PETE 4735: Petroleum Engineering Design II
Final Report

CHARLTON 30/31 FIELD DEVELOPMENT PROJECT

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This is to certify we have all shared in preparing and reviewing this copy of the PETE 4735: Petroleum Engineering Design project 3: The Charlton 30/31 Field Development Project.

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EXECUTIVE SUMMARY

A detailed five-phase plan for developing the Charlton 30/31 field is designed and delivered by Team 11 in the undergraduate Petroleum Engineering Design course at the University of Wyoming. Having data for various wells in the field, the project centers around wells that have been producing for 30+ years. By applying trend consistency assumptions, geophysical analysis, and engineering methods, the goal of the project is to optimally plan to drill additional wells for primary recovery if economically feasible. More specifically, this plan addresses the problem of recovering leftover oil within the reservoir (after many years of production) by targeting areas with indications of oil saturation and porous dolomitic zones. Those areas will be recognized on a static model from interpreting well logs and seismic data.

The Charlton 30/31 field is located in the Michigan Basin, in Otsego County Michigan, where select data has been provided by Dr. Brian Toelle. This is a project similar to his PhD research that integrates exploration and geology efforts with a team's petroleum engineering efforts. Specifically, the Charlton 30/31 Field in the North Michigan Silurian Reef Trend, of the Guelph Formation (formerly the Niagaran Brown Formation) is studied. This pinnacle reef has been known to contain a bulk porosity of approximately six percent, of which several wells have produced 2.6 million barrels of oil of the estimated 7 million barrels of oil in place.

Due to the amount of time and accessible data, seven wells in total are analyzed, with six of those wells vertical and one deviated. For each of those wells, static model components are obtained by the team prior to starting the project, which include interpretations of well logs for formation tops, 3D seismic data for horizons, topography, and individual well information like degree of deviation from vertical. After the initial design phase, that data is organized and made capable of being imported into Petrel. While inputting parameters into the software, analysis of the model occurs simultaneously.

During the interpretation and analysis of the static model, parameters such as oil and gas zones, permeability, porosity, hydrocarbon saturations, etc., will be observed. It will be shown how the time constraint will be a factor in deciding whether economics will be possible. Without the experience with petroleum software or with geological interpretation, research and consultation with faculty will take up a lot of time. Therefore, learning how, instead of actually interpreting data, is the major risk involved. It will be shown how that time constraint is addressed and overcome in the main body of this report.

Lastly, all progress going through the project is explained. The struggles such as the learning curve with Petrel, along with the success with visual representation are all shown. Thus, the entire progress for the project is discussed. Team 11 is in the process of visually showing and proving where it would be optimal to drill for oil in the field. To wrap up the project, recommendations and conclusions are made to better utilize petroleum engineering students' knowledge. Would it be beneficial for engineering students to run dynamic simulations in this field after already having a static model to try and match 30 years of production history? Will secondary recovery efforts benefit this field and if so, which ones? These questions should be answered to benefit similar studies in the future.

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NOMENCLATURE

UWI – Unique Well Identification number

TVD – true vertical depth

MD – measured depth

SSTVD – subsea true vertical depth

KB – Kelly bushing

.txt – text file

.las – well log file

.sgy – seismic file

.dlis – well log file that is less common than .las files

Microsoft Excel – a basic spreadsheet program

EORI – Enhanced Oil Recovery Institute

DEQ – Department of Environmental Quality

1. INTRODUCTION

1.1 BACKGROUND

The Charlton 30/31 Field Development project is based in Otsego County, Michigan on the North Michigan Silurian Reef Trend as part of the Guelph formation. This formation trend is typically brown to light brownish in color, usually consists of crystalline and dolostone minerals, and ranges from the Southern Peninsula of Michigan (which yields salt basins, oil wells, gypsum beds, coal mines, and good farming lands), over to New York, and up into Southern Ontario, Canada. In addition, the underlying rocks are Ordovician (rock types include sandstone, shale, dolomite, and limestone) to Pennsylvanian (rock types include sandstone, siltstone, shale, coal and limestone) aged. These rocks are characterized by horizontal break-bedrock with deposits of gravels, sands, silts, and clays. Therefore, with the Charlton 30/31 area being 400 million years old in geologic depositional time, it is known to contain a decent source of hydrocarbon generation. This hydrocarbon source is proven in Dr. Brian Toelle's paper, "CO2 Sequestration Potential of the North Michigan Silurian Reef Trend," in that several wells have produced 2.6 million barrels of the estimated 7 million barrels in place. With successful exploration having been supported by those results and figures 1.1.1, 1.1.2, and 1.1.3, it is evident that hydrocarbon generation is prevalent in the area. Figure 1.1 shows oil, gas, dry hole, and other wells across Michigan in 2001. Otsego County yields a conglomerate of oil wells and a few gas wells (which is where the trends cross). Drilling for oil in a crowded field that has been producing for over thirty years is the challenge that makes this study reasonable.

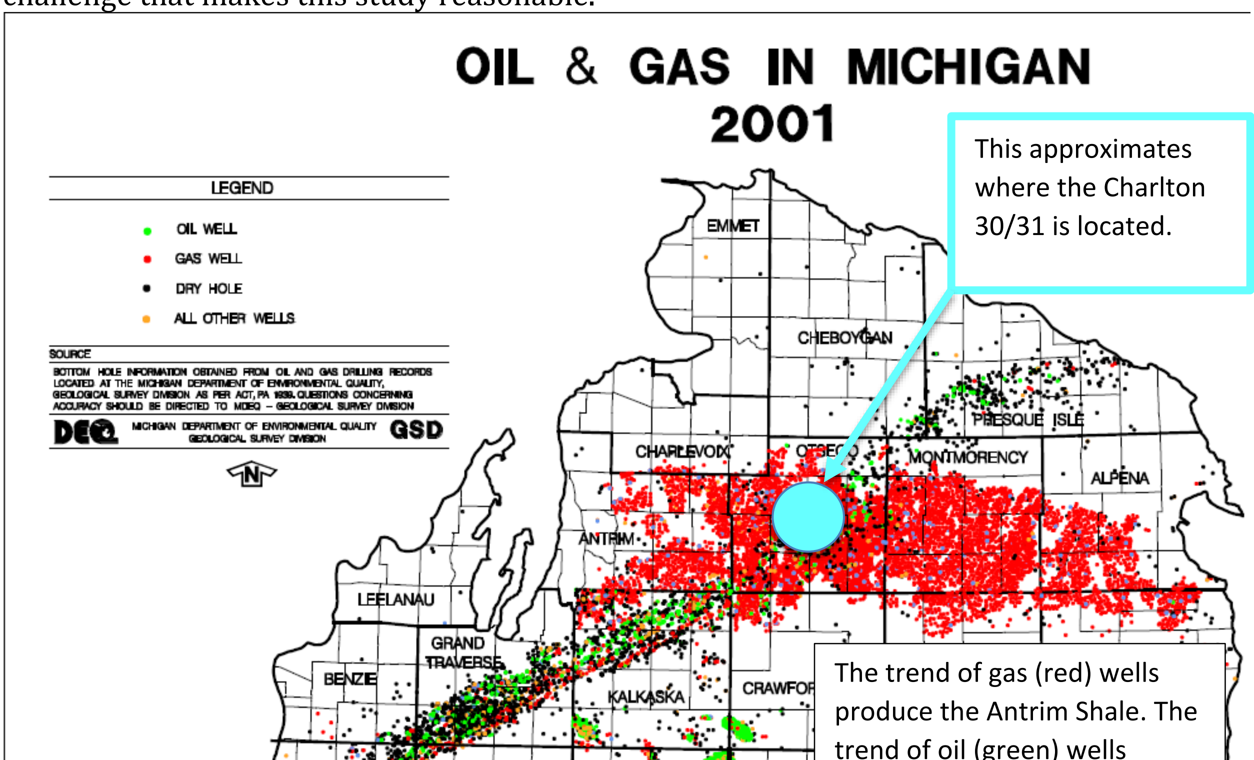


Figure 1.1.1: Oil and Gas well map for Michigan in 2001.

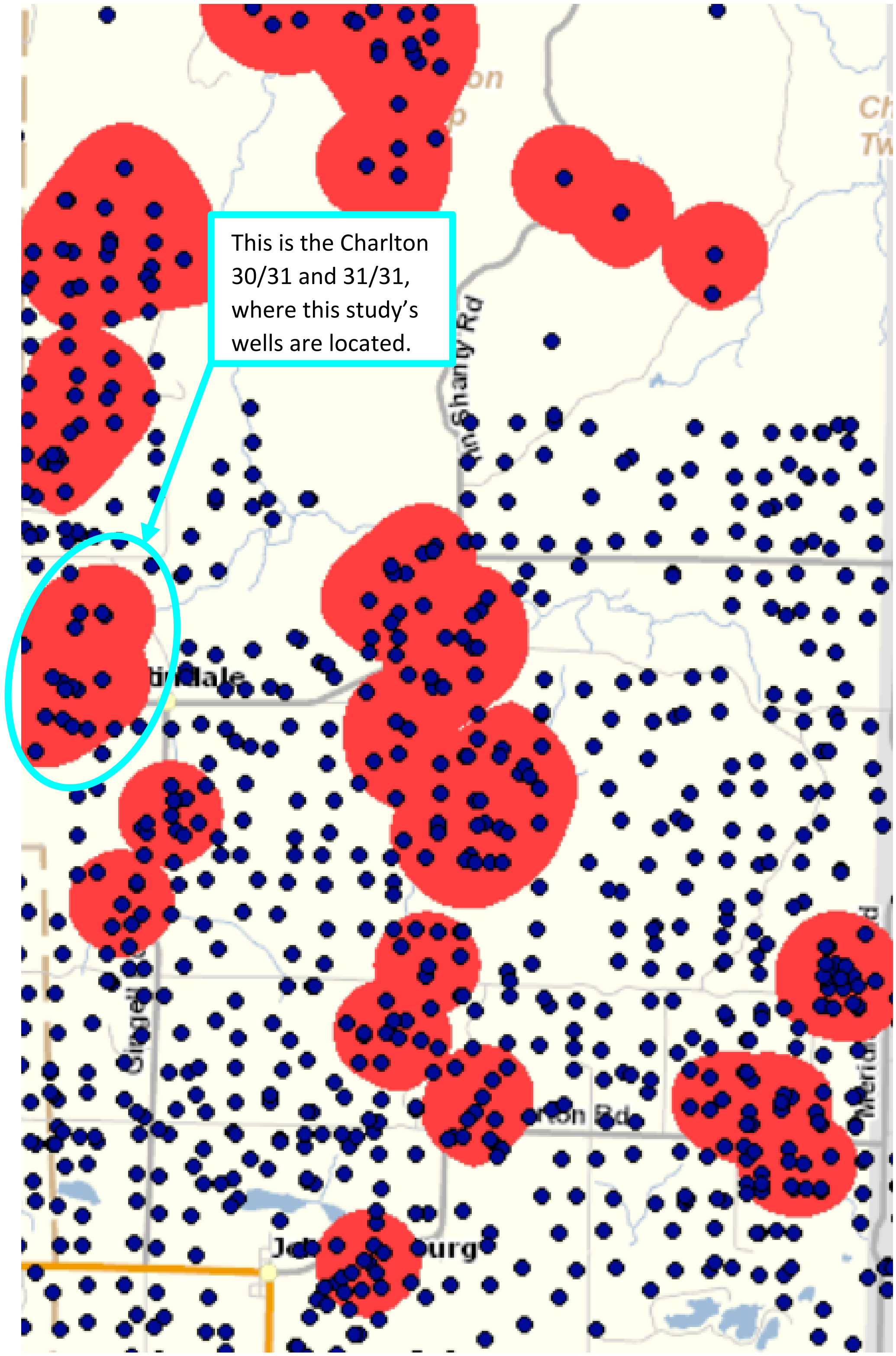
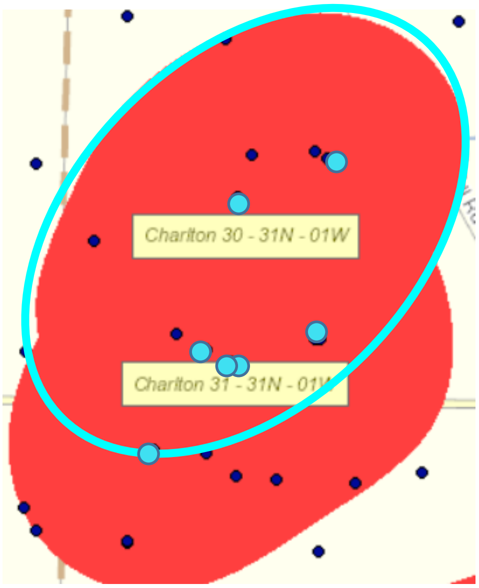
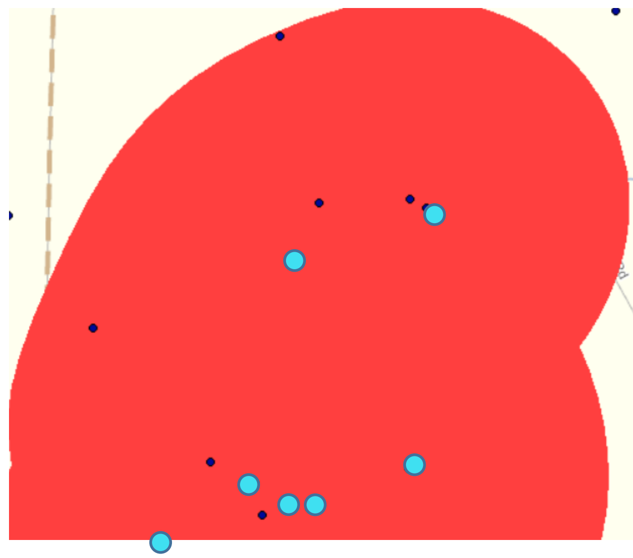


Figure 1.1.2: This shows approximately all of the wells within the boundaries of the Charlton Township. Red boundaries represent the Niagaran Brown Formation, while the other wells shown are producing from different formations.



(a)



(b)

Figure 1.1.3: (a) shows all of the wells that will be explained on the model later in the paper and also highlights the Charlton 30/31 and 31/31 which is not part of the project. (b) is a close-up image of the 30/31 specifically. The red indicates the Niagaran Brown formation, and the two oval shapes, represent the Niagaran Brown for both 30/31 and 31/31 fields.

