-16 ***
DTSM_FAST   -0.1242716  0.0008142 -152.638  < 2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.0625 on 1722 degrees of freedom
Multiple R-squared:  0.9755,    Adjusted R-squared:  0.9755
F-statistic: 1.716e+04 on 4 and 1722 DF,  p-value: < 2.2e-16
```

```
Call:
lm(formula = YME_V_DYN ~ VCLAY + RHOZ + DTCO + DTSM_FAST, data = data2)

Residuals:
     Min       1Q   Median       3Q      Max
-0.69661 -0.10696 -0.01766  0.08638  0.69399

Coefficients:
             Estimate Std. Error t value Pr(>|t|)
(Intercept)  1.871935   2.570282   0.728    0.467
VCLAY       -0.250170   0.026359  -9.491  < 2e-16 ***
RHOZ         5.920029   0.787612   7.516 9.00e-14 ***
DTCO        -0.056869   0.008560  -6.644 4.09e-11 ***
DTSM_FAST   -0.055459   0.002354 -23.559  < 2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.1807 on 1722 degrees of freedom
Multiple R-squared:   0.73,     Adjusted R-squared:  0.7293
F-statistic:  1164 on 4 and 1722 DF,  p-value: < 2.2e-16
```

(a) (b)

Figure 2. (a) Multi-variate OLS results for dynamic horizontal YME and (b) dynamic vertical YME

```
Call:
lm(formula = PR_HORIZ_DYN ~ VCLAY + RHOZ + DTCO + DTSM_FAST,
    data = data2)

Residuals:
      Min        1Q    Median        3Q       Max
-0.072919 -0.001654  0.001127  0.003595  0.050445

Coefficients:
              Estimate Std. Error t value Pr(>|t|)
(Intercept)  8.705e-02  1.005e-01   0.866  0.38657
VCLAY        1.116e-02  1.031e-03  10.831  < 2e-16 ***
RHOZ         8.882e-02  3.080e-02   2.884  0.00398 **
DTCO        -1.130e-02  3.347e-04 -33.753  < 2e-16 ***
DTSM_FAST    5.808e-03  9.206e-05  63.089  < 2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.007067 on 1722 degrees of freedom
Multiple R-squared:  0.8908,    Adjusted R-squared:  0.8905
F-statistic:  3511 on 4 and 1722 DF,  p-value: < 2.2e-16
```

```
Call:
lm(formula = PR_VERT_DYN ~ VCLAY + RHOZ + DTCO + DTSM_FAST, data = data2)

Residuals:
      Min        1Q    Median        3Q       Max
-0.077964 -0.004947  0.001266  0.007057  0.066115

Coefficients:
              Estimate Std. Error t value Pr(>|t|)
(Intercept)  0.5071665  0.1682788   3.014  0.00262 **
VCLAY        0.0187248  0.0017258  10.850  < 2e-16 ***
RHOZ         0.0170512  0.0515657   0.331  0.74094
DTCO        -0.0126614  0.0005604 -22.593  < 2e-16 ***
DTSM_FAST    0.0043591  0.0001541  28.283  < 2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.01183 on 1722 degrees of freedom
Multiple R-squared:  0.7539,    Adjusted R-squared:  0.7533
F-statistic:  1319 on 4 and 1722 DF,  p-value: < 2.2e-16
```

(a) (b)

Figure 3. (a) Multi-variate OLS results for dynamic horizontal PR and (b) dynamic vertical PR

These results indicate that the multivariate models using the traditional variables explain the variance in the data fairly-well. When compared to multi-variate regressions with the traditional non-linear assumption, these linear models actually perform marginally better with increase in the adjusted R^2, indicating that the relationships may simplified and can be assumed to be linear based on the data set. These models were then cross referenced with values found in literature for vertical and horizontal dynamic YME and PR. An example of these comparisons is shown in **figure 4** and **figure 5**.

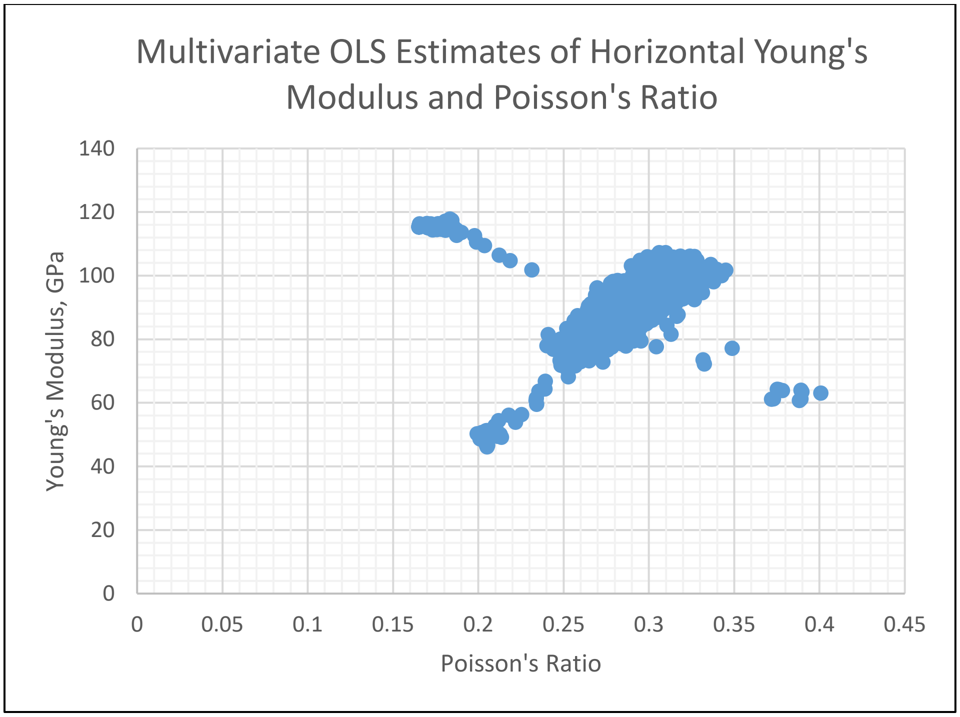

Figure 4. Cross-plot of vertical YME and PR using multivariate OLS modes

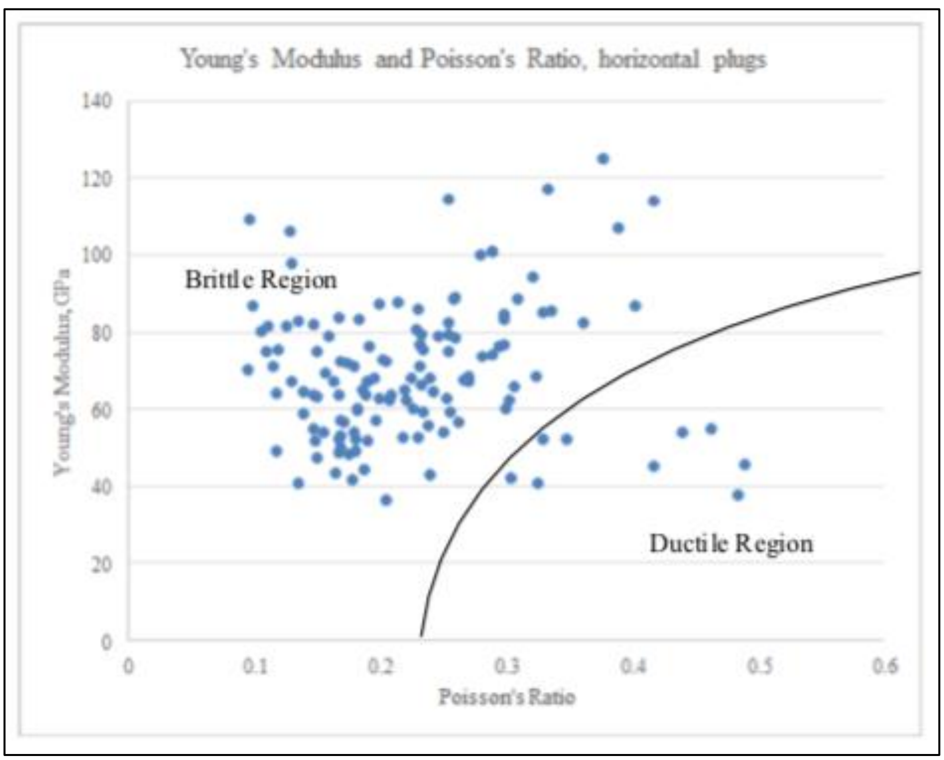

Figure 5. Cross-plot of vertical YME and PR from Pei and He (2014)

Further Verification: The results from the multi-variate models work predict the ratio of YME to PR fairly-well. This process will be used to verify other independent variables and cross referenced with literature estimates. This will eliminate the need to calculate these values using traditional methods from well log data and avoid any issues with collinearity.

Multi-Variate OLS and ANN: After verifying the independent variable validity using the above technique, the models will then be used as inputs into an Artificial Neural Network (ANN) to provide robust predictive power. This in combination with multi-variate OLS should provide insights into the interaction with the independent variables and S_h. These estimates will then be compared with estimations from Stimplan software.

Project Milestones and Timing:

The following timetable represents the estimated timing and development of important aspects regarding the proposed project. Important updates and progressions are highlighted in the following section.

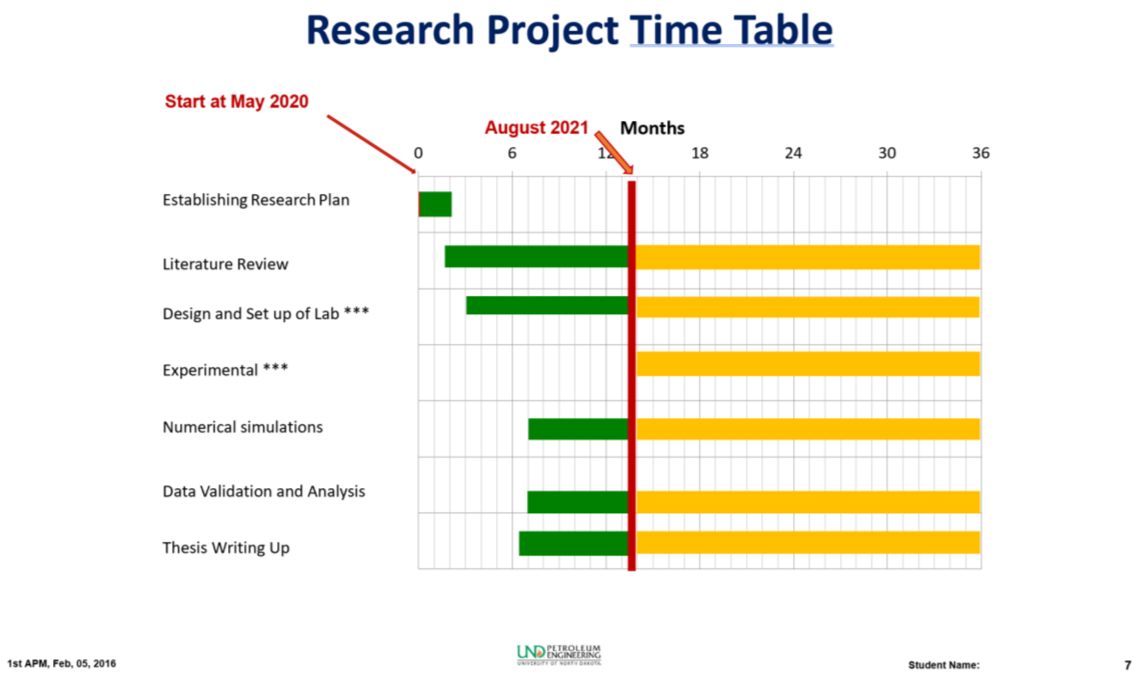

Figure 6. Multi-variate OLS results for dynamic vertical and horizontal PR

References:

Pei, P., He, J. (2014). Correlating geomechanical properties of the Bakken formation rocks with lithofacies and sequence. *ARMA 14-7437.*

Simulation of Hydromechanical Properties of the Three Forks Formation Under Polyaxial Stress Condition

Prasad Pothana,
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Problem Statement:

The Upper Devonian Three Forks formation overlies Birdbear formation and underlies the Bakken formation of the Williston Basin. Three Forks formation is an important part of the Bakken Petroleum systems as it holds around technically recoverable 3.4 billion barrels of oil and 3.5 trillion cubic ft of gas (Gaswirth and Marra 2015).

The hydro-mechanical coupling mechanism, in particular stress-dependent permeability, is important in many practical engineering applications, mainly production and injection design in hydrocarbon reservoirs (Li *et al.* 2021) and CO_2 sequestration (Zhou *et al.* 2011) among others. During the production phase of a hydrocarbon reservoir, pore pressure decreases which results in increases net effective stresses. This altered stress state further deforms the pores and results in fracture deformation including fracture closure, opening, and/or shear dilation and thereby change in permeability. Stresses acting normal to the fractures directly increase or decrease the hydraulic aperture whereas shear stress causes shear failure, dilation and causes flow localization (Min *et al.* 2004; Lei *et al.* 2017). Study of the stress-sensitive fracture deformation is important because fractures are the main conduits for flow in unconventional reservoir rocks. Furthermore, stress-permeability sensitivity display a wide range of variations, in some cases permeabilities reduced up to 98% of the original value under stress loading (Teklu *et al.* 2016; Boualam *et al.* 2020).

A number of experimental, analytical and numerical studies were carried out to accurately model this phenomenon. Robust analytical solutions do not exist to account for the permeability evolution resulted from shear failures or dilations that occur on the fracture planes. Therefore, numerical modelling is necessary to account for these effects and also to incorporate complex fracture networks in the model. Stress-induced normal fracture deformation, shear failure, dilation and their effect on flow discharge are successfully modelled Universal Distinct Element Code (UDEC) in 2D scenario (Zhang and Sanderson 2002; Min *et al.* 2004). While an increase in isotropic stresses decreases the permeability of an ensemble, an increase in anisotropic stresses can increase the permeability and create channelling effects (Min *et al.* 2004; Kevin *et al.* 2016). In addition to that, strain anisotropy and dynamic permeability anisotropy evolution were observed in numerical simulations on coal samples (Feng *et al.* 2020). This stress-sensitive permeability evolution is controlled by several factors viz., fracture properties such as distribution, fracture normal stiffness, shear strength, cohesion, fracture length, connectivity, orientation, and the surrounding rock's elastic properties, etc (Agheshlui *et al.* 2018; Cao *et al.* 2019). Most of the earlier studies of this kind were carried out in 2D scenarios and assumed transverse isotropic media. Poly axial stress effect on tensorial permeability variations, anisotropic deformation, the effect of joint roughness was less studied. Conventional 2D analysis neglects the effect of the intermediate stress variation and does not capture the true triaxial stress-dependent behaviour of 3D fractured rock samples, which could be significant (Lei *et al.* 2017).

In the proposed research we are planning to conduct a set of numerical and experimental simulations to investigate the effect of poly-axial stress variations on permeability tensorial variations, anisotropic deformation, and flow channelling effects. These studies will be focussed on the better characterization of the Three Forks formation of the Bakken petroleum system. This research will help in enhancing our current knowledge of the stress-sensitive fluid flow behaviour in fractured rock masses and production design, production forecasting, and CO_2 sequestration in the Bakken Petroleum system.

Objectives:

- To understand the stress-dependent permeability behavior in Three Forks formation.
- To understand the poly-axial stress effects on tensorial permeability variations in fractured rock.
- Devising numerical simulations and experiments of fluid flow in stress-sensitive fractured rock.
- Investigating and developing numerical and machine learning models for the effect of pore pressure and effective stresses on the permeability as a function of a function mineral composition, clay distribution, abundance & geometry of fractures and its hysteresis for Three Forms formation.

Methodology:

- Numerical simulation using 3DEC software to investigate the poly-axial stress effects on tensorial permeability variations in fractured rock.
- Devising experiments to understand the fluid flow through fractured rocks during stress loading and unloading conditions.
- Understanding the stress-permeability sensitivity coefficients as a function of mineral composition, clay distribution, abundance & geometry of fractures.

Significance:

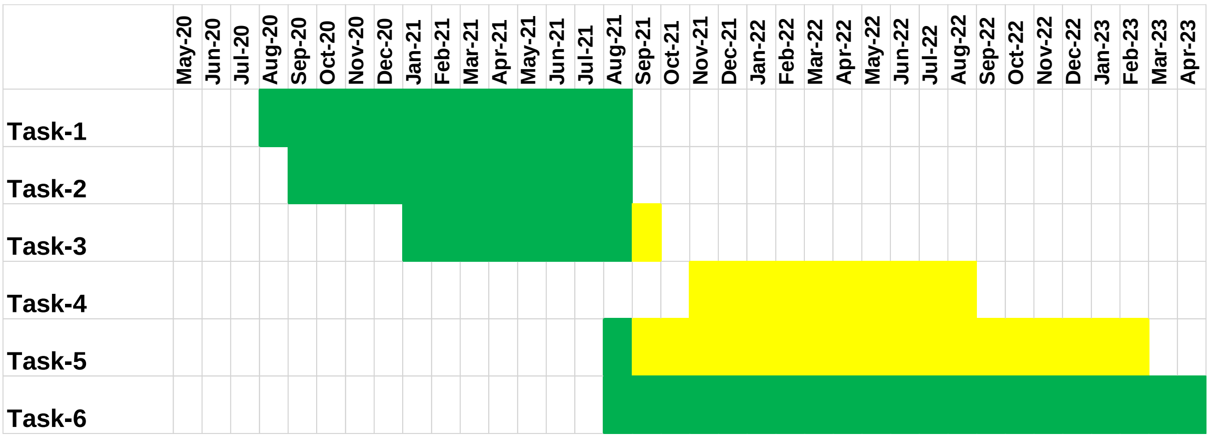
- Studies suggest that stress-dependent matrix permeability will have a big impact on early-stage production design and production forecasting of a reservoir.
- Stress-permeability sensitivity can be taken as input for improved hydrofracturing design.
- Stress-dependent permeability will play a critical role in designing the CO2 injection profile into a tight formation for enhanced oil recovery. Whether the existing micro/nano fractures provide a path for CO2 injection depends on the hysteresis behavior of the rock.

Project Milestone and Timeline:

Time major milestone of the project Include the following tasks:

- Task 1: Setting up the research problem
- Task 2: Literature review
- Task 3: Numerical simulation
- Task 4: Experiments

- Task 5: Data analytics/ empirical modelling
- Task 6: Thesis writing



Progress to Date:

Received 3DEC licence from Itasca.Inc. Performed numerical simulations on simple cases and compared the numerical results with the analytical solutions. Discrete fracture network of the Bakken formation is realized. At present simulation stress effect on the permeability tensorial various in DFN of Bakken is in progress.

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The Evaluation of the Three Forks Rock Properties Alteration Due to CO_2 EOR

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Problem Statement:

The Bakken Petroleum System of the Williston Basin is at the forefront of this new oil boom and contains mature source rocks (the Bakken Shales) and proven reservoirs (Middle Bakken and Three Forks). The Bakken Petroleum System is composed of three different formations in ascending order: Three Forks, Bakken, and Lodgepole. Due to its tight characteristics, Bakken Petroleum System requires unconventional methods for production. Multistage Hydraulic Fracturing is one of the most common method in North Dakota as an Enhanced Oil Recovery (EOR) method. CO_2 injection is an alternative EOR method that proved its efficiency, and the proper use of this technique is one of the most challenging topics in this research, by identifying the potential problems related to rock properties and evaluating their alteration caused by this operation. Economically, CO_2 emission during oil production implies taxes, and the environmental organization are requiring keeping the CO_2 emission rate at its current percentage. Apart from the capability of enhancing the oil recovery, CO_2 injection in unconventional oil reservoirs also ensure the maintain of CO_2 emission rate for the next 70 years. However, the rock behavior in the reservoir during the injection may be an obstacle for the operation. This is why a full understanding of rock properties alternation while injecting CO_2 is crucial to determine the feasibility of CO_2 EOR in the target formation.

Injecting CO_2 will increase the total porosity, which may be due to the mineral dissolution/precipitation. The change in mineralogy should be analyzed to understand the CO_2-rock interaction and characterize the effect on geological change. In Carbonate formations (like Three Forks), calcite dissolution due to this interaction tends to enlarge the accessible pores while the inaccessible pores are expected to decrease. However, a change in microstructure of the pores due to geochemical interaction and the minerals dissolution/precipitation will result in the change of hydromechanical properties such as deformation, elastic properties, rock strength, brittleness, and permeability. In addition, it may tend to enhance the fracture permeability and bridge the unconnected fractures, which may be critical for the rock stability. Moreover, the diagenesis and chemical processes such as CO_2 injection affects the microstructure, and the elastic properties of the rock significantly depend on the above parameters (i.e. mineralogy, pore structure, fractures…).

In the Bakken Petroleum System, the CO_2 is injected within the Middle Bakken and Upper Three Forks formations which are above and under Lower Bakken Shale, respectively. These two reservoirs have different characteristics and the effect of CO_2 on them need to be investigated separately. Thus, the focus in this study will be only on Three Forks formation.

Objectives:

- Determining the effect of CO_2 on the geological parameters such as the mineralogy redistribution due to the interaction between CO_2 and rock matrix, the pore structure, and the existing fractures change.
- Monitoring reservoir properties changes and their link to the velocity variation and stresses. The properties include dolomitization (lithology factor) and anisotropy due to the pore space variation, and/or fractures and cracks.
- Modelling velocity changes due to CO_2 injection.
- Estimating the stress field changes due to CO_2 in a dolomitic reservoir versus limestone reservoir. Then, in a carbonate reservoir with different pore types.

Methodology:

- Literature review by identifying the well-documented case studies, analyze them, and establish an efficient comparison methodology.
- Collection of data. The target wells contain useful cores for the laboratory experiments for the representative scenarios discussed above. The requirements for the core samples are variety of dominant mineral (dolomite/calcite), variety of pore shapes (cracks/interparticles/moldic), and anisotropy due to fractures.
- XRD testing to capture the mineralogy changes after CO_2 flooding.
- SEM images acquisition to get the pore typres and shapes.
- Porosimetry to have the porosity in the sample, which is an important parameter that affects velocity.
- Ultrasonic velocities, anisotropic velocities (Calculate Thomsen parameters, in this part, samples should be extracted at different angles from the core).
- Conventional triaxial and stress sensitivity tests to understand the stiffness and its change due to CO_2 flooding.
- Use Rock Physics models for velocity modeling before and after CO_2 injection.
- Use all the above steps to estimate the stress changes at log scale due to the CO_2 EOR at the mentioned scenarios.

Significance:

- The first work that evaluates the microstructure changes and estimates the elastic properties due to CO_2 injection in the Three Forks formation.
- Ability to derive general conclusions about the effect of CO_2 in both carbonates and limestone reservoir in Three Forks formation, which makes its applicability within the whole Williston Basin depending on the adapted conditions.
- The work provides a modelling of elastic properties in carbonate reservoir with different pore shapes; thus, we can assess the risks when dealing with CO_2 EOR in Three Forks

formation. The effect of pore morphology on elastic properties after CO_2 injection has not been studied before

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature Review
- Task 2: Data Collection
- Task 3: Data Processing
- Task 4: Lab experiments
- Task 5: Results interpretation
- Task 6: Analytical Solutions
- Task 7: Writing the peer review papers
- Task 8: Thesis writing up

Table 1: Project Milestone and Timing Table

Time / *Tasks*	*6*	*12*	*18*	*24*	*30*	*36*
Literature Review						
Data Collection						
Data Processing						
Laboratory Experiments						
Results Interpretation						
Analytical Solutions						
Writing the Peer Review Papers						
Thesis Writing up						

Progress to date:

As of August 2021, a significant amount of literature has been reviewed in relation to the Bakken petroleum system, and its geological characteristics, in addition to EOR technology and regulations related to CO_2 EOR technology. There has also been significant review of geomechanics and regarding the works done in the evaluation of rock properties alteration, and the work done regarding the use of rock physics models to estimate elastic properties. Another significant part of the work till date, is the mapping of the methodology in order to achieve the objectives. Furthermore, the investigation of potential fields and wells from which data will be collected in the target formation has been done, where well 24123 is the target for applying the concepts that will be derived from the general concepts of different conditions discussed above. There are also some other wells that have been selected from Mountrail County that can probably be used for satisfying the conditions of core samples extraction while modeling the properties above at different scenarios. The next step is the core sample extraction to achieve the objectives.

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Geological Carbone Dioxide Storage in Deadwood Saline Formation, Williston Basin

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Problem Statement:

Carbon dioxide is the principal component causing climate change and global warming. A significant reduction in the amount of net global greenhouse gas emissions is possible through permanent storage technologies of CO2 particularly geological storage. This practice is important to achieve the goals of the Paris agreement that the international community authorized. The target of this agreement is to keep the average temperature rise under 2°C (International Energy Agency, 2016) during the second half of 21^{st} century.

Looking for geological reservoirs is necessary because it corresponds to a possible final stage of CO2 destination in the Carbone Capture and Storage sequence. The potential storage candidates include depleted oil and gas reservoirs, saline aquifers, unmineable coal seams, and hydrate-bearing sediments. Among these reservoir categories, saline aquifers are considered the best CO2 storage sites due to their massive storage capacity.

The Deadwood Formation is one of the formations being evaluated for CO2 storage by the United States Geological Survey (USGS). The Deadwood is reported to match the necessary geological requirement for CO2 sequestration in terms of its depth, thickness, and petrophysical properties (Timothy O. Nesheim,2020)

This project consists of full characterization of the Deadwood formation in Williams County using data from twenty vertical wells. Geological, petrophysical and geomechanical models will be constructed and 3D numerical simulations of the CO2 in the formation will be carried out. An evaluation of the cap rock (Icebox Formation) and the underburden (Deadwood B member and Precambrian basement) formations is also considered. Finally, the basement faults and fractures instability during the storage will be assessed to prevent induced seismicity.

Objectives:

The objectives of this study are as follows:

- Petrophysical evaluation and mineralogical modeling of Deadwood Formation, Black Island, and Icebox using advanced well logging.
- Mineralogical model identification and calibration using XRD data.
- Investigating the mineral components, pore system and the impact of diagenesis on the petrophysical parameters.
- Building the static model using Petrel and machine learning techniques.
- Study the reaction between mineral component and CO2 and its impact on the storage capacity and the integrity.
- Estimating the geomechanical properties (dynamic and static) and the in-situ stress for reservoir and cap rock to investigate any CO2 leakage or any fault reactivation in the Precambrian basement, which is the source of many faults in the basin.
