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DATA ANALYTICS OF NATURAL GAS INJECTION ENHANCED OIL RECOVERY FOR UNCONVENTIONAL RESERVOIRS

By

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ABSTRACT

Unconventional Enhanced Oil recovery, via the injection of natural gas has attracted great attention, as studies and projects have shown to be promising. An overview of pertinent studies has been carried out. Core Scale Laboratory Experiments, Core Scale Simulation, Field Scale simulation and pilot projects are analyzed. Data is collected for Core, Reservoir, Operational, and recovery information. Thereafter, Data analysis techniques are applied to identify data ranges, distributions, trends, relationships, and to eventually reach conclusions.

Huff and Puff injection is the preferred mode of injection, delivering most promising results for unconventional reservoirs. Across all the studies, with increase in amount of injected Gas volume and number of cycles, the Recovery factor is seen to increase. After reaching a maximum value, the Recovery factor tends to stabilize and becomes unresponsive to any further increase. For core experiments, core size is seen to be inversely related to the recovery factor. For field scale simulation, injecting above the bubble point pressure results in greater recovery, owing to greater gas absorption, oil swelling and viscosity reduction. In all the studies the formations and cores which have been investigated are mainly Eagle ford, Wolf camp, Bakken and Niobrara shale. During field Projects, Huff and Puff injection has proven to be successful, with promising results with no injection issues reported.

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My completion of the master's degree with a thesis is an accomplishment which has been possible by owing to the efforts of a lot of people. Firstly, I would like to thank my advisor, Dr. Baojun Bai, who has been there to help, guide and supervise me with all the technical challenges and obstacles. My co-advisor, Dr. Wei, has been kind enough to agree to be part of my committee and she gave her valuable insight at a number of critical points when I felt stuck or had no idea how to proceed. It was due to their persistent support that I have been able to complete this work of research.

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NOMENCLATURE

Symbol	Description
NG	Natural Gas
EOR	Enhanced Oil Recovery
LSW	Low Salinity Water
MMSCFD	Million Standard Cubic Feet Per Day
RF	Recovery Factor

1. INTRODUCTION

1.1. STATEMENT AND SIGNIFICANCE OF THE PROBLEM

The petroleum industry of United States is soon poised to lead the globe by significant margin, in terms of having the highest oil production, mainly due to the production from Unconventional resources. Due to low permeability, slow recharge from matrix and poor connectivity, these resources have very low Recovery Factors. Among the current EOR techniques, NG injection has shown promising results in the field, with some unique advantages such as availability, injectivity and lower corrosion.

During the past few years the industry has seen a change in its business model, whereby the opportunities and potential of Data Analysis and Artificial Intelligence have been realized. All the major Oil & Gas Companies are trying to introduce such business models which fully capitalize the potential of Data Science and Machine learning. The applications of said techniques are immense, and upon right application, can reveal trends, relationships and conclusions which can have a substantial effect on any process or area of application.

While considering Natural Gas Injection EOR, there are no studies which does a comprehensive review of the topic and carries out a Data collection and analysis. It was thought to be a unique and lucrative research area which has not yet been addressed and this study ventures to investigate the same.

1.2. OBJECTIVES

The primary objective of this study is generate conclusion and results, based upon Data analysis techniques, applied on a data set, constructed from Natural Gas Injection based literature, studies and experiments. Specific objectives include:

- To review Natural Gas Injection based Enhanced Oil Recovery studies for Unconventional Reservoirs, in order to extract reservoir, operational and recovery related information, so that a data set can be built.
- To segregate the data as per the mode of investigation, that is core flooding experiments, core scale simulations and field scale simulations and then to carry out data profiling, to improve its quality, remove errors or inconsistencies, while ensuring a baseline across the whole dataset.
- To generate histograms, box plots and pie charts to highlight the data distribution, ranges, quality and statistical analysis.
- To carry out Single variant analysis for each of the three data sets.
- To investigate relationships of the different operational and reservoir parameters via cross plots, bubble charts, scatter plots and regression analysis, leading to conclusions and results.
- To provide a guideline for anyone who wants to investigate this area of expertise, by generating a data baseline, which may be used for core studies and field scale simulations.

1.3. ORGANIZATION OF THIS STUDY

This study has been organized into four sections. First section is the overall introduction and the objective of the study. The second section is an overview of all EOR methods for unconventional reservoirs with their challenges and success rates. Thereafter, it discusses NG injection, with its literature review, advantages, recovery mechanisms and Huff'n'Puff injection dynamics. The third section discusses Data collection process and challenges. It then presents Data visualization in the form of pie charts, histograms, box plots along with single variant analysis. Lastly this section explores the relationship between different parameters via scatter plots and bubble charts. The last section then highlights the results and the conclusions.

2. NATURAL GAS EOR FOR UNCONVENTIONAL RESERVOIRS

2.1. OVERVIEW OF EOR FOR UNCONVENTIONAL

Owing to the unique properties such as ultralow permeability, low porosity and tight pore throats, application of EOR techniques for Unconventional reservoirs is a major challenge. More than 20 IOR techniques have been found to be successful for conventional reservoirs, however all of them cannot be applied to unconventional reservoirs. Some methods have been investigated for unconventional reservoirs and their details are below:

2.1.1. Chemical Methods. These methods include three types of EOR methods that is surfactant, polymer and alkaline. Among these surfactants has been found to have the best potential to improve recoveries. As unconventional reservoirs are known to be intermediate wet to oil wet, with the application of surfactants the wettability is altered, to become more water wet. This enhances water imbibition in the reservoir and aids in increasing recoveries. In addition, the interfacial tension is also reduced. Generally, in all reported simulation and experimental studies, this method has shown incremental recoveries.

Alvarez et al., (2014) conducted experimental work to evaluate surfactant potential to alter wettability in unconventional liquid rich reservoirs by using ionic and nonionic surfactant and found out that surfactant can lower contact angle (more water wet) and improve oil recovery. Dawson et al. (2015) conducted experimental work on how surfactant can be used in Bakken formation to enhance oil recovery and upscaled lab results to field scale by numerical simulation methods. Xu et al (2015) found that using surfactant with stimulation fluid increased the penetration of fracturing fluid twice. Wang et al, (2016) investigated he imbibition rate of surfactant and the penetration depth into matrix and concluded that surfactant cannot be much beneficial in increasing oil recovery, if it would be performed in reservoir with only hydraulically induced fractures. Alvarez et al., (2016) investigated the effect of different types of surfactants on interfacial tension and contact angle by using premium basin cores. They found all types of surfactants could change the wettability from oil wet to water wet. However, the anionic surfactant had better performance by reducing both the interfacial tension and contact angle in unconventional liquid rich cores.

The other EOR methods in chemical category is Polymer. Not much work has been done on this type because of the injectivity problems which polymer might have in such tight and low permeability reservoirs. Also, polymer is expected to plug the pore throats which are narrow in unconventional reservoirs.

The last technique in Chemical EOR is Alkaline EOR and like polymer not much work has been done for the same. The reason for the same is that there is no compatibility between alkaline chemical agent and the mineral composition of the unconventional reservoir plays.

2.1.2. Water Injection. Studies have shown promising results for the injection of low salinity water for unconventional reservoirs, whereas water injection has shown no additional recoveries in Pilot studies for unconventional reservoirs. Wettability alteration or Inter Facial Tension reduction come into play for the case of injection of Low salinity water in Unconventional Reservoirs. At an optimal concentration of salt, maximum recovery can take place. In addition, for some recent studies shale cracking has been proposed also one of the mechanisms which cause additional recovery.

Low salinity water was investigated by Morsy et al (2013) where they investigated LSW on eagle ford formation. The achieved higher recovery rate for samples placed in distilled water as compared to 2% KCL and attributed this to shale cracking due to clay swelling. Valluri et al (2016) conducted experiments by injecting different concentrations of Sodium chloride and calcium chloride brines, to change shale rock wettability and increase recovery. Wood et al. (2011) reported eight pilot tests, for water injection in Canadian Bakken, by using water flooding. Some of them showed encouraging results. The pilot tests were unique in the sense that the spacing between injector and produced wells was far less as compared to US bakken, i.e.of the order of 200 ft, although the porosity and permeability of Canadian bakken is bigger. All the wells had toe-heel pattern. The Oil production rate due to water injection was increased from 75 bbls/day to 550 bbls/day.

For US Bakken Hoffman et al (2016) reported three pilot tests which used water flooding as well as water Huff'n'Puff mechanism. For the Huff and Puff pilot injected 1200 bbls/day for 2 cycles with one-month injection and 2 weeks of soaking time. Also, no surfactant was used with water to alter wettability. For this Huff and Puff pilot no 6, additional oil was recovered. The other pilot was water flooding with one injector surrounded by four offset wells. 1350 bbls/day of water was injected for 8 months which raised the bottom hole pressure to 6000 psi. However; the injected water got breakthrough and no additional oil was recovered after a period of 7 months.

2.1.3. Miscible Gas Injection. Miscible Gas injection is one of the most investigated EOR mechanisms for Unconventional Reservoirs. Mainly the gases which have been investigated are Carbon-di-Oxide, Nitrogen and Natural Gas. However, most of the studies have focused on carbon-di-oxide due to several reasons such as environmental initiatives, lower MMP etc.

The early works in for CO2 started by using modelling methods (shuaib et al 2009; Wang et al., 2010), which showed good results, having that 10-20% of incremental oil by continuous gas flooding while 5- 10% could be recovered by huff-n-puff ' gas protocol (Hoffman et al., 2016). Dong et al., (2013) reported a numerical study evaluating C02 injection performance for Bakken and their simulation study reported that using C02 injection can increase oil recovery from 5% to 24%. Xu et al., (2014) evaluated the reservoir performance of Elm Coulee field in Eastern Montana under C02 flooding with different Hydraulic fracture orientations. They found that transverse fractures have higher oil recovery factor but lower utilization factor. Alfarge et al. (2017b) compared the recovery factor while using different gases such as lean gas, rich gas and CO2 for Bakken shale and they found out that hydrocarbon gases could be a better option due to requirement of less molecular diffusion effect for Hydrocarbons as compared to CO2. Alharty et al (2018) conducted a comprehensive study of CO2 and concluded that history matched field scale model showed less dependence on diffusion on incremental recovery, as compared to the result as achieved form the core experiments.

Regarding lab works study of Song et al. (2013) did the early studies which started conducting experimental work to compare results from injecting C02 and water in cores from Bakken- Canada. They found that water flooding would enhance oil recovery better than immiscible C02 in Huff-n-Puff protocol. However, miscible and near miscible C02 Huff-n-Puff would perform better then water flooding. Hawthorne et al., (2013) investigated the mechanism beyond increasing oil recovery by C02 injection in Bakken cores. They proved that diffusion mechanism is the main mechanism for C02 to increase oil recovery in these complex plays. However, to extract oil from shale matrix by C02, long times of exposure combined with large contact areas are required. Gamadi et al. (2014) conducted experimental work on shale cores from Mangos and Eagle Ford to investigate potential of C02 injection in these reservoirs. Their laboratory results indicated that cyclic C02 injection could improve oil recovery from shale oil cores from 33% to 85% depending on the shale core type and other operating parameters. Alharthy et al.. (2015) compared injecting different types of gases such C02, C1 -C2 mixtures, and N2 on enhancing oil recovery from bakken cores. They concluded that injecting C1, C2 mixtures result in the same recovery as that from the injection of CO_2, that is 90 % for middle Bakken and 40% for lower Bakken cores. Yu et al.,(2016) investigated N_2 flooding process experimentally on Eagle Ford core plugs saturated with dead oil. They examined different flooding range and different injection pressure on N_2 flooding performance. They found that more oil was produced with a longer flooding time and higher injection pressure

For CO_2 Hoffman et al (2016) reported three pilots in US Bakken. The pilots were in North Dakota and Montana. Two of the pilots used Huff and Puff gas injection whereby one of them used continuous injection. For the Huff and Puff 1500 Mscf/Day of gas was injected at a pressure of 2500 Psi. However no additional oil was recovered. For the continuous injection 500 Mscf/Day of gas was injected, however conformance control problems were observed with no additional recovery of gas. These three projects did not show additional recovery attributable to CO_2 and the explanation for the same is considered to be that diffusion mechanisms are not present, as thought to be present during simulations and lab studies.

2.2. NATURAL GAS INJECTION FOR EOR OF UNCONVENTIONAL

Two modes of natural gas injection for shales are found in the literature. One is the continuous flooding, whereby injector wells serve to inject the gas and some other wells serve as the producer. In this method, due to the presence of fractures, conformance control and gas breakthrough from injector to producer have been found to be one of the main issue. The other technique is the Huff and Puff injection technique, which has shown far more superior results. A well is initially injected with the gas for some period of time. After that the well is shut and some soaking time is provided for the gas to reach and mix will all parts of the reservoir. Thereby then the well is put on production. This technique has a number of key advantages which are unique and only applicable to natural gas injection:

- Having an early and quick response to gas injection which makes the reservoir react and respond to the applied pressure, injected gas and stimulation especially above MMP
- The decrease of oil saturation near the wellbore takes place due to evaporation of the reservoir fluids due to the change of the pressure and temperature conditions. Having ultra-low permeability of the unconventional reservoirs the pressure

transport problem is removed. This is further important if we have reservoirs with good injectivity

- Operation with a greater than expected drawdown pressure due to the pressure different in the reservoir, the associated wellbore and the differential, amalgamation effect

However it needs to be noted that the above effects become important under a special conditions that the wellhead pressure should be above the bubble point pressure or near the minimum miscibility pressure, as only in that region it will result in changing the fluids profile. The gas will serve to enter the oil, reduce its viscosity as well as cause oil swelling hence resulting in greater recovery volumes.

2.3. HISTORY OF NATURAL GAS EOR

Natural gas injection has been quite successfully used in conventional reservoirs. It serves to reduce viscosity, provide pressure maintenance, improves permeability hysteresis etc. in conventional reservoirs. However, their applicability in unconventional reservoirs is yet to be firmly established as a few pilot projects and some research work is being carried out. While considering Core and Laboratory experiments, Haines and Monger (1990) conducted natural gas huff-n-puff injection in waterflooded cores and found that approximately 40% of water flood residual oil is recovered by using two injection cycles. Shayegi et al. (1996) presented the results of laboratory investigations of cyclic gas injection process using CH_4, N_2 and mixtures of these gases with CO_2 in immiscible condition in consolidated sandstone cores. He used water flooded residual oil. He was able to conclude that Methane recovers approximately the same amount as CO_2

whereas N_2 recovers about half. Zhang et al. (2006) did a laboratory investigation by CO_2 /flue gas huff-n-puff process. He concluded that both the gases can be compared. Ivory et al. (2010) studied cyclic solvent injection using a solvent mixture (e.g., CH_4 /propane) injected to heavy-oil reservoirs and the oil recovery after primary production. He conducted the experiment of CH_4 Huff-n-Puff injection in the core samples, confirming that condensate recovery increase by 6% in the Huff-n-Puff injection operation.

With respect to the simulation studies, first time simulation was carried out by Wan et al. (2013). It was showed that total oil recovery can be increased up to 29% by cyclic gas (77% C1, 20% C2, 3% C6) injection in shale. On the other hand the primary depletion has 6.5% recovery. Wang.X 2010 and Sanchez Riveria Z, 2015 showed that CH_4 can take the place of CO_2 in some situation due to its high compressibility and rich sources. Alfarge et al. 2017 showed that the extension of soaking period and increasing injection volume are beneficial to improve the well production. Wang and Sheng (2015) used dual-permeability simulation to study gas injection in fractured shale oil reservoirs and demonstrated that matrix/fracture and matrix/matrix diffusion play an important role in the oil recovery process. Alfarge et al. (2017b) compared the performances of miscible Huff-n-Puff for the Bakken Shale using lean gas, rich gas and CO_2 solvents. They found that hydrocarbon gases could be a better option as it required less molecular diffusion effects to increase the recovery compared to CO_2.However, the gap of recovery mechanisms between lab-scale and field-scale needs to be addressed. It has also been demonstrated that natural gas can be another option that can potentially recover as much oil as CO_2 does (Jin et al., 2017)

2.4. ADVANTAGES OF NATURAL GAS INJECTION

Below are some of the main advantages of Natural Gas which assist the recovery mechanisms. Also it is because of these advantages that Natural Gas in found to be more advantageous as compared to the other available gases such as Nitrogen, Carbon dioxide etc.

- Natural Gas has a lower molecular weight as compared to CO2. This makes it easier to be injected especially for smaller pore throats that are in the range of 0.00001-1 mD.
- Due to the small molecular weight of natural gas it does not require large contact areas, as in the manner which CO2 does. Hence with small contact area or small region of exposure, good results can be achieved.
- Natural gas is easily available in the field. As in any routine production operations of an oil and gas company, gas is produced with the production of oil and the same gas can be easily deployed for injection purposes after removal of heavier components, water contents or making the composition of gas as per required injection and recovery increment requirements. This is a big advantage in comparison to other gases such as CO2 or N2 which may have to be brought to the field via some special transportation modes have requirements of accommodation and their composition remains the same.
- Natural gas has the capability to have its composition altered as per requirements for any particular injection operation. Research has shown that for any particular case and reservoir, there exists a particular composition which serves to give the best recovery rate. The same can be pure methane, some optimum combination of

methane, ethane, propane etc. The compositions depends on the reservoir properties, oil properties and the particular case at hand.

- Natural gas are not very strong functions of natural fractures as CO2. Hence for strongly fractured reservoirs natural gas can be used whereby CO2 or other gases might not be feasible.
- Cyclic natural gas injection has one great advantages that it results in lower corrosion levels as compared to other gases. Hence its injection can serve to ensure the life of the production facilities, tubing, and other equipment associated with Oil and Gas production.

2.5. RECOVERY MECHANISMS

The main recovery mechanisms which aid in recovery are thought to be as follows as per order of most influence:

- Pressure maintenance is one of the most main and influential recovery mechanism. Via the injection of gas the pressure in the reservoir is maintained. The energy of the reservoir stays intact and thus the same is influential in making the hydrocarbons flow to the surface. If the gas is being injected above or in the near miscible regions, this has additional advantage that miscible mixture is created and oil flows to the surface in the form of a miscible mixture.
- Gas has a high compressibility thereby which makes it one of the ideal candidates for increment in oil recovery. When injected in the reservoir its high compressibility exerts a force on the oil in the matrix and hence does serve to push it towards the production wells or the fractures. The causes the oil to flow

out of the rock matrix via the fractures or rock towards production wells. In case of huff and puff the same results in increasing the potential energy of the wells and during huff phase oil production is assisted.