In addition to the area and the rock and reservoir features uncovered during background research, Dr. Toelle originally provided data for 9 wells. This data consisted of individual well information (Appendix A) and a 3D seismic survey. From the given data, it was initially thought that a model could be built using IHS Energy's software called Petra. Petra could import .txt files, .las files and can handle the manual importation of formation tops, UWI, TVD, MD, SSTVD, KB elevation datum, surface location in X-Y coordinates, the county of that location, and well log suites per well. Previous versions of Petra with the module Petraseis also could read .sgy files, however, the version the University of Wyoming installed could not. The solution to this problem included switching over to Schlumberger's software called Petrel, which could handle 3D seismic data directly and interpret it for the static model. The progress made with Petrel along with the seismic complications will be discussed further in the main body of this paper.

1.2 OBJECTIVES

Now that there is a set background of the Charlton 30/31, the scope of the project and objectives will be defined. The scope of the project consists of Team 11 designing a project that incorporates the engineering skills acquired at the University to perform tasks and present results to senior management. In internships and entry level jobs, managers do not provide much instruction for given projects. This ensures an end-of-project evaluation of the employee on their ability to problem solve and manage time well. This project is of similar structure, receiving little instruction and leaving great potential to prove how team integration, time management, and solving problems can be utilized. With that being said, this project requires two objectives to be met: 1) the building of a static model with given data and 2) using that static model and data to develop drilling plans for additional production wells. A couple considerations need to be taken into account for these steps. In the building of the static model, uncertainties with data interpretation and experience may alter the reliability of the final deliverable of the project. Also, the majority of this project has already been performed. What can the team do with the Charlton 30/31 after replicating Dr. Toelle's static model? These will be taken into consideration when the interpretation phase, discussed later, is reached. Now that the objectives have been established, the problem itself and how Team 11 plans to approach and handle it will be described.

1.3 PROBLEM STATEMENT AND PLAN

One way to think of this project is with the uncertainty of the quality of production of certain wells in the Charlton 30/31, as opposed to others, and which of the regional trends would be more beneficial to drill and produce. The most effective method to address the problem would be to analyze the geology of the area at a closer proximity to decide where to drill and how to drill; however, geological analysis costs both time and money. From the team's standpoint of not having these luxuries for further regional studies, the optimal method in determining well placement is by analyzing trends in formations within the reservoir, analyzing surface topography for contour changes in elevation, observing fracture networks in the underlying rock, and then planning wells that will exploit the remaining oil with the shortest MD (measured depth) as possible. In order to address the problem efficiently, those general ideas are broken down into five phases. Of those phases, a timeframe with various assignments describing project progress, analysis of risk and data, model building and interpretation software, and undergraduate knowledge of geology and petroleum engineering will be utilized in developing the plan and the project. This design, in more depth, follows.

The project plan, as will be shown in a workflow and explained in more detail in section 2, is proceeded in five phases. In the first phase (project planning, scheduling, and data reviewing), the project is carefully designed and little physical progress is made. This phase includes creating a workflow, a Gantt chart to show deadlines, a risk analysis to know what may go wrong and how to mitigate it, and then importing the given data into software to start on building a static model. The team runs into Petra not being sufficient for the model in the next phase.

In the second phase (building of the static model), the static model is actually created. This includes importation of all provided data before actually interpreting it. Upon inputting data into Petra and researching why the 3D seismic does not work in the school's version of Petra, however, the team decides that switching over to Petrel is necessary. Therefore, the project moves back into phase 1 to import data into Petrel. The team again precedes to encounter more issues with the seismic. The projection systems will not align between the wells and the seismic data, which means it is inaccurate. Later in the paper, these issues and how they are overcome will be discussed.

After phase 2, phase 3 (data and model interpretation) starts, where analysis of cross sections and creating structural maps can occur. Cross section analysis reveals how properties of the reservoir vary from well to well. Also, analysis of interpretation of seismic data combined with well logs can create visual analysis of porosity and permeability through structural maps. These maps are used to plan drilling intervals and locations in phase 4. Therefore, those visual representations are shown later in this report.

Once the model is analyzed and everything is shown on the model, drilling plans are made for phase 4 (drilling plans for additional boreholes). This phase plans out where on the surface is optimal to drill from and how deep in the formation needs to be drilled to and perforated. The model from phases 2 and 3 will be a lot of help, once those oil zones are located.

In the last phase (economic evaluation), assumptions are necessary with regards to approximately equal costs in drilling new wells as wells already there. Based on the lack of production data from the wells back in the 70's, it remains a challenge without reservoir simulations as to how much production is expected from a new well. With more time and resources, it would be optimal to see if a new well or two would actually pay off and make a profit. As will be discussed, the team makes the decision to run economics on drilling and completions costs but no rate of return.

Now that an overview of the project and plan has been covered, an in depth discussion of developing the design plans will be generated. This will include a workflow, a project schedule implementing a Gantt chart, a risk analysis, a data review and a brief overview of Team 11's current progress in the project since the last update. Conclusions and recommendations from the results upon moving forward will also be provided at the end. The following will propose the generated design plans.

2. MAIN BODY

2.1 WORKFLOW

In order to show the flow of the project and reaching its deliverables through individual phases, a workflow was created. The workflow is shown in Figure 2.1. In the workflow, it lists individually the five phases along with input, output, decision points, and where it starts and ends. The following is a walk-through of the workflow and a description of what will be accomplished in each phase. In addition, a legend/key for following the shapes and colors in the workflow is on page 12.

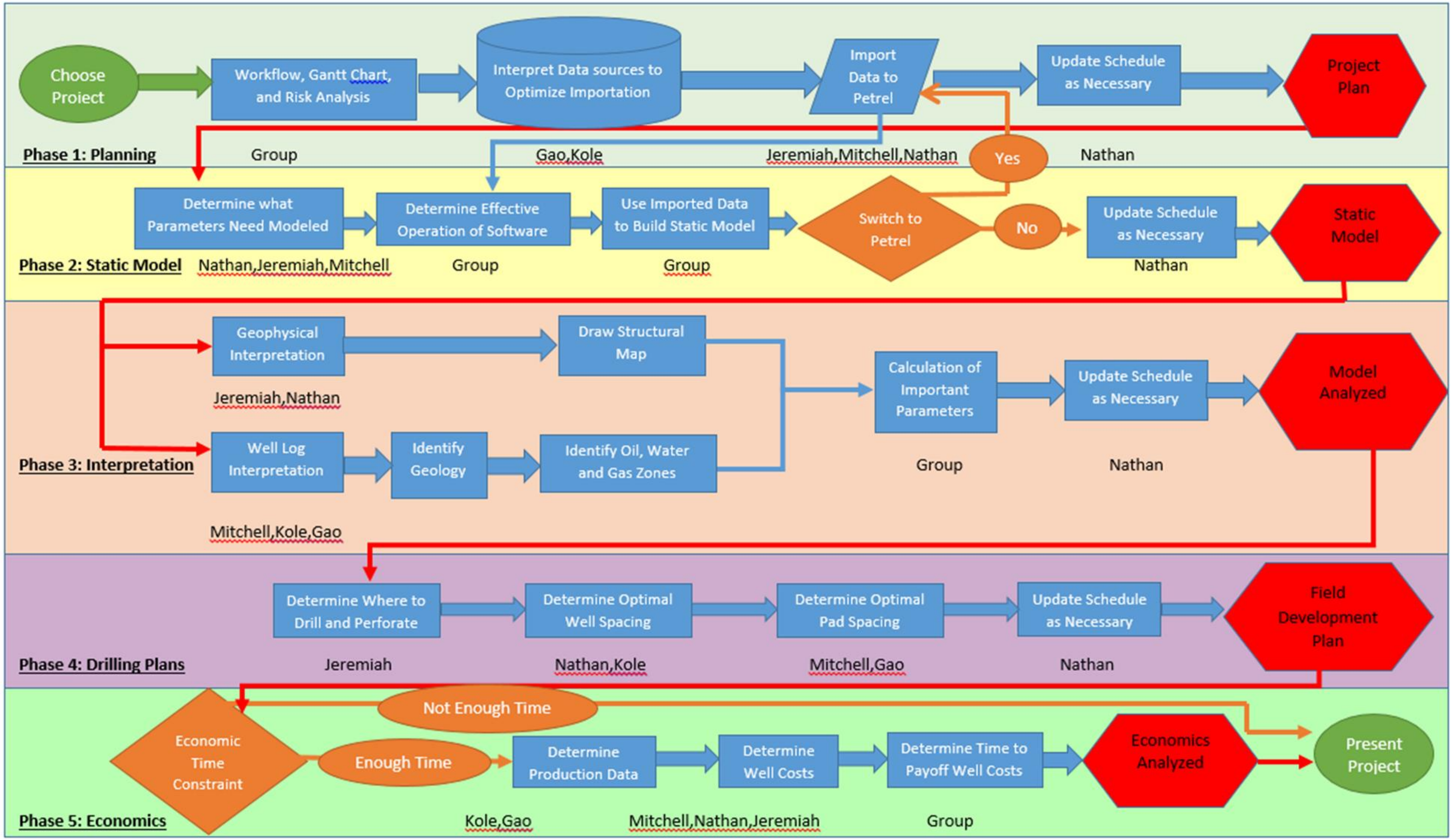


Figure 2.1: This is a workflow of the project. It shows the flow of the project through its phases, tasks, decision points, deliverables and the member responsibilities for each phase and task.

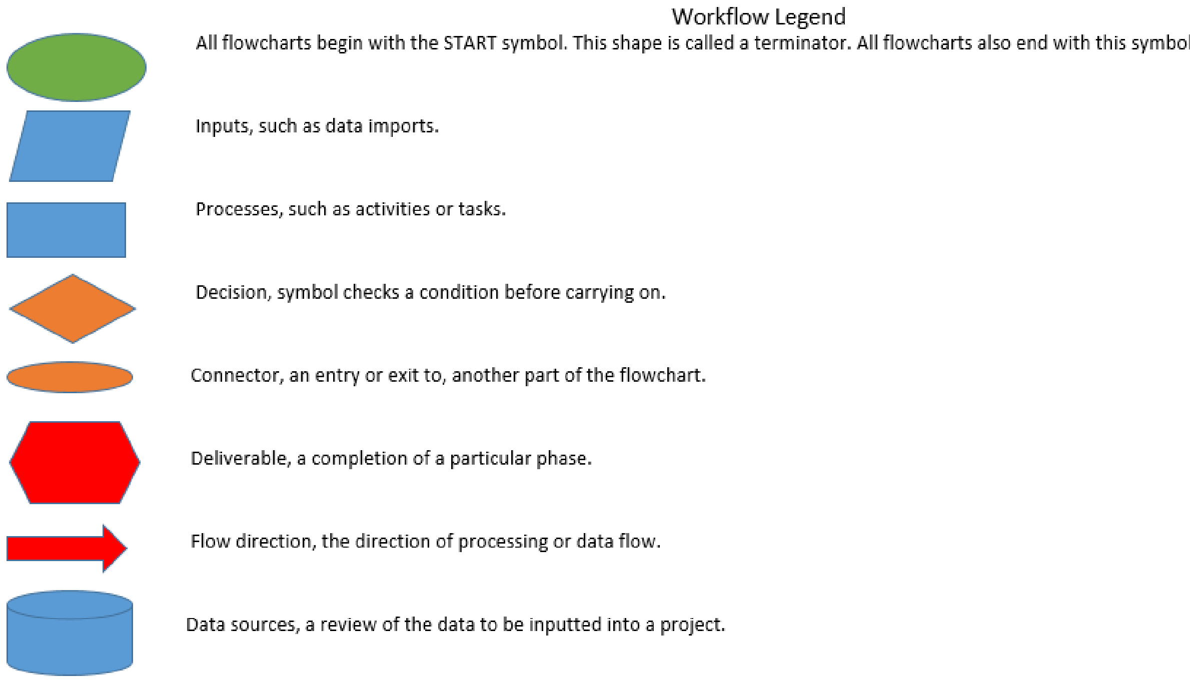


Figure 2.1 (cont'd): This legend should aid in following the workflow.

In Figure 2.1, the start (green oval) of the project is choosing the project. This takes into account having already formed the team before deciding between various projects. Obviously, progress on planning a project does not start until a problem is identified, and constituents and a goal are chosen. Team 11 chose to address the problem of adding additional wells to produce hydrocarbons from the Charlton 30/31 with the constraint of only having select data to work with.

Phase 1, the planning, scheduling, and data organization phase of the project, consists of four tasks. The first task is to create the workflow and Gantt chart, the second task is to interpret data within files to import data into Petrel, the third task is to actually import the data, and the fourth task is updating the schedule. As can be seen in Figure 2.1**,** task 3 is an importation rhombus that connects to the task of determining the effective operation of the software in phase 2. Importing the data and learning the software go hand-hand because by importing the data, the operation of the software is learned whether mistakes are made or not. At the end of this phase, deliverable has been produced when the project is planned and the data is imported.

Phase 2, building the model itself, has four tasks with a decision point along the way. The first phase 2 task is to determine what parameters and data need modeled, the second task is to be familiar with the operation of the software, the third task is to use the imported data to build the static model, the decision point is whether to switch over to Petrel from Petra to build the model, and the fourth task is to update the schedule as necessary, based on that decision. For the decision point, since the software switch was necessary, the project looped back to importing the data and determining the operation of the software in the first phase. Then the project would continue as scheduled. This phase ends after the static model has been developed.

Phase 3, interpretation of the static model, involves four tasks. The first task is geophysical interpretation, in which the seismic data will be analyzed and a structural map will be drawn, the second task is interpretation of well logs, in which zones of rock containing oil or water will be identified, the third task is the combining of tasks one and two to calculate important parameters and tie structure with properties, the fourth task is to update the schedule as necessary. In the third task, important parameters consist of oil saturation, water saturation, porosity, and permeability for each zone. This will determine where the producing zones are and therefore where drilling needs to take place during our drilling plans for additional boreholes phase.

Phase 4, drilling plans for additional boreholes, involves four tasks using the results from phase 3. The first task will be determining where on the surface to drill, how deep to drill to hit the producing zones, and where in the zone will be best to perforate depending on whether the well is vertical or horizontal. The second task will be to determine the optimal well spacing. The third task will be to determine the optimal pad spacing and how many wells per pad. And the fourth task will be to update the schedule as necessary. The deliverable will have been fully developed when the plans are complete.