- Dynamic simulation of the CO2 sequestration and plume scenarios.

Methodology:

To achieve the above objectives, several tasks need to be completed including:

- Digitizing of available logs on the NDIC website using Neuralog software.
- Performing advanced petrophysical evaluation using NMR and sonic scanner integration.
- Reconstruction of the missing logs using machine learning.
- Petrophysical mineralogy modeling by calibration of the results using XRD and XRF data
- Core description of the three target formations (Deadwood, Icebox and the Precambrian).
- Description and Interpretation of more than 300 available thin sections.
- Building the 3D geological model using machine learning.
- Geomechanical lab Measurement (full triaxial test, pore volume compressibility)
- 1D and 3D geomechanical model construction.
- CO2 sequestration simulation using CMG.

Significance:

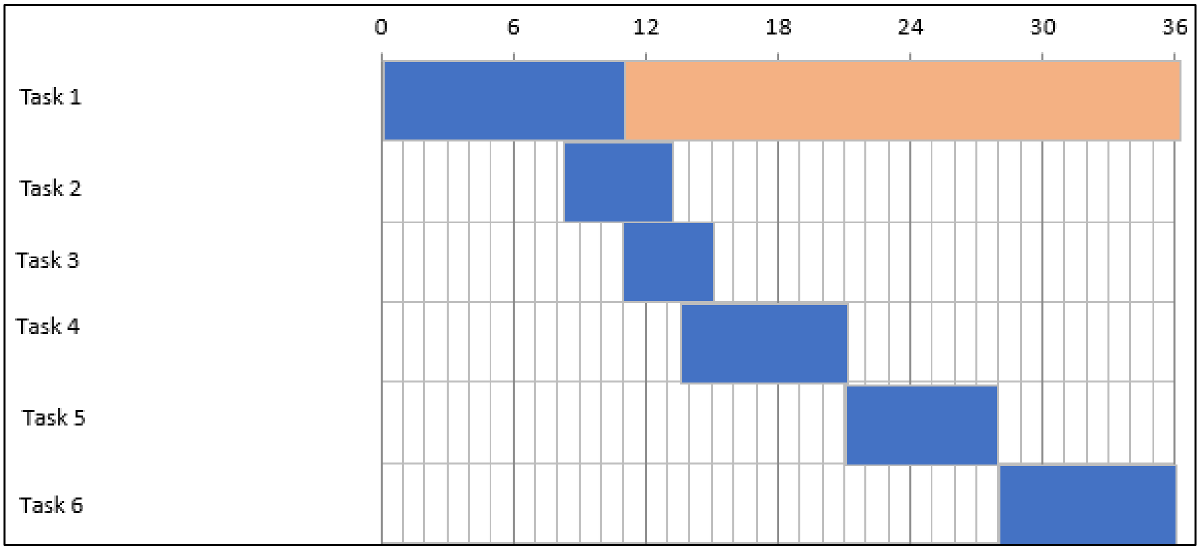
This study includes several unique aspects which distinguishes itself from similar studies. Some of these include:

- The introduction of the impact of diagenesis on the petrophysical properties and integrating this impact into the geological model in a rational and consistent way.
- This is the first study to investigate the performance of the Deadwood as a CO2 sequestration reservoir.
- This study is one of the few studies that examine faults and fractures reactivation in the basement due to CO2 Storage in the Williston Basin.

Project Milestone and Timeline:

The followings are the major milestones of the project:

- Task 1: Literature Survey
- Task 2: Data Collection
- Task 3: Petrophysical evaluation
- Task 4: Core and thin sections description
- Task 5: Static model and geomechanical models
- Task 6: Dynamic CO2 simulation



Progress to Date:

As of August 2021, a significant amount of literature has been reviewed in relation to geological carbon storage. Data collection (Logs, Core photos and thin sections) and digitizing has also been done. The petrophysical analysis of the wells is in progress.

References:

Timothy O. Nesheim, The Deadwood Formation: A Potential Stratigraphic Unit for CO2 Sequestration.

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Summary and Comparison of Bakken CO_2 EOR in the Williston Basin, North Dakota; as Related to Reservoir Geological Parameters

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Problem Statement:

The combination of horizontal drilling and multi-stage hydraulic fracturing has boosted the oil production from Bakken tight oil reservoirs in recent times (Saputra, W., W. Kirati, and T. Patzek, 2020), Bakken Shale Oil Production Trends: Texas A&M University, 133 p.. Unfortunately, the primary oil recovery factor is very low due to the extremely tight formation, with permeabilities measured in micro- to nanodarcys (Anyanwu, J., 2015) resulting in substantial volumes of oil still remaining in place. Although carbon dioxide (CO_2) is widely used in conventional reservoirs to improve oil recovery, it is a new subject and not well-understood in unconventional oil reservoirs such as the Bakken formation (Yu, *et al*, 2015). To overcome this situation, operators in the Williston Basin have employed myriad forms of CO_2-assisted EOR practices over the last decade, with varying degrees of success. Given the disparate results, it is clear that some of these procedures are more effective than others. To investigate the possibilities of reservoir heterogeneity, a 3-dimensional array of EOR practices/results vs. reservoir (upper, middle, and lower Bakken, Upper Three Forks) is to be constructed. It is hoped that this will outline both Bakken 'sweetspots' and demonstrate which CO_2-based EOR practice is best suited for each of the 4 main reservoirs in the Williston Bakken.

Objectives:

- Construct a comprehensive recent literature review to create a bank of data and general description of both procedures and problems.
- Delineate the reservoir geology, lithology, mineralogy, thermal maturity, fluid properties, and pore structures and connectivity in order to obtain reliable assessment of CO_2 EOR projects per each reservoir unit.
- Quantify specific reservoir parameters for each of the four reservoirs considered to obtain a 'type' section for each.
- Delineate and quantify the various modes of CO_2 EOR that have been carried out in the Bakken over the last decade.
- Compare and contrast the efficacy of the varying CO_2 EOR projects as compared to the varying lithologies of the various Bakken and Upper Three Forks reservoirs.
- Develop a chosen methodology of best practice for each of the four chosen reservoirs in the Bakken.

Methodology:

- Gathering data from previous works by reviewing science journals, conference papers, PhD dissertations, and reports.
- Obtain case histories from ~10 of the current largest Bakken operators detailing their experiences and results with CO_2 EOR practices in the Williston Basin.

- Integrating data gathered through interviews with operators as to their experiences, problems and best practices in the Bakken.
- Establish which, if any, independent or interdependent parameters are the most critical for CO_2 EOR in the Bakken when correlated with varying geological, geochemical and petrophysical parameters of the Bakken; as determined by cores, log and production profiles.
- Cross-correlate and endeavor to develop relationships between CO_2 EOR best practices and Bakken ‘sweet spots’; or can certain types of CO_2 EOR have positive, or negative, influence on certain types of Bakken-specific reservoir parameters.

Significance:

The significance of this research study is it a comprehensive study in more detail that includes real-world case histories as well as real-world problems and the solutions to an expensive, and oftentimes, chancy EOR project. By including actual case histories, from different companies operating in different areas of the Williston, along with actual in-person testimony as well as core, log and production results; this will not only generate a better understanding of the Bakken reservoir formations, but the preferred reactions to the various types of CO_2 EOR programs enacted over the last decade.

Project Milestone and Timeline:

TASKS	Semesters									
	F 2020	SP 2021	S 2021	F 2021	SP 2022	S 2022	F 2022	S 2023	S 2023	F 2023
Comprehensive Literature Review										
Data Collection - Operators										
Data Collection - Core and log data										
Data Collection - Interviews										
Data collation and interpretation										
Validate Results										
Rough Draft of Paper										
Peer Review Results										
Edit Paper										
Present Paper										
F: Fall, SP: Spring, S: Summer										

Progress to date:

- Through Summer 2021, I have contacted several of the larger operators in the Bakken in North Dakota. Conversations regarding data and data confidentiality were held.
- I have yet to receive any detailed information, but have been put in contact with the personnel which both are privy to this data and able to access it for this study.
- I have constructed an extensive literature archive regarding:
    a. Bakken petroleum geology
    b. Bakken CO_2 EOR case studies
    c. Bakken-specific oilfield practices and procedures
    d. Bakken reservoir engineering
    e. Bakken volumetrics: the 'how' and 'why' of Bakken reserve reporting.
- Begun to determine "type" parameters for each of the four Bakken reservoirs included in this report.
- Delineating which cores are available for which reservoir and CO_2 EOR type.

References:

Anyanwu, J., 2015, Nanopetrophysics Characterization of the Bakken Formation: The University of Texas at Arlington, 65 p.

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Yu, W., H. R. Lashgari, K. Wu, and K. Sepehrnoori, 2015, CO_2 injection for enhanced oil recovery in Bakken tight oil reservoirs: Fuel, v. 159, p. 354–363, doi:10.1016/j.fuel.2015.06.092.

Characterization of Vertical Growth of Fractures in Layered Formations

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Problem Statement:

Hydraulic fracturing is a popular and well known well stimulation technique that is routinely employed to not only accelerate hydrocarbon production but also influence the overall recovery from subterranean formations. Although for several decades after its inception in the late 1940s, the primary targets were generally sandstone reservoirs, the recent technological advances now allow this method of well stimulation to be successfully extended to even the ultra-low permeability source rocks and produce hydrocarbons from them, within the economic constraints.

Vertical growth of hydraulic fractures is a topic of great interest amongst researchers as it is key to the success of any fracturing treatment. Observations made in the field however show that the current fracture simulators and models do not adequately predict fracture growth especially in shallower formations. In layered formations, more that material property changes in the layers, the interfacial bonding between them, plays an important role is controlling fracture growth (Daneshy, 1978), especially in the shallower formations. Depending on conditions present at the interface, the hydraulic fractures either crosses the interface or truncates their resulting in propagation along the interface itself (Gu and Siebrits, 2008) leading to a development of horizontal fracture component. Such a behavior is also likely to happen in high-stressed deeper wells if the injection pressures exceed overburden pressures during the treatment; such an outcome can greatly reduce the expected gains from hydraulic fracturing as its ability to increase the contact area diminishes with the onset of horizontal component(s) of the fracture. The objective of this research work is to develop fracture height growth models that can accurately predict fracture growth in layered formations.

Progress to Date – Results & Discussion:

Following are the highlights of the progress made in the research so far, where, in the first stage of study (May 2020 to Oct 2020):

1. A robust fracture height growth model was developed for multi-layered formations that is based on principles of equilibrium height growth model and superposition methods.
2. The model can accurately replicate the published results from a 7-layered stress model (**Fig. 2**) available in the literature; it was then extended to 100 data input layers.
3. The model was successfully applied on several field cases (Pandey and Rasouli, 2020a; Pandey and Rasouli, 2021b) where it was able to accurately predict the fracture height growth when compared with field measurements; **Fig. 1** shows an example.
4. Modification to the model was carried out to include effects of fluid flow in fracture, for cases where a mismatch was observed.
5. Results from the study showed that in heavily layered formations, the fracture growth is restricted and also once the fracture reaches a sufficiently height after breaking into high stresses barriers, further growth can occur at lower net pressures also.

In the continuation of this work, in the second phase of the study (Oct 2020 to Jan 2021) pressure history match capabilities and other features to the model and calculation procedures were introduced. Following are the highlights of second phase of the study:

1. A new theoretical equation to calculate fluid/fracture velocity-based stress intensity factor, which is a critical input in fracture height estimation, was developed. This equation combines the lubrication equation (fluid flow) and solid mechanics approach to predict more reasonable stress intensity factors than laboratory estimated or values from rock data base that are generally not applicable.
2. The fracture height and location versus net pressure mapping obtained for given formation properties and stress profile was used in adding a pressure history module to the model.
3. The study shows that in majority of cases, because of field adopted procedure of rapid injection rate increase, the fracture height growth is rapid in early part of pad. To keep the height growth contained, the injection rates should be increased gradually. **Fig. 3.** The results from a commercial simulator points to the same behavior as seen in **Fig. 4**.
4. The effect of tip dominated, and fracturing fluid viscosity were studied, and various treatments pumped in shallow coalbed methane wells, and also foamed treatments pumped in sandstone reservoirs were analyzed. Analysis of treatments pumped showed (Pandey and Rasouli, 2021c) that the tip effects only dominated in the early part of the treatment, and not as much as the viscous fluids enter the fracture. This effect is highlighted in **Fig. 5**.

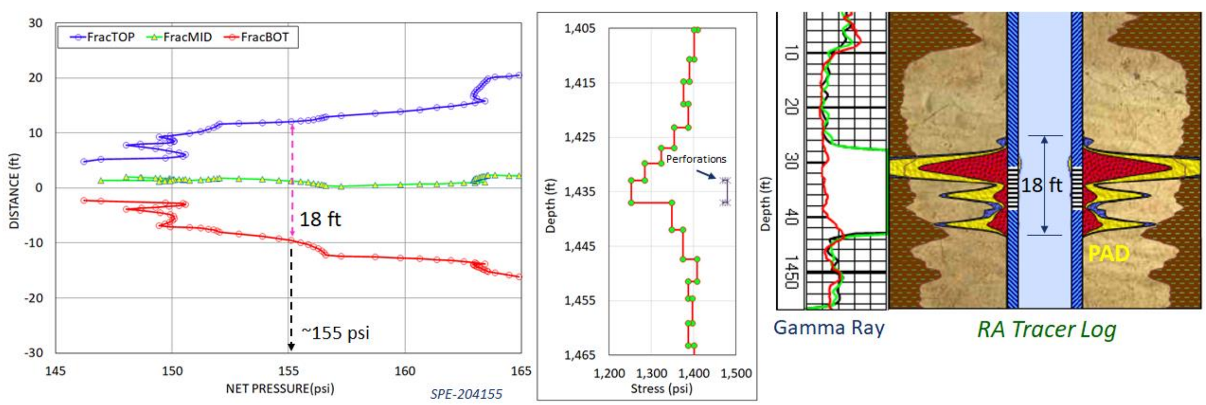
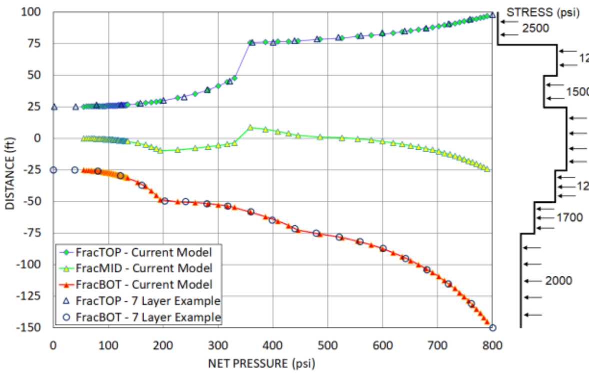


Figure 1. Net pressure vs. fracture location map (left) and fracture height observed in the field for 155 psi net pressure.



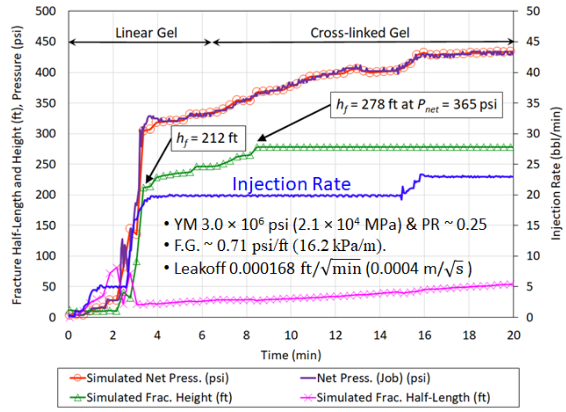
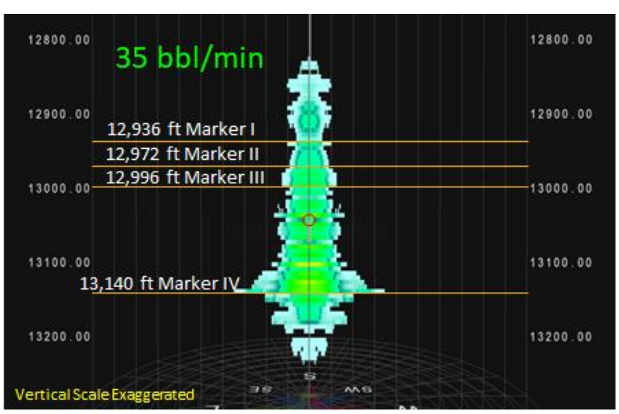


Fig.2: Fracture location vs. net pressure mapping replicated from literature data.

Fig. 3: Fracture height evoluition from history match of field data using the new model developed.

In the third phase of study (Feb 2021 to Apr 2021) calculations to predict the restrictions to fracture growth in layered formations were introduced. Following are the highlights of this section of study:

1. The calculations are based on effective incremental net stress on fracture that results from generation of width. The effects were used to induce layered stresses in addition to given stresses, for cases where the fluid pressure in the fracture followed a quadratic and/or non-constant, and non-uniform distribution.
2. A few case histories were presented in this case (Pandey and Rasouli, 2021d) where the microseismic (MS) data recorded during the field operations pointed to a distinct truncation of upward fracture growth possibly to due layer slippage and/or existence of horizontal component, both of which can be explained with the help of this new approach. Results from one of the simulations is shown in **Fig. 6**.



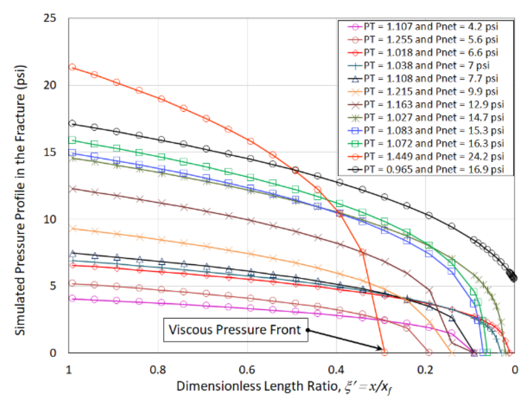


Fig.4: Simulated fracture height growth at high injection

Fig. 5: Simulated fracture tip pressures. rates.

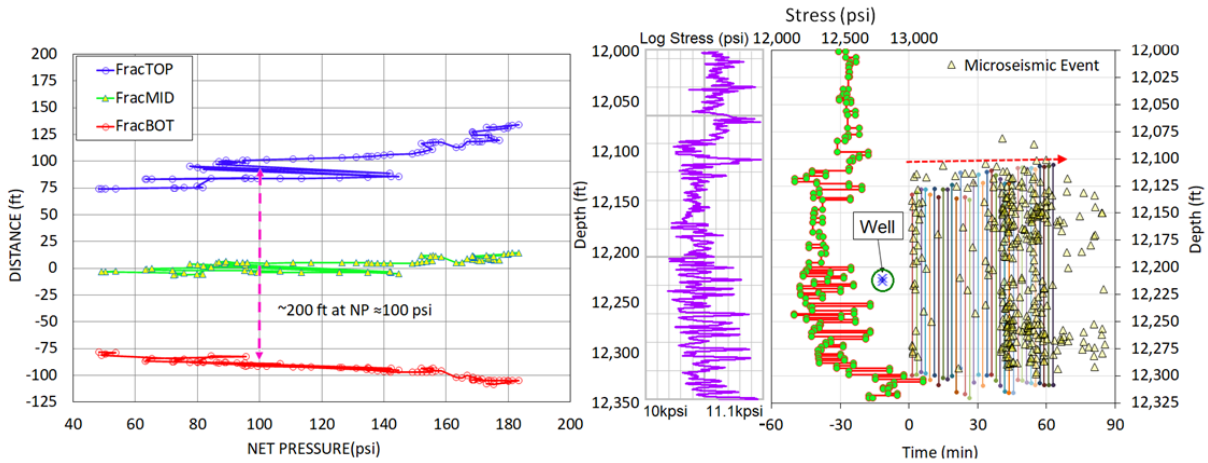


Fig. 6: Simulation of limited fracture vertical growth as observed in the field. The red arrow on the right plot indicates fracture limited to 12,110 ft with 100 psi net pressure for a fracture height of 200 ft. Vertical bars on right plot indicate various fracture heights and yellow triangles are microseismic events.

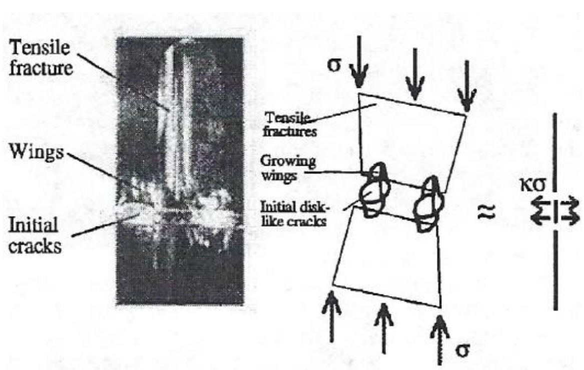


Fig. 7 – Splitting crack generation (Dyskin et al., hydraulic 1994) and a 2D model of 3D crack ((Gemanovich, et al. 1996).

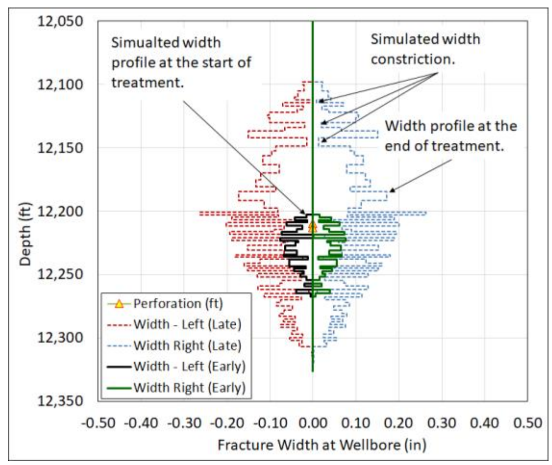


Fig. 8 – Evolution of fracture width during a fracturing treatment initiated from a horizonal well.

Path Forward:

In the last phase of the study, further research work and model modification is underway to incorporate horizontal fracture components to fracture. The objective is to allow automatic picks of location where there is such a possibility and predict the fracture growth based on the solutions obtained. This work entails a close look at fracture width models along with 3D modeling as shown in **Fig. 7** and **Fig. 8**.

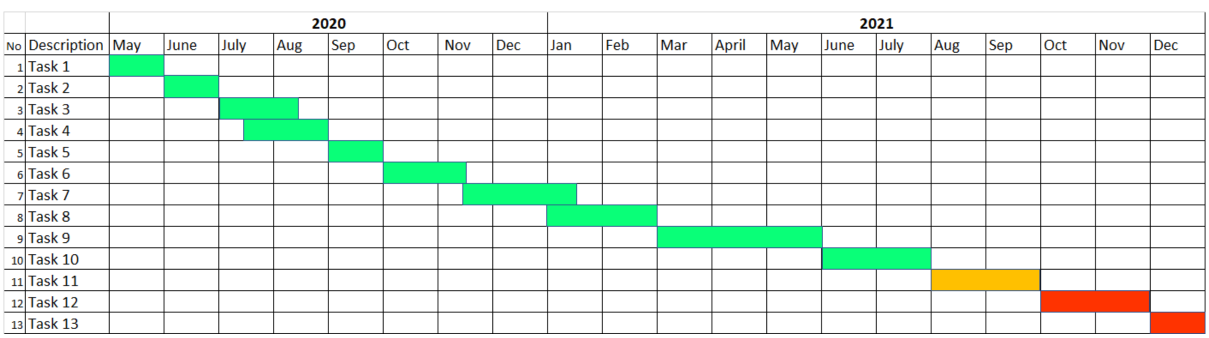
Significance of the Research Work:

1. Accurate prediction of fracture vertical growth during hydraulic fracturing treatment.
2. Predict out of zone fracture growth and steps to limit that.

3. Predict possible abrupt truncation of fractures and its effect on stimulation treatment.
4. Assist in well planning to place wells, perforations, landings, etc. with an objective to maximize the outcome of fracturing treatment.
5. Assist in generating optimal pumping schedules that have the correct combination of pad volumes, proppant volume, proppant concentrations, fluid types and injection rates to maximize the benefit.

Project Milestones and Timeline:

Task	**Name**
1	Concept and Problem Definition
2	Preliminary Model to Benchmark w/existing work
3	Apply to Case Histories
4	Start - End Paper writing - Paper I (intro to problem)
5	Research Phase (II) - Non-equilibrium, tip velocity, other factors
6	Start - End Paper writing - Paper II (Results after inclusion of other factors)
7	Research Phase (III) - Knowledge/data gathering/Rock/Frac Mech.
8	Development of alternate methods, benchmarking & analysis
9	Start - End Paper writing - Paper III
10	Research Phase (IV) - Real-world examples evaluated with new model
11	Start - End Paper writing - Paper IV – **On Track 11th August 2021**
12	Research Phase (V) - Real-world examples evaluated w/modern day simulators.
13	Start - End Paper writing - Paper V and Thesis



Colors: Green – Tasks Completed; Orange – In Progress; Red – Not started.

Progress to Date:

1. As a part of the study an extensive search on literature was carried out (Rice, 1968; Fung et al. 1987; Warpinski and Smith, 1989; Mack et al. 1992) and a semi-analytical calculation method that combines the solid mechanics and fluid mechanics solutions to forecast fracture vertical growth in heavily laminated reservoirs, was developed (Pandey and Rasouli, 2021). Several

case histories were presented and the adjustment to the models to account for actual observations made in the field were also made. ***Paper printed in JPSE July 2021 issue***. (Task 1 thru 4)

2. New modeling approach of fracture height growth by determining fracture toughness from tip velocity was developed. ***Paper printed in RMRE May 2021***. (Task 6).
3. Concept of predicting sites of possible fracture growth truncation using width calculations developed. **Paper submitted to *JPSE* for review.** (Task 9)
4. 3-Dimensional aspect of fracture growth. **Task 11 is in progress**.

List of Papers written after commencing PhD in May 2020.

1) Pandey, V.J. Pressure Interpretation in Acid Fracturing Treatments, 2021. To be presented at The SPE's Annual Technical Conference and Exhibition, Dubai, Sept 21-23, Dubai, UAE. SPE-205990-MS.
2) Pandey, V.J. and Rasouli, V. 2021d. Development of a fracture width induced net stress model to predict constraints to fracture height growth. *J. of Pet. Sci. & Eng – under review.*
3) Pandey, V.J. and Rasouli, V. 2021c. Fracture Height Growth Prediction Using Fluid Velocity Based Apparent Fracture Toughness Model. May 2021. *Rock Mech Rock Eng* (2021). https://doi.org/10.1007/s00603-021-02489.
