SYSTEMATIC ASSESSMENT OF WELLBORE INTEGRITY FOR GEOLOGIC CARBON STORAGE PROJECTS USING REGULATORY AND INDUSTRY INFORMATION

FINAL TECHNICAL REPORT

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ABSTRACT

Under this three year project, the condition of legacy oil and gas wells in the Midwest United States was evaluated through analysis of well records, well plugging information, CBL evaluation, sustained casing pressure (SCP) field testing, and analysis of hypothetical CO_2 test areas to provide a realistic description of wellbore integrity factors. The research included a state-wide review of oil and gas well records for Ohio and Michigan, along with more detailed testing of wells in Ohio. Results concluded that oil and gas wells are clustered along fields in areas. Well records vary in quality, and there may be wells that have not been identified in records, but there are options for surveying unknown wells. Many of the deep saline formations being considered for CO_2 storage have few wells that penetrate the storage zone or confining layers. Research suggests that a variety of well construction and plugging approaches have been used over time in the region. The project concluded that wellbore integrity is an important issue for CO_2 storage applications in the Midwest United States. Realistic CO_2 storage projects may cover an area in the subsurface with several hundred legacy oil and gas wells. However, closer inspection may often establish that most of the wells do not penetrate the confining layers or storage zone. Therefore, addressing well integrity may be manageable. Field monitoring of SCP also indicated that tested wells provided zonal isolation of the reservoirs they were designed to isolate. Most of these wells appeared to exhibit gas pressure originating from intermediate zones. Based on these results, more flexibility in terms of cementing wells to surface, allowing well testing, and monitoring wells may aid operators in completing CO_2 storage project. Several useful products were developed under this project for examining wellbore integrity for CO_2 storage applications including, a database of over 4 million items on well integrity parameters in the study areas, a systematic CBL evaluation tool for rating cement in boreholes, SCP field testing procedures and analysis methodology, a process for summarizing well integrity at CO_2 storage fields, a statistical analysis of well integrity indicators, and an assessment of practical methods and costs necessary to repair/remediate typical wells in the region based on assessment of six test study areas. Project results may benefit both CO_2 storage and improved oil recovery applications. This study of wellbore integrity is a useful precursor to support development of geologic storage in the Midwest United States because it sheds more light on the actual well conditions (rather than the perceived condition) of historic oil and gas wells in the region.

Table of Contents

Page

1.0 Introduction ... 1

1.1 Project Background ... 1
1.2 Project Objectives ... 2
1.3 Acknowledgments ... 4

2.0 Well Record Collection ... 6

2.1 Regional Well History Analysis ... 6
2.2 Well Construction Data ... 6
2.3 Plugging and Abandonment Data ... 15
2.4 CBL Data ... 20

3.0 Well Record Analysis ... 24

3.1 Study Area Analysis ... 24
3.1.1 Michigan ... 25
3.1.1.1 Southeast Calhoun County ... 25
3.1.1.2 South-central Otsego County ... 27
3.1.1.3 Central Saint Clair County ... 29
3.1.2 Ohio ... 30
3.1.2.1 Northern Trumbull County ... 30
3.1.2.2 Northern Muskingum County/Southern Coshocton County ... 32
3.1.2.3 Noble County ... 33
3.2 Population Summary Statistics and Spatial Representations ... 34
3.2.1 Ohio ... 34
3.2.1.1 Raw Data and Data Cleaning ... 34
3.2.1.2 Key Parameters ... 35
3.2.1.3 Summary Statistics and Maps ... 35
3.2.2 Michigan ... 41
3.2.2.1 Raw Data and Data Cleaning ... 41
3.2.2.2 Key Parameters ... 42
3.2.2.3 Summary Statistics and Maps ... 42
3.2.3 Risk Indicator Analysis ... 47
3.2.3.1 Risk Indicator Methods ... 48
3.2.3.2 Ohio ... 50
3.2.3.3 Michigan ... 52
3.2.3.4 Aggregate Risk Calculation ... 55
3.2.3.5 Aggregate Risk Maps ... 56
3.2.3.6 Ohio ... 56
3.2.3.7 Michigan ... 59
3.3 Statistical Analysis of Well Integrity Indicators ... 62
3.3.1 Objective of the Statistical Analysis ... 63
3.3.2 Well Condition Indicators ... 63
3.3.3 Well Integrity Coding Scheme ... 65
3.3.4 Initial Site Screening for Selected Potential Storage Fields ... 67

4.0 SCP Evaluation ... 74

4.1 SCP Field Data Collection Methods ... 74
4.1.1 Well Review and Selection ... 74
4.1.2 Gas Sampling and Analysis ... 75
4.1.3 Wellhead Pressure/Temperature Logging ... 77

Table of Contents (cont)

Page

4.1.4 Gas Flux/Vapor Space Analysis 78
4.2 SCP Methodology 80
4.2.1 Cement Integrity Model 82
4.3 Well Site Description 92
4.3.1 AB-1 (WV Well) 92
4.3.1.1 Geology 92
4.3.1.2 Well Construction 92
4.3.1.3 Well History 93
4.3.2 AB-2 through AB-5 (Guernsey County, Ohio) 94
4.3.2.1 Geology 94
4.3.2.2 Well Construction 94
4.3.2.3 Well History 94
4.3.3 AB-6 through AB-12 (N. Canton, Ohio) 95
4.3.3.1 Geology 95
4.3.3.2 Well Construction 95
4.3.3.3 Well History 96
4.4 Field SCP Monitoring Results 97
4.4.1 AB-1 97
4.4.1.1 Pressure Analysis 97
4.4.1.2 Gas Analysis 99
4.4.2 AB-2 through AB-5 100
4.4.2.1 Pressure Analysis 100
4.4.2.2 Gas Analysis 103
4.4.3 AB-6 through AB-13 103
4.4.3.1 Pressure Analysis 103
4.4.3.2 Gas Analysis 116
4.5 SCP Conclusions 117

5.0 Well Integrity Evaluation 118

5.1 Cement Integrity Evaluation 118
5.1.1 Well Cementing Practices in the Region 118
5.1.2 Cement Materials and Additives 120
5.1.3 Cement Plugs 122
5.1.4 CBL Analysis 125
5.1.4.1 CBL Data Collection 125
5.1.4.2 CBL Evaluation Methodology 126
5.1.4.3 CBL Evaluation 129
5.2 Regional CBL Analysis 131
5.2.1 Michigan 131
5.2.1.1 Data Distribution 131
5.2.1.2 Cement Quality Results 134
5.2.1.3 Cement Factor Analysis 134
5.2.2 Ohio 136
5.2.2.1 Data Distribution 136
5.2.2.2 Cement Quality Results 138
5.2.2.3 Cement Factor Analysis 139
5.3 Local-Scale CBL Study Areas 139
5.3.1 Guernsey County, Ohio 141
5.3.2 Muskingum/Coshocton County, Ohio 145
5.3.3 Noble County, Ohio 149

Table of Contents (cont)

Page

5.3.4 Otsego County, Michigan ... 149
5.3.5 St. Clair County, Michigan ... 152
5.4 Well Casing Evaluation ... 155
5.4.1 Well Construction in the Region ... 155
5.4.2 Casing Materials ... 156
5.4.3 Casing Evaluation ... 158
5.4.3.1 Physical Techniques ... 158
5.4.3.2 Wireline Techniques ... 158
5.5 Hydrologic Conditions ... 164
5.5.1 CO_2 Storage Zones ... 164
5.5.1.1 Cambrian Basal Sandstone Interval ... 164
5.5.1.2 Copper Ridge Dolomite ... 164
5.5.1.3 Silurian Clinton Sandstones ... 166
5.5.1.4 Silurian Niagara Group and Lockport Dolomite ... 166
5.5.2 Subsurface Conditions ... 167

6.0 CO_2 Storage Assessment ... 168

6.1 Well Integrity Remediation ... 168
6.1.1 Corrective Action Guidance ... 168
6.1.2 Corrective Action Costs ... 168
6.1.2.1 Site Reconnaissance ... 168
6.1.2.2 Field Testing of Wells ... 170
6.1.2.3 Monitoring for Leakage at Abandoned Wells ... 170
6.1.2.4 Plugging of Wells ... 171
6.1.2.5 Remedial Cementing of Wells ... 172
6.1.2.6 Re-entry, Drill-out, and Plugging of Wells ... 172
6.2 CO_2 Storage Siting ... 173
6.2.1 Site Selection and Screening ... 173
6.2.2 UIC Class VI Permit Requirements ... 173
6.2.3 Penetration of Confining Zone ... 174
6.2.4 Historical Research ... 174
6.2.5 Assessment of Identified Abandoned Wells ... 174
6.2.6 Review of Abandoned Well Plugging ... 174
6.2.7 Plan for Corrective Action ... 175

7.0 Local-Scale CO_2 Storage Test Study Area Analysis ... 176

7.1 Site Selection ... 176
7.2 Corrective Action ... 177
7.3 Ohio Study Areas ... 180
7.3.1 Geologic Setting ... 180
7.3.2 Underground Drinking Water ... 180
7.3.3 Test Areas ... 182
7.3.3.1 Trumbull County, Ohio ... 182
7.3.3.2 Muskingum/Coshocton County, Ohio ... 186
7.3.3.3 Noble County, Ohio ... 191
7.4 Michigan Study Areas ... 194
7.4.1 Geologic Setting ... 194
7.4.2 Underground Drinking Water ... 196
7.4.3 Test Areas ... 197
7.4.3.1 Otsego County, Ohio ... 197

Table of Contents (cont)

Page

7.4.3.2 St. Clair County, Ohio 202
7.4.3.3 Calhoun County, Ohio 207

8.0 Conclusions 209

8.1 Well Record Data Analysis 209
8.2 Well Integrity Evaluation 210
8.2.1 Cement Integrity 210
8.2.2 Casing Integrity 210
8.2.3 Hydrologic Conditions 211
8.3 Statistical Analysis of Wellbore Integrity Indicators 211
8.4 Well Integrity Remediation Guidance 211
8.5 SCP Testing 212
8.6 CO_2 Storage Siting Guidance 213

9.0 Technology Transfer 215

9.1 Technical Advisory Meetings 215
9.2 Presentations at Professional Conferences 216
9.3 Paper Publications 217

10.0 References 218

List of Figures

Page

Figure 1-1. Oil and Gas Wells and Large CO_2 Sources, Midwest United States 2
Figure 2-1. Distribution of Total Wells and Plugged Wells in Michigan Based on Drilling Completion Date (by decade). 6
Figure 2-2. Locations of Total Wells and Plugged Wells in Michigan Based on Plugging Completion Date (by decade). 7
Figure 2-3. Distribution of Total Wells and Plugged Wells in Ohio Based on Drilling Completion Date (by decade). 8
Figure 2-4. Well Count versus Depth for Michigan 9
Figure 2-5. Well Count versus Depth for Ohio 10
Figure 2-6. Well Counts by Formation for Michigan 11
Figure 2-7. Well Locations by Formation for Michigan 12
Figure 2-8. Well Counts by Formation for Ohio 13
Figure 2-9. Well Locations by Formation for Ohio 14
Figure 2-10. Depths of All Plugged Wells Relative to Plugging Details Subset for Michigan................ 15
Figure 2-11. Depths of All Plugged Wells Relative to Plugging Details Subset for Ohio 16
Figure 2-12. Plug Count for Michigan Wells 17
Figure 2-13. Plug Count for Ohio Wells 17
Figure 2-14. Plug Thickness Distribution of Michigan Wells 18
Figure 2-15. Plug Thickness Distribution of Ohio Wells 18
Figure 2-16. Plug Thickness versus Depth Distribution for Michigan 19
Figure 2-17. Plug Thickness versus Depth Distribution for Ohio 20
Figure 2-18. Locations of CBLs and 10% Subsample Dataset for Michigan... 21
Figure 2-19. Locations of CBLs and 10% Subsample Dataset for Ohio 22
Figure 3-1. Locations of Oil and Gas Wells (black dots), CO_2-emitting Facilities by Size (red triangles), and Six Selected Study Areas (blue stars) in Michigan and Ohio.................... 24
Figure 3-2. Calhoun County Study Area Showing Well Locations 26
Figure 3-3. Locations and Depths of Wellbores with CO_2 Storage Zone Highlighted, Calhoun County Study Area.. 27
Figure 3-4. Otsego County Study Area Showing Well Locations 28
Figure 3-5. Saint Clair County Study Area Showing Well Locations 29
Figure 3-6. Trumbull County Study Area Showing Well Locations.. 31
Figure 3-7. Locations and Depths of Wellbores with CO_2 Storage Zone Highlighted, Northern Trumbull County Study Area 31
Figure 3-8. Northern Muskingum County/Southern Coshocton County Study Area Showing Well Locations 32
Figure 3-9. Noble County Study Area Showing Well Locations 33
Figure 3-10. Determination of Wellbore Depth for Vertical and Non-vertical Wells 34
Figure 3-11. Ohio Well Depths Broken Down by Decade of Well Completion 39
Figure 3-12. Ohio Weighted-average Cement Bond Broken Down by Deepest Geologic Formation, Well Depth, and Well Age 40
Figure 3-13. Ohio Well Locations Color Coded by (A) Age of Well (year completed), (B) Well Depth, and (C) Well Status 41
Figure 3-14. Michigan Well Depths Broken Down by Decade of Well Completion 45

List of Figures (cont)

Page

Figure 3-15. Michigan Weighted-average Cement Bond Broken Down by Deepest Geologic Formation, Well Depth, and Well Age ... 46
Figure 3-16. Michigan Well Locations Color Coded by (A) Age of Well (year completed), (B) Well Depth, and (C) Well Status ... 47
Figure 3-17. Spatial Distribution Across Ohio of Risk Associated with the Standard 1,2,3 Risk Scoring of Each Risk Parameter ... 50
Figure 3-18. Number of Wells in each 1-Square-Kilometer Grid Cell Across Ohio. ... 51
Figure 3-19. Frequency of Low-, Medium-, and High-risk Wells in Ohio According to Each Risk Parameter ... 52
Figure 3-20. Spatial Distribution Across Michigan of Risk Associated with the Standard 1,2,3 Risk Scoring of each Risk Parameter ... 53
Figure 3-21. Number of Wells in Each 1-Square-Kilometer Grid Cell across Michigan ... 54
Figure 3-22. Frequency of Low-, Medium-, and High-risk Wells in Michigan According to Each Risk Parameter ... 55
Figure 3-23. Aggregate Risk in Ohio Assigning Equal Weighting to the Risk Parameters, and Calculating Average Risk within Each 1-Square-Kilometer Grid Cell ... 57
Figure 3-24. Aggregate Risk in Ohio Assigning Equal Weighting to the Risk Parameters, but Taking the Worst-case (maximum-risk) Well within Each 1-Square-Kilometer Grid Cell ... 58
Figure 3-25. Aggregate Risk in Ohio Assigning a Higher Weighting (70%) to Well Depth, then Averaging Risk within Each 1-Square-Kilometer Grid Cell ... 59
Figure 3-26. Aggregate Risk in Michigan Assigning an Equal Weighting to the Risk Parameters, and Calculating Average Risk within Each 1-Square-Kilometer Grid Cell ... 60
Figure 3-27. Aggregate Risk in Michigan Assigning Equal Weighting to the Risk Parameters, but Taking the Worst-case (maximum-risk) Well within Each 1-Square-Kilometer Grid Cell . 61
Figure 3-28. Aggregate Risk in Michigan Assigning a Higher Weighting (70%) to Well Depth, then Averaging Risk within Each 1-Square-Kilometer Grid Cell ... 62
Figure 3-29. Lithology of the Michigan and Ohio Study Areas ... 64
Figure 3-30. Integrity Coding for Depth, Age, and Status of Wells ... 66
Figure 3-31. Integrity Scores for 1-Square-Kilometer Grid Cells across Ohio, Relative to the Queenston Confining Layer ... 68
Figure 3-32. Integrity Scores for Potential Storage Fields in Ohio, Relative to the Queenston Confining Layer ... 69
Figure 3-33. Finer-scale View of the ATB Field in Ohio for 1-Square-Kilometer Grid Cells ... 70
Figure 3-34. Integrity Scores for 1-Square-Kilometer Grid Cells across Michigan, Relative to the Salina Confining Layer ... 71
Figure 3-35. Integrity Scores for 1-Square-Kilometer Grid Cells across Michigan, Relative to the Trempealeau Confining Layer ... 71
Figure 3-36. Integrity Scores for Potential Storage Fields in Michigan, Relative to the Salina (OTS and STC fields) and Trempealeau (CAL field) Confining Layers ... 72
Figure 3-37. Finer-scale View of the STC Field in Michigan for 1-Square-Kilometer Grid Cells ... 73
Figure 4-1. Collection of Annular Gas Sample at Test Well ... 75
Figure 4-2. Pressure/Temperature Recording Gauge ... 78
Figure 4-3. Flow Meter Used to Measure Gas Chamber Volume in Test Wells ... 79
Figure 4-4. Idealized SCP Build-up Curve ... 80

List of Figures (cont)

Page

Figure 4-5. Cement/Mud Annular System ... 81
Figure 4-6. Example SCP Test Data (Wellhead Annulus Pressure) ... 84
Figure 4-7. Simple Schematic of Assumed Orifice at (a) Top of Cement Column as Cement Defects and (b) Casing String as Tubular Defects ... 86
Figure 4-8. Rate Profiles for SCP Test for Same Cumulative Gas ... 90
Figure 4-9. AB-1 Well Diagram and Geologic Column ... 93
Figure 4-10. AB-2 through AB-5 Well Diagrams and Geologic Column ... 95
Figure 4-11. AB-6 through AB-9 Well Diagrams ... 96
Figure 4-12. SCP build-up in AB-1. ... 97
Figure 4-13. SCP well IF model for AB-1 test. ... 98
Figure 4-14. Gas Composition of Samples Collected at Well AB-1 ... 100
Figure 4-15. Field Test Data for Well AB-2 ... 101
Figure 4-16. Field Test Data for Well AB-3 ... 101
Figure 4-17. Field Test Data for Well AB-4 ... 102
Figure 4-18. Field Test Data for Well AB-5 ... 102
Figure 4-19. Gas Composition of Samples Collected at Well AB-2 ... 103
Figure 4-20. Field Test Data for Well AB-6 ... 104
Figure 4-21. Field Test Data for Well AB-7 ... 104
Figure 4-22. Field Test Data for Well AB-8 ... 105
Figure 4-23. Field Test Data for Well AB-9 ... 105
Figure 4-24. Field Test Data for Well AB-10 ... 106
Figure 4-25. Field Test Data for Well AB-11 ... 106
Figure 4-26. Field Test Data for Well AB-12 ... 107
Figure 4-27. Field Test Data for Well AB-13 ... 107
Figure 4-28. SCP Analysis for Well AB-6 ... 109
Figure 4-29. SCP Analysis for Well AB-7 ... 110
Figure 4-30. SCP Analysis for Well AB-8 ... 111
Figure 4-31. SCP Analysis for Well AB-9 ... 112
Figure 4-32. SCP Analysis for Well AB-11 ... 113
Figure 4-33. SCP Analysis for Well AB-12 ... 114
Figure 4-34. SCP Analysis for Well AB-13 ... 115
Figure 4-35. Comparison of Gas Compositions for Wells AB-6 through AB-12 ... 116
Figure 5-1. Jet Cement Mixer (on ground below bulk truck, right side of photo) ... 118
Figure 5-2. Recirculating Cement Pump Truck ... 119
Figure 5-3. Locations of Plugs with Additives in Ohio ... 123
Figure 5-4. Locations of Plugs with Additives in Michigan ... 125
Figure 5-5. Available CBLs and the 10% Subset in Michigan (left) and Ohio (right) ... 126
Figure 5-6. Well Information Required by the Interpretation Tool ... 127
Figure 5-7. Log Information Required by the Interpretation Tool ... 128
Figure 5-8. Interpretation Section of the Evaluation Tool ... 128
Figure 5-9. Distribution of Completed Wells by Decade and by Season, 1930s-2000s (Michigan dataset) ... 132
Figure 5-10. Distribution of Wells by Total Depth (top), Cement Column Thickness (middle), and Percent Cemented Pipe (bottom) (Michigan dataset) ... 133

List of Figures (cont)

Page

Figure 5-11. Distribution of Wells by Cement Quality Category (Michigan) 134
Figure 5-12. Locations of Michigan Wells Analyzed, by Cement Quality Category (Michigan dataset) 135
Figure 5-13. Distribution of Cement Quality Categories for Different Ranges of Cement Column Thickness (weighted) (Michigan dataset)... 135
Figure 5-14. Distribution of Completed Wells by Decade and by Season, 1970s-2000s (Ohio dataset) 136
Figure 5-15. Distribution of Wells by Total Depth, (top), Cement Column Thickness (middle), and Percent Cemented Pipe (bottom) (Ohio dataset)... 137
Figure 5-16. Distribution of Wells by Cement Quality Category (Ohio dataset) 138
Figure 5-17. Locations of Ohio Wells Analyzed, by Cement Quality Category (Ohio dataset) 139
Figure 5-18. Locations of Oil and Gas Wells in Michigan (left) and Ohio (right) by Depth, Available CBLs, and CO_2-emitting Facilities 140
Figure 5-19. Generalized Wellbore with Stratigraphy in the Guernsey County, Ohio, Study Area 142
Figure 5-20. Cement Quality (Average Cement Bond Percentage) for Wells in the Guernsey County, Ohio, Study Area 143
Figure 5-21. Wells in the Guernsey County, Ohio, Study Area with CBL Results 144
Figure 5-22. Total Footage of Cement Bonds by Specific Bond Percentages, Guernsey County, Ohio, Study Area.. 144
Figure 5-23. Cement Quality of Guernsey County, Ohio, Wells in Subsea Depth Plotted over Local Stratigraphy 146
Figure 5-24. Wells in the Muskingum/Coshocton County, Ohio, Study Area with CBL Results 147
Figure 5-25. Low-cement-quality Muskingum/Coshocton County, Ohio, Wells in Subsea Depth Plotted over Local Stratigraphy 148
Figure 5-26. Generalized Stratigraphy for Otsego County and Saint Clair County, Michigan 149
Figure 5-27. Cement Quality (Average Cement Bond Percentage) for Wells in the Otsego County, Michigan, Study Area 150
Figure 5-28. Wells in the Otsego County, Michigan, Study Area with CBL Results........................... 151
Figure 5-29. Cement Quality of Otsego County, Michigan, Wells in Subsea Depth Plotted over Local Stratigraphy 152
Figure 5-30. Average Cement Bond for Wells in the St. Clair County, Michigan, Study Area 153
Figure 5-31. Wells in St. Clair County, Michigan, Study Area with CBL Results 153
Figure 5-32. Low-cement-quality St. Clair County, Michigan, Wells in Subsea Depth Plotted over Local Stratigraphy 154
Figure 5-33. Historical Timeline of Oil and Gas Developments in Michigan 155
Figure 5-34. Historical Timeline of Oil and Gas Developments in Ohio 156
Figure 5-35. Example of a Multifinger Caliper Tool 159
Figure 5-36. Processed Data from a Multifinger Caliper Logging Tool 159
Figure 5-37. Example of Data Output from a Flux-Leakage Tool... 161
Figure 5-38. Example of an Ultrasonic Casing Evaluation Log Showing Holes in the Casing............ 162
Figure 5-39. Example of an Ultrasonic Log Data Depicting Casing Thickness 163
Figure 5-40. Example of a Temperature Log Showing Small Deflections in Temperature 163
Figure 5-41. Regional Stratigraphic Correlation Chart of Southern Michigan and Ohio Showing Potential CO_2 Storage Zones and Confining Units 165

List of Figures (cont)

Page

Figure 5-42. Locations of the Six Test Areas in Michigan and Ohio 166
Figure 7-1. CO_2 Storage Study Area Locations 177
Figure 7-2. Corrective Action Process 179
Figure 7-3. Example Stratigraphic Chart from Coshocton County, Ohio 181
Figure 7-4. Underground Drinking Water Sources in Coshocton County, Ohio 182
Figure 7-5. Location of the Trumbull County, Ohio, Study Area 183
Figure 7-6. 3-D View of Wells in the Trumbull County, Ohio, Study Area 184
Figure 7-7. Plugging Chart for Wells in the Trumbull County, Ohio, Study Area 185
Figure 7-8. Location of the Muskingum/Coshocton County, Ohio, Study Area 186
Figure 7-9. Histogram of the Formations Reached at Total Depth, Muskingum/Coshocton County, Ohio 187
Figure 7-10. Histogram of Status for the Wells of Interest Muskingum/Coshocton County, Ohio 188
Figure 7-11. Plugging Chart for Wells in the Muskingum/Coshocton County, Ohio, Study Area 189
Figure 7-12. Well Locations in the Muskingum/Coshocton County, Ohio, Study Area Requiring Wellhead Inspections (blue) and Monitoring (yellow) 190
Figure 7-13. Location of the Noble County, Ohio, Study Area 191
Figure 7-14. Histogram of Formations Reached at Total Depth, Noble County, Ohio 192
Figure 7-15. Histogram of Status for the Wells of Interest, Noble County, Ohio 192
Figure 7-16. Plugging Chart for Wells in the Noble County, Ohio, Study Area 193
Figure 7-17. Simplified Stratigraphy Column of Michigan Formations of Interest 195
Figure 7-18. Depth to the Glacial Drift in Otsego County, Michigan 196
Figure 7-19. Location of the Otsego County, Michigan, Study Area 197
Figure 7-20. Well Depths in the Otsego County, Michigan, Study Area 198
Figure 7-21. Status of the 133 Wells of Interest in the Otsego County, Michigan, Study Area 199
Figure 7-22. Plugging Chart for Wells in the Otsego County, Michigan, Study Area 200
Figure 7-23. Well Locations Requiring Corrective Actions 201
Figure 7-24. Location of the Saint Clair County, Michigan, Study Area 203
Figure 7-25. Well Depths in the Saint Clair County, Michigan, Study Area 204
Figure 7-26. Status of the 145 Wells of Interest in Saint Clair County, Michigan, Study Area 204
Figure 7-27. Plugging Chart for Wells in the Saint Clair County, Michigan, Study Area 205
Figure 7-28. Well Locations in the Saint Clair County, Michigan, Study Area that Require Wellhead Inspection (green), Plugging (orange), and a Survey (yellow) 206
Figure 7-29. Location of the Calhoun County, Michigan, Study Area 207
Figure 7-30. Plugging Chart for Wells in the Calhoun County, Michigan, Study Area 208

List of Tables

Page

Table 1-1. Objectives of the Data Analysis Effort 3
Table 1-2. Objectives of the Well Integrity Evaluation Effort 3
Table 1-3. Objectives of the CO_2 Storage Assessment Effort 4
Table 3-1. Corrective Actions and their Definitions 25
Table 3-2. Corrective Action Scenarios for Certain Well Statuses 25
Table 3-3. Formation Characteristics Used to Calculate Storage Capacity, Calhoun County Study Area 26
Table 3-4. Formation Characteristics used to Calculate CO_2 Storage Capacity, Otsego County Study Area 28
Table 3-5. Number of Wells Requiring Corrective Action, Otsego County Study Area 29
Table 3-6. Number of Wells Requiring Corrective Actions, Saint Clair County Study Area 30
Table 3-7. Formation Characteristics Used to Calculate Storage Capacity for Three Ohio Study Areas 30
Table 3-8. Number of Wells Requiring Corrective Action, Northern Muskingum County/Southern Coshocton County Study Area 32
Table 3-9. Number of Wells Requiring Corrective Action, Noble County Study Area 33
Table 3-10. Summary Statistics for Location and Depth Parameters and Weighted-average Cement Bond, Ohio Data 36
Table 3-11. Frequency Counts and Percentages for Ohio Well Status 37
Table 3-12. Frequency Counts and Percentages for Deepest Geologic Formation, Ohio 38
Table 3-13. Frequency Counts and Percentages for Age of Ohio Wells (decade completed) 38
Table 3-14. Summary Statistics for Location and Depth Parameters and Weighted-average Cement Bond, Michigan Data 43
Table 3-15. Frequency Counts and Percentages for Michigan Well Status 44
Table 3-16. Frequency Counts and Percentages for Deepest Geologic Formation, Michigan 44
Table 3-17. Frequency Counts and Percentages for Age of Michigan Wells (decade completed) 45
Table 3-18. Measured Parameters and Coding that Contribute to the Risk Calculation for Ohio 48
Table 3-19. Measured Parameters and Coding that Contribute to the Risk Calculation for Michigan. 49
Table 3-20. Scoring for Individual Wells in Ohio Based on Depth, Age, and Status 65
Table 3-21. Scoring for Individual Wells in Michigan Based on Depth, Age, and Status 66
Table 4-1. Analytical Results for Gas Samples Collected from Test Wells 76
Table 4-2. Baseline Pressure Data for Test Wells 77
Table 4-3. Gas Chamber Calculations and Volumes for Test Wells 80
Table 4-4. Parameters Required for SCP Analysis Testing 82
Table 4-5. Input Parameters for Well AB-1 Cement IF Model 99
Table 4-6. Specific Gravities of Gas Samples 116
Table 4-7. Summary of SCP Analysis Well Integrity Metrics 117
Table 5-1. Base Cement Types Listed in Ohio Casing String Records 120
Table 5-2. Cement Additives Listed in Ohio Casing String Records 121
Table 5-3. Summary of Cement Plug Additives in Ohio 123
Table 5-4. Summary of Cement Plug Additives in Michigan 124
Table 5-5. Slurry and Cement Yields 127
Table 5-6. Values Calculated by the Evaluation Tool for Statistical Analysis 129
Table 5-7. Statistical Output for Subset of Wells Showing Consistency between Interpreters 130

List of Tables (cont)

Page

Table 5-8. Factors used to Estimate Study Area Sizes (Ohio and Michigan) 141
Table 5-9. Casing/Tubing Materials, Applications, and Limitations.. 157
Table 5-10. Subsurface Hydrologic Conditions of Wellbore Integrity Test Areas in Michigan and Ohio 167
Table 6-1. Estimated Costs for Site Reconnaissance 170
Table 6-2. Estimated Costs for Well Testing 170
Table 6-3. Estimated Costs for Well Monitoring 171
Table 6-4. Estimated Costs for Plugging 172
Table 6-5. Estimated Costs for Remedial Cementing 172
Table 6-6. Estimated Costs for Well Re-entry, Drill-out, and Plugging 173
Table 7-1. Summary of Corrective Action Options 178
Table 7-2. Corrective Actions and Scenarios for their Use 178
Table 7-3. Parameters Used to Estimate the Size of the Trumbull County, Ohio, Study Area 183
Table 7-4. Parameters Used to Estimate the Size of the Muskingum/Coshocton County, Ohio, Study Area 186
Table 7-5. Summary of Recommended Corrective Actions, Muskingum/Coshocton County, Ohio, Study Area.. 190
Table 7-6. Parameters Used to Estimate the Size of the Noble County, Ohio, Study Area............ 191
Table 7-7. Summary of Recommended Corrective Actions, Noble County, Ohio, Study Area 194
Table 7-8. Parameters Used to Estimate the Size of the Otsego County, Michigan, Study Area ... 197
Table 7-9. Recorded Deepest Formations for all Wells in the Otsego County, Michigan, Study Area 198
Table 7-10. Summary of Required Corrective Actions for Wells in the Otsego County Study Area.. 202
Table 7-11. Parameters Used to Estimate the Size of the Saint Clair County, Michigan, Study Area 202
Table 7-12. Formations Penetrated at Total Depth of the Wells in the Saint Clair County, Michigan, Study Area.. 203
Table 7-13. Summary of Required Corrective Actions for Wells in the Saint Clair County Study Area 206
Table 7-14. Summary of Parameters Used to Estimate the Size of the Calhoun County, Michigan, Study Area.. 207
Table 8-1. Summary of CO_2 Storage Test Study Areas.. 213

Executive Summary

Wellbore integrity and abandoned wells are considered a key risk factor and migration pathway for carbon dioxide (CO_2) storage applications. In the Midwest United States, hundreds of thousands of wells are present because the region has some of the oldest oil and gas fields in the world. However, the risk in relation to the zones being targeted for carbon capture, utilization, and storage (CCUS) is not well defined. Shallow, old wells may not present actual risk to CCUS projects in deeper formations. In addition, the technical and economic feasibility of mitigating old wellbores has not been well studied. Many areas may have few wellbores and be more suitable for CO_2 storage fields. Processes related to the age of wells, materials, and construction procedures may also help define risk related to well integrity in old boreholes. For example, analysis of cement bond logs (CBLs) from existing wells can help understand the cement distribution in a well.