Phase 5, economic evaluation, has three phases and a decision point, and depends heavily on the amount of time taken on phases 2 through 4. The first task is finding production data for the field, the second task is determining well costs and comparing them to production revenue, and the third task is determining the time to pay off the well costs if the optimal drilling plans were implemented as opposed to non-optimal drilling plans. The decision point takes into account whether the team has enough time to evaluate economics. If there is time, economics will be run, but if there is not, the project will be over. It takes time to obtain data and/or make the correct assumptions. As stated earlier, the economics phase will only be completed with respect to drilling and completions costs.

The end of the project consists of presenting the project to senior staff who may consider implementing the ideas in the future. This is similar to the end of an internship, in that an intern often gives a presentation to senior staff for revision and evaluation of that intern’s work. Often times, this evaluation is representative for consideration of a job with that company in the future. The team plans to be at that level just before graduation.

2.2 PROJECT SCHEDULE

As is shown in the project workflow, this project has 5 phases, each with several tasks and subtasks. In order to keep this project on track, a Gantt chart was also employed. This allows the team to gauge how long each phase and task will take. Additionally, the Gantt chart allows the team to assign different tasks to specific individuals. The team also decided to use the Gantt chart to keep track of all of the oral and written deliverables that need to be met. Please see the subsection below for an image and brief explanation of the Gantt chart.

2.2.1 GANTT CHART

PETE 4720 Group 11: Nathan Driver, Mitchell Acheson, Jeremiah Ennis, Kole Stewart, Ce Gao

Phase/Task	Assignments	Timeframe Start	Finish
Phase 1: Planning, Scheduling, Data Review		***12-Oct***	***9-Dec***
Gantt Chart, Workflow, Risk Analysis	Entire Team	*12-Oct*	*9-Dec*
Interpret data and files to optimize importation	Entire Team	*26-Oct*	*15-Nov*
Import Data to Petrel	Jeremiah, Mitchell, Nathan	*1-Nov*	*9-Dec*
Update Schedule as Necessary	Nathan		
Phase 2: Build Static Model		***15-Nov***	***21-Jan***
What needs to be modeled?	Nathan, Jeremiah, Mitchell	*15-Nov*	*1-Dec*
Determining how to operate software effectively	Entire Group	*15-Nov*	*14-Jan*
Use Imported data to build static model	Entire Group	*1-Dec*	*30-Dec*
Update Schedule as Necessary	Nathan		
Phase 3: Interpretation		***14-Jan***	***15-Apr***
Geophysical Interpretation	Jeremiah, Nathan	*14-Jan*	*30-Mar*
Draw Structural Map	Jeremiah, Nathan	*14-Jan*	*30-Mar*
Well log interpretation	Mitchell, Kole, Gao	*14-Jan*	*30-Mar*
Identify Geology	Mitchell, Kole, Gao	*14-Jan*	*30-Mar*
Identify Oil, Water, and Gas Zones	Mitchell, Kole, Gao	*14-Jan*	*30-Mar*
Calculation of Important parameters	Entire Group	*7-Feb*	*15-Apr*
Update Schedule as Necessary	Nathan		
Phase 4: Drilling Plans of Additional Boreholes		***21-Feb***	***15-Apr***
Determine where to drill and perf	Jeremiah	*21-Feb*	*15-Apr*
Determine well spacing	Nathan, Kole	*24-Feb*	*15-Apr*
Determine pad spacing	Mitchell, Gao	*28-Feb*	*15-Apr*
Update Schedule as Necessary	Nathan		
Phase 5: Economical Evaluation		***31-Mar***	***30-Apr***
Production data from reservior model	Kole, Gao	*31-Mar*	*15-Apr*
Determine Well Costs	Mitchell, Nathan, Jeremiah	*8-Apr*	*30-Apr*
Payoff Time	Entire Group	*15-Apr*	*8-May*

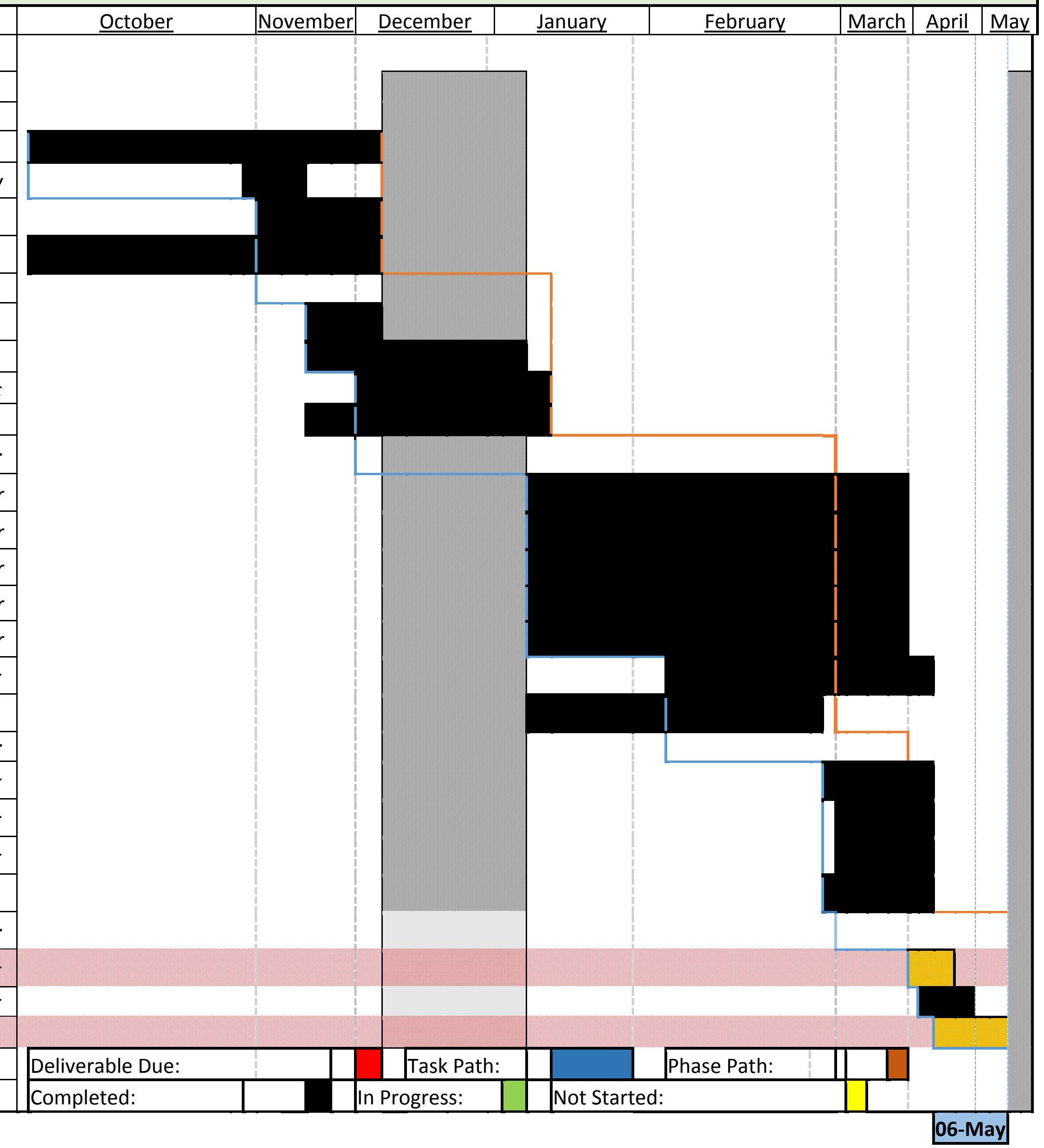


Figure 2.2: A Gantt chart for the project that outlines assignments and responsibilities.

PETE 4720 Group 11: Nathan Driver, Mitchell Acheson, Jeremiah Ennis, Kole Stewart, Ce Gao		October	November	December	January	February	March	April	May
Written Deliverables									
Completion schedule	*21-Oct*								
Draft final design	*11-Nov*								
Final design	*7-Dec*								
Update Workflow and Gantt Chart	*2-Feb*								
Progress Report 1	*29-Feb*								
Progress Report 2	*28-Mar*								
Final Project Report (Draft)	*18-Apr*								
Final Project Report	*6-May*								
Oral Presentations									
Present first draft final design	*11-Nov*								
Practice presentation final design	*4-Dec*								
Design Presentation at senior design symposium	*9-Dec*								
Progress Report 1	*Week of 29-Feb*								
Project Peer Review	*Week of 28-Mar*								
Progress Report 2	*Week of 18-Apr*								
Final Report Presentation	*30-Apr*								

Deliverable Due: | Task Path: | Phase Path:

Completed: | In Progress: | Not Started:

06-May

Figure 2.2 (cont'd): This shows the deliverables and due dates to keep the team on track

As can be seen in Figure 2.2, the Gantt chart shows each phase with its associative tasks and subtasks, it shows deliverable due dates, it outlines deadlines for each part of the project along with individual team member assignments, and it shows the dependencies of later phases or tasks on earlier phases or tasks. To highlight these main dependencies, in Figure 2.2, the solid blue line follows the path by which the time dependency to move onto the next task is based upon. The orange line similarly shows how later phases are dependent on the earlier phase's time to finish. This guarantees that the team stays on track and does not move onto another phase or task until another one is complete to its outlined extent.

2.3 RISK ANALYSIS

In order to assist with the scheduling of the project, and to try to predict possible future problems, the group completed a risk analysis. Six areas of risk were identified as being directly applicable to this project. Within these six areas, 19 individual risks were identified. They are as follows:

- Management Risk – Risk stemming from disagreement with management
    1. Judges disagreeing how the group inputted data into the model.
    2. Judges disagreeing with the group's choice of software.
    3. Judges disagreeing with the group's interpretation.
    4. Judges questioning the accuracy of the group's conclusions.
    5. Judges disagree with the group's assumptions.
- Data Risk – Risk stemming from data
    6. Specific data is not available for a certain well or the whole field.
    7. Data is not correctly formatted for the group's software and/or model.
    8. Accurate economic data may not be available.
- Reputational Risk – Risk stemming from damage to reputation of group or employer
    9. The group is not able to answer specific questions from the audience after presentations.
    10. The project gets off schedule and the mentor begins to question the group's value and or work ethic.
    11. The project gets off schedule and individual group members begin to question themselves or other members.
- Productivity Risk – Risk stemming from loss or lack of productivity
    12. The group's productivity decreases due to stress factors both inside and outside of the project.
- Time Risk – Risk stemming from time management
    13. Any number of tasks could take too long to complete.
    14. There is limited meeting time for the group.
    15. Individual group members may have different schedules in the spring.
    16. The mentors may change due dates and deliverables.
- Technical Risk – Risk stemming from technology
    17. Hardware malfunctions and or failures.
    18. Software malfunctions and or failures.
    19. Software is unable to use the provided data.

2.3.1 RISK MITIGATION

In order to address the risk associated with this project, possible risk mitigation techniques were created for each specific risk. They are as follows:

1. Risks 1-5: The team took them as learning experiences and adjusted the project accordingly. For the case of presenting the material, the thought process was explained and appropriate recommendations were asked for.
6. The area was researched and people were contacted to try and fill in those data gaps.
7. The team either changed the data format or found software that could use the data.
8. Economics with respect to production was cut due to lack of valid information.
9. The team took it as a learning experience and adjusted the project.
10. The team tried to show the mentor effort to get back on track.
11. The team worked as a team to get everyone back on track.
12. Either other group members stepped in to help or the group worked on identifying how to reduce stress related to the project.
13. The team tried to put in more time and work to get the project back up to speed and running smoothly.
14. The team used electronic communications such as email, text and phone calls as well as meeting as a partial group to keep up effective communication.
15. The team worked out new meeting times that worked for everyone.
16. The team worked as hard as possible to meet deadlines for the dates that were moved up. Also, the Gantt chart was updated as needed.
17. Luckily, this did not happen. The team made sure all files were backed up and online.
18. Same as 15. The team also would have consulted the IT people to help fix the problem.
19. The team switched to Petrel from Petra because it was unable to use the seismic data.

2.3.2 RISK ANALYSIS CHART

In order to assess which risks will be most threatening to the project, a risk analysis chart was developed. It is as follows.

Probability risk will occur, %	negligible	minor	moderate	serious	critical
80-100			4, 6, 7		
60-80		18	8, 12	17	13
40-60		10	11	3, 14, 16	9
20-40		19			
0-20	2	1	5	15	

Impact on Project

Figure 2.3: This risk chart analyzes the risk involved with the project. Green is low risk, yellow is moderate risk, and red is high risk.

2.4 DATA REVIEW

An overview of the given data set revealed vital information in regards to the geology of the area including seismic data, well logs, formation tops, surface well locations, and individual well labeling information, as can be seen in Appendix A. These types of data have typically been interpreted to reveal stratigraphy, zones of hydrocarbons, porosity, permeability, reservoir volume, etc. However, some problems with the data existed at first glance, as well as after basic analysis. Dr. Brian Toelle's PhD data was obtained and organized in three folders: 1) Seismic, 2) Well Data, and 3) Well Logs. The following is a list of problems with the data files or data for importation in each of the folders, in the order Team 11 came across them:

1) Immediately, Petra would not read the .sgy (3D seismic) file in the seismic folder. This meant that either another program would be needed, or the seismic data would need to be excluded. Excluding it altogether would be a poor project management decision because wells could not be planned to extract more oil in the fracture networks or to avoid potentially hazardous geologic intrusions. Since a Petrel

introductory session was offered during the first semester of this class, it was decided that the Petrel software would be looked into before second semester. After switching to Petrel for the second semester, another problem existed with the seismic data. The wells and seismic wouldn't align in the program due to having different projection systems. The immediate solution was to convert the state plane projection system into a geometric projection system using Army software called Corpscon, however, Petrel did not include NAD27 state plane 2112 or NAD83 US foot projection systems like originally assumed. Figuring out the seismic projection system problem had to be determined and would be the focus before moving onto other phases in the project. Following the projection systems problem, Dr. Toelle provided a model with the wells already in place and the seismic data loaded as well. However, the amplitude versus acoustic impedance weren't correctly loaded which added another problem. In the following weeks, Dr. Toelle provided the team with a model so that interpreting the seismic horizons and creating structural maps could occur.