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Pandey, V. J. and Rasouli, V. 2022. Estimating fracture growth constraints in layered formations using 3D fracture growth assumptions. For presentation at HFTC 2022, Feb 1-3, The Woodlands, TX. Abstract Submitted.

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Reservoir Modelling for the Underground Gas Storage in the Devonian Carbonate, Duperow Formation.

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Problem Statement:

With Natural Gas is a vital component of the world's supply of energy. It is one of the cleanest, safest, and most useful of all energy sources.

Underground gas storage may be defined as the long-term safe isolation of natural gas within geological formations and can be stored for an undetermined period of time. The original and primary scope of underground gas storage (UGS) was the variation in peak demand of a well-defined consumer area and the optimization of the transport network. Storage also served to conserve some of the gas being wasted or flared during summer months (Verga,2018).

One way to ensure large-scale energy storage is to use the storage capacity in underground reservoirs, since geological formations have the potential to store large volumes of fluids with minimal impact to environment and society.

Natural gas is commonly stored in depleted petroleum reservoirs, which are oil-producing geologic formations that have produced oil and/or gas, and storage space is available in the pore space previously occupied by the oil or gas.

Depleted reservoirs are the most commonly used storage sites because of their wide availability. They are relatively easy to convert for storage and close to consumption centers and existing pipelines.

There are some basic requirements for underground gas storage (Aminian, Mohaghegh 2009),

- A structure overlain by caprock is an impermeable stratum above the reservoir that prevents gas migration toward the surface. Water in caprock seals the tight rock from penetration by gas phase and prevents it from rising vertically. It also leads to accumulation of gas in storage zone below the caprock.
- Sufficient depth for gas storage under pressure.
- A high porosity and permeability zone under caprock for gas storage and flow.
- Water below storage zone to confine the stored gas

The Duperow is a regionally extensive Devonian Carbonate with excellent storage potential. This formation attains a thickness greater than 500 ft in northwestern North Dakota. Geologically, it is a carbonate formation with interbedded evaporites (Wilson,1987).

The Beaver Lodge Field as a potential location for conducting a gas injection model projected on the Duperow as the majority of Duperow production in the Beaver Lodge Field is part of the Devonian Pool/Unit (the field may have started producing from the Duperow Formation before the Duperow was officially named/defined in North Dakota).

The Devonian Pool (Duperow) in the Beaver Lodge Field has been unitized and has had water injected for enhanced oil recovery.

In this thesis, the Devonian Carbonate potential for being an underground gas storage will be studied. The Duperow formation is identified for static and dynamic modelling, to quantify the potential capacity for underground gas storage.

Objectives:

- Demonstrate underground natural gas storage concepts in Duperow formation.
- Determine consistent petrophysical properties for input into further detailed technical studies as part of the UGS project in Duperow formation.
- Calculate probabilistic determinations of Original Gas in Place (OGIP) for the potential UGS site
- Characterization of the geomechanical properties
- Establish the diagenetic history to predict rock fault properties
- Study the effect of reservoir heterogeneities on the system's dynamic response during gas storage
- Evaluate cap rock integrity and fault stability and the effect of injection on completion design.

Methodology:

- Data gathering, selection, digitizing, and processing.
- Lab experiments: computerized tomography scan (CT- scan), X-ray diffraction (XRD), (XRF), thin section, scanning electronic microscope (SEM), and direct measurements of the threshold pressure on the caprock cores.
- Fracture analysis and well testing for the evaluation of reservoir characteristics (or alternative well testing procedures)
- Rock-type determination is aimed at using a statistical approach to build a better geological model well-fitted to reservoir variables.
- Geomechanical modeling
- Build static reservoir model
- Dynamic reservoir simulation

Significance:

- This is one of the first studies to determine the Underground Gas Storage in North Dakota
- Underground natural gas storage feasibility analysis in Duperow formation.
- Impact of diagenesis on petrophysical properties to construct a model well-fitted to reservoir variables
- Predict storage capacity, injectivity and deliverability of the reservoir.
- Hysteresis analysis to predict the correct reservoir dynamic response over time.

Project Milestone and Timeline:

Time major milestone of the project Include the following tasks:

- Task 1: Literature Survey
- Task 2: Data Collection.
- Task 3: Lab experiments.
- Task 4: Petrophysical model. ·
- Task 5: Geomechanical model.
- Task 6: Static model.
- Task 7: Reservoir simulation for the Underground Gas Storage.

YEAR	2021					2022			2023		
TASK	Aug	Sep	Oct	Nov	Dec	Spring	Summer	Fall	Spring	Summer	Fall
Data Collection											
Lab Experiments											
Petrophysical Model											
Geomechanical Model											
Static Model											
Reservoir Simulation											

Progress to date:

As of August 2021, a significant amount of literature has been reviewed in relation to Underground Gas Storage. There has also been significant amount of collected data. Another significant part of the work till date, as has been the data digitalizing in order to achieve the data gathering in a proper way. Finally, different methodologies and alternatives have been studied, in order to prevent foreseeable issues related to the construction of the models.

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Techno Economic Assessment of gas Re-injection to Reduce Gas Flaring in the Bakken

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Problem Statement:

Flaring of associated gas from oil wells and the excess gas from gas processing units and oil refineries is one of the most critical resources of greenhouse gas emissions to the atmosphere. Flaring by definition is a method used to burn unwanted flammable gas, which produces significant amounts of methane, carbon dioxide, nitrogen oxide, and sulphur oxide. Yearly, the Petroleum industry adds millions of tons of CO2 into the atmosphere by flaring gas, which presents a serious problem due to the environmental and the economic impact associated with it.

In the light of increasing awareness of this threat, economic means to reduce anthropogenic release of greenhouse gases to the atmosphere are being investigated by the industry. North Dakota Industrial Commission (NDIC) adopted new regulations to restrict flaring. Operator companies must respect the established gas capture limits or the oil production must be reduced. NDIC allowed the use of different technologies to meet its established gas capturing goals.

Reducing emissions from gas flaring can be successfully achieved by re-injecting all, or a portion of, associated gas into either:

- a producing reservoir for enhanced oil recovery (EOR). Reinjection of gas into a crude oil reservoir increases pressure within the reservoir resulting in greater oil production; or
- a geological formation for temporary or permanent storage. Reinjection of gas underground permanently disposes of associated gas or stores it over short- or long-time periods for later use or sale.

Reinjection of excess gas back into the oil production reservoir or another, ideally depleted reservoir within the vicinity of the production wells, requires pre-treatment facilities, such as compressors, reinjection wells, and other auxiliary equipment and infrastructure. Systems for reservoir management and monitoring reservoir behavior are also required, especially when gas is injected into a production reservoir for EOR. Valuable heavy hydrocarbon liquids such as liquid petroleum gas (LPG) and condensate could be separated prior to re-injecting. This project will provide a techno economic assessment of natural gas reinjection as a means to reduce flaring.

Objectives:

- Study the applicability of gas re-injection for EOR and/or gas storage to minimize or eliminate flaring in the Bakken.
- Develop strategies for reinjection, an assessment of the economics, and study of the logistics of injecting gas from multiple wells into one or more injectors.
- Investigate cost effective approaches to inject the excess gas such as utilizing production wells as injectors and optimization to realize the most productive and cost-efficient means of operation. The application includes multi-well pads where gas flaring, due to various constraints, may limit oil production.

- Investigate the possible constraints and the best way to approach them such as well completion, availability of gas compressors, gas injection limits, and gas composition.
- Address the NDIC gas capturing goals in the long and short term by implementing gas re-injection method.

Methodology:

1- **Collect field data**
   - PVT of the reservoir, and gas injection composition.
   - Define well head location.
   - Deviations survey (ASCII).
   - Formation tops.
   - Wireline logs for each well (porosity, permeability, water saturation, shale content and other logs and petrophisical log interpretation reports).
   - Production history data for wells within the selected zones.
   - Completion and reservoir test data such as perforation, well test, acid and frac data.
   - A reservoir correlation, reservoir zonation. Upper Reservoir and Lower Reservoir.
   - A porosity permeability relationship to use as a permeability predictor if available.
   - Upper reservoir structural map if available.
   - OWC(s) determined from RFT's for the upper and lower reservoirs.
   - Saturation versus height curves for modelling saturations in the upper and lower reservoirs. Possible lab experiments (J function)
   - An oil-water relative permeability curve for use in the flow simulation. Possible lab experimental data (SCAL)
   - Oil, water and rock properties necessary for input into the flow simulator.

2- **Build 3D Reservoir model (Schlumberger Petrel software)**
   - Reservoir zonation and mapping.
   - Structural and property modeling.
   - Log blocking and Facies modeling.
   - The work can be expended to include the geomechanical modeling.

3- **Reservoir Simulation (Schlumberger Eclipse software)**
   - History match Single well model, and 8 wells unit model. Serve as base case.
   - Local grid refinement will be applied to accurately simulate the flow near well-bore.
   - Model various injection/production scenarios for a single well to understand optimization of injection rates, pressures, downtime, and production uplift. Use a range of gas volumes from normal flared gas volumes to full sales gas volume.
   - Relative to multi-well pad simulations assume the following cases:
     - Temporary gas storage – Injection of 100% gas production volume for a period of 6-months.

- Elimination of routinely flared gas. Injection of routine gas flaring for a 10-year period. (Flared gas = <10% of produced gas).
- Elimination of sporadically flared gas. Find examples of well-pads that flare intermittently versus routinely. Construct a case based on gas volumes and duration from production data.

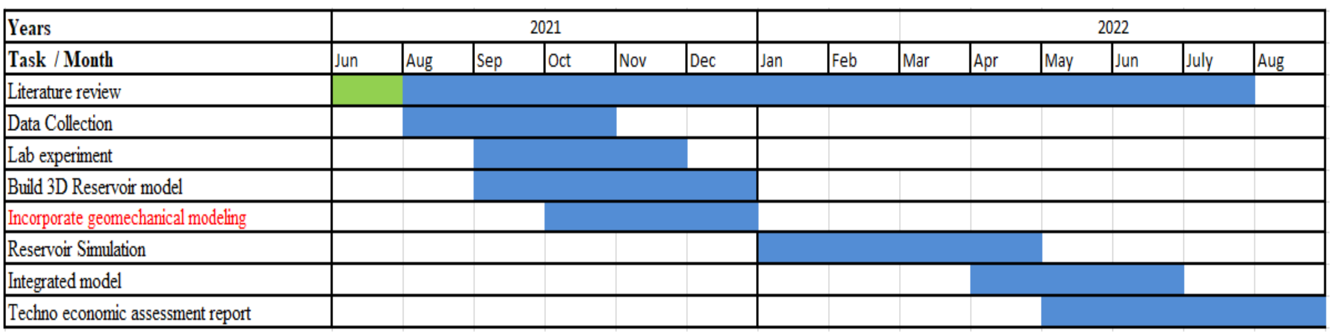
4- Integrated model

- Wells and network modeling using PETEX Software (Gap & Prosper or PIPESIME).
- Integrate surface network injection and production with reservoir model.
- Model production/injection cases to inform and optimize the selection of injection system and cycling to optimize production. Determine injection pressures, rates, and downtime.
- Use model results to examine economics.
- Determine injection costs based on typical Gas-lift installation.

Progress to date:

In the last few months I've been conducting an intensive literature review, a draft of a paper entitled "Advanced Technologies to Capture Gas Flaring: A Review of Literature" is on progress, to be finalized by the end of August.

Project Milestone and Timeline:



New Improved Model to Determine the Onset of Liquid Loading in Gas Wells

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Problem Statement:

Multiphase flow has gained a lot of attention in oil and gas industry lately. A multiphase flow is any fluid flow consisting of more than one phase or component. It could be two phase (or more) flow of fluid, gas and solid or any combination of each with another. The complexity that comes with the multiphase flow makes it does into different subset of smaller problems. For instance, the onset of liquid loading and the relative concept of the critical velocity at which the onset of liquid loading starts in gas wells is one the most challenging parameters to predict. Many researchers have investigated the critical velocity of gas liquid loading/unloading in vertical and horizontal pipes.

Multiple investigations (experimental and numerical simulations…) were done and different models were proposed (analytical and empirical) by researchers.

The approach of the liquid droplet was adopted by (Turner et al., 1969) who developed the first empirical model for liquid loading by calculating critical gas velocity. After that researchers tried to adjust the model to fit wider conditions. Lately, researchers proved experimentally that this approach is far from reality looking to the size of the droplet assumed by Turner and thus the need for an alternative was necessary.

The second approach is the liquid film thickness which has gained popularity among the scientific community after the so many experiments that proved with observation that this approach is the closest to reality. The transition from annular flow to intermittent flow is the main drive of the original model proposed by (Barnea, 1986) who elaborated an analytical model that calculates the critical velocity. Many improvements were done on the model to include the effect of inclination and the non-uniformity of the liquid film. However, one fundamental assumption of the model is that the liquid is transported in perfect film and has no entrainment in the gas core, which is also not close to reality.

Progress to date:

As of February 2020, the project has started by a meeting between Abderraouf Chemmakh as a Ph.D candidate and Dr Ling as academic advisor and Mr. Ahmed Shammari from Schlumberger as co-advisor. After that, an extensive literature has been conducted. Based on the findings an alternative model by (Alves et al., 1991) was found that considers the two effects simultaneously to solve the problem. The liquid film is the main supposition and the droplet entrainment in the gas core was considered while developing the closure model equations. Even though the model is more realistic, it still has some points to improve and investigate.

Plan to elaborate new model:

In order to establish a better performance model, some critical points are considered to be reviewed and improved:

- the correlations for liquid rate entrainment: the entrainment model considered by the original (Alves et al., 1991) is by (Wallis, 1969) which may not be very accurate. Some new models were proposed and we will conduct a careful study to assess the improvement of the model by using these models and if necessary work on improving our own model.
- the internal friction factor: the main point if discussion in two phase flow problem, the model by (Alves et al., 1991) uses (Wallis, 1969) model, which has been improved by some researches and it is our interest to use the latest improvements in the original model.
- The supposition of the average film thickness in deviated wellbore: each researcher puts an assumption for this critical aspect and propose a solution, our goal is to carefully review the assumptions and use the most convenient one in our model development.
- After elaborating ana analytical model, a Turner-like correlation will be developed in order to make it easier for production engineers to use in the field which is the main goal.

The proposed project will aim to address the pre-stated issues and tries to elaborate new models which will help to accurately predict the onset of liquid loading in order to avoid the loading phenomena and the cost of the removal process. Data Gathering has been conducted and a considerable dataset is already collected and ready to use once the model is developed. Experimental work is still being considered if we come to improve the flow that we have. The use of machine learning in order to better tune the model is also part of the plan.

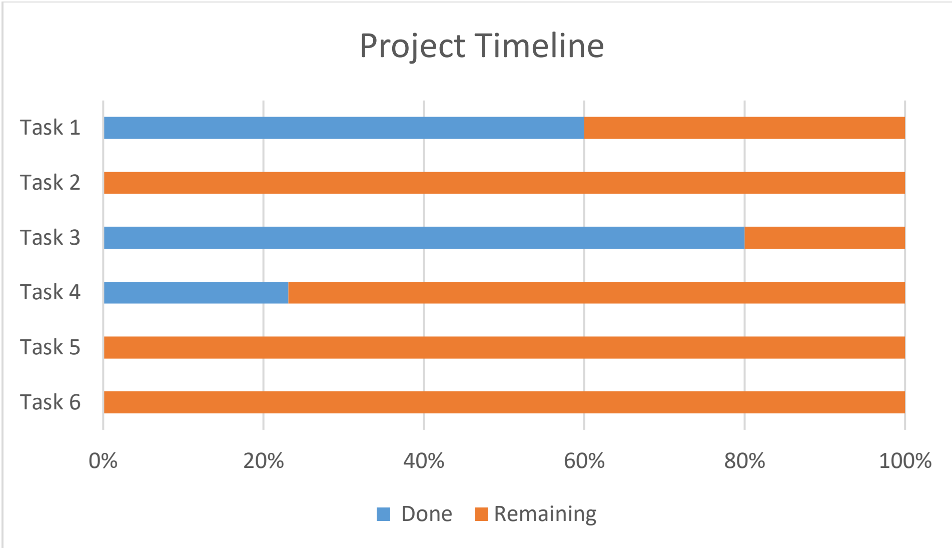
The model will be compared with the existing models in literature and an application to prospected field in North Dakota is suggested since some findings of prospected gas wells from NDIC data bank which are subject to liquid loading problems.

The proposal will be submitted to the concerned company right after the model is elaborated.

Project Milestone and Timeline:

Time major milestone of the project Include the following tasks:

- Task 1: Literature Survey
- Task 2: Conduct experimental work.
- Task 3: Data Collection
- Task 4: Development of models
- Task 5: Assessing the models in wider conditions.
- Task 6: Validating the models and elaborating results.



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Advantages of Injecting CO_2 with Oilfield-Produced Wastewater into Non-Hydrocarbon Bearing Reservoirs via Deep-Saltwater Disposal Wells

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Problem Statement:

In post-Soviet Russia, environmental laws were tightened considerably. Gone were the days of "oil at any cost" (Bini, E., G. Garavini, and F. Romero, *eds.*, 2016). There was increasing political pressure on oil and gas operators to not only increase domestic oil production, but also repair the destruction of the environmental that neary 75 years of Communism had caused on both the oilfields and adjacent lands of Eastern and Western Siberia (Newell, J. P., and L. A. Henry, 2016). Oilfield wastewaters were no longer allowed to be flowed off at the surface (Belokrylova, E. A., 2019). The same went for associated "grey" or 'bywaters' related to the human activities in and around oilfields. This meant that drastic measures were needed to dispose of the billions of barrels of oilfield-produced wastewater, 'greywater' and associated industrial fluids in a cost-effective and environmentally acceptable manner (Voloshin, A. I., *et al*, 2003). This meant that deep water-disposal wells were needed. It was not just a simple mater of drilling these wells and injecting the unneeded fluids, but the well needed to be designed given the restrictions of the new Russian technology and manufacturing capabilities. Then, there was the geological problem of choosing non-hydrocarbon bearing reservoirs that could accept the wastewaters (Foley, 1994). Following the situation as it evolved, one can take the methodologies used in Western Siberia, i.e., injection of CO_2 along with the wastewaters, and apply those understandings to the problem of increased oilfield wastewater disposal from the Bakken, *et al.* Since this also involves injection, disposal and sequestering of CO_2 (Gaurina-Međimurec, et al, 2020), this is important for the environment as the lack of injection reservoir capacity and increased wastewater volumes from hydraulic fracturing in the Bakken and other reservoirs in the Williston Basin of North Dakota are developing. It is generally prohibited to discharge wastewater into the environment without a permit, discharge prohibited substances with waste water and exceed any prescribed emission limits.

Objectives:

- Construct a comprehensive literature review to build a bank of data and general guidelines.
- Obtain operator data for present injection rates, locales and stratigraphic units in the Williston.
- Understanding of geology, lithology, mineralogy, thermal maturity, fluid properties, and pore structures & connectivity in order to obtain reliable assessment formation injectivity.
- Construct database of Bakken related oilfield produced waters; formation saltwater, fracturing operations flowback, produced water, 'gray' water, etc.
- Understand the physical, chemical mechanisms, and key parameters affecting the effectiveness of wastewater injection in the Bakken formation.
- Quantify the parameters that impacts wastewater injectivity in the Williston Basin.
- Quantify the amount of wastewaters that can be adsorbed onto and diffused into non-oil reservoirs in the Williston Basin.

Methodology:

- Gathering data from previous works by reviewing science journals, conference papers, PhD dissertations, and reports.
- Obtain case histories from the current largest Bakken operators detailing their experiences and results with wastewater injection practices in the Williston Basin.
- Integrating data gathered through interviews with operators as to their experiences, problems and best practices related to drilling, completion and production in the Bakken.
- Establish which, if any, independent or interdependent parameters are the most critical for wastewater injectivity from Bakken activities via deep water-disposal wells in the Williston Basin.
- Define correlation with varying geological, geochemical and petrophysical parameters of the key deep injector reservoirs; as determined by cores, log and production profiles.

Significance:

- The significance of this research is that it will be a comprehensive study utilizing the latest 'real world' data regarding wastewater injectivity in the Bakken or other reservoirs in the Williston Basin. By cross-correlating this data with historical Russian Western Siberian data and wastewater injection practices, it will allow the combining of the two models and application of the Siberian practices to Bakken injectivity issues where such problems were addressed and ameliorated earlier.

Project Milestone and Timestone:

TASKS	Semesters									
	F 2020	SP 2021	S 2021	F 2021	SP 2022	S 2022	F 2022	S 2023	S 2023	F 2023
Comprehensive Literature Review										
Data Collection - Operators										
Data Collection - Core and log data										
Data Collection - Interviews										
Data collation and interpretation										
Validate Results										
Rough Draft of Paper										
Peer Review Results										
Edit Paper										
Present Paper										
F: Fall, SP: Spring, S: Summer										

Progress to date:

- Through Summer 2021, I have contacted several of the larger operators in the Bakken in North Dakota for injectivity data. Data has been slow forthcoming.
- I have yet to receive any detailed information but have been put in contact with the personnel which both are privy to this data and able to access it for this study.

- I have constructed an extensive literature archive regarding:
    - Bakken petroleum geology
    - Bakken case studies
    - Bakken-specific oilfield practices and procedures
    - Bakken injectivity profiles
    - Bakken volumetrics: the ‘how’ and ‘why’ of Bakken reserve and injectivity reporting.
- Delineating which cores are available for which injector reservoirs.

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Application of Surfactants for Enhanced Oil Recovery in Three Forks Formation

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Problem Statement:

Unconventional resources particularly tight/shale oil reservoirs have attracted much attention over the years due to diminishing conventional oil resources and higher energy demand. Ultimate recovery from such formations calls for the use of advanced techniques such as horizontal drilling and hydraulic fracturing to wider reservoir contact and free flow of hydrocarbons towards the producing well. Nonetheless, production from these reservoirs utilizing the reservoir natural energy is not above 20% of the original oil in place (Hirasaki et al., 2011). Normally, waterflooding which is a widely known secondary recovery method would be applied to recovery the remaining oil right after the primary recovery. However, due to the complex petrophysical (low permeability and porosity) nature of tight plays, this method usually results in limited recovery.

While is true that unconventional plays such as the Three Forks Formation located in the state of North Dakota in the United States have demonstrated high oil recovery potential, primary recovery in this formation is barely above 10% of the original oil in place (Gupta et al., 2020). This necessitates the need to introduced advanced techniques in addition to horizontal drilling and extensive hydraulic fracture networks to unlock the oil trapped in these formation. Luckily, surfactant flooding has proved to be an efficient enhanced oil recovery technique in recovery oil from tight/shale oil reservoirs owing to surfactants capacity to reduced oil-water interfacial tension and alter rock wettability. This allows trapped oil to be released from rock surface while favoring spontaneous water imbibition thereby resulting in high oil recovery rates (Sheng, 2011).

Over the years, surfactant flooding operation has been conducted in reservoirs with low temperature and low salinity. Only a few studies have addressed reservoirs with high temperature high salinity due to the complexity of achieving the desired recovery output given such extreme conditions (Belhaj et al., 2020). Yet, the numerous reservoirs appropriate for surfactant EOR are marked by high temperature and high salinity, usually temperature of 70℃ to above 120℃ and brine salinity (hardness and total dissolved solids) of about 200,000 mg/L and beyond (Puerto et al., 2012). In addition, critical factors such as reservoir temperature, surfactant type, surfactant concentration, surfactant adsorption, surfactant cost, salinity, pH and among others can impede the implementation of surfactant EOR operation (Bataweel and Nasr-El-Din, 2012). These conditions make surfactant flooding process design convoluted since the surfactant injected has to remain stable throughout the entire flooding process and beyond (Puerto et al., 2012). Consequently, it is only wise to fully assess the selected surfactant's capacity in meeting the aforementioned criteria during flooding process and this can be done through a series of tests such as phase behavior, microemulsion, thermal stability, interfacial tension, wettability among others. These systematic laboratory study aims at designing and optimizing surfactant formulations capable of ultimately yielding minimum oil-water IFT as well as modifying rock wettability in order to enhance oil recovery. This present study therefore seeks to investigate surfactant formulation capable of recovering residual oil at the expense of reduced surfactant adsorption at extreme reservoir conditions through experimental and simulation approach.

