

# Natural Reservoirs Task Methodology

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## Abstract

Task 2 for this project involves the mapping and characterization of natural reservoirs within the Appalachian Basin region of New York (NY), Pennsylvania (PA), and West Virginia (WV). The intention of this memo is to present the methods that have been used for the completion of this task's milestones. The reservoir data collection and compilation methods used for NY are different than those used for PA and WV, as will be described below. Reservoir analysis and uncertainty quantification methods are consistent across the tri-state region.

## 1 Sources of Existing Data

Phase 1 of this project was limited to the analysis of existing data. Because drilling for oil and gas in the Appalachian Basin has taken place for over a century, the petroleum industry has vast amounts of data for reservoirs. For the purpose of Phase 1, only proven hydrocarbon reservoirs were considered; future work may include the consideration of dry, or non-producing, reservoirs.

### 1.1 Terminology

The oil and gas industry uses the term *field* to describe a group of wells that all penetrate into the same formation to produce oil or gas; therefore, all sources of data for this project used the term *field*. However, in the geothermal industry, the term *reservoir* is more commonly used, to mean a given volume of heated and permable rock from which heat can be extracted using circulation of fluids. A *field* and a *reservoir* are essentially the same thing, but the perspective is shifted from the wells to the entire body of rock. All cases where the term *field* was encountered in our original datasets were changed to *reservoir* for the remainder of the project.

### 1.2 Pennsylvania and West Virginia:

Extensive data collection and reservoir mapping work was completed in the early 2000s for the purpose of carbon sequestration research. Geographic Information System (GIS) data from the Midwest Regional Carbon Sequestration Partnership (MRCSP) was available for use as a starting point for this project. The dataset includes oil and gas reservoirs located in PA and WV, but does not include reservoirs in NY. New York joined the Partnership years later with a different methodology, and their dataset did not include GIS work. The MRCSP calculated potential storage volume for the reservoirs by using a volumetric analysis (total volume of rock corrected by reservoir porosity). The dataset included the following reservoir parameters:

1. Average reservoir production depth
2. Reservoir name
3. Formation code (geologic code for the producing formation)
4. State

5. Reservoir Latitude and longitude
6. Reservoir area
7. Reservoir pressure
8. Porosity
9. Net thickness
10. Shapefiles (polygons) to use in a GIS

### 1.3 New York:

Data collection began with the work done by the geologists at the New York State Geological Survey (NYSGS) for their carbon sequestration analysis, and continued using well data from the Empire State Organized Geologic Information System (ESOGIS) database. The carbon sequestration research was used as a starting point, as all viable reservoirs in NY deeper than 2000 feet were considered. That work provided us with a baseline list of reservoirs to consider. That list was then cross-checked with data of producing wells on ESOGIS, and well locations and associated data were downloaded and saved in a GIS. Polygons were not available, so we were required to create reasonable buffer zones around wells that pertained to a given reservoir. For details on the process of calculating the buffer zone, see the document “Reservoir Parameter Inputs”.

New York geologists do not report formation or reservoir porosity in their geological database (ESOGIS), nor did they use porosity in their carbon sequestration work. Therefore, porosity data was unavailable and had to be researched for each reservoir-bearing formation in NY. Details on porosity value choices can be found in the document “Reservoir Parameter Inputs”. The available well data from ESOGIS, which were used for this project, included:

1. Total Vertical Depth
2. Producing Formation
3. County
4. Reservoir Name
5. Well Latitude and Longitude
6. Elevation

## 2 Data Compilation

### 2.1 Missing Data

The following data were missing from either database, and required research and/or input:

1. Porosity (NY)
2. Permeability (NY, PA/WV)
3. Reservoir thickness (NY)
4. Reservoir depth (NY)
5. Surface elevation (NY)
6. Reservoir GIS polygons (NY)

For details regarding the input of these values into their respective databases, please see the document “Reservoir Database Inputs”.

## 2.2 Depth Cut-off

Due to the large size of the PA/WV reservoir database, a depth cut-off was chosen to trim the database and reduce the workload given time constraints. To pick a cut-off depth, first a cut-off temperature of 50°C was selected using the Lindal Diagram of temperatures and potential end-uses. A conversation with Cornell graduate student Jared Smith (who is working extensively on the Task 1 thermal maps) led to the decision to remove reservoirs located shallower than 1250 meters (or 4100 feet) in the PA/WV database. No such cutoff was necessary for NY, as the database was much smaller and more manageable. This decision was made knowing that any shallow reservoirs in NY would be eliminated once the thermal map was integrated with the reservoir map.