This report presents the results of a three year project to examine wellbore integrity in the Midwest United States, based on analysis of well records and testing of sustained casing pressure (SCP). The project team included Battelle (lead), BP Alternative Energy, and NiSource-Columbia Gas Pipeline Group. The goals of this project were to 1) determine the distribution of active and plugged wellbores in the study area through collection and analysis of well records, evaluation of annulus pressure from Class II injection/production wells and/or gas storage wells, and analysis of well integrity in relation to CO_2 storage targets; and 2) evaluate regulatory, field deployment, and commercial implications of the well failure risk profiles at selected sites for CO_2 storage or utilization. The project included systematic review of well records to determine categories of well integrity in a real-world field setting. The data review was linked to analysis of field records on well annulus/casing pressure as they relate to well condition. The project addresses U.S. Department of Energy (DOE) Funding Opportunity Announcement (FOA) **Area of Interest 1- Studies of Existing Wellbores Exposed to CO_2** and specifically addresses the research need for analyzing well failure risks by factors such as age, construction, region, regulations, use of wells, and operational data.

The condition of legacy oil and gas wells in the Midwest United States was evaluated through analysis of well records and well plugging information; CBL evaluation; SCP field monitoring; and analysis of hypothetical CO_2 test areas to provide a realistic description of wellbore integrity factors (IFs). The research included a state-wide review of oil and gas well records for Ohio and Michigan, along with more detailed testing of wells in Ohio. Results concluded that oil and gas wells are clustered along fields in areas. Well records vary in quality, and there may be wells that have not been identified in records, but there are options for surveying unknown wells. Many of the deep saline formations being considered for CO_2 storage have few wells that penetrate the storage zone or confining layers. Research suggests that a variety of well construction and plugging approaches have been used over time in the region. Well status, condition, CBLs, and plugging records were used to estimate corrective actions necessary to prepare the test areas for CO_2 storage.

Overall, the project concluded that wellbore integrity is an important issue for CO_2 storage applications in the Midwest United States. Realistic CO_2 storage projects may cover an area in the subsurface with several hundred legacy oil and gas wells. However, closer inspection may often establish that most of the wells do not penetrate the confining layers or storage zone. Therefore, addressing well integrity may be manageable. Field monitoring of SCP also indicated that tested wells provided zonal isolation of the reservoirs they were designed to plug off. Most of these wells appeared to exhibit gas pressure originating from intermediate zones. Based on these results, more flexibility in terms of cementing wells to surface, allowing well testing, and monitoring wells may aid operators in completing CO_2 storage projects.

This project generated several useful tools and methodologies for examining wellbore IFs for CO_2 storage:

- a database of over 4 million items on well integrity parameters in the study areas,
- a systematic CBL evaluation tool for rating cement in boreholes,
- SCP field monitoring procedures and analysis methodology,
- a process for summarizing well integrity at CO_2 storage fields,
- a statistical analysis of well integrity indicators, and
- an assessment of practical methods and costs necessary to repair/remediate typical wells in the region based on assessment of six test study areas.

Together, these products provide practical tools for supporting CO_2 storage applications in the region (and in other locations). The tools may be applied to individual wells, but they appear to be more useful in evaluating many wells for trends based on spatial location, well age, well depth, and/or geologic formations. Project results may benefit both CO_2 storage and improved oil recovery applications. This study of wellbore integrity is a useful precursor to support development of geologic storage in the Midwest United States because it sheds more light on the actual well conditions (rather than the perceived condition) of historic oil and gas wells in the Midwest.

1.0 Introduction

This carbon dioxide (CO_2) storage assessment final report examines information on the condition of oil and gas wells in the Midwest United States as it pertains to CO_2 storage potential in deep rock formations. The project was focused on providing a geographic review of well integrity factors (IFs) in the region, followed by more detailed review of six test study areas. The data were used to determine the methods, costs, and effort needed to address wellbore integrity risks at potential CO_2 storage sites in the Midwest United States.

1.1 Project Background

Wellbore integrity and abandoned wells are considered a key risk factor and migration pathway for carbon capture, utilization, and storage (CCUS) applications. In the Midwest United States, hundreds of thousands of wells are present because the region has some of the oldest oil and gas fields in the world (Figure 1-1). However, the risk in relation to the zones being targeted for CCUS is not well defined. Shallow, old wells may not present actual risk to CCUS projects in deeper formations. In addition, the technical and economic feasibility of mitigating old wellbores has not been well studied. Many areas may have few wellbores and be more suitable for CO_2 storage fields. Processes related to the age of wells, materials, and construction procedures may also help define risk related to well integrity in old boreholes. For example, analysis of cement bond logs (CBLs) from existing wells can help understand the cement distribution in the well.

The objective of this project was to complete a systematic assessment of wellbore integrity using regulatory and industry information. The following project tasks were set up to determine the condition of wellbores in the study area:

- Well record collection
- Well record analysis
- Sustained casing pressure (SCP) evaluation
- Well integrity evaluation
- CO_2 storage assessment
- Local-scale CO_2 storage test study area analysis

Well records were systematically reviewed to determine categories of well integrity. The data review was linked to an analysis of field records on well annulus/casing pressure as they relate to well condition. This project was designed to meet objectives of the Department of Energy (DOE)/National Energy Technology Laboratory (NETL) research goals on CO_2 storage with a combination of field work and technical analyses. This project research is aimed at DOE Geologic Research and Development Area of Interest 1: Studies of Existing Wellbores Exposed to CO_2. The project team consists of Battelle, BP Alternative Energy, and NiSource (Columbia Gas Transmission).

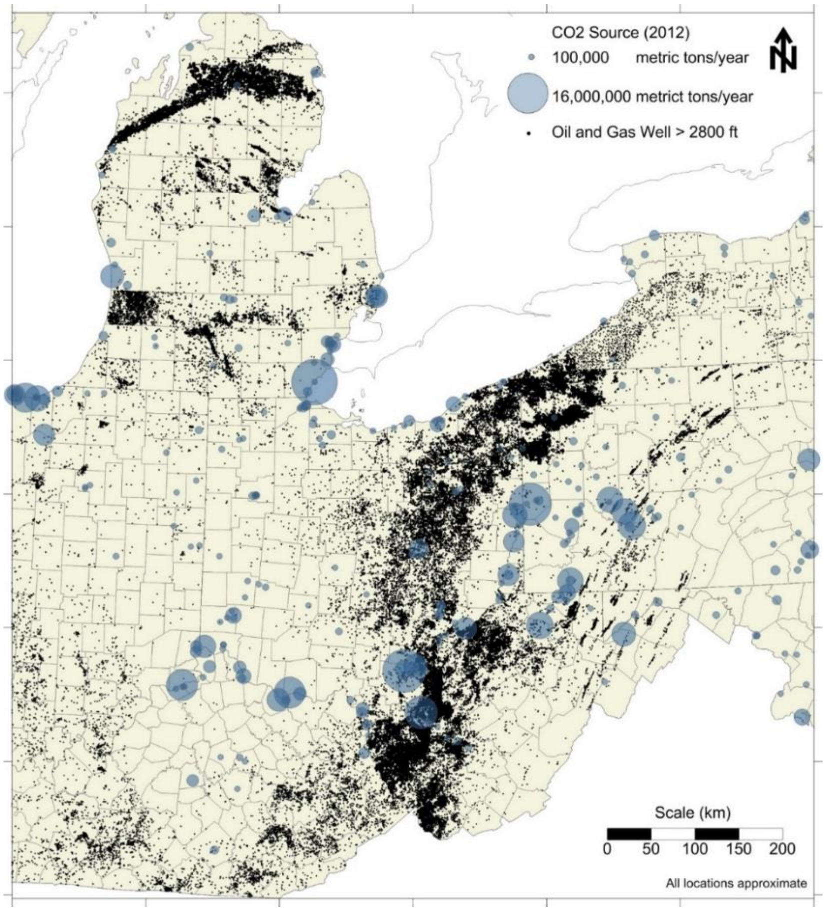


Figure 1-1. Oil and Gas Wells and Large CO_2 Sources, Midwest United States

1.2 Project Objectives

The overall objective of the data analysis effort was to evaluate the condition of oil and gas wells in the region based on well records. The source of data included over 4 million items collected for Michigan and Ohio. Analysis methods included graphs, tables, maps, and statistics. Data were analyzed according to well depth, deepest geologic formation penetrated, well age, well status, and other categories. Hypothetical test areas were also examined to provide practical examples of the level of effort needed to address boreholes within the test study areas (Areas of Review [AoRs]) to ensure safe CO_2 storage applications. Objectives of the data analysis effort are described in Table 1-1.

Table 1-1. Objectives of the Data Analysis Effort

Task	Objectives	Methods
Regional Well History Analysis	Depict general trends in well construction, plugging and abandonment (P&A), CBL, and SCP data	Maps, graphs, and timelines of key parameters related to wellbore integrity
Test Area Analysis	Examine status of oil and gas wells in six hypothetical study areas (AoRs), determine well conditions, and identify corrective actions necessary to prepare areas for CO_2 storage	Tabulation of well information, categorization of well conditions, CBL evaluation
Statistical Record Analysis	Describe well parameter data populations, define wellbore IFs based on well condition indicators, portray spatial distribution of well IFs, estimate risk factors for general population of oil and gas wells in study areas (AoRs)	Populations statistics on wellbore integrity, geostatistical spatial analysis, risk indicator evaluation

The overall objective of the well integrity evaluation effort was to evaluate the condition of oil and gas wells in the region based on well records for Michigan and Ohio. Analysis methods use graphs, tables, maps, and statistics to illustrate overall wellbore integrity. This evaluation effort complemented previous work on characterizing the location, status, depth, materials, and age of oil and gas wells in the study area.

Three key elements associated with wellbore integrity are evaluated in this report: cement integrity, well casing, and hydrologic conditions. The cement integrity evaluation was designed to assess the emplacement of cement for well casing and cement plugs. The well casing evaluation was aimed at investigating the condition of well casing and options for surveying casing. Finally, hydrologic conditions in the subsurface were reviewed for the study area in relation to the potential to affect wellbore integrity. Together, these items were depicted to better define well IFs in the region. The effort complemented previous work on characterizing the location, status, depth, materials, and age of oil and gas wells in the study area. Objectives of the major well integrity evaluation effort, and the methods used to perform the tasks associated with this effort, are described in Table 1-2.

Table 1-2. Objectives of the Well Integrity Evaluation Effort

Task	Objectives	Methods
Cement Integrity Evaluation	Analyze cement conditions for wells in the region in terms of materials, methods, and long-term integrity	Evaluate CBLs, cement types, additives, cement volumes, actual cement tops, and possible associations with SCP.
Well Casing Evaluation	Examine well casing conditions and long-term integrity of casing in the region	Analyze available casing inspection logs, cement evaluation logs, and/or records of casing failures. Assess casing installation procedures, materials, and condition as indicators of well integrity
Hydrologic Conditions	Describe hydrologic factors that may affect well integrity	Summarize reservoir pressure, temperature, fluids, geochemistry, and petrology for different well categories and geologic settings

The overall objective of the CO_2 storage assessment effort was to evaluate the real-world impact of wellbore integrity issues for CO_2 storage applications in the Midwest United States. Table 1-3 summarizes the specific objectives of this effort. The statistical analysis of well integrity indicators work was aimed at providing a more high-level view of the condition of wellbores in the region for siting of CO_2 storage projects. The CO_2 storage siting subtask included review of actual well conditions to determine the appropriate well testing, monitoring, and/or plugging options for preparing a site for CO_2 storage. To facilitate the project objectives, six test study areas were described in terms of wellbore integrity conditions. These test areas provide an overall sampling of actual level of effort necessary to account for well integrity in the region.

Table 1-3. Objectives of the CO_2 Storage Assessment Effort

Task	Objectives	Methods
Statistical Analysis of Well Integrity Indicators	Depict factors that may show a higher probability of casing or cement integrity issues. Prioritize wellbores that require detailed assessment or remediation before storage or enhanced oil recovery (EOR) projects are undertaken.	Perform a statistical analysis of well integrity indicators, map well factors, develop a well rating system
Well Integrity Remediation Guidance	Summarize well remediation options as they relate to CO_2 storage applications. Describe well plugging methods, costs, and level of effort for CO_2 storage test study areas.	Tabulate well information for six test study areas, determine corrective actions, estimate costs
CO_2 Storage Siting Guidance	Provide guidance for well integrity siting, characterization, monitoring, and operations for CO_2 storage applications.	Develop options for addressing wellbore integrity based on results of six test study areas

1.3 Acknowledgments

Support for this project was provided by DOE-NETL under its program to ensure permanent geologic carbon storage (Agreement DE-FE0009367). Project support was also provided under the Ohio Development Services Agency (ODSA) Ohio Coal Development Office (OCDO) (Grant CDO/D-13-1). The project team thanks DOE-NETL and ODSA for sponsoring this research, which is especially important for the Midwest United States, home to some of the oldest oil and gas fields in the world. Project guidance was provided by Mr. William O'Dowd and Ms. Dawn Deel from DOE-NETL. Mr. Greg Payne and Mr. Bob Brown also provided guidance for ODSA on Ohio energy issues.

BP Alternative Energy provided both funding and in-kind support for the project. Mr. Nigel Jenvey provided technical advice throughout the overall project. Mr. Walter Crow assisted in the systematic CBL analysis methodology. Mr. Bryan Dotson was lead on the SCP analysis of field data. Ms. Yun Wu (University of Texas) and Dr. Steven Bryant (University of Alberta, Canada) developed the SCP method fundamentals in partnership with BP.

NiSource-Columbia Gas Pipeline Group provided valuable technical guidance based on its experience with underground gas storage operations. Mr. Anthony Theodos was the technical lead from NiSource-Columbia Gas Pipeline Group. Mr. Jason Martin was very helpful with interpreting some of the field data on well construction and casing pressure.

The project team would also like to acknowledge operators who allowed field monitoring of SCP. The field data were extremely valuable in determining the actual condition of a variety of wells in the region.

We would also like to thank the Michigan Department of Environmental Quality (DEQ) Office of Oil & Gas and the Ohio Department of Natural Resources (ODNR) Division of Oil & Gas, which monitor oil and gas drilling and provided records on wells in the study areas.

Project results reflect contributions from many people on the project team. The project lead was Battelle, and Mark Moody and J.R. Sminchak were the principal investigators. Dr. Neeraj Gupta was technical advisor. Autumn Haagsma led the cement bond analysis and test area analysis. Matt Place was the lead for field monitoring. The Battelle project team also included Glenn E. Larsen, Andrew Burchwell, Jacqueline Gerst, Bruce Buxton, Stephanie Weber, Priya Ravi-Ganesh, Ben Grove, Joel Main, Drew Kimble, and Isis Fukai. Project control was administered by Mary Allison Comfort. Carol Brantley was project administrative assistant. Desiree Padgett provided technical editing for project reports. The project benefited from previous research on CO_2 storage and wellbore integrity.

2.0 Well Record Collection

2.1 Regional Well History Analysis

The objective of the regional well history analysis was to summarize well construction items, P&A methods, CBLs, and historical information on SCP. Well records were summarized with tables, graphs, and maps to illustrate trends in well integrity items. Well age, depth, completion information, plugging information, and construction materials were examined. These parameters help to define borehole integrity issues in terms of location, time, and other categories.

2.2 Well Construction Data

Well construction data provided information on the materials, methods, and status of wells in the region. Figure 2-1 shows the distribution of wells in Michigan based on the date (by decade) that drilling was completed. Well completions spiked in the 1940s and declined through the 1970s, followed by another increase in completions in the late 1980s. From the 1930s to 1980s, records indicate that 70% to 85% of wells were plugged. Only about 16% of the wells from 1995 to 2010 were listed as plugged, because these wells are still open (Figure 2-2).

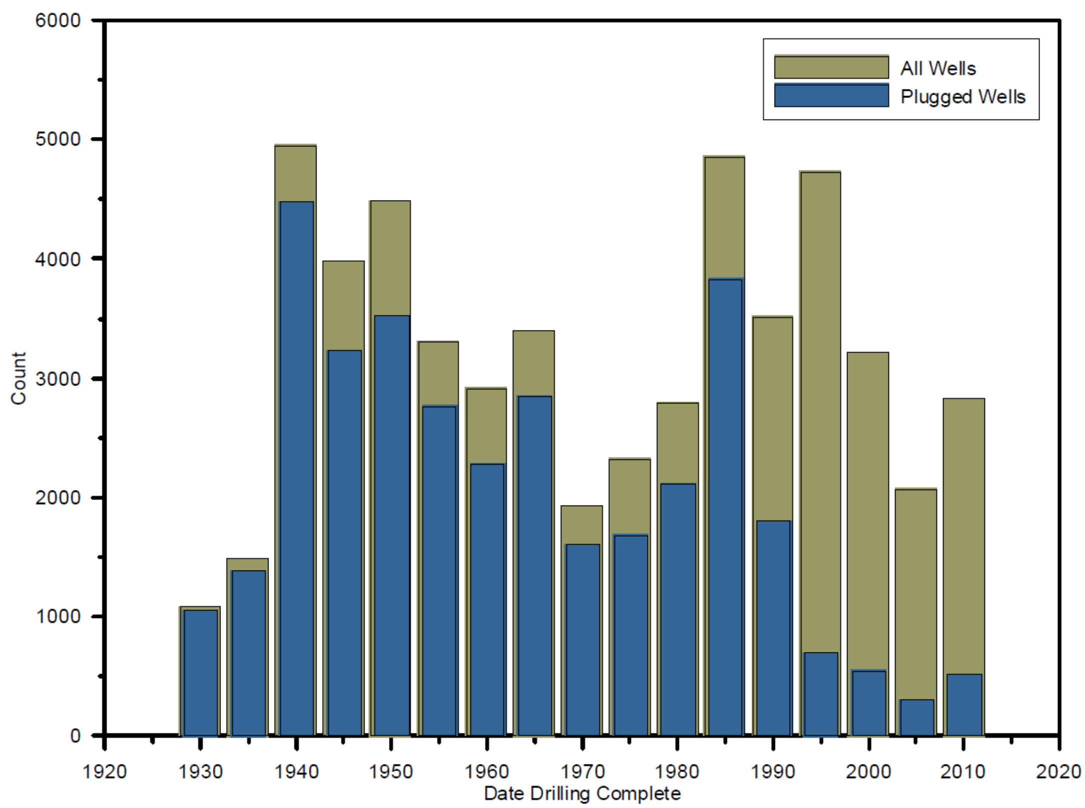


Figure 2-1. Distribution of Total Wells and Plugged Wells in Michigan Based on Drilling Completion Date (by decade).

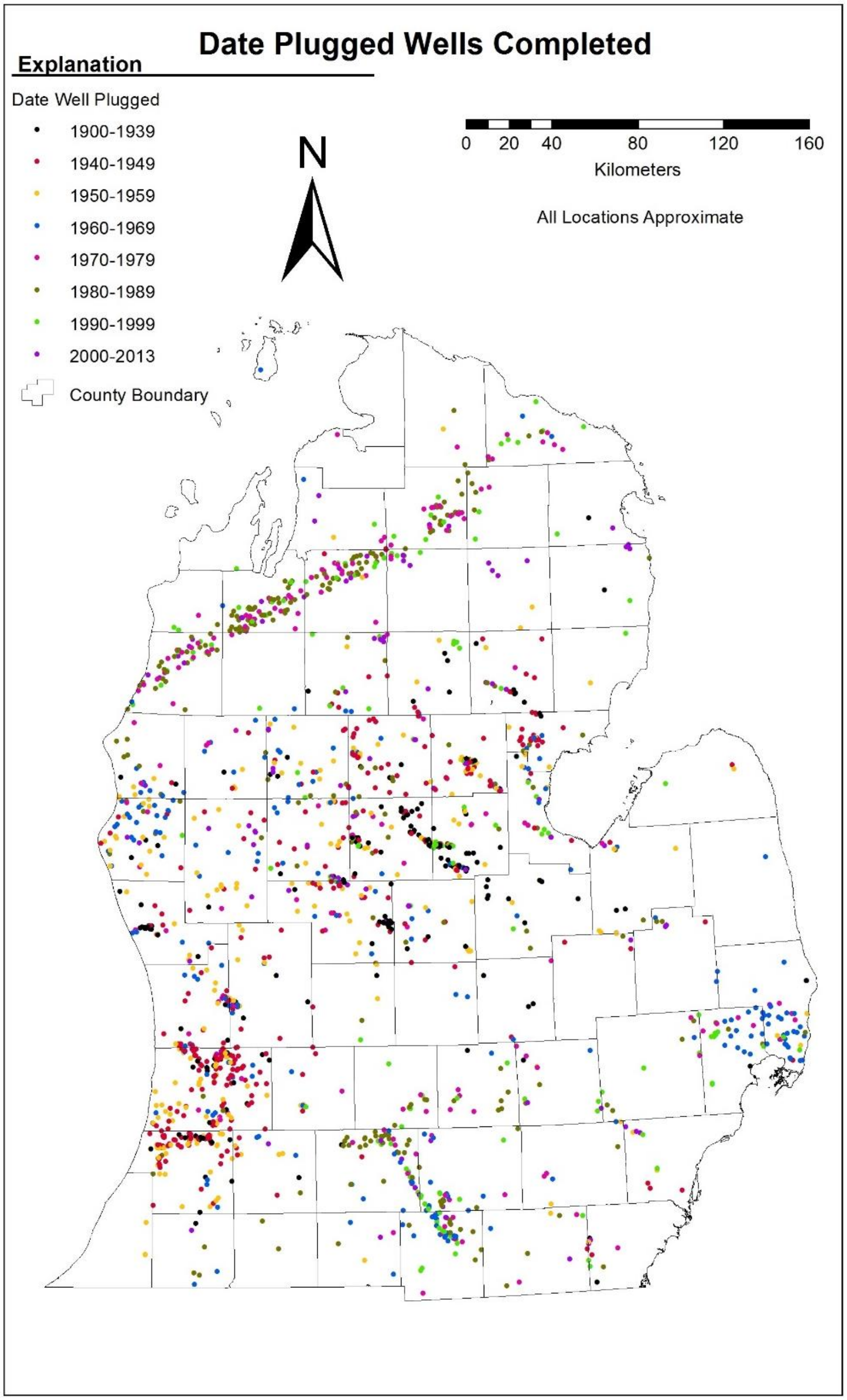


Figure 2-2. Locations of Total Wells and Plugged Wells in Michigan Based on Plugging Completion Date (by decade).

Well records were examined based on the date the drilling was completed. Figure 2-3 shows the distribution of wells in Ohio based on the drilling completion date by decade. Through 1975, approximately 3,000 to 7,000 wells were drilled per year, and records suggest that 65% to 80% of these wells were plugged. In the early 1980s, drilling spiked due to the energy crisis of the 1970s. This increase continued into the early 1990s. Records suggest that 30% to 40% of the wells drilled from 1980 to 1995 were plugged. Only 15% to 20% of the wells drilled from 1995 to 2010 were listed as plugged, likely because these wells are still open.

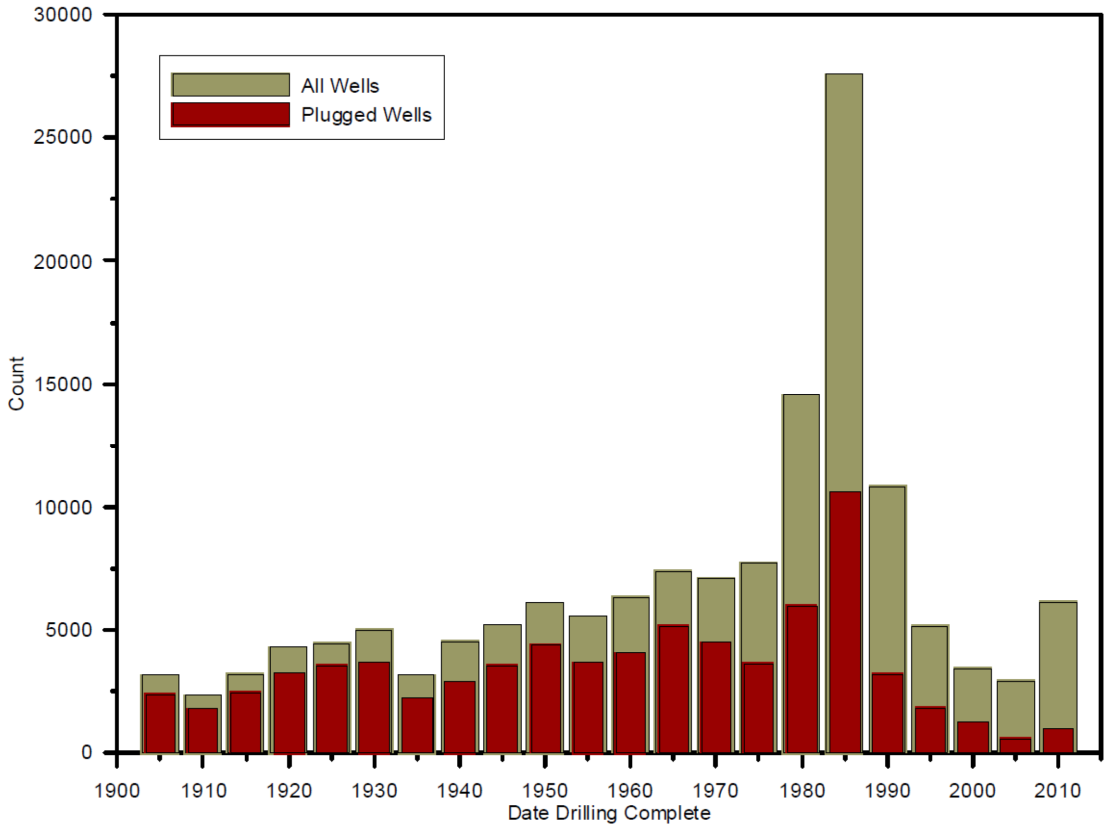


Figure 2-3. Distribution of Total Wells and Plugged Wells in Ohio Based on Drilling Completion Date (by decade).

Well records were also examined based on total depth of the well. Figure 2-4 shows the distribution of wells in Michigan based on depth. Wells are concentrated at depths around 1,700 and 4,000 feet. A large portion of unplugged wells are present at the 1,700-foot depth interval. These wells are mainly Antrim shale wells which have long, sustained production. Below 5,000 feet, most wells are listed as plugged.

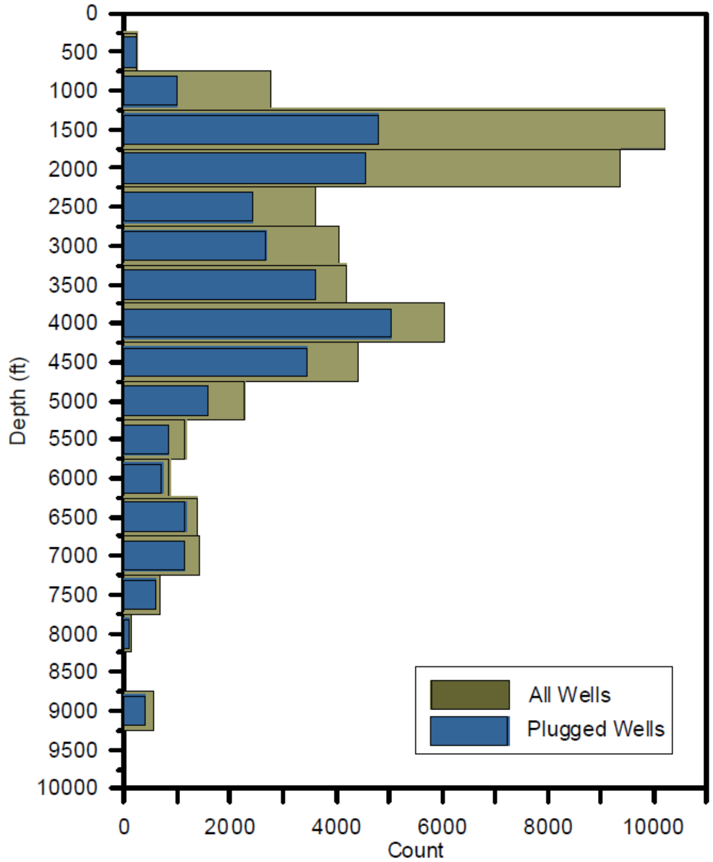


Figure 2-4. Well Count versus Depth for Michigan

Figure 2-5 shows a graph of well count versus depth for Ohio. Wells are concentrated at depths around 1,200 and 3,500 feet deep. However, a large number of wells are located down to the 6,000-foot depth range. A large portion of wells are listed as unplugged at most depths.

