Charlton 30/31 Field Development Project

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5/6/16

Professor Ken Baum
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Laramie, WY 82071

To Professor Ken Baum:

Please find enclosed the final report for the optimal field development plan of the Charlton 30/31 oil field in Otsego County, Michigan. To develop the field, the drilling of infill wells was proposed. However, reservoir simulations indicate that no new well placement scenario will improve oil production enough to make the field profitable. Furthermore, economic analysis reveals the wells currently producing from the field to be unprofitable. Therefore, it is recommended that no new wells be drilled and the wells currently producing from the field be shut it.

Sincerely,

Group #3
Charles Cole Monroe
Mitch Weigel
Darren Turner
James Segrave
Elizabeth Barsotti

Team Leader’s Signature: [Signature]

Elizabeth Barsotti
EXECUTIVE SUMMARY

From well log information on seven wells in the Charlton 30/31 Field and information in the literature about the productivity of those wells, it is clear that those wells are not producing optimally. Located in Otsego County, Michigan, the Charlton 30/31 Field contains wells that, though drilled more than forty years ago, have produced relatively small quantities of oil. For the first fifteen years of their lives, they produced almost no oil, while in the second half of their lifetimes they have produced some oil but with an appreciably large water cut. The objective of the Charlton 30/31 Field Development Project, is to drill a new production well to improve and optimize oil production from the field.

In accordance with a project plan developed during the Fall 2015 semester, Petrel and CMG have been used to create static and dynamic models of the reservoir. By comparing both models to information available the literature, they were validated. By identifying zones of high permeability, high porosity, and high oil saturation in the static model, three new well sites were proposed. CMG simulations were carried out for each of these sites to determine their productivity. Economic analysis was then carried out to determine their profitability. Based on the economic analysis, all of the new well sites were unprofitable. Further analysis revealed that if the reservoir were to keep producing with its current number of wells, it too, would become unprofitable in the near future. Therefore, it is recommended that to “optimize” the field, no new wells be drilled and all wells currently producing be plugged and abandoned.

In the case that the operator should disregard our recommendation, we have also provided permitting information for drilling new wells.
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<tr>
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<td>After Tax Net Cash Flow</td>
</tr>
<tr>
<td>EIS</td>
<td>Environmental Impact Statement</td>
</tr>
<tr>
<td>GI</td>
<td>Gross Income</td>
</tr>
<tr>
<td>IDC</td>
<td>Intangible Drilling Costs</td>
</tr>
<tr>
<td>IRR</td>
<td>Internal Rate of Return</td>
</tr>
<tr>
<td>JOA</td>
<td>Joint Operating Agreement</td>
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<td>LOE</td>
<td>Operating Costs</td>
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<td>Net Income</td>
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<td>Net Revenue Interest</td>
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<td>TAC</td>
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<td>TDC</td>
<td>Tangible Drilling Costs</td>
</tr>
<tr>
<td>TC</td>
<td>Technical Cost</td>
</tr>
<tr>
<td>TI</td>
<td>Taxable Income</td>
</tr>
</tbody>
</table>
1. Introduction

The Charlton 30/31 field is located in Otsego County in the central Michigan peninsula. It produces from the Niagaran formation, a limestone formation widely exploited throughout central Michigan for oil and gas. The Charlton 30/31 field is an oil field, which based on previous production data, has not produced much oil since its wells were drilled more than thirty years ago.\textsuperscript{1,2} Although the wells were drilled in the early- to mid-1970’s, production data is only available from 1982 onward.\textsuperscript{1,2} It can be divided into three time regimes: 1982-1992 exhibits a traditional decline curve, 1992-2004 the wells were shut in, and 2004-present a dump flood occurred and enhanced oil recovery by CO2 injection began.\textsuperscript{3–6} Production data from one of the wells in the field, the State Charlton 2-30, can be found in Figure 1.\textsuperscript{1,2}

![State Charlton 2-30](image)