## 2.3 Data Integration Among States

Due to slight differences in database parameters, the following steps were taken to amalgamate the two databases:

1. The NY database has values for well depths but not reservoir depths. To estimate the depth of the reservoirs in NY, the *Total Vertical Depth* of producing wells in each reservoir were averaged, to produce an *Average Reservoir Depth*.
2. The PA/WV dataset holds values for each reservoir’s *net thickness* (which is likely *pay thickness*, where oil and gas was produced from). The NY ESOGIS database does not contain information on reservoir thickness, but the NYSGS geologists provided us with formation thicknesses (in the form of isopach contour maps in GIS format). Formation thickness tends to be greater than pay thickness—though neither accurately describes the true thickness of rock through which fluids are likely to flow. Thus, the two thickness data types were merged, and the potential discrepancy was reflected in their assigned Uncertainty Index, which is described below and in the “Reservoir Database Inputs” document.

All other PA/WV and NY dataset values were similar enough to be merged together without any extra explanation.

## 3 Reservoir Quality Quantification

Following the completion of our reservoir parameter database, a reservoir quality metric needed to be selected or developed. The goal of this task was to use known reservoir properties to estimate the favorability of natural reservoirs in the basin, and display those results in a meaningful way in a GIS. This section details the methodology used for developing a reservoir quality quantification tool.

### 3.1 Background

After thermal quality, injection flow rate is the second-most important factor affecting geothermal heat production (Bedre and Anderson, 2012). However, because flow rate is highly dependent on engineering and operational selections, it is a difficult reservoir metric to estimate with reservoir parameters alone. The challenge, therefore, was to develop a reservoir metric that considers flow rate but is described using only reservoir parameters, including porosity and permeability, depth, and reservoir thickness and area.

The petroleum industry often uses a term called the well productivity index (PI) to quantify the productivity of a given oil or gas well producing from a reservoir that is dominated by matrix, or intergranular, flow. The PI is defined as the volumetric flow rate of a well divided by the pressure drop from the reservoir to the producing well, shown as follows:

$$PI = \frac{Q}{\Delta P} = \frac{2\pi kh}{\mu \ln \frac{D}{r_w}} \quad (1)$$

where  $Q$  is flow rate ( $\text{m}^3/\text{s}$ ),  $\Delta P$  is the pressure drop from the reservoir to the production well (Pa),  $k$  is permeability ( $\text{m}^2$ ),  $h$  is reservoir thickness (m),  $\mu$  is the fluid viscosity (Pa-s),  $D$  is the distance between the injection and production well (m), and  $r_w$  is the wellbore radius (m) (Gringarten, 1978).

PI has also been used to characterize the productivity of well doublet geothermal reservoirs, for both EGS reservoirs and sedimentary aquifer reservoirs (Gerard et al., 2006; Sanyal and Butler, 2009; Augustine, 2014; Cho, 2015). The reservoir team used a similar metric to the PI to quantify the favorability of our potential sedimentary geothermal reservoirs.

### 3.2 Reservoir Productivity Index

Equation 1 was modified for the purposes of this project in three ways:

1. Parameters not pertaining to the reservoir characteristics were omitted:  $D$ ,  $r_w$ .
2. Fluid viscosity was retained in the equation, because the depth of the reservoir affects the viscosity of the fluid (temperature effects). For more information, see document “Reservoir Database Inputs”.
3. A unitless area factor ( $f_a$ ) was added to the equation to incorporate the effect of reservoir size. For more information, see document “Reservoir Database Inputs”. Reservoirs larger than a specified threshold were given a larger area factor to boost their favorability. Larger reservoirs may contain more heat, but there may be practical barriers to accessing all the heat from very large reservoirs. For these reasons, the area factor was added to Equation 1.

The final Reservoir Productivity Index (RPI) equation used for this task is as follows. The conversion factor of  $10^9$  results in a final value in units of liters per MegaPascal-seconds.

$$RPI = \frac{Q}{\Delta P} = \frac{2\pi khf_a}{\mu} * 10^9 \quad (2)$$

### 3.3 Reservoir Flow Regime Considerations

During the database compilation phase of this project, our reservoirs were categorized as either stratigraphically-controlled (porous medium) or structurally-controlled (fractured medium), based on what is known about the reservoirs from literature (i.e. Gas Atlas 1996). The original intention was to calculate the PI of each reservoir using an appropriate equation based on the play type; however, to our knowledge there does not exist an equivalent PI equation for fracture-dominated reservoirs. Modified equations from fracture flow analytical models do not result in a meaningful value for PI with available permeability data. (i.e. it neither matches production volumes nor is comparable to the result for porous flow reservoirs). Therefore, the equation for PI in porous medium reservoirs was applied to all reservoirs as a first-order approximation.