- Due to the injection and mixing with oil the gas serves to swell the oil which makes it less viscous and more prone to flow easily. The oil swelling makes it lighter, more mobile and less dense and less viscous and hence this serves to be one of the recovery mechanism.
- Diffusion from a region of high concentration to ta region of low concentration is the process of diffusion. When gas is injected in a reservoir which does not have any gas in place then the diffusion of gas place a very important role in increasing the recovery of the HCs. The gas moves throughout the reservoir due to the diffusion and hence makes the reservoir more filled with gas which has its own advantages in terms of increasing the oil recoveries and creation of miscible mixtures.
- With the injection of gas, the relative permeability of the hydrocarbons should increase which shall make the flow of hydrocarbons and oil easier towards the surface.
- With the injection of gas, there is a reduction in the interfacial tension between the oil and gas phases which results in assistance in the formation of the miscible single mixture. This helps further in the formation of miscible mixture apart from other favorable properties of natural gas.
- Owing to the different viscosity of the oil and gas and with the injection of oil the lower viscosity gas has a beneficial effect towards the total viscosity and flow

characteristics of the system. Hence with the injection of gas, the viscosity of the system is improved and more oil flows.

- The capillary forces play a dominant role in the drainage of oil from reservoir. In the case of unconventional reservoirs with the injection of gas, the capillary forces are reduced and this serves to change the relevant contacts in the wells and hence aid towards the production of hydrocarbons more easily from the reservoirs.
- Via the proper designing of the Natural Gas injection scheme and if injected while keeping the downhole Well head pressure above the dew point pressure then the injection of gas will result in creation of miscible conditions. This shall have beneficial effect on the recovery as that additional liquid will flow towards towards the well. However in order for this recovery mechanism to be applicable and working, it needs to be ensured that the gas is injected at a pressure which is near or above the Dew point pressure.
- If the gas is injected near the dew point then injection above that dew points shall result in the vaporization of the liquid hydrocarbons and hence this additional gas production shall also contribute towards the enhanced recovery of the oil. However for this mechanism to be applicable the gas is required to be injected near the dew point of the reservoir.
- A counter current flow takes place due to the injection of the gas in the unconventional reservoir. This counter current flow especially around the matrix and the fractures assists in lifting the oil and pushes it towards the production well.

- The injection of gas does have an impact on the wettability of the system. With the injection of more gas the wettability of the reservoir is prone to change from that of a more Oil wet to having some mixed wet or water wet characteristics which is more helpful towards increasing the recoveries from the reservoir.
- The light components are removed from the reservoir due to injection and in the course of production. These components help in the production of HCs from the reservoirs.
- With the injection of gas a miscible mixture is created and the same mixture has a lower gravity as compared to the oil which is may be lying on the upper layers of the reservoirs layers. Hence the higher weighing oil moves downwards due to gravity drainage and help in the production of oil towards to the well bore and the production well.

2.6. HUFF AND PUFF INJECTION DYNAMICS

As compared to continuous flooding, Huff and Puff is the recommended method, as this method has a number of advantages and removes the problems associated with the continuous flooding. Firstly, continuous flooding has the issues of conformance control whereby the gas can break through o the producer well as this is obviated by the Huff and Puff injection. Secondly there is a lot of operational flexibility which this method of huff and puff renders and hence this makes this technique successful.

Every investigative method has had a unique setting in which the study was carried out. In some works the amount the most optimum parameters were found out which shall ensure to get the highest recovery rate, however in some cases it was endeavored to find the recovery rate while some gas composition and operational parameters were already provided. In essence the parameters under the control of the operator during the injection of Natural Gas for unconventional Reservoirs for Huff and Puff operations are:

- Injection time
- Soaking time
- Production time
- Amount of gas injected
- Injection rate
- Gas Composition (Not fully controllable if using produced gas, can be maneuvered with usage of Low temperature separation or injection of heavier components)
- Number of wells which can be converted to injectors

Whereas the variables which have an effect on the total success of the methods which are beyond the control of the operator are:

- Injection pressure. Generally, the injection pressure shall be the reservoir pressure whereby with the decrease of the reservoir pressure with production the injection pressure shall also decrease
- Reservoir characteristics. The same play a very important role and vary form case to case.
- Reservoir Oil properties

It is evident that Huff'n'Puff has a number of different parameters and which are in and beyond the control of the operator and are to be taken into consideration for a successful test.

3. DATA ANALYTICS FOR NATURAL GAS UNCONVENTIONAL EOR

3.1. DATA COLLECTION PROCESS FOR NATURAL GAS EOR

Data analysis was carried out for Unconventional Reservoirs EOR via Natural Gas. The data primarily distributed into three sections which are given as

- Core Laboratory Experiments
- Core Scale Simulations
- Filed Scale Simulations

For each of the above mentioned three Data sets, following were the parameters which were investigated.

Table 3-1 Parameters Collected in Data Collection Process

Parameter	Simulation	Core Experiments	Simulation for Core Experiments
Porosity	X	X	X
Permeability	X	X	X
Injection Rate	X		
Injection Period	X	X	X
Soaking Period	X	X	X
Recovery Period	X	X	X
Production Period	X	X	X
Number of Cycles	X	X	X
Recovery Factor Increase	X	X	X
Reservoir Thickness	X		
Reservoir Depth	X		
Reservoir Pressure	X		
Reservoir Temperature	X		
Core Length		X	X
Core Diameter		X	X
Injection Pressure		X	
Depletion Pressure		X	

These were the minimum parameters which were deemed to be essential for reaching results and making the Data analysis process meaningful. There could have been some additional data which could have been included also such as Fracture modelling details, or the Core Laboratory set up data, but that was not available for every study and also would have made it difficult to draw a baseline across the whole data set.

A number of studies and experimental works were analyzed for the data collection process. The Pie chart below highlights the distribution of the sources of studies. A total of 33 papers were analyzed, out of which 21 were relevant to Field Scale Simulation, 9 were relevant to Core Simulation and Experiments whereas 3 were relevant to Pilot Tests.

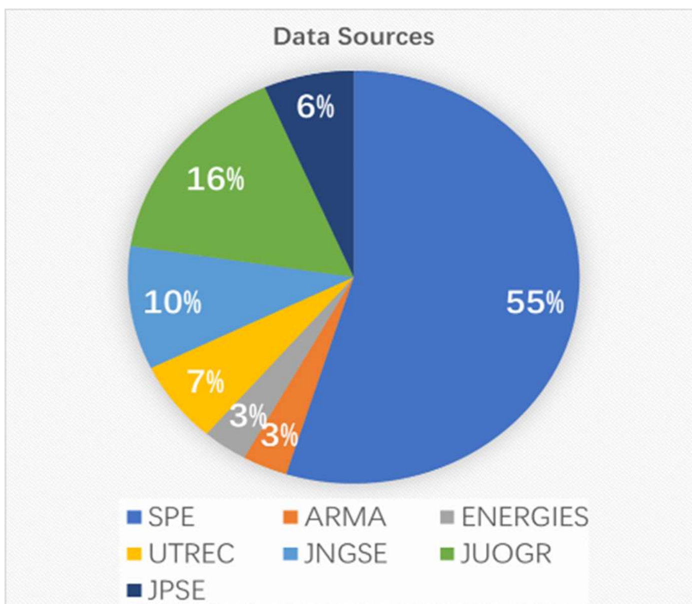

Figure 3-1 Sources of Data used in the Data Collection Process

During the process there were some challenges which were faced. Owing to the fact that this field has not be studied extensively in Literature and Experiments, hence it was observed that the data is scarce. Very few studies highlight this area solely, whereas if data is found, it overlaps with other studies or modes of injection such as continuous flooding, or different gases are used for injection such as Nitrogen, Carbon-di-oxide etc. It was also seen that having a baseline across all the studies is difficult as each study tend to handle this topic in its own manner. As a result, some of the variables, were always found to be missing in a particular study. Thereby, it was endeavored then to find those parameters is some different studies or works which have similar modes of investigation or experimental setting. In addition, one of the most main challenge was to enter the data in the data base. As all the data was extracted from the studies hence it had to be manually entered, which was a time consuming and a laborious process.

It was endeavored to make the Data collection and presentation most methodological and systematic as possible. Each of the record, collected was given a unique number on the basis of the Paper from which is was derived. All the relevant operational parameters were clearly mentioned, while also having the reservoir, area, pressure and field in the data. Recovery factor was clearly mentioned on each of the record which made it clear that different operational parameters and settings delivered different results. A total of 2400 records were collected which included both the Core and Field Scale Simulation studies.

Table 3-2 Data Collected Records, with each Record Having a Separate Number

Formation	Record Number	Porosity	Depth	Thickness	Permeability
Wolfcamp	SPE-180219-MS-1	6	6000	150	0.005
Wolfcamp	SPE-180219-MS-2	6	6000	150	0.005
Wolfcamp	SPE-180219-MS-3	6	6000	150	0.005
Wolfcamp	SPE-180219-MS-4	6	6000	150	0.005

Table 3-3 Data Collected Records, with each Record Having a Separate RF

Injection Rate MMSCFD	Injection Pressure Psig	Injection Period Days	Soaking Period Days	Production Period Days	Number of cycles	RF increase %
5	4000	25	20	100	1	2
5	4000	25	20	100	2	5
5	4000	25	20	100	3	10
5	4000	25	20	100	4	20
5	4000	25	20	100	5	33
5	4000	25	20	100	6	45
5	4000	25	20	100	7	65
4	4000	25	20	100	1	2
4	4000	25	20	100	2	7
4	4000	25	20	100	3	13
4	4000	25	20	100	4	25
4	4000	25	20	100	5	33

3.2. GENERALIZED OBSERVATION OF STUDIES ANALYZED

The studies, while being different in their manner of application and investigation of the topic, had some similarities and key observations which are given below:

- Almost all the works whether using simulation or the laboratory methods do confirm the potential and greater recoveries achieved by the natural gas technique.
- Every study has targeted a particular region of reservoir with some particular operational setting while having SRV and Non- SRV regions.
- Some works try to find the most optimum operational parameters such as the most optimum gas compositions, most optimum huff and puff cycles whereas some studies try to gauge the results which shall be achieved by the injection of some particular gas composition or Gas Volume.

- Both the modes of injection that is huff and puff and Gas flooding have been found to be used in the studies, however the more preferential one has been gas huff and puff, with most studies targeting the huff and puff setting. Mostly it has been seen that Huff and Puff is successful in Unconventional reservoirs, whereby Continuous flooding has drawback and is not that successful.
- The formations as investigated in the core studies have been found to be Wolfcamp, Bakken and Eagle Ford.
- The formations as investigated in the simulations studies have been found to be mainly Bakken, Eagle ford and Niobrara Shale.
- For the majority of simulation studies the simulator which has been used is CMG GEM.
- The model deployed for simulations has been primarily dual porosity model.

3.3. RESULTS, SINGLE VARIANT & RELATIONSHIP ANALYSIS

As per the three data sets which have been collected for the study, the results have also been generated as per the three data sets as discussed. For each, the results are presented in the form of Histograms, Box plots, Single Variant Analysis as well as the relationship and cross plot analysis.

3.3.1. Core Laboratory Experiments Core lab experiments mean the experiments in which cores from unconventional reservoirs were brought in for analysis via laboratory infrastructure. All the Core which were analyzed were mainly for Wolf camp, Eagle Ford and Bakken. No other core analysis studies were found.

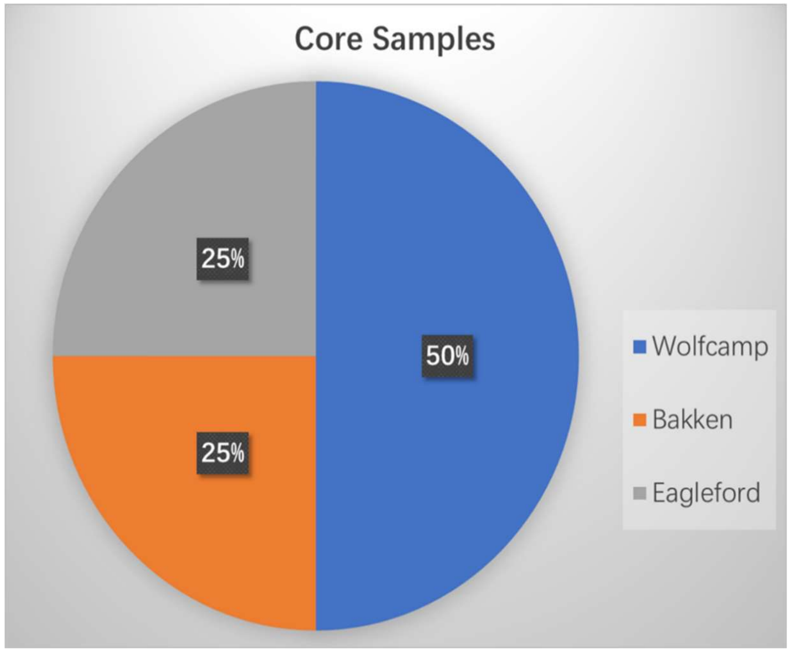

Figure 3-2 Distribution of Formation Investigated in Core Lab Experiments

3.3.1.1. Histograms. Histograms are used to display the dataset graphically and to depict the sampling distribution of the dataset. Figure 3-3 illustrates the dataset for the distribution of Core Permeability and Core Porosity for Core lab experiments. For Core Permeability the Histogram shows a single peak with a unimodal shape (single recurring groups of numbers). The peak includes Core permeability values between 0.0003 and 0.0005 mD, and the second peak contains values between 0.0001 and 0.0003 mD. Based on this result, the core which were used had their permeability mainly in between 0.0003 to 0.0005 mD. The second Histogram shows the distribution for Core Porosity. The data again shows a unimodal distribution with the majority of the values lying between 8 to 8.5 percent of porosity. The second peak contains values between 7 and 7.5 percent. Based on this result, the cores which were used had their porosity mainly in between 7and 7.5 percent.

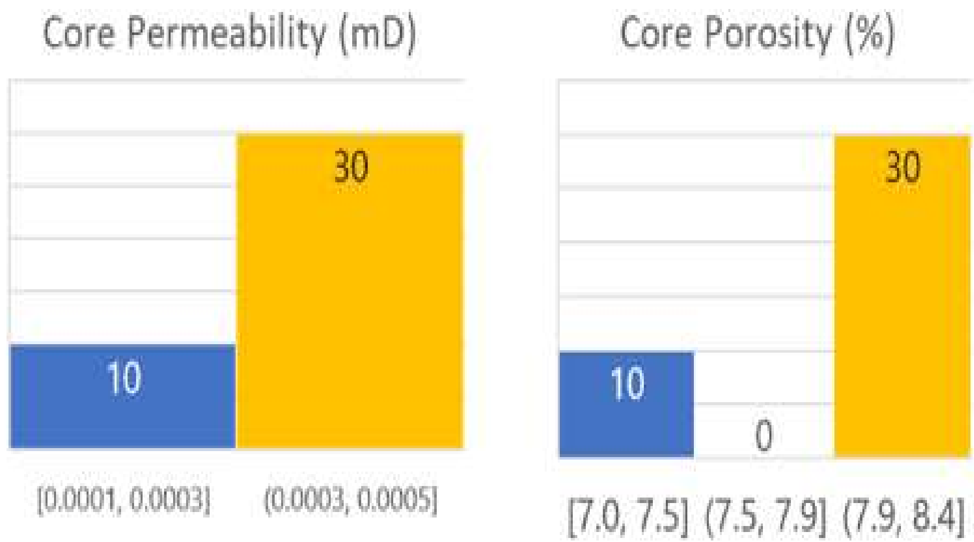

Figure 3-3 Core Porosity (%) and Permeability (mD) for Core Experiments

Figure 3-4 illustrates the dataset for the distribution of Core diameter and Core length for Core lab experiments. For Core diameter the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes Cores having diameter values between 1 and 2 Inches, and the second peak contains values between 3 and 4 Inches. Based on this result, the core which were used had their diameter mainly in between 1 and 2 Inches. The second Histogram shows the distribution for Core Porosity. The data again shows a unimodal distribution with the majority of the values lying between 2 and 2.2 Inches that is the length of the cores. The second peak contains values between 2.4 and 2.7 Inches Based on this result, the cores which were used had their length mainly in between 2 and 2.2 Inches. This result also shows that generally the cores which were used were indicative of lab equipment limitations.

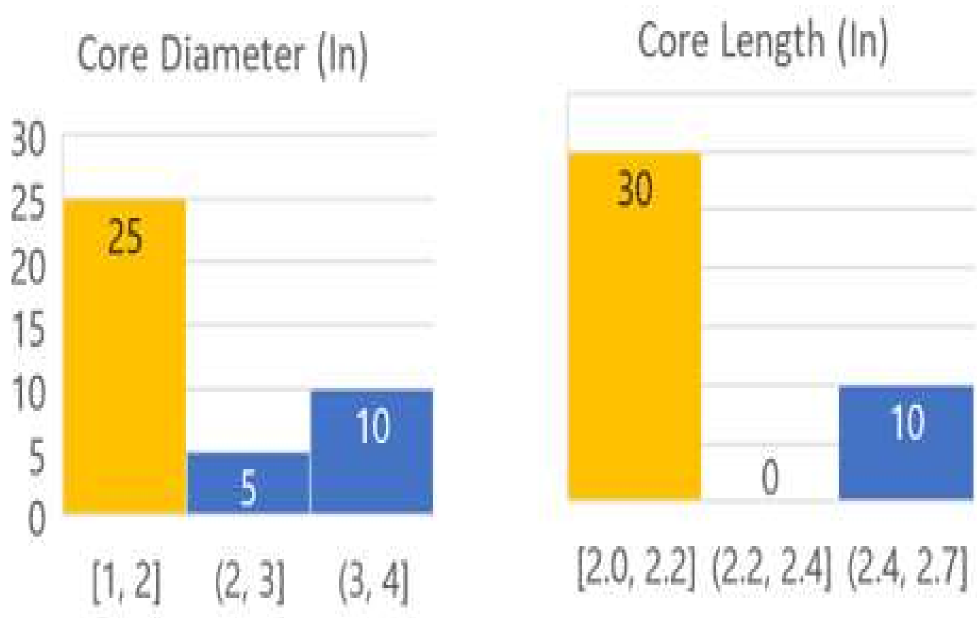

Figure 3-4 Core Diameter (In) and Core Length (In) for Core Experiments

Figure 3-5 illustrates the dataset for the distribution of Injection pressure and Depletion Pressure for Core lab experiments. For Injection pressure as well as the depletion pressure, the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes Injection pressure value between 2000 and 2100 Psi. The second peak contains values between 2100 and 2200 Psi. Based on this result, the majority of the cores had their injection pressure in between 2000 and 2100 Psi. The second Histogram shows the distribution for Depletion pressure. The data again shows a unimodal distribution with the majority of the values lying between 15 to 760 Psi. The second peak contains values between 760 to 1400 Psi. Based on this result, the cores which were used had their depletion pressure between 15 and 760 Psi with second peak being in between 760 to 1400 Psi.