2) All the files in the 'Well Data' folder that were capable of being input directly into IHS Energy's Petra were input. However, Petra was incapable of handling Excel files, .txt2 files and .dlis files directly. The files that could not be imported without conversion into a text file included: a seismic coordinates file (Excel), a deviated survey file (Excel), a topography file (Excel), two formation tops files (Excel), a well coordinates file (Excel), three formation tops files (.txt2 files), and a well log suite file (.dlis). Solutions for most of these files were easy to develop. All of the Excel files and .txt2 files could be converted into text files by saving them as text (tab delimited) or by opening them in Notepad. The .dlis file could not be converted into a .las file though. Therefore, the conclusion that was reached was that Petrel would be a valuable asset in the case of analyzing that one well. Petrel could handle every one of those files. Unfortunately, the surface topography in Petrel was more tedious and timely to incorporate into the model. That would be looked into further after the initial seismic problem was dealt with.

3) In addition to the correcting of files, some data in those files also needed correction or interpretation. For the files containing formation tops, there was data for some but not all wells. Also, one well had two different files with similar formations due to different interpretations of well logs. Assumptions had to be made regarding which files were more consistent with the other wells' formation top data and additional assumptions had to be made to fill in the missing formation top data for wells due to elevation (datum) changes from well to well.

2.5 PROJECT RESULTS

2.5.1 Building the Model

At the start of the second semester, the project had moved on to using Petrel to build the static model (to see the first semester progress through December 2015, see Appendix B). This included inputting wells, well logs, formation tops, and seismic in a correct projection system. Also, more research was conducted on the individual wells of which data was provided. It was found on the Michigan DEQ (Department of Environmental Quality) Oil and Gas page that one well was assumed to have an incorrect permit number, which correlated with one well's formation top data being incorrect as well. Team 11 added the two additional wells provided (from section 11 in Michigan according to driller's logs), corrected well and formation top data, and updated the Gantt chart, workflow, and risk analysis.

In addition, progress in fixing the problem with the differences in projection systems between the seismic and the wells was attempted over the course of the second semester. The team experienced difficulties with getting these projections aligned until Dr. Toelle dealt with the problems by providing an updated model. With everything aligned, another couple issue occurred with inputting the provided acoustic impedance and amplitude volumes for seismic interpretation. Fortunately, Dr. Toelle provided a model with those in Petrel as well. The model in Petrel only required interpretation of the seismic data and interpretation of the well logs to develop a complete understanding of the highly permeable and porous dolomitic intervals containing hydrocarbons in the reservoir.

From the provided model, the first step was to make surfaces from the provided well top data. This process began by defining a simple 3D grid that bounded the areas of the well tops in the x, y and z directions. After the grid was defined, the well top locations from each well were used to create separate surface for each formation top. This was done using the horizon creation process in Petrel (Figure 2.5.1). This data is not very accurate in terms of mapping the reservoir, because it requires Petrel to make very large interpolations between each well, which leads to an essentially linear model with very little contour to it. It really was useful only for determining the correct seismic horizons to use later in the modeling process. Nevertheless, it was a simple step that made life much easier for the team when it came to the seismic interpretation process.

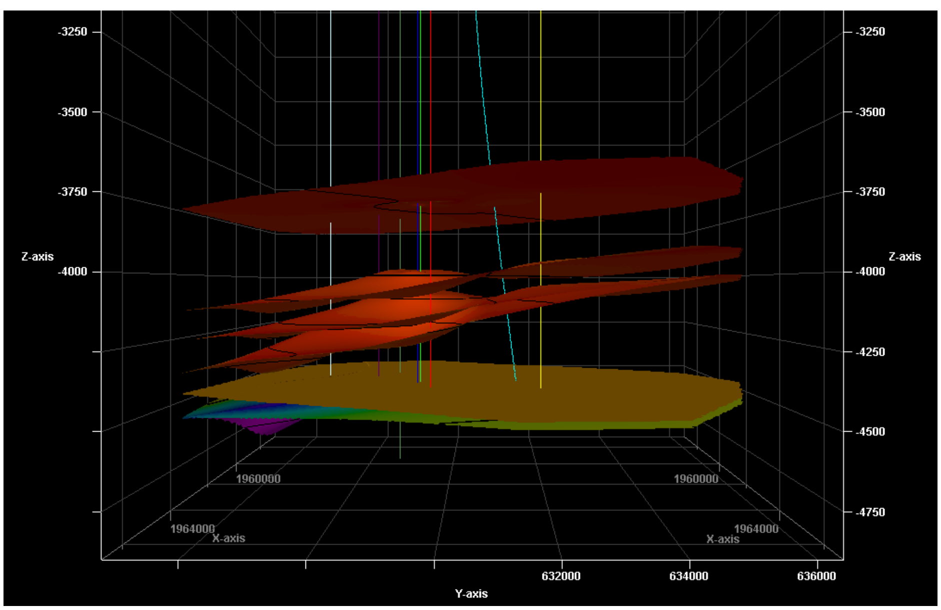


Figure 2.5.1: This a picture of the well tops that were developed in the model from the makers on the well logs. This view is directly from the east.

The task of interpreting of well logs by hand was used as a check to make sure everything surrounding those wells in Petrel looked accurate on the model. If the water saturation on the well logs surrounding the wells dropped, and the neutron porosity on the well logs increased, that would indicate an area of oil to compare with the structural maps that would be created following seismic interpretation. These checks qualitatively checked out, however, they could potentially be better proven on the model through well to seismic ties.

For the seismic interpretation task, the amount of problems that the team faced was described in detail. With the complete and accurate data for the seismic in the team's possession, the seismic interpretation could be completed. The first step in building the structural map was to pick individual seismic horizons from the data (Figure 2.5.2). The team made use of the 3-D auto picking feature in Petrel to accomplish this task. The team picked out features in the acoustic impedance volume that were distinct. An individual cross line of the acoustic impedance that was in the middle of the reservoir was used to accomplish this. Petrel then followed that specific feature in x, y and z directions to create a specific seismic horizon (Figure 2.5.3). The acoustic impedance volume was used rather than the amplitude volume because it had a much more detailed response in the producing formation. The amplitude volume had so little detail, that even the auto picker function was unable to identify distinct trends. This process led to six different distinct seismic horizons.

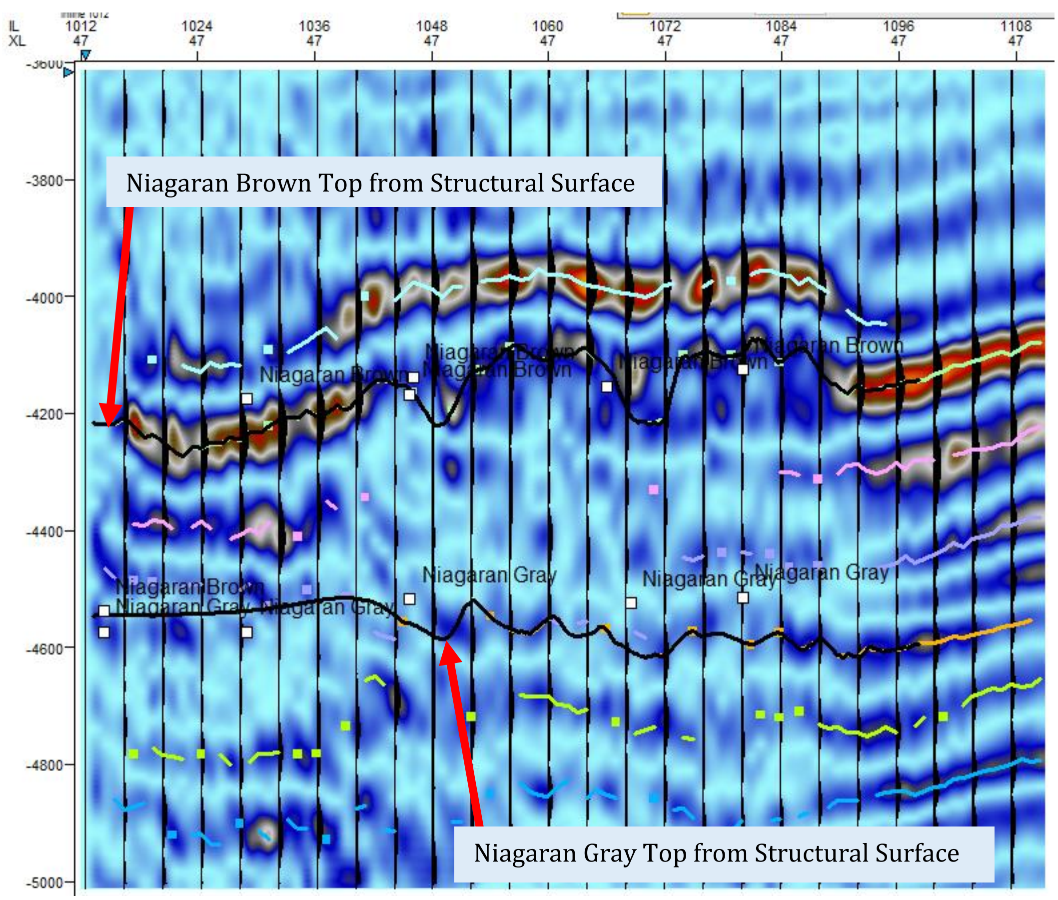


Figure 2.5.2: The top picture is the crossline of seismic that was used to interpret the structure with the 3D auto-picking tool. It includes the horizons picked and well tops.

The next step was to create contoured surfaces from the seismic horizons. To do this, a simple 3D grid was created between the top and bottom seismic horizons. Each horizon was then converted into a 3D surface that shows the depth changes of the specific seismic response throughout the seismic volume (Figure 2.5.3). From these six surfaces, the well top surfaces from the well logs were used to determine which seismic horizons were in the zone of interest. Additionally, some of the deeper horizons were not included in the property modeling process because they were located below the well log responses. Three seismic horizon surfaces were then determined to be in the correct area for the property modeling process. These three surfaces that were chosen for property modeling were also the basis for the structural maps of the reservoir which will be discussed more in the Model Interpretation section.

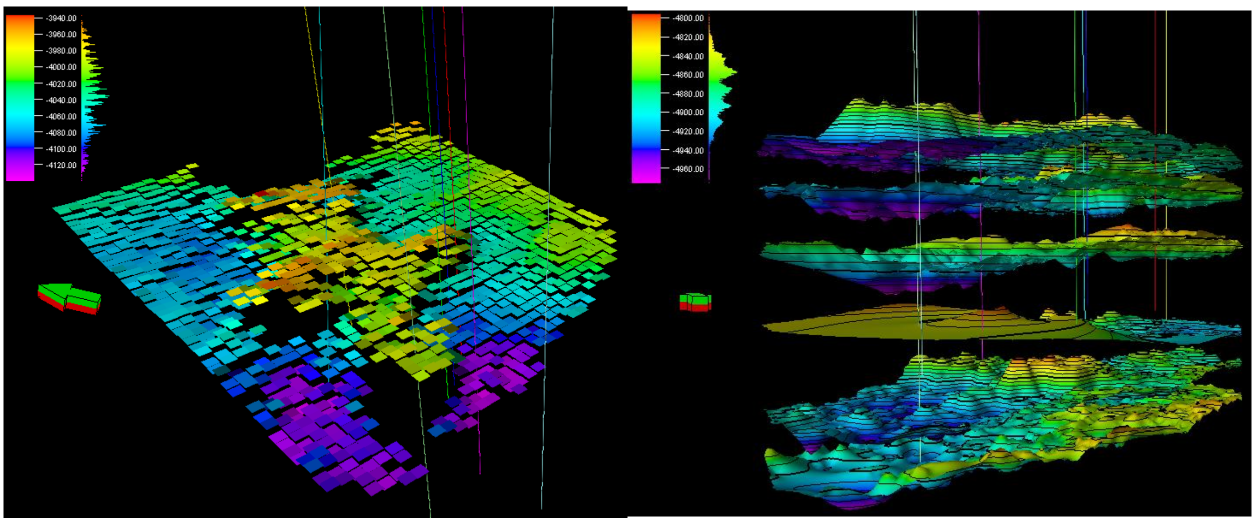


Figure 2.5.3: These are pictures of the seismic interpretation portion of the model. Left is a picture of the seismic horizon generated for the A1 carbonate formation, which offered the best visual due to severe vertical relief. Right is a picture of all the surfaces created from the seismic horizons. From top to bottom they are the A1 carbonate, Niagaran Brown top, Niagaran Brown mid, Niagaran Gray and two unknown surfaces below the target zone.

Logically, the next step was the property modeling process. This included using the three chosen seismic horizon surfaces to make a 3D "cube" that was then populated with reservoir parameter data from the well logs. Petrel was able to fill in areas away from the wells through extrapolation. The first part of this process was to upscale the well logs inside of the three surface 3D area. This process was done for the porosity log, water saturation log, permeability log and a manually created oil saturation log. The oil saturation log was created by pulling the water saturation log from wells that had it in their suite into an Excel file. Once in the Excel file, the oil saturation log was created using the saturation ($S_O = 1 - S_W$) equation, where S_O is oil saturation and S_W is water saturation. The 2-phase assumption made earlier in the project made life easy. These logs were then converted to text format and imported into petrel. Once all of the desired logs were upscaled into the 3D volume, the property modeling could begin. This process was done using the Petrophysical Modeling tab in petrel. The most important decision made in this process was the method used for populating the zones with values. After some trial and error, the Gaussian random function simulation was determined as the best choice. With this choice made, the properties of water saturation, porosity, permeability and oil saturation were modeled. The results of the property modeling can be seen in figures 2.5.7 – 2.5.9.

2.5.2 Model Interpretation

In addition to the static model being built for phase 2, analysis of well logs was started over the cross sections for the wells with enough data. This included comparing density, neutron porosity, resistivity, water saturation, gamma ray, sonic, and calculated total porosity logs to identify oil-bearing intervals. The pores were assumed to contain oil instead of gas, other than that dissolved in the oil, based on the trend between the North Silurian Reef (typically oil wells) and the Antrim Shale (typically gas wells). To briefly show how the logs were analyzed, Figure 2.5 and 2.6 is a picture of the log suite for the State Charlton 1-30.

