Reservoir Database Inputs

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Abstract

This document is intended to augment the "Reservoirs Methodology Memo" document, by providing more details on the original and modified database inputs for New York, Pennsylvania and West Virginia. Additionally, all research and literature that affected decisions for the reser-voir data input are recorded here. This especially includes data for geologic formations in the Appalachian Basin.

1 Missing Data Details

1.1 Average Reservoir Depth

The PA/WV database holds values for each reservoir's *Average Production Depth* (which our team interpreted as the average perforated depth of the well). The NY ESOGIS database does not have production depth data, but instead has data for each well's total depth (which comes from the original well files). The NYSM geologists also have GIS shapefiles of structure contours (depth to top of formation), the source(s) of which is less known. When the values for *Depth to Formation Top* are populated into our working integrated database and compared with the average well depth for each reservoir, the well depths are usually but not consistently deeper than the formation tops. Due to both the lack of consistency and what is known about the sources of each parameter, the 'average well depth' values will henceforth be used as an approximation of the reservoir depths in NY.

1.2 NY Reservoir Polygons

The buffer distance around producing wells in each reservoir in NY was 900 meters. This choice was made by comparing the only available polygons for NY reservoirs, which were the Trenton-Black River reservoirs (WVGES Trenton-Black River Project database). Inputting those shapefiles into a GIS and comparing them to the locations of the wells showed that an average distance of 900 meters around all wells in a reservoir was the best choice.

1.3 Porosity and Permeability

Porosity and permeability values were assigned based on average values for the producing geologic formation in which the reservoir is located.

1.3.1 NEW YORK:

This database required porosity and permeability inputs for all reservoirs.

1. Queenston:
   (a) Average porosity: 10.8% (smith/lugert brine report page 83)
   (b) Average Perm: 0.185 mD

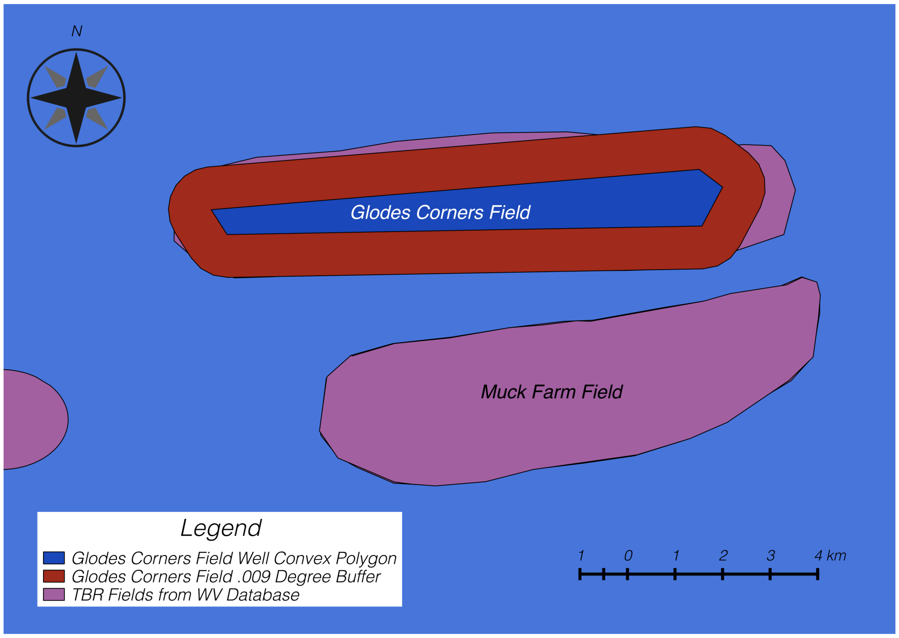

Figure 1: Example of Trenton-Black River polygons in GIS, which aided in creating a systematic buffer zone for NY reservoirs.