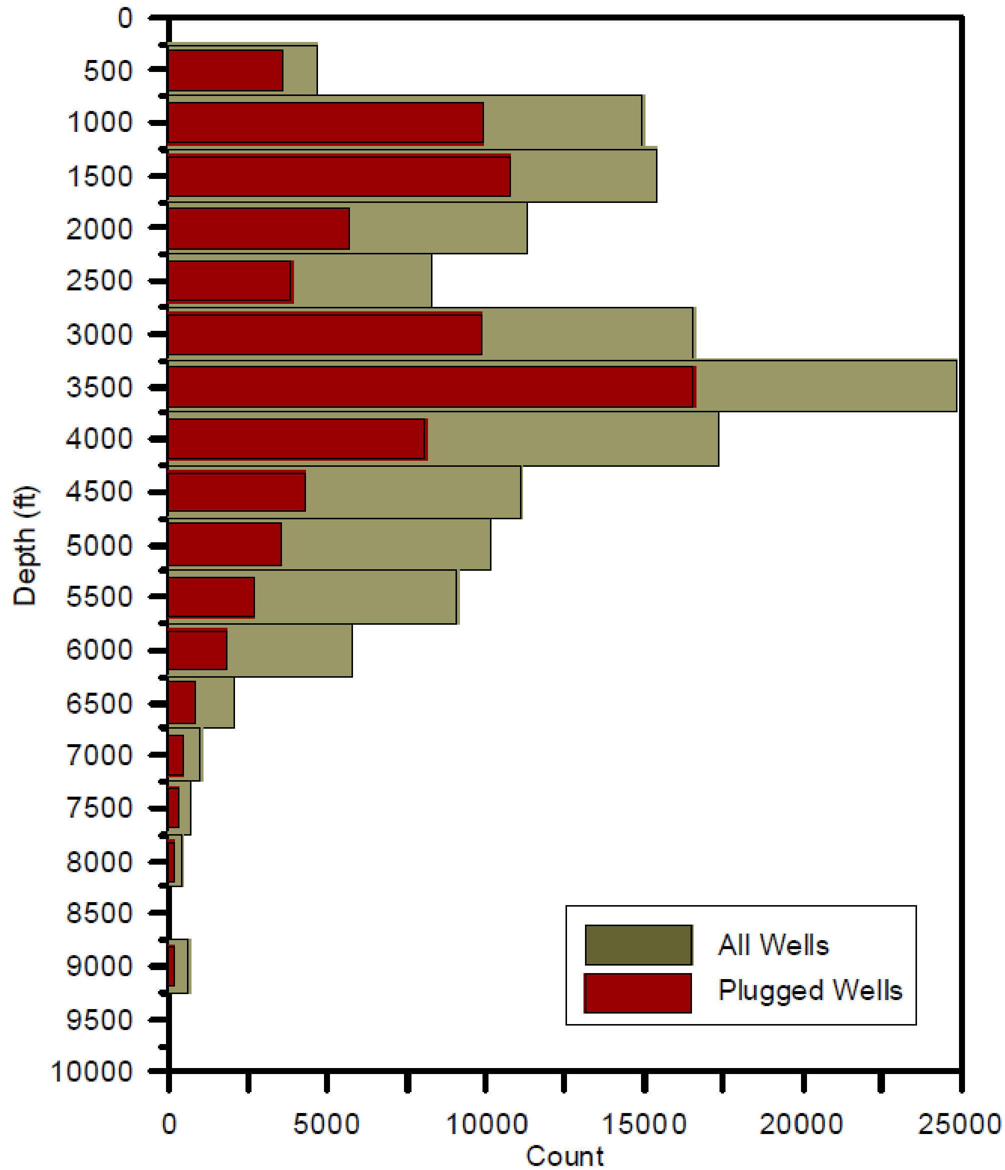


Figure 2-5. Well Count versus Depth for Ohio

The well population was also categorized based on deepest formation penetrated. For Michigan, the well counts by formation are shown in Figure 2-6, and the well locations by formation are shown in Figure 2-7. As shown, a large portion of the unplugged wells are completed in the Antrim-Dundee-Detroit River formations. Most of the wells in the deeper formations are listed as plugged and abandoned. Figures 2-8 and 2-9 show well counts and well locations by formation, respectively, for Ohio. Many wells did not have the deepest formation identified in the log. Approximately 80% of the unidentified wells did not include a total depth. A large portion of the unplugged wells are completed in the Clinton-Cataract to Cincinnati-Queenston formations.

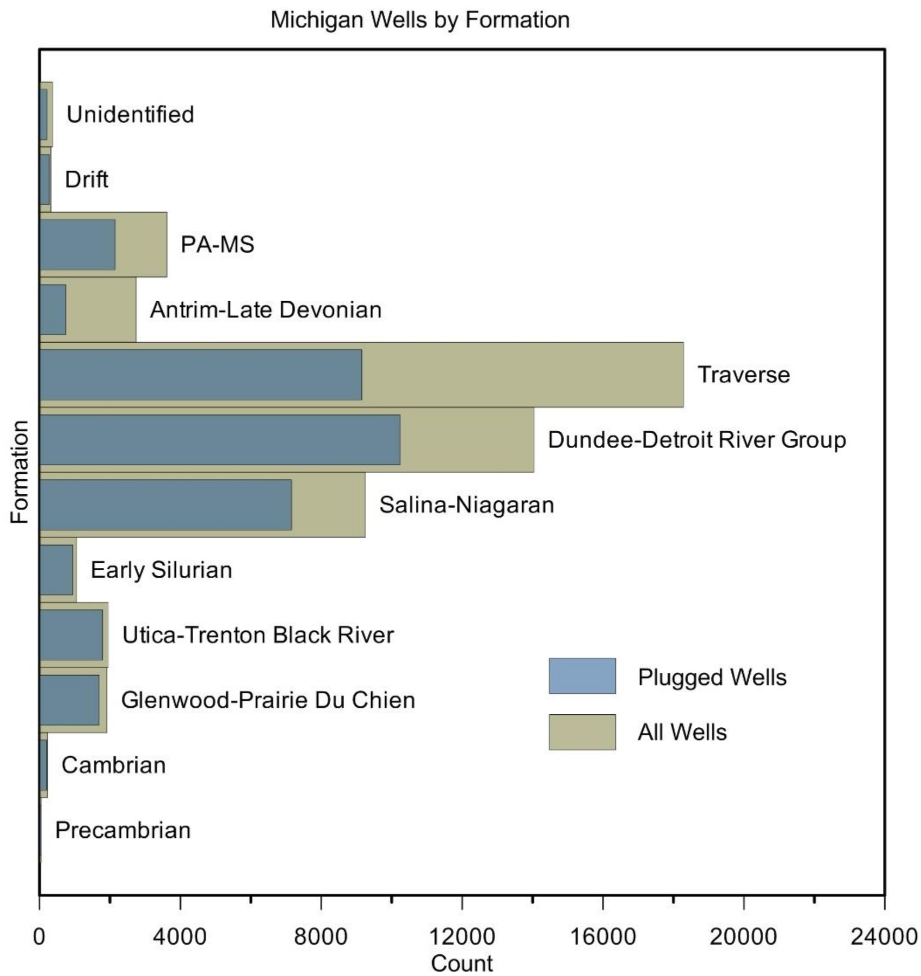


Figure 2-6. Well Counts by Formation for Michigan

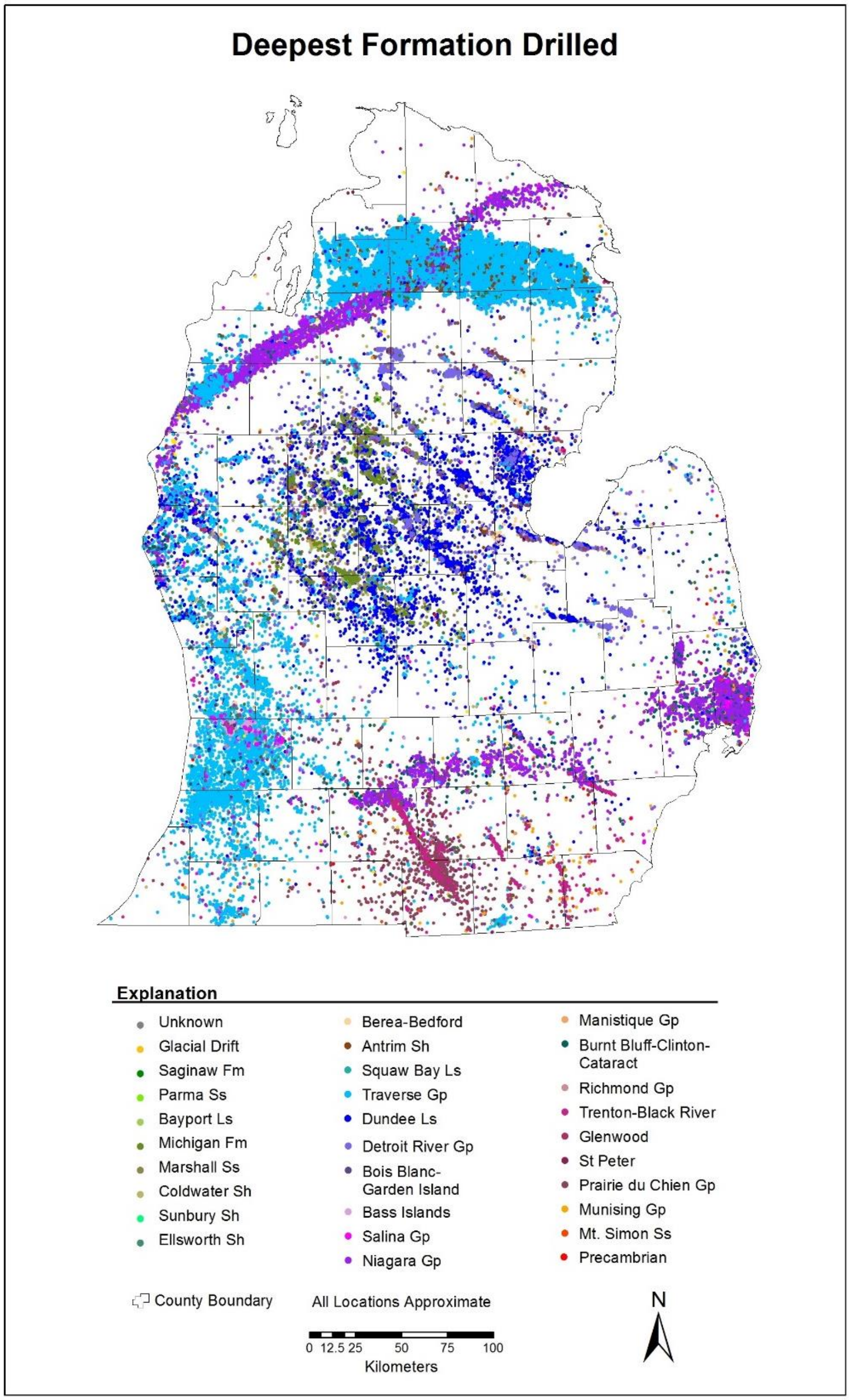


Figure 2-7. Well Locations by Formation for Michigan

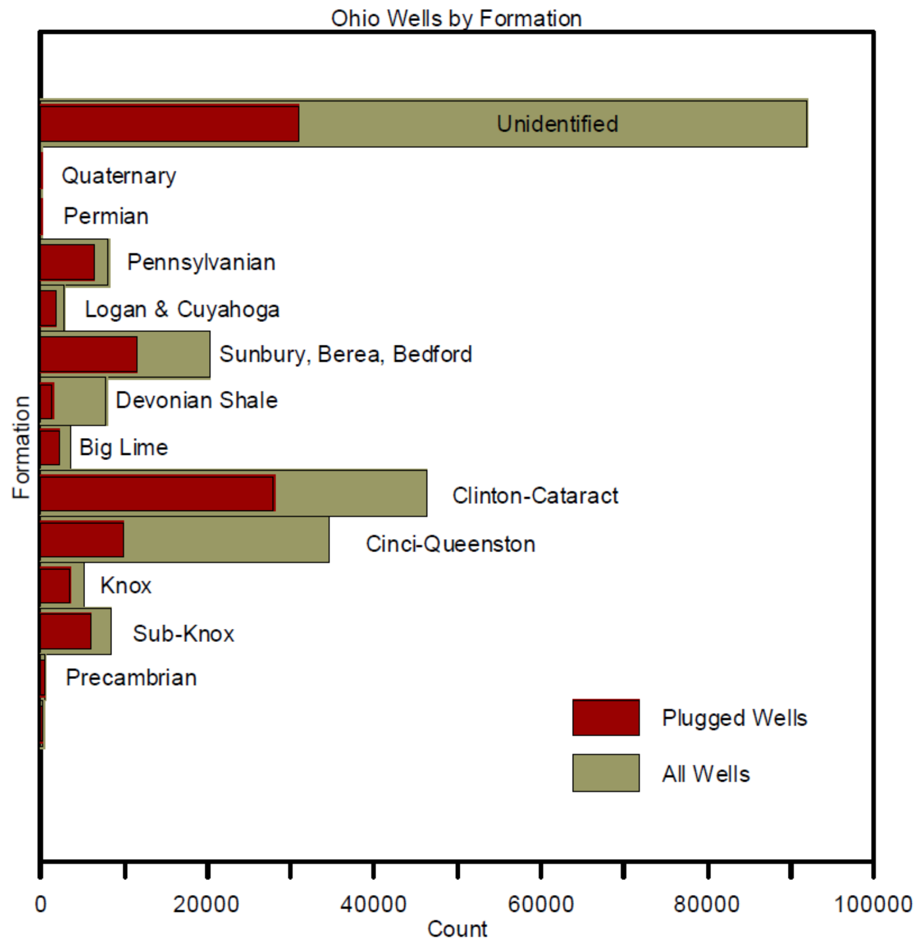


Figure 2-8. Well Counts by Formation for Ohio

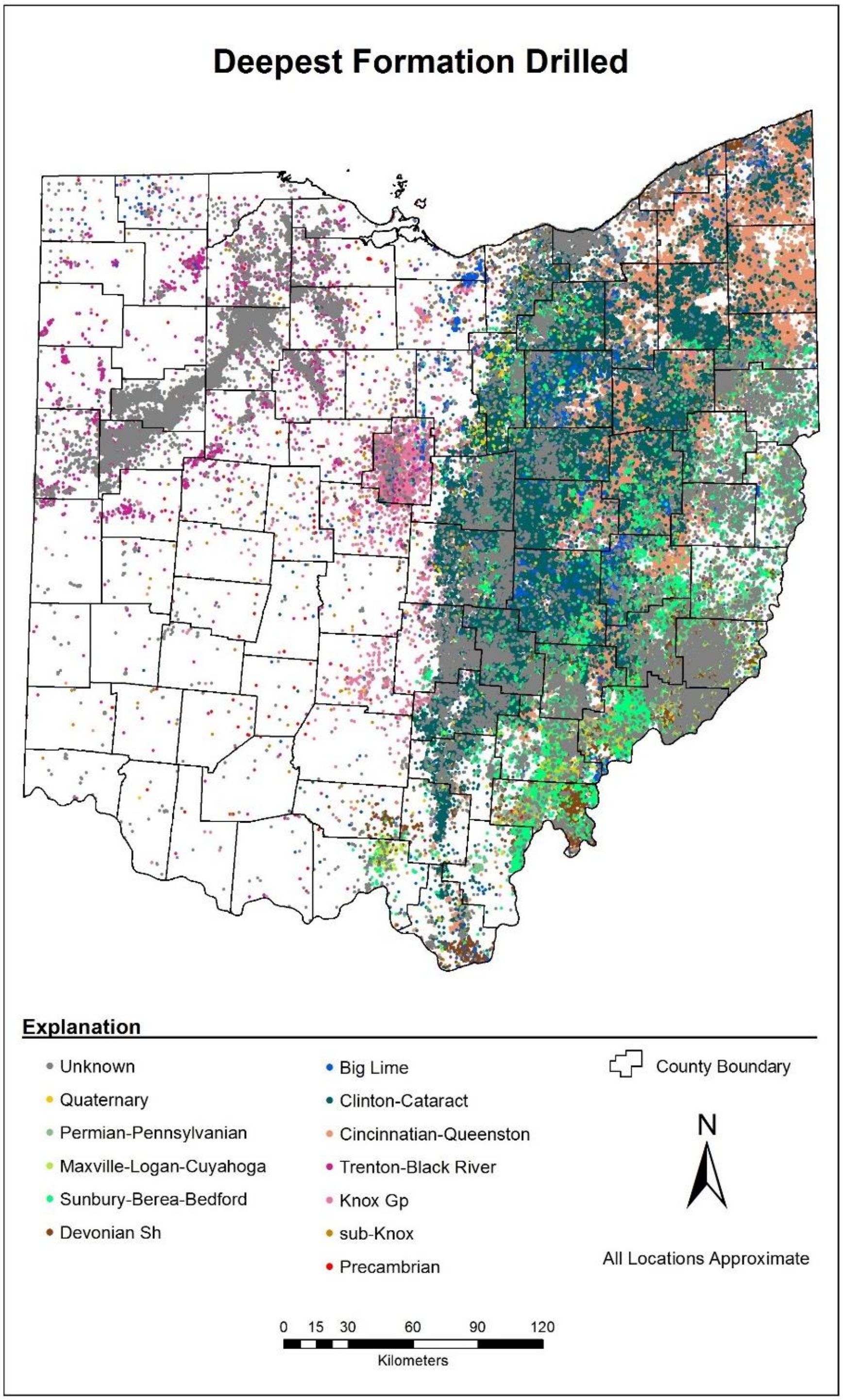


Figure 2-9. Well Locations by Formation for Ohio

2.3 Plugging and Abandonment Data

Plugs were defined as any material used to provide hydrologic isolation to secure a well for abandonment.P&A data provide information on the number, depth, and location of plugs and on materials and methods used to plug wells. This information was used to determine formations, depths, and locations that are more susceptible to wellbore integrity problems in relation to CO_2 storage. P&A data were evaluated for the Michigan and Ohio study areas.

Figure 2-10 shows the depth of all plugged wells in relation to the random subsample set for Michigan. Based on depth, the subsample dataset has a similar distribution compared to the overall population of plugged wells. Consequently, the subsample dataset is considered representative of the overall population of plugged wells in Michigan.

Figure 2-11 shows the depth of all plugged wells in relation to the subset with plugging details for Ohio. The subset was included in the Risk Based Data Management System (RBDMS) database, so it does not represent a random subsample of the overall population. The subset does appear to be representative of the overall population of plugged wells in Ohio based on depth. However, a review of the subset did indicate that most of these records are from the 1990-to-2010 time interval.

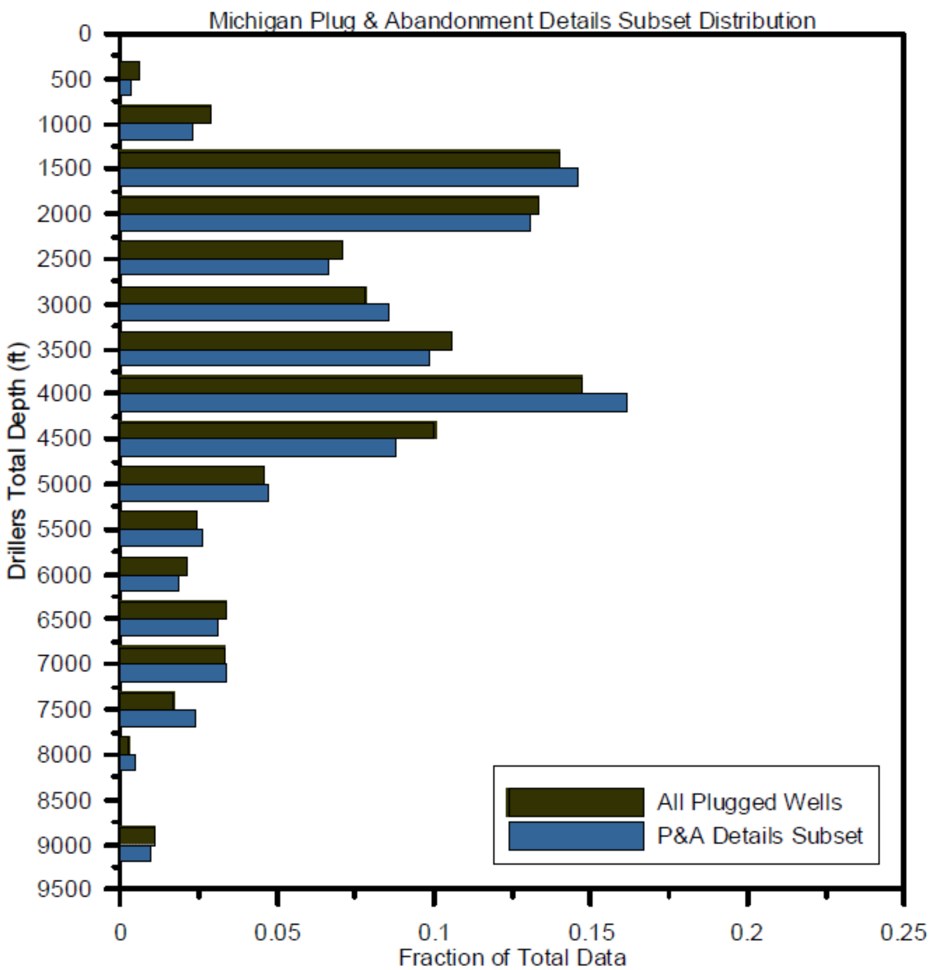


Figure 2-10. Depths of All Plugged Wells Relative to Plugging Details Subset for Michigan

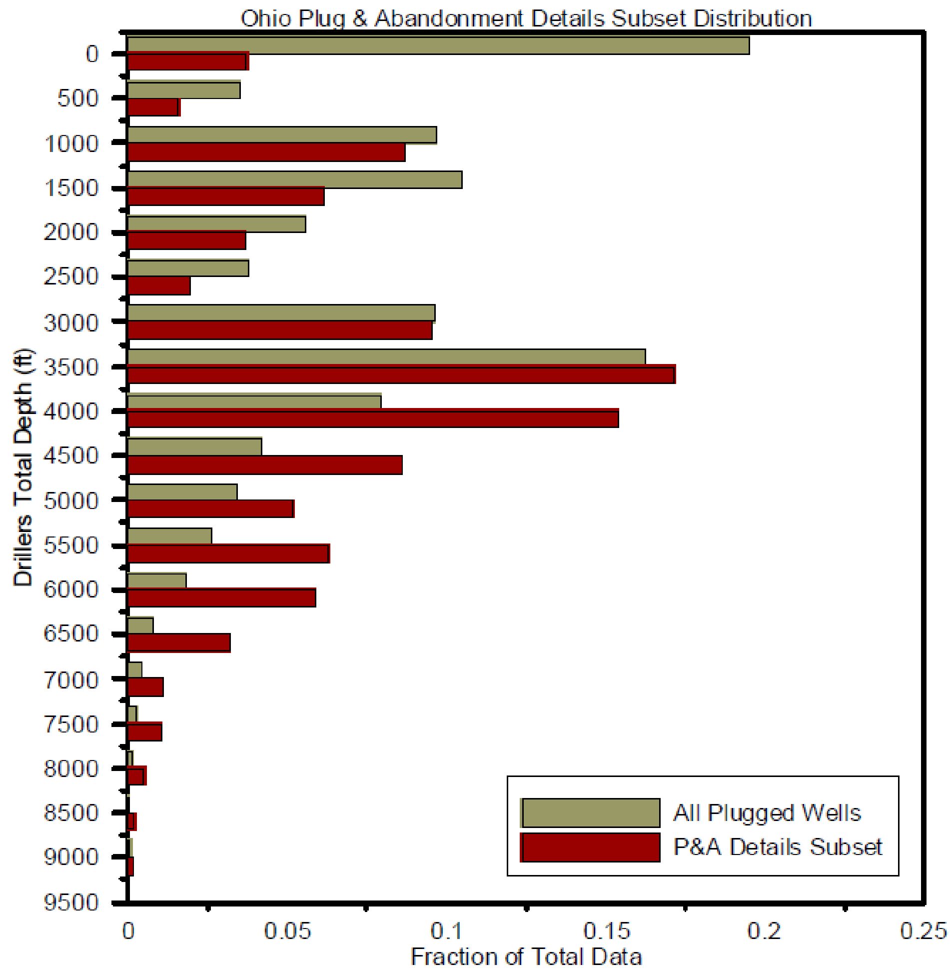


Figure 2-11. Depths of All Plugged Wells Relative to Plugging Details Subset for Ohio

Information from the plugging details of the subsample datasets was graphed to express trends in population distributions. In general, more plugs may be considered a better seal, although some wells may have a few thick plugs and still provide a strong seal. Figure 2-12 shows the plug count for the subset of data tabulated for Michigan. This dataset accounts for 1,730 wells. Most wells contain one to six plugs. Figure 2-13 illustrates the plug count for wells in Ohio. The database contains information on 6,390 wells. As shown, most wells were plugged with one to four plugs.

Plug thickness was also graphed out to review the distribution of plug thickness in the wells. The plug thickness was calculated based on reported top and bottom cement and clay plugs. Mud plugs were not included in the analysis. Figure 2-14 shows the distribution of plug thickness for Michigan. Most plugs are 100 to 400 feet thick, with few plugs over 400 feet thick. Figure 2-15 shows the distribution of plug thickness for Ohio. Plug thickness in Ohio has a much wider distribution. Many plugs are in the range of 200 to 1,200 feet thick, with another increase in frequency of occurrence from 2,000 to 4,000 feet thick. Many plug thicknesses were estimated using bore hole diameter and the amount of cement recorded because thickness were not always recorded. The estimated plug thicknesses could be over or under estimated.

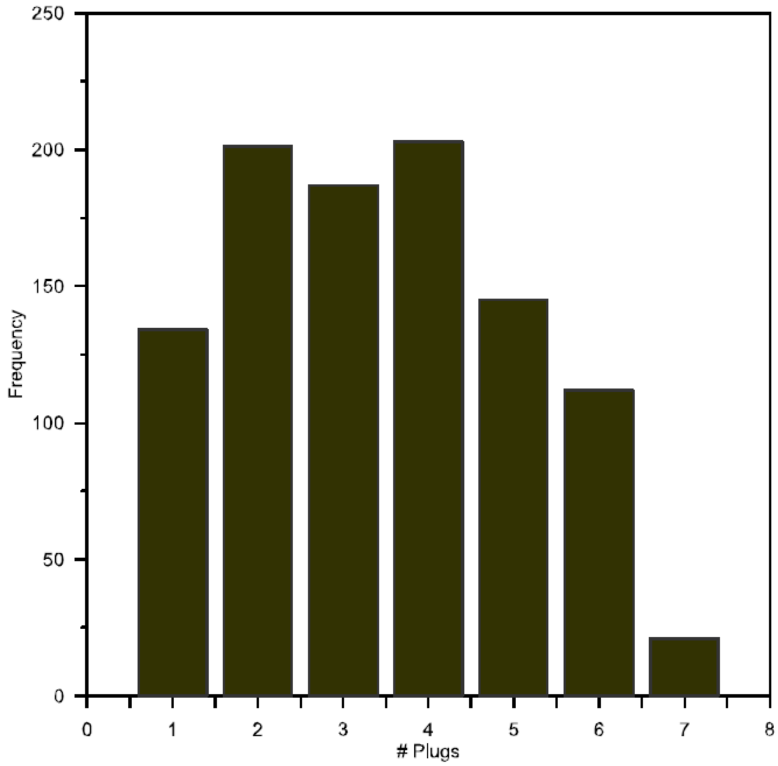


Figure 2-12. Plug Count for Michigan Wells

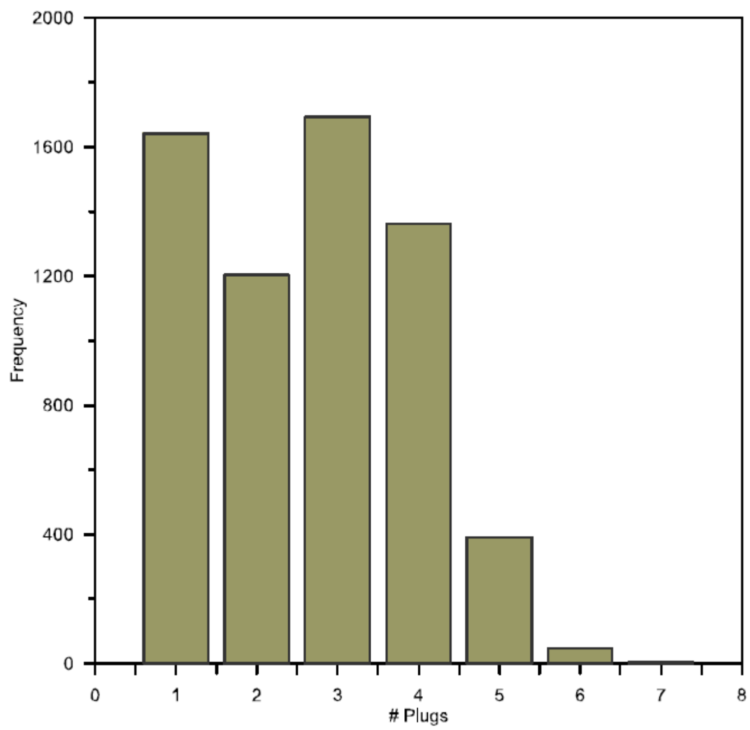


Figure 2-13. Plug Count for Ohio Wells

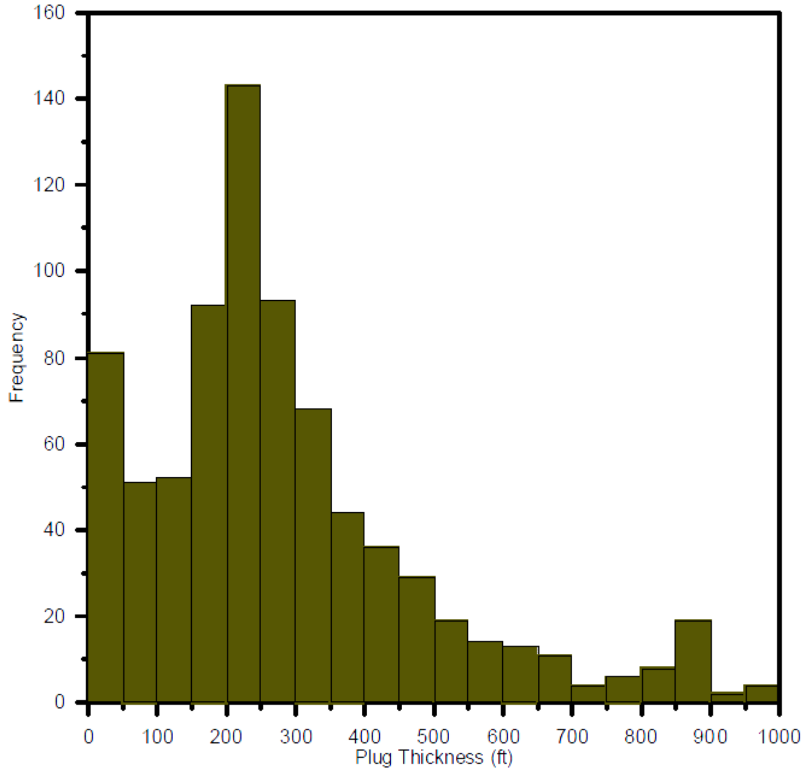


Figure 2-14. Plug Thickness Distribution of Michigan Wells

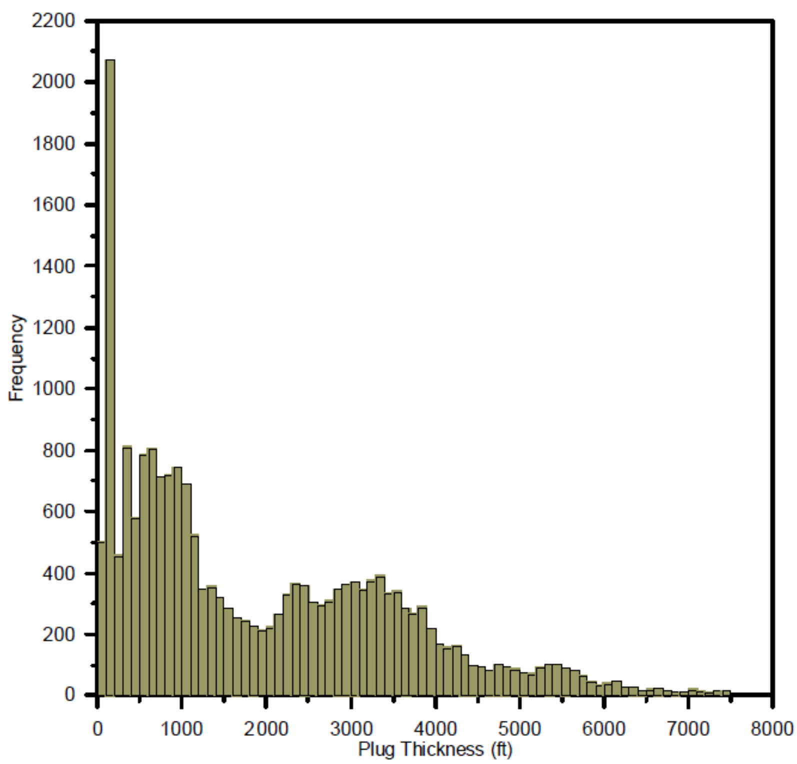


Figure 2-15. Plug Thickness Distribution of Ohio Wells

Plugging detail information was also examined for plug depth versus plug thickness to determine if plugs were concentrated at certain depth intervals. Figure 2-16 shows plug depth versus thickness for the Michigan plugging detail data subsample Plugs are mostly less than 500 feet thick at depths less than 2,500 feet. Figure 2-17 shows plug depth versus thickness for the Ohio plugging detail data subset. Many plugs less than 1,500 feet were run to surface. Many plugs are over 500 feet thick. Overall, the graphs help define depths where thicker plugs were placed.