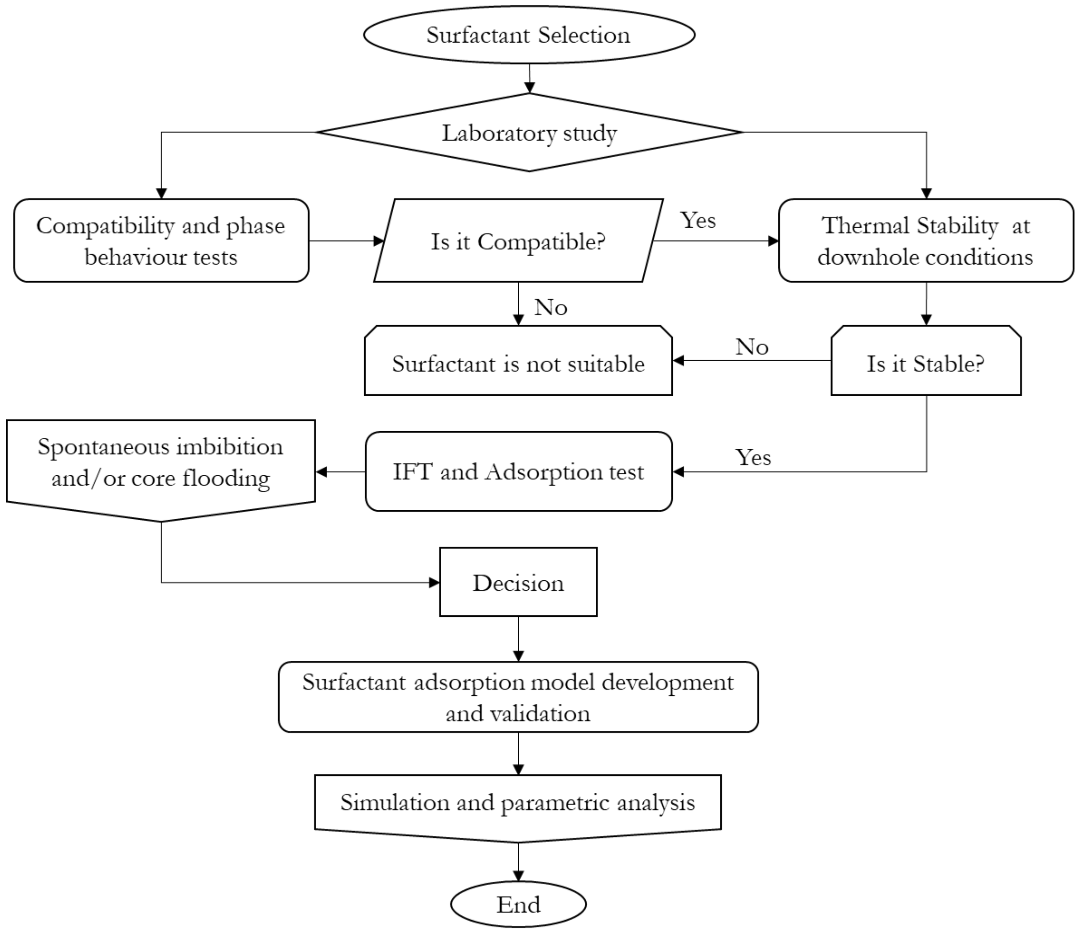


Figure 1. Project Flowchart

Progress to Date:

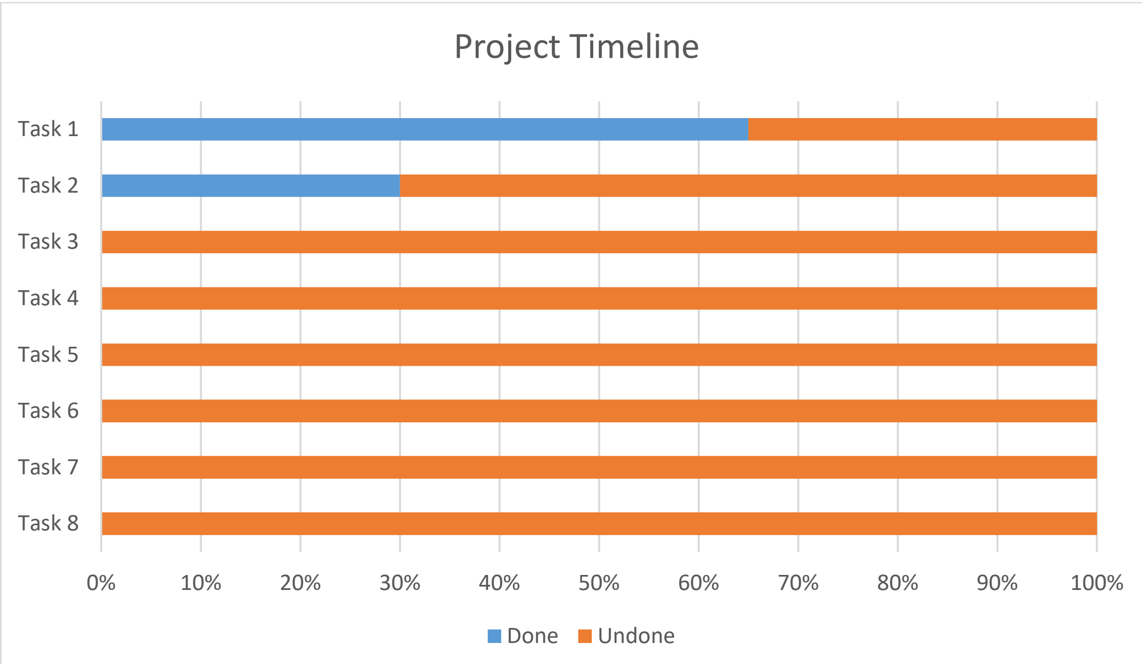
- **Data Gathering/Sourcing for Surfactants**

As of July 2021, an appreciable amount of literature concerning surfactant enhanced oil recovery application in conventional and unconventional reservoirs has been reviewed. Also, recovery mechanisms and influencing parameters in relation to surfactant flooding operation have well been understood. Another significant part of the work till date, has been on gathering the necessary data as well as sourcing for the needed surfactants for the laboratory investigations from various manufacturing companies as this forms a critical part of the project.

Project Milestone and Timeline:

Time major milestone of the project include the following tasks:

- Task 1: Literature Survey
- Task 2: Sourcing for surfactant/data gathering
- Task 3: Compatibility and Phase behavior test
- Task 4: Adsorption test
- Task 5: Spontaneous imbibition/core flooding test
- Task 6: Simulation study
- Task 7: Analysis of results
- Task 8: Thesis write-up



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Hirasaki, G., Miller, C., Puerto, M. (2011). Recent Advances in Surfactant EOR. SPE J. 16(4), 889−907.

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Experimental and Simulation Study of Surfactants Flooding in High Salinity and High Temperature (HSHT) Reservoir Conditions

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Problem Statement:

A well-known prolific world energy resource is the unconventional reservoirs. Economic production from tight oil formations requires long horizontal wells with an extensive hydraulic fracture network (Lotfollahi et al., 2017). However, the recovery rate for primary depletion still remains less than 20% of the original oil in place. In this case, water flooding is limited due to the low permeability and intermediate- to oil-wet nature of the rock. Although reservoirs like Wolfcamp, Bakken, and Eagle Ford formations play a significant role in improving oil and gas production in the United States, their primary recovery rates are rarely more than 10% (Gupta, Rai, & Sondergeld, 2020). Surfactant flooding is promising in liquid-rich shale reservoirs by altering the wettability, favoring for counter-flow imbibition process, and decreasing the residual oil saturation. In the past, chemical EOR was developed for many low to moderate salinity reservoirs with temperatures mostly below 80 °C (Abalkhail, Liyanage, Upamali, Pope, & Mohanty, 2020). The surfactant's mass and thus the cost of the surfactant needed for chemical EOR is proportional to the surfactant retention in the reservoir. The transitions between the different microemulsion types of surfactant are governed by temperature, brine composition (salinity and hardness), oil composition, pressure, and the surfactants' concentration and chemical structures co-solvents. Experimental observations of the microemulsion phase behavior, interfacial tension and viscosity are used to design and optimize chemical formulations. This study aims to analyze chemical EOR formulation that would result in both very low residual oil saturation and low surfactant retention for a high-temperature (~100 °C), high-salinity (~60,000 ppm) reservoirs.

Objectives:

The overall aim of this project is to evaluate surfactants that are applicable for enhanced oil recovery in harsh reservoir conditions. Some specific objectives include:

- Investigate the surfactant's dependence on stimuli such as temperature, pH, salinity, and ionic strength.
- Perform Phase behavior experiments on the selected compatible surfactants.
- Investigate the oil recovery efficiency of the surfactant using a core flooding machine at HSHT.
- Develop a predictive model for surfactant adsorption from the experimental study.
- This is important for computational modeling, economical and cost-effective planning of enhanced oil recovery operations involving green surfactant.
- Perform a simulation study on Surfactant Flooding and Investigate the relationship between surfactant concentration and recovery rate for different injection rates.

Methodology:

The surfactant will be check for its compatibility with different chemicals and brine build-up at reservoir conditions. Thereafter, phase behavior experiments are then carried out on the selected compatible surfactants. These experiments are capable of screening large amounts of possible surfactants in a short period of time. Surfactants that form middle-phase microemulsion are expected to have an ultra-low interfacial tension. Again, the potential surfactant is expected to possess long-term stability since its duration in a reservoir could be up to a few weeks. After that, the surfactant's potential to reduce interfacial tension will be determined and the limit of adsorption on the surface of the reservoir rock by the surfactant. Lastly, core flooding experiments will be carried out on potential surfactant formulations to determine how much oil can be recovered at reservoir conditions.

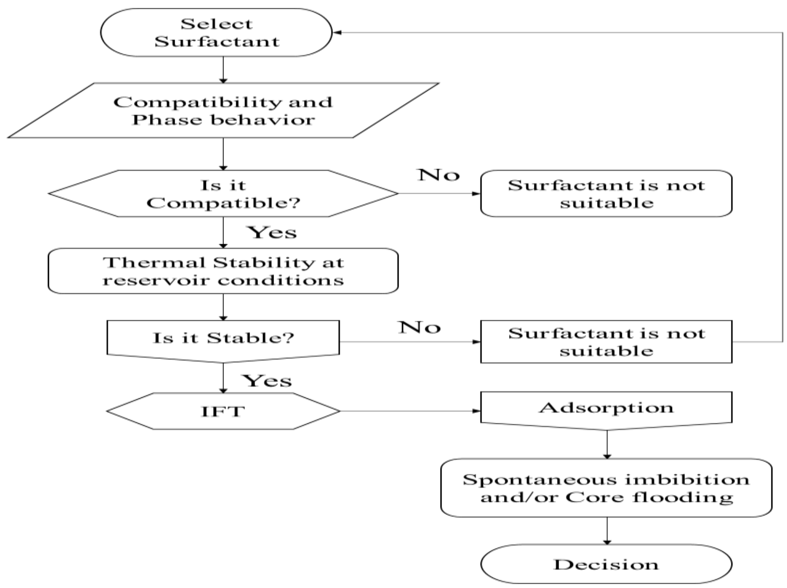

Figure 1. Experimental flowchart for Chemical EOR (Kamal, Hussein, & Sultan, 2017).

Significance:

This study will improve upon the existing literature on the use of surfactant in enhanced oil recovery of harsh reservoirs. This work will develop a predictive model for surfactant adsorption, which is important for computational modeling.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

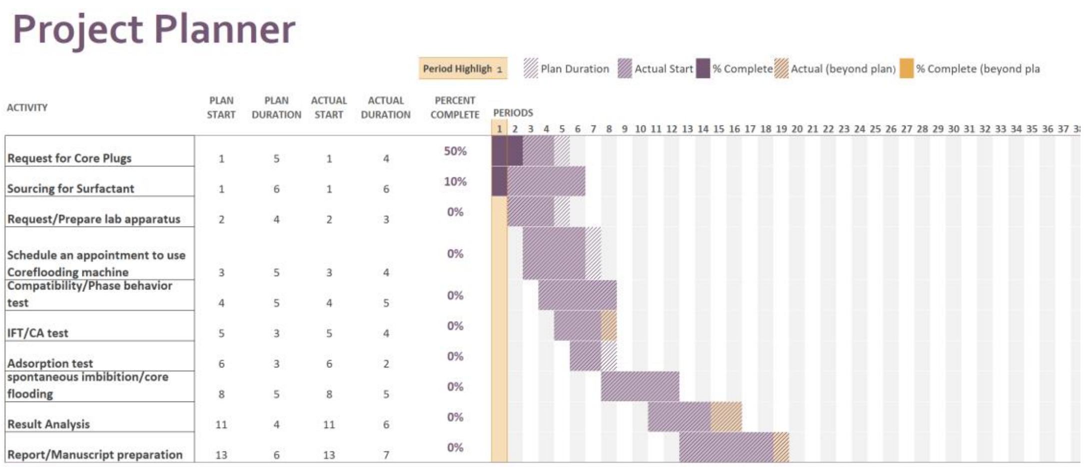

Figure 2 Project Milestone and Timeline

Progress to date:

As of August 2021, a considerable amount of literature had been reviewed to better understand surfactant characterization and phase behavior, the effect of surfactant structure, salinity, and temperature on IFT behavior, experimental screening and design of surfactant EOR, including spontaneous imbibition and/or core flooding, as well as surfactant flooding in the lab and field application.

References:

Abalkhail, N., Liyanage, P. J., Upamali, K. A., Pope, G. A., & Mohanty, K. K. (2020). Alkaline-surfactant-polymer formulation development for a HTHS carbonate reservoir. Journal of petroleum science and engineering, 191, 107236.

Gupta, I., Rai, C. S., & Sondergeld, C. H. (2020). Impact of Surfactants on Hydrocarbon Mobility in Shales. SPE Reservoir Evaluation & Engineering.

Kamal, M. S., Hussein, I. A., & Sultan, A. S. (2017). Review on surfactant flooding: phase behavior, retention, IFT, and field applications. Energy & fuels, 31(8), 7701-7720.

Lotfollahi, M., Beygi, M. R., Abouie, A., Sepehrnoori, K., Wheeler, M. F., & DiCarlo, D. A. (2017). Optimization of surfactant flooding in tight oil reservoirs. Paper presented at the Unconventional Resources Technology Conference, Austin, Texas, 24-26 July 2017.

Multiple Surface Pipeline Leak Detection Using Real Time Sensor Data Analysis

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Problem Statement:

Pipelines remain the most cost-effective system for the transportation of large volumes of petroleum products. However, the come with the associated challenge of oil spills. This challenge has the capacity of impacting the environment, the wildlife, and the socioeconomic life of the communities where these pipelines traverse. It also impacts on the finances of the operators arising from lost revenues , fines, and cleanup costs. The objective of this work is to develop a leak detection system using real-time data sensor data analysis for the detection of multiple leaks from surface pipelines. The use of data analytics provides an opportunity for the detection of pipeline leaks using algorithms which can utilize pipeline models and real-time sensor data for the detection and localization of these leaks. Several studies have been undertaken resulting in the development of algorithms capable of detecting single leaks using simulated data. The methodology developed for this work is shown in Figure 1.

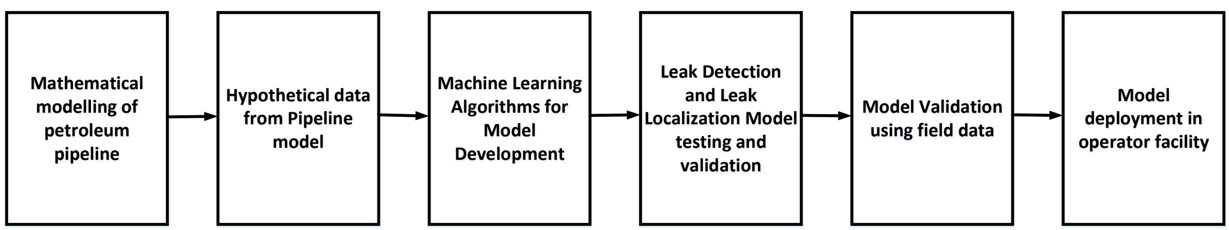


Figure 1. Workflow for the development of the real time leak detection and localization system

Progress to Date – Results and Discussion:

***Pipeline Leak Modelling*:** The analysis of fluid flow in pipelines for leak detection research requires actual leak data to train the leak detection model. However, such data is very scarce and difficult to obtain from oil and gas fields and operators. This provides the justification for the use of hypothetical data generated by the transmission pipeline model. The transient pipeline flow model provides the foundation for pipeline simulation and modelling. The basic equations governing this model include the continuity, the momentum, and the energy equations and the equation of state. The continuity equation focuses on the conservation of mass principle. It requires that the difference in mass flow into and out of any section of the pipeline is equal to the rate of change of mass within the section. This is expressed mathematically as shown in Equation 1:

$$\frac{d(\rho)}{dt} + \rho\frac{\delta(V)}{\delta s} = 0 \qquad \text{(Equation 1)}$$

In this equation, ρ = density, t = time, V = flow velocity and s = pipeline location coordinates

The conservation of momentum equation is represented in Equation 2:

$$\frac{d(V)}{dt} + \frac{1}{\rho}\left(\frac{\delta P}{\delta s}\right) + fs = 0 \qquad \text{(Equation 2)}$$

In this equation, V = the flow velocity v, t = time, P = pressure , s = pipeline location coordinates and fs = pipeline friction.

The conservation of energy principle is represented in equation 3.

$$\frac{dh}{dt} - \frac{1}{\rho}\left(\frac{dp}{dt}\right) - I_L = 0 \qquad \text{(Equation 3)}$$

In this equation, h = enthalpy, t= time, ρ = density, P = pressure, I_L= specific loss performance L

These equations are used in developing the required pipeline model for the specific fluid being transported. The simulation of a leak is accomplished by introducing a branch pipe of a given diameter on the main pipeline. This branch pipe can be located at any point on the main line with the leakage rate made variable. The variable leakage rate enables the study of different leak types on the main pipeline. This pipe model is represented in schematically in Figure 2. In this Figure, *D*1 is the distance between leak point and upstream pressure sensor and *D*2 is the distance between leak point and downstream pressure Sensor.

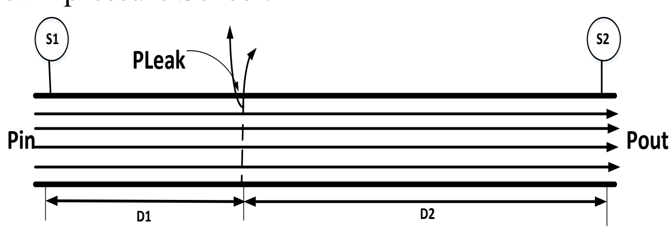


Figure 2. Section of the pipeline with the leak at distance D1 from the inflow section.

$$Pin = Pout + Pleak + Ploss \qquad \text{(Equation 4)}$$

$$Pout = \beta Pin - PLeak - PLoss \qquad \text{(Equation 5)}$$

Where β=Pressure Loss Factor due to length of pipeline

PLoss = Pressure loss due to wax buildup in the pipeline

PLeak = Pressure loss due to leak.

This pipeline model can produce sufficient data for different leak conditions and the data will be used for training the leak detection model. The model shown in Figure 2 for a pipe section can be extended to cover the entire pipeline network and be extended to enable the detection of multiple pipeline leaks from pipelines. The installation for entire pipeline network is shown schematically in Figure 3.

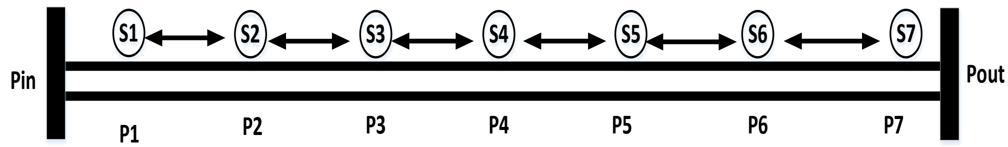


Figure 3. Pipeline network modelling for leak detection

The pipeline section in Figure 3 comprises of sensors installed at specific points. The goal of the simulation of this pipeline network is to determine the minimum distance for installation of sensors which can provide end to end leak detection from multiple leak sources. The sensors are connected to microcontrollers and wireless transmission systems for the transmission of the acquired data to the cloud storage location. Leak detection and localization algorithms are then used to analyze the data and determine the onset of a leak and the location in real time. The proposed system diagram with the sensor installations are shown in Figure 4.

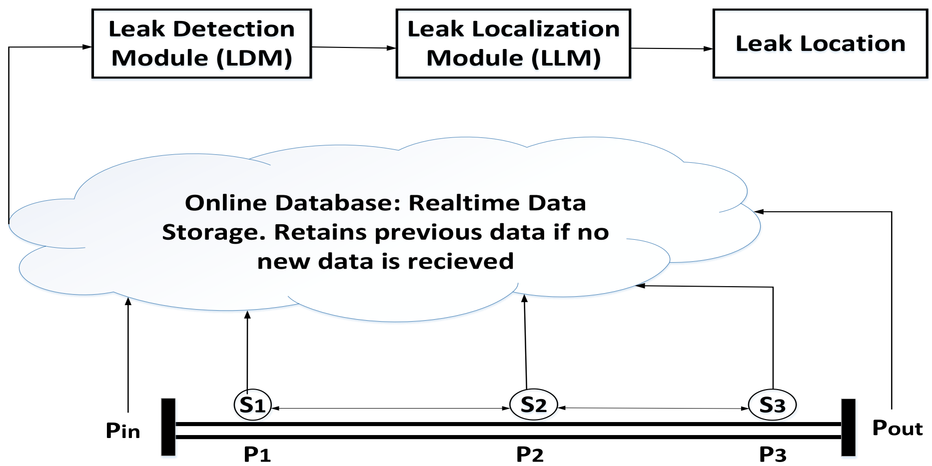
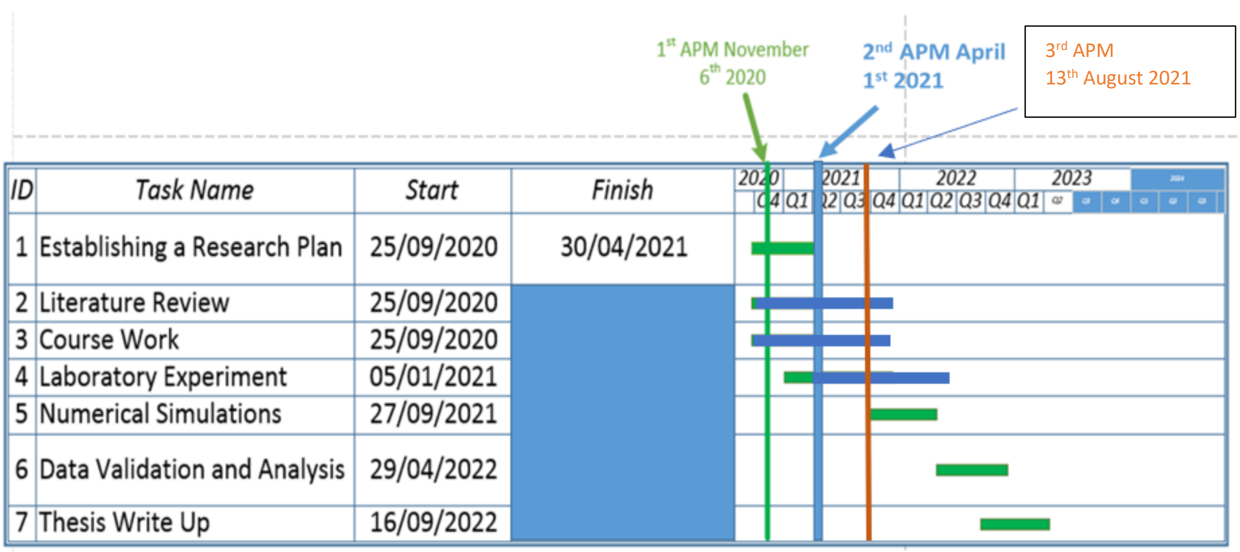


Figure 4. Pipeline leak detection system using field-based sensors.

Project Milestone and Timeline:



Investigation of Multiphase Flow Performances in the Undulating Horizontal Bakken Shale Wells

Youcef Khetib
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Problem Statement:

Shale plays are produced using multistage hydraulically fractured horizontal wells/ well pads, with a short well lifecycle it is necessary to optimize the wells production to maximize the production, long horizontal wells show undulations, due to drilling through different formations with different rock properties, these undulations affect the flow performances, with the presence of three fluid phases, the flow segregates and creates slugging effect(Norris, 2012). The slugging effect need to be investigated into more details and solutions should be proposed.

Modeling of such systems has been rarely done, using available transient simulators and investigating a more advanced modeling techniques enabling the engineers to consider a detailed wellbore geometry and surface properties is expected to lead to a more reliable tool to simulate such systems. Especially in the presence of the Density Wave Oscillation phenomenon(Ochoa et al., 2020a, 2020b), which onsets the instabilities, while condition do not lead to slugging flow regime.

CFD tools (Adaze et al., 2019), lab flow loop experiment and field calibrations are important steps to address such challenges.

Apart from a more advanced models, productions operations recommendations / best practices will be issued by the end of this project.

Objectives:

- Bring a better understanding of multiphase flow of undulated horizontal shale wells
- Fine tune / modify current transient multiphase flow fundamental models with DWO
- Drilling / Productions operations recommendations / best practices to be delivered

Methodology:

- Literature Review
- Data Gathering:
  - Wells architecture / completion,
  - Reservoir fluids,
  - Operating parameters gathering and
  - Wellbore geometry and surface properties collection.
- Simulation Phase
  - Using OLGA® a transient well operation (start-up, shut down, turn down, and normal operations) should be simulated following current practices in terms of geometry and surface properties (H. et al., n.d.)

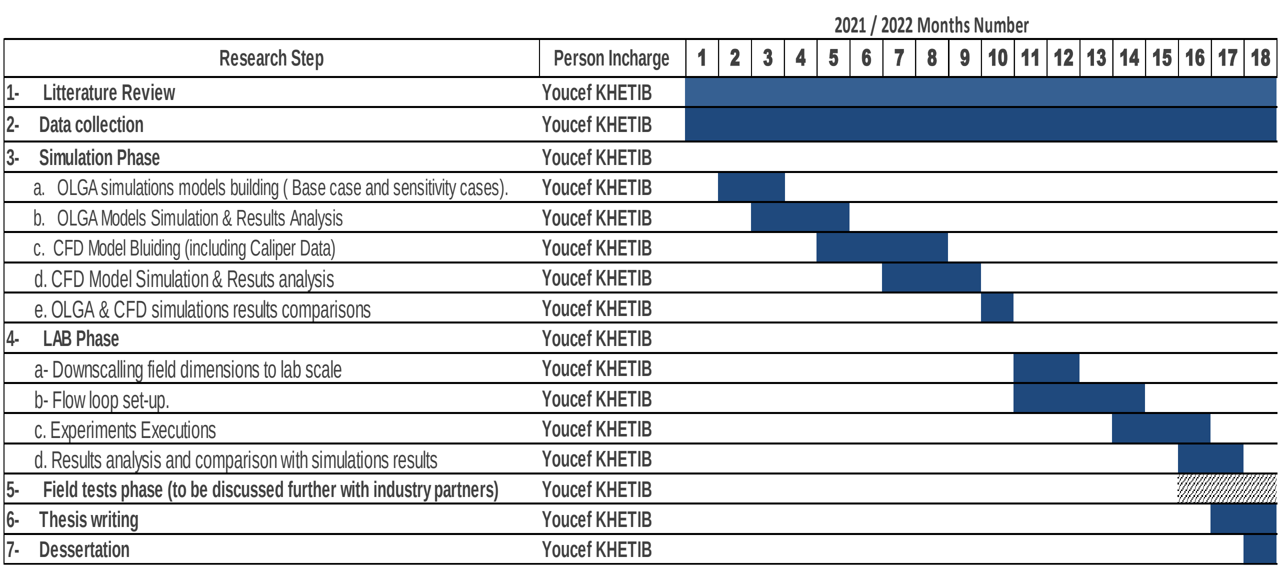
- Using CFD a transient well operation (start-up, shut down, turn down, and normal operations) should be simulated following current practices in terms of geometry and surface properties.
- Operating conditions sensitivities, Dimensionless groups monitoring, Caliper Data usage for open-hole sections.
- Determination of slug flow condition envelope for different operating scenarios:
  - GAS/Oil ratios
  - Water/Gas & Water/Oil Ratios
- Results analysis, OLGA & CFD Comparisons.