(c) Poro perm relationship: 0.005exp(0.05478*poro) (smith/lugert brine report page 83)

2. Black River:

   (a) Poro perm relationship: 1.8716exp(0.4967x) (smith/lugert brine report)
   (b) Average porosity: 7%
   (c) Average Perm: 60 mD

3. Galway/Theresa/Rose Run:

   (a) Nomenclature Issues (with help From Brian Slater): The interval of interest in this study has long been called the Theresa sandstone play in the subsurface, but as it turns out, that name is probably inaccurate when compared to the outcrop stratigraphy. Our work shows that the interval of interest is Upper Cambrian in age and occurs above the Potsdam Sandstone (earliest Upper Cambrian in age) and below the Little Falls Formation (uppermost Cambrian in age). Landing of the New York State Museum recently revised all Cambrian and Lower Ordovician stratigraphy in New York State (Figure 1). His work was published in a field guide in 2007 and will soon be published as a Bulletin. Landing makes a convincing case that the Theresa Formation is Ordovician in age and is actually younger than even the Tribes Hill Formation. The Theresa can only be found in northernmost New York in the Ottawa Graben. This being the case, the Theresa, sensu stricto, probably never occurs in the subsurface in the central and western parts of the State. According to Landing, the Galway Formation occurs below the Little Falls and above the Potsdam. Using this work, it is clear that the producing formation in Western New York is the Galway Formation. On March 2nd, brian said "I believe the upper sandstone member of the Galway formation (called the Rose Run) is the gas producing unit in NY." I will be paying attention to Rose Run now. It is clear that nomenclature for this formation and associated units does not have consistent terminology. I checked ESOGIS again and only Theresa fields are reported as producing reservoirs below 4100ft. There is no Rose Run listed in producing formation options. The Galway report says that Bockhahn, Cascade Brook, and Northwoods fields all produced from the Rose Run. Those are 3 of our 10 Galway fields, and those 10 fields are all in the same region. I will assume the Rose Run is the unit we should be paying attention to.

(b) Average porosity:

i. Page 2-18 of the Galway report, the Stahl well is listed as having an average porosity of 7% for the Rose Run.

ii. Page 2-5 of the Galway report, the Kennedy 1 well is listed as having an average porosity of 6% for the Rose Run.

iii. The Hooker Chemical well has porosity values only for the "B sand and B dolomite" (below rose run)

iv. *I will use an average porosity of 6.5 % for the Galway/Theresa/Rose Run reservoirs.*

(c) Effective porosity

i. Galway report used all of the Hooker Chemical #1 data (2848.7-3031.5 ft) to come to an effective porosity of 5% for the whole core. But looking at tops data for the well, the core harvested rock from both Galway and Potsdam. Looking at tops data on ESOGIS, the Potsdam formation starts at 2935 (Rickard pick). If I use only the Galway values, I get an effective porosity of 2.6%.

(d) Average Permeability:

i. Galway report only has permeability relationships for the B units, not the Rose Run.

ii. Brian Slater, on the choice of a linear relationship between poro-perm, said: "It's been so long that I can't say for sure, but I believe we chose a linear scale because the characteristics of the Rose Run are not highly variable. As opposed to the Queenston or TBR where you can have anywhere from tight rock to vuggy porosity with darcies of perm. For those more variable formations, a log scale was more effective for showing the full spectrum."

iii. I will use a linear relationship from the Hooker well data, even though it doesn't penetrate Rose Run. This is the only data we have for Galway permeability. My choice: remove the Potsdam values from the Hooker data table (slater used galway and Potsdam for their equation) using top of the Potsdam according to the Rickard pick, and find the linear fit in Excel. I get: $y = 0.6621x - 1.7261$.

iv. Av Perm of 2.6 mD (for average poro of 6.5%)

4. Medina:

(a) Porosity: Lugert brine disposal report says one field was 7% poro and 0.1 mD perm.

(b) Permeability: Lugert reports 0.1 mD.

5. Onondaga:

(a) Porosity: Gas Atlas page 102 says average porosity from plugs taken from Steuben County (NY) core in a productive field is 5.2%.