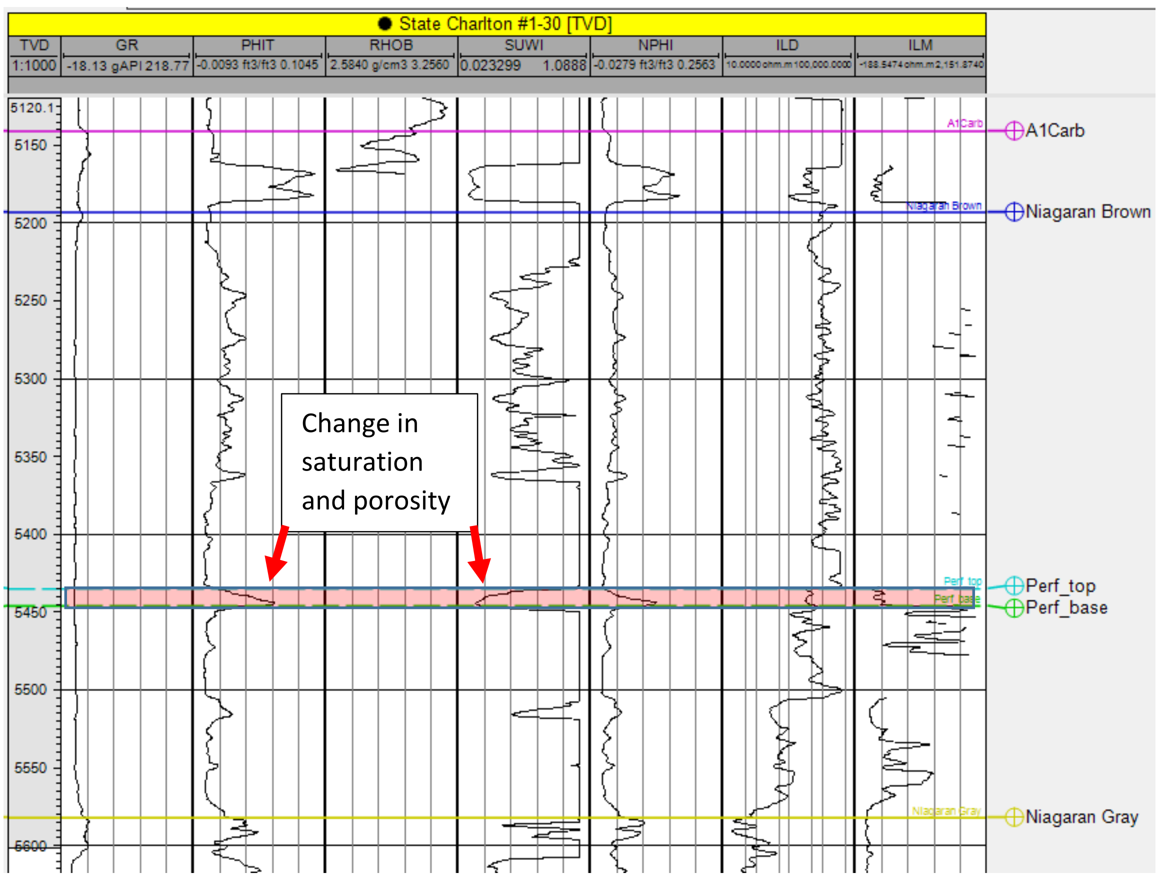


Figure 2.5.4: This is a well log suite for the State Charlton 1-30. The red indicates an oil zone.

As can be seen in figure 2.5.4 from left to right, the suite contains a gamma ray log, a deep induction resistivity log, a medium depth induction resistivity log, a bulk density log, a water saturation log, a calculated total porosity log, and a neutron porosity log. Everything is useful, but the saturation curve, porosity curves, and resistivity logs are most helpful for finding oil zones. For example, at around 5430 feet, the water saturation curve drops while the porosity curve increases. This identifies an oil zone because without gas in the reservoir, hydrocarbon saturation is inversely proportional to water saturation (thus, if water saturation decreases, oil saturation increases), and if porosity increases, there is more fluid occupancy. All of the wells had similar trends when they were analyzed at different depths.

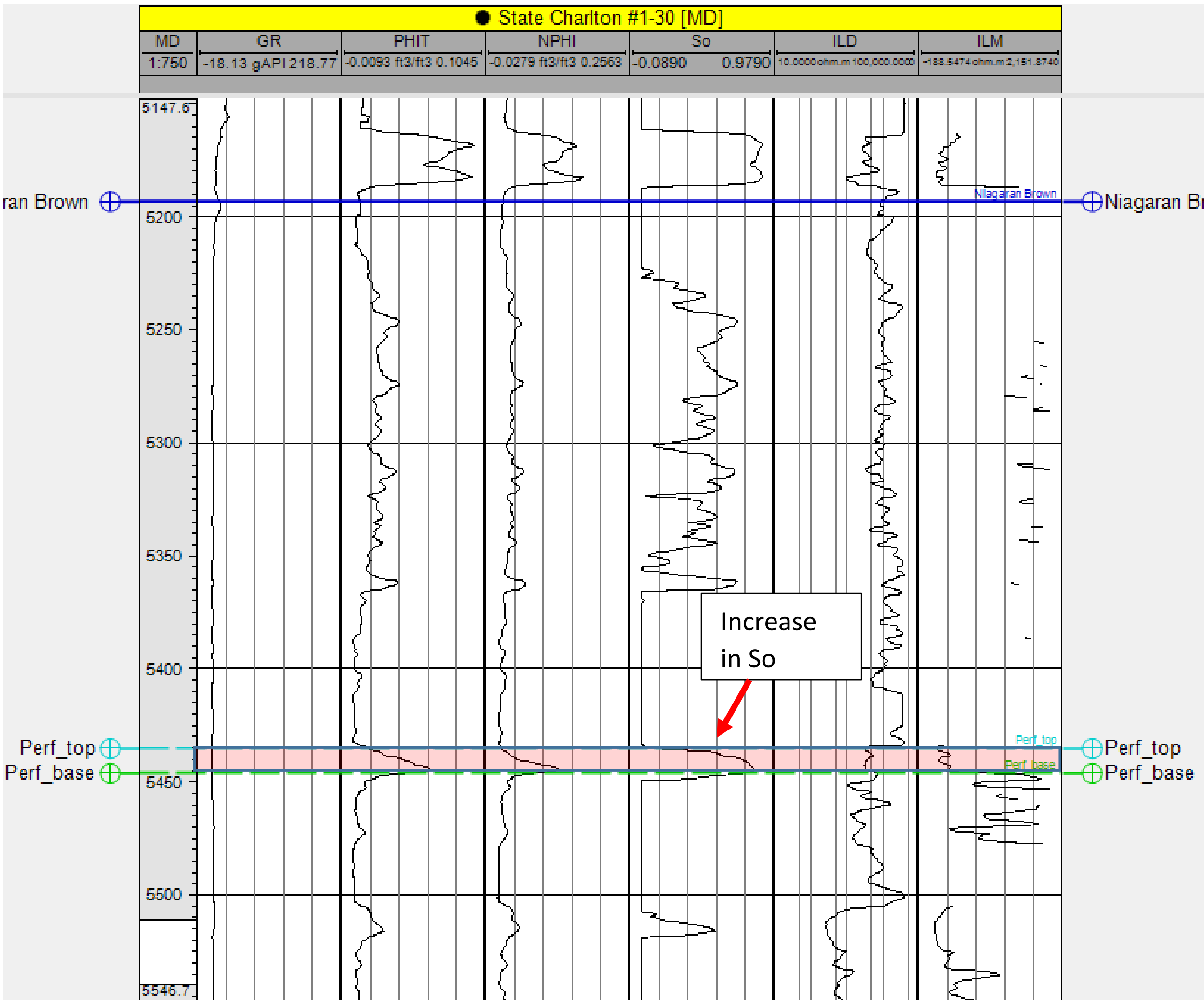


Figure 2.5.5: This is a well log suite with perforation tops and bases of State Charlton #1-30

As can be seen in figure 2.5.5 from left to right, the suite contains a gamma ray log, a calculated total porosity log, a neutron porosity log, a calculated oil saturation log, a deep induction resistivity log, and a medium depth induction resistivity log. The oil saturation log has been created by subtracting the water saturation log results from 100% total saturation. With the assistance of Dr. Toelle's static model, the perforation interval can be seen in the figure. The perforation top is represented in blue, the perforation base represented in green and the red zone is the producing zone (perforated zone). Within that zone, we can observe an increase in total porosity along with an increase in oil saturation. This result confirms that the perforation zone is correct, and also that oil saturation matches the seismic results shown later. Being able to confirm this is very important in identifying the oil saturation zone within the reservoir for the planning of additional boreholes. The same results can be found throughout the other wells.

An important part of the model interpretation process is understanding the reservoir structure. The surfaces created during the seismic interpretation are used to make structural maps in order to better understand exactly where the reef trend is located. From these maps and the literature research a rough idea of the reservoir boundary can be developed. In Figure 2.5.6, the white line shows the approximate boundary of the reservoir that we will be using to make sure that any proposed wells will still be on the reef structure.

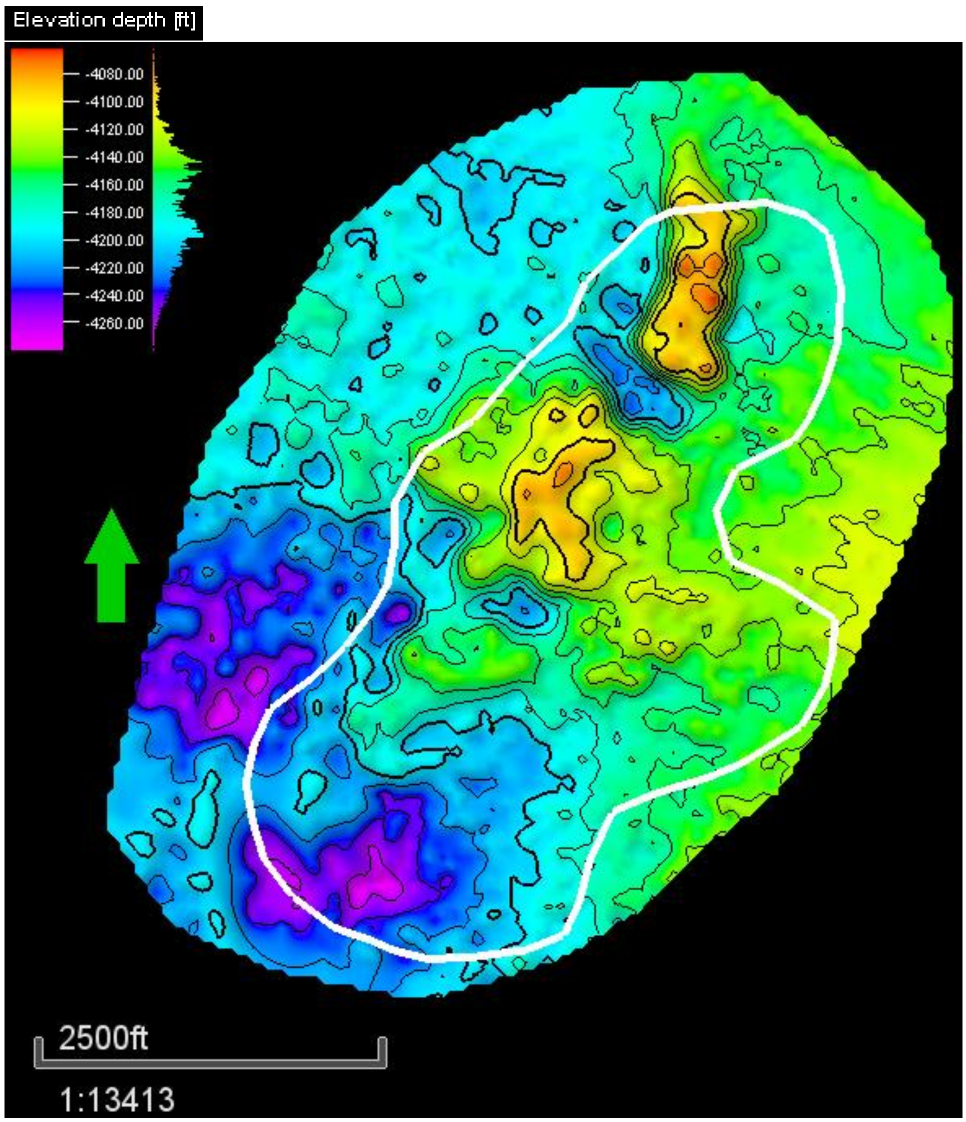


Figure 2.5.6: Structure map of the top of the reservoir.

From the analysis of wells logs, each well's oil saturation, porosity, and permeability has been identified around the borehole. Property maps have been constructed to identify these three properties throughout the reservoir, where Figures 2.5.7, 2.5.8, and 2.5.9 depict these properties.