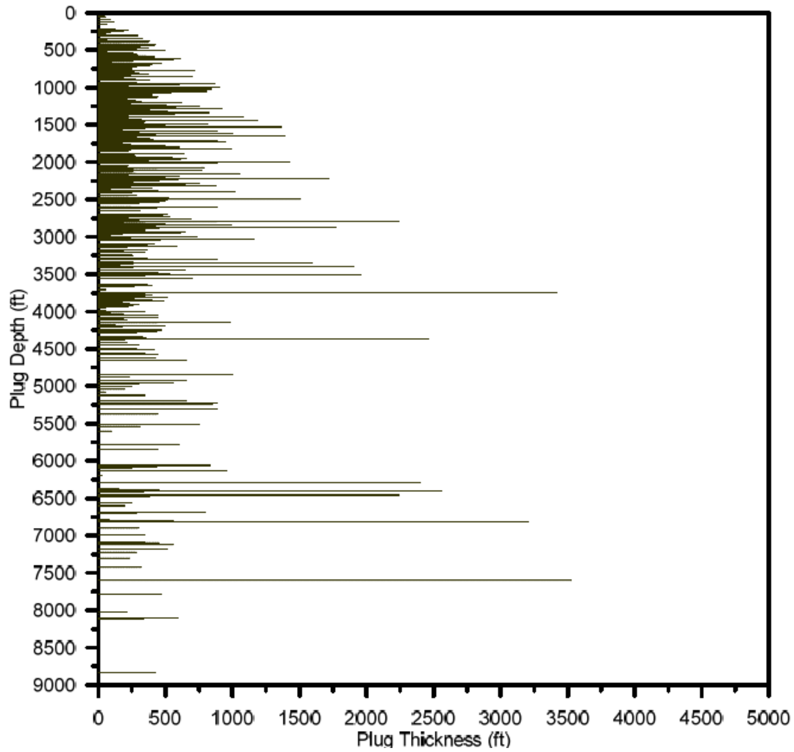


Figure 2-16. Plug Thickness versus Depth Distribution for Michigan

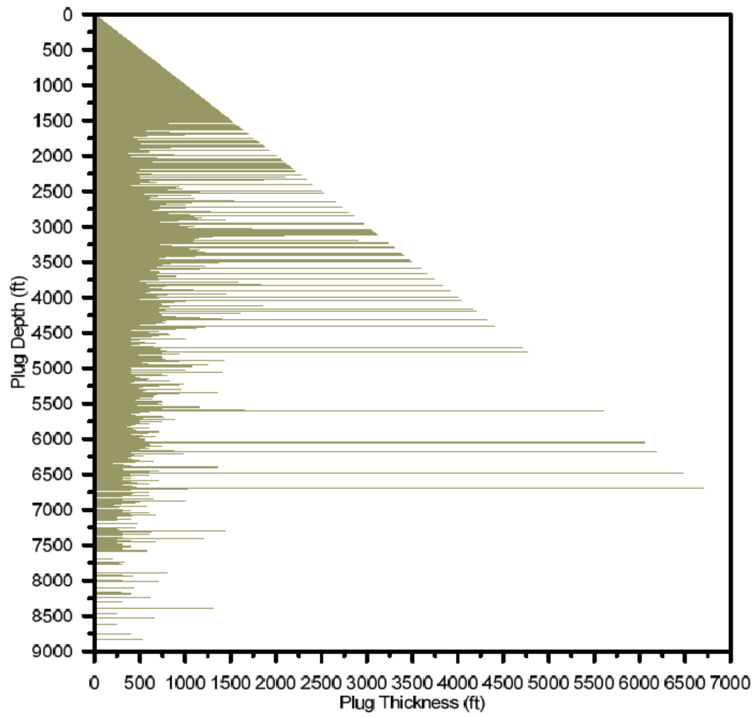


Figure 2-17. Plug Thickness versus Depth Distribution for Ohio

2.4 CBL Data

CBLs were evaluated for the Michigan and Ohio study areas. Records indicated that 1,720 CBLs were available for Michigan and 1,060 CBLs were available for Ohio. These records were randomly subsampled to obtain 10% of the logs. The 10% subsample was acquired and collated with well records for further analysis. Figure 2-18 plots the subsample versus all CBLs for Michigan, and Figure 2-19 plots the subsample versus all CBLs for Ohio.

Oil and gas well CBLs are highly interpretive and qualitative. A methodology was developed to evaluate CBLs with some degree of consistency. The early CBLs measure the attenuation of a sonic signal which represents an average bond measurement at a given depth for the total circumference of the pipe. The methodology involves standardized procedures to determine CBL response. Minimal log response is considered 0% bond (free pipe) and maximum log response is considered 100% bond. The difference between the minimum and maximum log responses is divided into 10% bond increments so that relative percentage of cement bond can be estimated. Intervals are classified accordingly. Analysis was represented with a weighted average bond index across the cemented interval. For example, a bond log may indicate a zone from 3,000 to 3,100 feet with 90% bond and a zone from 2,600 to 3,000 feet with 40% bond. The weighted average index for the well would be 0.57. The methodology also noted any indications of leakage pathways such as a micro-annulus, cracks, voids, gas-cut cement, channeling, etc.

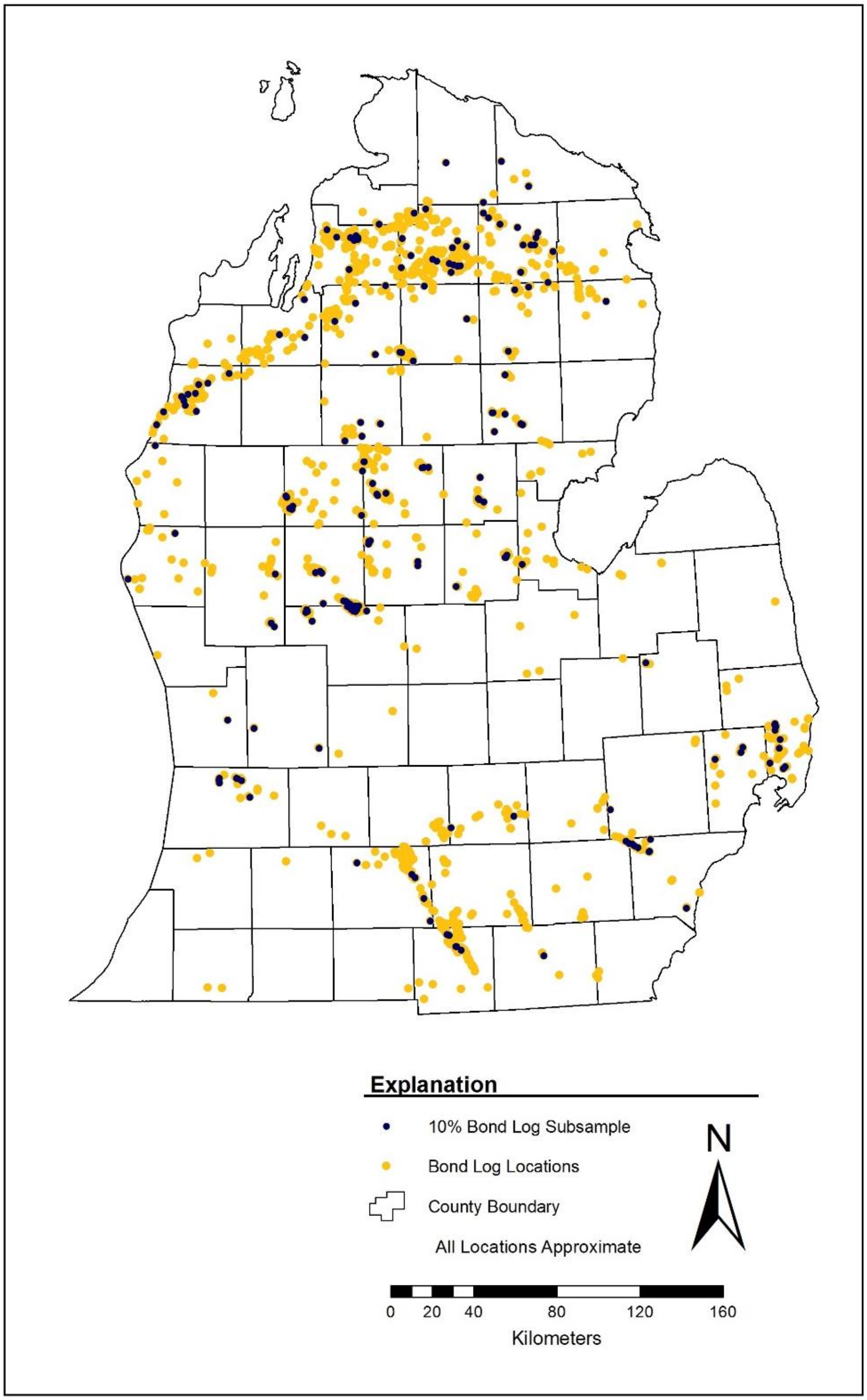


Figure 2-18. Locations of CBLs and 10% Subsample Dataset for Michigan

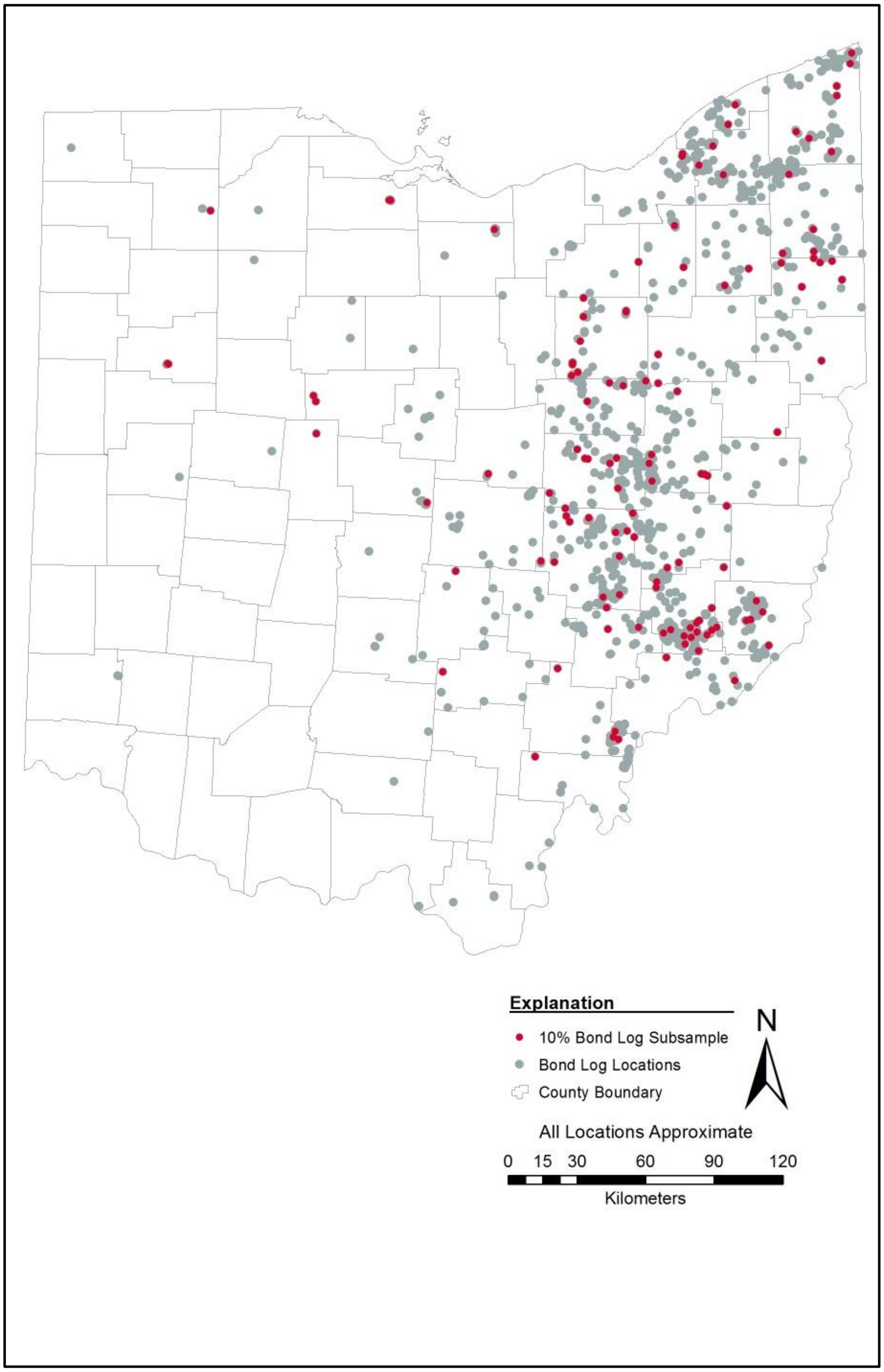


Figure 2-19. Locations of CBLs and 10% Subsample Dataset for Ohio

Results of the systematic CBL evaluation indicated that weighted average cement rating averaged 0.71 in Michigan and 0.73 in Ohio. In general, most logs had at least 50 feet of cement rated over 75% above the isolation zone. Results were analyzed based on well depth, deepest geologic formation penetrated, and age. Analysis shows decreasing cement bond index with depth that is paralleled with deeper formations. More detail on the CBL analysis is presented in Section 5.0 of this report.

Records for wells in Michigan and Ohio were reviewed to determine if any SCP data were available in existing databases that could be analyzed for wellbore IFs. Historical operational records were collected and reviewed for Class II underground injection control (UIC) wells in Ohio. A total of 67,507 records were obtained from 670 wells. The records included monthly injection volumes, pressure, annular pressure, rates, and days injecting. Data were reviewed for trends in annular pressure and injection pressure that may be proxies for SCP. Class II records were also evaluated for several wells in Michigan. Most of these injection wells maintain a positive pressure on the annular space, so they are not suitable for analysis. Oil and gas regulations were also evaluated for both states to determine if any SCP data were available. Regulations indicated that operators were not required to report wells that had SCP. Recently, shale gas wells have been under more regulations to report instances of significant SCP and install controls to address the process. No source was found with a history of casing pressure buildup over time in the review. Overall, no useful data were found in the database; most data related to the monthly reporting period, which is not suitable for SCP analysis. Consequently, more effort was assigned to collect SCP data in the field through this project.

3.0 Well Record Analysis

3.1 Study Area Analysis

The objective of this task was to determine the real-world level of effort necessary to address existing boreholes at hypothetical CO_2 storage study areas in Ohio and Michigan. Maps were created plotting oil and gas wells with recorded depths, wells with CBLs, and locations of CO_2 emitting facilities with approximate emission size. Areas with deep wells, available CBLs, and close proximity to CO_2 emitting facilities were of most interest. Six study areas meeting the above criteria, three in Michigan and three in Ohio, were selected (Figure 3-1).

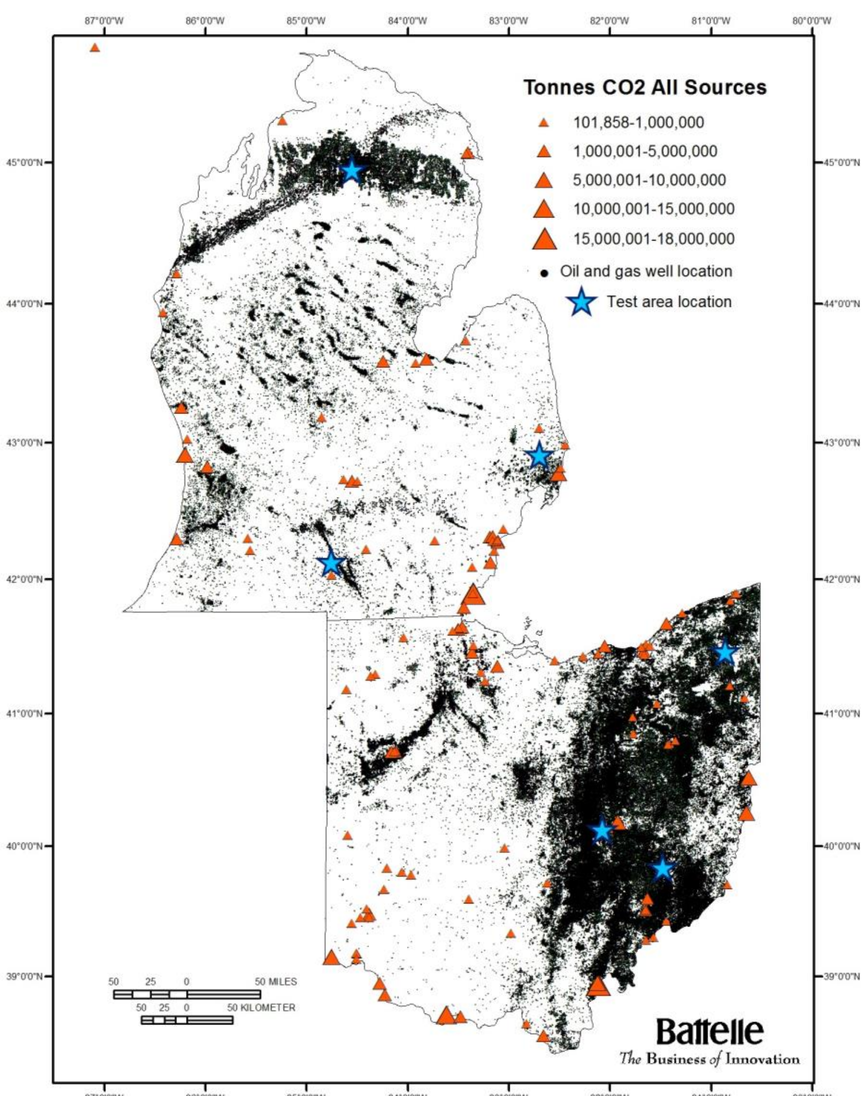


Figure 3-1. Locations of Oil and Gas Wells (black dots), CO_2-emitting Facilities by Size (red triangles), and Six Selected Study Areas (blue stars) in Michigan and Ohio

Corrective action guidelines were created based on the type of well, well status, and condition of the well. Table 3-1 lists possible corrective actions, and Table 3-2 shows which corrective action scenario is warranted based on well status.

Table 3-1. Corrective Actions and their Definitions

Corrective Action	Description
Zero Corrective Action	No action is required
Inspect Wellhead	Visually locate wellhead
Survey Well	Survey well condition with pressure log or CBL
Monitor Wellhead	Monitor wellhead for CO_2 leakage with surface methods
Replug Well	Re-enter and add plugs to well
Overdrill and Plug	Overdrill well and plug

Table 3-2. Corrective Action Scenarios for Certain Well Statuses

Corrective Action	Well Status
Inspect Wellhead	Producing wells, P&A wells
Survey Well	P&A w/ no records
Monitor Wellhead	Domestic well w/ no records, historical producer
Replug Well	Unplugged well
Overdrill and plug	Unplugged well or well that demonstrates leakage during CO_2 storage period

Note: P&A = plugged and abandoned.

3.1.1 Michigan

Three study areas, located in southeast Calhoun County, south-central Otsego County, and central Saint Clair County, were chosen in Michigan.

3.1.1.1 Southeast Calhoun County

The southeast Calhoun County study area (Figure 3-2) used the Mt. Simon sandstone formation as the potential storage zone with the overlying Eau Claire formation as the confining layer. The test study area was determined based on a calculated storage volume using the parameters in Table 3-3 and assuming 3.5 million tonnes of CO_2 for 20 years (70 million metric tonnes) (Figure 3-3).

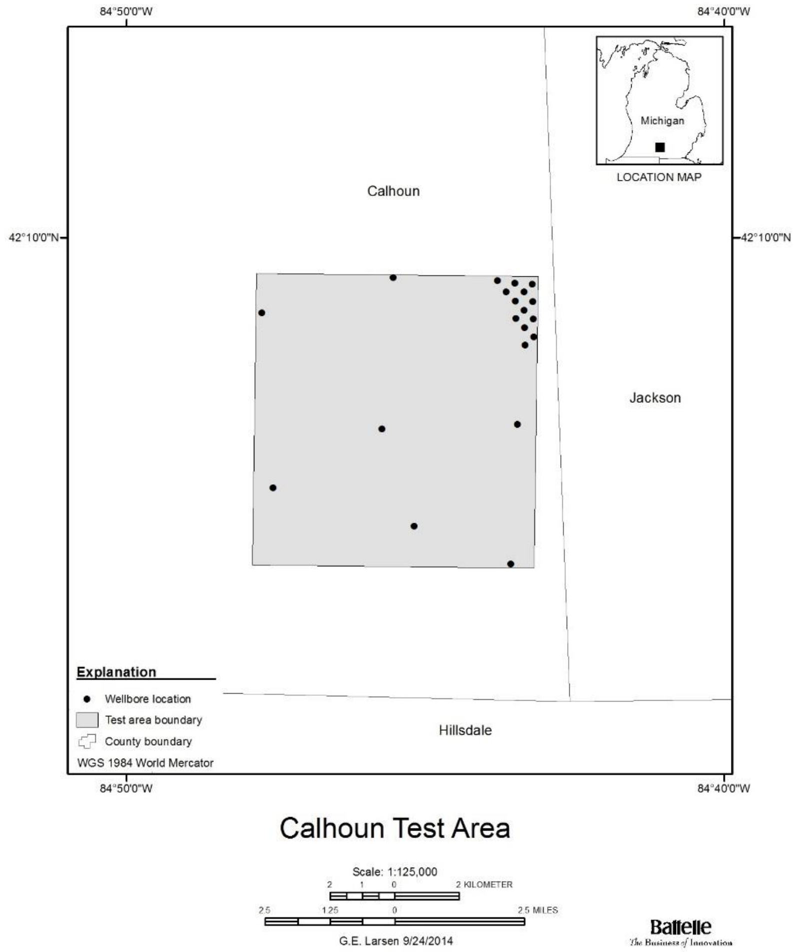


Figure 3-2. Calhoun County Study Area Showing Well Locations

Table 3-3. Formation Characteristics Used to Calculate Storage Capacity, Calhoun County Study Area

Formation: Mt. Simon		
Depth	5,580	feet
Thickness	330	feet
Porosity	0.12	fraction
Pressure	2,500	psi
Salinity	225,000	ppm
Temperature	44.4	Celsius
CO_2 Density	0.756	g/cc

Note: psi = pounds per square inch
ppm = parts per million
g/cc = grams per cubic centimeter

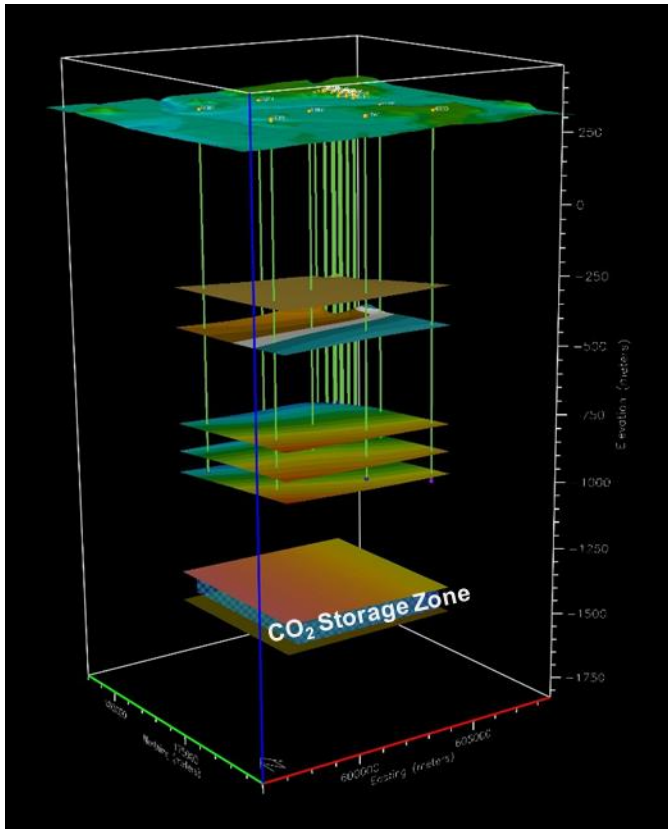


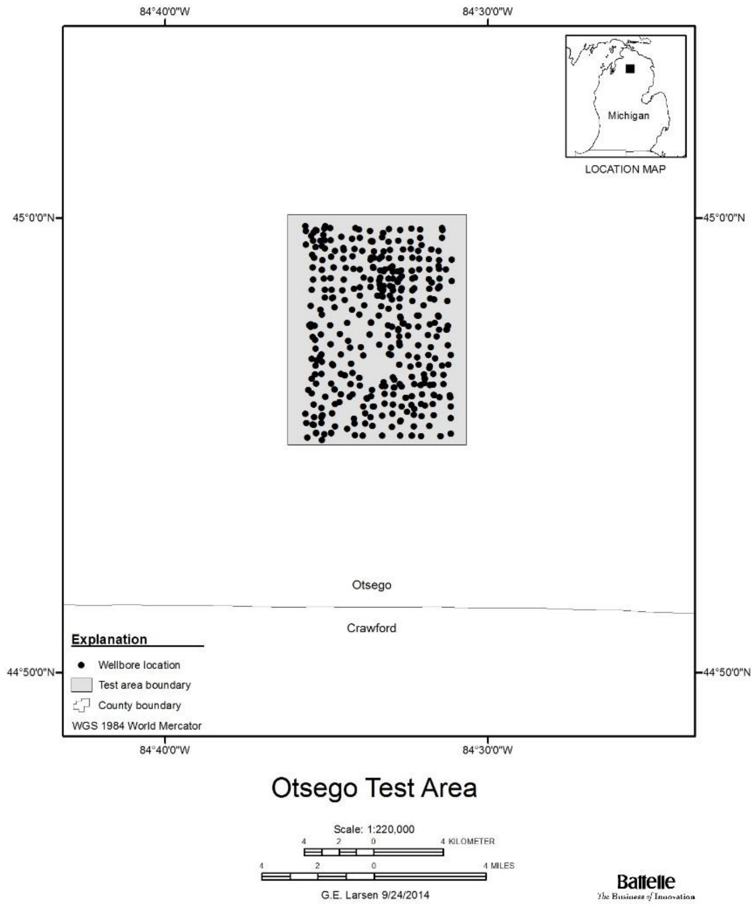
Figure 3-3. Locations and Depths of Wellbores with CO_2 Storage Zone Highlighted, Calhoun County Study Area

The 23,000- x 23,000-ft study area contained 22 wells. All of the wells were plugged, and none of them penetrated the confining layer. Because the confining layer was not penetrated, this site warranted zero corrective action.

3.1.1.2 South-central Otsego County

The south-central Otsego County study area (Figure 3-4) used the Niagara formation as the potential storage zone and the Salina group as the confining layers. A storage rate of 3.5 million metric tons of CO_2 for 20 years was assumed, putting the study area at a 19,700- x 19,700-feet area. Table 3-4 lists the parameters used in the calculations. All parameters were estimated from nearby well logs and published literature.

In the Otsego County study area, there are 447 oil and gas wells, 10 available CBLs (120 in the entire county), and one nearby CO_2-emitting facility. Of the 447 wells, only 133 wells penetrate the storage zone and/or the confining layers. One well has unknown depth, with no record of well completion. This well most likely was permitted but never drilled.



Note: The CO_2 emitting facility is just outside of Otsego County (southwest).

Figure 3-4. Otsego County Study Area Showing Well Locations

Table 3-4. Formation Characteristics used to Calculate CO_2 Storage Capacity, Otsego County Study Area

Formation: Niagara		
Depth	6200	feet
Thickness	400	feet
Porosity	0.12	fraction
Pressure	2,500	psi
Salinity	350,000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

The 133 wells of interest were evaluated using the corrective action guidelines. Table 3-5 summarizes the number of wells which require the correction actions.

Table 3-5. Number of Wells Requiring Corrective Action, Otsego County Study Area

Corrective Action	Number of Wells
Zero Corrective Action	314
Inspect Wellhead	133
Survey Well	0
Monitor Wellhead	0
Replug Well	3
Overdrill & Plug	0
Total # of Wells	447

3.1.1.3 Central Saint Clair County

The same parameters used for the Otsego County study area were used for the Saint Clair study area (Figure 3-5). In the 19,700- x 19,700-kilometer study area, there are 156 oil and gas wells. Ten of these wells do not penetrate the storage zone or the confining layers, so they do not require any corrective action. The remaining 146 wells were evaluated using the corrective action guidelines (Table 3-6).

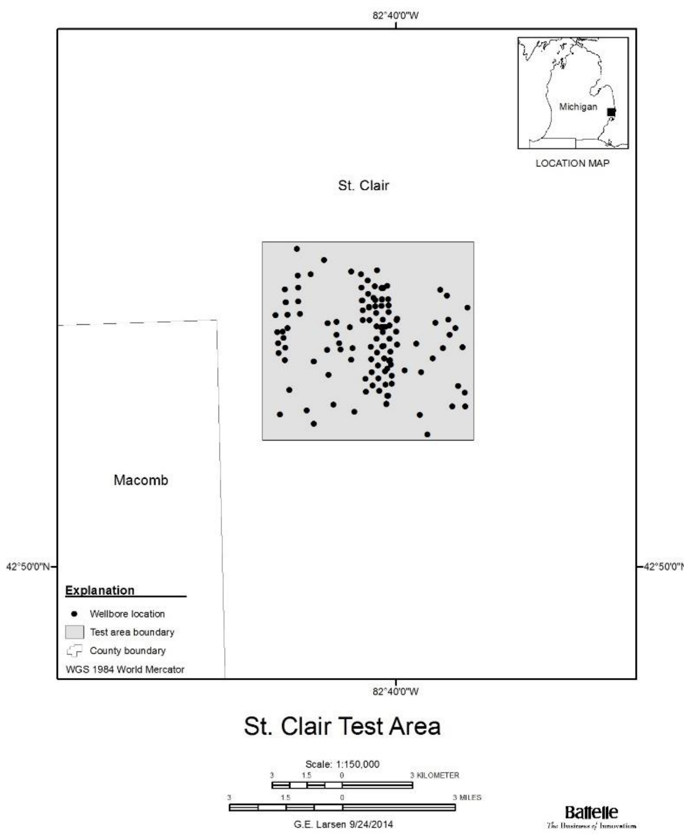


Figure 3-5. Saint Clair County Study Area Showing Well Locations

Table 3-6. Number of Wells Requiring Corrective Actions, Saint Clair County Study Area

Corrective Action	Number of Wells
Zero Corrective Action	10
Inspect Wellhead	146
Survey Well	1
Monitor Wellhead	1
Replug Well	18
Overdrill & Plug	0
Total # of Wells	156

3.1.2 Ohio

Three study areas, located in northern Trumbull County, northern Muskingum County (crossing into southern Coshocton County), and southern Noble County, were chosen in Ohio. All three locations used the interval from Copper Ridge Dolomite to Basal Sandstone as the storage unit, with the interval from Queenston Shale to Beekmantown Dolomite as the confining layers. A storage volume of 3.5 million metric tons a year for 20 years was calculated, totaling 70 million metric tons of CO_2 to be stored. Each study area is 49,200 x 49,200 feet. Table 3-7 summarizes the formation characteristics used in the calculations.