(b) Permeability: Gas Atlas page 102 says average permeability from plugs (see above) is 22.4 md.

6. Oriskany:

(a) Porosity: Appendix D of MRCSP II Report on page D-17 says the Oriskany is typically 4-6% porosity. I choose 5% as an average value. Page D-24 says average of 5.2%. It's all from core data from PA and OH, however.

(b) Permeability: Appendix D of MRCSP II, Page D-24 says average of 1 mD. **NOTE that the Stagecoach field previously Helderberg is now Oriskany.

7. Helderberg: There is one field for this (Stagecoach) and it turns out that geologists changed the producing formation to the Oriskany (Lugert brine report, page 23)

8. Bass Islands:

   (a) Porosity: Due to lack of data for this formation in NY, I used Michigan data for Bass Islands dolomite. (Harrison et al 2009, AAPG environmental geosciences). Average poro is 12.5%.

   (b) Permeability: Same as above, lack of data. Average permeability is 22.4 mD. (Harrison et al 2009, AAPG environmental geosciences).

1.3.2 Pennsylvania and West Virginia:

This database only needed permeability inputs, as porosity was already reported for all reservoirs.

1. Lockport Dolomite:

   (a) Poro-perm relationship: MRCSP Phase II Appendix A, page A-28: y = 3E-05*exp(1.1716x)

2. Onondaga: used average permeability value from NY Onondaga, because reported porosity in PA/WV Onondaga reservoirs was similar to the average porosity for NY Onondaga reservoirs.

3. Galway/Rose Run: adopting poro perm relationship from Galway/Rose Run formation in NY. Fields in question are located in PA and OH, not in WV

   (a) Gas Atlas reports: Rose Run porosities range from 2-25 percent and average 10%. Permeabilities range from 0.01 to 198 md and average 5 md (page 184). This fits very well with my linear trend for NY. MRCSP reports porosities between 8-10 for the fields. That is near the average, so I will also use the average perm of 5 md.

4. Elk Group: I renamed the Brallier, Gordon, and Benson to Elk Group for simplicity, based on formation grouping. Clay-rich turbidite slope apron deposit (atlas page 78).

   (a) Porosity: between 5-10% and perm between 0.1 to 2.0 md. (Gas Atlas page 82). Because reported porosities are 11%, I chose to assign permeability of 2 md.

5. Lockhaven:

   (a) Lockhaven was given the same value as Elk Group, but not renamed.

6. Bass Islands:

   (a) Harrison paper reports average porosity of 12.5% and permeability of 22.4 md. The two fields in the MRCSP database report porosity of 10 and 14%, so I am comfortable using a permeability of 22.4 md for both.

7. Bald Eagle:

   (a) Just one field, the Grugan field. There was permeability data for it in the Gas Atlas. Most permeability is from fractures, but the average perm is 0.07 md.

8. Beekmantown Limestone:
   (a) Lugert brine disposal report says that there were no major distinctions found between the reservoir properties of the Queenston and the Beekmantown, so they were not evaluated separately. Av poro listed as 10.8% and av perm listed as 0.185 md. o The MRCSP field for the Beekmantown is 7% porosity, so I will use the above permeability.
9. Berea Sandstone:
   (a) Atlas reports average poro of 12% and average perm of 3.84 md. The MRCSP fields say 10% porosity so I will use the above permeability for all of them.
10. "Chazy" Limestone":
    (a) According to the DOI Geology report (Cambrian Rock of Pennsylvania, 1896), the Chazy is another term for the Black River limestone. These fields are listed as having porosity of 8% in the MRCSP database. I am changing them to Black River, and using the same poro perm relationship as used for the NY Black River. This results in a permeability of 99.5 md for all 4 fields.
11. Helderberg Limestone:
    (a) "Characterization of the Helderberg Group as a geologic seal for CO2 sequestration" by Lewis et al 2009: says very low permeability (0.001 md)
12. Huntersville and HV/OK play:
    (a) The MRCSP Phase II document (topical doc on mid Devonian to mid Silurian) lists a maximum permeability of 0.003 md for the Dho play (Hv/Ok) and I used that for Huntersville too.
13. Oriskany Sandstone:
    (a) Same data source as was used for New York.
14. Medina:
    (a) Same data source as was used for New York.
15. Loysburg:
    (a) Applied values from Beekmantown Dolomite. No other data available.
16. Newburg:
    (a) Claims of good permeability, but no numbers published anywhere to be found. Some fields are combo structural and stratigraphic, and others are just stratigraphic plays. Due to this fact, I did not want to use a depositional environment or a play type inference. I found out from the Gas Atlas database (excel file) and found that two fields in the Newburg have permeability data. I used the average perm and poro data for those fields to get a relationship: y = 2.1591exp(0.1699x). o Most of the other fields had very similar porosities, so I felt comfortable using this relationship even with just two points.
17. Weir:

