PGE 383 Project Update #2 - Team 01

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1 Executive Summary

Reservoir Subsurface Team 1 has continued evaluation of the 271 wells and has initial assessment of bulk reservoir characteristics (heterogeneity, oil in place). This update includes efforts taken to mitigate spatial sampling bias, differences between facies encountered, assessment of reservoir heterogeneity, and development of an initial uncertainty model. The potential impact of drilling 10 additional wells is also evaluated.

The spatial sampling bias in the data collected has been accounted for. Additionally, it has been determined that the two facies identified (sandstone and shale) are statistically different from each other in terms of their porosity and permeability characteristics. Static measures suggest the reservoir is very heterogeneous with certain portions of the reservoir contributing more to production. For the reservoir in question, the Lorenz coefficient was found to be 0.686. The estimated mean value of oil in place is approximately 15.27 million of barrels with a standard deviation of approximately 3 million of barrels. Uncertainty analysis revealed that the development of 10 additional wells would change the predicted standard deviation for predicted oil in place by 0.01. We therefore advise against the development of new wells solely for the reduction of uncertainty.

2 Description of Workflows and Methods

The following steps were conducted in an annotated Python Jupyter Notebook:

1. Declustered spatial well data (Cell Declustering)
2. Tested significance of difference in mean porosity and permeability between the facies (Hypothesis Testing)
3. Reevaluated univariate statistics based on declustered data
4. Assessed heterogeneity in the reservoir (Coefficient of variation, Dykstra-Parsons, and Lorenz)
5. Developed initial uncertainty model of porosity and permeability (Bootstrap)
6. Estimated facies proportions and oil in place (Bootstrap)
7. Assessed impact of 10 additional wells on the uncertainty model

3 Results

3.1 Cell Declustering

Cell declustering was applied to account for the biased spatial sampling of the reservoir. Spatial weights were calculated and are displayed in Figure 1. Larger circles and warmer colors indicate larger declustering weights while smaller circles and cooler colors indicate lower weights. Univariate statistics for porosity and permeability were recomputed based on these weights and are given below. Sample statistics were computed individually by facies, as well as for the entire reservoir using both raw (outliers present) and cleaned (outliers removed) datasets.

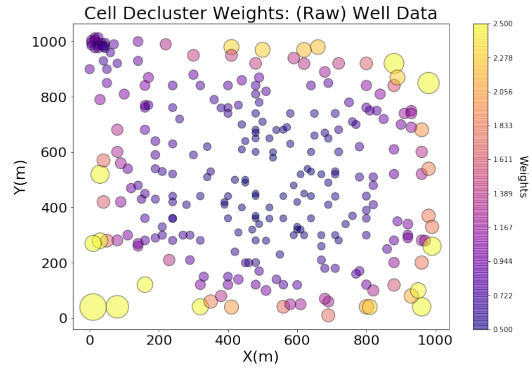

Figure 1: Cell Declustered Data

Declustered Univariate Statistics				
Facies	μ_{Perm} (mD)	σ_{Perm} (mD)	μ_{Por}	σ_{Por}
Reservoir (Cleaned)	14.37	28.76	0.132	0.024
Sandstone (Cleaned)	20.85	33.69	0.141	0.021
Shale (Cleaned)	2.04	2.90	0.116	0.021
Reservoir (Raw)	317.76	2045.2	0.135	0.028
Sandstone (Raw)	480.61	2509.5	0.145	0.025
Shale (Raw)	7.03	23.64	0.115	0.021

Table 1: Univariate statistics after declustering for both raw and cleaned datasets (outliers present/outliers removed)

3.2 Porosity and Permeability by Facies

The t-test and Welch's t-test were conducted to test the porosity and permeability distributions of each facies (sandstone and shale). For the porosity values, p-values of ~ 0.0 were computed from both the t-test and Welch's t-test, suggesting that the **mean values of porosity are statistically different between facies**. Permeability data was inconclusive with the t-test reporting a p-value of 0.14 and the Welch test reporting a value of 0.007. An F-test was conducted to determine whether the variance of the sandstone permeability and the shale permeability data were equal; the p-value computed from the F-test was ~ 0.0, suggesting unequal variance. Therefore the conclusion from the Welch test is used, which is that the **mean permeability values from each facies are statistically different**.