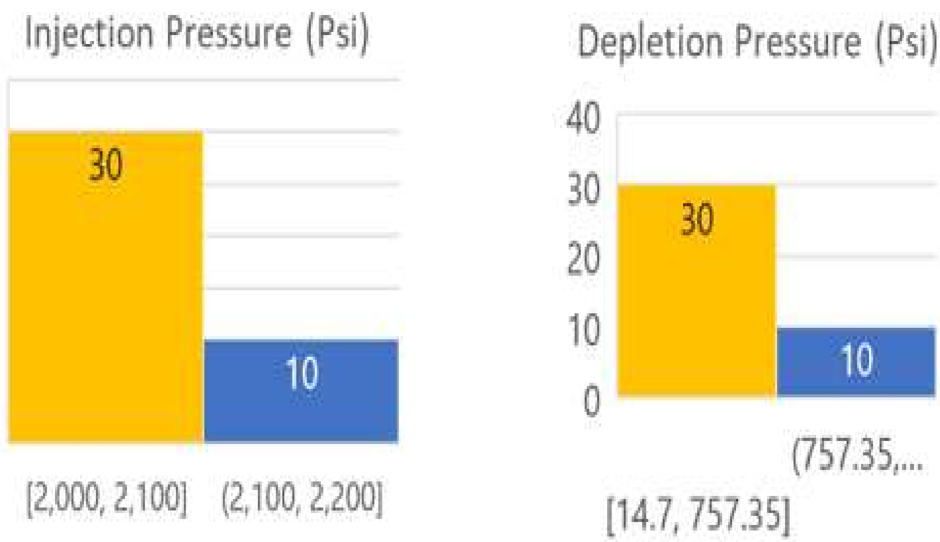

Figure 3-5 Injection Pressure (Psi) and Depletion Pressure (Psi) For Core Experiments

Figure 3-6 illustrates the dataset for the distribution of Injection period and soaking period for Core lab experiments. For Injection period as well as the soaking period, the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes injection period values between 0.24 to 0.93 hours. For the second peak, we have two peaks and they contain values between 0.93 to 1.62 hours and 1.62 to 2.31 hours. Based on this result, the majority of the cores had their injection period in between 0.24 and 0.93 hours. The second Histogram shows the distribution for soaking period. The data again shows a unimodal distribution with the majority of the values lying between 0.9 and 1.35 hours. The second peak contains values between 0 and 0.45 hours. Based on this result, the soaking period for cores used was between 0.9 and 1.35 Hours.

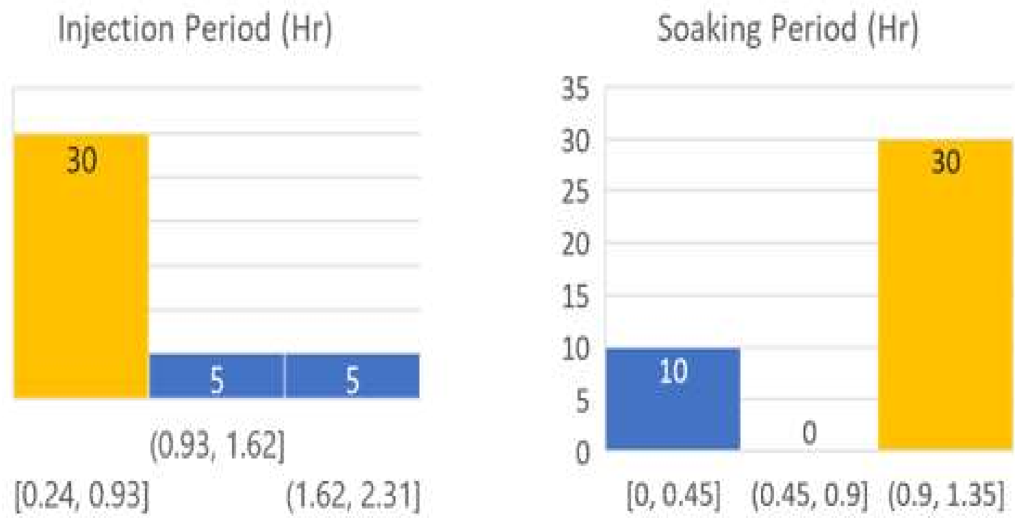

Figure 3-6 Injection Period (Hr) and Soaking Period (Hr) For Core Experiments

Figure 3-7 illustrates the dataset for the distribution of Number of cycles and Recovery Factor for Core lab experiments. For number of cycles the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes cycle value between 1 and 2. Then for the second peak we have three peaks with valies between 2 and 3, 3 and 4 and between 4 and 5. Based on this result, the majority of the cores had their number of cycles between 1 and 2. The second Histogram shows the distribution for recovery factor. The data shows a bimodal distribution with the majority of the values lying between 25 and 42 percent. The second peak contains values between 8 and 25 percent and the number of values are very close to the first peak. Based on this result, the cores which were used had their recovery factors between 25 and 42 %.

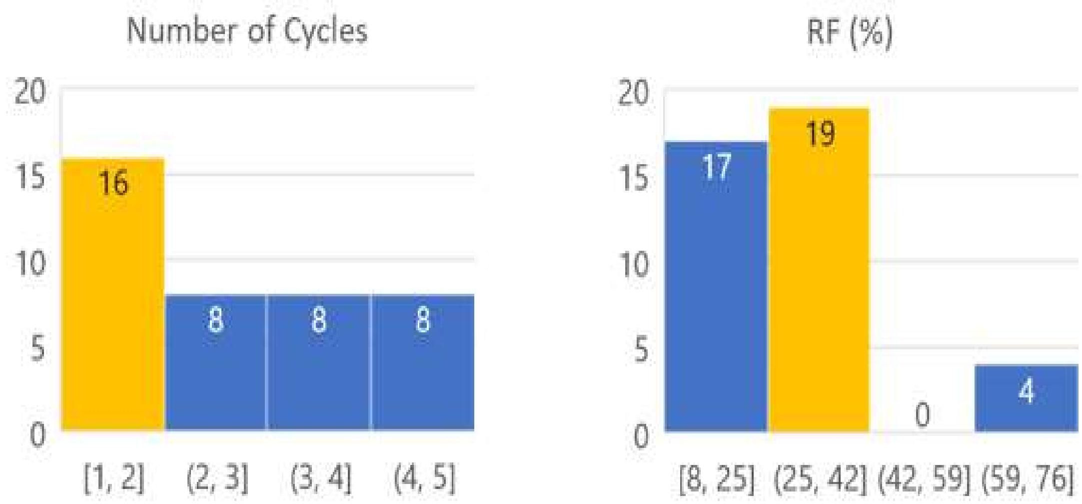

Figure 3-7 Number of Cycles and Recovery Factor

Figure 3-8 illustrates the dataset for the distribution of Production period and CI component of injected gas for Core lab experiments. For both the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes production period values between 0.2 and 0.3 hours. The second peak contains values between 0 and 0.1 hours. Based on this result, the majority of the cores had their production period in between 0.2 and 0.3 hours. The second Histogram shows the distribution for C1 component. The data again shows a unimodal distribution with the majority of the values lying between 90 and 95 % of C1 component in injection gas. The second peak contains values between 85 and 90 %. Based on this result, the cores had their injection gas in between 95 and 100 % of C1 component. This shows the mainly lean gas was used for injection purposes with slight variants of having C2 or C3 components, however being less then 5%.

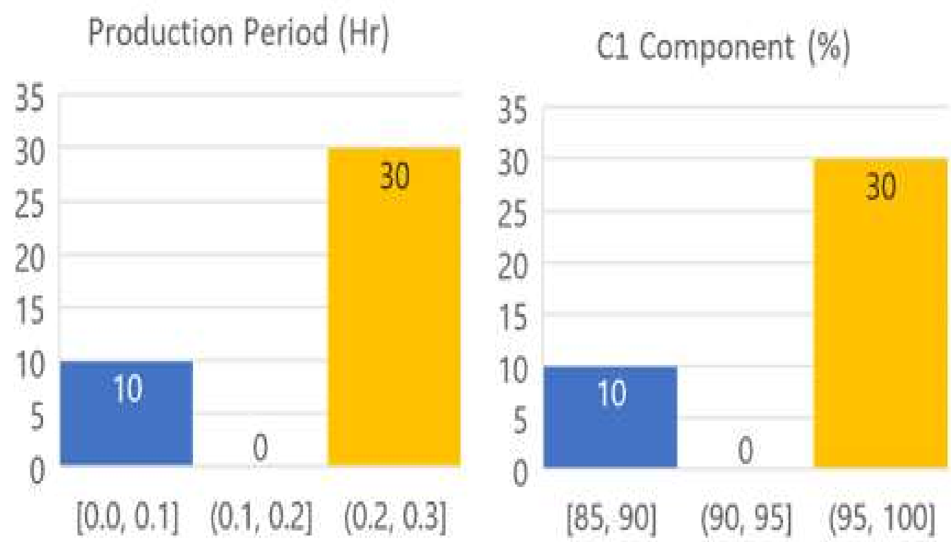

Figure 3-8 Production Period and C1 Component (%)

3.3.1.2. Box plots. For core permeability we can see that the mean of the values lies at 0.0004 mD. The maximum value in the data set is 0.0005 and the minimum value is 0.0001, where the inter quartile range is between 0.0002 to 0.0005 mD. For core Porosity, the Interquartile range is from 7.2 to 8 percent, whereas the mean of the values is 7.8 inches. The maximum value used for the porosity is 8 whereas the minimum value is 7. For temperature the mean of the values in 88 Degree F. The maximum value is 95 Degree F and the minimum value used is 68. Inter quartile range for the values is from 74 to 95 Degree F. For depletion pressure mean of the lies at 400 Psi. The minimum value is 0 whereas the maximum value is 1100 Psi and the interquartile range for depletion pressure is from 20 to 1100 Psi. It needs to be noted that the inter quartile range for the pressure is seen to be a bit extended which shows the distribution of the data being well disperse.

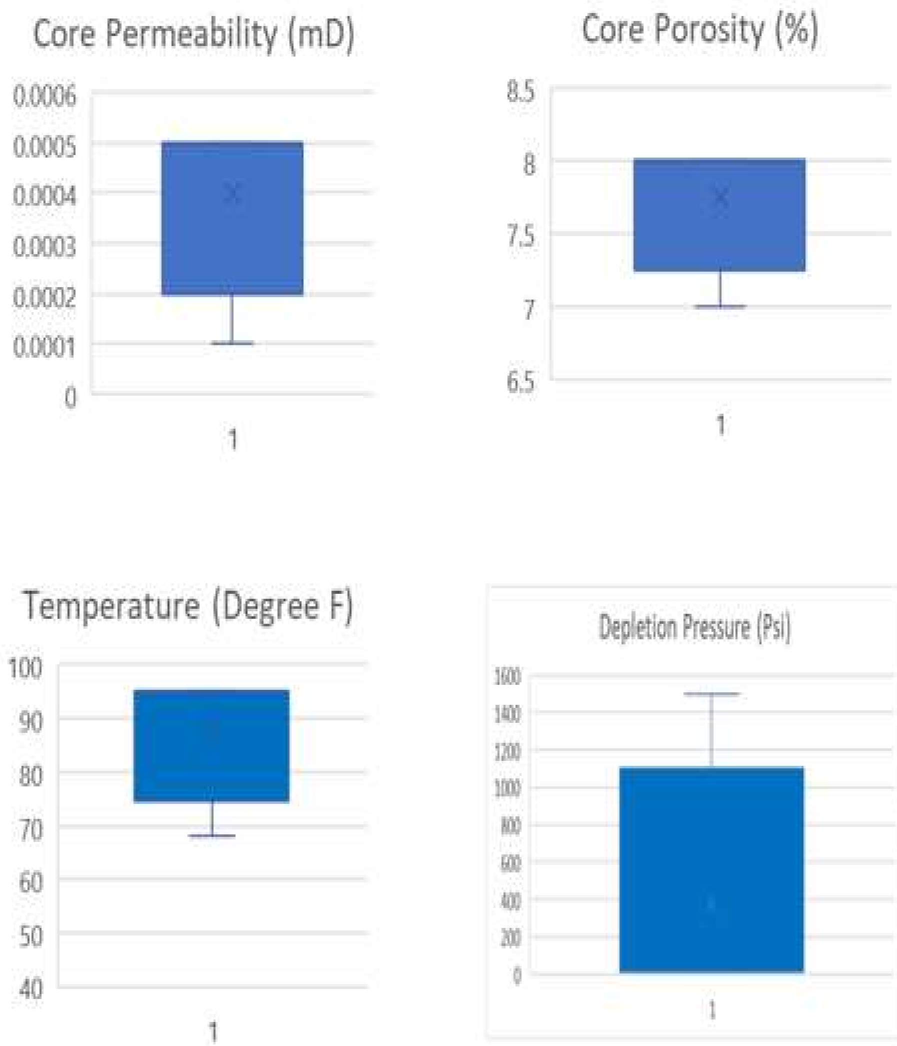

Figure 3-9 Data Ranges for Permeability, Porosity, Temperature, Depletion Pressure

For core diameter we can see that the mean of the values lies at 2.3 inches. The maximum value in the data set is 1 and the minimum value is 4, where the inter quartile range is between 1 to 4 inches. For core length, the Interquartile range is from 2 to 2.4, whereas the mean of the values is 2.2 inches. The maximum value used for the core length is 2.5 whereas the minimum value is 2. For injection pressure the mean of the values in 2050 Psi. The maximum value is 2200 Psi and the minimum value used is 2000. Inter quartile range for the values is from 2000 to 2150. For C1 component the mean value is 94 percent. The minimum value is 85 whereas the maximum value is 100 percent.

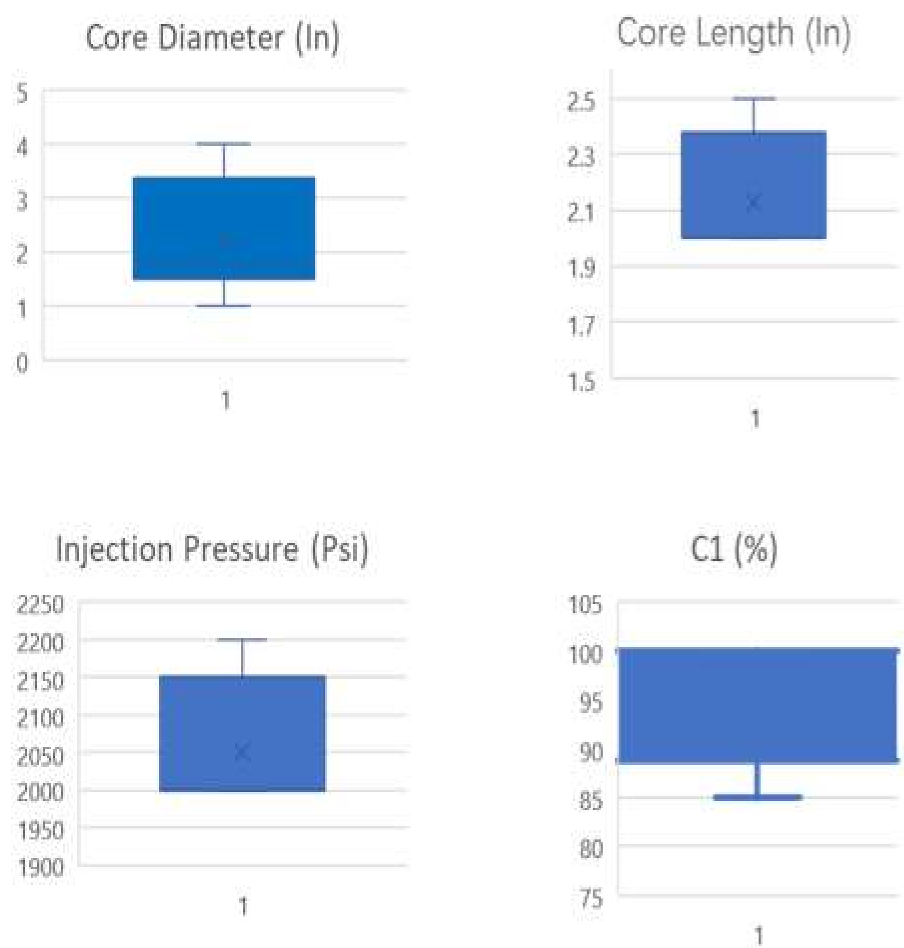

Figure 3-10 Data Ranges for Core Dia, Length, Injection Pressure and C1 %

For production period we can see that the mean of the values lies at 0.17 hours. The maximum value in the data set is 0.24 and the minimum value is 0.06, where the inter quartile range is between 0.06 to 0.24 hours. For injection period, the Interquartile range is from 0.2 to 1.2, whereas the mean of the values is 0.6. The maximum value in the data set is 2 whereas the minimum value is 0.2. For number of cycles all the experiments were seen to be composed of 5 cycles and hence the mean, median of the data was 5. For recovery factor the mean of the values was found to be 25 and the median 28. The maximum value is 37 and the minimum value 20. Inter quartile range for the values is from 19 to 36.