(a) There are two reservoirs in the database, and one of them has values in the Gas Atlas database. Ashland/Clark has poro of 11% and perm of 8md. I will apply 8 md to the other field (Stovall Ridge) also.

18. Keefer:

    (a) Altas says on page 148 that average permeability is 7.06 md. One field in my database, gave it that value.

19. Devonian Unconformity Play:

    (a) There was a poro-perm table in the gas altas book on page 134. The poro was comparable to the one listed, so I used the listed permeability as well (15.3 md).

20. Tuscarora:

    (a) Gas atlas says most of the permeability is associated with fractures. Horizontal Permeability in one field ranges from 0 to 10.7 md. Many reports lump Tuscarora in with Medina and Clinton. I will do the same and apply 0.1 md.

21. "Multi":

    (a) These are undetermined geologic formations. I cross-checked the names of the fields listed as "multi" with the Gas Atlas database, and it turns out that there really is a mix of formations. I choose to give a blanket permeability of 1md for now.

22. Marcellus Shale:

    (a) Many publications report permeability under 1 microdarcy for the Marcellus in the Appalchian Basin. A chosen publication is Wang and Reed (2009), Society of Petroleum Engineers. 0.003 md was chosen as a moderate value for these reservoirs.

23. Trenton:

    (a) This play is found only in WV, where permeability is associated primarily with fractures. Just like similar play types, I will assign 0.1 md because more precise data cannot be found.

24. Tully:

    (a) Only one reservoir in database. No data available, so was assigned a low permeability value and high uncertainty.

25. Mahantango:

    (a) Only one reservoir in database. No data available, so was assigned a low permeability value and high uncertainty.

2 Reservoir Productivity Index Details

2.1 Viscosity

Fluid viscosity was retained in the equation for RPI, because the depth of the reservoir affects the temperature of the fluid, and therefore affects the dynamic viscosity of the fluid. Dynamic viscosity data for water were taken from Engineering Toolbox, and affects of salinity on viscosity were assumed to be negligible.

Algorithm 1 Query used in QGIS to solve for water viscosity using temperature at depth of reservoir.

CASE WHEN "TmpForVisc" >= 90 THEN 0.000299 WHEN "TmpForVisc" < 90 AND "TmpForVisc" >= 80 THEN 0.000335 WHEN "TmpForVisc" < 80 AND "TmpForVisc" >= 70 THEN 0.0003795 WHEN "TmpForVisc" < 70 AND "TmpForVisc" >= 60 THEN 0.0004355 WHEN "TmpForVisc" < 60 AND "TmpForVisc" >= 50 THEN 0.000507 WHEN "TmpForVisc" < 50 AND "TmpForVisc" >= 40THEN 0.0006 WHEN "TmpForVisc" < 40 AND "TmpForVisc" >= 30 THEN 0.0007255 WHEN "TmpForVisc" <30 THEN 0.0009 END

2.1.1 Temperature at Depth of Reservoir

In the interest of time, state-wide thermal gradients were used for this calculation. The following values were averages taken from the thermal mapping task, done by Jared Smith.