\textbf{Figure 1}. Production data from the State Charlton 2-30 in the Charlton 30/31 Field. Courtesy of Michigan’s Department of Environmental Quality.\textsuperscript{1,2}

Due to the relatively poor performance of the field, the objective of this project is to design and drill a new production well to improve and optimize the performance of the field. To this end, a plan of action was developed in the Fall 2015 semester, and has been carried out in the Spring 2016 semester. The plan included the creation of a project work flow, Gantt chart, and risk analysis. Following the steps set forth in the work flow and Gantt chart, a static model and dynamic model of the reservoir have been built. These models have been analyzed to determine new well sites necessary to optimize production from the field.
2. Project Workflow

One of the most important aspects of designing a project is the development of the project plan. This plan is shown in the form of a workflow diagram in Figure 2. The workflow breaks down the project into a design phase and four development phases.

The workflow begins with the design phase in which teams are organized, a project is chosen, and development phases are generated for the project. After performing a risk analysis to ensure the most probable outcome of each of the development phases, initial and final designs are established. Based on the changing needs of the stakeholders and the possibility of new information on the Charlton 30/31 field becoming available, the final design will either be executed or altered.

Phase One involves the acquisition of well logs and geological information pertinent to the accurate determination of the Charlton 30/31 field properties. Data obtained from the literature is then compared to information from the well logs. If the two sets of information do not agree, further information must be acquired in order to properly determine formation properties of the Charlton 30/31 field. When the data sets do agree, Phase Two will commence.

Phase Two is centered on building a static reservoir model in Petrel, a software package by Schlumberger commonly used for static reservoir simulations. The well logs will be loaded into Petrel and interpreted to obtain the reservoir properties, such as porosity and permeability. Next, the reservoir properties will be statistically extrapolated to spread the rock and fluid properties throughout the field, which is represented by a series of gridblocks. Gridblocks are small volumetric representations of the reservoir, which when combined, will represent the field as a whole in the static model. The static model will be compared to data from the literature. When the static model does not agree with the data, the static model will be revised. When they do agree, Phase Three will begin.

In Phase Three, the static Petrel model will be loaded into CMG, a software package commonly used for dynamic reservoir simulations. Information on fluid properties of the Charlton 30/31 field will also be loaded into CMG. Using the Petrel model and the fluid properties, CMG will generate a dynamic model. The dynamic model will be refined through history matching of the available well data before being used to forecast the productivities of potential new well locations.

Lastly, Phase Four will entail economic analysis of the new well locations as well as acquisition of all the permitting information for the new wells. In the economic analysis, the costs and forecasted production of each scenario will be subjected to net present value (NPV), internal rate of return (IRR), and payback period calculations.

Based on the economic analysis, the scenario that is the most economically efficient will be chosen as the new wellbore location for the optimization of the Charlton 30/31 field, and permitting information will be acquired for it. Completion of the project will occur once the optimal scenario is determined.
Figure 2. Project Workflow.
3. Project Schedule

Imperative to successfully completing the project plan is the scheduling of the project. To ensure that enough time was allotted for the successful completion of each phase, the phases were split over two semesters. First, in the Fall 2015 semester, the planning phase of the project was carried out. Second, in the Spring 2016 semester, the development phases were carried out. A Gantt chart for the 2015/2016 year is given if Figure 3.

Do to the unpredictable nature of many of the tasks listed within the Gantt chart, individual tasks were not assigned to team members. Rather, each phase was assigned a “leader” who assigned the duties for that phase as he or she saw fit.
**Figure 3.** Project Gantt chart.
4. Risk Analysis

To ensure the successful completion of the project, risk analysis was carried out for each of the phases of the project.

In Phase One, much of the risk came from uncertainty of the accuracy of the parameters given in the well logs and gained from the literature review. Because the risk was not immediately apparent, much of the data had a high level of uncertainty, and the accuracy of the data had a large impact on the successful completion of the project. Phase One was considered to be high risk.