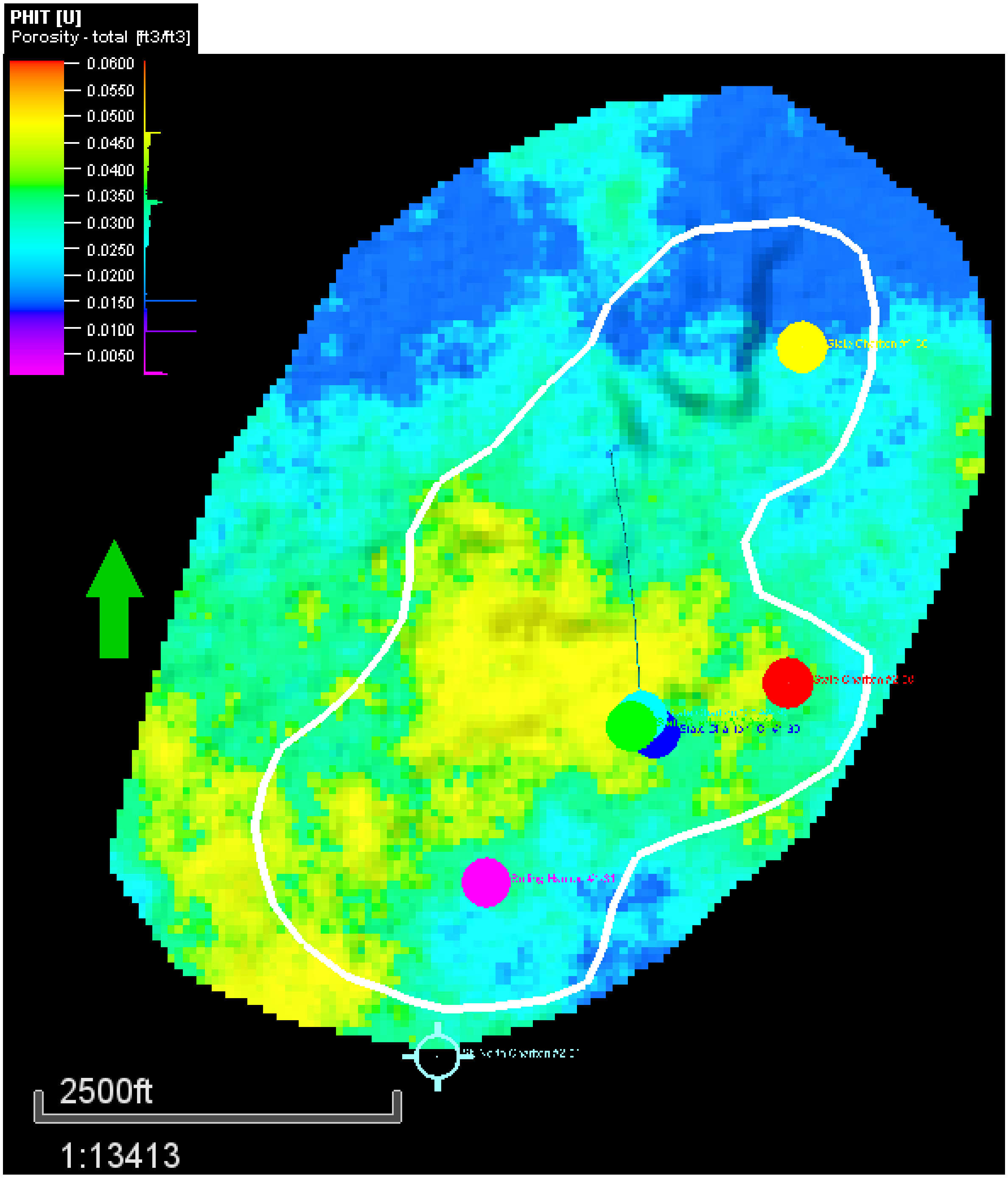


Figure 2.5.7: Porosity map of the State Charlton 30/31 reef.

Figure 2.5.7 displays a porosity map of Sate Charlton 30/31 reef located in Otsego County. Through the map, we can see the areas of porosity that the 7 wells have targeted. It can be observed from analysis of the map that the southwest location of the reservoir exhibits relatively good porosity in comparison to the rest of the reservoir and that the area has not yet been drilled into. Through this map, a relatively good area of porosity has been identified for potential development. The central part of the reservoir exhibits good porosity, however, the zone appears to be relatively crowded.

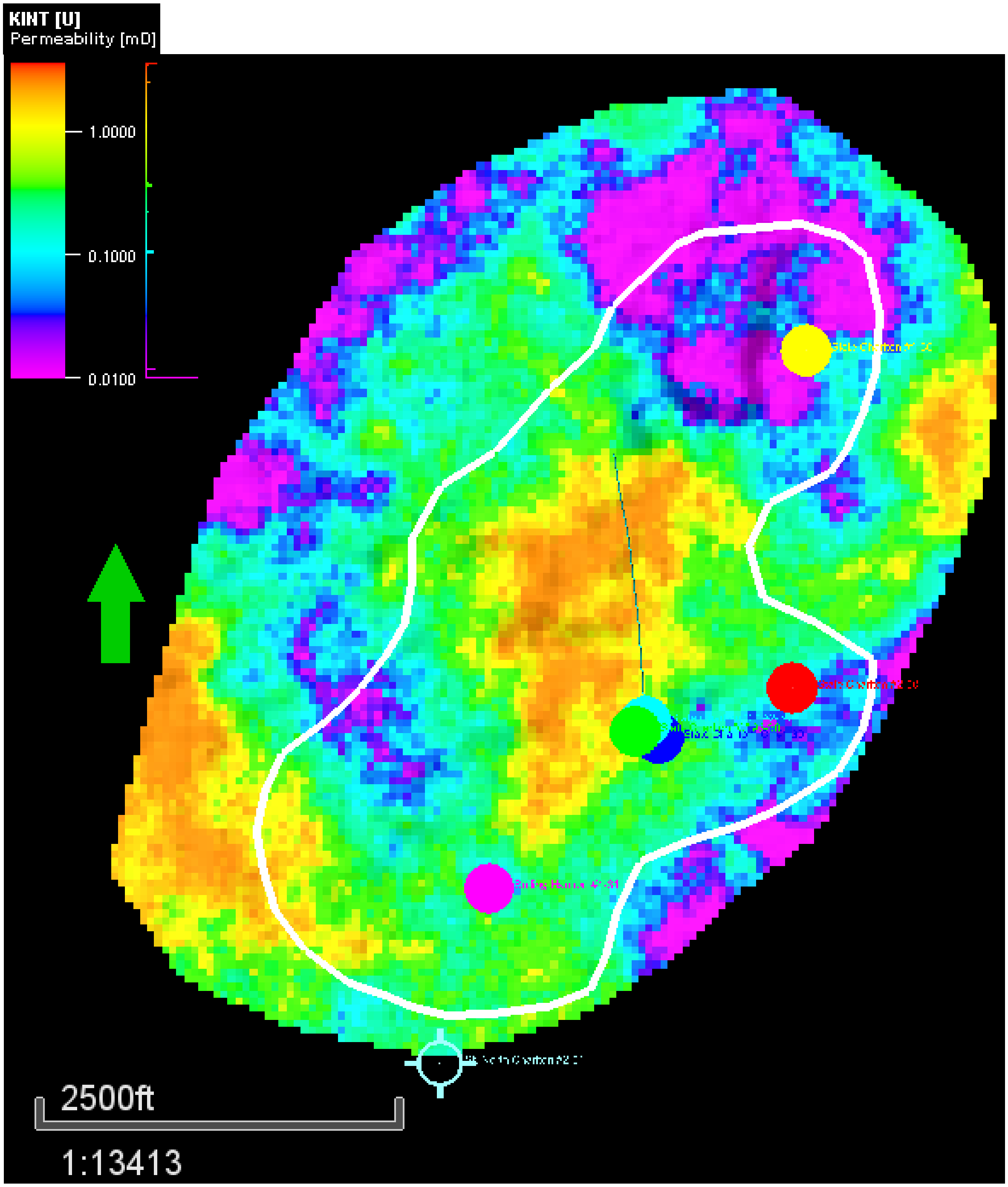


Figure 2.5.8: Permeability map of State Charlton 30/31 reef.

Figure 2.5.8 displays a permeability map of Sate Charlton 30/31 reef located in Otsego County. Through the map we can see the areas of permeability that the 7 wells have targeted. Analyzing the map, it can be observed that the southwest location of the reservoir exhibits relatively good permeability in comparison to the rest of the reservoir and that the area has not yet been drilled into. Through this map, a relatively good area of permeability has been identified for potential development. The central part of the reservoir exhibits good permeability, however, the zone appears to be relatively crowded. It should be noted that the entire reservoir exhibits low permeability but the areas noted appear to contain the best permeability. Since the State Charlton 30/31 reef is carbonate in nature, acid stimulation should be considered after planning where to drill additional boreholes. Therefore, this stimulation method will be explored later in the paper.

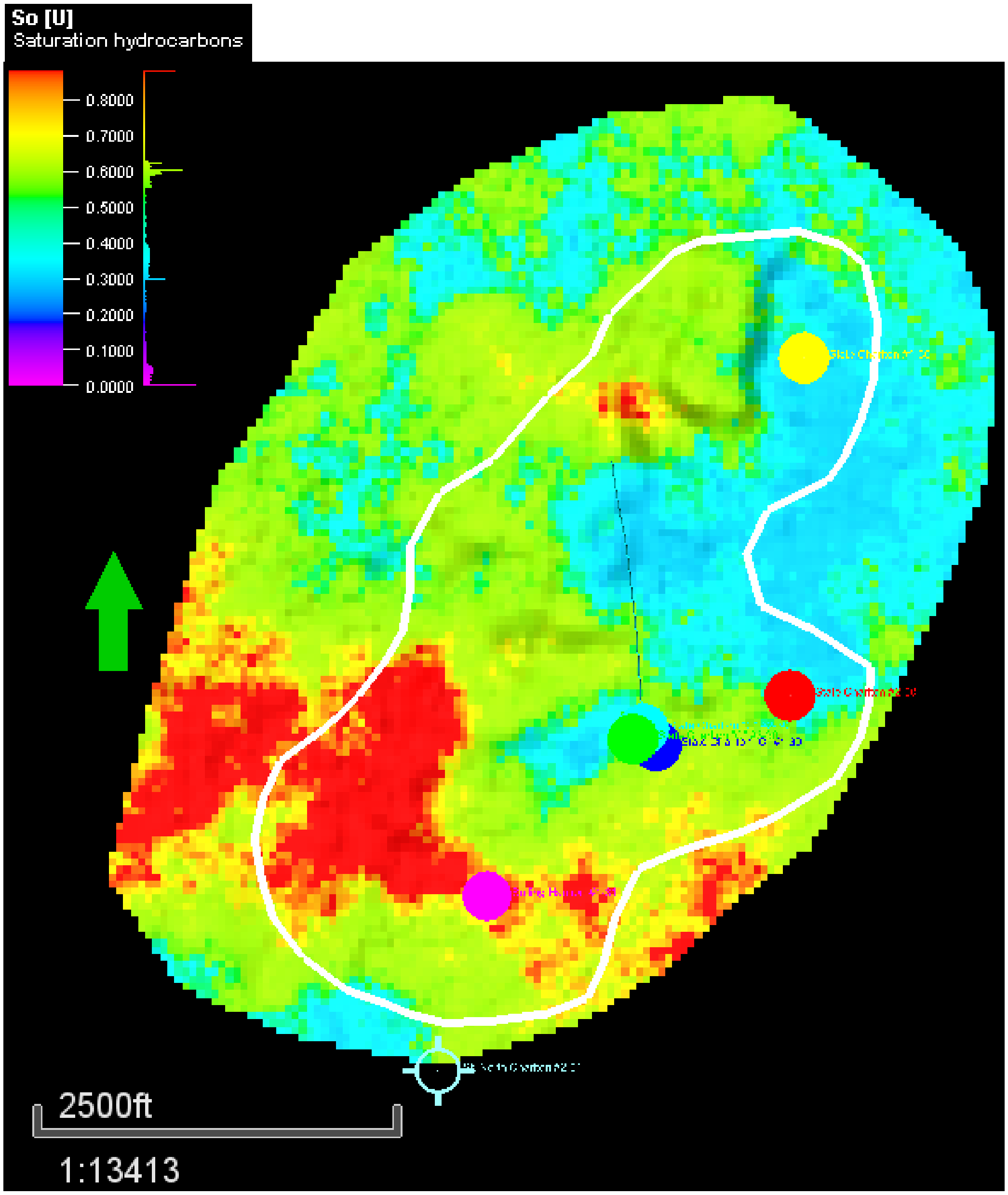


Figure 2.5.9: Oil saturation map of State Charlton 30/31 reef.

Figure 2.5.9 displays an oil saturation map of State Charlton 30/31 reef located in Otsego County. Though the map we can see the areas of porosity that the 7 wells have targeted. Analyzing the map, it can be observed that the southwest location of the reservoir exhibits excellent oil saturation in comparison to the rest of the reservoir and that the area has not yet been drilled into. Through this map, an excellent area has been identified for potential development.

Analyzing figures 2.5.7, 2.5.8, and 2.5.9 together, areas of higher porosity, permeability, and oil saturation have been identified. When analyzing all 3 maps together, it has been observed that the southwest corner of the reservoir exhibits the greatest values of all 3 properties. Through these maps, it can be seen that none of the wells have currently drilled into this location. Therefore, from this analysis, the southwest corner of the reservoir should be considered for future field development. This will be discussed in detail in section 2.5.3.

2.5.3 Planning of Wells

Analysis of the above property maps for porosity, permeability, and oil saturation is indicative of effective locations for primary recovery wells. Obviously, targeting areas with a higher volume of oil and rock with good permeability is the main goal. For this field, that area is the southwest corner of the formation shown in Figures 2.5.7-2.5.9 above. To try and show that better, a theoretical well has been moved around in Petrel until in a zone that exhibits the highest potential in all three categories with permeability being of most importance, porosity being of second importance, and oil saturation being of third importance. To show where this is on a map and to explain further, potential locations are indicated on a structure map of the Charlton 30/31 field (Niagaran Brown Top), Figures 2.5.10, 2.5.11, and 2.5.12, which are a property maps with a theoretical well, and a map that shows state lease ownership for townships surrounding the area, respectively. These will all be discussed in the order they are presented, followed by a comparison between them.