- Lab Phase
  - Downscaling real well trajectory section and wellbore surface properties to lab scale.
  - Set-up the flow loop to carry-on the experiments with respect to Dimensionless groups preservations (Densities, Reynolds number. etc.).
  - Execute tests and capture the data
  - Results Analysis
  - Field Tests Phase, to be discussed with industry partners.
- Thesis writing and dissertation.

Significance:

- Optimizing wells flow performances to increase production at both early & late production stages leading to higher Net Present Value.
- Reduction of operating issues of shale wells.
- Understand the multiphase flow for undulated open-hole sections.
- Modify / enhance modeling capabilities.

Project Milestone and Timeline:



Progress to date:

As of July 2021, a significant amount of literature has been reviewed in relation to Multiphase flow Modeling and simulation, slugging effects and shale wells productions mechanisms. Data Collection has been done for conventional wells and still exploring unconventional Bakken Shale wells on NDIC, Simulation models have been built and simulation runs started on the remote server machine, the foreseeable challenge would be to get high frequency production data for shale wells, so that the modeling and simulation work is applied on Bakken shale wells.

The conceptual design of the experimental set-up has been finalized as per this report writing date.

- Performing Literature Review (Continuous Task)
- Conventional Well Coupled Model 90% (rebuilt from scratch)
- Unconventional Bakken Shale Wells Data Collection
- Flow loop Experiment conceptual Design finalized
- Papers Writing

References:

Adaze, E., Al-Sarkhi, A., Badr, H. M., & Elsaadawy, E. (2019). Current status of CFD modeling of liquid loading phenomena in gas wells: a literature review. Journal of Petroleum Exploration and Production Technology, 9(2), 1397–1411. https://doi.org/10.1007/S13202-018-0534-4

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Ochoa, O. M., Nolasco, S. V., Díaz-Soto Pérez, I., Fairuzov, V., & Fairuzov, Y. (2020b). A Stability Criterion for Gas-Liquid Flow in a Well-Flowline-Separator System. http://onepetro.org/SPEATCE/proceedings-pdf/20ATCE/2-20ATCE/D021S001R003/2372557/spe-201509-ms.pdf/1

Simulating Tip Screen Out using Lattice Formulation

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Problem Statement:

Hydraulic fracturing is a commonly used stimulation technique to create flow paths and produce low permeability and tight formation. This technique can also be used for high permeability formation; however, some factors need to be considered, like high leak-off. In order to bypass damage or stimulate unconsolidated sands, a technique called (Frac and Pack) can be implemented.

Tip Screen-Out (TSO) is an operational hydraulic fracturing method used to prevent sand production. It is a combination of hydraulic fracturing and gravel pack (Chekhonin & Levonyan, 2012). The operational process of this method needs to follow a precise design that considers the high leak-off of the formation (around 90% of the injected fluid leaks into the formation) (Smith et al., 1987). It consists of creating a short and wide hydraulic fracture.

During the operation, the pad will initiate the hydraulic fracture. After that, the slurry will be injected in an increasing quantity increment. This will cause bridging of the proppant; thus, the net pressure will decrease once the proppant creates a plug. The flow will move from a Poiseuille flow into a Darcy flow, and the propagation of the fracture stops. Continues injection of slurry will cause an increase in width, which will be filled with gravel and stay open. It is highly important to understand the pack permeability; this parameter influences the total design of a TSO. **Figure 1** illustrates a TSO treatment.

Figure 2 illustrates a Frack and Pack job pressure response to the designed pumping schedule

Fan et al. (2001) ran an analysis on 500 TSO treatments in the Kern River field in order to identify the main influencing parameters on a Frack & Pack treatment. They found that volume of the pad, the volume of slurry, and the ratio between them, proppant mass, and the tip screen-out time have a major influence on the well's productivity.

Different analysis has been conducted in order to identify and simulate the tip screen out procedure and results. A KGD model was modified to simulate Frack and Pack stimulation (Chekhonin and Levonyan, 2012). A log-log pressure in function of time was used to identify TSO occurrence (Bai et al., 2003). A 3D simulator has been used by Fan et al. (2000) in the Eugene Island field in order to obtain an optimum design.

Getting the correct input to simulate TSO can be challenging. For instance, Minifrac data interpretation in high permeability formation is more complex due to the high permeable formation, thus the short time for closure. Multiple calibration methods must be conducted to ensure the consistency of the results. A new approach was used in (Neumann et al., 2002) where the author used ISIP as the upper limit for closure pressure, the Horner plot pressure as the lower pressure, for more accurate closure pressure estimation an additional interpretation was introduced using another derivative plot (ISIP -x dP/dx).

Because the industry simulators were designed for low permeability formation hydraulic fracturing, they use some simplified approaches for computational efficiency. The same case study was run on different simulators resulted in different outcomes. The interpretation of that was not possible due to the hidden formulation of these simulators (Chekhonin and Levonyan, 2012). This work consists of simulating and calibrating a Frack and Pack treatment using the lattice formulation in XSite. XSite is a grain based fully coupled simulator. This will allow a more precise simulation that takes into consideration many factors for an optimum design.

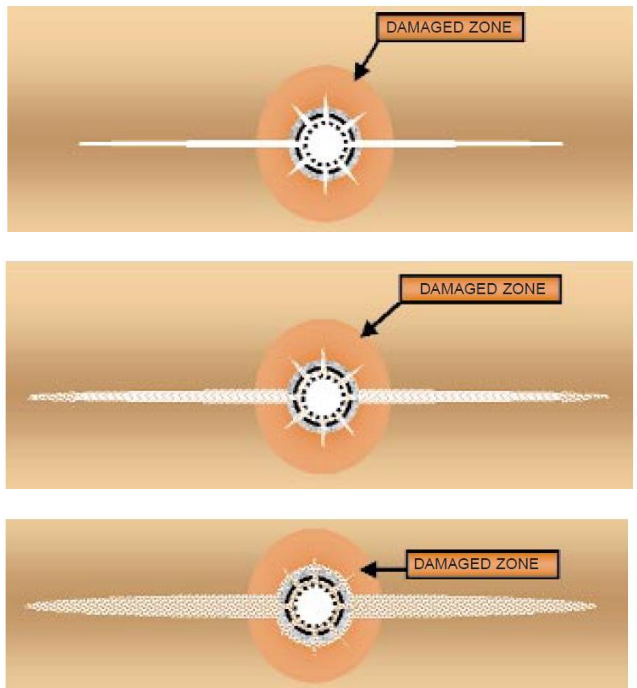


Figure 1. Major stages of a TSO. Pad pumped without proppant extends initial fracture past near-wellbore damage (Top). Proppant screens out at tip of fracture, arresting fracture extension (Middle). Continued pumping with high concentrations of proppant extends fracture width and increases proppant loading. Perforation tunnels, screen/casing annulus, and near wellbore are tightly packed with proppant (Ellis, 1998).

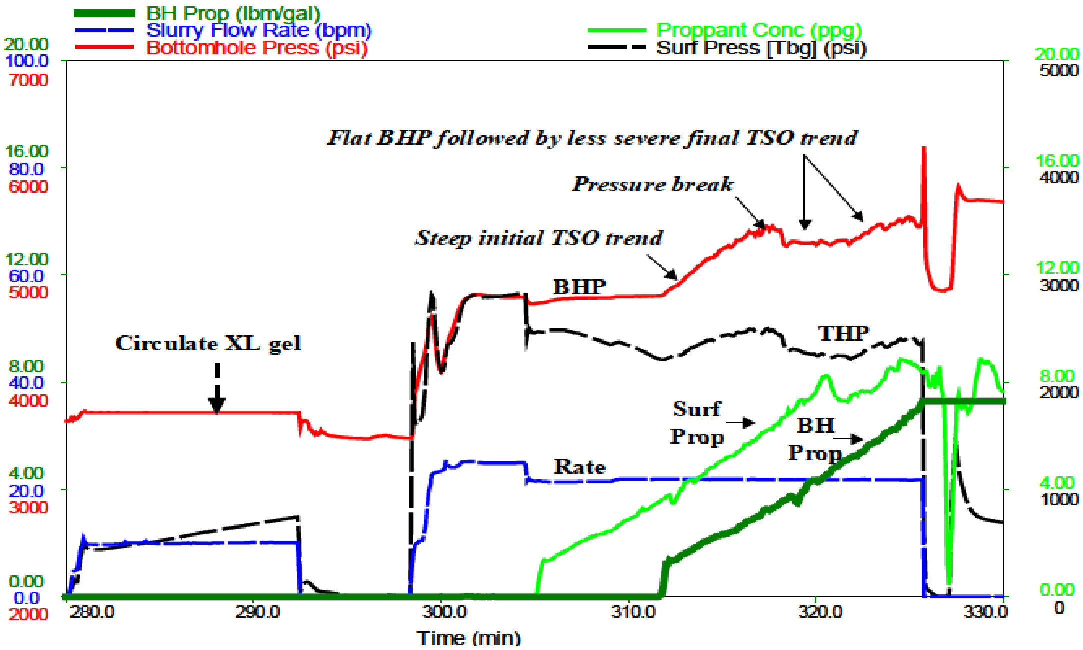


Figure 2. Frack and Pack job data (Cipolla et al., 2005)

Objectives:

- Simulate frac-pack model with the real field data to prove the ability of XSite to Simulate TSO and compare with the fracture dimensions obtained by another 3D planer simulator.
- The effect of fluid viscosity and leak-off on the fracture attributes in a TSO design.
- Study the effect of poroelasticity on the propagation of hydraulic fracture in the soft formation.
- Study the effect of stress anisotropy and shale beddings on the occurrence of TSO.
- Set the Industry standard for the maximum perforation length for a feasible frac-pack operation.

Methodology:

- Gather and assess data for a frac-pack operation where tip screen-out occurred.
- Simulate the model in XSite and StimPlan.
- Calibrate both models according to real data.
- Run sensitivity analysis to study the effect of different parameters on a frack-pack job.
- Optimize the selection of pumping parameters for frac-pack job.

Significance:

- Prove the ability of XSite to simulate the Frac-Pack operation.
- Develop a lattice formulation-based understanding of Tip screen-out.
- Understand the effect of low-stress anisotropy on Tip screen-out occurrence.
- Develop an optimized approach for designing Frac-Pack job.
- Set limits for perforation length for technical limitations.

- Set a workflow for frac-pack job design optimization.

Progress to Date:

In this work, a fracpack job have been designed then simulated. the method have been simulated using the Nolte Method in (Martins et al., 1992). The pumping schedule have been simulated in both XSite300 and P3D commercial software. The results show similar behavior in term of pressure and with different geometries. The pressure results are illustrated in **Fig. 3** and **Fig. 4**.

A paper under the title "Comparison of Lattice and Pseudo 3D Numerical Simulation of Tip Screen Out Operation" were submitted for a journal publication.

In the study we are running a sensitivity analysis for the effect of rock mechanical and petrophysical properties and pumping properties on the fracture geometry of a fracpack treatment.

The next step is to study two case studies one in the Boahi Bay and another one in Alaska where the oil has very high viscosity that controls the fracture leakoff.

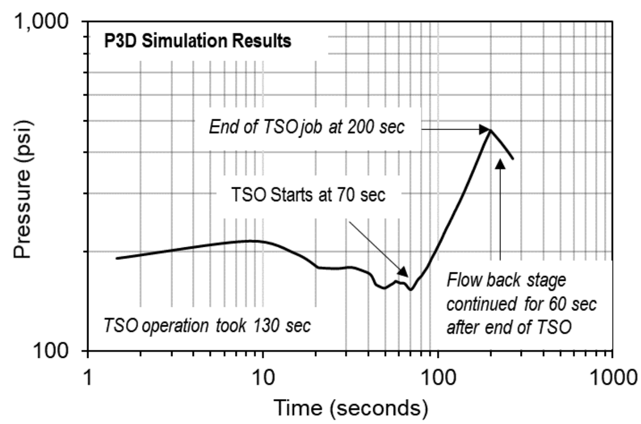


Figure 3. The net pressure plot obtained from P3D model.

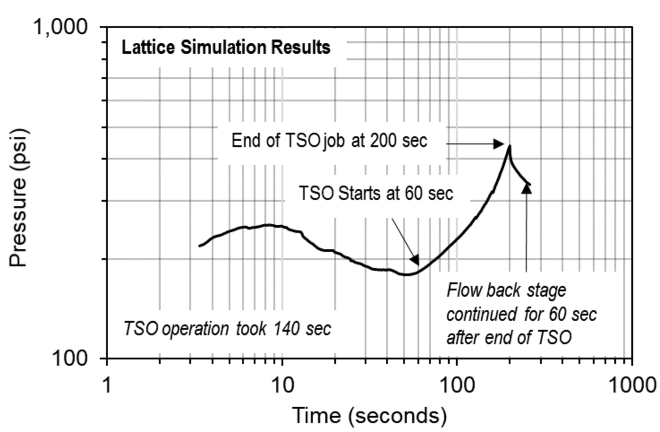
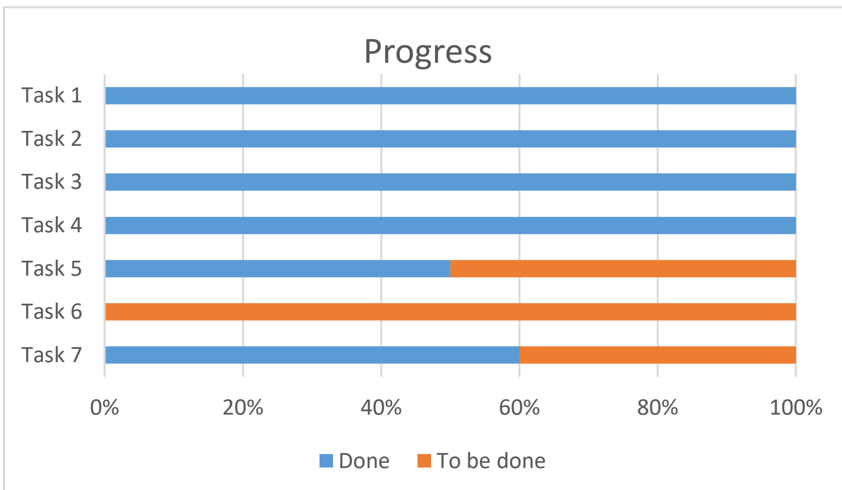


Figure 4. Resulted net pressure evolution per time in lattice simulation.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature survey
- Task 2: Software learning XSite/ P3D model
- Task 3: Data collection
- Task 4: Development of models in both software and calibrate it
- Task 5: Sensitivity analysis for different parameters and cases
- Task 6: Design optimization for frac-pack treatment
- Task 7: Report results and produce paper



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Remote Sensing for Co2-leak Detection in EGS And Geological Sequestration Sites

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Problem Statement:

As a renewable energy alternative, geothermal is a stable source with low CO2 emissions, thus helping to mitigate climate change. The primary limitation for commercial EGS is the current inability to costeffectively create high-permeability reservoirs from impermeable. Recent advances in hydraulic fracturing techniques and horizontal drilling represent a key driver for EGS development. Although, ensuring safe, permanent storage of CO2 is vital for the success of subsurface geologic CO2 storage and EGS projects. The development of robust monitoring technology is vital for validating storage permanence, as well as for ensuring the integrity of storage operations (E. Clark, J. Jacob, M. Tyler, F. Materer, and J. Pashin). Accordingly, monitoring programs are considered essential for meeting the goals of CO2 emissions reduction, environmental protection, and human health and safety (NETL, 2012). This study aims at advancing the state-of-the-art of surface and airborne monitoring and includes the deployment of low-flying unmanned aerial vehicles (UAVs) for near-surface detection of CO2 plumes emanating from the land surface. This study focuses on using hyperspectral imagery and/or another gas or marker that would be part of the CO2 storage stream as indirect remote sensing method for detection of leaking CO2 and identifying faults, fractures, and other geologic discontinuities that could serve as shallow subsurface flow paths that could affect the flux of water and gas.

Objectives:

This project's primary goal is to explore the use of low-cost sensors coupled with the appropriate hardware and software to produce a low-cost system capable of detecting both long- and short-term carbon dioxide leaks from EGS and Carbon sequestration projects. In addition, an aerial system will be designed to measure the CO2 distributions above the surface. Both the ground and UAV based systems will be designed, tested, and deployed in the study field.

Techniques:

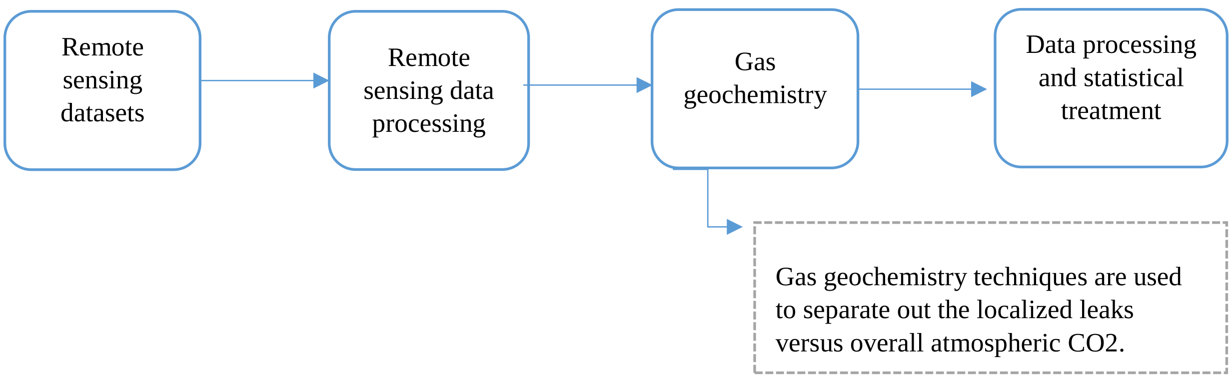
The approach employs underground and surface sensors and unmanned aerial vehicles (UAV) to collect data. We propose to develop the CO2 sensors and the UAV platform at UND facilities based on laboratory tests, the integrated system would then be installed, tested, and optimized at a field site. The analytical approach for this research consists of two main components:

(1) stratigraphic analysis and (2) structural analysis. This approach is designed to characterize the geologic framework of the study area from reservoir depth to the surface. The results of this analysis are then used to formulate conceptual models that help guide the design and implementation of surface and airborne monitoring technologies in the area.

Methodology:

- literature review of available information directly related to geothermal energy, regional geology and geophysical studies, groundwater and geohazard investigations, Carbon Dioxide interaction chemistry, satellite imagery.
- Laboratory experiments: A robust characterization of rock & fluid, core analysis, petrophysics & facies analyses (SEM, thin section), mineralogy & rock typing, rock elemental analyses (XRD, XRF), Analysis of CO_2-rock interaction during injection phase through core flood tests: short- and long-term impacts.
- Numerical Simulation (fluid flow, heat transfer and rock-fluid interactions) based on laboratory and NDIC Data.
- Field Reconnaissance Surveys and Investigations, environmental and social issues, local
- infrastructure availability.

<u>Field methods:</u>



- At the conclusion of this stage, a detailed geo-scientific report will be developed covering the explored area, including a Design study for a field pilot test of EGS with CO_2.

Significance:

Atmospheric and near-surface monitoring provides assurance that stored CO_2 is not being released to the atmosphere or endangering drinking water. Development of surface monitoring methods, technologies, and tools is needed to improve certainty in:

- detecting and tracking the movement of CO_2 in diverse geologic settings of storage complexes
- demonstrating long-term stability of the CO_2 plume
- tracking associated geochemical and other physical property changes to identify possible release pathways in diverse geologic settings
- proving the effectiveness of CO_2 as working and/or fracking fluid in EGS systems

Progress to Date – Results & Discussion:

The previous research topic was “Hyperspectral Imaging for mineral heat capacity detection’’. During this semester a review of the information was carried out, resulted in change of the Research Topic:

- Cores analysis of Red River formation at “core lab” to classify the minerals

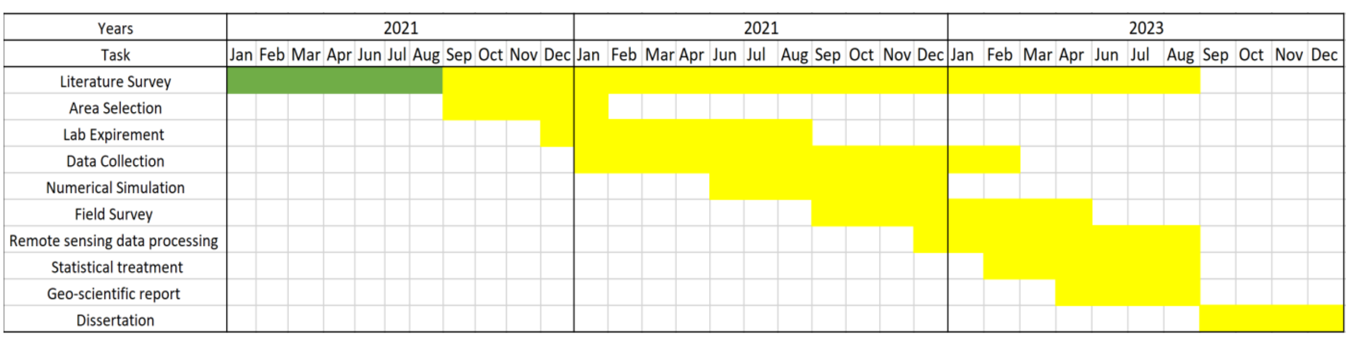
(a) (b)

Figure 1. (a) cores simples: RedRiver formation ND (b) core section.

- A reconnaissance field trip was made from Grand Forks to Williston Basin in order to survey the area closely and verify the possibility of making hyperspectral scanning, plus an analogue simulation made with CMG to estimate the potential heat that could be generated from near surface formation.

Based on this evaluation, it was concluded according to the energetic potential and geological conditions, that North Dakota Especially Red River Formation is not a suitable area to detect Heat capacity by hyperspectral imaging, another research topic has been proposed in the aim at getting a better result by changing the parameters required for detection, and coordinate two main hot research area in the US together: (Geothermal and CO2 storage).

Project Milestone and Timing:



Assessment and Data Analysis of Red River Formation Geothermal Properties, for Design Optimization and Identifying the Sweet Spot for Geothermal Energy Extraction

Julio Figueroa
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Problem Statement:

The energy industry is struggling to optimize the high financial cost that geothermal systems have. This situation reduce the opportunities to advance, because the cost of the activities like the exploration, production, and drilling, and the high risk related to the lack of technical information in the subsurface for this specific type of resources, only can support by technologies with the potential to impact the optimization of the characterization and modeling processes of geothermal reservoirs, creating the correct atmosphere to the economic and energetic viability of this type of projects.

The challenges for the coming decades will be strongly related to the efficiency and optimization of natural resources. One of the great opportunities to enhance energy sources is the development of hydrothermal energy. North Dakota has favorable conditions to maximize the benefits of subsurface resources, combining hydrocarbon production with hydrothermal potential. The upgraded geothermal systems stimulated by fracture contribute to improving the necessary conditions for obtaining the resource present in this type of deposit. Considering this, the identification of the spatial variation of the fractures to determine their orientation and location becomes a challenge for the characterization of naturally fractured reservoirs. New technologies such as Machine Learning (ML) favors the accuracy, reduces the processing time, improve the interpretability, and linked the physical properties to create reliable geological models, to evaluate the temperature gradient, the effective permeability, and the capacity of fluids in the formation, to make it easy and precise the evaluation of the resource and finally helps to define the selection of the best candidates for geothermal development.

Objectives:

- Novel approach of data analysis and variable´s selection to complete and assessment of geothermal project using high-resolution geological characterization.
- Identification of better geological units for geothermal development according to the implementation of a methodology of primary parameters and technical variable´s selection in the Williston Basin
- optimize the equations of the geothermal potential calculation making it more efficient for the area of interest, using data science tools.
- Determine the potential of the geothermal reservoir and natural fracture characterization of spatial grid (vertical and lateral). as well as optimizing the parameters that best adjust the experimental data.
- Apply conventional analytical and statistical evaluations and the results of the machine learning tools on geological modeling to compare the results and define the advantages and disadvantages of both techniques.

Methodology:

- Detailed literature review of state of the art.
    - Study cases in the U.S.
    - Theoretical results
    - Practical results

  Gathering and evaluation of existing data available laboratory and field data including rock physical properties, well logs, etc.
    - Inventory
    - QA
    - QC
- Determination of the study area based on the availability of the information, select the study area, and narrow down its location
    - Coordinates
    - Population of the grid
    - Selection of distribution method (Normal or Gaussian)
- Parameter selections use statistical analytical techniques to determine the behavior of the data and proceed with the different models of evaluation of selection of the variables making use of machine learning
    - Decision Tree
    - Principal Component Analysis
- Run a numerical simulation model using as input the information obtained from the ata analysis
- Report and summarize task 1 to 5 outcomes and outline the future work based on the completed work. (Write the papers)

Significance:

- Decrease uncertainty in the economic analysis for hydrothermal resources in the state
- Optimize the volume calculations using high performance geostatistical models
- Determine the best targets for geothermal projects and pilots.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Selection of the area of interest into the basin.
- Task 2: Literature review.
- Task 3: Data collection.
- Task 4: Parameter selection by data analysis
- Task 5: Create a statical model (petrel)
- Task 6: Geothermal Model (CMG)
- Task 7: Data analysis comparison of results
- Task 8: Papers write up

Task	Months					
Selection of the area of interest into the basin	6	12	18	24	30	36
Literature review.						
Data collection.						
Parameter selection by data analysis						
Create a statical model (petrel)						
Geothermal Model (CMG)						
Data analysis comparison of results						
Papers write up						

Progress to date:

During this semester a review of the information was carried out and according to its evaluation, it was concluded that according to the energetic potential and geological conditions the best prospecting area is in the Red River formation, with this information a first static model was carried out in petrel and a simulation was made in CMG both to improve, another important advance was the considerations for the characterization of the naturally fractured reservoirs, the literary revision was made and the search for seismic information for the characterization of the formation of interest began.(Red River).

Optimize Treatment of Mineral Scale Deposition in Unconventional Reservoirs

Omar Bakelli
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Problem Statement:

With oil production decrease and prohibitive cost of well construction and development related to the application of directional drilling and stimulation techniques, a huge consideration is given to optimize wells production and maximize profitability. One of the big threats of production optimization is scale deposition, defined as deposit or coating formed on the surface of metal, rock, or other material, caused by thermodynamics change (between reservoir, wellbore, and surface) and fluids mixing. Scale deposits are divided into organic scale and mineral scale, the deposition of scale yield reduction in pore space and pipe diameter which decrease flow rate and can result in reservoir damage and failure of equipment. Many solutions have been deployed to prevent, treat, and remove scale deposition.