1. New York: 22.19 ºC/km
2. Pennsylvania: 21.19 ºC/km
3. West Virginia: 23.19 ºC/km

Those gradients were multiplied by each reservoirs average depth, and to that product we added average surface temperature (again, state-averaged):

1. New York: 9.66 ºC
2. Pennsylvania: 11.33 ºC
3. West Virginia: 13.87 ºC

The results for estimated temperature at the depth of all reservoirs was used in the following query (Algorithm 1) to calculate the approximate viscosity of water in the reservoir.

2.2 Area Factor

The area factor was appended to this equation to include the importance of reservoir size into the ideality metric, since area was previously not a part of the well PI equation. Area is an important reservoir characteristic to include, because it theoretically implies more thermal availability, or space for multiple well doublets. However, in order to stay focused on the quality of the reservoir and not how it is utilized, the area factor was kept small. Reservoirs greater than 785,400 square meters were assigned an area factor of 2; reservoirs smaller than that were assigned a factor of 1. This path was chosen to boost the ideality of large reservoirs, while not “punishing” those reservoirs which were smaller than the cutoff. The cutoff was chosen based on the five-spot well pattern from Gringarten (1978), which has been proven to increase heat recovery by a factor of 1.5. We chose a radius of 500m between the outer wells and the inner well, giving us an area of 785,400 m2.

3 Uncertainty Index Details

3.1 Uncertainty Index Model

All parameters except for permeability were given the same uncertainty index scheme. Permeability was given a different (more erroneous) scheme because reported permeability values can be two to three orders of magnitude lower than what is actually encountered in ther reservoir or in core data.

Index	k	h	μ	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

3.2 Permeability

The following list describes how the uncertainty index was assigned to each reservoir's permeability value:

0 Data is site-specific (pertains to that *exact* reservoir). This assignment was very uncommon.

1 Published poro-perm equation available from local/nearby reservoirs of same formation.

2 Data comes from use of a published equation from data that is region specific.

3 Computed equation from available data; Range or average value for the formation is available, or state/region specific data is available.

4 Porosity-permeability relationship (or average value) can be applied from a similar formation or same formation from another state/region.

5 Generic low value assigned due to lack of data or understanding.

3.3 Reservoir Thickness

The following list describes how the uncertainty index was assigned to each reservoir's thickness value:

0 Not used for reservoir thickness.

1 Assigned to all reservoirs in the PA/WV database, because *pay thickness* is likely to represent the actual thickness of rock that fluids will be able to flow through, therefore was given a deviation of 10%.

2 Not used for reservoir thickness.

3 Assigned to all reservoirs in the NY database, because *formation thickness* is likely to be an overestimate of actual thickness that fluids will be able to flow through, therefore was given a standard deviation of 30%.

4 Not used for reservoir thickness.

5 Not used for reservoir thickness.

3.4 Viscosity

The following list describes how the uncertainty index was assigned to each reservoir's fluid viscosity value:

0 Not used for fluid viscosity.

1 Assigned to all reservoirs in the PA/WV database, because original data was *average perforated depth*, which is likely to represent an accurate estimate of the reservoir depth. These were given a deviation of 10%.

2 Not used for fluid viscosity.

3 Assigned to all reservoirs in the NY database, because the original data was average well depth, which is likely to be an overestimate of the true reservoir depth. These were given a deviation of 30%.

4 Not used for fluid viscosity.

5 Not used for fluid viscosity.

3.5 Area Factor

The following list describes how the uncertainty index was assigned to each reservoir's area factor value:

0 Not used for area factor.

1 Not used for area factor.

2 Assigned to all reservoirs in NY because a vetted buffer distance was applied to these reservoirs. Deviation for this index is 20%

3 Not used for area factor.

4 Not used for area factor.

5 Assigned to all reservoirs in PA/WV because a vetted buffer distance was not used, and because there was no supporting documentation on the methods used for the polygon creation in the database. Deviation for this index is 50%

References

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