For moving the well into the correct location, the following process was used:

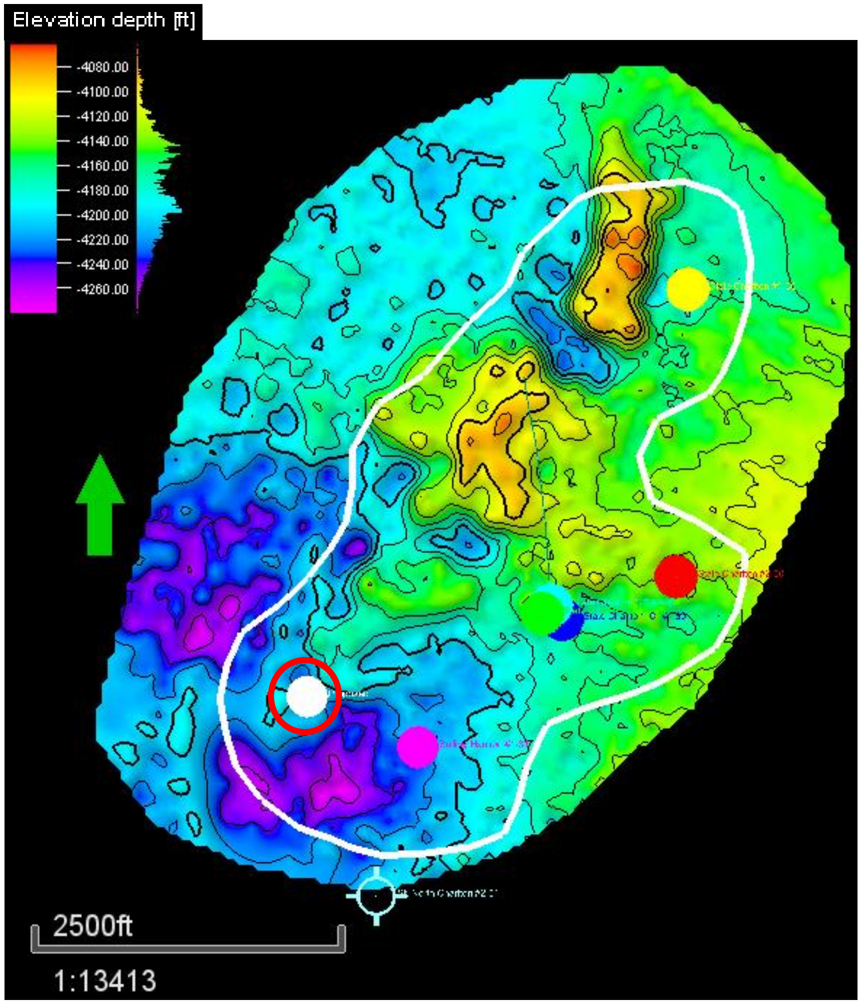


Figure 2.5.10: This is a structure map of the Charlton 30/31 highlighting where we would drill a vertical well.

Aside from the property interpretation, it is imperative to make sure that any new wells are drilled into the reef structure in order to produce oil.

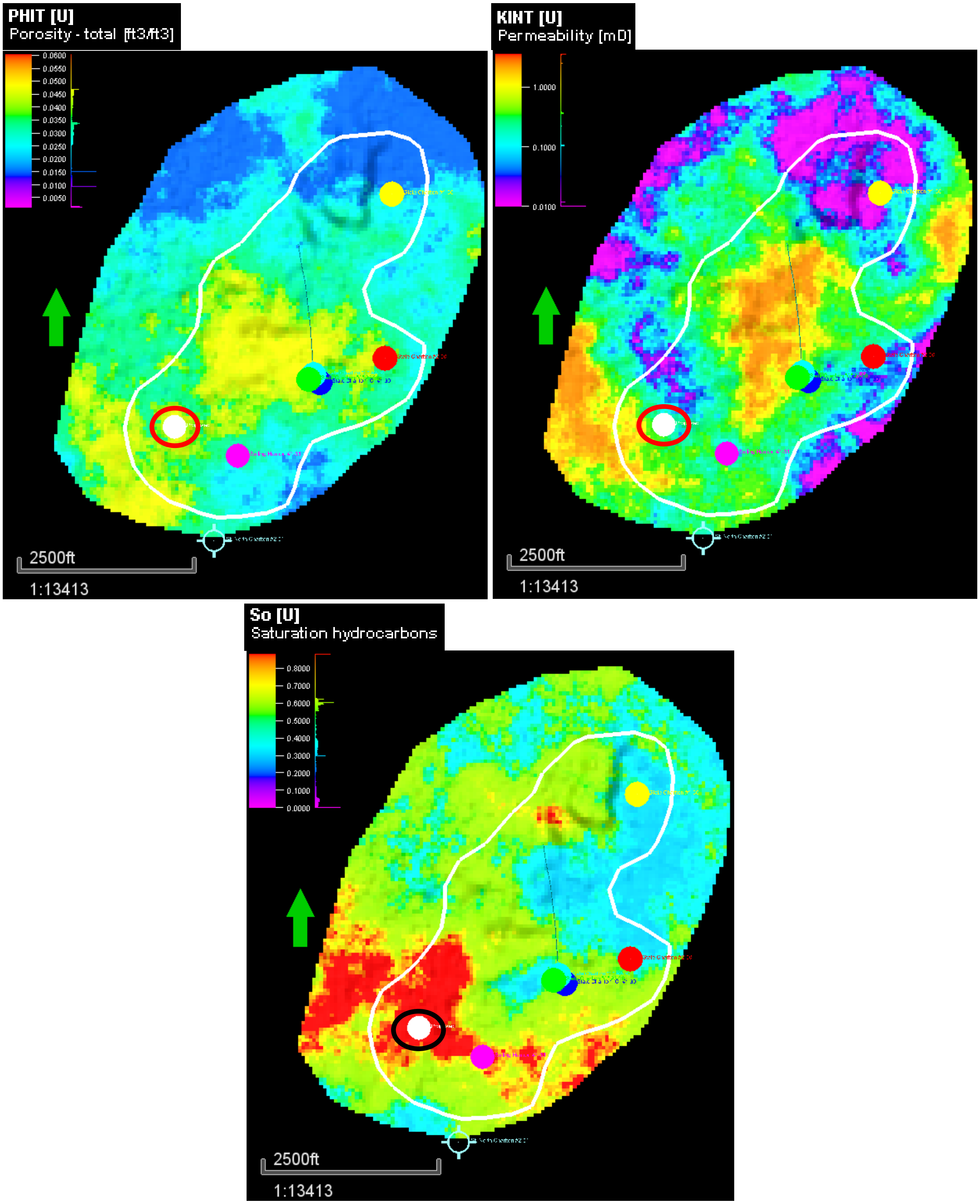


Figure 2.5.11: These are property maps showing the theoretical well. Top is the porosity map, bottom left is permeability map and bottom right is oil saturation map. The proposed well is inside of the red and black open circles on each picture.

Connections were made between figure 2.5.10 and figure 2.5.11 to find the best area for drilling. A location on the trap as well high values of desirable properties lead to the optimal placement of the new well as indicated by the red and black open circles.

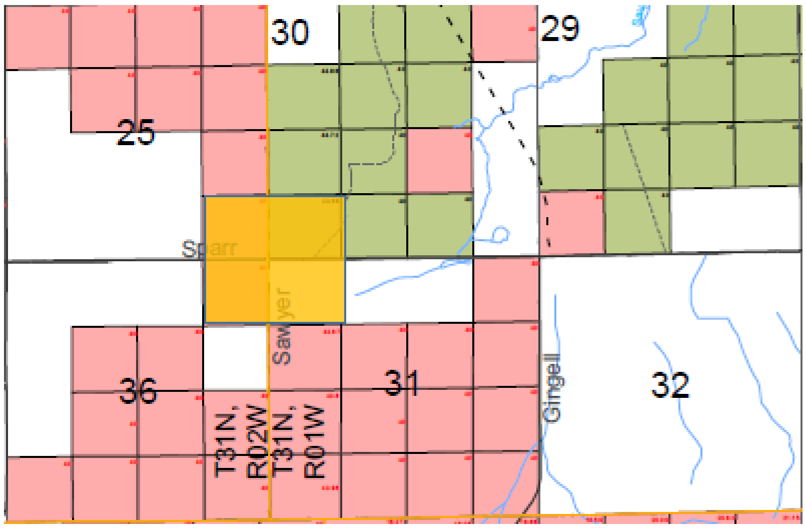


Figure 2.5.12: This shows the various state owned lease agreement information for each township in each section surrounding the wells in this project. The orange area is essentially where those wells are located, the red is state owned mineral rights, and the green is both state owned surface and mineral rights.

2.5.4 Lease Considerations

After identifying a location within the reservoir for future field development, a lease location must be identified to conduct the drilling operation. After analyzing figure 2.5.12, the lease location (T31N, R01W Section 30 (SW of SW)) will be the surface location for the drilling and completion of the proposal well.

2.5.5 Well Design

Since it is assumed for simplicity that a new vertical well would be drilled, another assumption that drilling methods would be similar to that of the Salling Hanson #1-31. A table has been created for typical drilling decisions made on this well. Table 2.5.1 is as follows:

Drilling and Well Info	Salling Hanson	
Casing Strings	16"	after 20 " hole to 100'
	11-3/4"	after 15" hole to 200'+ of base of glacial drift
	8-5/8"	after 10 5/8" hole to 100'+ base of Detroit River Evaporite
	5-1/2"	after 7 7/8" hole to TD, 5 1/2" liner
Oil Zone (Niagaran)	approx. 152'	
Perforations	2 shots per foot, 12 hole intervals of 22'	

Table 2.5.1: While drilling the Salling Hanson #1-31, Shell Oil Company had a permit for these steps along with very technical ones beyond the scope of this paper. We assumed similar basic drilling techniques to get to total depth instead of designing the entire drilling operation.

As can be seen in Table 2.5.1, Shell used general guidelines for running strings of casing of various sizes, how large the oil zone may be, and how many holes there will be before running tubing into the hole. These rules consist of drilling a 20" hole to 100 feet, running a 16" conductor pipe and cementing to surface, drilling a 15" hole to 200+ feet below the base of the Glacial Drift, setting 11-3/4" casing and cementing to surface, drilling a 10-5/8" hole below the base of the Detroit River Evaporite, setting 8-5/8" casing and running cement, and finally drilling a 7-7/8" hole to total depth, followed by logging and completing with a 5-1/2" liner. New wells today would probably be logged while drilled, however, for the sake of simplicity, it was assumed the drilling of the Salling Hanson would be representative of the drilling of a new producing well. Following drilling, production tubing would be run into the hole with a packer, and a 4-inch perforating gun would be used at two shots per foot to start production at that interval. Once the well no longer flows economically on its own, other means of lift and stimulations are desired.

Cement			
Hole size (")	Casing Size (")	Volume (ft^3)	20% Excess
20	16	72.22	86.664
15	11-3/4	396.6795117	476.015414
10.63	8-5/8	766.0564236	919.267708
7.88	5-1/2	405.5565875	486.667905

Table 2.5.2: Cement volume calculations for cementing casing in place.

Table 2.5.2 shows the amount of casing required to cement each string of casing in place when completing the proposal well. A 20% excess calculation has been used as well to take into account that some cement may be lost to the formation and due to the fact the wellbore may not be perfectly circular.

Due to the relatively low permeability the State Charlton 30/31 reef exhibits, an acid stimulation is recommended to optimize the hydrocarbon recovery efforts. An acid wash and an acid squeeze should be performed in the completion phase of the new wellbore. An acid wash will commonly be performed to remove skin damage located near the wellbore within the formation. Skin damage commonly occurs during drilling, completion, or by deposits from produced water. Commonly, the acid will be pumped at a lower pressure and below the reservoir fracture pressure, allowing the acid to restore natural permeability of the formation. By removing the skin damage, the well's productivity can be improved resulting in a production increase. An acid squeeze is performed by pumping acid at a high rate and pressure, but below the formation's fracture pressure. The acid will find the path of least resistance and travel through natural occurring fractures. As the acid passes through the formation it dissolves formation rock and cement located between the grains. The result is a much more permeable zone.

To ensure the acid is dispersed properly a foam diversion agent should be used. Foam chemicals are used in an acid stimulation to provide diversion and ensure uniform distribution throughout the targeted zone. Naturally the acid will follow the path of least resistance during a stimulation. Performing a stimulation with a foam diversion agent will allow the acid the ability to target areas that require more treatment and avoid zones that do not require the stimulation. Coiled tubing is recommended for the acid stimulation procedure.

2.5.6 Economics

During the initial planning of our project, there was incentive to evaluate new wells based on production data and well histories for the wells. However, the team ran into the problem of not being able to access accurate production data. The information they found is that the field did not start recording production data until 1982, years after most of them started producing. In a study by Dr. Toelle for his dissertation in 2012, the method the reservoir engineers for that project implemented was to run a reservoir simulation in time steps from which the initial reservoir volumetrically produced, and then another reservoir simulation on the static model after the ending of production in 1997. They then matched the costs of their wells with well histories to see if they matched up. Since this team did not define a reservoir simulation in the scope of the project, there was not enough time to learn CMG to run one, and therefore, economics with respect to production was not possible. Economics with respect to the cost of drilling a completing the well will be discussed.

In order to understand the cost of drilling and completing the proposal well, simple economics have been conducted with respect to the casing, rig rental, fuel, and acid stimulation cost.

Casing				
Casing size (")	Length (ft)	PPF	$/lb	Cost ($)
16	92	65	0.3	1794
11.75	837	47	0.3	11801.7
8.625	3650	36	0.3	39420
5.5	2342	17	0.3	11944.2
Total Cost				64959.9

Table 2.5.3: Casing cost of completing the proposal well

Table 2.5.3 examines the cost for each string of casing in the wellbore. The calculations have been performed based on 30 cents per pound of steel. Due to the current state of the industry, many companies are offering oil and gas companies reduced rates for their product. Typically the price for a pound of steel is around 50 cents but with the assistance of Professor Baum, a value of 30 cents per pound of steel has been used.

Rig Rental		
Days	$/Day	Cost ($)
19	7500	142500

Table 2.5.4: Rig rental cost for the proposal well

Table 2.5.4 shows the rig rental cost for the drilling of the proposal well. A value of $7500 a day has been used. This value has been obtained through Professor Baum. The 19 days to drill the well is based of the time it took to drill Salling Hanson. It should be noted that Salling Hanson was drilling in the 1970's and that over the past 40 years, technology with respect to drilling oil and gas wells have improved significantly. It can be concluded that the proposal well could be drilled potentially in 5-10 days.

Fuel			
Days	Volume (gal)	$/gal	Cost ($)
19	10000	2	380000

Table 2.5.5: Fuel cost for drilling the proposal well

Table 2.5.5 shows the cost of fuel for drilling the proposal well.

Acid Treatment	
Volume	Acid
4000 gal	28 % HCl
Cost ($)	125000

Table 2.5.6: Acid treatment cost for the proposal well.

Table 2.5.6 shows the cost of the acid stimulation that has been proposed. The treatment volume and acid type has been obtained though the stimulation program that was performed on the Salling Hanson well. A cost of $125000 has been obtained though past experiences when working with acid stimulations.

Proposal Well	
Location	T31N, R01W Section 30 (SW of SW)
Lat/Long	45.0410 / 84.4901
TD (ft)	5440
Formation	Niagaran Brown
Perforation Depth (ft)	5315 - 5440
Cost ($)	712460

Table 2.5.7: Summary of proposal well

Table 2.5.7 shows the total cost of drilling and completing the proposal well along with its location, depth, and producing formation. The latitude, longitude and perforation depth values are related to the proposal well in the Petrel model. These values would change in a real life scenario to ensure the optimum drilling program.