Table 3-7. Formation Characteristics Used to Calculate Storage Capacity for Three Ohio Study Areas

Formation: Copper Ridge-Basal SS		
Depth	7050	feet
Thickness	115	feet
Porosity	0.065	fraction
Pressure	3,385	psi
Salinity	250,000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

3.1.2.1 Northern Trumbull County

In the northern Trumbull County study area, there were 357 total wells. None of these wells penetrate the confining layers or the storage zones; therefore, this study area requires zero corrective action. Figure 3-6 shows the study area, with black dots representing plugged well locations. Figure 3-7 shows well depths in this study area.

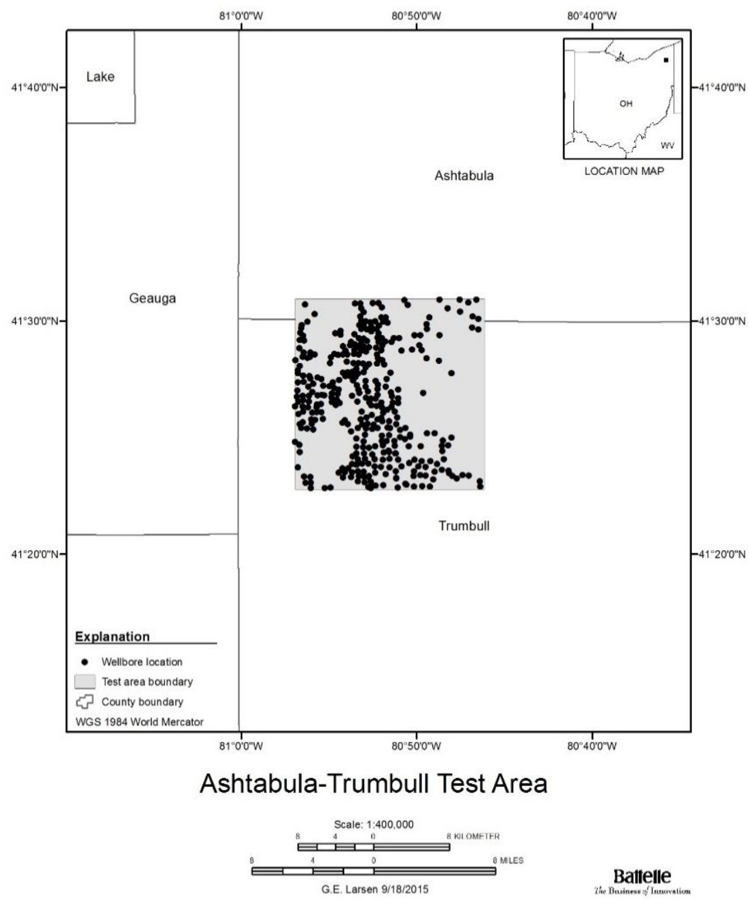


Figure 3-6. Trumbull County Study Area Showing Well Locations

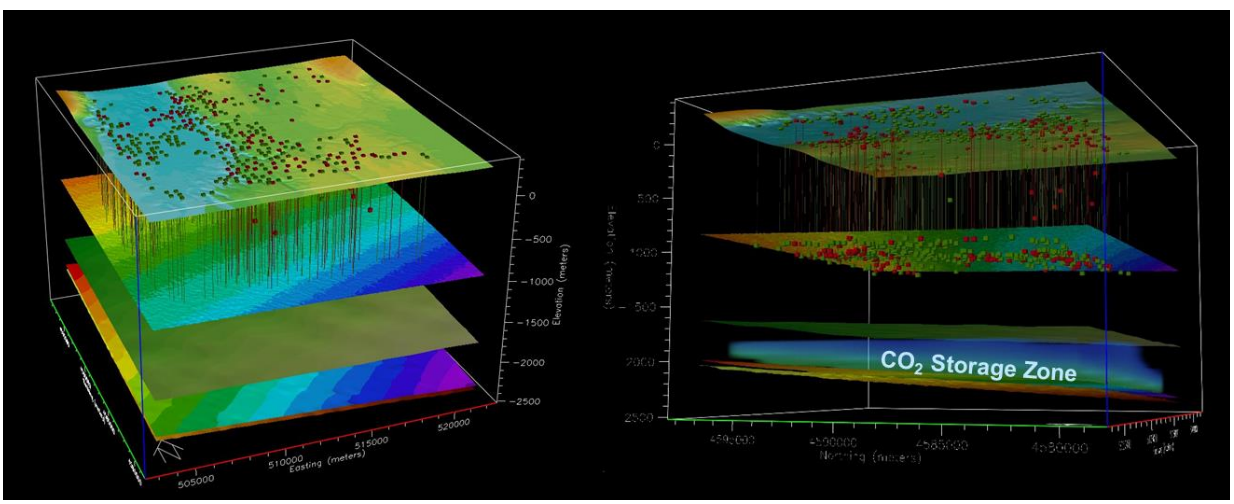


Figure 3-7. Locations and Depths of Wellbores with CO_2 Storage Zone Highlighted, Northern Trumbull County Study Area

3.1.2.2 Northern Muskingum County/Southern Coshocton County

In the northern Muskingum/southern Coshocton County study area, there are 1,221 wells total, with 302 wells penetrating the storage zone and/or the confining layers. Most of these wells are either producing or have been plugged. Nine wells are historical producers. Figure 3-8 shows the location of the study area and wells. Table 3-8 summarizes the corrective actions required at this study area.

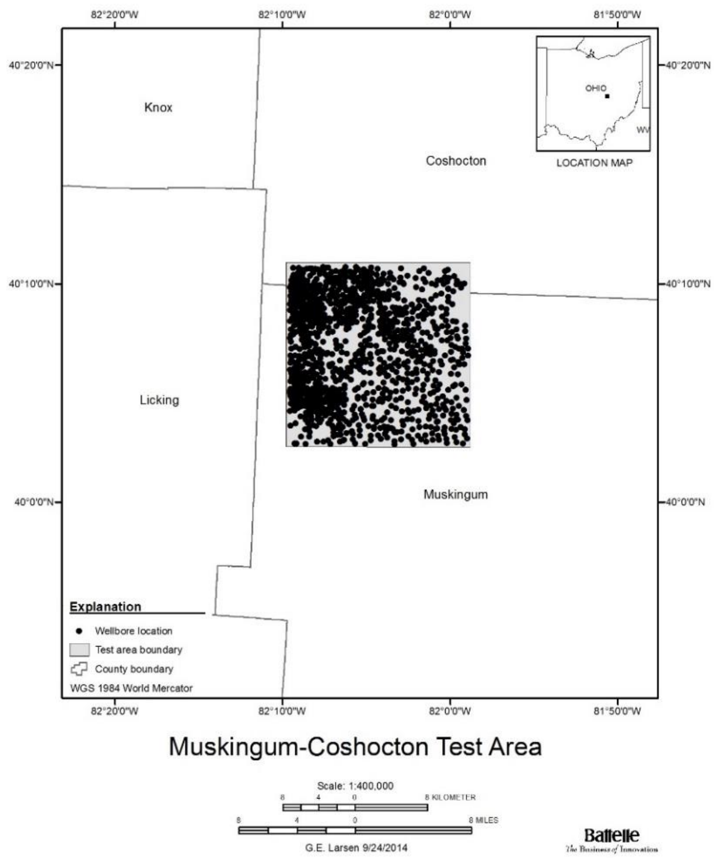


Figure 3-8. Northern Muskingum County/Southern Coshocton County Study Area Showing Well Locations

Table 3-8. Number of Wells Requiring Corrective Action, Northern Muskingum County/Southern Coshocton County Study Area

Corrective Action	Number of Wells
Zero Corrective Action	919
Inspect Wellhead	293
Survey Well	0
Monitor Wellhead	9
Replug Well	0
Overdrill & Plug	0
Total # of Wells	1,221

3.1.2.3 Noble County

The Noble County study area consists of 870 wells total, with 238 wells penetrating the storage zone and/or the confining layers. One well was recorded as reaching a total depth greater than 5,000 feet; however, no records accompany this well. This well was probably permitted and not drilled, but because there are no records, the well needed to be evaluated. Figure 3-9 shows the location of the study area and wells. Table 3-9 summarizes the corrective actions required at the Noble County study area.

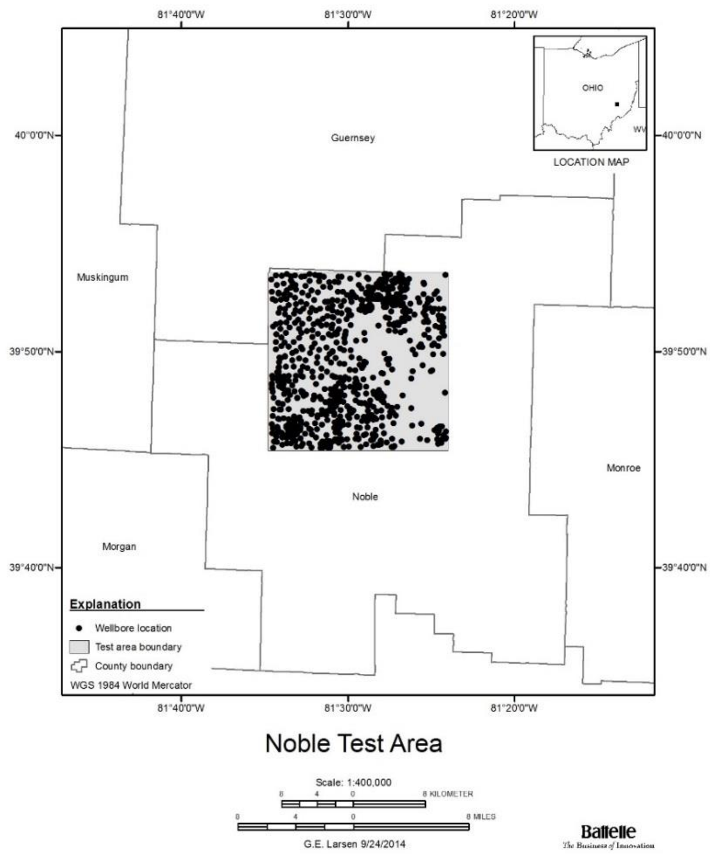


Figure 3-9. Noble County Study Area Showing Well Locations

Table 3-9. Number of Wells Requiring Corrective Action, Noble County Study Area

Corrective Action	Number of Wells
Zero Corrective Action	631
Inspect Wellhead	234
Survey Well	1
Monitor Wellhead	4
Replug Well	0
Overdrill & Plug	1
Total # of Wells	870

3.2 Population Summary Statistics and Spatial Representations

This section describes, in detail, the well data collected for Ohio and Michigan, as summarized above. It presents the distribution of key well IFs, both statistically and spatially, and outlines a method for estimating risk factors and overall risk for the general population of oil and gas wells in the Ohio and Michigan study areas.

3.2.1 Ohio

3.2.1.1 Raw Data and Data Cleaning

The well construction/status data contain records for 209,015 wells throughout Ohio. Measured attributes of the wells include the location of the wellhead and bottom of the hole, total depth of the well as recorded by the driller (DTD), total depth of the well as recorded by the loggers (LTD), total vertical depth of the hole (TVD), type of well, status of well, and dates of well initiation and completion.

In order to determine a consistent measure for the depth below ground surface of the bottom of each well, a new variable was created that was equal to DTD if the well was listed as being vertical (99.4% of all wells) and equal to TVD if the well was listed as directional or horizontal (less than 1% of all wells) (Figure 3-10). DTD was selected instead of the depth recorded by the logging tool due to increased coverage across the dataset. Where both the DTD and LTD are present in the dataset, the values are within 100 feet of each other for over 97% of the wells.

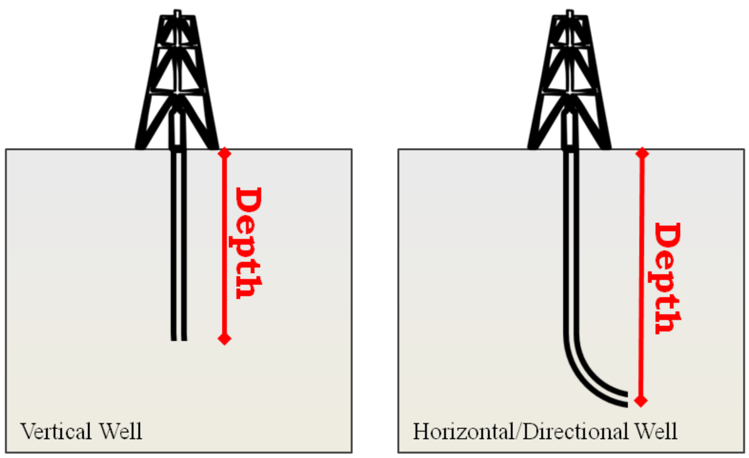


Figure 3-10. Determination of Wellbore Depth for Vertical and Non-vertical Wells

The approximate age of each well was generally determined using the completion date. For wells that do not have a completion date in the database, but have a spud date reported, the year of the spud was used to estimate the age of the well. This occurred for 5,757 wells. Where wells have both the completion and the spud date, over 98% of the wells have dates within two years of each other, allowing for a reasonably accurate measure of age in years.

The plugging data for Ohio contain 20,767 records for 6,388 unique wells. These data were organized such that each unique plug was contained in its own record with information on the date implemented, the plug interval, type of plug, plug status, and amount of material used. During data cleaning and processing, the records were transposed such that all of the plugs for a single, unique well were included in a single record. The plug-specific variables were appended with a numbered suffix and the total number of plugs was calculated.

Estimates of the weighted-average cement bond based on bond log data for 105 wells across Ohio were also included in the analysis dataset. Down each wellbore, measurements were collected for each cemented interval of the percentage bond (i.e., 100% is a thoroughly complete bond, and anything less than 100% was a partially complete bond) and the length of the interval. The weighted-average bond was then calculated by averaging the percentage bonds, using the length of each interval as the weighting factor.

The three separate datasets (well construction, plugging, and cement bond data) were merged according to the unique 14-digit American Petroleum Institute (API) number assigned to the well when the permit was issued. After merging the datasets, 209,487 unique wells are represented, with all or some of the data from the three separate datasets.

The combined dataset was then screened to eliminate wells that could not be used in the risk analysis, including wells that had no location information or had location information that was outside of the bounds of the State of Ohio, and wells that had a status of “Cancelled” or “Not Drilled.” This step reduced the number of wells in the final analysis data set to 208,911.

3.2.1.2 Key Parameters

After a careful evaluation of the available wellbore attributes by Battelle’s team of researchers and oil and gas subject matter experts, it was determined that the key parameters for consideration in the evaluation of risk for CO_2 leakage should include the following:

- Location of the well
- Year that well construction was completed
- Depth of the bottom of the well
- Well status (including whether the well was plugged or is producing)
- Estimate of the deepest geologic formation through which the well penetrates

In addition, the weighted-average cement bond data based on bond log analysis for the small subset of wells were used to help categorize the geologic formations as part of the process for estimating risk.

3.2.1.3 Summary Statistics and Maps

Tables 3-10 through 3-13 present summary statistics for some of the key parameters in the wellbore dataset. Table 3-10 summarizes the spatial location parameters, as well as the weighted-average cement bond (W.Ave.Bond). The summary statistics include the number of wells with valid measurements (N), the arithmetic average (mean), standard deviation (sd), minimum value (min), percentiles of the frequency distribution (5% to 95%), and maximum value (max). Note that while every wellbore had a valid horizontal location (longitude, latitude), a smaller number (149,414) had a valid depth, and only a very small number of wells had valid weighted-average cement bond data.

Table 3-11 presents frequency counts for the different values of well status. Nearly 90% of wells were either plugged and abandoned (29%), producing (26%), historical production wells (18%), or final restoration wells (15%). Among the remaining wells, the most frequent status was domestic well (2%), storage well (2%), dry and abandoned well (1%), and unknown or missing status (5%).

Table 3-10. Summary Statistics for Location and Depth Parameters and Weighted-average Cement Bond, Ohio Data

Parameter	N	mean	sd	min	5%	25%	50%	75%	95%	max
DTD (ft)	150160	3035.95	1602.57	5	635	1638	3112	4068	5625	16640
LTD (ft)	52843	3982.01	1618.38	1	1300	3126	3900	4948	6307	17700
TVD (ft)	185	4369.87	2843.36	3	441.2	2132	3458	7596	8313.6	9223
Depth (ft)	149414	3019.79	1578.69	0	632	1630	3103	4050	5612	14990
W.Ave.Bond	102	0.87	0.13	0.47	0.62	0.78	0.90	0.97	1.00	1.00

Table 3-11. Frequency Counts and Percentages for Ohio Well Status

Status	Description	Count (%)
AI	Active Injection	364 (0.17%)
CA	Cancelled	0 (0.00%)
DA	Dry and Abandoned	2,533 (1.21%)
DG	Drilling	233 (0.11%)
DM	Domestic Well	4,402 (2.11%)
DR	Well Drilled	445 (0.21%)
EM	Exempt Mississippian Well	7 (0.00%)
FR	Final Restoration	30,541 (14.62%)
HP	Historical Production Well	38,071 (18.22%)
I1	Temporary Inactive Well Status 1st Year	25 (0.01%)
IA	Drilled, Inactive	36 (0.02%)
LH	Lost Hole	91 (0.04%)
LU	Location Unknown	323 (0.15%)
NF	Field Inspected, Well Not Found	745 (0.36%)
O	Other	8 (0.00%)
OR	Orphan Well – Ready	568 (0.27%)
PA	Plugged and Abandoned	61,445 (29.41%)
PB	Plugged Back	133 (0.06%)
PR	Producing	54,374 (26.03%)
RO	Reopen	28 (0.01%)
RP	Replugged Well	61 (0.03%)
SI	Shut In	70 (0.03%)
SW	Storage Well	3,252 (1.56%)
TA	Temporarily Abandoned	5 (0.00%)
UN	Unknown	4,565 (2.19%)
WP	Well Permitted	704 (0.34%)
WW	Plugged Back for Water Well	15 (0.01%)
-	Missing	5,867 (2.81%)
Total	All wells	208,911 (100%)

Table 3-12 presents frequency counts for the deepest geologic formation penetrated by each Ohio wellbore. The formations are sorted according to typical stratigraphy—that is, the shallowest formations at the top of the table and increasingly deeper formations from there down. The deepest formation penetrated for approximately half of the wells was the Clinton-Cataract (26%), Cincinnatian-Queenston (16%), or Sunbury-Berea-Bedford (13%). For about 25% of the wellbores, the deepest formation was unknown or missing.

Table 3-12. Frequency Counts and Percentages for Deepest Geologic Formation, Ohio

Formation Group	Count (%)
Quaternary	1,152 (0.55%)
Permian-Pennsylvanian	8,999 (4.31%)
Maxville-Logan-Cuyahoga	3,808 (1.82%)
Sunbury-Berea-Bedford	26,611 (12.74%)
Devonian Shale	8,381 (4.01%)
Big Lime	4,690 (2.24%)
Clinton-Cataract	53,624 (25.67%)
Cincinnatian-Queenston	34,438 (16.48%)
Trenton-Black River	5,774 (2.76%)
Knox Gp	8,538 (4.09%)
sub-Knox	506 (0.24%)
Precambrian	335 (0.16%)
Unknown	50,616 (24.23%)
Missing	1,439 (0.69%)
Total	208,911 (100%)

Table 3-13 presents frequency counts summarizing the general age of the wellbores— that is, the decade in which each well was completed. The ages of the wells are reasonably uniformly distributed over the past 100 years, with relative spikes in the 1970s (11%) and 1980s (18%). Also, the date completed is unknown for a relatively large number of wells (31%).

Table 3-13. Frequency Counts and Percentages for Age of Ohio Wells (decade completed)

Decade Completed	Count (%)
Before 1910	5,346 (2.56%)
1910s	7,508 (3.59%)
1920s	9,615 (4.60%)
1930s	7,854 (3.76%)
1940s	11,302 (5.41%)
1950s	11,829 (5.66%)
1960s	14,456 (6.92%)
1970s	22,112 (10.58%)
1980s	38,170 (18.27%)
1990s	8,675 (4.15%)
2000s	7,372 (3.53%)
Missing	64,672 (30.96%)
Total	208,911 (100%)

Figure 3-11 summarizes the frequency distribution of the depth of the wells, broken down by the approximate age of the wells (i.e., decade of completion). Depth likely reflects the location of the targeted oil and gas resources, and also probably the availability of drilling technologies to access those resources. It can be noted (Figure 3-11) that the relative spike in drilling seen in the 1970s and later (see Table 3-13) was apparently accompanied by a movement to access resources at greater depths. Before the 1970s, it appears that drilling was typically performed to depths of 1,000 to 3,000 feet, but from the 1970s and later, drilling was taken to depths of 3,000 to 5,000 feet.

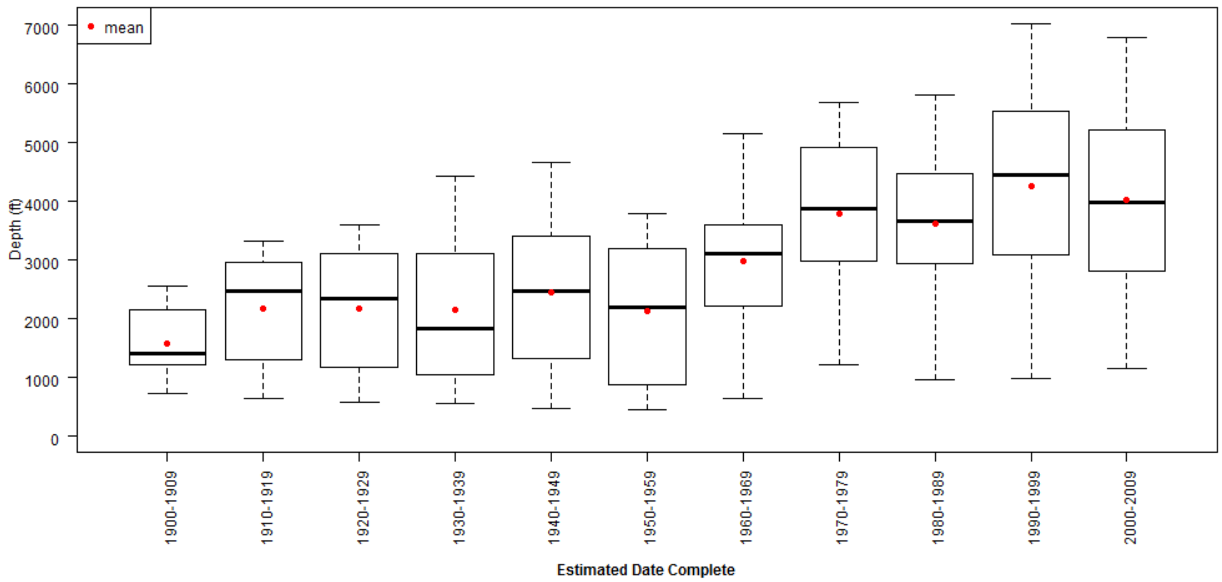


Figure 3-11. Ohio Well Depths Broken Down by Decade of Well Completion

Figure 3-12 summarizes the frequency distribution of the weighted-average cement bond data, broken down in three ways: by the deepest penetrated geologic formation (with formations sorted by depth from left to right in the figure), well depth, and approximate age of the wells (broken into four intervals). The cement bonds are generally 0.70 (70%) or better, with a couple of possible exceptions, most notably for deep wells in the 6,000- to 7,000-foot range where cement bonds are more often less than 0.70. However, the cement bond dataset is relatively small (N = 105), so generalizations may not be reliable.

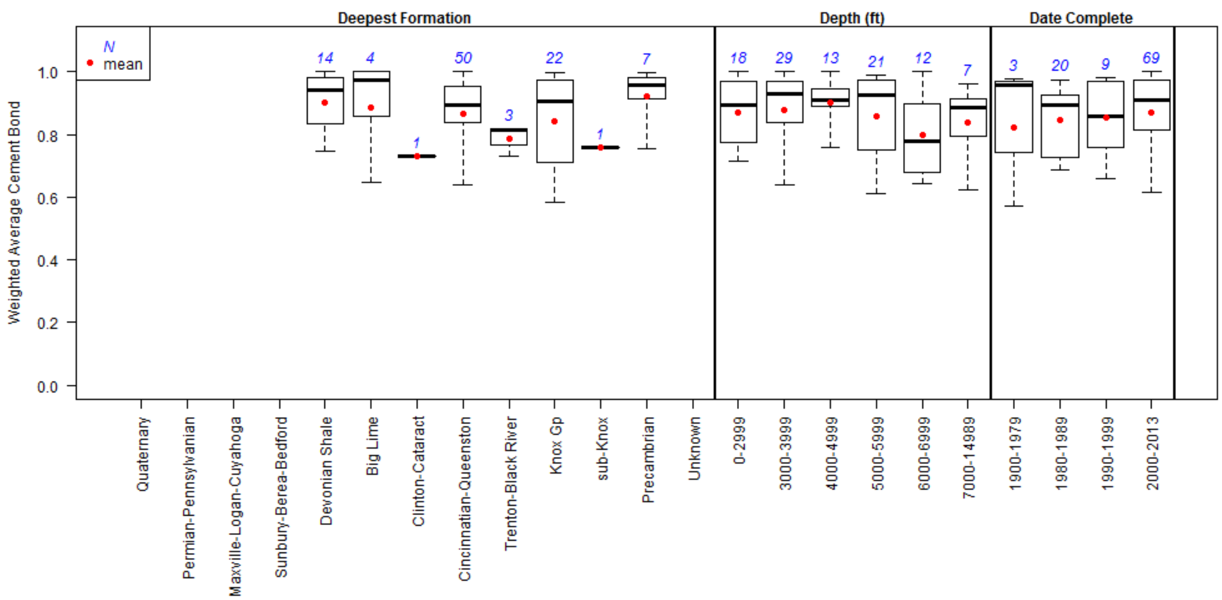


Figure 3-12. Ohio Weighted-average Cement Bond Broken Down by Deepest Geologic Formation, Well Depth, and Well Age

The maps in Figure 3-13 show the spatial distribution of key wellbore characteristics: the age, depth and status. In these figures, a 1-square-kilometer (3280 x3280 feet) grid was first defined across the area of interest; then, the average age and depth and the most common status were calculated across all wellbores located in each grid cell. These statistical summaries for each grid cell were then color-coded and displayed on the maps. The map of well depth shows the most evident spatial trend, with depths in east-central Ohio tending to increase in broad bands from west to east. All of the maps show reasonably large, mostly homogeneous areas, although at the same time, reasonably significant variation at the smallest spatial scales of a few kilometers.

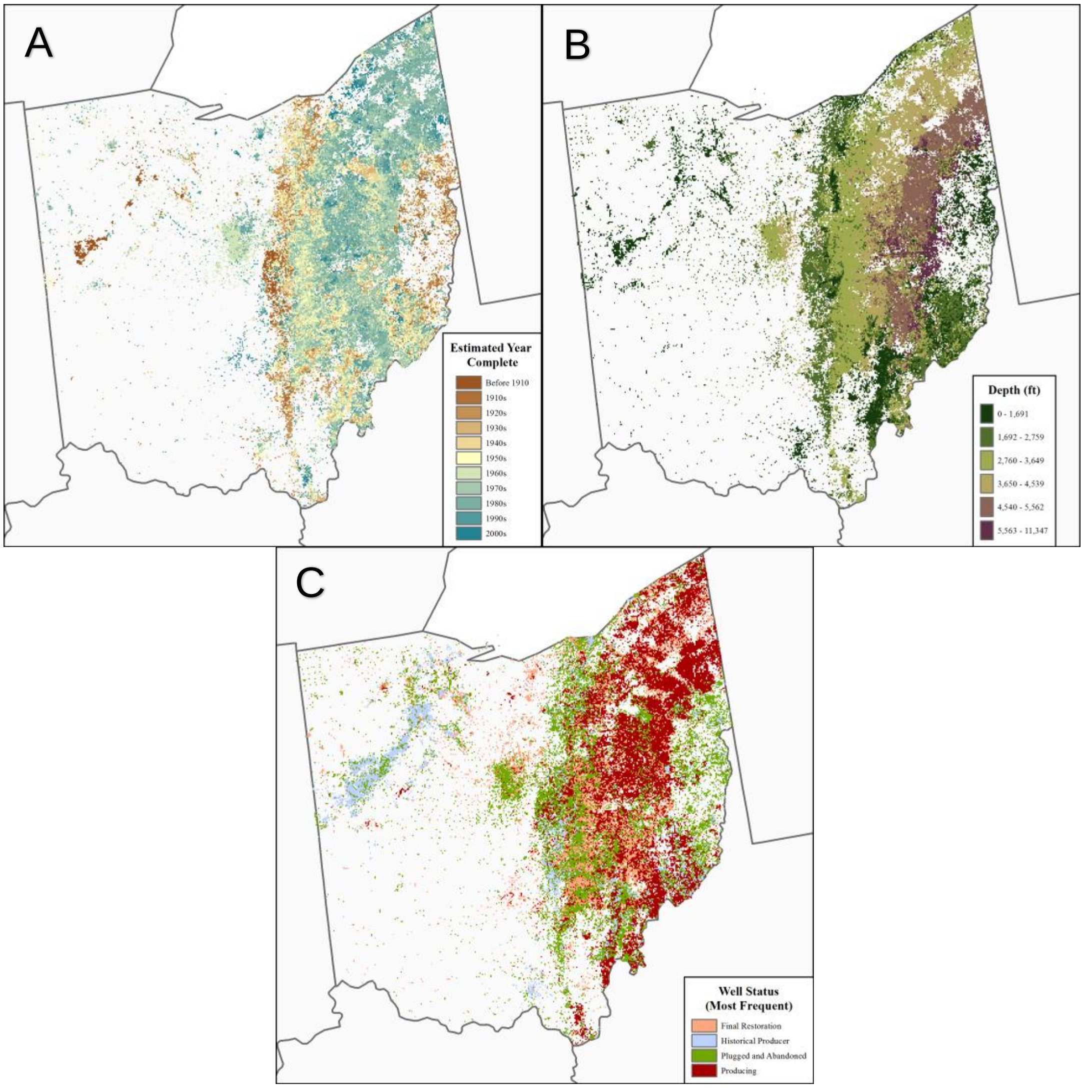


Figure 3-13. Ohio Well Locations Color Coded by (A) Age of Well (year completed), (B) Well Depth, and (C) Well Status

3.2.2 Michigan

3.2.2.1 Raw Data and Data Cleaning

The well construction/status data for Michigan contain records for 53,825 wells. Measured attributes of the wells include the location of the wellhead and bottom of the hole, total depth of the well as recorded by the driller (DTD), total vertical depth of the hole (TVD) for directional wells, type of well, status of well, and estimated date of completion.

Similar to Ohio, well depth was calculated to be equal to DTD if the well was listed as being vertical (89.6% of all wells) and equal to TVD if the well was listed as directional (10.4%) (see Figure 3-10).