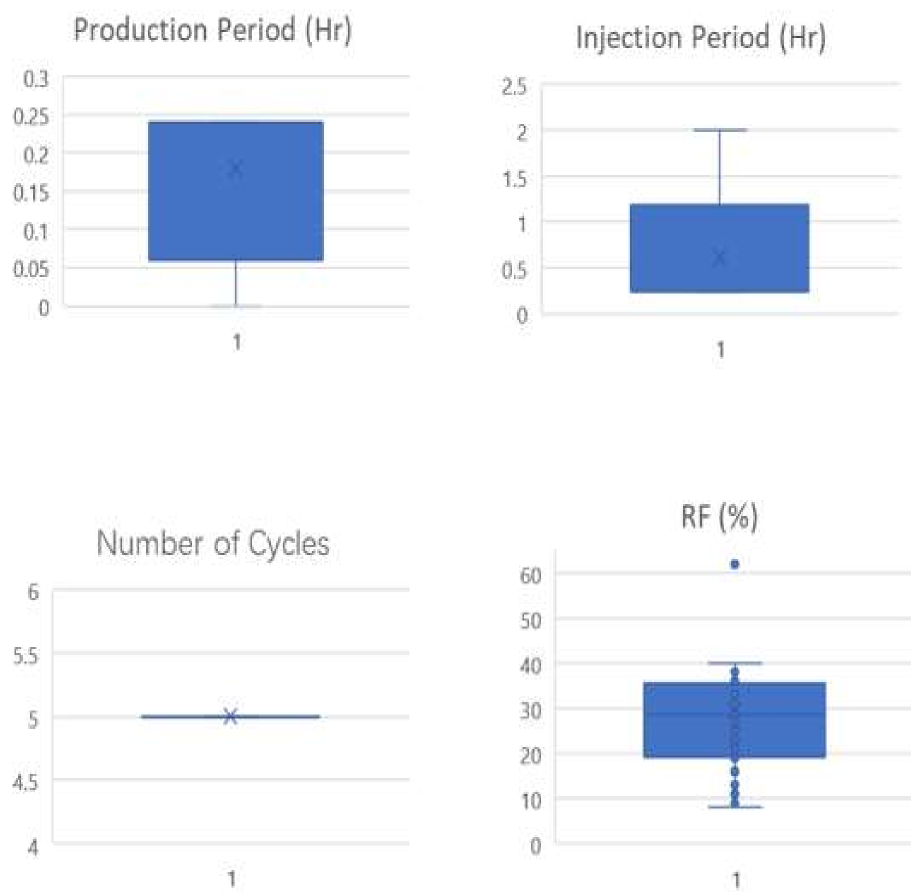

Figure 3-11 Data Ranges for Cycle Timings and RF

3.3.1.3. Single variant analysis. Via single variant analysis the statistical details of the dataset can be collected which can aid in designing new experiments in the future.

Table 3-4 Single Variant Analysis for Core Lab Experiments

Parameter	Min	Max	Mean	Median	Std. Dev.
Core Length (Inches)	2	2.5	2.125	2	0.22
Core Diameter (Inches)	1	4	2.25	1.75	0.16
Core Permeability (mD)	0.0001	0.0005	0.0004	0.0005	0.0001
Core Porosity (%)	7	8	7.75	8	0.43
Injection Pressure	2000	2200	2050	2000	87
Depletion Pressure (Psig)	14.7	1500	381	14.7	624
Temperature (Degree F)	68	95	88	95	11.8
C1 Component (%)	85	100	96	100	6.57
Number of Cycles	1	5	3	3	1.43
Injection Period (Hrs)	0.24	2	0.61	0.24	0.67
Soaking Period (Hrs)	0	1	0.75	1	0.43
Production Period (Hrs)	0	0.24	0.18	0.24	0.1

Some interesting results can be derived from the single variant analysis. The mean length and diameter of the cores which have been investigated in the core lab experiments is 2.1 and 2.2 inches respectively. The core length does not show much variation, however different types of diameters of cores have been investigated in literature with bigger range. The mean permeability of the core is 0.0004 mD which is very low, and typical of unconventional reservoirs. The mean porosity of the core is 7.75 percent. The mean of the injection pressure is 2050 Psi and the mean of the temperature is 88 Degree F. Most of the records have lean gas as being injected, whereas the minimum C1 component was seen to be as 85 %. The mean of the cycles is 3 cycles and the there were some records which had no soaking period with the mean for the injection, soaking and production periods being 0.6, 0.87 and 0.18 hours respectively.

3.3.1.4. Key relationships and dependencies. For the different parameters as collected, the data was analyzed and explored to find out the different parameters effect on the recovery Factor. It was emphasized that the relationship with RF is explored and how an increase in decrease in a parameters effects the RF value.

Upon investigation the first relationship which was found out was the dependence of Recovery Factor in the size of the core. As the below graph explains that when the size of the core is increase while keeping all the other injection and experimental considerations the same, it was seen that the recovery factor decreases. Initially, the RF was seen to decrease as a slower rate, whereby decreasing at a greater rate, with the gradual increase of size.

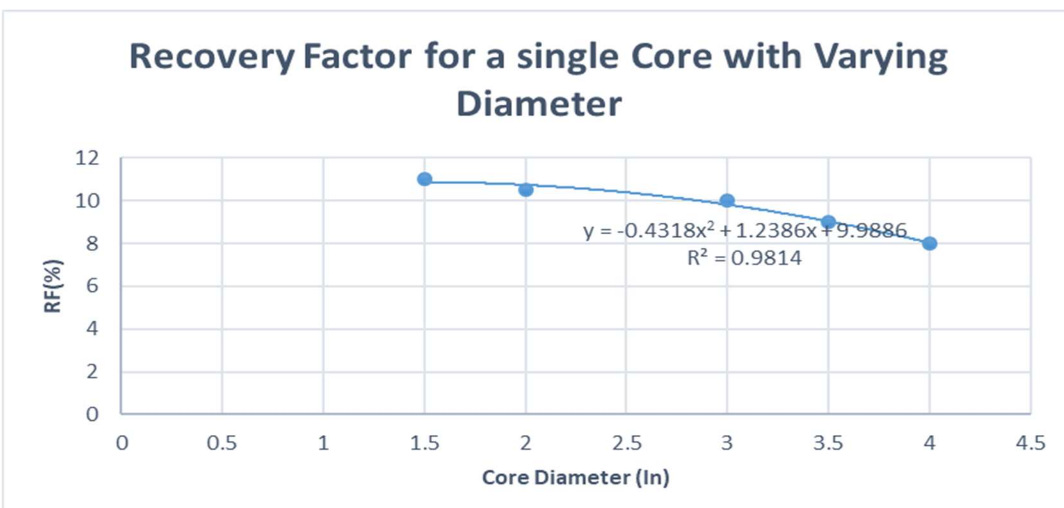

Figure 3-12 Relationship between RF and the Size of the Core

The second main observation has been with reference to the number of cycles. For six core the graph below explains this trend. When the number of cycles increases the recovery factor increases too. This was seen for all the cores. However, the initial cycles show a greater increase in RF, whereby with the cycles increasing as seen later.

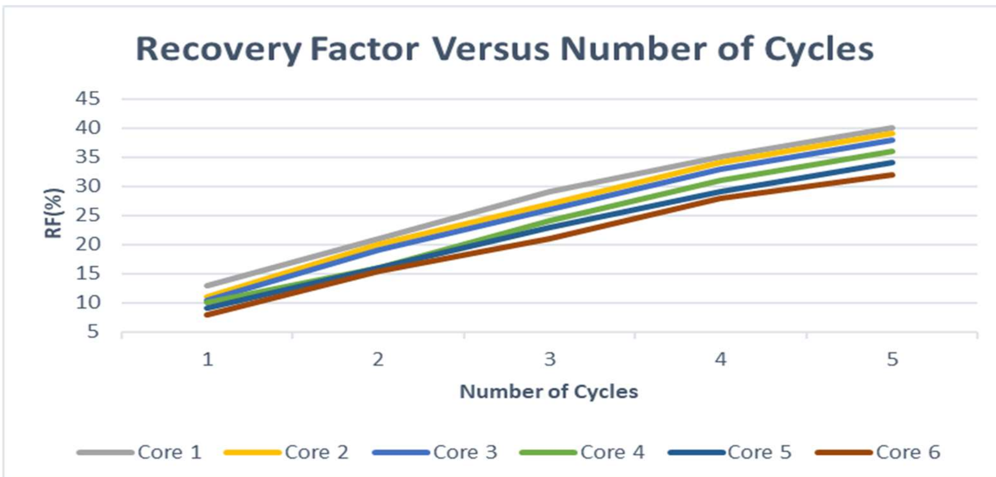

Figure 3-13 Relationship between RF and the Number of Cycles

3.3.2. Core Scale Simulation. Core scale simulations refer to the data set which was collected for the core simulations. This included all the parameters as mentioned before in the document. Core scale simulation refers to the simulation of cores whereby a model is developed, and history matched as per the core saturation and depletion experiments. In the same it is also ensured that the conditions of the cores are matched with those which are in practice in the real experimental settings which includes temperature, pressure, porosity, soaking, production times, etc.

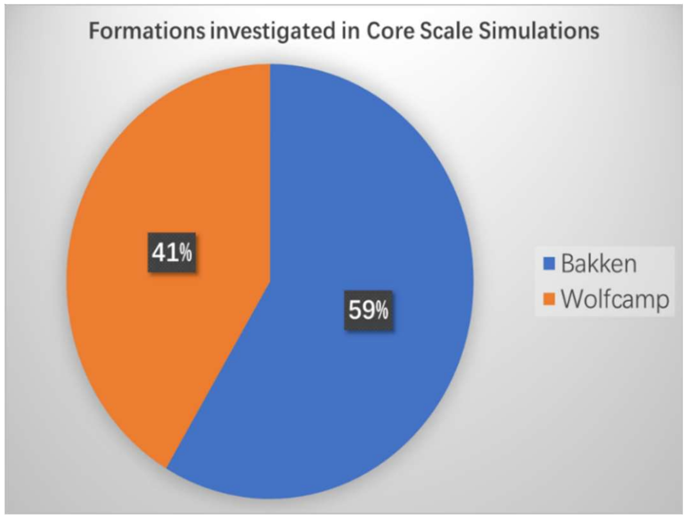

Figure 3-14 Distribution of Formation Investigated in Core Simulations

3.3.2.1. Histograms. The dataset for the distribution of Core Porosity and Core Permeability for Core scale simulations is illustrated by Figure 3-15. First Histogram shows the distribution for Core Porosity. The data shows a bimodal distribution with the majority of the values lying between 5 to 6 percent of porosity. The second peak contains values in around 6 percent. Based on this result, the cores which were used had their porosity mainly in between 5 and 6 percent. For Core Permeability the Histogram shows two closely following peaks with a bimodal shape. The peak includes Core permeability values between 0.0195 and 0.0385 mD, and the second peak contains values between 0.0005 and 0.0195 mD. Based on this result, the core which were used had their permeability mainly in between 0.0195 to 0.0385 mD. This shows that the permeability ranges for the core scale simulation used is higher as compared to the ones used in the core experiments, which were very low and might not be typically seen in the unconventional formations of North America.

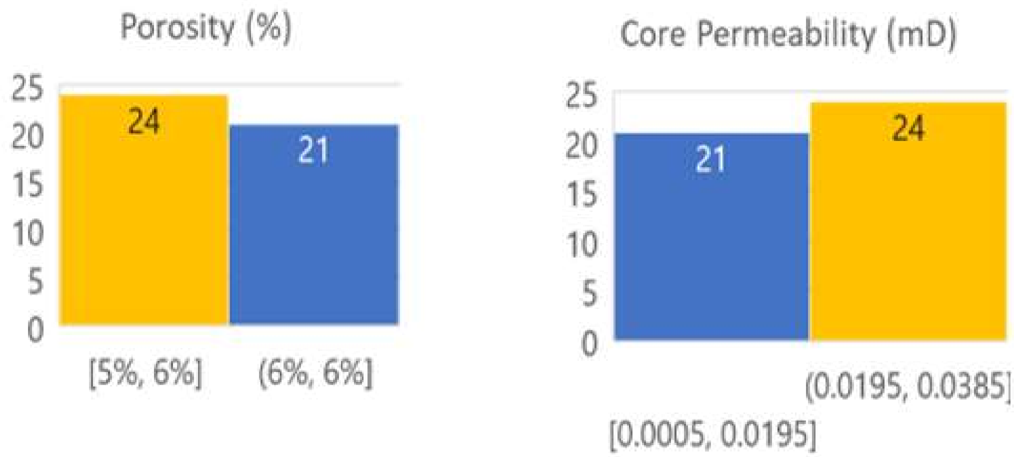

Figure 3-15 Porosity, Permeability for Core Simulations

Figure 3-16 illustrates the dataset for the distribution of Core diameter and Core length for Core scale simulations. For Core diameter the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes Cores having diameter values between 0.5 and 2 Inches, and the second peak contains values between 3.5 and 5 Inches. Based on this result, the cores which were simulated had their diameter mainly in between 0.5 and 2 Inches. The second Histogram shows the distribution for Core Porosity. The data again shows a bimodal distribution with the majority of the values lying between 1.5 and 1.75 Inches. The second peak contains values between 1.75 and 2 Inches. Based on this result, the cores which were used had their length mainly in between 1.5 and 1.75 Inches. This results shows that the cores used in the core simulation had their sizes smaller then the ones used in the core experiments and also the simulations did not investigate the effect of size on the RF, which may be of interest especially for core studies.

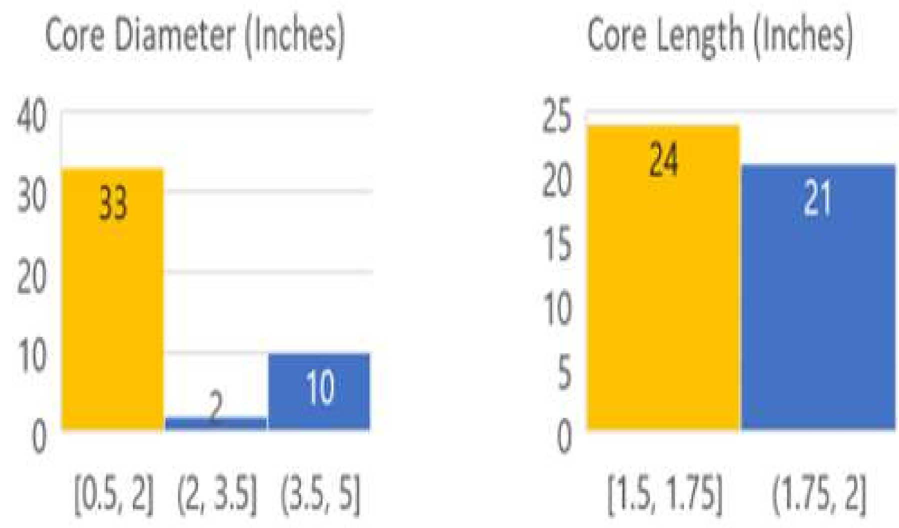

Figure 3-16 Core Diameter (In) and Core Length (In) for Core simulations

Figure 3-17 illustrates the dataset for the distribution of Temperature and Injection pressure for Core scale simulations. For temperature the Histogram shows a single peak with a bimodal shape. The peak includes Cores having values between 68- and 75-Degree F, and the second peak contains values between 88- and 98-Degree F. Based on this result, the cores which were simulated had their temperature mainly in between 68- and 78-Degree F. The second Histogram shows the distribution for Injection Pressure. The data again shows a bimodal distribution with the majority of the values lying between 1500 and 1750 Psi. The second peak contains values between 1750 and 2000 Psi. Based on this result, the cores which were used had their length mainly in between 1750 and 2000 Psi. These pressure ranges are smaller than the ones used in field scale simulations and higher the then the ones used in core simulations. Also, the variation in these variables is not that much as compared to field scale simulation.

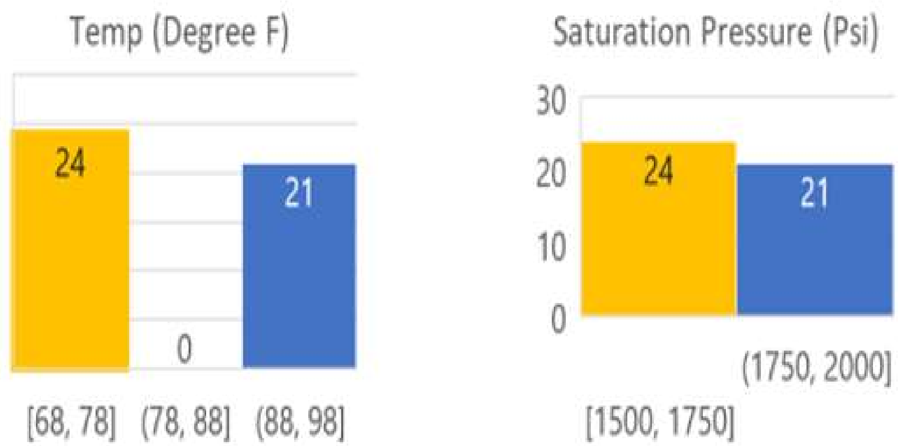

Figure 3-17 Temperature and Saturation Pressure for Core Simulations

Figure 3-18 illustrates the dataset for the distribution of Injection period and soaking period for Core scale simulations. For Injection period as well as the soaking period, the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes injection period values between 15 to 22 days. For the second peak, we have values between 0 to 8 days. Based on this result, the majority of the cores had their injection period in between 15 to 22 hours. The second Histogram shows the distribution for soaking period. The data again shows a unimodal distribution with the majority of the values lying between 0 and 22 days. The second peak contains values between 44 and 66 hours. Based on this result, the soaking period for cores used was between 0 and 22 Hours. Also this shows that for some of the cases soaking period was not even used which might be true for unconventional reservoirs as owing to low permeability then might not be able to soak the gas even with soaking time given.

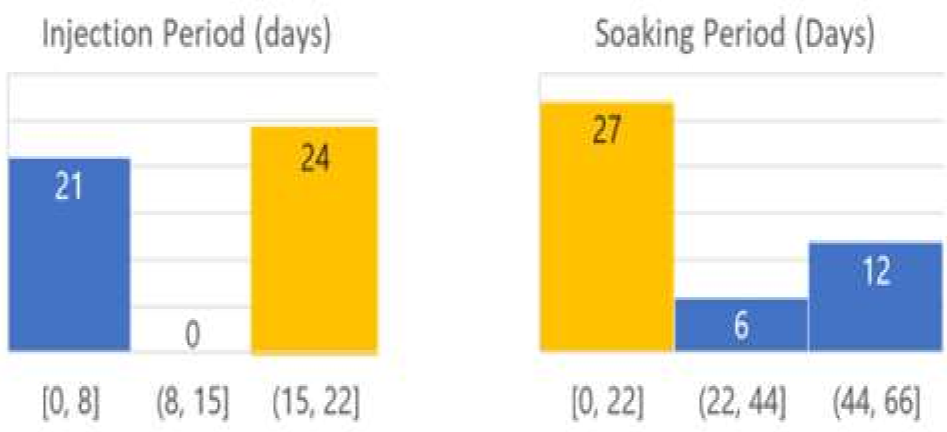

Figure 3-18 Injection Pressure (Psi) and Soaking Period (Days)

Figure 3-19 illustrates the dataset for the distribution of Gas injected and C1% for Core scale simulations. For Injection period as well as the soaking period, the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes injection period values between 15 to 22 days. For the second peak, we have values between 0 to 8 days.   Based on this result, the majority of the cores had their injection period in between 15 to 22 hours. The second Histogram shows the distribution for soaking period. The data again shows a unimodal distribution with the majority of the values lying between 0 and 22 days. The second peak contains values between 44 and 66 hours. Based on this result, the soaking period for cores used was between 0 and 22 Hours. This soaking period was seen to have varying values and as the document further shows that having an optimum soaking period is required for maximum recoveries, whereby no or maximum soaking period does not help in having the recovery factor to the maximum.