The efficient method actually used for Barium Sulfate treatment at the reservoir is by performing squeeze jobs, which consists of placing inhibitors in reservoir rock in a way to be released at desired concentration while production back. current studies demonstrated ability to model squeeze operations with good correlation comparing real field data, the challenges are in the selection of optimal chemical product that has to be compatible with formation water, does not create formation damage and extend well production lifetime.

The objective of this research is to better understand the deposition mechanisms of Barium Sulfate in a way to identify the main factors contributing to its precipitation, then and the most important is to develop effective methods to treat Barite deposition under given well, reservoir, and completion/production conditions.

Objectives:

- Better understanding of the Barite formation and deposition mechanisms
- Assessing current inhibition and treatment technology as well as potential improvements for optimal Barite scale-handling strategies
- Developing an optimized squeeze treatment model

Methodology:

- Literature review for work related to Barium Sulfate formation mechanisms and treatments
- Fluid and scale sampling and laboratory analysis to characterize scale and produced fluid
- Experimental test to understand deposition mechanisms and the main factors contributing in
- Software simulations calibrated with experimental data
- Development of machine learning model for scale prediction

Significance:

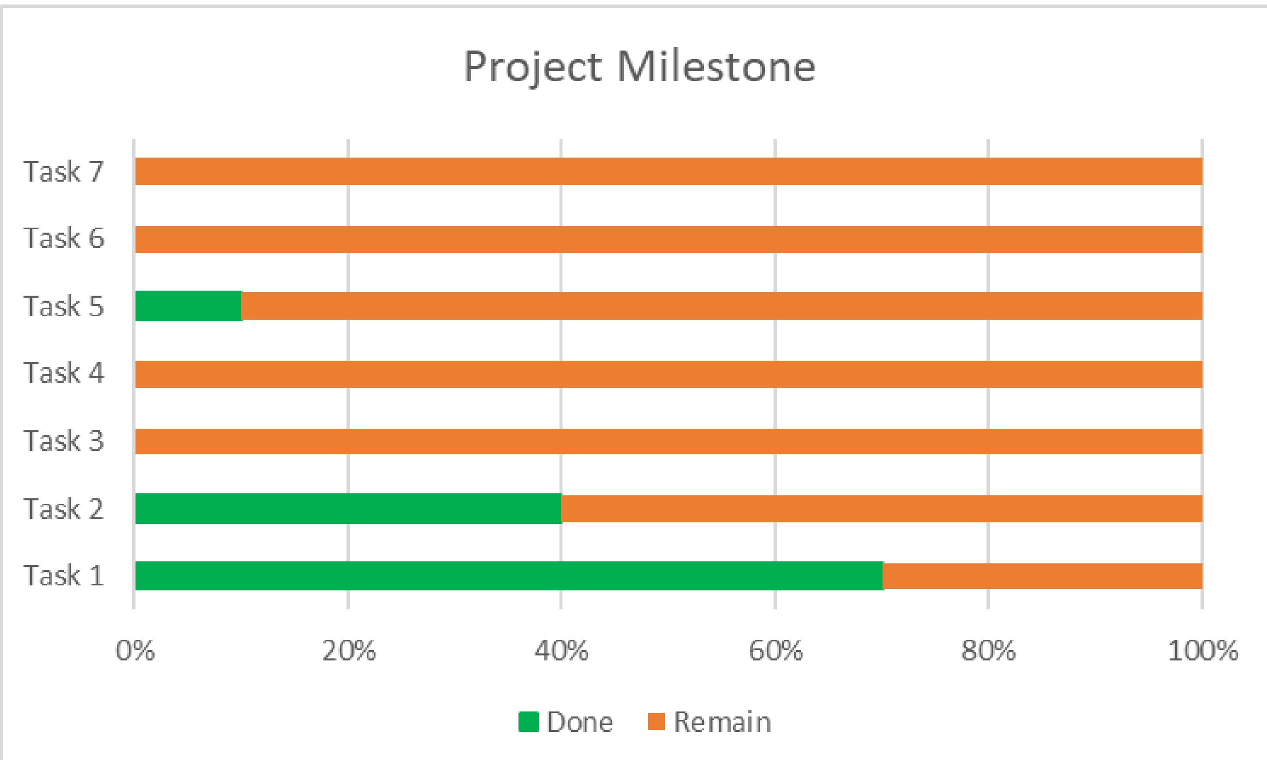
- Better understanding of Barite formation mechanism will support adopting accurate treatments

- Prediction model will serve to preventive intervention with low cost
- Appropriate analysis workflow will help in a better decision making

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature review
- Task 2: Research plan design
- Task 3: Fluid and scale sampling and lab analysis
- Task 4: Experimental tests
- Task 5: Data collection and simulations
- Task 6: Data processing and results interpretations
- Task 7: An improved prediction model



Progress to date:

From February 2021, the project starting date, the first step was to deepen topic knowledge, for that an extensive literature review has been done in relation to Barite scale, and a visit has been made to a service company in that field to better understand issue situation in Williston Basin, Also, workshops and conferences has been attended to learn about the recent research advancement with the treatment of Barium Sulphate, the task actually in progress is updating our research proposal and prepare a draft copy of a review paper.

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Development of a Fully Coupled Hydro-Seismo-Mechanical Model to Validate Hydraulic Fracturing Simulation (Accurate Monitoring and Mapping)

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Problem Statement:

The Bakken formation reservoirs are extremely low porosity and permeability and must be efficiently and effectively hydraulically fracture stimulated to produce at commercially economic rates. Understanding the location and geometry of the created fractures' network and the area of the pay affected by the fracture treatment is key to maximize the values of the completion and reservoir management program and to optimize the operation design, for instance, the alteration of the final geometry of the fractures to reduce or prevent undesirable problems such as water production, treatment overlap, fluid loss or uneconomic pumping.

The complete geomechanical deformation of the hydraulic-fracture network is expressed by microseismic activity. In this work we develop a numerical model that combines the formation rock properties and the hydraulic fracturing pressures to predict microseismicity. The outputs from the model will be compared to the field acquired data in order to obtain the best fit possible for fracturing simulation and modeling calibrations. An integrated study will be conducted to investigate all the controlling factors considered during the hydraulic fracturing simulation. The inputs to the simulation and modeling will be varied continuously to achieve the match targeted. For instance, the formation properties (P & T, stresses state: magnitude and orientations, geomechanical properties, orientation and strength of the planes of weakness: faults, joints and natural fractures), fluid properties (Gas or Oil), treatment job parameters (injection rates, pump schedule, frac fluid viscosity & additives, proppant properties, leakoff rate, etc.).

Objectives:

This project will cover and address the following challenges that are industry problems to be solved:

- Investigation of the controlling factors considered during hydraulic fracturing simulation and modeling for simulation and modeling calibration purposes
- Characterization of the natural fractures and simulation of the interactions between the hydraulically induced fractures and the natural network
- Hydraulic fractures network monitoring and screen outs detection

Methodology:

- As part of the exploration program, collect geological, geophysical, and geochemical data for preparing geologic model
- Characterization of the matrix, natural fractures and all reservoir properties controlling the hydraulic fracturing simulation
- Microseismic data collection and analysis
- Collect PTA/RTA and all available data that can help building a fracturing simulation model

- Development of a physics-based model to predict synthetic miceoseismicity from the geomechanical and hydromechanical properties of the studied field.
- Development of a numerical model to simulate the created fractures network (natural and hydraulically induced fractures)
- Matching of the synthetic microseismicity to the acquired one while varying all the modeling controlling parameters to achieve the best fit
- Validation of the simulation model
- Lab experiments for simulation results validation
- Statistical analysis and machine learning, deep learning and data analytics integration

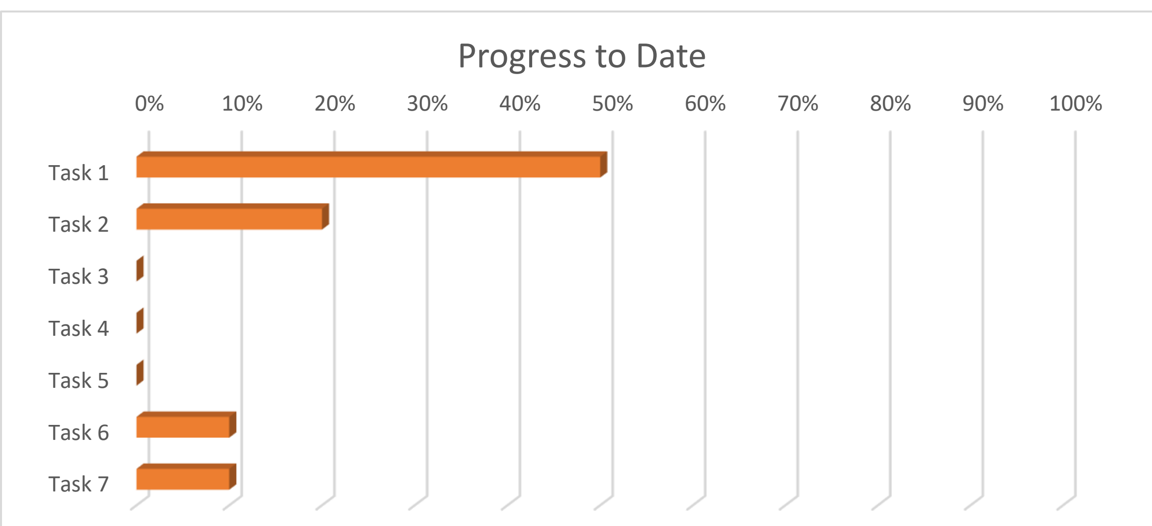
Significance:

- Development of a physics-based model to validate the hydraulic fracturing simulation results.
- Development of a machine learning model to optimize the hydraulic fracturing jobs design and operations
- Monitoring and elimination of some the hydraulic fracturing operational issues, for instance, detection of the screen outs

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Comprehensive literature review of state of the art
- Task 2: Available laboratory and field data gathering
- Task 3: Model Development
- Task 4: Validation of the simulation model
- Task 5: Lab experiments for simulation results validation
- Task 6: Machine learning model development
- Task 7: Report and summarize task 1 to 6 outcomes and outline the future work based on the completed work. The deliverable and detailed time allocation for the project is shown in the project timeline



Progress to date:

As of August 2021, a significant amount of literature has been reviewed in relation to reservoir geomechanics, hydraulic fracturing and microseismic for hydraulic fracturing monitoring. Another significant part of the work done till date is the gathering of real field data needed for the achievement of this study.

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Microseismic monitoring and interpretation of injection data from the In Salah CO2 storage site (Krechba), Algeria Volker Oyea), Eyvind Akerb), Thomas M. Daleyc), Daniela Kühna), Bahman Bohlolib), Valeri Korneevc).

A Numerical Investigation into Fracture Hits in Unconventional Reservoirs

Usama Khand
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Problem Statement:

In this work, a mathematical framework to estimate stimulated reservoir volume by coupling the key processes or events during fracturing operations including multiple simultaneous hydraulic fracture propagation, and perturbed formation stress and reservoir pressure. And sensitivity studies on the impact of well spacing, rock mechanical properties, injection pressure, cluster spacing, number of clusters, and fluid rheology are planned to be conducted. The hybrid numerical model to be implemented applies displacement discontinuity method to simulate non-planar hydraulic fractures propagation and represent the induced stress triggered by the stimulation process. The pore pressure equation will be discretized using finite difference method. The failure state of each natural fracture will be determined using Warpinski theory. Unequal flow rate distribution among the fracture network, perturbation of the reservoir permeability in the stimulated region will be considered. In this work, the formation is assumed to be brittle and inelastic behavior is negligible.

Progress to Date – Results & Discussion:

"Fracture hit" was initially referred to the interaction between an infill-well fracture and an adjacent well during hydraulic fracturing process. However, over time its use has been expanded beyond this form of interference. This connection with the parent well leads to an increase in pressure and high abrupt spike in water cut. Lawal et al. (2013) and King and Valencia (2016) linked this behavior to the overlapping of the hydraulic fracture networks of the parent and the child (**Fig.1a**). With time, the hydraulic fracture closed ad the communication between the parent and child wells reduced or completely disappeared (King 2014). Similar observation was reported by Rucker et al. (2016). Warpinski et al. (2008) also repored that fluid can reactivate natural fractures, bedding planes, high-permeability streaks, faults, and other formation discontinuities during stimulation because of high pressure. These processes might cause a fracture hit in nearby parent wells, but the openings can close when the pumping stops, and the communication seizes. Hence, fracture-hit did not include long-term interwell communication when the term was originally coined.

Well interference has traditionally been referenced to the overlap of drainage areas of adjacent wells in conventional reservoirs during production. In unconventional reservoirs, this may mean that the fracture networks of the child and parent wells do not intersect but are close enough to cause communication through the matrix (**Fig. 1b**). Yu et al. (2016) presented another form of communication in unconventional shales, where the parent/child-well fracture networks are connected through the pre-existing natural fracture network (**Fig. 1c**). This extened connection through the natural fractures can cause both fracture hits and long-term interwell communication.

Fracture hits have become one of the biggest concerns for shale operators. The percentage of parent wells drilled in the Midland Basin in the United States compared to child well is decreasing yearly. This essentially means that the well spacing is reducing. Currently, operators are drilling at a well spacing varying between 200 and 800 ft. the increased infill drilling, tighter well spacing, and bigger completions are causing an increase in both sibling/siblin fracture hits and parent/child fractures. The term "sibling wells" refers to wells drilled at the same time on a multiwell pad.

As the hydraulic fracture clusters propagate into the matrix, certain regions around the clusters are disturbed by the process. Causing second-order effects in the matrix and/or failure of the natural fractures and an increase in the reservoir pressure. The evolution of the reservoir pressure due to the stimulation process has been modeled with nonlinear diffusion equation (Shapiro and Dinske, 2009), linear diffusion equation in 3D (Yu and Aguilera 2012; Kwang et al. 2018), and numerically (Ren et al. 2018; Yu et al. 2017; Sangnimnuan et al. 2021; Wu and Olson 2015), to mention a few. In addition to these efforts, Maulianda et al. (2014) proposed that the stimulated reservoir volume can be divided into tensile failure and shear failure zones, a classification similar to the work of Ge and Ghassemi (2012) who determined the stimulated zone from shear failure using Mohr-Coulomb criterion.

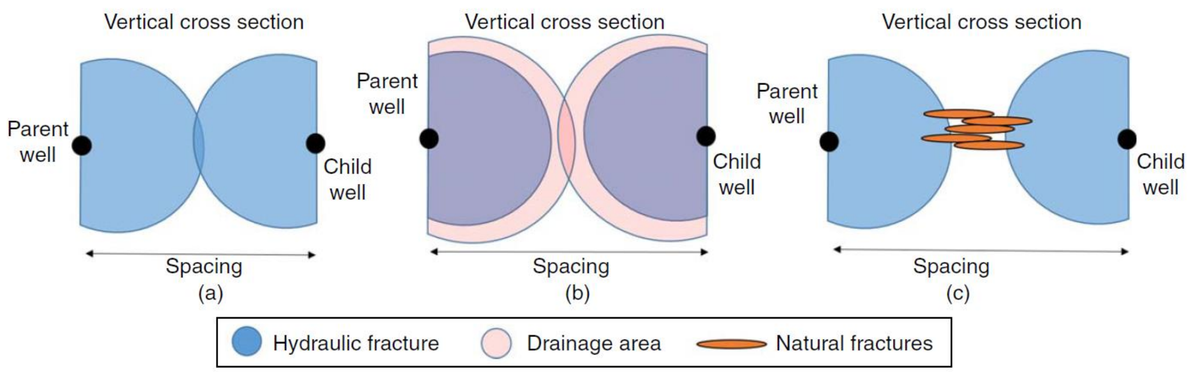

Figure 1. Different forms of inter-well communication between the parent and child wells in unconventional reservoirs. (a) Communication is through overlapping fracture networks of parent and child wells, commonly referred to as fracture hit. (b) Well interference when fracture networks of both wells are close enough to communicate through the microfractures induced in the matrix. (c) Well interaction occuring when the fracture networks are connected through the pre-existing natural fracture networks

It is very critical to know the stress distribution in the formation during the stimulation process

as well. Nassir et al. (2014) used finite element method to simulate the formation stress changes. Displacement discontinuity method (DDM) is the prominent method used for estimating the changes in the formation stress distribution due to multi-cluster fracturing (Olson and Wu 2012; Wu and Olson 2013; Lin et al. 2017).

In shale fracturing five important processes are important: hydraulic fractures propagation, changes in formation stresses, increase in reservoir pressure, failure of nature fractures, and nonlinear response of the stimulated region. Each of these processes is included in this framework. This work will use displacement discontinuity method to simulate non-planar hydraulic fractures propagation and determine the induced stress by the stimulation process. The reservoir pressure will be estimated using a finite difference discretization method, while the failure state of the natural fractures is predicted by the tensor equations from Warpinski failure theory. The modeling considers unequal flow rate distribution through the hydraulic fracture clusters, non-planar fracture propagation under stress interference, changes to the reservoir permeability, and different failure states of natural fractures.

In multistage multi-cluster fracturing of a horizontal well, several hydraulic fractures intiate from each of the perforating clusters (**Fig. 2**). As the fractures propagate into the formation, the matrix deforms and triggers induced stress, which change the formation stress, mechanical properties of the matrix, and consequently affects the growth of the fractures. In the process, the growth of the interior fractures is stunted, and the exterior fractures become non-planar, while the fracturing fluid leaks off into the matrix, increasing the reservoir pressure. Consequently, massive natural fractures will be affected by the induced stresses and incareased pore pressure, and some of them will slip when the shear stress imposed on them exceed the shear strength. Also, if the pressure in the enclosed natural fractures exceed the tensile strength, then tensile failure may occur, independent of the shear slip. These secondary processes will enhance the permeability of the shale matrix, together with the second-order effects.

To start with, the stimulation of the parent well is assumed to be known. Hence, only the fracturing of the child well is the focus of this work.

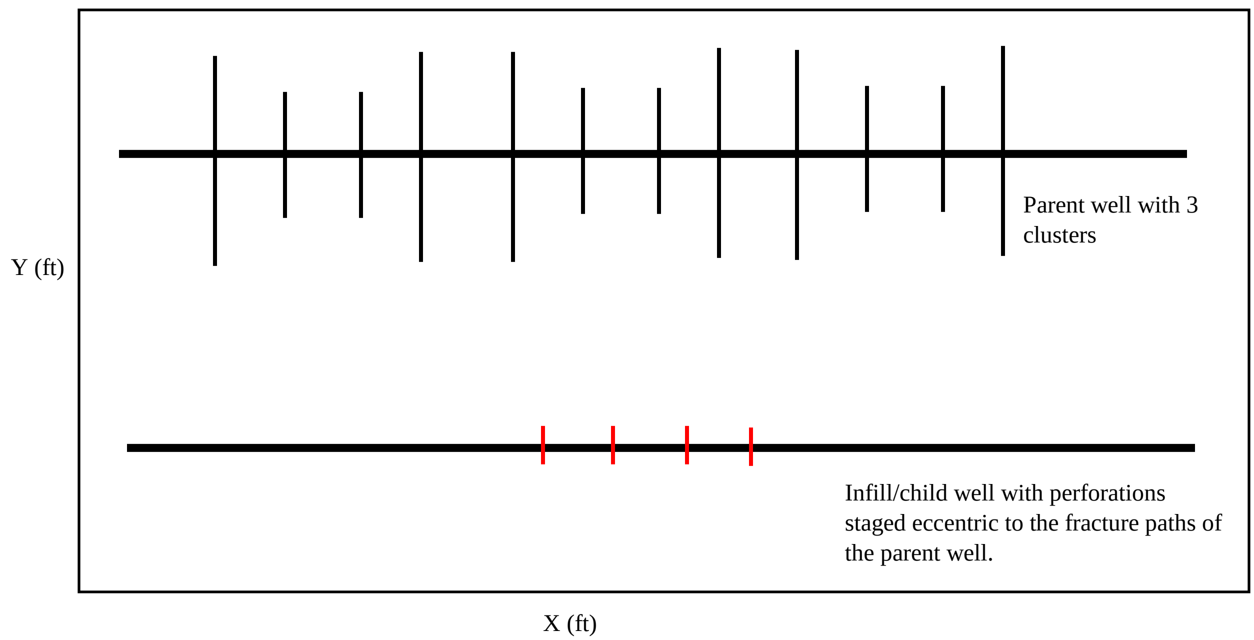

Figure 2. A schematic representation of the model used for this analysis

The procedure for implementing the solution to the coupled problem is as follows:

- State and initialize the geological and fracturing parameters.
- Calculate the flow rate distribution, length, width, and pressure of each hydraulic fracture, predict the propagating angle of each hydraulic fracture. It should be noted that the fracture width and propagating angle are obtained by coupling formation stress, leak-off volume, and reservoir pressure.
- Calculate the induced stress and update the current stress in the formation (sum of stress due to in-situ stress and stimulation)

- Estimate the reservoir pressure and fracturing fluid leak-off volume. The reservoir permeability to be used is based on natural fracture failure criterion.
- Determine the natural fractures failure condition and reservoir permeability change.
- Using the failure fractures coordinates data to estimate the shear and tensile stimulated reservoir volumes and take the union of the two volumes as the total stimulated reservoir volume.
- Output the hydraulic fracture, stress, and pressure variables, and stimulated reservoir volume.
- Return to step II for the next time step.

Project Milestone and Timing:

Table 1. Project Milestone

PhD Program	Spring 2021	Summer 2021	Fall 2021	Spring 2022	Summer 2022	Fall 2022	Spring 2023	Summer 2023	Fall 2023
Literature Review									
Research Plan									
Data Collection									
Simulation Work									
Publication and Thesis Writing									

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Reservoir Modeling and Study of the Impact of CO2 Injection on the Mechanical Properties within the Red River Formation, Cedar Creek Anticline

Abdelmalek Abes
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Problem Statement:

CO_2 injection is a most promising method for enhancing oil recovery from petroleum reservoirs especially from depleted one. The most prominent advantage of CO_2 injection is reducing greenhouse gases in the atmosphere and consequently reducing environmental problems.

The Red River formation has produced more than 600 million barrels of oil from over 2,700 wells distributed between Southern Saskatchewan and North America and much of the production has been from horizontal wells drilled along Cedar Hills anticline in the southwestern portion of North Dakota. The Red River is dominated by variations of porosity and pore shape, and secondarily by pressure, mineralogy, and fracture density.

The main production has been found across much of the central portion of the Williston Basin of North Dakota. This carbonate formation, Ordovician-aged, is the third largest oil producing system in the Williston Basin. Current research might be interested to examine whether the Red River can be a potential unconventional resource play to be exploited.

The main objective of this thesis is to investigate the use of CO_2 as injection gas for enhanced oil recovery and estimate the potential of additional oil recovery from the Red River formation.

Objectives:

- Obtain a reliable predictive reservoir model.
- Modeling the distribution of the different facies, petrophysical parameters, pression and temperature within the Red River Formation.
- Geomechanical study of the cap rocks and reservoirs, as well as determining the elastic and dynamic properties from well logs. Also, triaxial testing and ultrasonic velocity measurement on plugs will be performed in Red River reservoir and cap rocks to determine the pore volume compressibility, static and dynamic properties, rock strength, Vp and Vs.
- Study the interaction between CO2 and mineral components during CO2 flooding storage.
- Understand flow units, heterogeneity features and their impact on subsurface flow mechanisms to guide the optimization of the injection and maximize the oil recovery from the reservoir.
- Increase oil recovery and permanent storage of CO2 in geological formation.

Methodology:

- Data collection.
- In laboratory: experiments with core samples, Computerized tomography scan (CT- scan), X-ray diffraction (XRD), (XRF), thin section, and scanning electronic microscope (SEM) will be conducted.
- Mineral component and diagenesis effect.
- Fracture analysis using core, borehole imagery data, well test data, and digital elevator model (satellite images and geological map).
- The petrophysical analysis will be carried out (porosity, shale volume, permeability), and mineralogic model will be executed.
- Geomechanical study of cap rocks and reservoirs by elaborating multiple 1D MEM, and their calibration will be carried out from triaxial testing, and the pore volume compressibility.
- Geological 3D Static and dynamic models describing the petrophysics, characterization of hydrocarbons in place, and reservoir characterization.
- Reservoir simulation in order to predict the performance of the field.

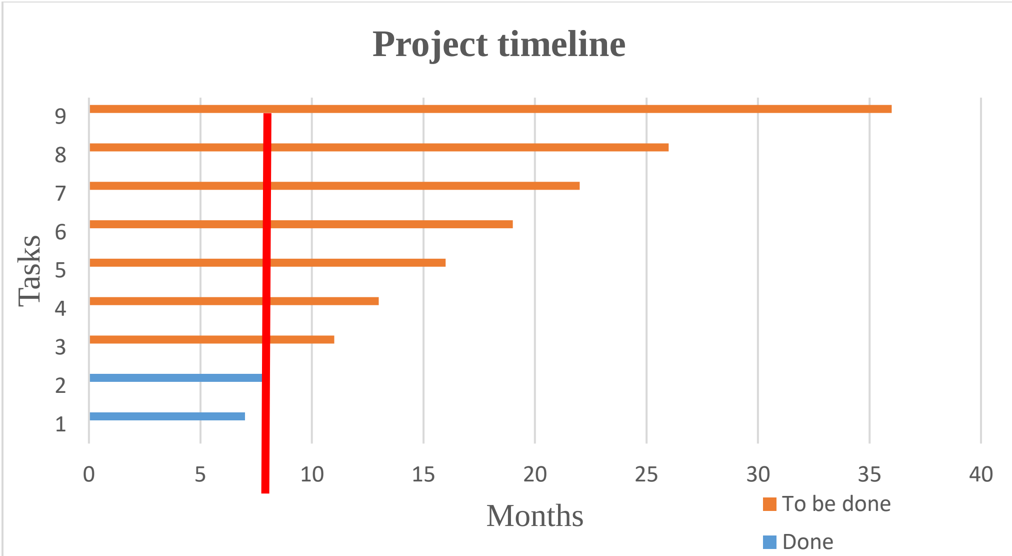
Significance:

- Characterization of the properties of the reservoir.