3.3 Assessment of Heterogeneity

Reservoir heterogeneity was characterized through computation of 3 different static measures. Namely, the coefficient of variation, Dykstra-Parson's coefficient, and the Lorenz coefficient. These static measures were computed by facies as well as for the overall reservoir. In the case of the Lorenz coefficient, a reservoir thickness of 20 meters was assumed. Static measures were computed for both cleaned data (without outliers) as well as for the raw data of all 271 wells.

Static Measures for Reservoir Heterogeneity			
Facies	Coefficient of Variation	Dykstra-Parson's	Lorenz Coefficient
Reservoir (Cleaned)	2.001	0.883	0.686
Sandstone (Cleaned)	1.616	0.875	-
Shale (Cleaned)	1.423	0.867	-
Reservoir (Raw)	6.436	0.912	-
Sandstone (Raw)	5.220	0.871	-
Shale (Raw)	3.363	0.867	-

Table 2: Static measures to address and classify reservoir heterogeneity for both raw and cleaned datasets (outliers present/outliers removed

3.4 Reservoir Uncertainty Model

Bootstrapping was applied to the porosity and permeability data by facies to characterize the uncertainty surrounding the mean and standard deviation values of those parameters. All of the well data was considered in this analysis, leaving the results suceptible to outlier effects.

Porosity and Permeability Mean Uncertainty (By Facies)					
Property	Mean	Variance	P10	P50	P90
Sandstone Porosity	0.145	3.15	0.143	0.145	0.148
Shale Porosity	0.115	7.21	0.112	0.115	0.119
Sandstone Permeability	470.4	29178	258	461.0	698
Shale Permeability	21.28	94.66	5.954	20.34	33.29

Table 3: Uncertainty in the mean values of porosity and permeability (by facies)

Porosity and Permeability Standard Deviation Uncertainty (By Facies)					
Property	Mean	Variance	P10	P50	P90
Sandstone Porosity	0.025	1.4787	0.023	0.025	0.027
Shale Porosity	0.0209	3.1297	0.019	0.021	0.023
Sandstone Permeability	2346.76	562678	1303	2426	3270
Shale Permeability	21.28	94.66	5.96	20.34	33.29

Table 4: Uncertainty in the standard deviation values of porosity and permeability (by facies)

Facies Uncertainty Model

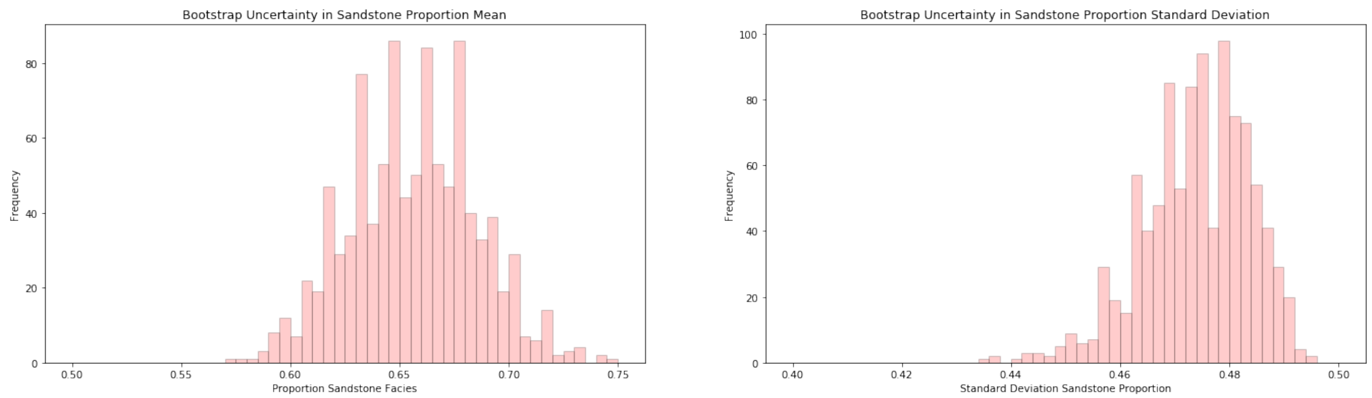

Figure 2: Uncertainty in mean and standard deviation estimates of facies proportions (Proportion of sandstone displayed)

The uncertainty about the proportion of sandstone in the reservoir is depicted in Figure 2. The distribution of the mean value of the sandstone proportion is on the left, centered around a value of 65.6% sandstone. The standard deviation distribution is on the right, centered around a value of 0.47.