## 4 Uncertainty

An important piece of this project is the quantification of uncertainty in reservoir data, and therefore, uncertainty of our calculated RPI across the basin. In order to calculate and communicate the uncertainty, we performed a Monte Carlo Simulation on all the reservoirs. To do this, the required inputs were standard deviations and distribution types (normal, log-normal, etc.).

### 4.1 Reservoir Parameter Uncertainty Index

Each parameter involved in Equation 2 ( $k$ ,  $h$ ,  $\mu$ ,  $f_a$ ) has inherent uncertainty associated with it, largely due to the variation in data quality. The reservoir team, with the guidance of our statistical and risk analysis colleagues, decided on the use of an uncertainty index that ranges from 0 (no uncertainty) to

Index	k	h	$\mu$	$f_a$
0	0%	0%	0%	0%
1	12.5%	10%	10%	10%
2	25%	20%	20%	20%
3	50%	30%	30%	30%
4	100%	40%	40%	40%
5	200%	50%	50%	50%
Distribution Type	log-normal	triangular	normal	triangular

Table 1: Reservoir Parameter Uncertainty Index Assignments

5 (most uncertain). Each uncertainty index value (0-5) corresponds to the likely standard deviation from the parameter input, shown in Table 1. An uncertainty index value (0-5) was assigned to each parameter for each reservoir depending on the source and quality of the data. Additionally, each parameter was assigned a distribution type for the following Monte Carlo Simulation.

The standard deviations assigned to each parameter’s uncertainty index were chosen based on the likely amount of deviation from the input value, based on background knowledge of reservoir parameters, and knowledge of the specific geologic formations. For example, an uncertainty factor of 2 for an average permeability value represents a possible spread of 25%, while a factor of 2 for thickness represents a spread of 20%. Distribution types were determined based on common practices for reservoir statistical modeling. More details on how the uncertainty indices were assigned can be found in the document “Reservoir Database Inputs”.

## 4.2 Monte Carlo Simulation

A Monte Carlo Simulation with 100,000 repetitions was coded in MatLab and performed on the reservoir productivity index for each reservoir in our dataset. The simulation outputted a most likely RPI value for each reservoir, using the assigned uncertainty indices and distribution types in Table 1.

## 4.3 Uncertainty Metric

The metric deemed most useful for illustrating the uncertainty of each reservoir was the Coefficient of Variation (CV) of the RPI, which is the ratio of the standard deviation of the RPI to the mean of the RPI. Using the CV allowed us to normalize the RPI of each reservoir by its uncertainty. A lower CV has a lower RPI standard deviation relative to its mean RPI, and is therefore a more ideal reservoir.

# 5 Mapping Thresholds

## 5.1 Thresholds for Reservoir Productivity Index Mapping (L/MPa-s)

A three- or five-color threshold map is required by the project SOPO, so divisions for color cutoffs were chosen. Literature on economic flow rates for direct use geothermal heating systems is sparse, likely due to the economic dependency on the end-use of the heat, chosen infrastructure, and other factors. However, cutoff choices based on conversations with experts and the results of the MCS are listed below. Reservoirs that are “good enough” without any stimulation techniques are considered here as ideal reservoirs. Agemar et al. (2014) report that pressure drawdown for sedimentary geothermal systems typically range between 1-3 MPa. If we conservatively assume the greatest pressure drop of 3MPa, and 30 kg/s is the minimum mass flow rate acceptable for the system, our PI threshold for the ideal reservoirs “as is” (i.e. no stimulation required) is 10 L/MPa-s in the five-color threshold map. The three-color threshold map is less useful for the reservoirs based on the distribution of ideality,

since most reservoirs would fall in the acceptable region. Therefore, the threshold for ideal-acceptable is moved to 1.0 L/MPa for the three-color map.

- Maximum: 301
- Minimum: 3E-5
- Three-color thresholds: 0.1, 1.0
- Five-color thresholds: 0.01, 0.1, 1.0, 10

## 5.2 Thresholds for Uncertainty CV

Thresholds were selected using equal intervals, in order to best illustrate relative uncertainty across the reservoir population in the basin. The thresholds are listed below.

- Maximum: 1.74
- Minimum: 0.16
- Three-color thresholds: 0.69, 1.21
- Five-color thresholds: 0.48, 0.79, 1.11, 1.42

## References

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