- Evaluate how fracture permeability and reservoir hydrocarbon model affects CO_2 injection
- Increase the efficiency of oil recovery
- Establish a field development plan.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature review.
- Task 2: Data Collection.
- Task 3: Lab experiments.
- Task 4: Fracture analysis.
- Task 5: Petrophysical model.
- Task 6: Geomechanical model.
- Task 7: Static model.
- Task 8: Reservoir simulation and CO_2 injection.
- Task 9: Dissertation writing



Progress to date:

As of February 2021, a significant amount of literature has been reviewed in relation to Williston basin and Red River formation.
Data collected from the NDIC website, we have 18 wells and 11 cores from the company Denbury Onshore LLC.

Table 1. Well data collected from NDIC.

Wells number	TVD	Caliper	GR	Resestivity	Neutron Porosity	Density	Sonic (DTc/DTs)	Photoelectric
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W14XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W16XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W14XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
W15XXX	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes

Table 2. Cores data collected from NDIC

Core number	Cores Photos	Thin section	Core formation
35XX	No	No	Ordovician
40XX	No	No	Ordovician
32XX	No	No	Ordovician
30XX	No	No	Ordovician
41XX	Yes	Yes	Ordovician
12XXX	Yes	Yes	Ordovician
29XX	Yes	Yes	Ordovician
27XX	Yes	Yes	Ordovician
33XX	Yes	Yes	Ordovician
33XX	Yes	Yes	Ordovician
31XX	Yes	Yes	Ordovician

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Advancement in the Use of Seismic Data in Unconventional Shale Play (Possible Area of Study Vaca Muerta – Argentina)

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Problem Statement:

Recent high price of crude oil coupled with advances in horizontal drilling and multiphase fracturing has led to a boom in shale oil and unconventional reservoirs exploitation. Most of the available geophysical techniques use in exploration, reservoir characterization and field development and monitoring techniques are developed and more suited for conventional reservoirs.

Unconventional shale reservoirs are characterized with unique petrophysical properties such as extremely low porosity and permeability, high Total Organic Carbon (TOC). Pre-stack 3D seismic inversion are routinely used as a very cost-effective tool to help optimize shale reservoir development and reduce cost and risk (Truman et al, 2014). Seismic inversion calibrated to well control is used to discriminate sweet spots and predict the petrophysical/geomechanical properties of shale to the extent possible. In addition to this, multicomponent seismic can be used to estimate some anisotropy properties such as Young Modulus etc., this can be accomplished by the use of shear wave splitting or PP-PS joint inversion.

However, seismic characterization of unconventional reservoirs requires high-resolution seismic input data with great trace-to-trace correlation, high signal-to-noise ratio (S/N), reliable amplitude data, and densely sampled azimuthal information. These could only be achieved by an adaptative seismic processing workflow targeted towards improving SNR to produce high fidelity 3D data, with high vertical and spatial resolution.

4D seismic is considered as an important tool in field development and monitoring, using the changes in the petrophysical and geomechanical behavior of the reservoir to provide a field wide monitoring of the reservoir as well as over- and under-burden. The ability of extracting and validating the initial geomechanical concept and updating the subsurface models using 4D inversion is becoming more important.

Machine Learning algorithm as a tool that is increasingly used in modelling, extraction and analysis of geophysical data both 3D and 4D seismic data and attributes (Dramsch, 2019). The field is still evolving and there are lots of improvements and optimizations that are still required in this field.

The statements above highlights three potentials area of research that will have apparent operational impact have been recognized.

- High Resolution Processing
- 3D reservoir characterization
- 4D Interpretation and characterization

Possible Area of Research:

- Develop an optimize workflow for processing of High resolution multi component data required for an accurate and useful petrophysical and geomechanical properties of shale reservoir.
- Using Machine Learning and Data mining analyze and define all possible correlation between seismic data, its attributes with petrophysical and geomechanical properties of shale reservoir.
- The use of 4D seismic data in shale reservoir monitoring, validation of previous petrophysical and/or geomechanical model from 3D, in addition to the use in field optimization. How can data science help?

Methodology:

After comprehensive discussion and detail review of two out the three possible research area will be point of focus

- Data mining assisted 3D seismic in reservoir characterization
  - Comprehensive workflow and methodology to assist in extracting and optimizing petrophysical (TOC, Φ, K …) and geomechanical (E, ν, μ …) models from seismic and its attributes using data mining techniques.
  - Identification of sweet spots
  - Extracting isotropy information (azimuthal …) from seismic and available geophysical data. (pre-stack seismic data, sonic logs, multi component data, …).

- Data Mining assisted 4D interpretation workflow
  - Well based 4D modelling to validate petrophysical and geomechanical model
  - 3D and 4D seismic modelling using available static and dynamic models with the view to validate the Petrophysical and Geomechanical model. This will include advance wave equation modelling to generate time lapse data.
  - The above flow is tailored towards updating available reservoir models.

Significance:

Significant and immediate impact in identification, well placement and optimization of shale reservoirs development.

Required Data

- 3D full and sub-stacks
- 3D inversion results if available
- Velocity Model
- Well logs (sonic, lithology logs, etc.)
- Helpful documentations.

Project Milestone and Timing:

Timing of the milestone stated below is subject to review and final decision on agreed research topic:

- Task 1: Discussion on Research subjects
- Task 2: Literature Review
- Task 3: Data Collection
- Task 4: Develop Methodology and Workflow
- Task 5: Develop Metrices and Validation
- Task 6: Test Robustness of the Methodology on Several Examples

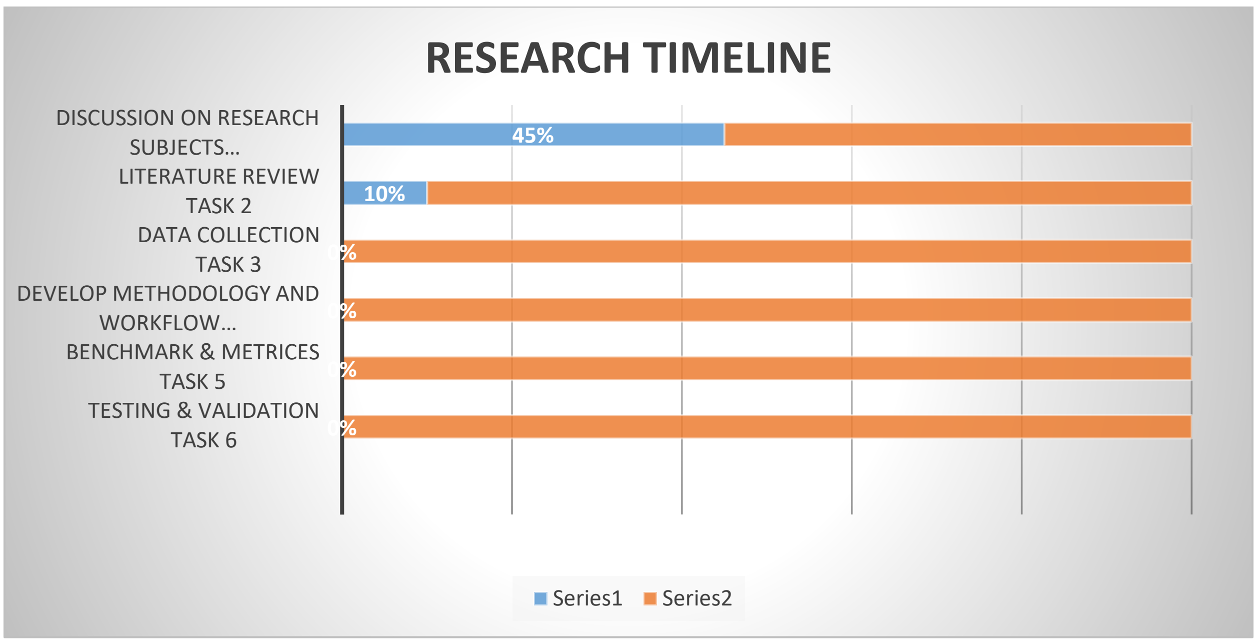

Figure 8. Project Milestone

Progress to date:

A comprehensive inventory of data required purposes have been completed and agreed with Total Argentina. Discussion of confidentiality issues completed. I am currently waiting for the agreed data to be delivered.

Literature review and concept definition and development are ongoing.

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Waterflood Data Driven Modeling and Optimization

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Problem statement:

The application of the waterflooding technique requires modeling of static (structural and petrophysical) and dynamic (fluid properties and flow behavior). The modeling task is based on analytical models or numerical models that are based on the physics of fluid movement. The degree of accuracy or capacity of the model to replicate real behavior depends heavily on the quality and amount of data covering most of the area to be modeled. The number of wells, location, rate and response time are all dependent on the model, but most of the time sufficient data is unattainable leading to inaccurate estimates and forecasts that impact the economics of a project.

The only way to verify the validity of a reservoir model—calibration—is through production and field development, and there are always deviations. The severity of the deviation will dictate the need for a model update which usually is based on geological features such as reservoir heterogeneity, and petrophysical properties such as permeability and saturation. The update of the model will require reinterpretation of the existing data and acquisition of more information, delaying the take of action to optimize the waterflooding development due to the long times it takes to follow traditional methods of reservoir modeling.

Objective:

- To develop a reduced physics model for waterflooding to reduce the time of model optimization and offer a rapid solution for waterflooding performance deviation.

Methodology:

- Building a waterflooding model in a commercial numerical simulator
- Running the simulator for all possible combinations of M, Kro, Krw, PHI, So, Sg, Sw, and history matching the results.
- Extracting the simulated data
- Applying ANN
- Sensitivity analysis

Significance:

- Reduce the time and resources allocated to correction of performance deviation in a waterflooding project through the use of a data driven model.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature review
- Task 2: Data collection.
- Task 3: Build an analytical reservoir model
- Task 4: Build a numerical reservoir model.
- Task 5: Compare results and cross check models.
- Task 6: Use machine learning to create a reduce physics/data driven model.
- Test the data driven model and compare to the results of the analytical and numerical model.

Progress to date:

This semester I read material related to the classical waterflooding design. Besides numerical simulation and semi analytical stream lines models, I went through the basic equations to develop and analytical model. I studied the assumptions and limitations of Buckley and Leveret, Stiles and Craig-Geff-Morsen. I have found that an equation developed for waterflooding performance prediction are limited to certain patterns and geometries. On the contrary, numerical models are not limited to patterns or geometries.

After reading and understanding the equations, I started the application of those equation for a real field. However, I realized that because the case I had at had was not a pattern waterflood but a peripheral one I decided to investigate if there is another way to model a peripheral waterflood. From my reading, I have found that a material balance may be more appropriate to use for a peripheral waterflood because in my case I have an aquifer that has different degree of influence in the south and the north of the field. I have studied how to create a material balance model in excel but it seems that for field scale is not going to be feasible. And now I'm trying to learn MBal, which is a software used for material balance model at field scale.

I also learned that for any method I need to compute the remaining oil. So, my next task is calculating the original oil in place (OOIP) and subtract the oil produced (Np), to find the remaining oil. Once the remaining oil is calculated I will proceed to identify the areas that are more promising (more remaining oil) for secondary recovery.

From this calculation will follow the estimation of the voidage replacement ration (VRR). For the VRR, I have to quantify the amount of water influx from the aquifer, and add the volume of water the aquifer has contributed to the reservoir. I will calculate the total poral volume, subtract the total fluids produced (oil, water and gas) and add the volume of water contributed by the aquifer. The result will be the voidage generated by reservoir production. That voidage is the fraction of the poral volume that require fill up to take the pressure back to the bubble point.

After the calculations mentioned in the previous paragraph, I will proceed to estimate the recovery (forecast) for different number of wells, locations and water rates. With my analytical model I will compare and crosscheck the results I get from the numerical model and will be ready to proceed with the application of the machine learning model to forecast oil recovery from a waterflood.

CO_2-EOR and Storage Applications Within the Bakken Petroleum System

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Problem Statement:

Unconventional oil and gas resources have arguably become an important kind of energy in the United States, and the increasing shale oil production in the country has made it one of the biggest oil production countries worldwide.

As production from mature fields is declining and new hydrocarbon discoveries are not sufficient to match the growing energy demand. Enhanced Oil Recovery (EOR) is emerging as an essential technique in global oil production.

In this context, seeking a new concept, such as Enhanced Oil Recovery (EOR) is therefore a crucial application for the development of the shale plays.

The CO_2 injection plays an active role as a part of the Enhanced Oil Recovery (EOR) process that injects carbon dioxide (CO_2) into the oil layer and recovers crude oil efficiently. When this process is performed, carbon dioxide, which is collected from emitted gas at energy production or other industries, is utilized in some cases. There is high expectation for this oil recovery process because it can also serve as a carbon capture and storage (CCS) process for preventing the release of large quantities of carbon dioxide into the atmosphere.

Several publications reported that any effort to improve the recovery factor through an EOR process is worthwhile and could increase the incremental oil by several billion barrels. Subsequently, applying CO_2 injection is mandatory because it leads to increase recoverable oil from its primary depletion value, improve the long-term well productivity, and contribute the cost-effective production less than other techniques.

Progress to date:

This research aims to investigate and conduct CO_2-EOR technique using experiment works, simulation studies, and pilot tests to understand unconventional resources and EOR mechanisms in tight formations, as well as to characterize the impact of the CO_2 injection on the reservoir rock properties.

Special core analysis, thin section analysis, HPMI (High Pressure Mercury Injection), XRD/XRF analysis, SEM, NMR core, Micro-CT, Capillary pressure curves and relative permeability determination will allow this study.

As of August 2021, a significant amount of literature has been reviewed in relation CO_2 injection as a mean to enhance the oil recovery and its effects on reservoirs. There has also been significant review of the different methodologies applied in the oil and gas industry to assess the reservoir rock properties in order to choose the most accurate techniques for the reservoir case studies.

Also, several textbooks, case histories, real-field data, and manuals that address the problem of production performance in unconventional reservoirs are meticulously analyzed and summarized to meet the research's major goal. Experiments will also be performed in the lab to examine, explain, and quantify CO_2-EOR processes. Furthermore, upscaling methodologies will be used to investigate the major elements that could influence CO_2-EOR performance at the field size.

Project Milestone and Timing

Time major milestone of the project Include the following tasks:

- Task 1: Literature review
- Task 2: Data Collection
- Task 3: Laboratory experiments
- Task 4: Petrophysical model
- Task 5: Reservoir simulation

Year	2021					2022			2023		
	Aug	Sep	Oct	Nov	Dec	Spring	Summer	Fall	Spring	Sum	Fall
Literature review											
Data Collection											
Laboratory experiments											
Petrophysical model											
Reservoir simulation											

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Shockwaves Fishbone Integrated Solution for Rock Fracturing

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Problem statement:

The Bakken Formation is a tight formation where oil flows with difficulty due to the low porosity and low permeability of rocks. To resolve the difficulties in production, we use a process called hydraulic fracturing in which water and other materials are pumped with high pressure into the borehole to create fractures and enhance the permeability.

However, the fracking process promotes the fact that most of the chemicals used to extract oil and natural gas can defile wells to the point that the gets combustible. Also, the amount of wasted water that the fracking process needed, an estimation said that it may take up to 30 million gallons of water to complete the process. Which means billions of gallons of wasted water was used each year to improve the oil productivity.

Fishbone multilateral wells is suggested to be an alternative solution for hydraulic fracturing, this technology is applied to enhance well productivity by increasing the contact area between the bottomhole and reservoir region. Fishbone wells are characterized by reduced operational time and a competitive cost in comparison to hydraulic fracturing operations.

Fishbone wells are also characterized by larger drainage area; consequently, higher production rates can be achieved compared to vertical and horizontal wells. In comparison to hydraulic fracturing operations. Furthermore, fishbone wells have shown better performance than fractured horizontal wells in producing from tight reservoirs.

The use of this technology is still limited which needs more optimization, so a study must be done in order to maximize the contact area, and the permeability by creating fractures into the micro-bore hole of the fishbone wells along with a small diameter down-hole motor.

High voltage pulsed discharge (HVPD) has the ability to create fractures which has primarily been used in the mineral industry, including but not limited to such practices as breaking down oil and gas wells, rock breaking and well drilling, and reservoir fracturing.

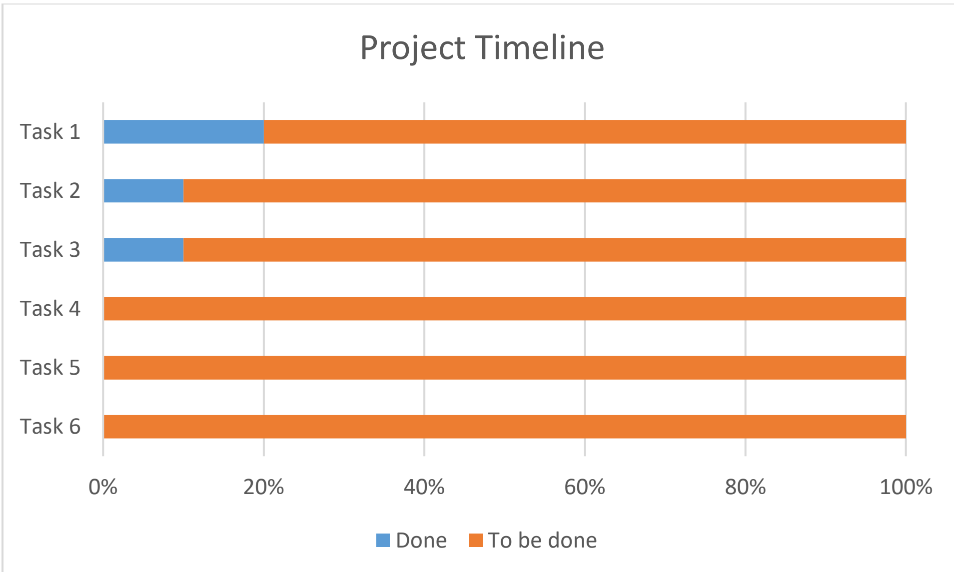
Methodology:

- Literature review of plasma shockwave and fishbone drilling.
- Collecting data and identify the apparatus components from existing studies.
- Set up different possible experiments with different characteristics and combinations.
- Evaluate the damage of samples and gather the results.
- Set up a design for a prototype and run a test to define the performance.
- Rectify any malfunction or issues that might appear.
- Set up the final product.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature Review
- Task 2: Data collection
- Task 3: Laboratory experiment
- Task 4: Sensitivity analysis
- Task 5: Correct issues and prototype design
- Task 6: Merging the project with two others PhD projects



Progress to date:

The objective of this project is to investigate the impact of different parameters of the plasma shockwave circuit on fracture creation, as well as finding the best combination of parameters for the optimal fracture. Moreover, modelling a new design for a small diameter down-hole motor with an integrated plasma shockwave generator.

As for July 2021, a notable amount of literature has been reviewed in both Fishbone technology and Plasma Shock Wave technology, also the experimental mock-up has been set-up.

To reach the objective of the projects, several studies are currently in progress and will be conducted in the future, basically:

- Identify the existing apparatus and their capabilities of shockwaves generating.
- Identify and investigate the existing plasma generator tools, and their limitations.
- Define the optimal plasma's circuit parameters.
- Design and build a prototype that is integrated with the down-hole motor.

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Frac-Hit Prediction, Prevention, and Mitigation for the Bakken Pad Drilling and Stimulation

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Problem Statement:

Frac Hit is any form of inter-well hydraulic communication between two adjacent horizontal wells where an existing offset well, often termed as parent well, is affected by the pumping of a hydraulic fracturing treatment in a new well-called child well.

This can be the consequence of the pressure depletion of parent wells, when a producer drew a large volume of reservoir fluids a pressure sink is created for the new fractures this reduced pressure attracts influxes from flows that are injected in nearby areas. The space between the parent and child well plays a major role to generate the Frac Hits, the nearer the child well from the parent the well, the harder it´s going to impact the hit to the existing offset well also geological stress changes during the pressure depletion causes child well fractures to be directed towards the producing well. Reductions in wells production, pressure communication between wells, and sanded in inside the offset well, are a consequence of this phenomenon which causes economic losses for the companies and safety risk for the workers. This problem has occurred during fracking operations in the Bakken Shale. The objective of this research project is to study the stress shadow and parameters affecting the frac-hit in order to propose mitigation and prevention approaches. The existing analytical methods will be reviewed in detail and their applications will be assessed using data from the Bakken. Also, numerical simulations will be performed using the XSite software in order to investigate the underlying parameters in the frac-hit process.

Progress to date:

Analytical Models: Researchers have developed diverse equations to calculate the stress shadow effect caused by the hydraulic fracturing process. Sneddon in (1946) developed his theory taking in to account the stress field located around an infinitely long 2D crack in a homogeneous, isotropic, elastic body having Poisson's ratio, an internal pressure *P* and the crack's height *h*. Figure 1 shows the model geometry schematically.

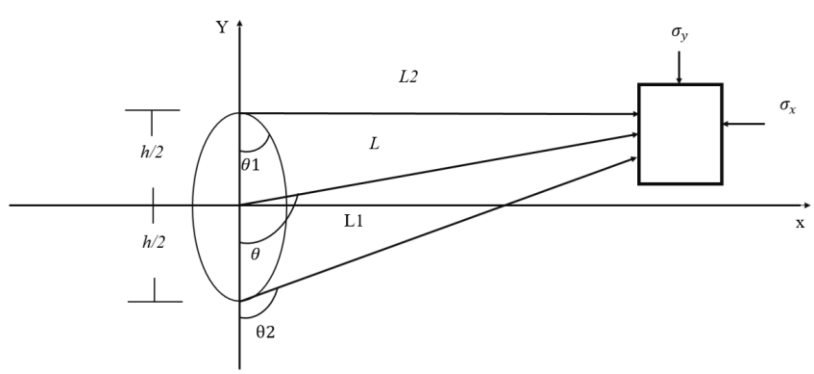

Figure 1. Sneddon (1946) analytical model geometry.

Sneddon (1946) stress shadow equations:

$$\frac{(\sigma_x + \sigma_y)}{2} = -p\{\frac{L_1}{\sqrt{L_1 L_2}} * \cos[\theta - \frac{(\theta_1 + \theta_2)}{2} - 1\}$$

$$\frac{(\sigma_y - \sigma_x)}{2} = p\{\frac{Lsin\theta}{\frac{h}{2}}\left(\frac{\frac{h^2}{4}}{L_1 L_2}\right)^{\frac{3}{2}} * \sin\left[\frac{3}{2}(\theta_1 + \theta_2)\right]\}$$

$$\tau_{xy} = -p\{\frac{Lsin\theta}{\frac{h}{2}}\left(\frac{\frac{h^2}{4}}{L_1 L_2}\right)^{\frac{3}{2}} * \cos\left[\frac{3(\theta_1 + \theta_2)}{2}\right]\}$$

$$\sigma_z = \mu(\sigma_x + \sigma_y)$$

Based on the Sneddon's analyses, Warpinski and Teufel (1987) determined the effect of dilated fracture on the stress field. They considered a different crack geometry to carry out their analysis, where the parameter h/2 is the fracture half-length and y is the distance away from the fracture (see figure 2).

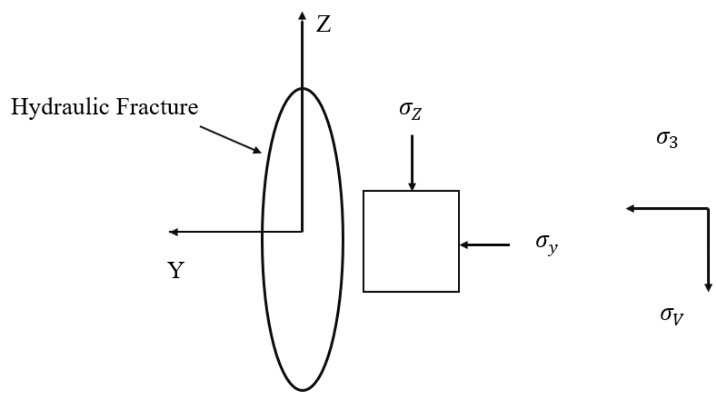

Figure 2. Warpinski and Teufel (1989) analytical model geometry.

Warpinski and Teufel (1987) stress shadow equations:

$$\sigma_y = p_t[1 - \frac{y^3}{\left(h_{\frac{1}{2}}^2 + y^2\right)^{\frac{3}{2}}}]$$

$$\sigma_z = p_t[1 - \frac{2h_{\frac{1}{2}}^2 y + y^3}{\left(h_{\frac{1}{2}}^2 + y^2\right)^{\frac{3}{2}}}]$$

$$\sigma_x = p_t[1 - \frac{2L_{hf}^2 y + y^3}{\left(L_{hf}^2 + y^2\right)^{\frac{3}{2}}}]$$

To the determine the differences or similarities between the Sneddon and Warpinski and Teufel analytical methods, a comparison between the minimum horizontal stress values obtained using their corresponding equations was carried out considering their mathematical and physical definitions. An injection pressure of 4681 psi, fracture half-length of 1.5 and a Poisson's ratio of 0.5 were used the input data. For the mathematical analysis the vertical and minimum horizontal stress functions and their derivates were calculated. For the minimum horizontal stress was concluded that the two analytical models show similar results. The difference between them is decline rate of the magnitude of the stress: the magnitude of the values in the Sneddon's model decreases faster than Warpinski and Teufel's model. In general, the stresses move from tension to compression for both cases. For vertical stress at the beginning both models show similar values but at some point, Warpinski and Teufel's model increases whereas the Sneddon's model decreases its magnitude. In other word, the vertical stress is in compression for Sneddon and in tension for Warpinski and Teufel's model.

Numerical simulations*:* The geomechanical model of the Bakken Shale was built using Xsite software. The main idea of this model is to simulate different hydraulic fracturing scenarios by changing the position of the horizontal wells to estimate the stress changes around them. The Bakken shale model created has the geomechanical characteristics and in situ stresses shown in Tables 1 and 2.

Table 1. Geomechanical characteristics for the Bakken shale.

Material Properties	Average
Density (kg/m^3)	2650
Young's modulus (Pa)	7.00E+10
Poisson's ratio	0.25
UCS (Mpa)	200
Tensile strength (Pa)	2.00E+07
Fracture Toughness (Pa*m^0.5)	1.00E+06
Flant joint friction angle (°)	26.565
Porosity (%)	2.00
Permeability (m^2)	1.00E-13
Biot's coefficient	1.00
Thermal Conductivity (W/m*degree C)	3.00E+00
Specific Heat (J/Kg*degree C)	7.95E+02
Thermal expansion coef (1/Degree C)	8.00E-06
Carter leak-off coefficient (m/sqrt(sec))	0.00E+00
Carter spurr-loss coefficient (m)	0.00E+00

Table 2. In situ stresses for the Bakken Shale.