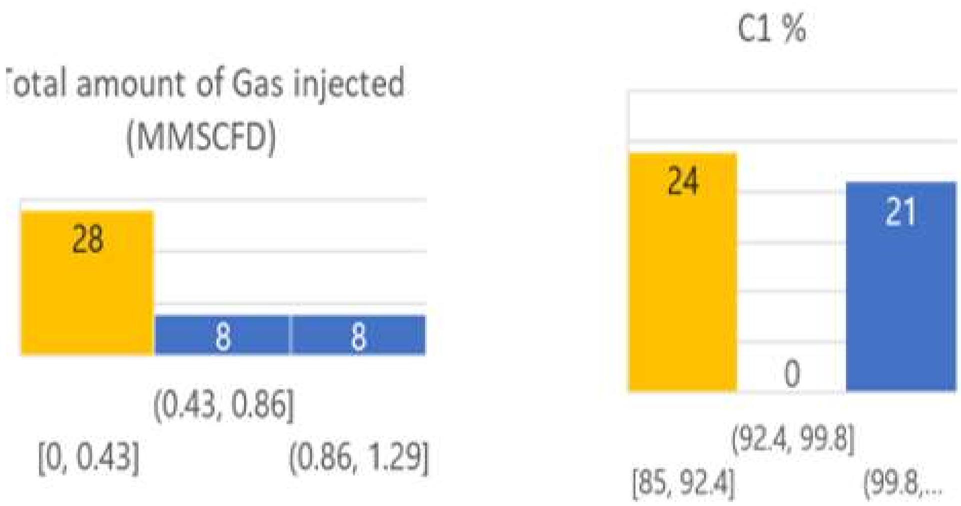

Figure 3-19 Gas Injected and C1 Component for Core Simulations

Figure 3-20 illustrates the dataset for the distribution of Production period and number of cycles for Core scale simulations. For Injection period as well as the soaking period, the Histogram shows a single peak with a unimodal shape (single recurring group of numbers). The peak includes injection period values between 15 to 22 days. For the second peak, we have values between 0 to 8 days.   Based on this result, the majority of the cores had their injection period in between 15 to 22 hours. The second Histogram shows the distribution for soaking period. The data again shows a unimodal distribution with the majority of the values lying between 0 and 22 days. The second peak contains values between 44 and 66 hours. Based on this result, the soaking period for cores used was between 0 and 22 Hours.   It needs to be noted here that the production period for this core simulations is in days and for the core experiments the time is in hours. This shows that how the timing of injection, soaking and production for the core lab experiments were treated at a smaller time scale.

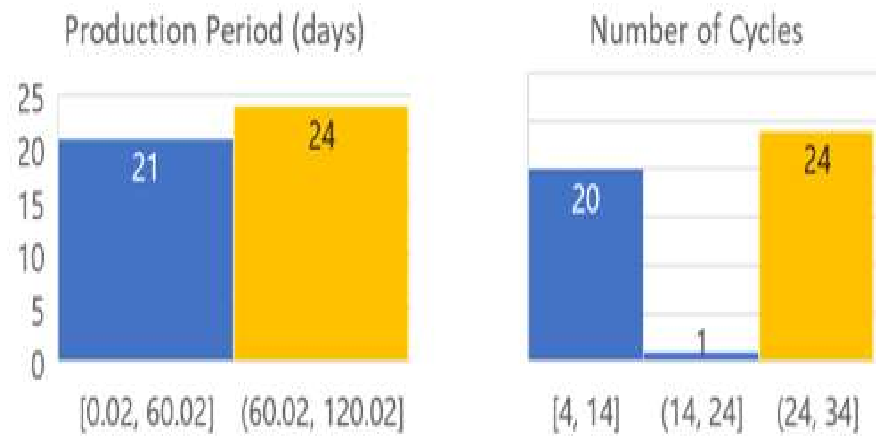

Figure 3-20 Production Period (Days) and Number of Cycles

Figure 3-21 illustrates the dataset for the distribution of Recovery Factor for cycle 1 and cycle 2, which was seen for core scale simulations. For cycle 1 RF we see that the data is has a single peak and most of the data lies between 8 to 17 percent of RF. For the second histogram we can see that the data is bimodal with two peaks having data from 9 to 14 percent as well as from 14 to 19% of recovery factor. Hence, from this the result which we can infer is that during cycle 2 most of the values lie between 9 to 19 %. We can see that RF cycle 2 has to same peaks and hence it is classified as Bimodal distribution. Also the range of the values for both the said peaks is that same hence the distribution has a close similarity. It needs to be noted here that the production period for this core simulations is in days and for the core experiments the time is in hours. This shows that how the timing of injection, soaking and production for the core lab experiments were treated at a smaller time scale as compared to the core simulations.

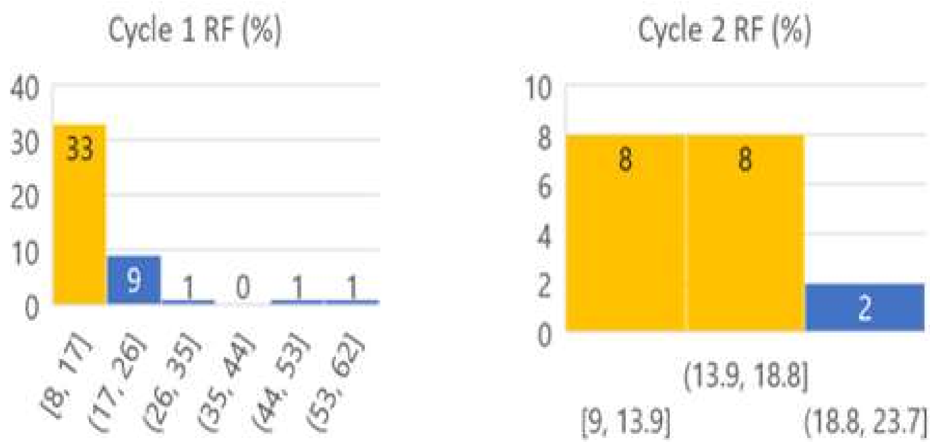

Figure 3-21 Cycle 1 RF and the Cycle 2 RF

3.3.2.2. Box plots. We can see the data distribution information of the box plot for Core Diameters, Core Length, Injection Pressure and temperature in the above box plots. For core diameter we can see that the mean of the values lies at 1.5 inches. The maximum value used for the core diameter is 4 inches, where in inter quartile range is between 0.5 and 3.2 Inches. For core length, the Interquartile range is from 1.5 to two inches, whereas the mean of the core length values is 1.75 inches maximum value used for the core length is 2 inches whereas the minimum value is 1.5 inches. For saturation pressure the mean of the values in 1750 Psi. The maximum value used is 2000 Psi and the minimum value used is 1500 Psi. Inter quartile range for the values in between 1500 and 2000 Psi. For temperature the mean of the values used in the simulation lies at 80 Degree F. The minimum value is 70 Degree F whereas the maximum value used is 98 Degree F. the inter quartile range for temperature used is 65 and 98 Degree

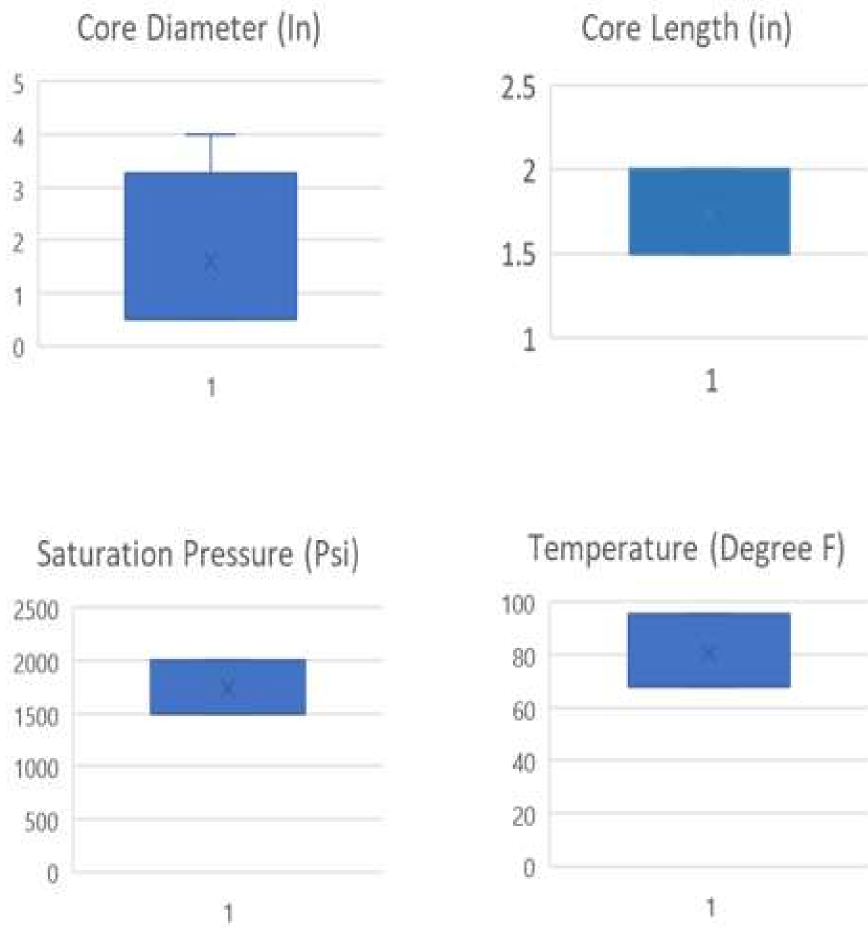

Figure 3-22 Data Ranges for Core Dia, Length, Saturation Pressure and Temperature

We can see the data distribution information of the box plot for Core Porosity, Core Permeability, Injected Gas and C1(%) component of the injected gas. For core Porosity we can see that the mean of the values 6 percent. The maximum value used for the core porosity is 6 % whereas the minimum value is 5 %. The interquartile range is between 5 and 6 Percent. For core permeability, the Interquartile range is from 0 to 0.04 mD. The minimum value used is 0.0002 mD whereas the maximum value is 0.038 mD. The mean of the values is 0.02 mD. For injected gas the minimum value lies at 0.2

MMSCFD and the maximum value lies at 1.2 MMSCFD. The mean of the value is 0.7 and the interquartile range is between 0.4 and 1 MMSCFD. For C1 component of the injection gas, mean value lies at 93 percent and the minimum value lies at 85 whereas the maximum value lies at 100 percent and the interquartile range is between 85 and 100%.

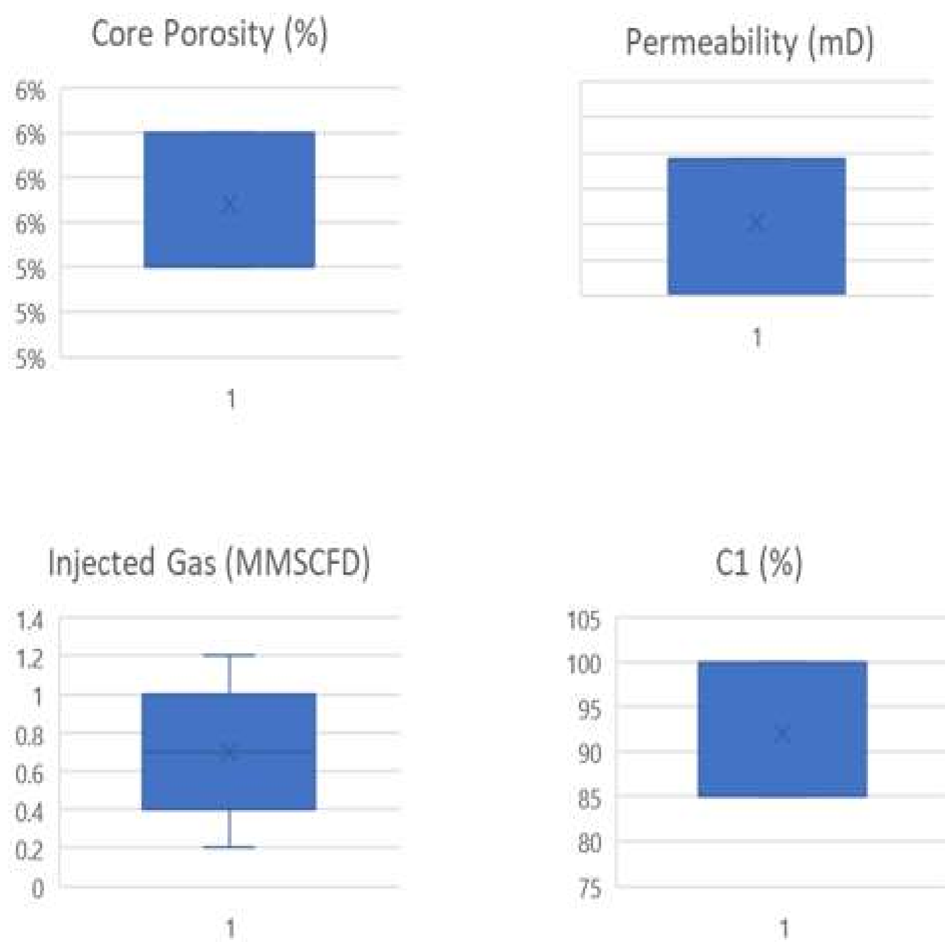

Figure 3-23 Data Ranges for Core Porosity, Permeability, Injected Gas and C1

For injection periods mean of the values is 8 days and the interquartile range is 0.5 to 15 days. The minimum value is 0.5 and the maximum value is 15. For soaking period, we can see that the interquartile range is from 1 to 45 days. The mean of the values is 20 and the median of the values is 15. The minimum value of the soaking period is 0.5 days, whereas the maximum values lies at 60 days. For the recover value of the cycle 1 we see that the mean value is 15 and the medina is 14. The minimum value achieved is 8 whereas the maximum values which has been seen in the data set is 18. The interquartile range is from 10 to 18 days. For the recover value of the cycle 2 we see that the mean value is 23 and the medina is 24. The minimum value achieved is 11 whereas the maximum values which has been seen in the data set is 18.

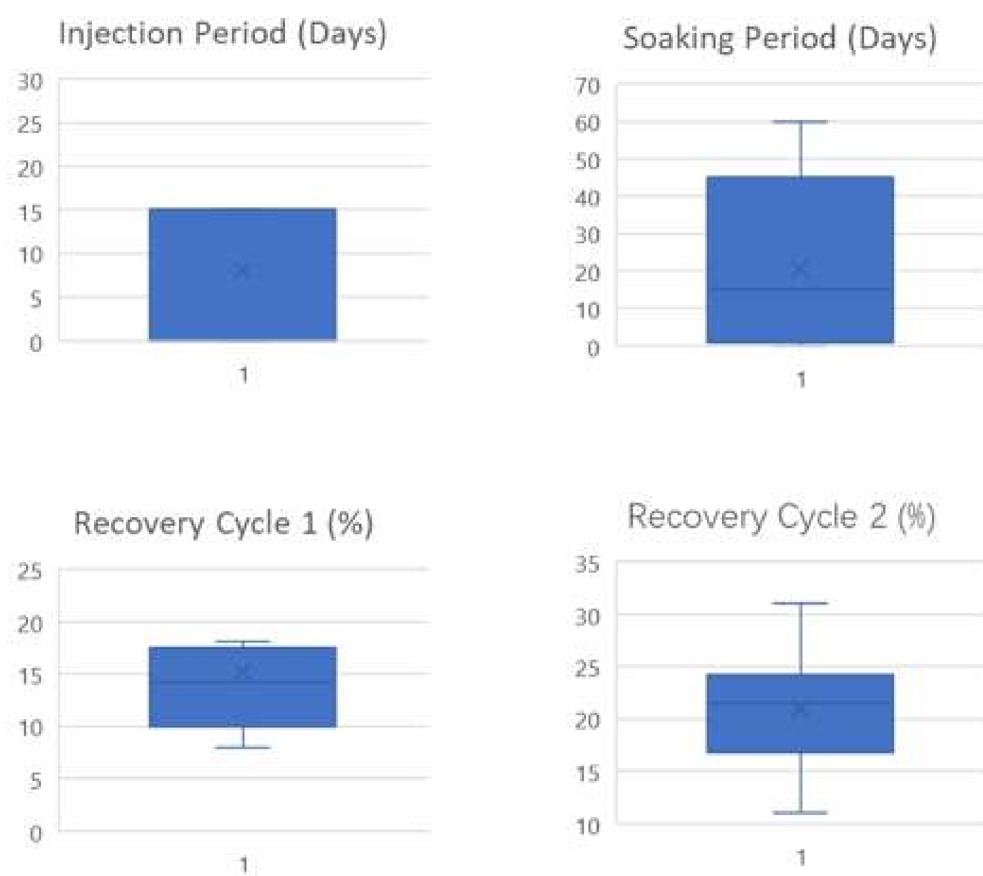

Figure 3-24 Cycle Timings and RF for Core Simulations

For production period mean of the values is 70 days and the interquartile range is 0.5 to 130 days. The minimum value is 0.5 and the maximum value is 120. For number of cycles we can see that the interquartile range is from 12 to 32. The mean of the values is 23 and the median of the values is 17. The minimum value of the cycles is 11, whereas the maximum values lies at 32. For the recover value of the cycle 3 we see that the mean value is 28 and the median is 26. The minimum value achieved is 18 whereas the maximum values which has been seen in the data set is 39. The interquartile range is from 25 to 31. For the recover value of the cycle 4 we see that the mean value is 35 and the medina is 37. The minimum value achieved is 20 whereas the maximum values which has been seen in the data set is 42. The interquartile range is from 27 to 38 days.