Phase Two, the creation of the static Petrel model, encompassed more moderate risks than Phase One. The most important of these risks was the ability of the static model to correctly identify regional and local sweetspots, which were crucial to the eventual design and placement of the new wells. This risk was easily mitigated, however, through validation of the Petrel model by comparison to other models available in the literature.

Phase Three, the design of the CMG dynamic model, was a high level risk. Phase Three involved the ability to create an accurate dynamic model. None of the team members had any previous experience with CMG; however, its completion and accuracy was vital to realistic predictions of future production from the reservoir. To mitigate some of this risk, history matching was carried out using production data available in the literature.

Phase Four, the economic analysis of potential well sites and the acquisition of permitting information for those well sites, primarily involved moderate risks except for permitting information and oil and gas prices. The moderate risks were mitigated through consultation with industry experts, who provided estimates for drilling and completions costs in central Michigan, along with values for typical economic figures, such as rates of return and interest rates. Permitting information was readily available from Michigan’s Department of Environmental Quality and so needed no mitigation. Conversely, the high risk associated with the price of oil could not be mitigated. Methods for forecasting oil prices, such as the Monte Carlo method, were considered, but were ultimately found to be unreliable. Therefore, the current price of oil was used rather than estimations of future prices.

A list of all of the risks which were encountered throughout the Charlton 30/31 Field Development Project can be found in Figure 4, where they are grouped in terms of low level, moderate, and high level risks.

Figure 4. Risk analysis chart of the low, moderate, and high level risks for the Charlton 30/31 project.

**LOW LEVEL RISKS**
- Permitting Information

**MODERATE LEVEL RISKS**
- Petrel’s Software Calculations
- CMG’s Software Calculations
- Calculated/Interpreted Variables from Well Logs
- Interest Rates for Future Calculations
- Internal Rate of Return
  - Net Present Value
  - Payback Period
- Cost of Drilling & Completions
- Economic Limits
- Reserve Calculations

**HIGH LEVEL RISKS**
- Undetectable Faults
- Correctness of Static Model
- Correctness of Dynamic Model
- Production History Matching
- Correct Identification of Regional and Local Sweet Spots
- Price of Oil & Gas
  - Well Logs
- Literature Review
  - Seismic
- Production History
  - Well Locations
5. Data Review

The data available for the Charlton 30/31 field includes drillers’ logs,\textsuperscript{1,2} permit information,\textsuperscript{1,2} environmental impact statements and location reports,\textsuperscript{1,2} as well as wireline well log data. Each of these contains an immense amount of data. For example, the drillers’ logs contain well names and numbers, locations, deviation data, stimulation records, the type of fluids encountered downhole and their depths, casing and cementing information, types of well logs that were run and their depths, stratigraphic intervals and their formation-top depths, and physical descriptions of formations from samples.\textsuperscript{1,2} Likewise, the wireline well logs give detailed explanations and representations of the rock and fluid properties that exist downhole, while the permit information was used to locate production data from wells in the field. This historical production data formed the basis for production forecasting for the new wells.

6. Project Results

6.1. Static Model

The available well logs were loaded into Petrel, and their values were interpolated to generate a static model of the reservoir. Static reservoir models are representations of the fluid content and geology of the reservoir at a single point in time. Of primary importance was information about the porosity, permeability, and oil saturation of the reservoir, since these three characteristics formed the criteria for the initial evaluation of the reservoir for new well locations. Maps of the porosity, permeability, and oil saturation of the reservoir as generated in the static model can be found in Figures 5a-5c.
6.2. Dynamic Model

By loading the static model into CMG along with additional rock and fluid properties, such as rock compressibility and oil density, the dynamic model was generated. Dynamic models are extensions of the static model meant to forecast changes to the reservoir over user-defined time intervals. In doing this, maps similar to those from the static model were produced. Maps for the porosity, thickness, permeability, and oil saturation can be found in Figures 6a-6d.
6.3. Validation of the Models

The static model was validated by comparing it to the static model presented by Toelle (2012).³