3. SUMMARY

In summary, the project was designed through five comprehensive phases. Each of those phases reassured a smooth transition from one phase to the next. A workflow diagram was constructed to highlight tasks and subtasks involved in each phase, as well as associative decision points. The workflow diagram also illustrated how the transitions from one task to another were made and highlighted project planning, construction of the static model, analysis of the model, drilling plans of additional boreholes, and economical evaluation.

A Gantt chart was also constructed to act as a guide when completing the project. The Gantt chart focused on each of the five phases and the timeframe associated with each phase. The Gantt chart also included an assignment breakdown of the team members responsible for each task. The Gantt chart was constantly updated as progress was made.

A risk analysis was constructed to highlight any potential risks associated within the project and proper steps that could be taken to mitigate those risks. This was important for nearly guaranteed complications that arose in the project. It was a good learning experience to brainstorm and experience the risks involved and handle the impact when something went wrong.

Through the workflow diagram, Gantt chart, risk analysis, and data review, data importation into Petrel was completed, which allowed the construction of the static model. The team interpreted the static model within Petrel (since the projection systems problem was mitigated). Drilling plans were also completed. The most optimal location of drilling was shown in various figures throughout the report. Finally, the economics phase was performed with respect to drilling and completing cost. Due to a lack in production data, a rate of return calculation was not performed.

4. CONCLUSIONS

In conclusion, this project was not as big a success as expected, however progress was made to integrate the knowledge of undergraduate petroleum engineering students with the knowledge of geologists. Integration is a huge part in the oil in gas industry, or any industry with people of mixed backgrounds. If two departments do not understand one another, they cannot work together or communicate. For this project specifically, the team learned what a static model was, what seismic data looked like, what interpreting that seismic data looked like, what porosity and permeability maps can influence drilling locations, and also how to operate a software that geologists (who, we have potential to work with) use in industry. That being said, our project was not externally successful, with Dr. Toelle's research being so similar. There was not any additional studies to what Dr. Toelle did besides research the drilling specific plans on these old wells (which he may have done, but was not the emphasis of his paper. Internally though, this project was a success. Now the team knows more about how finding fracture networks through structural maps created from seismic interpretation can give an idea of where to drill, what depth to drill to, and oil saturated porosity in the reservoir.

5. RECOMMENDATIONS

Based on the findings of the project, the team put together a few recommendations for future studies that could build on this study's results; the first being economics for the placement of the additional boreholes. Economics are an important phase when planning to do a project, such that everything involves efficiency of time and/or money. In the case of any project similar to the study above, each phase could involve its own economics portion. For instance, as a team working for a company plans out a project, it takes time away from actually performing direct tasks. Those employees still get paid for the time because careful planning tends to save the company money in the long run when mistakes are minimized. Even though Team 11 is not receiving a paycheck for their work, they receive a grade based on careful planning and another grade for project effectiveness. Those grades are valued about the same to undergraduate students trying to obtain their degrees as pay is to employees trying to keep their job (by impressing their boss through good work).

Another recommendation would be to obtain a regional study of the geology and formations around the Charlton 30/31. This would be appropriate in order to find where the source rock would yield the highest hydrocarbon content after having other wells in place. Unfortunately, most times it is not economical to run further analysis on a specific area because tools cost money, running these tools takes time away from production time which costs money from the production stream, and wells in the area producing already provides reassurance that there is a decent producing zone within the reservoir boundaries.

Perhaps another recommendation would be the research and implementation of Petrel or even CMG software to further analyze the project. Petrel's capabilities are much broader, from initial geological exploration capabilities through implementing reservoir simulation models and production data in CMG, which means the software could allow time to be managed more wisely in an organized manner. For someone wanting to further the ideas of this project in Petrel, they could immediately take the model, obtain previous production data, run a reservoir simulation, and predict areas and methods that would lead to a successful reservoir depletion (for either primary or secondary recovery). Thus, a step further than the above project would be to plan out wells, both injecting and producing, and run a simulation until the economic limit for the reservoir has been reached. With these recommendations, future studies on placement of additional wells for production in the Charlton 30/31 could be more efficient, and theoretically provide the most economical amounts of hydrocarbons in an actual company project.

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7. APPENDIX A: Given Data Set by Well

Well Name	UWI	County	State	TD (ft)	KB Elevation (ft)	X-Cord	Y-Cord	Lat	Long
State Charlton #1-30	29989	Otsego	MI	5650	1068	2291940.5	16375894	45.0501	-84.4781
Norman A. Wiegandt #2-11	33506	Otsego	MI	x	x	2290822	16375378	45.0050	-84.4784
State Charlton #2-30	31287	Otsego	MI	6251	1143	2291921.5	16373588	45.0438	-84.4784
State Charlton "C" 1-30	30195	Otsego	MI	5679	1182	2291019.5	16373217	45.0429	-84.4820
State Charlton "C" 3-30	32605	Otsego	MI	5746	1183	2290858.5	16373256	45.0429	-84.4826
Salling Hanson #1-31	29073	Otsego	MI	5770	1125	2289898.3	16372153	45.0400	-84.4826
State Charlton "C" 2-30	30203	Otsego	MI	6260	1182	2290928	16373312	45.0487	-84.4824
Black 1-11	28636	Otsego	MI	x	x	x	x	45.0071	-84.3986
State Charlton 2-31	33136	Otsego	MI	x	x	x	x	45.0368	-84.4878

Figure A.1: Individual well information from first semester.

Log Suites by Well						
Logs:	Delta -T	Gamma Ray	Nullified Pad	Total Porosity	Effective Porosity	Bulk Density
Locations						
State Charlton #1-30	✓	✓	✓	✓	✓	✓
Norman A. Wiegandt#2-11	×	×	×	×	×	✓
State Charlton #2-30	✓	✓	×	✓	✓	×
State Charlton "C" 1-30	✓	✓	✓	✓	✓	✓
State Charlton "C" 3-30	×	✓	×	✓	×	✓
Salling Hanson #1-30	✓	✓	✓	✓	✓	✓
State Charlton "C"2-30	✓	✓	×	✓	✓	×
Black 1-11	×	×	×	×	×	×
State Charlton 2-31	×	×	×	×	×	×

Figure A.2: Available log suites given for each well

Formation Tops:	State Charlton #1-30	State Charlton #2-30	Salling Hason #1-30	Norman A. Wiegan dt #2-11	State Charlton "C" 1-30	State Charlton "C" 3-30	State Charlton "C" 3-30	Black 1-11	State Charlton 2-31
Base of Drift	✓	✓	✓	×	×	×	×	×	×
Antrim Sh	✓	✓	✓	×	×	×	×	×	×
Traverse Fm	✓	✓	✓	×	×	×	×	×	×
Traverse Ls	✓	✓	✓	×	×	×	×	×	×
Bell Sh	✓	✓	✓	×	×	×	×	×	×
Dundee	✓	✓	✓	×	×	×	×	×	×
Detroit River	✓	×	✓	×	×	×	×	×	×
Base DR Evap	×	×	✓	×	×	✓	×	×	×
Amherstburg Fm	×	✓	✓	×	×	✓	×	×	×
Bois Blanc	✓	✓	✓	×	×	✓	×	×	×
Bas Is.	✓	✓	✓	✓	×	✓	×	×	×
Salina G	✓	✓	✓	✓	×	✓	×	×	×
Salina F	✓	×	✓	✓	×	✓	×	×	×
Salina F Salt	✓	×	✓	×	×	✓	×	×	×
F Salt 7	×	×	✓	✓	×	×	×	×	×
F Salt 6	×	×	×	✓	×	×	×	×	×
F Salt 5	×	×	×	✓	×	×	×	×	×
F Salt 4	×	×	×	✓	×	×	×	×	×
F Salt 3	×	×	×	✓	×	×	×	×	×
F Salt 2	×	×	×	✓	×	×	×	×	×
F Salt 1	×	×	×	✓	×	×	×	×	×
Salina E	✓	✓	×	✓	×	✓	×	×	×
Salina D	✓	✓	✓	✓	×	✓	×	×	×
Salina C	✓	✓	✓	✓	×	✓	×	×	×
Salina B	✓	✓	✓	✓	✓	✓	✓	×	×
Base of Salt	×	×	✓	✓	×	✓	×	×	×
A2Carb	✓	✓	✓	✓	✓	✓	✓	×	×
A2Evap	✓	✓	✓	✓	✓	✓	✓	×	×
A1Carb	✓	✓	✓	✓	✓	✓	✓	×	×
A1 Evap	×	×	✓	✓	×	×	×	×	×
Niag Brown AM	✓	✓	✓	✓	×	✓	×	×	×
Base of Reef	✓	✓	✓	×	×	✓	✓	×	×
Niagaran Gray	✓	✓	×	✓	×	✓	×	×	×

Figure A.3: Available formation tops for the given wells.

8. APPENDIX B: Petra Model Progress (December 2015)

After the first semester of the course, phase one of the project was drawing toward a close. It was also in the process of phase 2. Within phase one (planning, scheduling, and data review), the initial decision to use Petra to create the static model was implemented. All of the data was organized which included 3D seismic, well logs, formation tops, and PhD data. The data was interpreted and files were optimized for Petra input. Within phase two (building the static model), data was imported into Petra. The imported data includes:

- Individual well information
    - UWI, well number, well name, operator, well orientation, the active datum, and the county were all input individually. [Appendix A]
- Well locations
    - Individual latitude-longitude or XY coordinates were input for each well.
- Formation tops
    - Each formation top was input for each well by TVD. From this, Petra calculated MD and SS automatically. However, some assumptions have been made on each of the wells' formation tops for the time being. Corrections were to be made in the future.
- Suites of logs per well
    - Different logs were run on each of the individual wells and could be previewed for manual interpretation. The software was capable of reading the logs themselves. Well log interpretation in the software was to be researched upon importing the data so that all data could be interpreted.

- Topography
    - Topography was properly analyzed and imported into Petra. This can be shown in the model in Figure B.1.

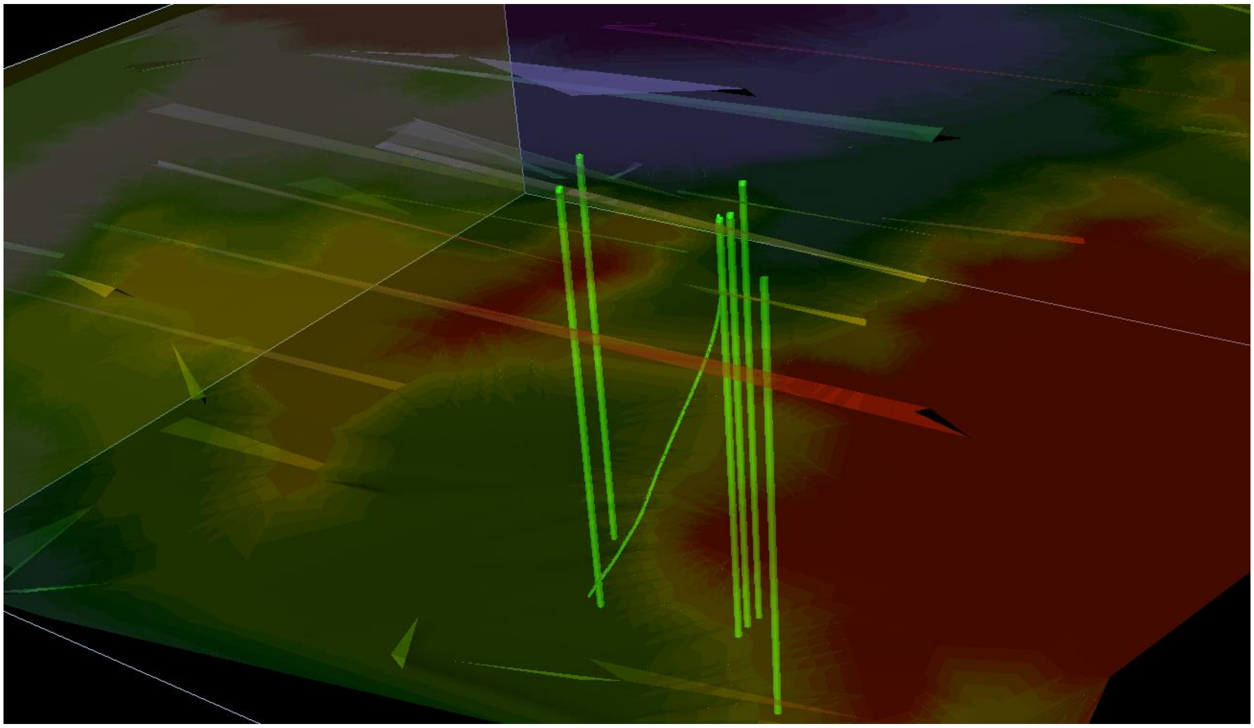

Figure B.1: This is an image of the 3D visualization model that was built in Petra. It should be noted that seismic data is not present, and that is a problem for identifying stratigraphy underneath the surface. Thus, the reason for switching to Petrel is prevalent.

Two complications rose as far as data loading went. Also the team's knowledge of Petra was not sufficient enough, so not all of the data was integrated and imported yet. The following data had yet to be input into Petra:

- Seismic Data
  - Petra does not handle 3D seismic data of .sgy files directly without the discontinued module called Petraseis. The team was in the process of looking at alternative input methods.
- Bottom hole locations
  - The team was in the process of analyzing files to properly identify each of the wells bottom hole location for Petra input. Unfortunately, it is hard to tell without a MD and TVD survey for each well.
- Formation top homogeneity
  - The team was in the process of analyzing files related to each of the wells formation tops. Correlations in each of the wells topography could allow the team to properly correlate the formation tops for each of the wells individually. Research into formation thicknesses could also aid in formation top correlations between wells.

As the process of inputting data progressed, a static model had begun to develop. Data for wells, formations, topography, etc. could all be extracted from Petra's interpretation and plotted on a 3D visual representation of the area, which to the team's understanding was the actual static model itself. Within the static model, all six of the vertical wells and one deviated well were developed. Within the seven total wells, each of the wells logs suites, topography, and formations tops with a few assumptions made concerning homogeneity were modeled. Moving forward within the static model, seismic data and correct formations tops would essentially lead to the development of a completed static model for interpretation for future field development. Depending on the success, or lack thereof, of the seismic data input into Petra, a transition to Petrel would be made for the full development of the static model.