The plugging data for Michigan contain 1,730 records. These data were organized such that all of the plugs for a single, unique well were included in a single record.

Estimates of the weighted-average cement bond based on bond log data for 155 wells across Michigan were also included in the analysis dataset.

The three separate datasets (well construction, plugging, and cement bond data) were merged according to API number. After merging the datasets, 53,830 unique wells are represented, with all or some of the data from the three separate datasets.

The combined dataset was then screened to eliminate wells that could not be used in the risk analysis, including wells that had no location information or had location information that was outside of the bounds of the State of Michigan. This step reduced the number of wells to 53,823.

3.2.2.2 Key Parameters

The key parameters for evaluating risk in Michigan are the same as those in Ohio:

- Location of the well
- Year that well construction was completed
- Depth of the bottom of the well
- Well status (including whether the well was plugged or is producing)
- Estimate of the deepest geologic formation through which the well penetrates

In addition, the weighted-average cement bond data were utilized as described in Section 3.2.1.3 for the State of Ohio.

3.2.2.3 Summary Statistics and Maps

Tables 3-14 through 3-17 have been developed with Michigan summary statistics in the same way as Tables 3-10 through 3-13 for the State of Ohio. Table 3-14 summarizes the spatial location parameters, as well as the weighted-average cement bond. As with the Ohio data above, the Michigan summary statistics include the number of wells with valid measurements (N), the arithmetic average (mean), standard deviation (sd), minimum value (min), percentiles of the frequency distribution (5% to 95%), and maximum value (max). Note that virtually all wells had valid horizontal and vertical (depth) location data, but only a very small number of wells had valid cement bond data.

Table 3-14. Summary Statistics for Location and Depth Parameters and Weighted-average Cement Bond, Michigan Data

Parameter	N	mean	sd	min	5%	25%	50%	75%	95%	max
DTD (ft)	53190	2988.22	1830.35	20	993	1525	2640.5	3992	6600	17466
TVD (ft)	3750	4106.29	2344.79	0	971.15	1707.50	4157	6058.75	7257	12373
Depth (ft)	51401	2856.47	1746.24	0	968	1489	2421	3864	6359	17466
W.Ave.Bond	151	0.82	0.19	0.12	0.43	0.76	0.90	0.96	0.99	1

Table 3-15 presents frequency counts for the different values of well status. Three status codes account for 96% of the Michigan wells: plugging approved (62%), producing (27%), and active (7%).

Table 3-15. Frequency Counts and Percentages for Michigan Well Status

Status	Description	Count (%)
ACT	Active	3,964 (7.36%)
DC	Drilling Complete	17 (0.03%)
OW	Open Well	4 (0.01%)
PB	Plugged Back	47 (0.09%)
PLA	Plugging Approved	33,630 (62.48%)
PLC	Plugging Completed	933 (1.73%)
PR	Producing	14,350 (26.66%)
SI	Shut In	303 (0.56%)
SUS	Suspended	8 (0.01%)
TA	Temporarily Abandoned	431 (0.80%)
WC	Well Complete	131 (0.24%)
-	Missing	5 (0.01%)
Total	All Wells	53,823 (100%)

Table 3-16 presents frequency counts for the deepest geologic formation penetrated by each Michigan wellbore. The deepest formation for approximately one-third of the wells was the Traverse (34%), followed by the Dundee-Detroit River Group (26%) and the Salina-Niagara (17%). These three formations account for about 75% of the Michigan wellbores.

Table 3-16. Frequency Counts and Percentages for Deepest Geologic Formation, Michigan

Formation Group	Count (%)
Drift	325 (0.60%)
PA-MS	3,615 (6.72%)
Antrim-Late Devonian	2,744 (5.10%)
Traverse	18,284 (33.97%)
Dundee-Detroit River Group	14,040 (26.09%)
Salina-Niagara	9,253 (17.19%)
Early Silurian	1,053 (1.96%)
Utica-Trenton Black River	1,949 (3.62%)
Glenwood-Prairie Du Chien	1,917 (3.56%)
Cambrian	228 (0.42%)
Precambrian	47 (0.09%)
Unidentified	368 (0.68%)
Total	52,823 (100%)

Table 3-17 presents frequency counts summarizing the general age of the wellbores – that is, the decade in which each well was completed. The ages of the wells are reasonably uniformly distributed over the past 100 years, with small relative spikes in the 1940s (16%), 1980s (16%) and 1990s (15%).

Table 3-17. Frequency Counts and Percentages for Age of Michigan Wells (decade completed)

Decade Completed	Count (%)
1920s	1,076 (2.00%)
1930s	6,430 (11.95%)
1940s	8,458 (15.71%)
1950s	5,727 (10.64%)
1960s	5,811 (10.80%)
1970s	5,112 (9.50%)
1980s	8,367 (15.55%)
1990s	7,946 (14.76%)
2000s	4,895 (9.09%)
Missing	1 (0.00%)
Total	52,823 (100%)

Figure 3-14 summarizes the frequency distribution of the depth of the wells, broken down by the approximate age of the wells (i.e., decade of completion). Well depths in the 1960s and earlier were typically in the 2,000- to 4,000-foot range. In the 1970s and 1980s, more wells were drilled to greater depths (up to about 6,000 feet). More recently, the trend appears to be toward shallower drilling (less than 2,000 feet).

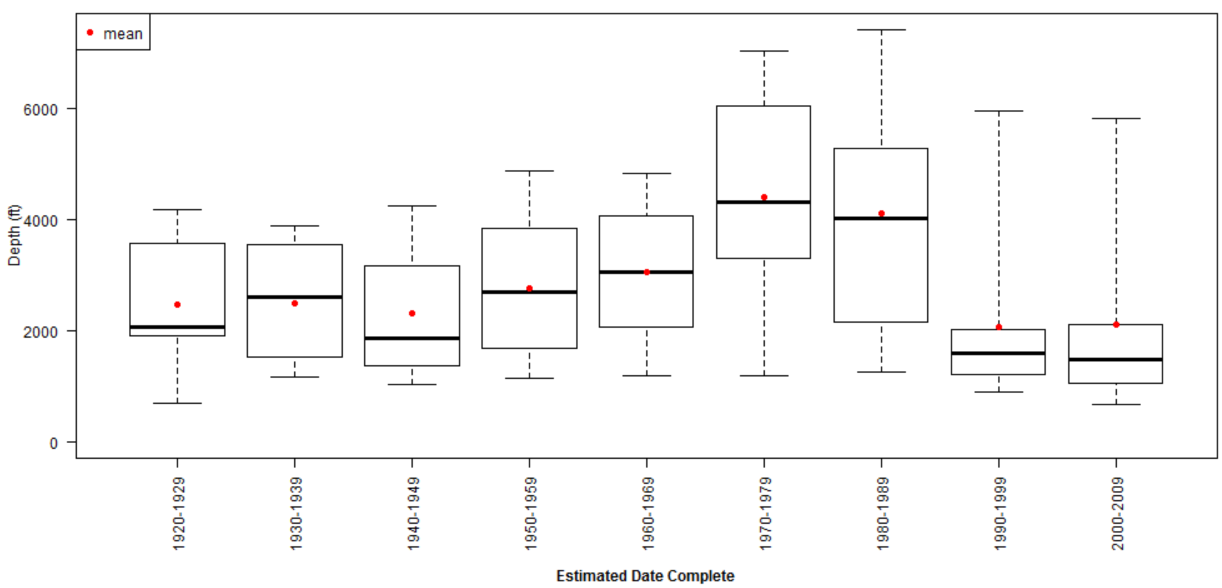


Figure 3-14. Michigan Well Depths Broken Down by Decade of Well Completion

Figure 3-15 summarizes the frequency distribution of the weighted-average cement bond data, broken down in three ways: by the deepest penetrated geologic formation (with formations sorted by depth from left to right in the figure), well depth, and approximate age of the wells (broken into four intervals). The cement bonds are most often 0.70 (70%) or better, with a possible indication that deeper wells have poorer (lower) weighted-average cement bonds.

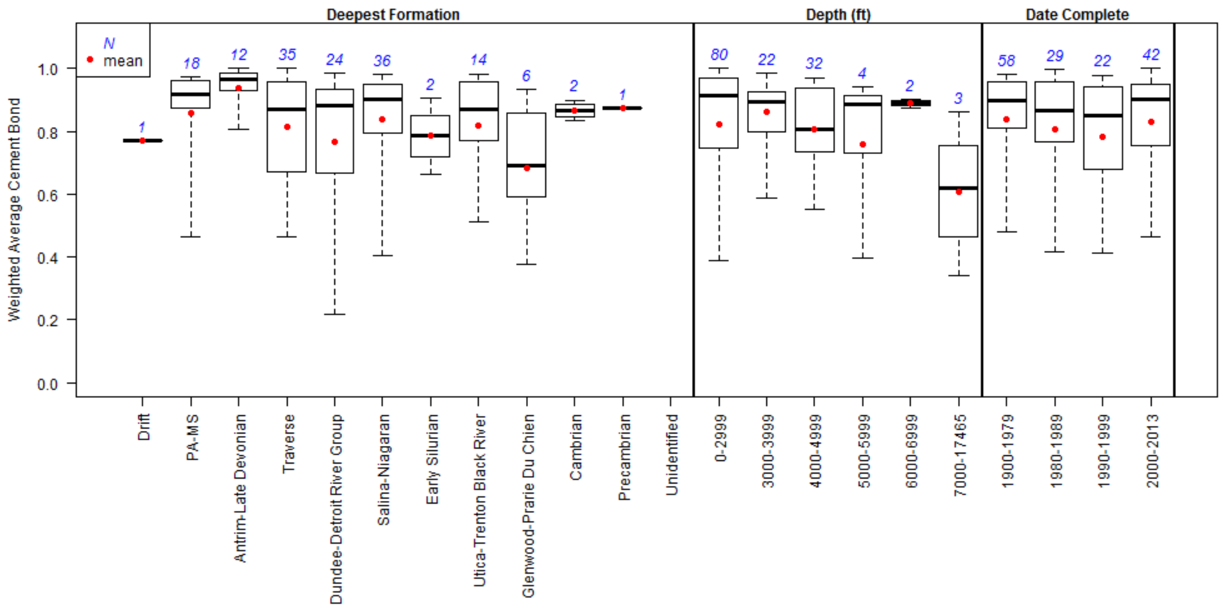


Figure 3-15. Michigan Weighted-average Cement Bond Broken Down by Deepest Geologic Formation, Well Depth, and Well Age

The maps in Figure 3-16 show the spatial distribution of wellbore age, depth, and status. As with the Ohio data above, a 1-square-kilometer (3280 x 3280 feet) grid was first laid across the state; then, the average age and depth and the most common status were calculated across all wellbores located in each grid cell. These summary statistics for each grid cell were then color-coded and posted on the maps. The most evident feature seen in all three maps is the cluster of producing wells in northern Michigan that were more recently drilled and to shallower depths. In addition, in that same part of the state there is a band of 'plugging approved' wells, oriented southwest to northeast, that were generally drilled deeper (4,000 to 6,000 feet) in the 1970s and 1980s.

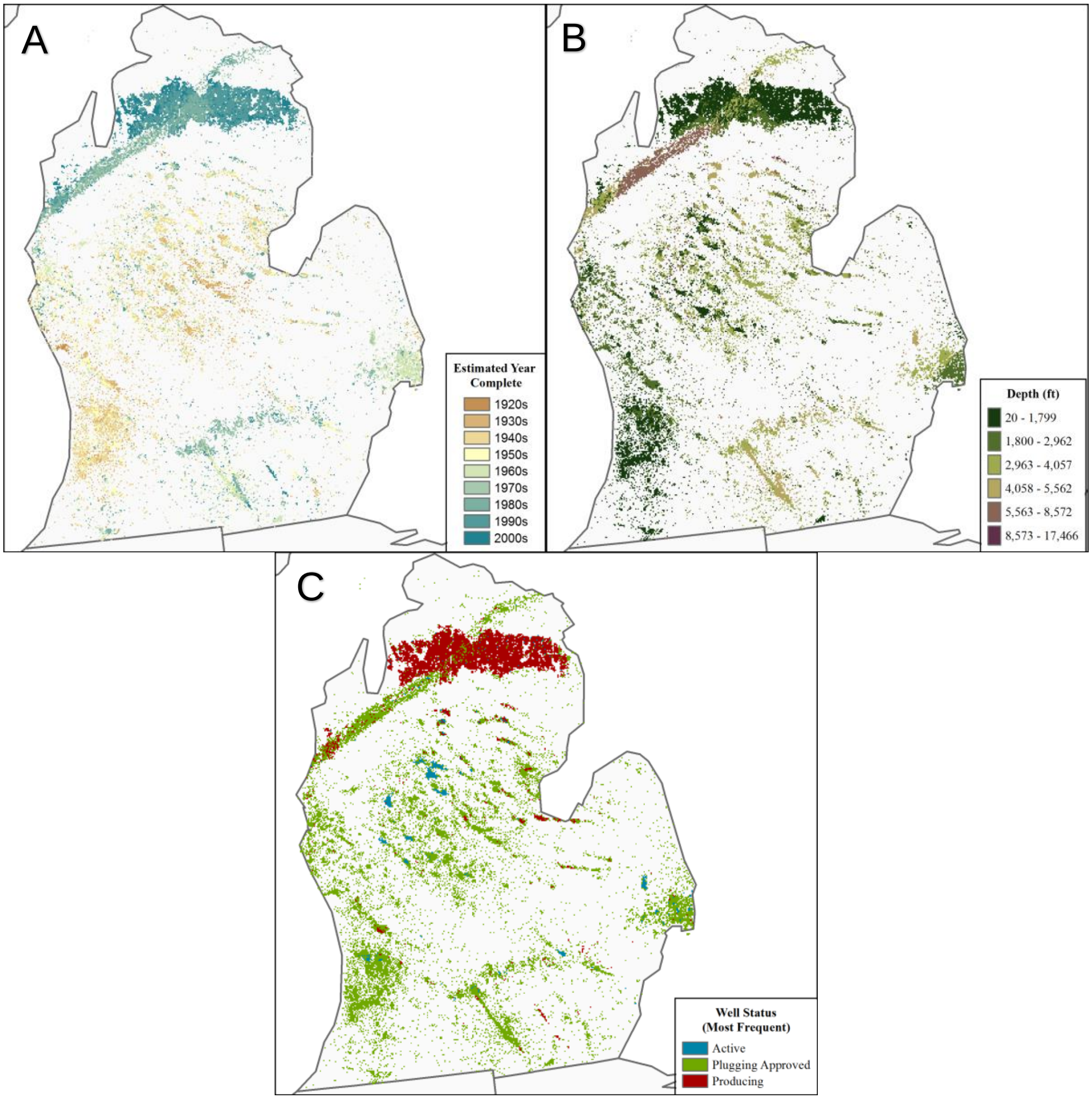


Figure 3-16. Michigan Well Locations Color Coded by (A) Age of Well (year completed), (B) Well Depth, and (C) Well Status

3.2.3 Risk Indicator Analysis

For the purposes of this project, "risk" is defined as the potential for CO_2 to leak from oil and gas wellbores in the area of a deep geologic storage facility. However, no available data directly measure the risk of CO_2 leakage. Therefore, in this section an approach is proposed for quantifying risk in terms of the other parameters discussed above for which data are available. The proposed approach is simple and can also be easily modified in sensitivity analyses to consider other variations that emphasize the different measured parameters to a greater or lesser degree.

3.2.3.1 Risk Indicator Methods

The proposed approach for assessing the potential risk of CO_2 leakage can be summarized as follows:

- Consider all of the parameters for which measured data are available, and identify those parameters that can be reasonably expected to be correlated with risk.
- Quantitatively recode the data for each parameter into a scale that is believed to be associated with increasing risk.
- Combine the recoded data across all of the selected parameters into an aggregate measure of risk.
- Evaluate the resulting risk data for statistical and spatial trends.

After reviewing all of the parameters discussed above, the parameters presented in Tables 3-18 and 3-19 are proposed as those that are more likely to be correlated with increasing risk for Ohio and Michigan, respectively. The tables also list the data coding that is believed to be correlated with increasing levels of risk, along with the technical rationale for the coding. Note that there is an implicit assumption in the data coding that the conditions associated with Code 2 represent twice the risk of the conditions associated with Code 1. Similarly, it is assumed that the conditions associated with Code 3 represent three times the risk of the conditions associated with Code 1. These assumptions can be easily varied in a sensitivity analysis by changing the coding levels and/or the definitions associated with those levels. For example, in the State of Michigan, the coding for the oldest wellbores (completed in 1938 and earlier) could be changed to Code 5 if it is felt that these oldest wells represent five times the risk of the newest wells (recent to 1994).

Table 3-18. Measured Parameters and Coding that Contribute to the Risk Calculation for Ohio

Ohio			
Parameter	**Risk Code**	**Description**	**Rationale**
Age of well	1	Recent to 1965	Establishment of the ODNR, Division of Oil and Gas, as a regulatory agency
	2	1964 to 1933	1933 state law required filing of drilling and completion records
	3	1932 and earlier	Older wells pre-dating regulations cited above
Depth of well	1	0 to 2,500 feet	2,500 feet is the preferred minimum depth for CO_2 reservoirs, so shallow wells will tend to be farther away vertically from potential reservoirs
	2	2,501 to 5,000 feet	Historical depth for most petroleum production, and thus not a preferred depth interval for CO_2 storage
	3	5,001 and deeper	Preferred depth for CO_2 storage, so wells at this depth pose greater risk for leakage
Deepest formation	1	Surface to top of Devonian shale	Shallower formations likely to be farther from CO_2 repositories and often cased off with surface casing in deeper wells
	2	Top of Devonian shale to top of Cincinnatian-Queenston	Formations with the majority of oil production

Ohio			
Parameter	**Risk Code**	**Description**	**Rationale**
	3	Top of Cincinnatian-Queenston to top of Precambrian	Deeper formations commonly with sandstones within which injection brine and waste often occurs
Well status (see Table 3-11 for description)	1	DG, DR, EM, FR, I1, PA, PB, RP, WP	Mainly final restoration and plugged and abandoned wells
	2	AI, IA, LH, PR, SI, TA, WW	Mainly producing wells
	3	DA, DM, HP, LU, NF, O, OR, RO, SW, UN	Mainly historical production wells

Table 3-19. Measured Parameters and Coding that Contribute to the Risk Calculation for Michigan

Parameter	Risk Code	Coding	Rationale
Age of well	1	Recent to 1994	Natural Resources and Environmental Protection Act redefined the regulation of oil and gas wells
	2	1993 to 1939	1939 state law requiring filing of drilling and completion records
	3	1938 and earlier	Older wells pre-dating regulations cited above
Depth of well	1	0 to 2,500 feet	2,500 feet is the preferred minimum depth for CO_2 reservoirs, so shallow wells will tend to be farther away vertically from potential reservoirs
	2	2,501 to 6,000 feet	Historical depth for most petroleum production, and thus not a preferred depth interval for CO_2 storage
	3	6,001 and deeper	Preferred depth for CO_2 storage, so wells at this depth pose greater risk for leakage
Deepest formation	1	Surface to top of Antrim	Shallower formations likely to be farther from CO_2 repositories
	2	Top of Antrim to top of Queenston	Ordovician, Richmond Group
	3	Top of Queenston to top of Precambrian	Deeper formations commonly with sandstones within which injection brine and waste often occurs
Well status (see Table 3-15 for description)	1	DC, PB, PLA, PLC, SUS, WC	Mainly plugging approved wells
	2	ACT, PR, SI, TA	Mainly active and producing wells
	3	OW, UN	Unknown and orphaned wells

3.2.3.2 Ohio

Figure 3-17 depicts the spatial distribution of the four risk parameters, each coded with the standard 1, 2, 3 risk scoring shown in Table 3-18 above, across the State of Ohio. As with earlier maps, Figure 3-17 was constructed by averaging the risk across all wellbores in each cell of a 1-square-kilometer (3280 x 3280 feet) grid covering the state. This average risk was then color-coded from green to yellow to red (from lowest to highest risk). Averaging the risk for multiple wells within each grid cell has the effect of declustering the data and reducing the chance of spatial bias due to over-representation in the clusters. Figure 3-18 shows the number of wells in each 1-square-kilometer (3280 x 3280 feet) grid cell, providing an indication of localized areas where clustering might be a concern.

The maps in Figure 3-17 depict the same general spatial trends seen in Figure 3-13, except in this case interpreted in terms of risk. All four maps in Figure 3-17 show a tendency toward east-west trending, with the map of well depth showing the strongest trend.

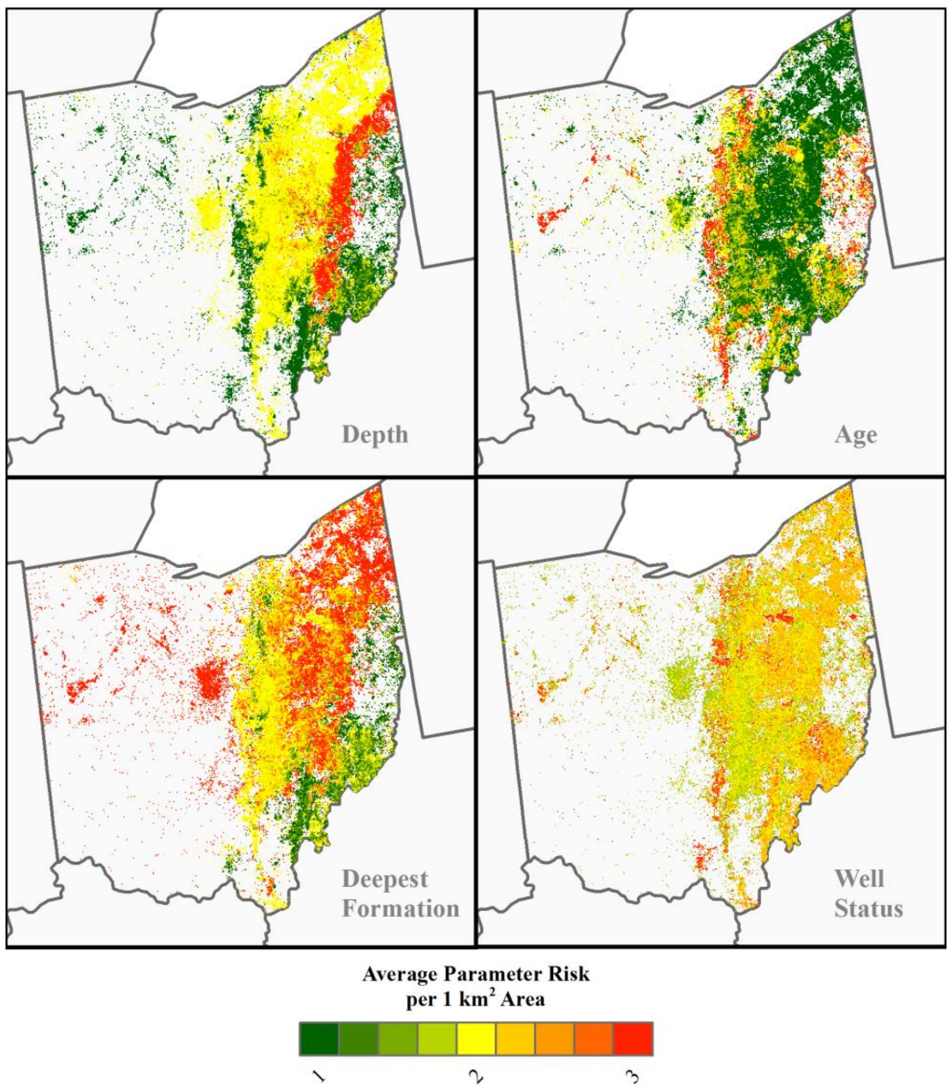


Figure 3-17. Spatial Distribution Across Ohio of Risk Associated with the Standard 1, 2, 3 Risk Scoring of Each Risk Parameter

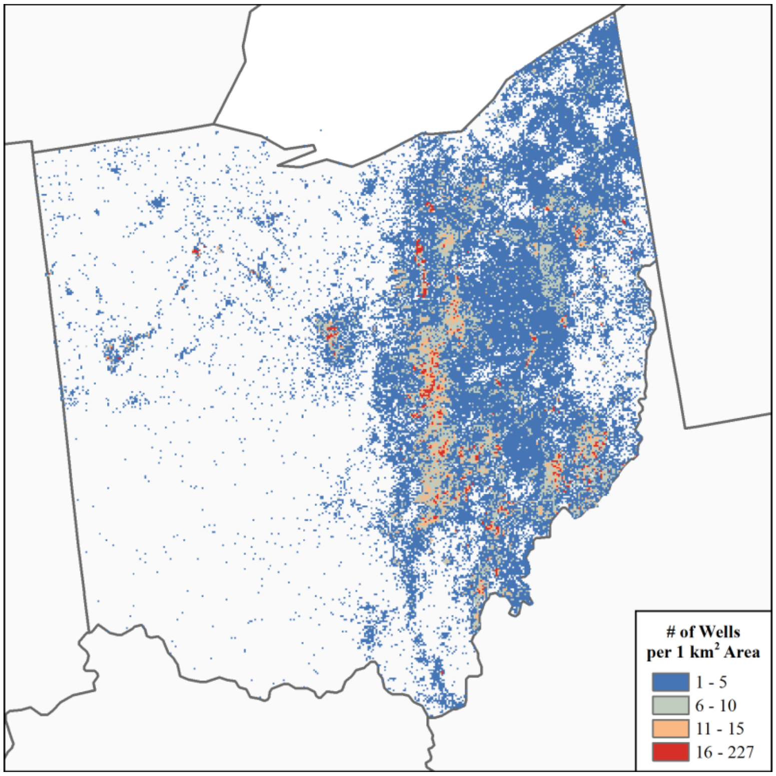


Figure 3-18. Number of Wells in each 1-Square-Kilometer Grid Cell Across Ohio.

Figure 3-19 summarizes across all wellbores the frequency with which each parameter was coded as low, medium, or high risk. Interestingly, with the standard 1, 2, 3 coding scheme, age of well and well status tend to be lower-risk parameters, due to the prevalence of Code 1 data. In contrast, depth of well and deepest formation might be seen as more medium-risk parameters, due to the prevalence of Code 2 data and the approximately equal numbers of Code 1 and Code 3 data (i.e., symmetric distribution).

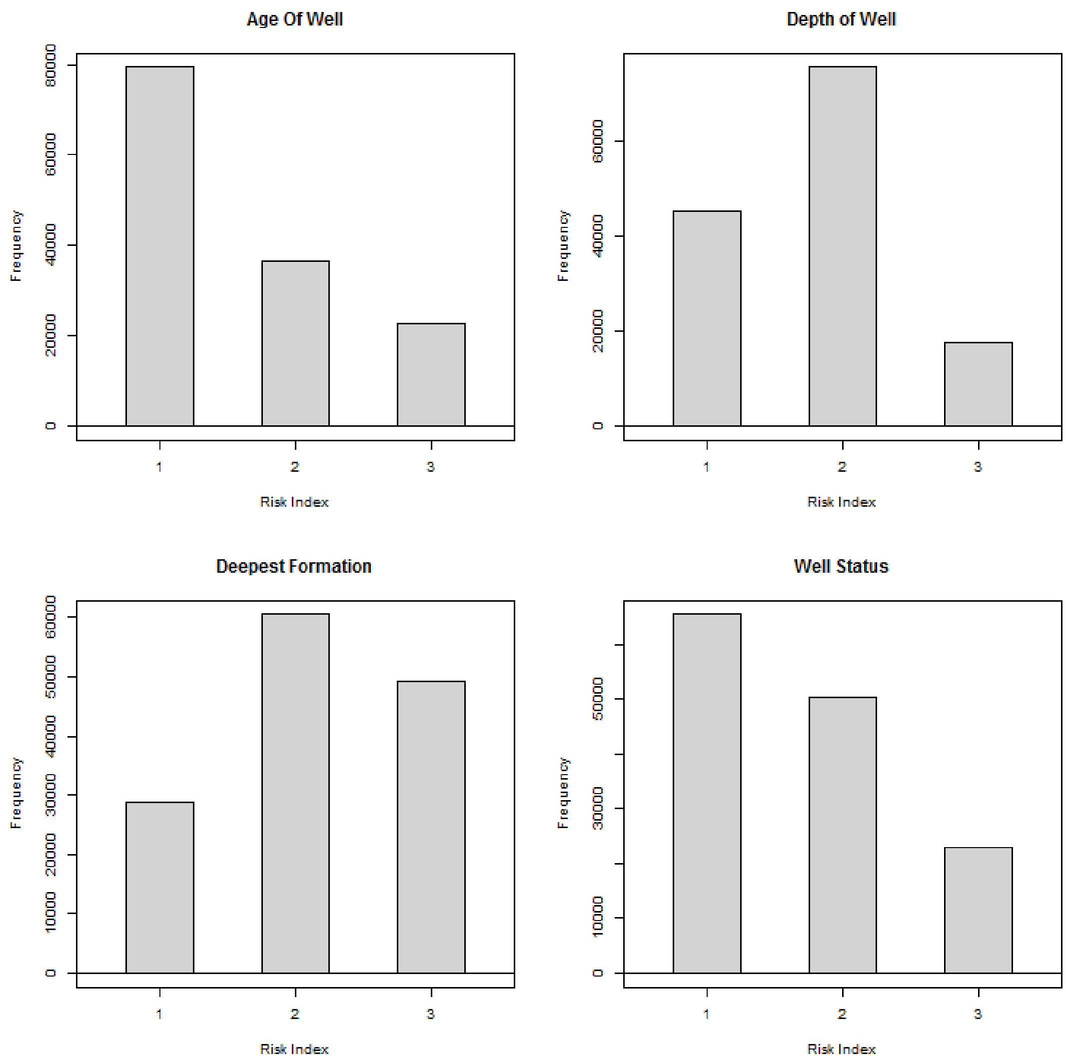


Figure 3-19. Frequency of Low-, Medium-, and High-risk Wells in Ohio According to Each Risk Parameter

3.2.3.3 Michigan

Figure 3-20 (analogous to Figure 3-17 above) shows the spatial distribution of the four risk parameters, using the 1, 2, 3 scoring scheme, across the State of Michigan. Figure 3-21 shows the number of wells averaged together within each 1-square-kilometer (3280 x 3280 feet) grid cell. These maps show similar spatial trends to Figure 3-16 above, but in this case expressed in terms of risk. Note that the bands of wells in northern Michigan are sometimes interpreted as lower- or higher-risk wells, depending on which risk parameter is considered.