3.5 Estimation of Oil in Place

To make an initial estimation of oil in place, some assumptions were made. Future updates will relax these assumptions to more accurately depict the uncertainty in the reservoir model. Currently, the oil saturation ($S0$) in the reservoir is assumed to be 90% and the thickness of the field is 20m. The estimated Oil In Place (OIP) is computed using the following formula: $OIP = s0 \times V \times \text{Porosity} \times 6.29$ where V is the volume of the field. For this analysis, the porosity values are acquired via bootstrap from the declustered porosity data.

Oil in Place Uncertainty Model

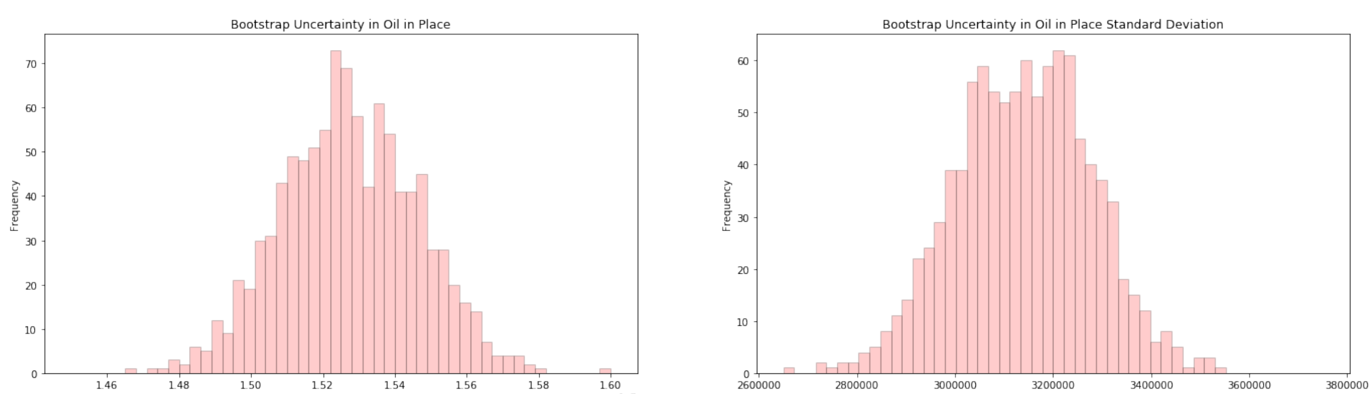

Figure 3: Uncertainty in mean and standard deviation estimates of the oil in place

The estimated mean value of oil in place is approximately 15.27 million of barrels. The average standard deviation about the estimated oil in place is approximately 3 million of barrels, and in future analyses we will work to reduce this uncertainty.

3.6 Impact of 10 Additional Wells

When 10 additional wells are considered, we assume that the 10 additional wells are from the same distribution as our prior 271 wells. Therefore the addition of 10 wells represents an increase of only about 4% of information. We simulate this impact by increasing the number of samples drawn during bootstrapping by 10. The change in the predicted standard deviation for the oil in place estimate was on the order of 0.01% and therefore deemed to be negligible.

4 Conclusions

Based on the data and analyses done, the reservoir was found to be extremely heterogeneous with a reservoir-wide coefficient of variation of 2.00 as well as a Dykstra-Parson's coefficient of 0.883. This information is crucial to constraining the interpretation of the depositional environment. It was also found that the coefficient of variation is sensitive to outliers in the dataset due to the strong dependence on the sample variance. Future work for assessing the heterogeneity of the reservoir should include dynamic measures including flow simulation. Furthermore, spatial declustering was performed on the data set and new summary statistics were presented. Hypothesis testing of the facies suggest statistically different values for porosity and permeability between the two facies (sandstone and shale). New analyses suggest a decrease in the average reservoir porosity and permeability from earlier predictions. The estimated oil in place is approximately 15.27 million of barrels, but we note that this is an early estimate with high uncertainty. The impact of drilling 10 additional wells is negligible in order to decrease the uncertainty.