As shown in Figures 7a and 7b, our static model closely matches the values found for porosity in the Toelle (2012) model. Because Toelle (2012) used history matching to validate their model, and the model was found to be accurate, we assumed the accuracy of our model simply because it closely matched that of Toelle (2012).³

The dynamic model was validated through history matching. According to the literature, the Charlton 30/31 field has produced 2.4 MMBO.³ Conversely the dynamic model was only able show the production of 136.3 MBO over the same time period. We attribute the large difference between actual production and simulated production to both incomplete and inaccurate data for the field. For instance, the production data, which was obtained from the Michigan DEQ, was accurate for the field, but not for each well.¹² According to the DEQ, all wells have the same production data, indicating that when it was reported,
the data for the field was equally divided among the wells and is not representative of the actual production from each well.\textsuperscript{1,2} Likewise, data from approximately the first ten years of production is missing altogether.\textsuperscript{1,2} Furthermore, there is no data for any of the CO2 injection wells or on the dump flood. Regardless, because no other data could be obtained from elsewhere in the field or from Core Energy, the field’s current operator, the dynamic model was used for all production forecasting.

6.4. Determination and Evaluation of New Well Locations

Using the static model, three potential locations for new wells were chosen based on high permeability, high porosity, and high oil saturation zones. The static model was used to locate these areas, merely because it was more efficient than waiting for the dynamic model to be complete – in accordance with the Gantt chart, the static model was completed well before the dynamic model. These three locations can be found in Figure 8 where they overlay the permeability model and are designated by a white “x,” a black “x,” and a red “x.”

\textbf{Figure 8.} New well locations.
6.5. Optimization Plan for the Field

CMG simulations were carried out for each case. The forecasted production of the field when each case was implemented can be found in Figure 9. Note that the base case is merely the forecasted production of the field without any additional wells. In forecasting the production, new wells were assumed to be drilled in 2016, to come on line in 2017, and to produce for 15 years. Fifteen years was chosen as a reasonable timeframe for which the dynamic model and economic calculations may remain accurate.

![Charlton 30/31 Field Yearly Oil Production vs. Time](image)

**Figure 9.** Forecasted production from the field found using the CMG model.

Using the forecasted production and the assumptions found in Table 1, the net cash flows for each case were calculated based on the method presented by Mian (2011)\(^7\) and can be seen in Figure 10.

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<tr>
<th>General Info</th>
<th>CAPEX</th>
<th>OPEX</th>
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<tr>
<td>Production Start</td>
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<td>Drilling ($M)</td>
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<tr>
<td>Production Until</td>
<td>2031</td>
<td>Completion ($M)</td>
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<tr>
<td>Royalty Burden</td>
<td>0.125</td>
<td>Facility ($M)</td>
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<tr>
<td>Working Interest</td>
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<tr>
<td>NRI</td>
<td>0.875</td>
<td></td>
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<tr>
<td>Oil Price ($/STB)</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>Gas Production</td>
<td></td>
<td>Flared</td>
</tr>
</tbody>
</table>

**Table 1.** Economic assumptions. CAPEX and OPEX values courtesy of Mike Palmer.\(^{10}\)
Because none of the new well placement scenarios resulted in a positive net cash flow, as shown in Figure 10, it was determined that no new wells should be drilled in the field.

To determine the profitability of the reservoir without drilling any new wells, the base case was analyzed at various discount rates as shown in Figure 11.

**Figure 10.** Net cash flows of each of the three new well placement scenarios. Calculation method may be found in Mian (2011).³

**Figure 11.** Net cash flow of the base case for a variety of different discount rates.
As shown in the Figure 11, not even the base case is economic. Therefore, the final recommendation for the optimization of the Charlton 30/31 field is to not drill any new wells and to shut in all wells currently producing from the field.

Further calculations were made to determine which conditions would have to be met in order for the base case to become economic. The results of these calculations can be found in Table 2.