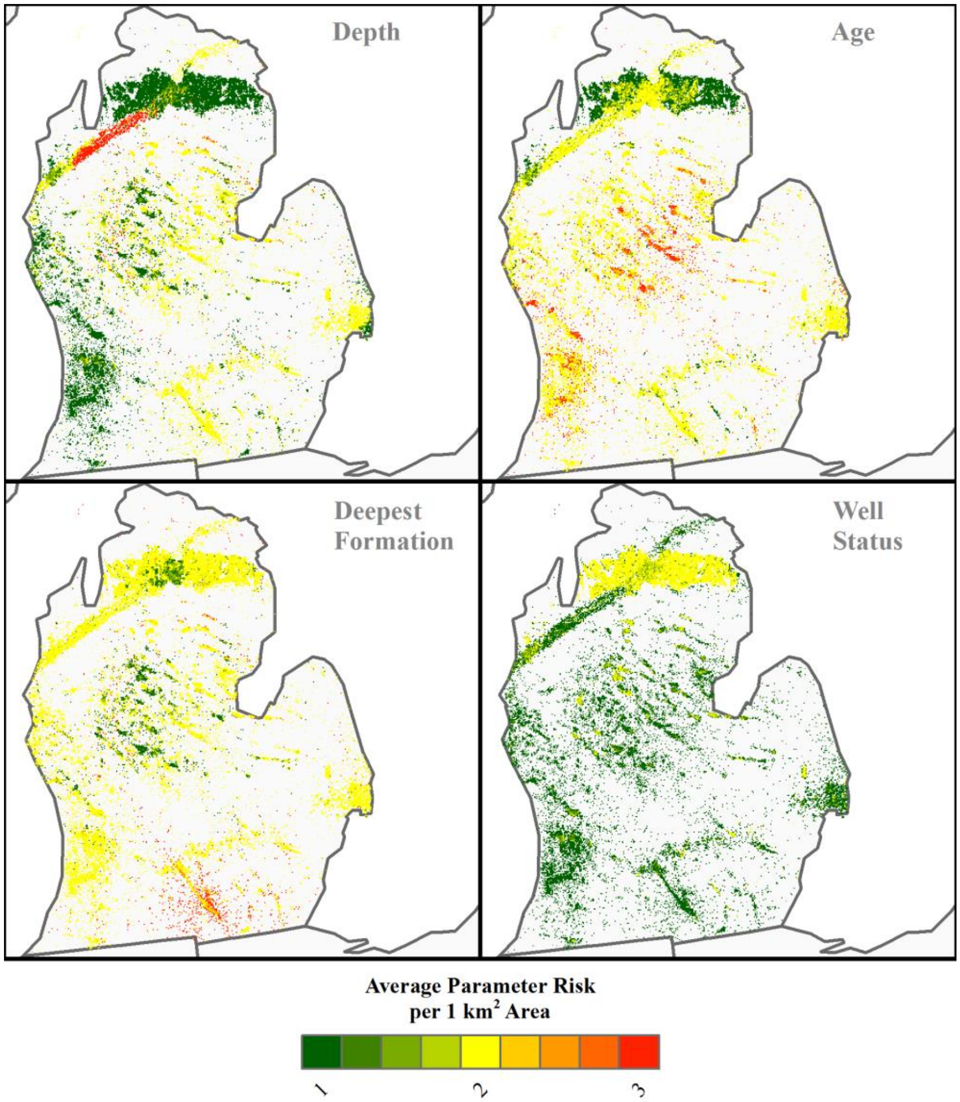


Figure 3-20. Spatial Distribution Across Michigan of Risk Associated with the Standard 1,2,3 Risk Scoring of each Risk Parameter

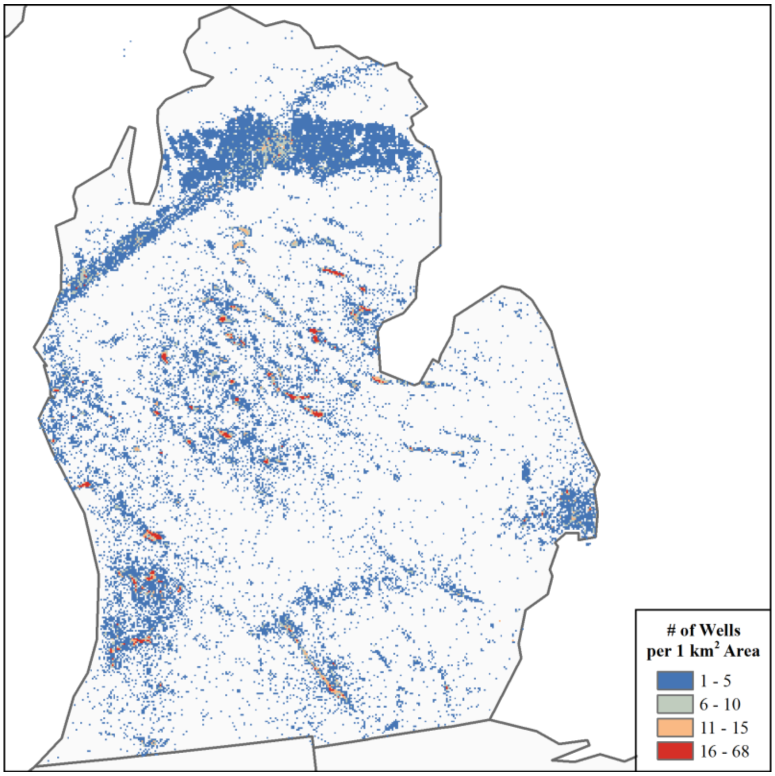


Figure 3-21. Number of Wells in Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell across Michigan

Figure 3-22 shows the frequency distribution of the scoring of each risk parameter. It is interesting to contrast these statistical summaries with those in Figure 3-19 above for the State of Ohio. In Ohio, the age of well might be characterized as a lower-risk parameter, while in Michigan it is clearly a medium-risk parameter. And, in Ohio, the depth of well tends to be a medium-risk parameter, while in Michigan it is a somewhat lower-risk parameter. The deepest formation and well status show similar trends in Ohio and Michigan, although it is interesting to note (Figure 3-22) that there were no high-risk wells in Michigan as judged by well status.

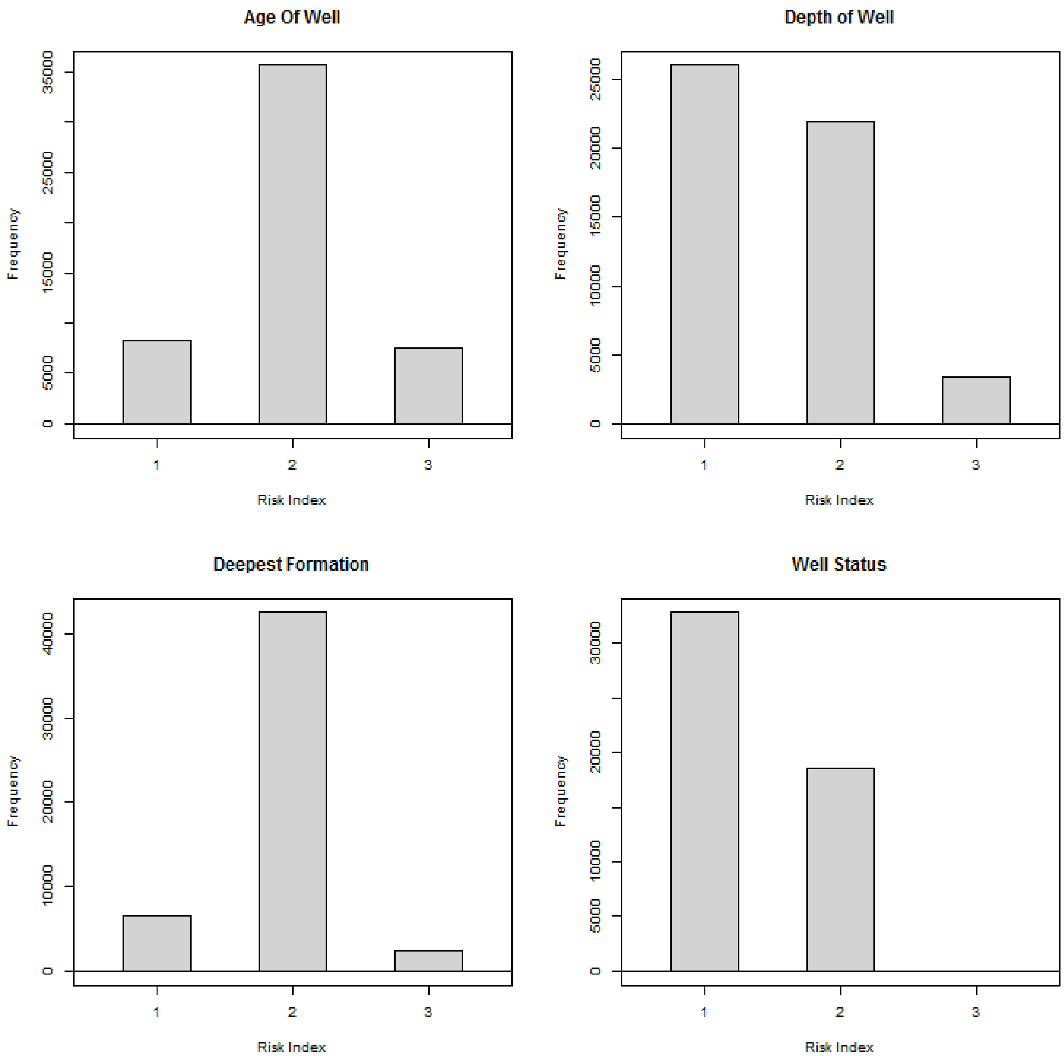


Figure 3-22. Frequency of Low-, Medium-, and High-risk Wells in Michigan According to Each Risk Parameter

3.2.3.4 Aggregate Risk Calculation

After establishing the definitions in Tables 3-18 and 3-19 above and coding the measured data, aggregate risk was calculated simply by adding up the codes for all four risk parameters. For example, if a particular wellbore's age, depth, deepest formation, and well status are coded as 3, 3, 2, and 1, respectively, then the aggregate risk measure is calculated as 9 (i.e., the sum). Under this approach, the maximum possible risk is 12 and the minimum possible risk is 4.

By taking the straight sum of the component risk measures, there is an implicit assumption that all of the four risk parameters are equally impactful on the aggregate risk. This assumption can be easily adapted by assigning a weight to each risk parameter, then calculating aggregate risk as the weighted sum of the component risks. With this approach, each of the four parameter weights should be a number between 0 and 4 (i.e., the number of parameters), where the sum of the weights is equal to 4. For example, if age and depth of the wellbore were believed to be three times more impactful on aggregate risk than the deepest formation and well status, then weights of 1.5, 1.5, 0.5, and 0.5 could be assigned to age, depth, deepest formation, and well status, respectively. For the hypothetical wellbore coding listed above, the weighted aggregate risk would be calculated as 10.5. Note that compared to the unweighted aggregate risk of 9 cited above, this weighted value of 10.5 reflects the greater emphasis on wellbore age and depth as the two more important risk parameters, along with the fact that these two parameters were coded at 3, the highest risk value. Also, note that the maximum and minimum possible weighted aggregate risks are 12 and 4, just as for the unweighted case.

3.2.3.5 Aggregate Risk Maps

To date, aggregate risk has been quantified in the following ways in an initial sensitivity analysis:

1. All four risk parameters were equally weighted for each wellbore, and the average risk across all wellbores within each 1-square-kilometer (3280 x 3280 feet) grid cell was calculated for mapping.
2. All four risk parameters were equally weighted for each wellbore, but the maximum risk across all wellbores within each 1-square-kilometer (3280 x 3280 feet) grid cell was then calculated for mapping. This corresponds to a more “worst-case approach” than #1 above.
3. Weighted aggregate risk was calculated with a 70% weight applied to well depth and 10% weight applied to each of the other three risk parameters. The weighted risk was then averaged within each 1-square-kilometer (3280 x 3280 feet) grid cell before mapping. Weighting in this way applies greater emphasis to one or more risk parameters (in this case, well depth) in the aggregate risk calculation.

These methods account for spatial variation in wellbore conditions, clustering of wells, and outliers.

3.2.3.6 Ohio

Figures 3-23, 3-24, and 3-25 show the spatial distribution of aggregate risk across Ohio for each of the three approaches described above (i.e., equal weighting, worst-case, and greater weighting on well depth). Figure 3-23 clearly shows the impact of equal weighting when averaging. For example, along most of the southeastern and eastern border, three of the four risk parameters are generally seen as low risk, and the fourth parameter (well status) is generally seen as medium risk. Therefore, the average aggregate risk is generally assessed at lower risk, as shown in Figure 3-23 for those areas. However, as a second example, just a bit farther west from the eastern border, in a north-south band of wells, risk is assessed quite differently for each of the risk parameters: well depth is generally high risk in this area, deepest formation appears evenly split between high and medium risk, well status is generally medium risk, and well age is generally seen as low risk. Therefore, aggregate risk for this band of wells “averages out” in Figure 3-23 to be medium risk.

Figure 3-24 shows the effect of taking the worst-case (i.e., maximum risk) well in each 1-square-kilometer (3280 x 3280 feet) grid cell, rather than averaging all of the wells in the grid cell (as in Figure 3-23). Generally speaking, this approach has the effect of raising the aggregate risk score by approximately one-half point; the average risk score in Figure 3-23 is about 7.4 and the average risk score in Figure 3-24 is about 8.0 (these numbers are not shown in the figures). This worst-case approach might be described as a more conservative approach of risk evaluation.

Figure 3-25 shows the impact of significantly changing the weighting of the risk parameters. Instead of equally weighting all four parameters at 25% each, the calculation in Figure 3-25 assigned a weight of 70% to well depth and 10% to each of the other three parameters. As might be expected, this strong weighting toward well depth forces the aggregate risk to also take on more of the trends seen in well depth alone (see Figure 3-17). Figure 3-25 essentially shows the same spatial trends as Figure 3-17, but with the highest-risk areas reduced a bit by the impact of the other three parameters, and the lowest-risk areas increased a bit by the impact of the other parameters.

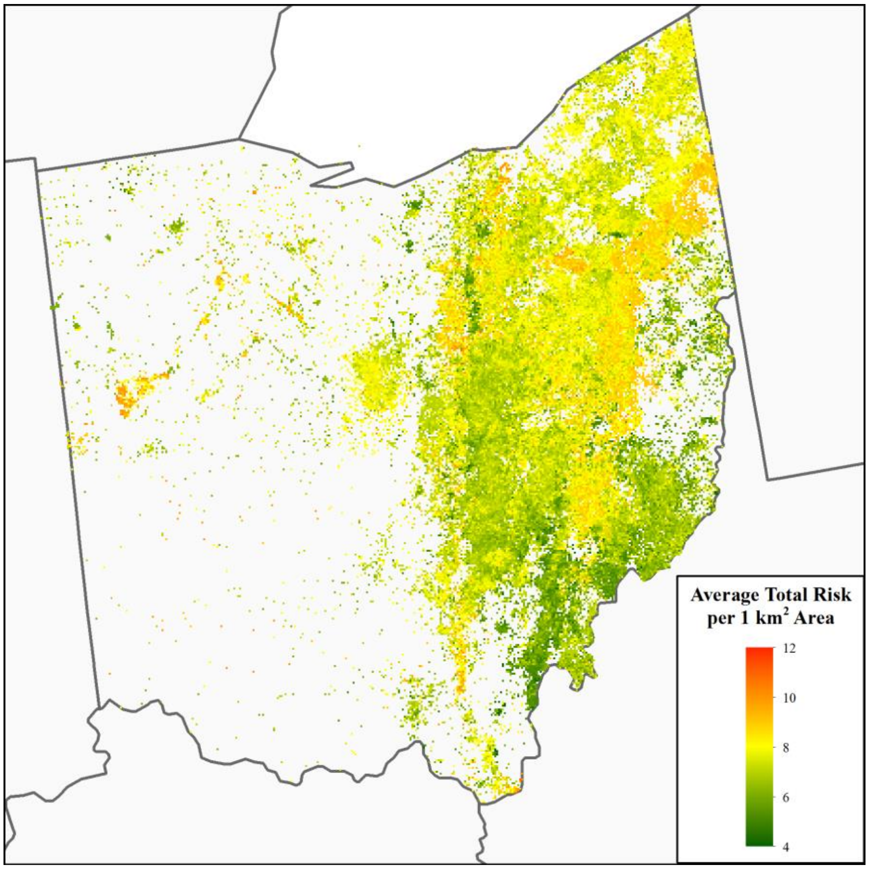


Figure 3-23. Aggregate Risk in Ohio Assigning Equal Weighting to the Risk Parameters, and Calculating Average Risk within Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell

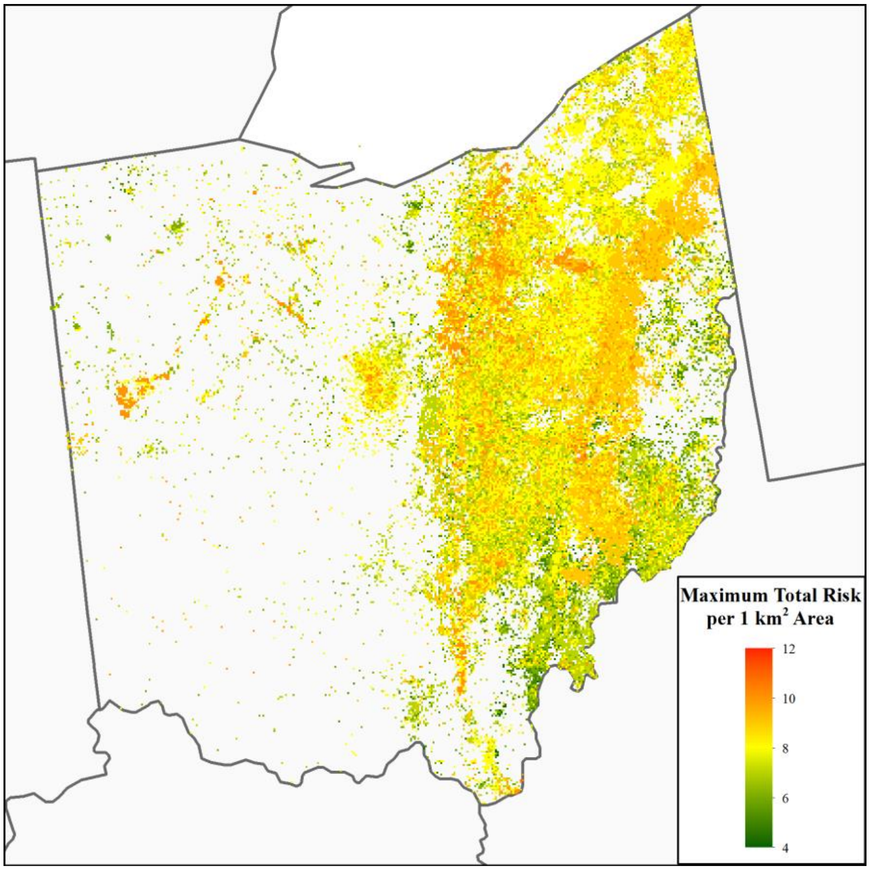


Figure 3-24. Aggregate Risk in Ohio Assigning Equal Weighting to the Risk Parameters, but Taking the Worst-case (maximum-risk) Well within Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell

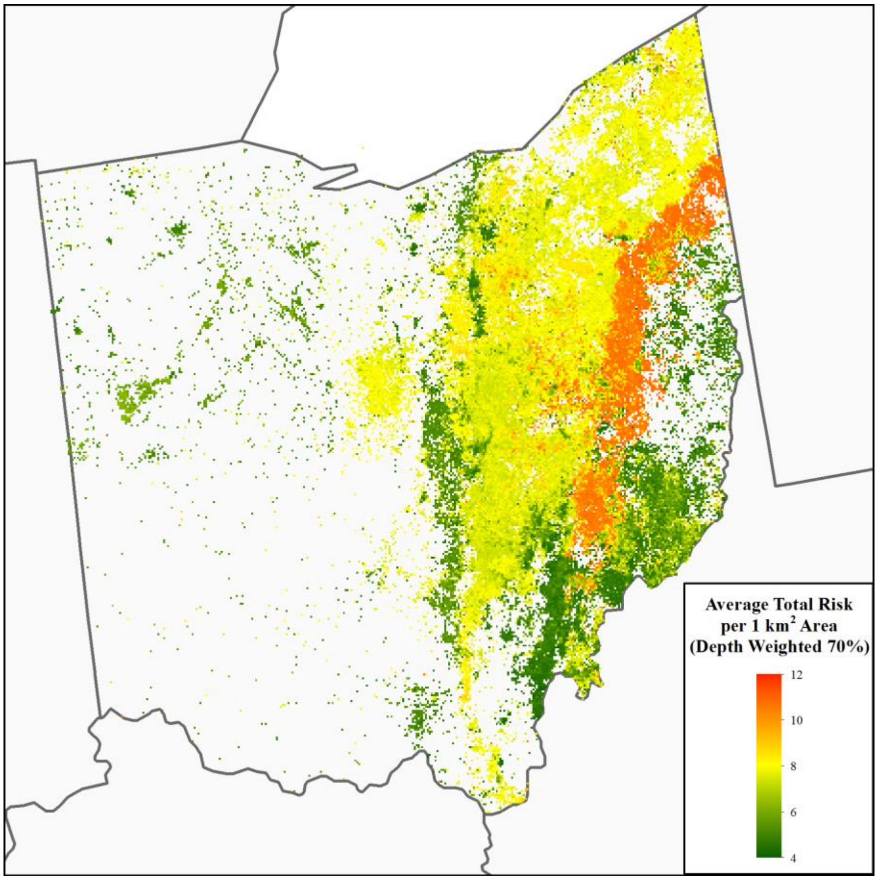


Figure 3-25. Aggregate Risk in Ohio Assigning a Higher Weighting (70%) to Well Depth, then Averaging Risk within Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell

3.2.3.7 Michigan

Figures 3-26, 3-27, and 3-28 provide aggregate risk results for Michigan that are analogous to those in Figures 3-23, 3-24, and 3-25 for Ohio. Comparing the equally weighted average risk in Figure 3-26 with the individual risk parameters in Figure 3-20, it is evident that spatial areas which are scored at the same risk level for all four parameters will reflect that same risk level in the aggregate. But areas with substantially different risk scores for the different parameters (e.g., see the narrow band of northeast-trending wells located in northwestern Michigan) will have an aggregate risk somewhere in the middle (i.e., medium risk).

The worst-case risk map in Figure 3-27 shows a modest increase in aggregate risk compared with Figure 3-26; summary statistics (not shown) indicate that the overall average risk increased by about 0.2 point. In comparison with the differences cited above for Ohio, this suggests that short-scale variability among wells in the same 1-square-kilometer (3280 x 3280 feet) grid cell is smaller in Michigan than in Ohio.

Figure 3-28 shows the effect of more heavily weighting well depth in the aggregate risk calculations. Figure 3-28 shows essentially the same trends as well depth in Figure 3-20, except that the highest-risk areas (e.g., northeast-trending band of wells in northwestern Michigan) are reduced somewhat by the effect of the other three parameters, and the lowest-risk areas (e.g., broad area in northern Michigan) are increased somewhat by the impact of the other parameters.

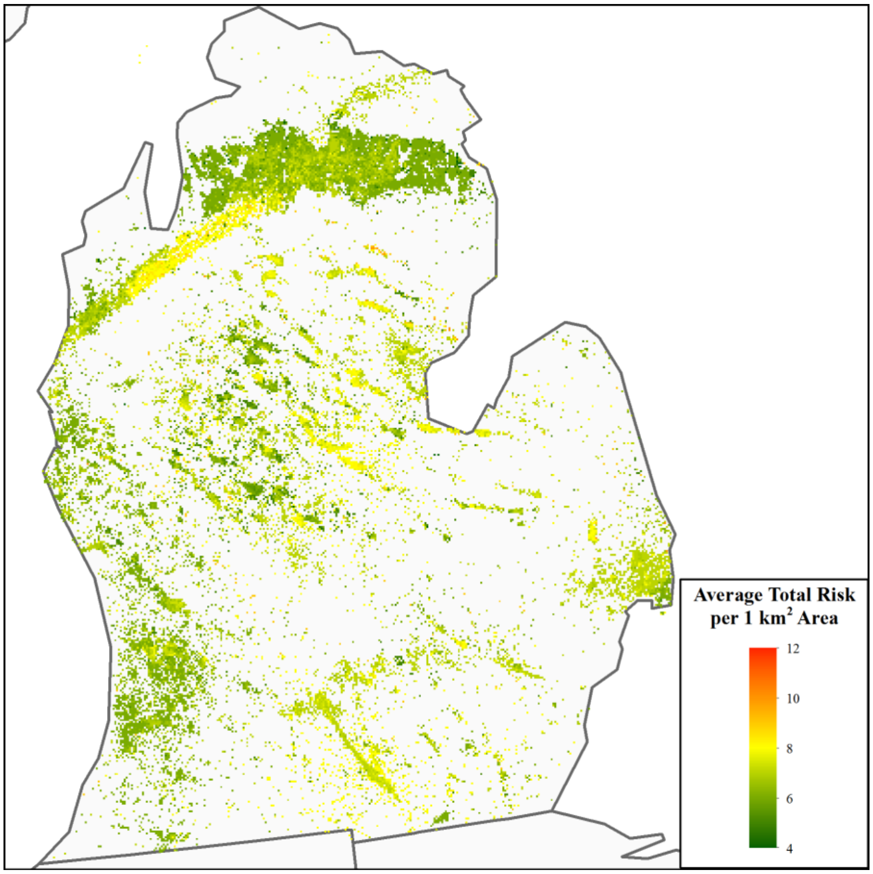


Figure 3-26. Aggregate Risk in Michigan Assigning an Equal Weighting to the Risk Parameters, and Calculating Average Risk within Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell

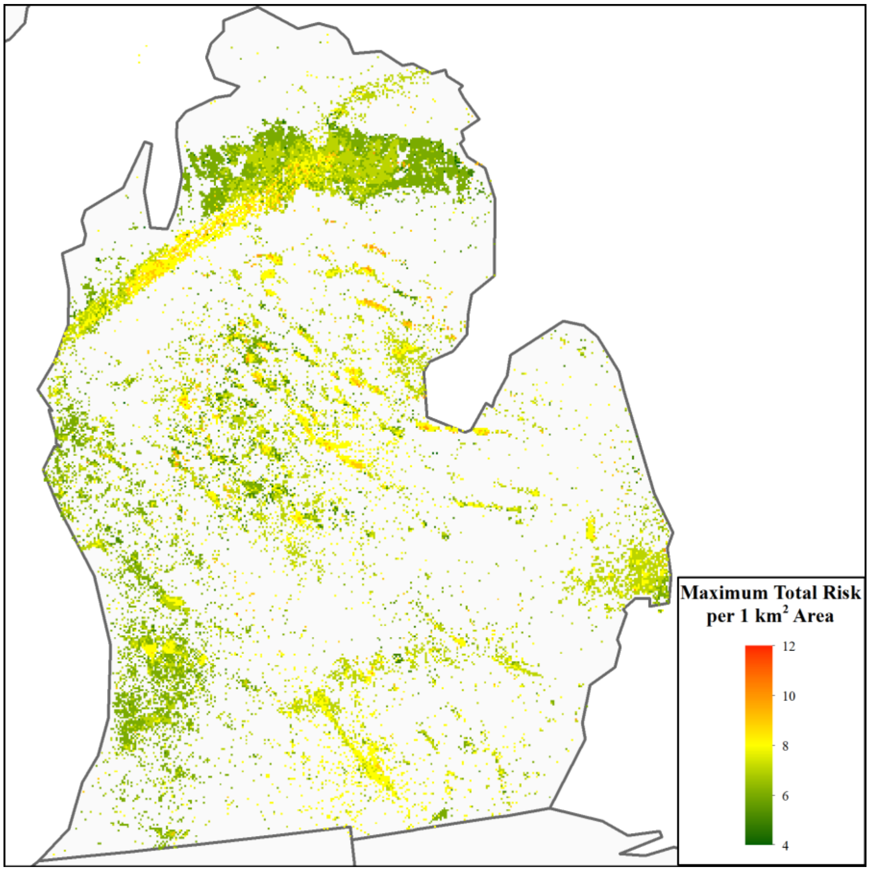


Figure 3-27. Aggregate Risk in Michigan Assigning Equal Weighting to the Risk Parameters, but Taking the Worst-case (maximum-risk) Well within Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell

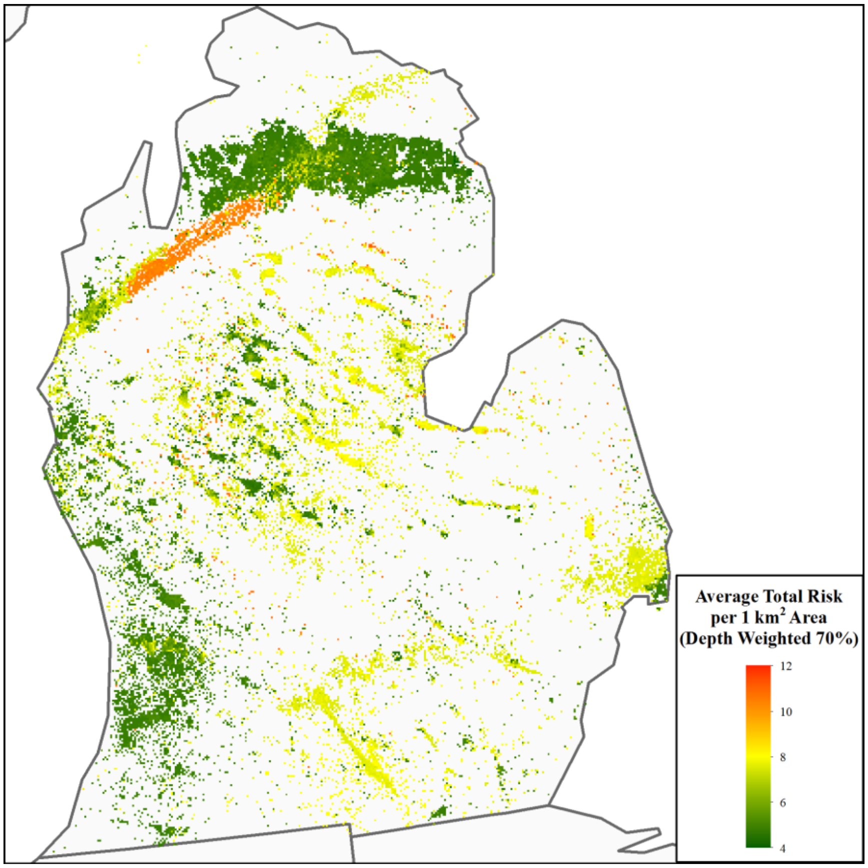


Figure 3-28. Aggregate Risk in Michigan Assigning a Higher Weighting (70%) to Well Depth, then Averaging Risk within Each 1-Square-Kilometer (3280 x 3280 feet) Grid Cell

3.3 Statistical Analysis of Well Integrity Indicators

The primary objective of the statistical analysis effort was to identify existing information characterizing the history and integrity of existing wellbores in Ohio and Michigan that might ultimately be used to help screen areas for potential CO_2 storage fields. Initial phases of the project identified four well integrity indicators that might reasonably be expected to impact wellbore integrity:

- Well age (defined from the date of completion)
- Well depth (in feet below ground surface)
- Deepest geologic formation penetrated by the well
- Well status (e.g., active or plugged)

Maps were developed of the distribution of these well condition indicators across the entire states of Ohio and Michigan. Initial scorings of well integrity, based on the well condition indicators above, were defined and assessed for possible use in screening. During the final phase of this task, well integrity scoring was refined and an approach for using the results to screen potential storage fields was proposed. Results from this final phase of work are discussed in the following sections.

3.3.1 Objective of the Statistical Analysis

The objective of the statistical well integrity indicator was to develop a useful quantitative screening tool that can help compare potential storage fields in terms of overall wellbore integrity. High "integrity" is interpreted as areas where the condition and number of existing wells is conducive to successful CO_2 storage (i.e., minimal leakage). In this screening, fields with higher weighted-average integrity indicators are preferable to fields with lower weighted-average integrity indicators. The proposed well integrity indicator should consider the existing body of knowledge for geologic confining layers, the number of existing wells in the immediate area, the condition of those existing wells, and uncertainty about the wellbore information (especially missing information). The rating process followed other research to apply systematic methods to evaluate wellbore integrity in hydrocarbon fields and CO_2 storage areas (Glazewski et al., 2013; Annandale and Conway, 2009; Haga et al., 2009; Corneliussen et al., 2007; Wakama and Adeniyi, 2004).