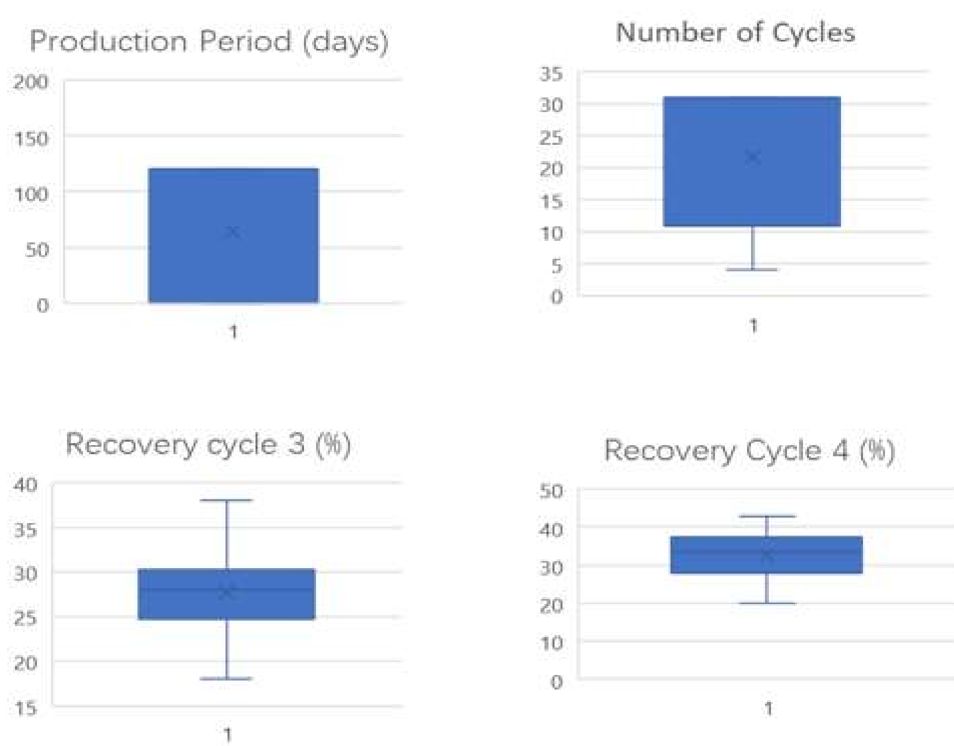

Figure 3-25 Production Period, Number of Cycles and RF for Core Simulations

3.3.2.3. Single variant analysis. Single Variant Analysis for Core Scale simulations is given as below. Some interesting results can be derived from the single variant analysis. The mean length and diameter of the cores which have been investigated in the core lab experiments is 1.73 and 1.6 inches respectively. The mean permeability of the core is 0.0205 mD. The mean porosity of the cores is 5.6 percent. The mean of the injection pressure is 1733 Psi and the mean of the temperature is 81 Degree F. Most of the records have lean gas as being injected, whereas the minimum C1 component was seen to be as 85 %. The mean of the cycles is 22 cycles. The mean for the injection, soaking and production periods was 8, 20 and 64 hours respectively.

Table 3-5 Single Variant Analysis for Core Simulations

Parameter	Min	Max	Mean	Median	Std. Dev.
Core Length (Inches)	1.5	2	1.73	1.5	0.25
Core Diameter (Inches)	0.5	4	1.6	0.5	1.45
Core Permeability (mD)	5E-05	0.038	0.0205	0.038	0.019
Core Porosity (%)	5.4	6	5.6	5.4	0.3
Injection Pressure (Psig)	1500	2000	1733	1500	250
Temperature (Degree F)	68	95	80.6	68	13.62
C1 Component (%)	85	100	92	85	7.5
Total Gas Injected (MMSCF)	0.2	1.2	0.7	0.7	0.39
Number of Cycles	4	31	22	31	10
Injection Period (Days)	0.02	15	8	15	7.54
Soaking Period (Days)	0.04	60	20.4	15	22.19
Production Period (Days)	0.02	120	64	120	60

This analysis indicates that core simulations had different data set with key difference with core experiments, with respect to core size, pressure, timings etc.

3.3.2.4. Key relationships and dependencies. For core scale simulations also, the key relationships and the dependencies were investigated. For the different parameters as collected, the data was analyzed and explored to find out the different parameters effect on the recovery Factor. It was emphasized that the relationship with RF is explored and how an increase in decrease in a parameter, effects the RF value.

Upon investigation the first relationship which was found out was the dependence of Recovery Factor to the amount of the Gas volume injected. As the below graph explains that when the amount of Gas Injected is increase, while keeping all the other injection and experimental considerations the same, it was seen that the recovery factor increases too. Initially, the RF was seen to increase at a greater rate, whereby the rate of increase, decreasing, with the gradual increase in injection volume.

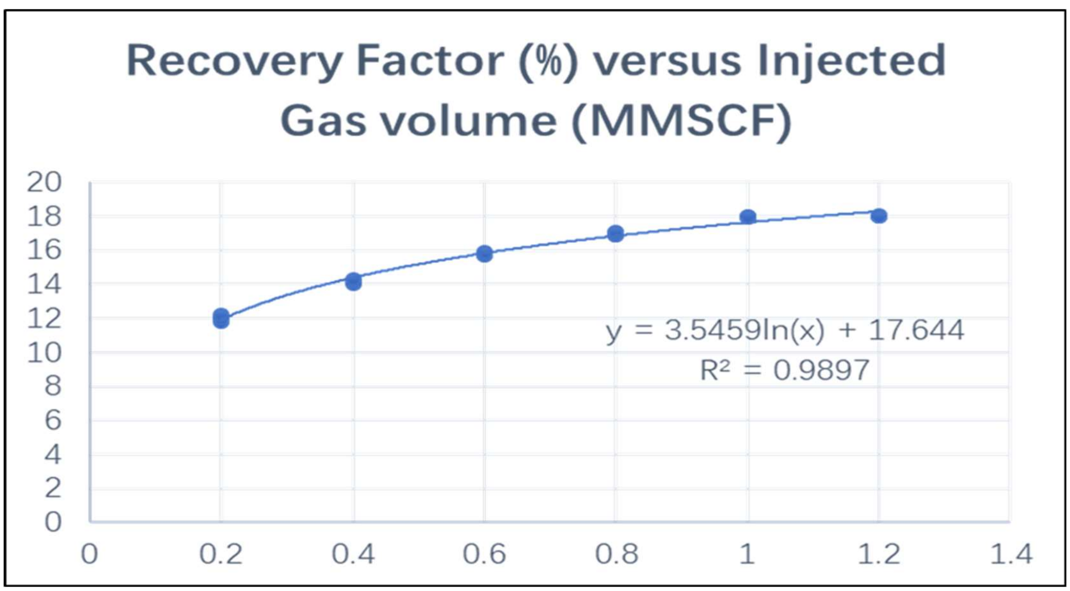

Figure 3-26 Recovery Factors Versus Gas Injected for Core Simulations

The second main observation has been with reference to the number of cycles. For eight cores the graph below explains this trend. When the number of cycles increases the recovery factor increases too. This was seen for all the core. However, the initial cycles show a greater increase in RF, whereby with the cycles seen during the later period.

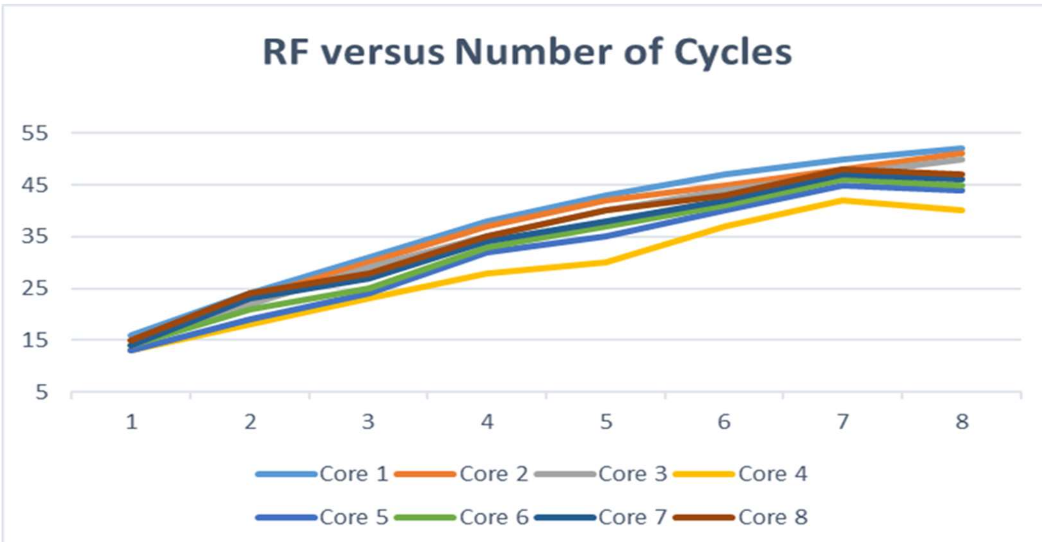

Figure 3-27 Recovery Factor Versus Number of Cycles for Core Simulations

3.3.3. Field Scale Simulation. The third main data set as collected was for the Field Scale Simulations. All the relevant parameters were looked into and collected. Following are the details for the data set. It needs to be noted that this data set was again developed from the papers as mentioned in the above sections. However, only those papers were focused upon which deal with simulation at the filed scale while considering the reservoir scale pressure, temperature, porosity, permeability, saturations etc.

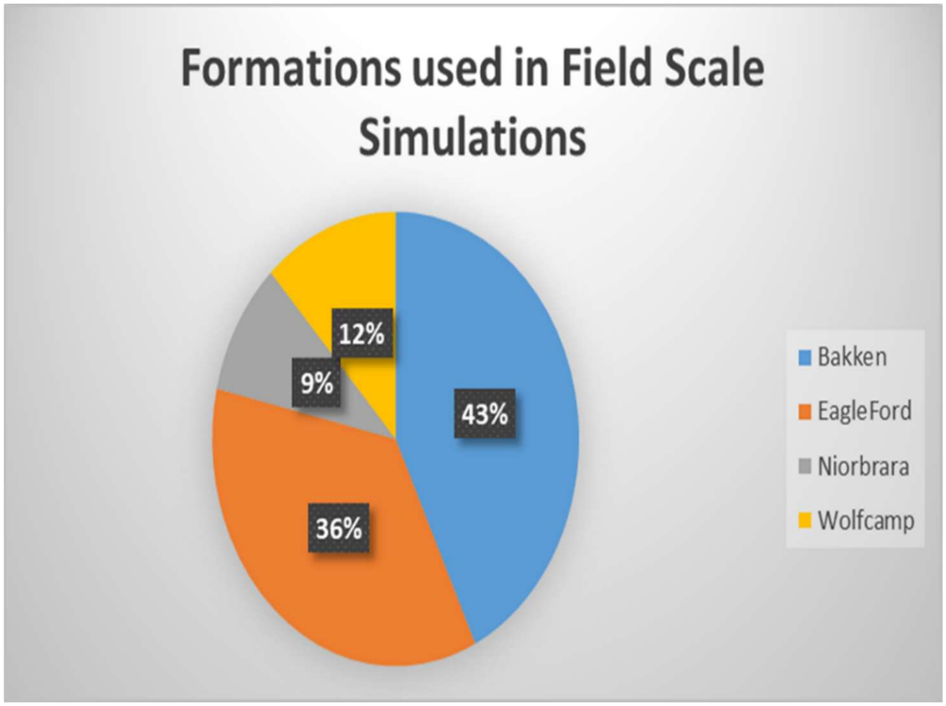

Figure 3-28 Unconventional Formations Modelled

3.3.3.1. Histograms. The dataset for the distribution of Core Porosity and Core Permeability for Field Scale simulations is shown by figure 3-29. First Histogram shows the distribution for Porosity. The data shows a unimodal distribution with the majority of the values lying between 5 to 6 percent of porosity. The second peak contains values in between 7 to 8 percent. Based on this result, the in simulation the records had their porosity mainly in between 5 and 6 percent. For Permeability the Histogram shows a unimodal shape. The peak includes Core permeability values between 0 and 0.0001 mD, and the second peak contains values between 0.001 and 0.002 mD. Based on this result, the the records had mostly their permeability mainly in between 0 to 0.001 mD.

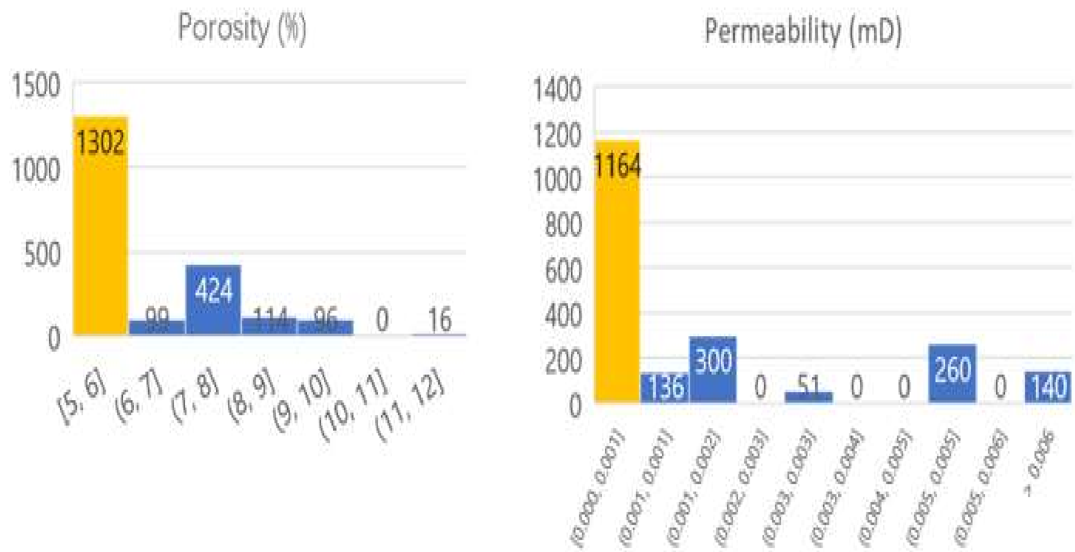

Figure 3-29 Porosity and Permeability Details for Field Scale Simulation

Figure 3-30 illustrates the dataset for the distribution of Reservoir temperature and Reservoir pressure for Field Scale simulations. First Histogram shows the distribution for Temperature. The data shows a unimodal distribution with the majority of the values lying in 150 to 175. The second peak contains values in between 176 to 203 Degree F. Based on this result, the in simulation the records had their temperature between 150 and 176 percent. For reservoir pressure we can see Histogram shows a bimodal shape with two closely related peaks. The peak includes reservoir pressure values between 6400 and 7100 Psi and the second peak contains values between 5700 and 6400 Psi. Based on this result, the records had mostly their reservoir pressure between 6400 and 7100 Psi. As the reservoir pressure is on the higher side, if it is greater the bubble point, we shall see that same will have significant contributions, in terms of generation of additional Oil volumes and increasing recovery factor.

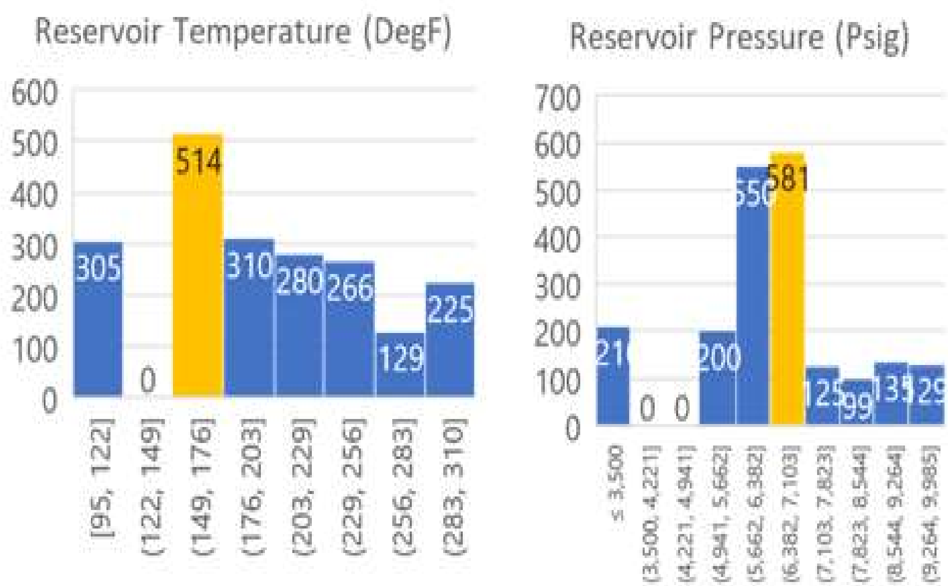

Figure 3-30 Reservoir Temperature and Pressure for Field Scale Simulations

Figure 3-31 illustrates the dataset for the distribution of Injection pressure and Reservoir thickness for Field Scale simulations. First Histogram shows the distribution for Injection pressure. The data shows a unimodal distribution with most of the values lying in 3500 to 4000 Psi. The second peak contains values in between 4500 to 5000 Psi. Based on this result, most of the simulation the records had their injection pressure between 3500 and 4000 Psi. For reservoir thickness we can see Histogram shows a bimodal shape with two closely related peaks. The peak includes reservoir thickness values between 126 and 158 feet and the second peak contains values between 94 and 126 feet. Based on this result, the records had mostly their reservoir thickness between 126 and 158 feet.