<table>
<thead>
<tr>
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<th>NPV @ 10% &amp; 15 YRS ($MM)</th>
<th>IRR</th>
<th>Technical Cost ($/STB)</th>
<th>T.C. ($/STB) Disc. @10%</th>
</tr>
</thead>
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<tr>
<td></td>
<td>$</td>
<td>170%</td>
<td>$</td>
<td>$</td>
</tr>
<tr>
<td></td>
<td>($1.80)</td>
<td></td>
<td>$570</td>
<td>$518</td>
</tr>
</tbody>
</table>

*Table 2. Conditions that must be met in order for the base case to become profitable.*

### 6.6. Acquisition of Permitting to Drill New Wells

In the case that a new well were to be drilled, however, the permitting process for Michigan has been thoroughly researched. In order to drill a new oil well in the state of Michigan, the operator must submit applications to the Michigan Department of Environmental Quality. This ensures compliance with environmental regulations.

The instructions for preparing an application to drill and operate an oil well are available to the public from the Michigan Department of Environmental Quality. Administratively complete applications are considered for permitting and usually receive a decision within 50 days of submittal. In order for applications to be “administratively complete,” the following forms must be filled completed: *Application for Permit to Drill and Operate a Well, Survey Record of Well Location, Bond for Conformance, Wellhead Blowout Control System, Well Permittee Organization Report, Inject Well Data, Soil Erosion and Sedimentation Control Plan, and an Environmental Impact Assessment.*

The first form in the application process, *Application for Permit to Drill and Operate a Well*, gives a general overview of the well to be drilled. It includes descriptions of the well location, the type of well to be drilled, and the drilling, casing, and cementing programs to be used. The *Survey Record of Well Location* discusses the surface location of the well, the deviation of the wellbore, and the proximity of the well to both man-made infrastructure and locations of environmental sensitivity. The *Bond for Conformance* form includes legal information pertinent to the operating company. Safe drilling processes are supported by the *Wellhead Blowout Control System* form which describes the blowout preventer that will be used to drill the proposed well. This form includes references to the maximum anticipated surface pressure, the annular B.O.P. rating, the B.O.P. ram rating, the valve and check valve ratings, the spool, and the well head configuration. In addition, this form requires the test pressures and procedures used to pressure test the B.O.P. The *Well Permittee Organization Report* form provides more information on the operating company. It describes the organization plan, the principals responsible for operational decisions, and the employees submitting the application. The *Soil Erosion and Sedimentation Control Plan* is responsible for describing well site size, facility size, access road size, and flowline size. This form also describes the requirements for control structures. Lastly, this form is responsible for describing site restoration. The *Environmental Impact Assessment* further discusses route and well site dimensions and proximity to important environmental structures.

Clearly, the process set up by the Michigan Department of Environmental Quality ensures that the drilling of new oil and gas wells respects the environment.
7. Summary

In summary, following a workflow diagram and a Gantt chart created in the Fall 2015 semester, the Charlton 30/31 field development project has been completed. A static model and a dynamic model of the reservoir were built using available well logs and data in the literature. Using both models, several new well sites were chosen and evaluated. Based on economics, the most profitable scenario has been chosen for optimization of the reservoir. Permitting information for new wells in Michigan has been collected, so that the well need only be drilled to optimize the reservoir.

8. Conclusions

Using the project plan set forth in the Fall 2015 semester, the Charlton 30/31 field optimization project has been completed. Based on the results of reservoir simulations and economic analysis, it is recommended that no new wells be drilled and all current wells in the field be shut in. Acquisition of more reliable data, however, could lead to an alteration of these results.

9. Recommendations

Based on the relatively small quantities of oil being produced from the Charlton 30/31 formation, future studies on the subject of its optimization should include in depth studies of various enhanced oil recovery methods beyond the scope of this project. In particular, case studies on the properties of specific rock and fluid samples from the field may ultimately lead to plans for carbon dioxide or surfactant flooding which may, in turn, result in better oil recovery than our generalized, macroscopic approach.
BIBLIOGRAPHY

9. Benjamin Cook, PhD. *Interview*.
10. Mike Palmer. *Interview*.