In-Situ stress (Mpa)-Gradient (Mpa/m)				
	Magnitude	**Dip Dir.**	**Dip angle**	**Gradient**
S1	5.48E+01	90	0	0
S2	6.16E+01	0	0	0
S3	6.84E+01	0	90	0
Reference minimun stress				0.0000+E00

Three cases are going to be studied. The first case or base case is one horizontal well with two clusters injecting water at the same rate. Figure 3 shows the model geometry in Xsite.

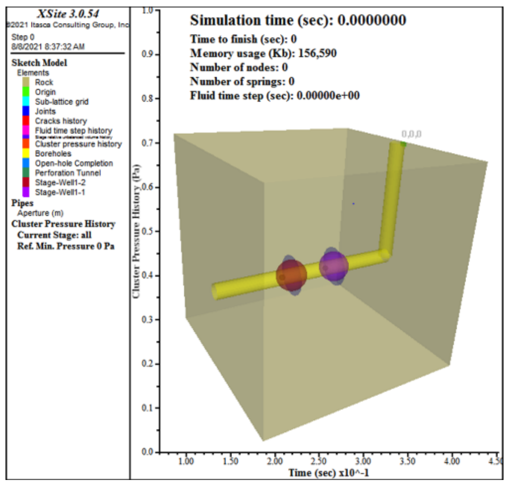

Figure 3. Geometry of a horizontal well and two clusters in Xsite.

The second case is a horizontal well with three clusters injecting water at the same rate, and the third case is two horizontal wells located near each other with three clusters in each. The idea is to understand how different well arrangements may affect the stress shadow phenomena in the Bakken Shale.

The model validation will be done using the analytical models and also will be compared with the results obtained using StimPlan 3D Software.

Project Milestone and Timing:

Table 3 shows the project timetable:

Table 3. Project Milestones.

`	2021												2022												2023							
Task	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Literature review																																
Analytical models review																																
Stress modeling																																
Hydraulic Fracturing modeling																																
Well pads designing																																
Mitigation strategy simulation																																
Results analysis																																
Thesis writing																																

Autonomous Field Scale Fluid Sampling System for Measurement

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Problem Statement:

The drilling mud plays an essential role in maintaining the stability of the drilling circulation system by including cooling the bit, lubricating the drilling pipes and creating hydrostatic pressure inside the wellbore to avoid hydrocarbon ingress into the wellbore.

After being mixed in the mud tanks, the drilling fluid circulates through the surface pipes and gets injected down the drilling pipes in order to reach the drilling bit. The fluid exits through the bit nozzles pushing the rock cuttings away from the bottom of the hole to the surface.

A small amount of the drilling fluid returns to the surface, carrying with it the drill cuttings and reservoir fluids. The fluid, now called "slurry" goes through a restoring process to establish its initial composition by adding chemicals. During this procedure, many sampling operations are done in the mud tanks, shale shaker, inline between the pipes, in the mud return line and any other necessary point in order to keep track of the fluid properties such as density and viscosity. Sampling is done manually by an assigned person that frequently takes samples every five to thirty minutes and measures the density and viscosity through a densitometer, marshal funnel or viscometer.

However, the manual sampling procedure not only has severe safety hazards and is highly costly but also is affected by human error.

In order to correct these issues, it is necessary to develop an automated fluid sampling system that will be able to take samples at set times in set points of the drilling system in order to measure the needed properties for hydraulic performance and lithology identification studies through drilling fluid sampling.

Objectives:

- Developing a reliable automated fluid sampling procedure for oil field application.
- Demonstrating the advantages of automated sampling technique over manual procedures.
- Optimizing the automated sampling procedure for improved fluid characterizations.

Methodology:

- Analyze the different resources available on the matter and widen the literature review into the application of sampling procedures in other industries.
- Set up different possible designs for the sampling device.
- Weighing the advantages and disadvantages of each potential design.
- Come up with a coherent design.
- Build up the initial prototype.
- Perform the sensitivity study in order to optimize the device
- Correct any issues that may appear.
- Validation of the final prototype.

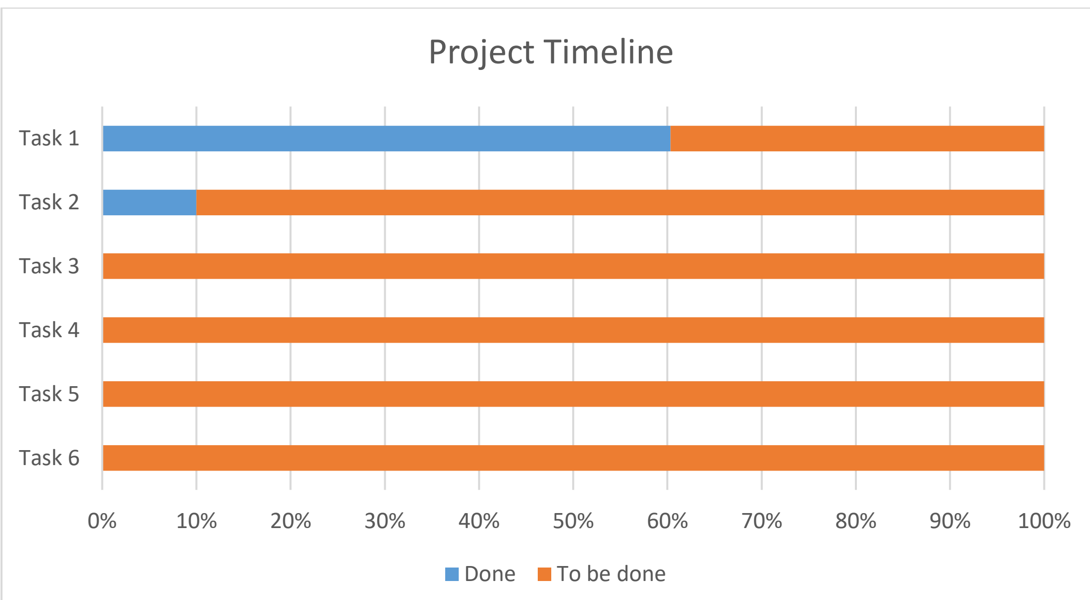
Significance:

- Accurate and reliable sampling results at set times and set points
- Optimization of the sampling and measuring procedure by the increase of productivity and reduction of the non-productive time.
- Significant economic reduction of the costs.
- Increase and improvement of safety.
- Reduction of the risks of potential problems that would happen because the manual sampling.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature Review.
- Task 2: Designing and manufacturing the robotic fluid sampling tool.
- Task 3: Comparison of the automated and manual sample collection procedures.
- Task 4: Configuration design sensitivity analysis.
- Task 5: Validation.



Progress to date:

As of August 2021, a significant amount of literature has been reviewed in relation to sampling devices in different industries and the methods used in order to design and implement the sampling procedure according to the industry and the field it will be applied in. Some parts of the design have been defined, notably the placement of the device, some of the sensors that will be used to measure the different parameters as well as the methods that will be used to enhance the accuracy and robustness of the device. The approach that best fits the project would be an inline device that would include multiple distributed parts throughout the drilling fluid circulation system.

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Fishbone Drilling Stimulation of Shale Plays Using Underbalanced Coiled Tubing Technology

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Problem Statement:

The USA started producing unconventional reservoirs in 1980 with rapid growth in horizontal drilling cost optimization, fracturing technologies developments, and enhanced oil recovery.

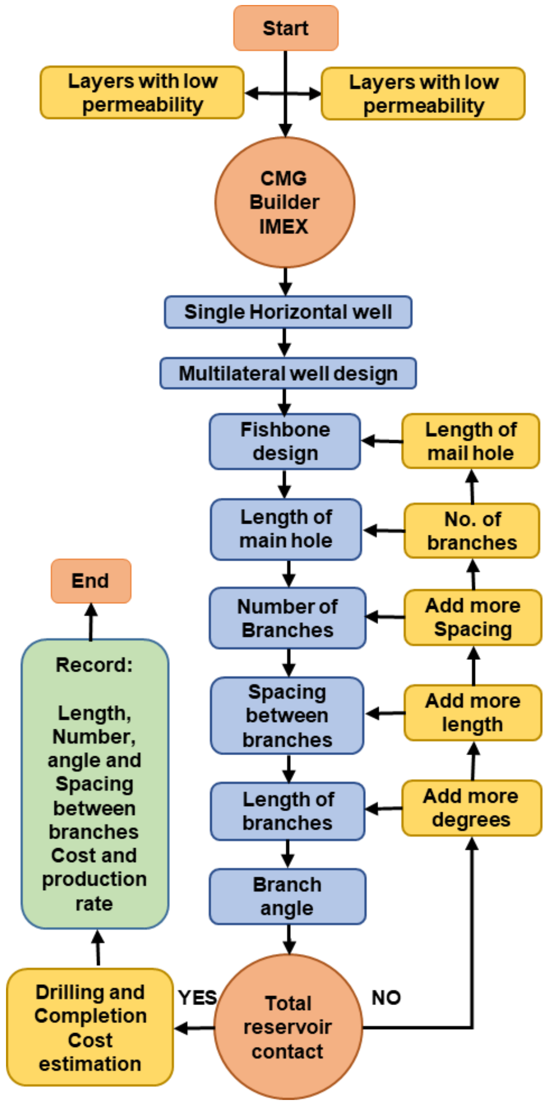
Multilaterals wells are one of the recent technologies in horizontal drilling. It is a well with multiple sidetracks and branches in different directions depending on the geological layers to increase the reservoir contact and the simulated volume reservoir.

Fishbone drilling technology is one of the multilateral drillings. It consists of drilling a number of micro-hole drillings in different directions from the main wellbore. They are called so because they look like the skeleton of a fish. The use of this type of drilling in naturally fractured reservoirs has been practiced to enhance production as a result of interconnecting as many natural fractures as possible.

Fishbone drilling at under-balanced conditions (the mud pressure is less than the pore pressure) and using coiled tubing offers further benefits. It results in the natural flow of the fluid to the wellbore, which enhances the production.

The fishbone drilling technology may be considered as an alternative method for hydraulic fracturing where the natural fractures in unconventional plays, known as sweet spots, are connected for enhanced recovery. Part of the new design for applying this technology in unconventional plays, mainly shale reservoirs, includes designing a small downhole motor to rotate the bit. Also, the generation of vibration through the drilling mud at different frequencies will create shear forces in order to induce shear failure of the natural fractures ahead of the bit and the creation of new cracks

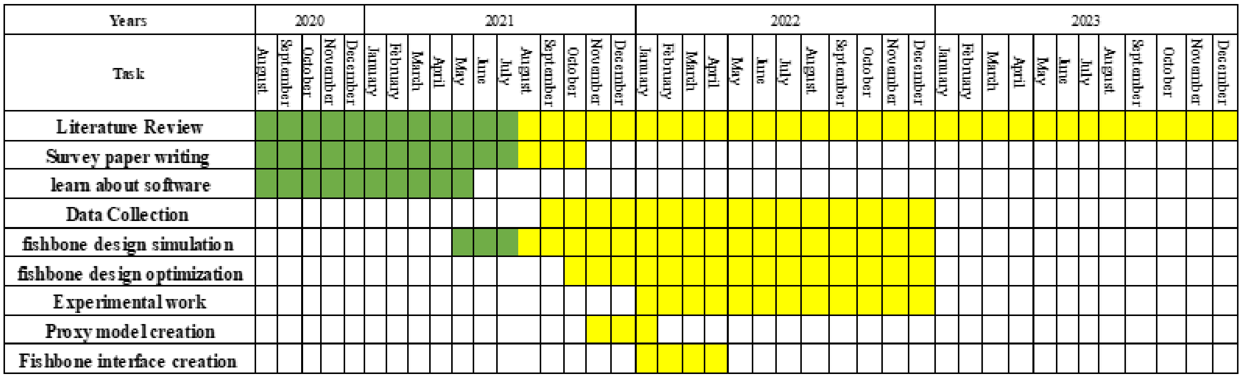
This project the optimum design of micro-bore holes of the fishbone well in combination with underbalanced coiled tubing drilling in the unconventional brittle reservoir. Study the effect of fishbone drilling in maximizing the stimulated reservoir contact and enhanced reservoir recovery.



Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 1: Literature Review
- Task 2: Survey paper writing
- Task 3: learn about software
- Task 4: Data Collection
- Task 5: Fishbone design simulation
- Task 6: Fishbone design optimization
- Task 7: Experimental work
- Task 8: Proxy model creation
- Task 9: Fishbone interface creation



Progress to date:

As of August 2021, a significant amount of literature has been reviewed concerning the application of multilateral fishbone technology worldwide. There has also been a test of different software existing in the industry to simulate the microbore holes and consider the reservoir contact when drilling in brittle formation.

Simulation part: Some basic simulation has been made using CMG, starting from creating micro branches using perforations. The second solution was to develop multilateral trajectories, to design the fishbone well. Many cases have been established starting from a vertical well, horizontal well, fishbone with two branches and with 8 branches. The results show a significant increase in tight formation in both cases.

An investigation of the direction of natural fractures has been simulated using CMG. The simulation consists of drilling parallelly or periodically to natural fracture. The result shows that by intersecting the natural fracture periodically, the production increases.

When I will get the approval for the model, I can start simulation of many models with many cases and designs to create the proxy model and start creating the interface for the optimized case.

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Optimization of Oil Production through Appropriate Practical Gas Lift Design

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Problem Statement:

When the reservoir energy is too low for the well to flow, or the production rate desired is greater than the reservoir energy can deliver, it becomes necessary to put the well on some form of artificial lift to provide the energy to bring the fluid to the surface. Hence, one of the challenges faced in lifting the oil and gas from the reservoir via the production tubing to the surface facilities is an unnecessary production decline which poses a serious problem to the oil and gas industry today or inability of the well to flow (expected rate) due to the viscous nature of the fluid. This decline may be because of mismanagement of wells, excessive pressure drops along the production system, oversized or undersized tubing, and improper perforation method etc. A change in a single component of the production system may lead to a change in the pressure drop behaviour of the other components since the various components are interactive. In addition, for the fact that artificial lift installed in wells increases the production rate, there are some problems encountered after the installation of these lifting techniques to help recover the column of fluid to the production facilities at the surface. Such as solid/sand handling ability, corrosion/scale handling ability, the stability, number of wells, flowing pressure and temperature limitation, well depth, production rate, flexibility, high GOR, electrical power, space, economics etc. which are factors to consider in the selection prior to the installation of any of the artificial lift techniques.

Gas lift is one of the most used artificial lift techniques in the world. High pressure gas is injected into the well to lighten the column of fluid and allow the reservoir pressure to force the fluid to the surface. The gas that is injected is produced with the reservoir fluid into the low-pressure system. Therefore, the low-pressure separator must have sufficient gas separation capacity to handle gas lift as well as formation gas. If gas lift is to be used, it is even more important from a production standpoint that the low-pressure separator be operated at the lowest practical pressure.

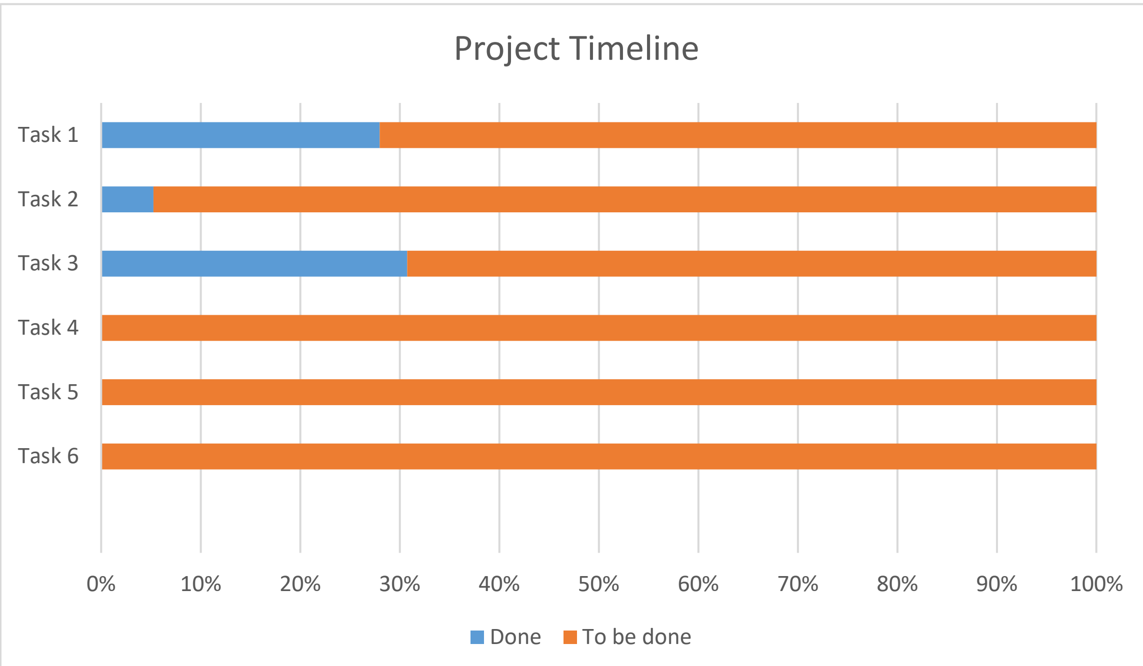
Appropriate Gas lift system design is obtained using optimization technics by combining PVT data with fluid and multiphase flow correlations. Several steps are required, from the selection of appropriate correlations followed by multiphase flow calculations at various points of injection. From actual pressure and temperature surveys and determining the point of injection, a gas lift performance curve is constructed for the well. To determine the optimal gas lift condition, Solution nodal method is used to determine optimum injection depth, optimum well-head pressure, optimum production rate and minimum injection gas volume. A considerable gain could be obtained from implementing recommendations. Finding the appropriate valve space is another important task to accomplish.

As we can see, the optimization of gas lift systems is not an easy task. The oil flow rate in a single vertical well undergoing gas lift operations is complicated by three factors: (1) The flow is driven by gas injection, in addition to the fluid flow potential gradient applied along the well, (2) the well is interfaced with a porous and permeable reservoir contributing with a fluid feed, and (3) the wellbore geometry may consist of concentric pipes of varying diameters and lengths, rather than a single-diameter pipe. Due to the complexity of the production system in terms of flow geometries and fluid properties. The steady state conditions are not a consistent approach to simulate this kind of problems. Thus, a dynamic simulation is the best approach for such complex flow conditions.

Project Milestone and Timing:

Time major milestone of the project Include the following tasks:

- Task 01: Literature review
- Task 02: Conducting experiments and data collection.
- Task 03: Multiphase flow models evaluation and improvement
- Task 04: Collecting data about gas lift in Bakken and simulation using commercial software
- Task 05: Optimization of current configuration
- Task 06: Using multiphase flow model improvement for gas lift optimization



Progress to date:

The objective of the project is the study of multiphase flow mechanisms through the evaluation and improvement of existing models, and then apply the results to optimize gas lift operation.

As for August 2021, an important number of papers have been reviewed regarding existing multiphase flow models. A complete review of these models will allow identifying areas to improve in multiphase flow modelling and then conduct experiments using the multiphase flow loop to try to improve one of the models or create a new model.

As for the gas lift part of the project, a first contact with an artificial lift company has been established to try to collaborate about a new practical technique of optimizing intermittent gas lift operation in oil wells, using some logging results in tubing-casing annular space. The objective is to improve the precision of the existing models in predicting the deepest injection point, which is a crucial parameter in gas lift systems.

To reach the objective of the projects, several studies are currently in progress and will be conducted in the future, basically:

- Literature review of multiphase flow models and gas lift optimization.
- Evaluation of existing multiphase flow models.
- Conducting experiments using multiphase flow loop.
- Using experimental results to improve existing models
- Study of gas lift operation in Bakken oil wells: challenges and optimization.

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New Downhole Motor Design for Microholes (Fishbones)

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Problem Statement:

Over the years the State of North Dakota has seen several episodes of drilling to try to recover a portion of the immense amount of oil that this formation has generated. Beginning with the initial discovery in 1953, the Bakken has been a significant contributor to the North Dakota economy. Over 44 million barrels of oil have been produced from this formation, and there is a large potential to add to that total with the current oil play.

Although a significant quantity of oil has been produced from the Bakken it is only a fraction of what the Bakken is capable of producing. Long considered to be a premier source rock, science places the oil potential of the Bakken between 10 and 400 billion barrels of oil (L.C. Price, pers. commun.). A comparison of the past drilling activity in the Bakken Formation with the current play provides a new insight into how technology can potentially unlock oil from this virtually untapped resource.

Due to the low productivity of individual wells and the high cost of drilling and fracturing a large number of wells, multi-fractured horizontal wells have been used to improve oil and gas production from low-permeability reservoirs.

The problems associated with this type of wells are well productivity decline due to fracture closure with time and uncertainty of fracture propagation due to the lack of knowledge of formation stresses. The disadvantages of multi-fractured horizontal wells may be avoided by using fishbone wells, a new technology developed in the recent years.

Fishbones is an open-hole completion and stimulation system. It is primarily used in carbonate, sandstone and basement formations. Fishbones is typically not considered for unconventional. The typical application is in low perm conventional reservoirs. Fishbones is being used onshore and offshore worldwide. Fishbones comes in two liner sizes, 4.5” and 5.5” liner sizes for 6.125” and 8.5” open holes, respectively.

We believe that Fishbones technology need new design to reach the require performance to complete successfully micro-holes in unconventional reservoirs.

The purpose of this study is to investigate and identify the capabilities of downhole motors related to small diameter. In support of this task, an extensive research will be conducted to optimize an existing motor or design a new one from scratch that can respond to operating conditions of the application of fishbone technology in unconventional reservoir.

Objectives:

- Investigate and identify the history and the state-of-the-art capabilities of down-hole motors related to small diameters in CT/fishbone drilling.
- Investigate and identify the history and the state-of-the-art capabilities of down-hole motors in other industry like mining.
- Define the operating conditions of the various types of downhole motors and their limitations.
- Define the range of bend angle of down-hole motors and operating parameters of micro-holes.
- Design a prototype and update it based on simulations.
- Validate the design of motor.

Methodology:

- Gather data and create a mini catalog of spec-sheet of small downhole motors.
- Gather and assess data about motors in other industries.
- Choose which type of motor is the optimum to work on.
- Study design optimization and build the first prototype.
- Simulate and update the design of prototype.
- Run sensitivity parameters to study the effect of drilling challenging parameters that affect the performance of motors.

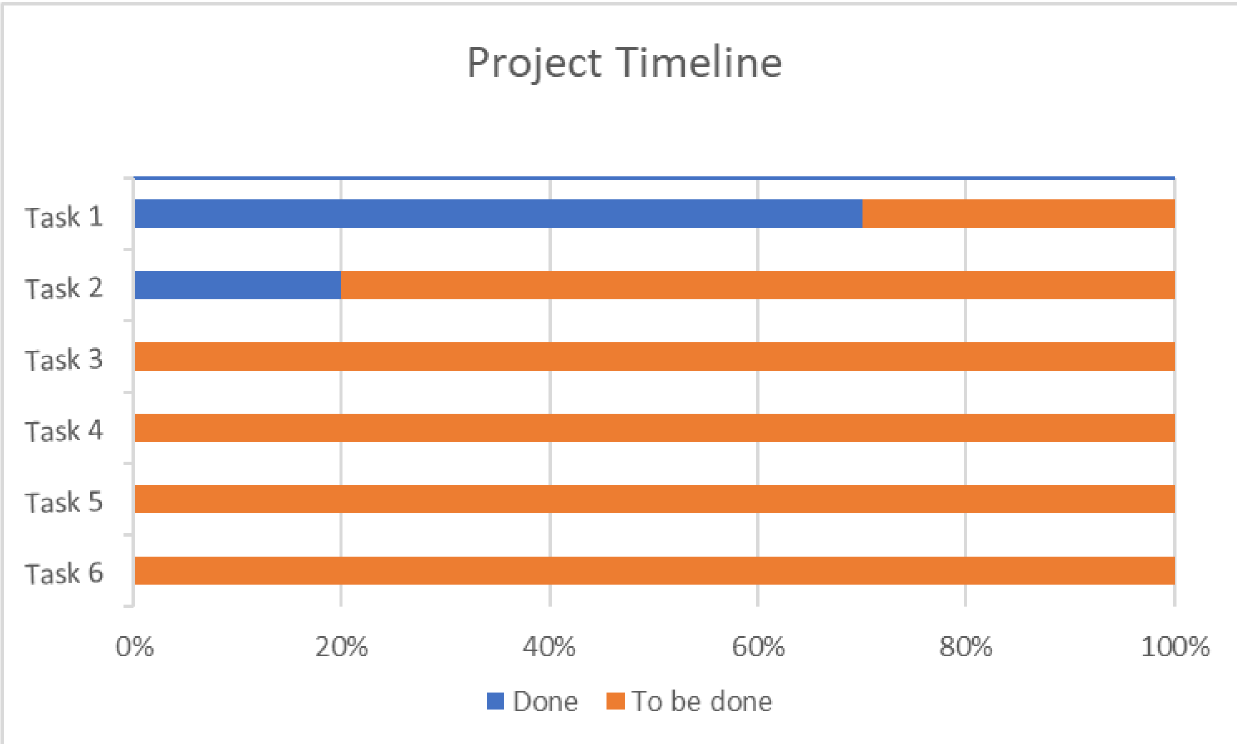
Significance:

- Stimulation of unconventional reservoir by fish-bone technology as an alternative to fracking.
- Establishing a connection between natural cracks
- Environmentally friendly solution technology.
- Reduce drilling costs associated with logistics and congestion, increase productivity, reduce operating time.
- Repackage the fishbone design (Downhole motor) concept in a manner suitable for unconventional applications.

Project Milestone and Timing:

Time major milestone of the project include the following tasks:

- Task 1: Literature Survey
- Task 2: Data collection
- Task 3: Sensitivity analysis
- Task 4: Prototype design
- Task 5: Design optimization
- Task 6: Report results and produce papers



Progress to date:

To August 2021, a variety of documents have been reviewed pertaining to the design of downhole motor, application of coil tubing and simulation of fishbone technology. Almost, all the existing small size downhole motor were investigated in the market. After assessing their capabilities, we found that they are not designed for drilling in shales.

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