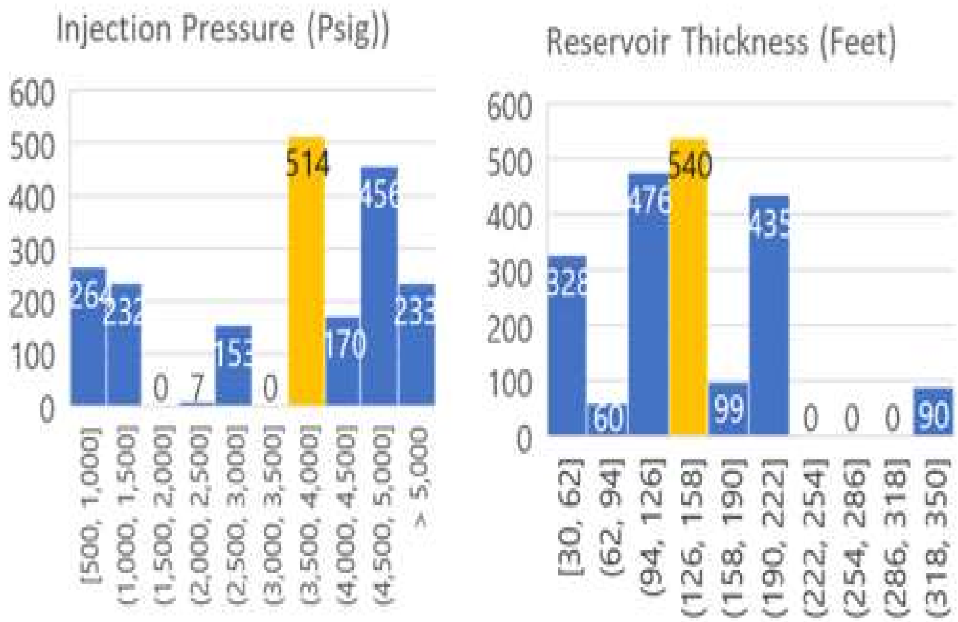

Figure 3-31 Injection Pressure and Thickness for Field Scale Simulations

Figure 3-32 illustrates the dataset for the distribution of C1 component and Injection period (days) for Field Scale simulations. First Histogram shows the distribution for C1 component in injection gas. The data shows a unimodal distribution with the majority of the values lying in between 90 to 100 percent. The second peak contains values in between 70 and 80, however the frequency of the values in the same is very less as compared to the first peak. Based on this result, most of the simulation the records had their C1 component between 90 and 100. For Injection period we can see the Histogram shows a unimodal The peak includes values between 0 and 45 days. For the second peak we have the values between 90 and 135 feet. Based on this result, the records had mostly their injection period between 0 and 45 days.

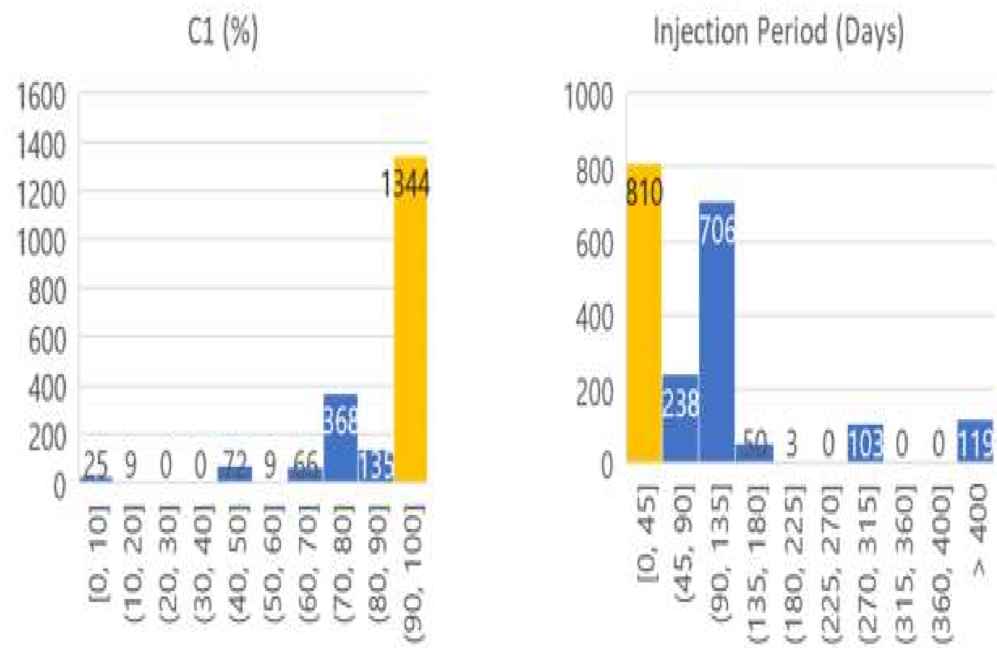

Figure 3-32 Injection Period and C1 % for Field Scale Simulations

Figure 3-33 illustrates the dataset for the distribution of Production period and number of cycles for Field Scale simulations. First Histogram shows the distribution for Production period. The data shows a unimodal distribution with the majority of the values lying in in 65 and 115 days. The second peak contains values in between 15 and 65 days. Based on this result, most of the simulation the records had their production period between 65 and 115 days. For number of cycles we can see Histogram shows a unimodal shape with. The peak includes number of cycle values between 1 and 6 cycles and the second cycle contains values between 6 and 12. Based on this result, the records had mostly their cycle numbers between 1 and 6.

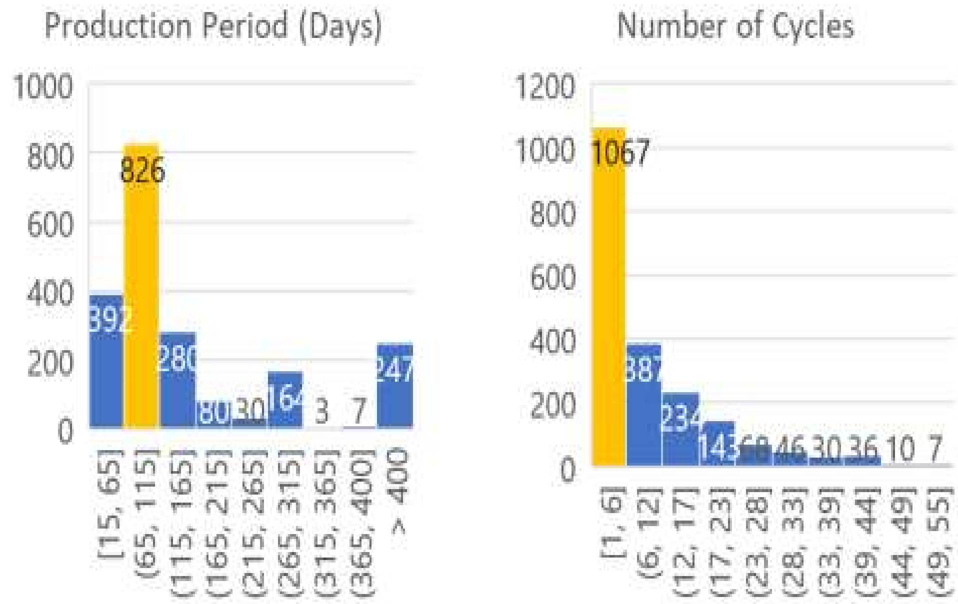

Figure 3-33 Production Period and Number of Cycles for Field Scale Simulations

Figure 3-34 illustrates the dataset for the distribution of Injection rate and RF increase for Field Scale simulations. First Histogram shows the distribution for Injection rate. The data shows a unimodal distribution with the majority of the values lying in from 0 to 1 MMSCFD. The second peak contains values in between 4 to 5, however the amount of records in the same is quite less as compared to the first peak. Based on this result, most of the simulation the records had their injection rate between 0 and 1. For RF increase we can see Histogram shows a unimodal shape. The peak includes RF values between 0 and 4 and the second peak contains values between 4 and 9 %. Based on this result, the records had mostly their RF increment value between 0 and 4. This shows that for most of the cases there was some increase in the RF as compared to base case.

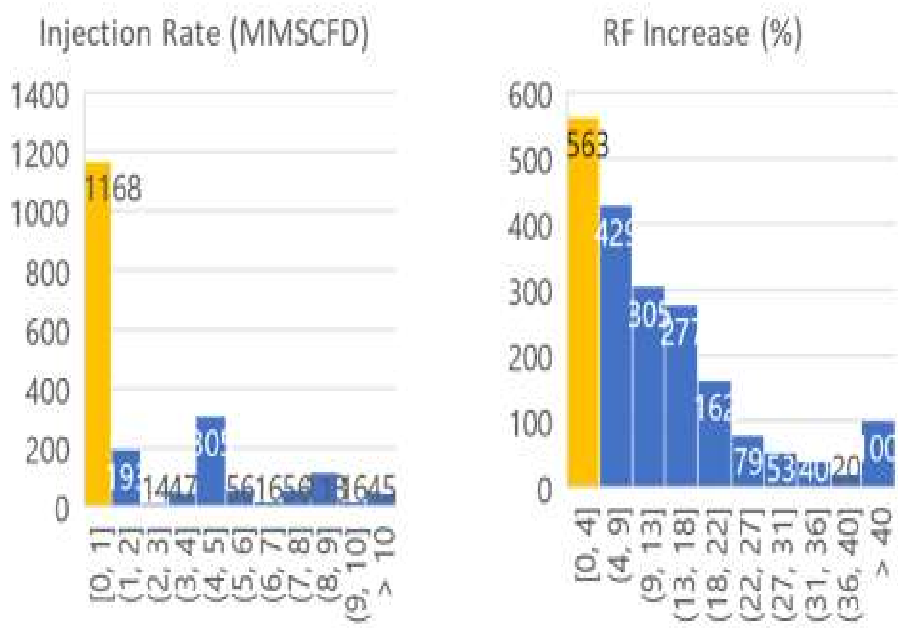

Figure 3-34 Injection Rate and RF Increase for Field Scale Simulations

3.3.3.2. Box plots. We can see the data distribution information of the box plot for Porosity, Permeability, Reservoir pressure and Reservoir temperature in the above box plots. For porosity we can see that the mean of the values lie at 6.8 percent. The maximum value used is 10, whereas the minimum value is 5. Also the inter quartile range is between 6 and 8. For permeability the Interquartile range is from 0.0001 to 0.0015 mD. The mean of the values is 0.0004 mD. The maximum value used is 0.003 mD. For reservoir pressure the mean of the values in 6400 Psi. The maximum value used is 7500 Psi and the minimum value used is 5500 Psi. Inter quartile range for the values in between 6000 and 6500 Psi. For reservoir temperature the mean of the values used in the simulation lies at 180 Degree F. The minimum value is 100 Degree F whereas the maximum value used is 310 Degree F. the inter quartile range for temperature used is from 150 to 240 Degree F.

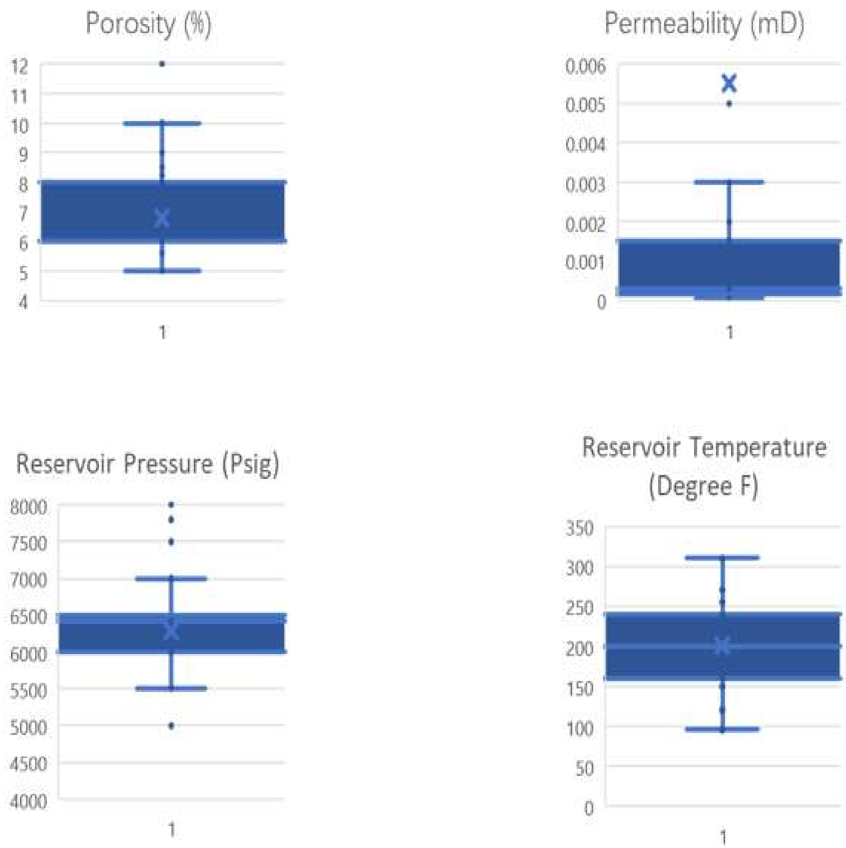

Figure 3-35 Porosity, Permeability, Reservoir Pressure and Temperature

We can see the data distribution information of the box plot for C1 % component, soaking period (days), Injection Rate and number of cycles in the above box plots. For C1 component we can see that the mean of the values is 90 whereas the median is 92. The maximum value used is 100, whereas the minimum value is 50.The inter quartile range is from 80 to 100. For soaking period, Interquartile range is from 0 to 35 days, whereas the mean of the values is 28 and median is 5. The maximum value used is 60 days whereas the minimum value is 0. For injection rate the mean of the values in 2.3 MMSCFD. The maximum value used is 11 with a few outliers and the minimum value is 0.1. Inter quartile range for the values in between 0.1 and 5. For number of cycles the mean value used in the simulation is 10. The minimum value is 3 whereas the maximum value is 28. the inter quartile range is between 3 and 13.

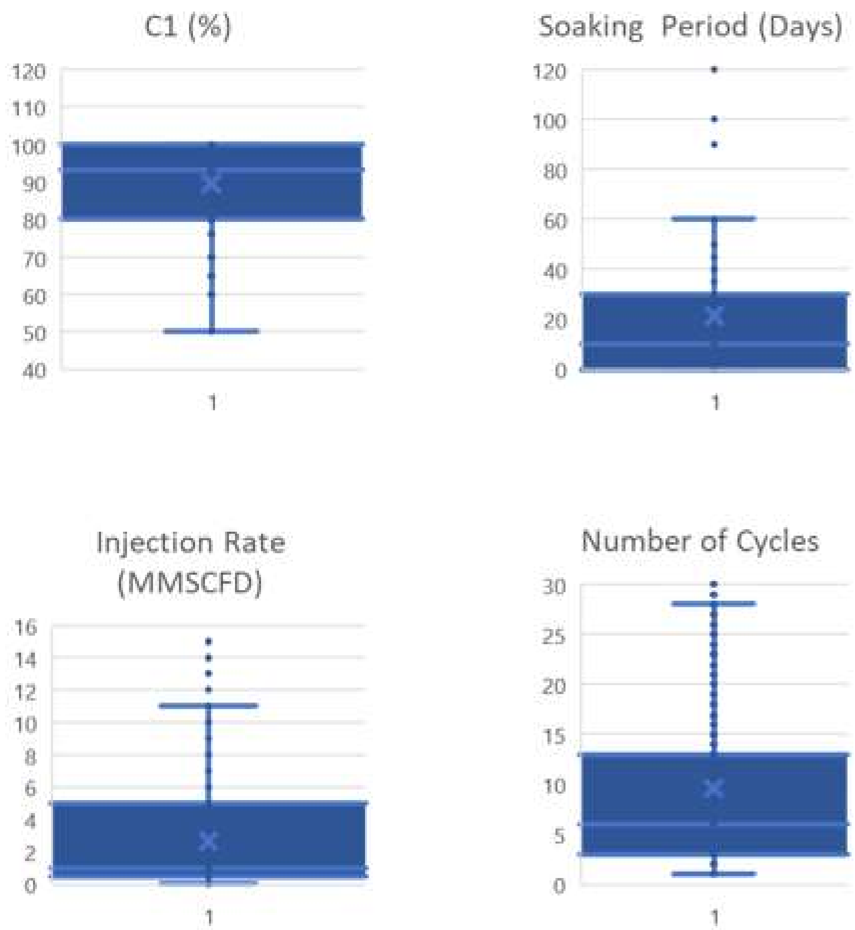

Figure 3-36 C1 %, Soaking Period, Injection Rate and Number of Cycles

We can see the data distribution information of the box plot for Depth, injection period, thickness and RF increase in the above box plots. For depth we can see that the mean of the values lie at 7500 inches. The maximum value used for depth is 9000 and the minimum value is 6000. The inter quartile range is between 7000 and 8000. For Injection period, the Interquartile range is from 25 to 100 days whereas the mean of the value is 80. The maximum value used is 200 the minimum value is 40. For thickness the mean of the values in 150 feet. The maximum value used is 350 feet and the minimum value used is 35. Inter quartile range for the values in between 100 and 200. For RF increase the mean of the values used in the simulation lies at 14. The minimum value is 0 whereas the maximum value used is 35. The inter quartile range for temperature used is from 6 to 18.

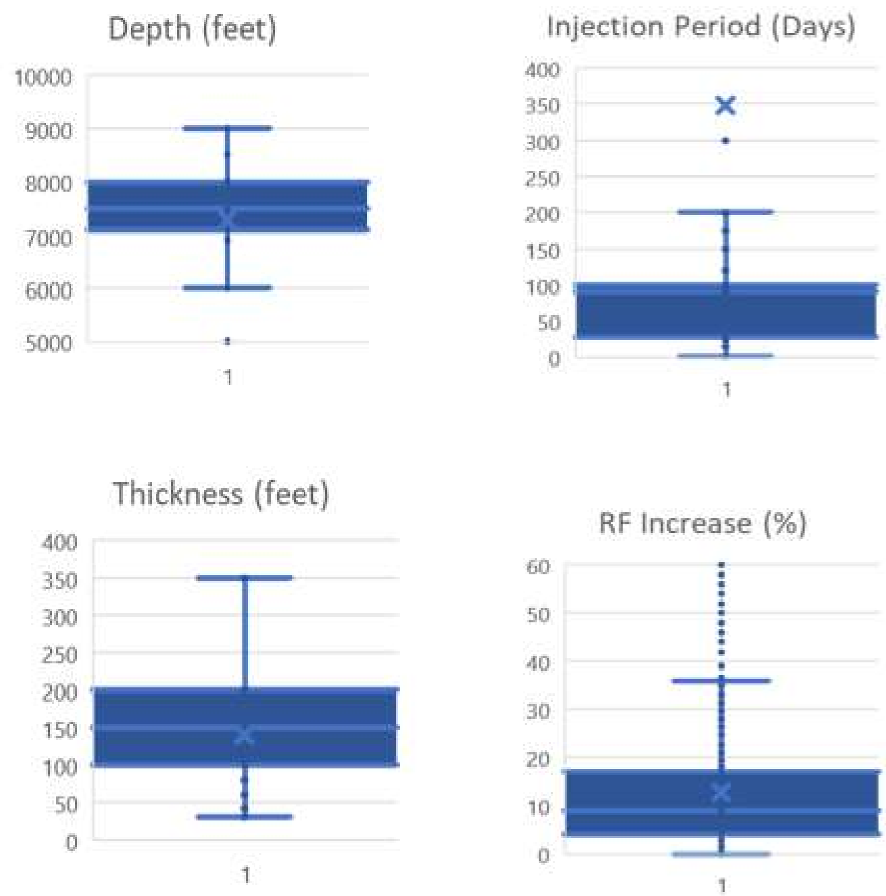

Figure 3-37 Depth and Thickness of Field Scale Simulations

3.3.3.3. Single variant analysis. Some interesting results can be derived from the single variant analysis. The mean Depth and thickness of the reservoir modelled was 7300 and 140 feet. The permeability of the reservoir was 0.0048 mD. The mean porosity of the cores is 7 percent. The mean of the Reservoir pressure is 6284 Psi and the mean of the temperature is 180 Degree F. Most of the records have lean gas as being injected, whereas the mean of the C1 component was seen to be 90 %. The mean of the gas injected rate is 2.7 MMSCFD. The mean of the injection pressure is 3800 Psi and the mean of the cycles is 10 cycles. The mean for the injection, soaking and production periods was 348, 21 and 444 days respectively. The given guidelines are given below in Table 3-6 and provide criterion for new simulation studies.

Table 3-6 Single Variant Analysis for Field Scale Simulations

Parameter	**Min**	**Max**	**Mean**	**Median**	**Std. Dev.**
Depth (Feet)	3000	9000	7271	7500	1478
Thickness (Feet)	30	350	141	150	68
Permeability (mD)	5E-05	0.1	0.0048	0.0003	0.016
Porosity (%)	5	12	7	6	1.26
Reservoir Pressure	2000	9985	6284	6425	1931
Pressure (Psig)					
Temperature (F)	95	310	180	185	62
C1 (%)	0	100	90	93	16
Injected Gas (MMSCFD)	0.005	15	2.7	1	3.13
Injection Pressure (Psi)	500	8000	3800	4000	1955
Injection Period (Days)	0.1	8000	348	90	1166
Soaking Period (Days)	0	120	21	10	30
Production Period (Days)	15	5500	444	100	1194
Number of Cycles	1	55	10	6	10

3.3.3.4. Key relationships and dependencies. The first relationship is between the number of cycles & gas Injected vs. recovery Factor. The number of cycles mean that how many times the whole process of huff and puff was carried out for a single formation. With the below bubble chart we can see that with the increase in number of cycles as well as with the increase in the amount of total gas injected, the sizes of the bubbles are increasing, which means that for these regions the Recovery Factor is greater. It can be easily seen that the upper right corner has greater recovery factor as compared to the lower right corner which shows less cycles and lower injection rates.

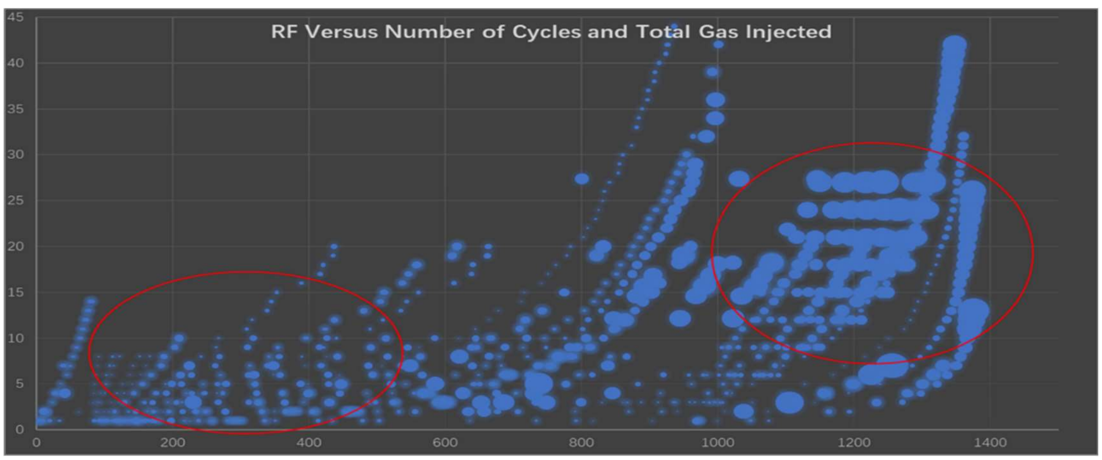

Figure 3-38 Number of Cycles Versus Total Gas Injected and RF

The second relationship is that of between Injection Rate and Recovery Factor. Injection rate and Recovery factor have also been found to have a relation. We can see that with the increase in Gas injection rate, the RF increases up, initially at a greater rate and thereby then becoming sort of stabilized, even with more increase in the Gas injection rate. The Recovery factors increases till a maximum point and beyond which then there is no or less increase with increasing injection rate. In essence an optimum injection rate as per economics should be used for injection purposes.

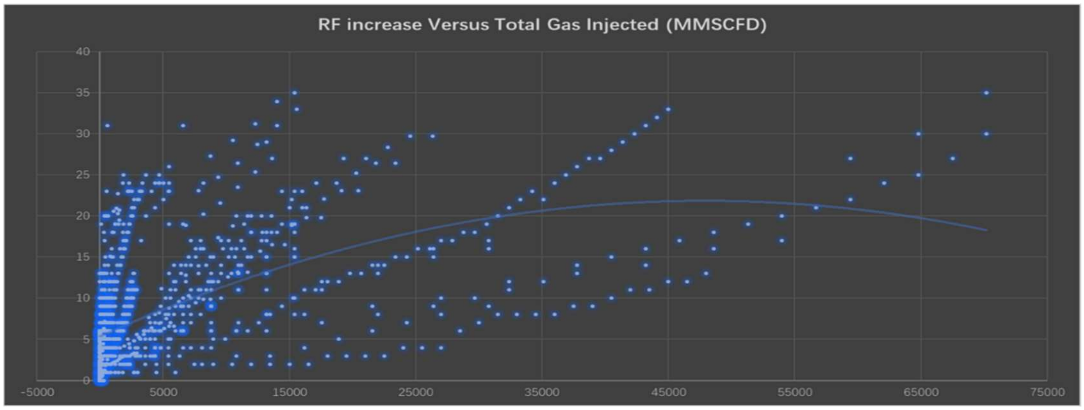

Figure 3-39 Injection Rate (MMSCFD) Versus the Recovery Factor

The third relationship is that of between Injection volume and Recovery factor. A generally positive relationship between injection pressure and RF has been seen that is with high cycle number and low gas injected the RF is high.

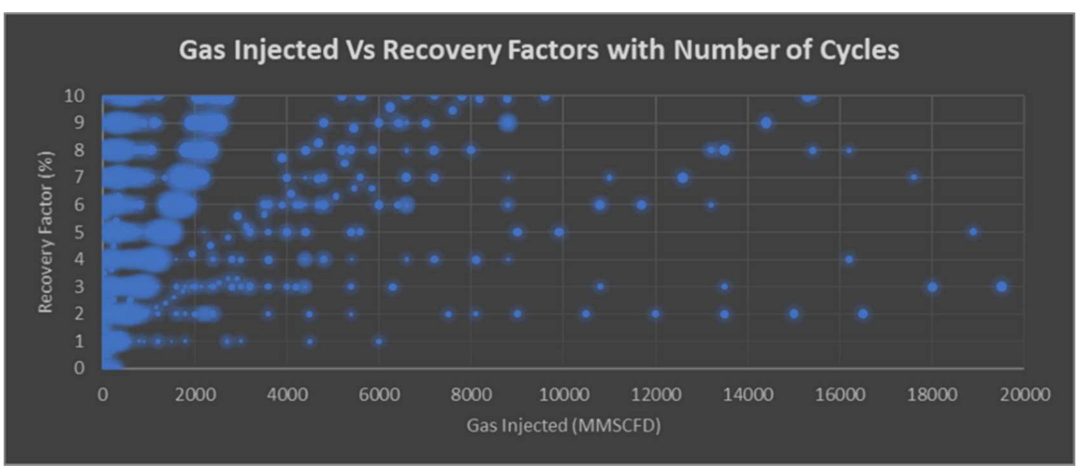

Figure 3-40 Gas Injected Versus RF with Number of Cycles

The fourth relationship is that of between Bubble Point and Recovery Factor. In the plot below we can see the bubble point line is at 2750 Psi. It is evident that when the injection pressure is below the bubble point pressure, then the recovery factor is lying in a range of values from 2 to 6 percent. However, when the bubble point pressure is exceeded then we can see that the range of Recovery factor increases whereby being in the range of 8 to 12 percent. The obvious reason for the same is that when the bubble point pressure is exceeded then conditions are such that oil is under saturated and viscosity reduction is oil swelling is carried out at a greater extent which explains the increase in the range of the Recovery Factor.

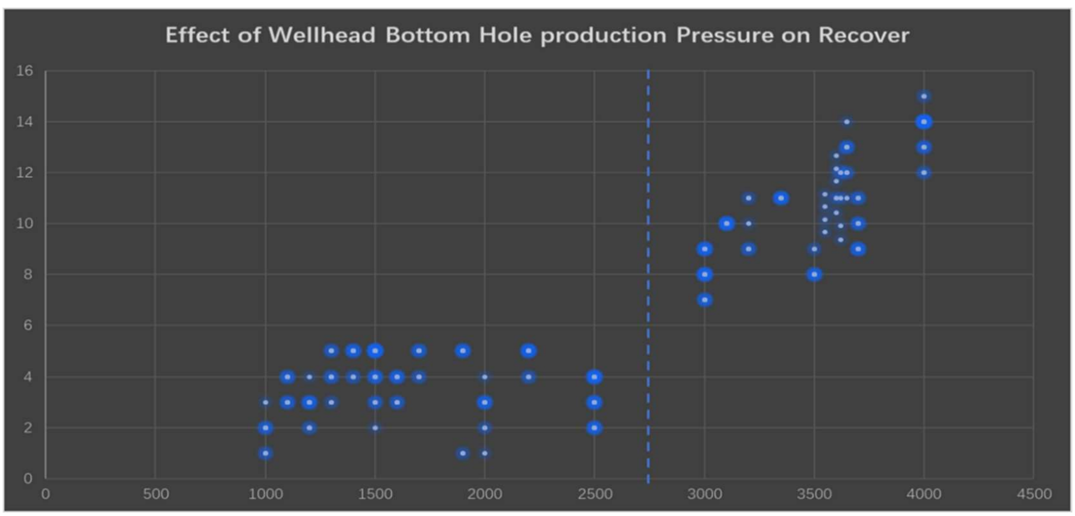

Figure 3-41 Effect of MMP and Bubble Point on Recovery

The last major relationship to be discussed is between soaking time and recovery Factor. The figure below shows that soaking time may not be totally necessary for some low permeability reservoirs. However, having some optimum value of soaking time would deliver the best results and while deviating high and lower than the soaking time shall result in a lower RF while keeping all the other variables as constant.

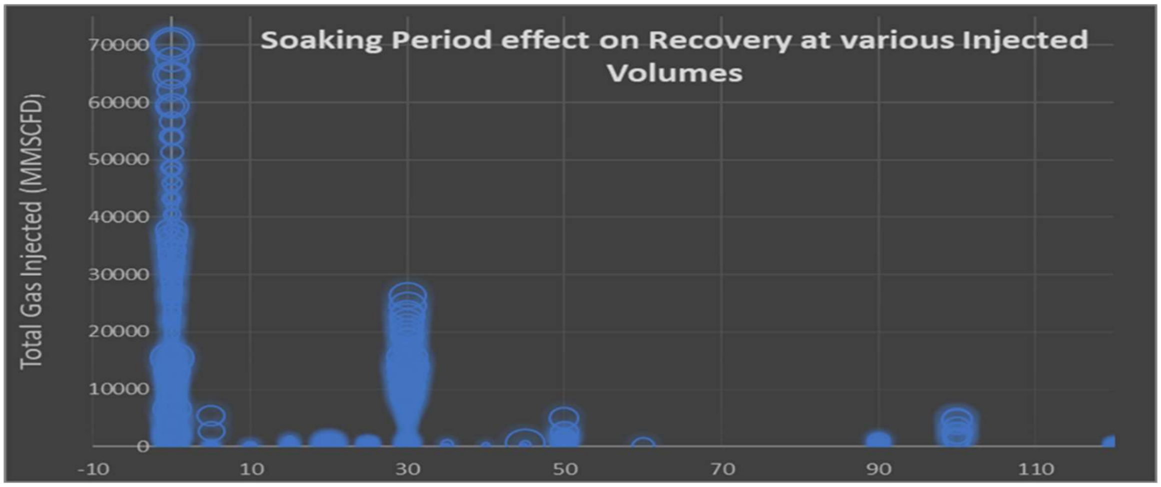

Figure 3-42 Soaking Period Effect on RF

3.4. PILOT PROJECTS

Owing to the acute interest of the industry and the academia in this field of expertise there have been a few pilot project which have been carried out and some of them are currently underway. Primarily the formally reported and finished pilot projects have been in for Bakken (US and Canadian Bakken) and for the Eagle ford formation in Texas. Overall it has been seen that the Natural Gas Injection has good results for unconventional reservoirs and the pilot projects seem to be promising. The recovery rates have increased from in the range of 10 to 30 percent whereby in some cases also being around 60 %. Details of the same are provided below:

3.4.1. Pilot Project at Canadian Bakken. Schmidt et al., (2014) reported a successful pilot project in the Canadian Bakken area. Some incremental oil was produced via the gas injection and in this project one mile horizontal injector and nine perpendicular horizontal producers were used. The wells pattern which was used was Toe-Heal pattern and lean gas was injected. The same had having volume of around 0.35 MMSCFD injected per day. The reported results indicated that there was some additional oil production, increasing from 135 bbl/day to 295 bbl/day. However at some of the locations there were some problems found with respect to the conformance control but still overall the project was considered to be motivating and a success.

3.4.2. Pilot Projects at US Bakken. Hoffman and Evans (2016) reported a natural gas pilot test conducted in the Bakken. It was carried out in the formation of North Dakota in 2014. An enriched natural-gas was injected in a continuous flooding mode and five wells pattern was used to perform the project. There was one injector in the middle and the other four wells were at the surrounding. The distance between the two producers, was 2300 ft (Alfarge et al., 2017a) and the distance between the two producers, was 900 ft (Alfarge et al., 2017a). The injected gas in this pilot contained a 55% methane, 10% nitrogen, and 35% of C2+ fractions. The operators injected the enriched natural gas at a rate of 1600 Mcf/day for 55 days with no disruption and in normal mode of injection.

The results of this injection were also encouraging, and it was observed that there is some increment in the Oil volume. These results paved the way towards having more interest in this technique and well as having a generally positive thought about this technique.

3.4.3. Pilot Projects at Eagle Ford. Success was reported by EOG resources with project of Huff and Puff gas injection in the Eagle Ford Area. It was stated by the company that all the wells under the operations can now produce 30 to 70 percent more oil under the new natural Gas huff and puff injection technique. A number of pilot tests were carried out by the company and the same included natural gas injection in huff and puff mode. It was 7 pilot projects which were executed and in total there were 49 wells which were involved in the same (Hoff man 2018). In all these pilot projects gas was injected for a period ranging from 3 to 5 years and the gas injection was on the leaner side while having a daily injection rate ranging from 0.2 to 0.8 MMSCFD of gas per day. In all these pilot projects the production was seen to increase in a very good rate and in some cases even reaching to such high level of 50 to 70 percent to the initial production. Also the same depended in the huff and puff scheme and the cycles which ranged from having time during from 4-06 weeks for the huff and puff timings and cycles. Nonetheless it was found to be a clear indication that Natural Gas injection has a very good potential for unconventional reservoirs especially in the Eagle ford region. Also it was confirmed that Natural Gas Injection is superior in terms of injectivity as well as being good for reservoirs which might have the issues of conformance control especially in the case of gas flooding mode.

4. CONCLUSIONS AND RECOMMENDATIONS

Several results can be deduced from the works which have been carried out and are presented below:

- Across all the studies, with the increase in the total amount of Gas injected, as well as the number of cycles, the recovery factor is seen to increase. However, after reaching a maximum RF point, further increases in number of cycles or the total amount of gas injected becomes irrelevant.
- The injection pressure shall depend on the reservoir upon which injection is being carried out. It has been observed that generally with an injection is carried out at a greater injection and subsequently at a greater reservoir pressure, the total recoveries are more especially near or greater than bubble point.
- For core experiments the amount of oil recovered increases significantly during the initial cycles and thereby the increase in the total oil recovered rate gradually decreases over with time with increasing cycles.
- Core sizes have found to generally have a correlation with the amount of oil recovered. The larger cores were observed to have a lower recovery rate as compared to smaller cores.
- The size of the core has an effect on the Recovery Factor, whereby cores with larger size generally have a lower recovery factor.
- For huff and puff experiments it has been found that there exists an optimum soaking time. Increase beyond the optimum soaking time does not increase in the total amount recovered.

- With respect to Huff and Puff operations short shut in periods with several cycles led to high recovery factors as compared to using long shut period with fewer cycles.
- The size of the Stimulated reservoir volume has one of the most important effect on oil recovery rate. If the size of reservoir volume contacted and stimulated is greater than the total amount of oil recovered shall also be greater.
- As in the case of gas flooding experiments, containment of natural gas is very important. If there is breakthrough of the injected gas then the amount of recovered oil shall decrease at quite a significant rate.
- The only formations which have been investigated in studies, literature and pilots are Eagle Ford, Niobrara, Bakken and Eagle Ford.

Natural Gas Huff'n'Puff injection has very solid applications and potential for unconventional reservoirs. Care need to be exercised by the operators to delve out the most optimum Huff and Puff scheme with the right production, soaking and injection times, as well as the right composition in line with their reservoirs. Pilots which have been carried out for this strategy are low in number and the range of variables that have been investigated in the simulation studies is limited. Hopefully, with new pilots, and studies coming up, it is really a possibility that the Huff and Puff Gas injection can serve to remarkably increase and prove to be a game changer for unconventional reservoirs. Investigation of new formations, as well as new and novel injection, soaking and production timings, with varying injection rates might lead the way in the development of optimum strategies to ensure maximum recoveries.

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