3.3.2 Well Condition Indicators

Building on the effort to characterize existing well condition information, the following factors in the wellbore database were used to calculate the integrity indicator:

- Well depth: Defined in terms of whether the well penetrates a given confining layer. This factor will generally change for a given well each time a new confining layer is considered.
- Well age: Defined in terms of the year in which the well was completed.
- Well status: Defined in terms of plugged, producing, or orphaned wells (among other possibilities).
- Spatial density: Defined in terms of the number of wells per square kilometer in a potential storage field.

In terms of well depth, the major intervals were chosen based on geologic formations in the Michigan and Ohio study areas. Figure 3-29 illustrates the major rock formations, CO_2 storage reservoirs, and confining layers in the region.

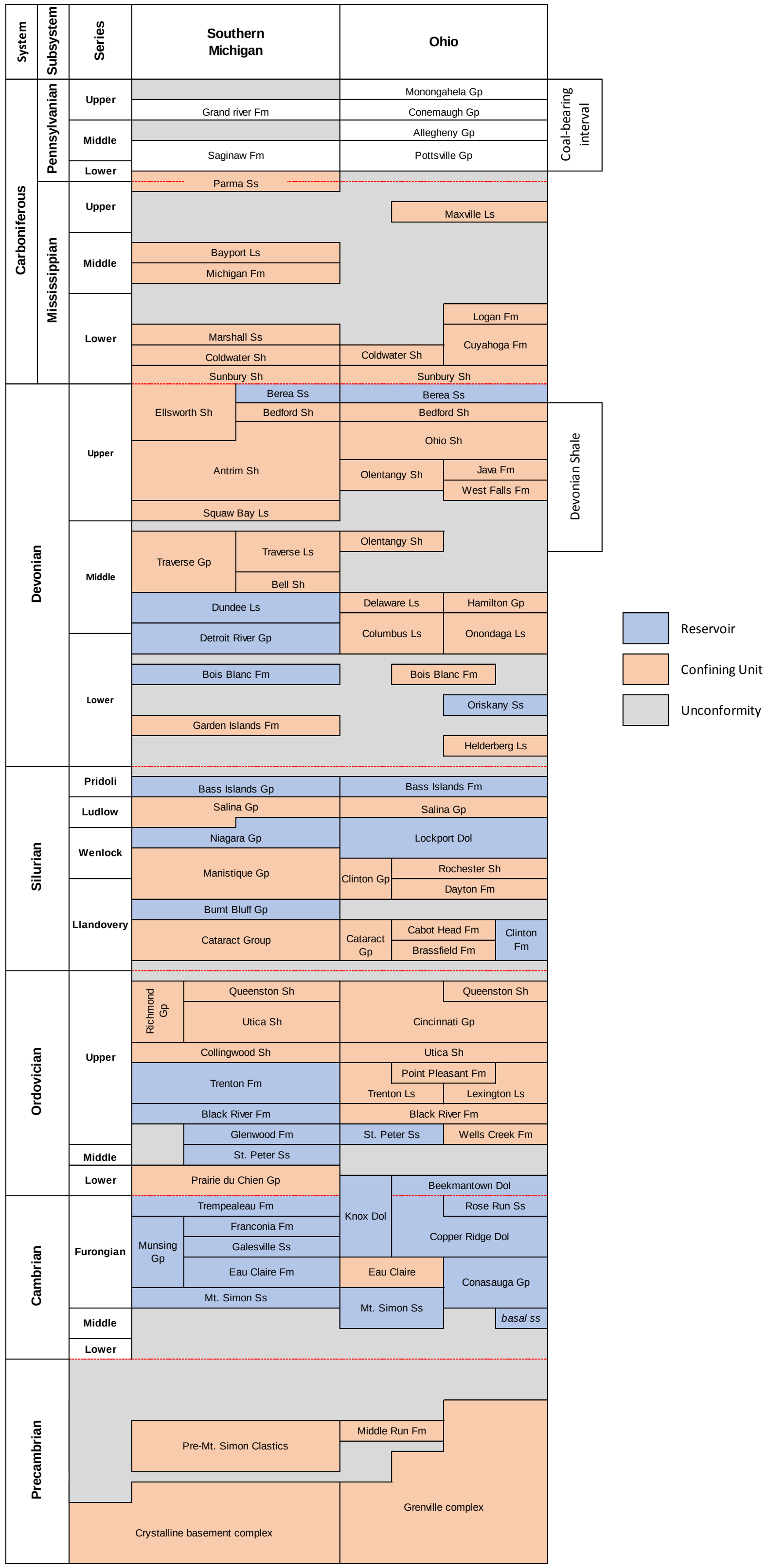


Figure 3-29. Lithology of the Michigan and Ohio Study Areas

Key units were chosen at the Devonian-Silurian unconformity, the Silurian-Ordovician unconformity, and the Ordovician-Cambrian boundary. In general, these intervals reflect key reservoirs and confining layers in the region. However, more detailed examination of CO_2 storage zones and confining layers would be necessary for a site-specific project.

3.3.3 Well Integrity Coding Scheme

Step 1. Code well condition indicators and score each well. For the purposes of quantifying well integrity, each of the first three well condition indicators above (depth, age, and status) was coded as to whether it is favorable, neutral, or unfavorable for well integrity. The specific codings for Ohio wells (Table 3-20) and Michigan wells (Table 3-21) are depicted in Figure 3-30. Note that the quantitative scoring for any given well can range from 19 (highest well integrity) to 1 (lowest well integrity).

Table 3-20. Scoring for Individual Wells in Ohio Based on Depth, Age, and Status

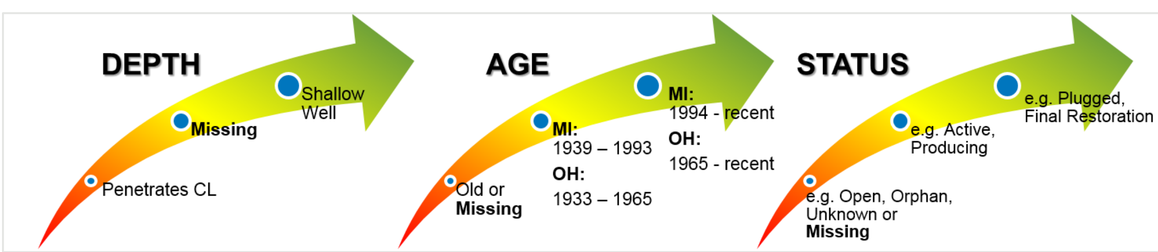
Score	Depth	Age	Status
Favorable	Shallow[1]	Recent to 1965	Plugged
Neutral	Deep[2]	1964 to 1933	Active and producing
Unfavorable	Missing	Pre-1933 or missing	Orphan, unknown, or missing
Best – 19	Shallow	Any	Any
18	Missing	Recent to 1965	Plugged
17	Missing	1964 to 1933	Plugged
16	Missing	Recent to 1965	Active and producing
15	Missing	1964 to 1933	Active and producing
14	Missing	Recent to 1965	Orphan, unknown, or missing
13	Missing	1964 to 1933	Orphan, unknown, or missing
12	Missing	Pre-1933 or missing	Plugged
11	Missing	Pre-1933 or missing	Active and producing
10	Missing	Pre-1933 or missing	Orphan, unknown, or missing
9	Deep	Recent to 1965	Plugged
8	Deep	1964 to 1933	Plugged
7	Deep	Recent to 1965	Active and producing
6	Deep	1964 to 1933	Active and producing
5	Deep	Recent to 1965	Orphan, unknown, or missing
4	Deep	1964 to 1933	Orphan, unknown, or missing
3	Deep	Pre-1933 or missing	Plugged
2	Deep	Pre-1933 or missing	Active and producing
Worst – 1	Deep	Pre-1933 or missing	Orphan, unknown, or missing

[1]Shallow means the well does not penetrate the confining layer.
[2]Deep means the well penetrates the confining layer.

Table 3-21. Scoring for Individual Wells in Michigan Based on Depth, Age, and Status

Score	Depth	Age	Status
Favorable	Shallow[1]	Recent to 1994	Plugged
Neutral	Missing	1993 to 1939	Active and producing
Unfavorable	Deep[2]	Pre-1939 or missing	Open, unknown or missing
Best – 19	Shallow	Any	Any
18	Missing	Recent to 1994	Plugged
17	Missing	1993 to 1939	Plugged
16	Missing	Recent to 1994	Active and producing
15	Missing	1993 to 1939	Active and producing
14	Missing	Recent to 1994	Orphan, unknown or missing
13	Missing	1993 to 1939	Orphan, unknown or missing
12	Missing	Pre-1939 or missing	Plugged
11	Missing	Pre-1939 or missing	Active and producing
10	Missing	Pre-1939 or missing	Orphan, unknown or missing
9	Deep	Recent to 1994	Plugged
8	Deep	1993 to 1939	Plugged
7	Deep	Recent to 1994	Active and producing
6	Deep	1993 to 1939	Active and producing
5	Deep	Recent to 1994	Orphan, unknown or missing
4	Deep	1993 to 1939	Orphan, unknown or missing
3	Deep	Pre-1939 or missing	Plugged
2	Deep	Pre-1939 or missing	Active and producing
Worst – 1	Deep	Pre-1939 or missing	Orphan, unknown or missing

[1]Shallow means the well does not penetrate the confining layer.
[2]Deep means the well penetrates the confining layer.



Note: CL = confining layer.

Figure 3-30. Integrity Coding for Depth, Age, and Status of Wells

Step 2. Calculate weighted-average integrity for potential storage fields. Screening at the level of storage fields takes into account the integrity scores for all existing wells, as well as the total number of wells, in the area. Fewer wells and wells with higher integrity scores lead to a more favorable site screening value (i.e., weighted-average integrity), while a greater number of wells and wells with lower integrity scores lead to a less favorable screening value. Specifically, the weighted-average integrity score for a potential storage field is calculated as follows:

1. Identify all existing wells within the spatial boundaries of the potential storage field.
2. Score the integrity, *I*, of each existing well using the coding scheme shown in Table 3-20 (for Ohio) or Table 3-21 (for Michigan) based on the target confining layer for the field.
3. Calculate the (arithmetic) average integrity score, $\bar{I}$, across all existing wells:

$$\overline{I} = \frac{\sum_{i=1}^{N} I_i}{N} \quad \text{(Eq. 3.1)}$$

where *N* is the number of wells in the field.

4. Determine the density of wells, *D*, at the site:

$$D = \frac{N}{A\ (km^2)} \quad \text{(Eq. 3.2)}$$

where *A* is the area of the potential storage field.

5. Calculate the weighted-average integrity score for the potential storage field, $\overline{I_w}$:

$$\overline{I_w} = \frac{\bar{I}}{D} \quad \text{(Eq. 3.3)}$$

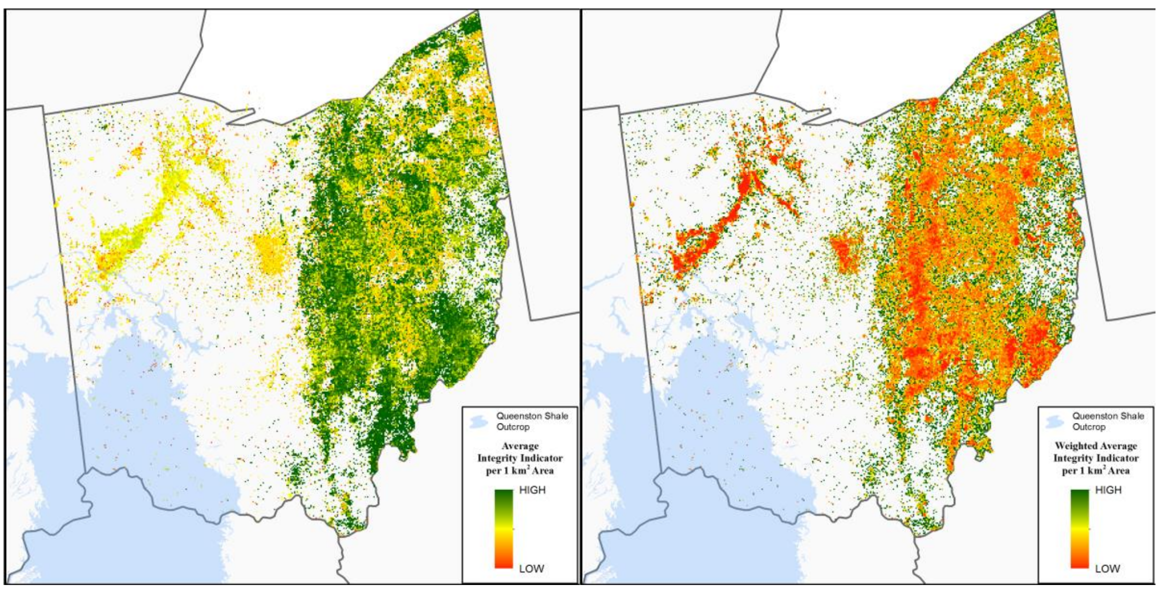
The procedure outlined above can be used to quantitatively score and compare (i.e., screen) multiple potential storage fields—for example, ranking the fields from highest to lowest in terms of weighted-average integrity score. It takes into account both the estimated overall well integrity, including cases where well record data are incomplete, and the number of wells potentially affecting storage efficacy. Note that given a constant well density, a higher average integrity score will lead to a higher weighted-average integrity score, while a higher well density leads to a lower weighted-average integrity score for a constant average intensity.

Alternatively, if there is interest to characterize and screen broader areas, such as a specific county or an entire state, then the weighted-average integrity score could be calculated and mapped (color-coded) for a grid (e.g., 1 square kilometer (3280 x 3280 feet)) that covers the entire area of interest.

3.3.4 Initial Site Screening for Selected Potential Storage Fields

This section explains how the integrity indicator scores can be used to screen potential storage fields. Three scenarios are discussed: one related to a single geologic confining layer in Ohio and two related to two different confining layers in Michigan.

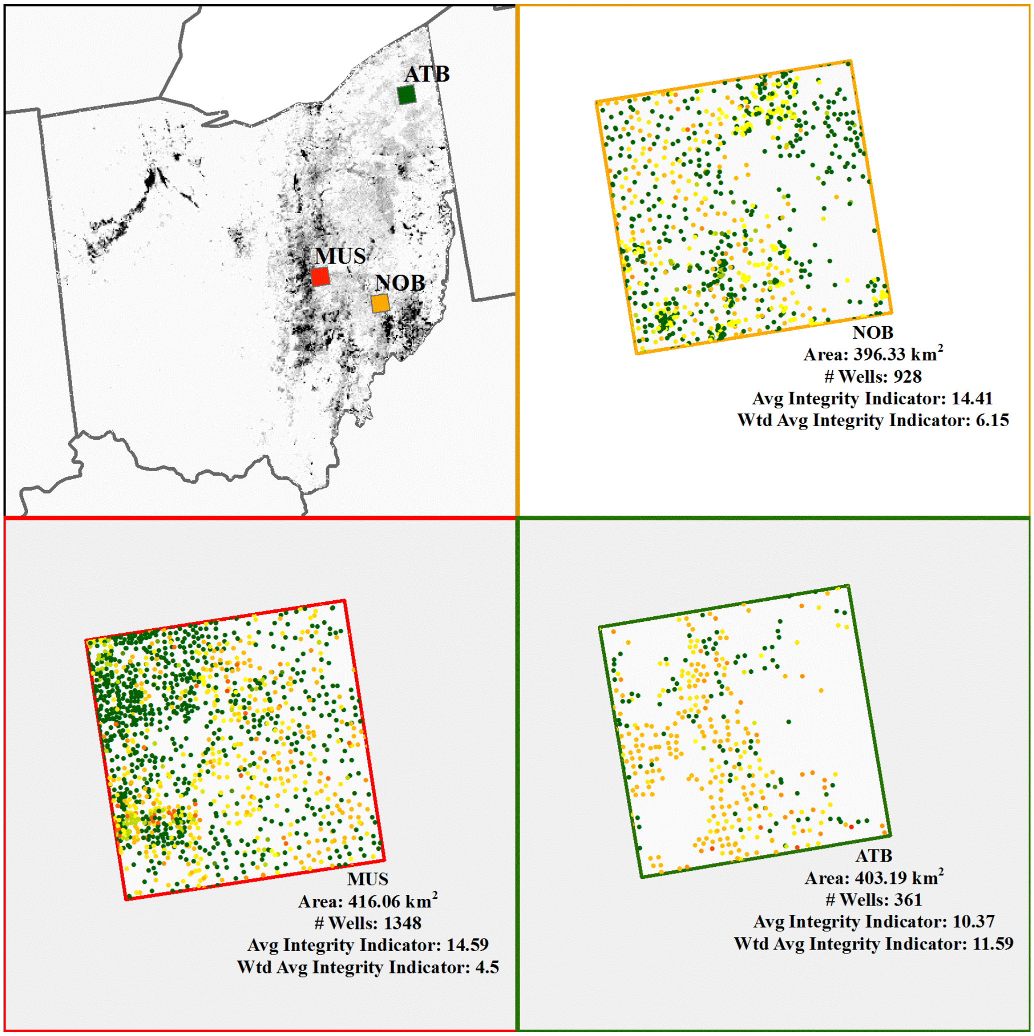
Potential storage field in Ohio: Queenston confining layer. As discussed in more detail in Section 6.0 of this report, potential storage fields have been considered in Ohio and Michigan. In Ohio, the Queenston geologic formation is being considered as a potential confining layer for CO_2 injection. As such, the depth factor of the well integrity score was calculated relative to this layer for all wells in Ohio. Those wells that do not penetrate the Queenston shale are considered to have the highest integrity. The average and weighted-average integrity scores for each 1-square-kilometer grid cell covering Ohio were calculated to provide a broad overview of the integrity and density of wells across the state; this information aids in identifying where potential storage fields may be located (Figure 3-31). To illustrate the separate influence of well density on the integrity score, maps for the average integrity score (Figure 3-31, left panel) and the weighted-average integrity score (Figure 3-31, right panel) were prepared. In this example, some areas, like southeastern Ohio along the border with West Virginia, appear favorable (green in Figure 3-31) when considering the average integrity score (based on the well condition indicators) in the left panel. However, some of those same areas appear less favorable (yellow to red in Figure 3-31) when well density is also taken into account (right panel). The weighted-average integrity score is a more complete screening tool because it considers both factors. At this scale, it can be used to consider the entire state and suggest broad areas (for example, the eastern part of the state) that might be better suited for storage fields.



Note: Left panel shows average integrity score; right panel shows weighted-average integrity score.

Figure 3-31. Integrity Scores for 1-Square-Kilometer Grid Cells across Ohio, Relative to the Queenston Confining Layer

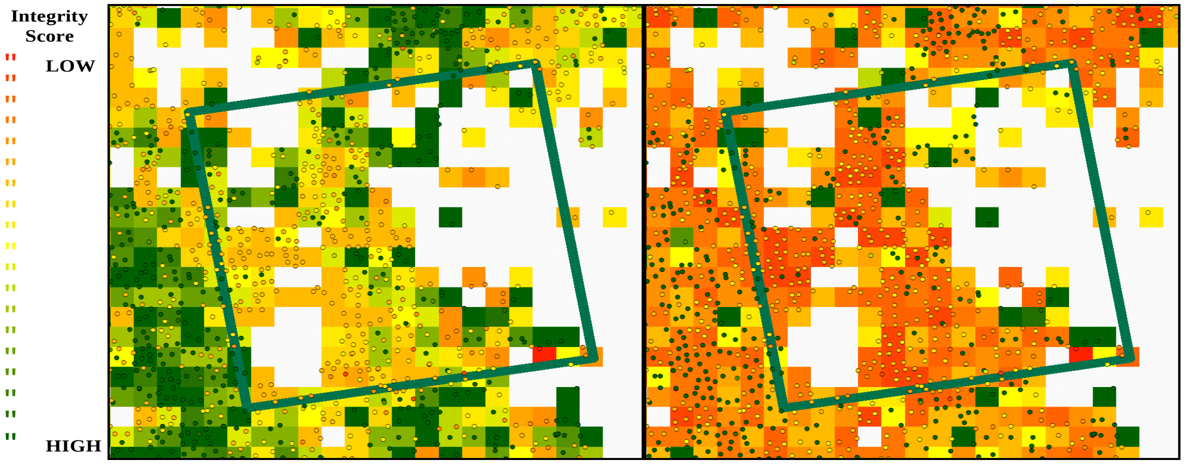
The assessment in Figure 3-31 is at a coarse spatial scale. Given that storage fields are likely to be only 100 to 200 square kilometers (38 – 77 square miles) in size or less, more detailed local screening is also appropriate. The integrity score provides perhaps an even more useful tool when calculated for specific candidate storage fields. For example, Figure 3-32 presents the average and weighted-average integrity scores for three candidate fields in Ohio, labeled as the ATB(Ashtabula/Trumbull), MUS (Muskingum/Coshocton), and NOB (Noble) fields, all of which consider the Queenston as their target confining layer. For each field, Figure 3-32 shows the existing well locations, color coded according to well integrity, along with the surface area of the field, number of existing wells, average integrity score, and weighted-average integrity score. Screening with the weighted-average integrity score suggests that the ATB field would be highest ranked among the three fields due to its significantly higher integrity score.



Note: Well locations are color coded by integrity score.

Figure 3-32. Integrity Scores for Potential Storage Fields in Ohio, Relative to the Queenston Confining Layer

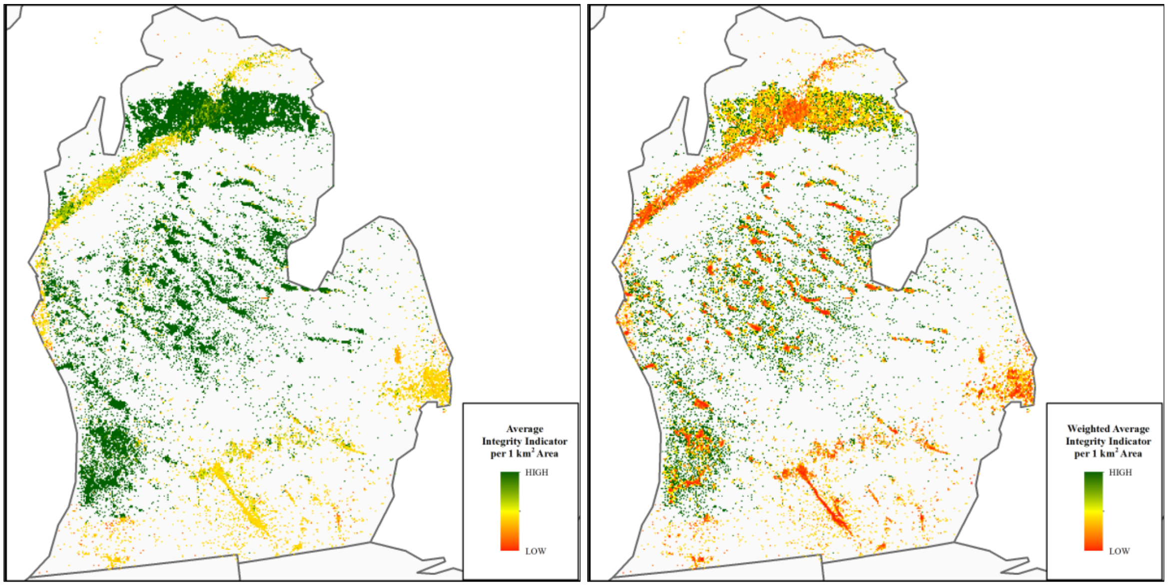
Similarly, the integrity evaluation can be considered at an even finer spatial scale to help examine trends in the well condition and well density within potential storage fields. This can be done by simply 'zooming in' on the 1-square-kilometer (3280 x 3280 feet) grid cells displayed in Figure 3-31 (illustrated in Figure 3-33 for the ATB field in Ohio). Figure 3-33 shows the average integrity score for 1-square-kilometer (3280 x 3280 feet) grid cells (left panel), the weighted-average integrity score (right panel), and the color-coded individual well integrity scores posted at their well locations. This figure again clearly shows the influence of well density; for example, reconsidering grid cells with reasonably favorable average integrity scores (green areas in the north-central area of the site on the left panel) to be less favorable (orange/red) when also considering well density (on the right panel).



Note: Well locations are color coded by integrity score. Left panel shows average integrity score; right panel shows weighted-average integrity score.

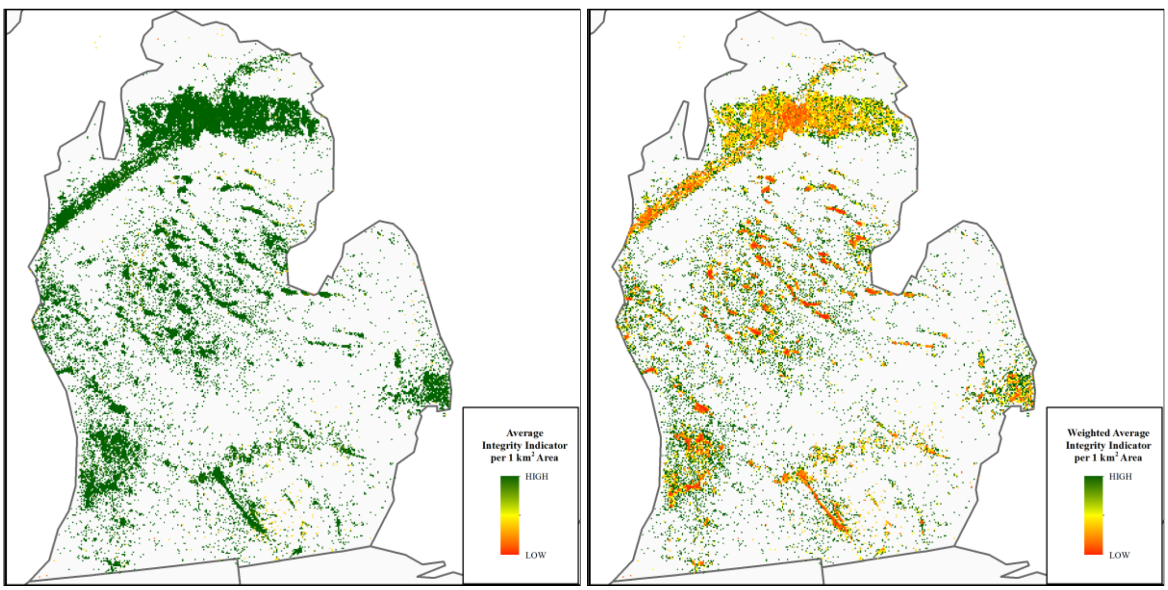
Figure 3-33. Finer-scale View of the ATB Field in Ohio for 1-Square-Kilometer Grid Cells

Potential storage fields in Michigan: Salina and Trempealeau confining layers. Within Michigan, potential storage fields have been considered at two depth horizons: some fields targeting the shallower Salina formation as the confining layer (approximate depths range from 2,500 to 6,000 feet below ground surface), and other fields targeting the deeper Trempealeau formation as the confining layer (approximate depths range from 4,000 to 11,000 feet below ground surface). Figures 3-34 and 3-35 show the average and weighted-average integrity scores associated with the Salina and Trempealeau confining layers, respectively. Comparing these two figures first shows the importance of well depth in the integrity scoring. For example, comparing the left panel of Figure 3-34 with the left panel of Figure 3-35 indicates that while some locations have only marginally favorable integrity scorings relative to the shallower Salina formation (Figure 3-34), virtually all locations have favorable integrity scores with respect to the deeper Trempealeau formation because they do not penetrate that deeper confining layer (Figure 3-35). In addition, both figures again illustrate the importance of well density when considering the weighted-average integrity score. Several areas that have high average integrity scores and might be considered favorable for siting based on that measure are considered less favorable when taking into account well density through the weighted-average integrity score.



Note: Left panel shows average integrity score; right panel shows weighted-average integrity score.

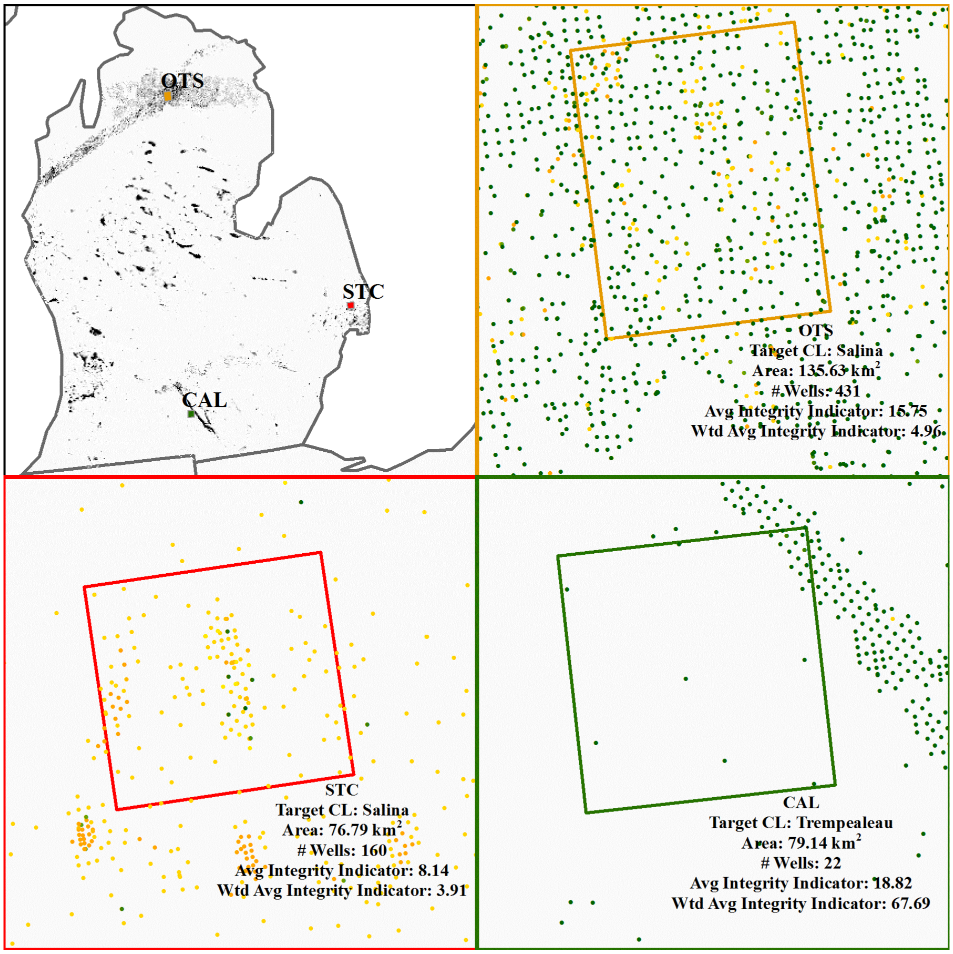
Figure 3-34. Integrity Scores for 1-Square-Kilometer Grid Cells across Michigan, Relative to the Salina Confining Layer



Note: Left panel shows average integrity score; right panel shows weighted-average integrity score.

Figure 3-35. Integrity Scores for 1-Square-Kilometer (3280 x 3280 feet) Grid Cells across Michigan, Relative to the Trempealeau Confining Layer

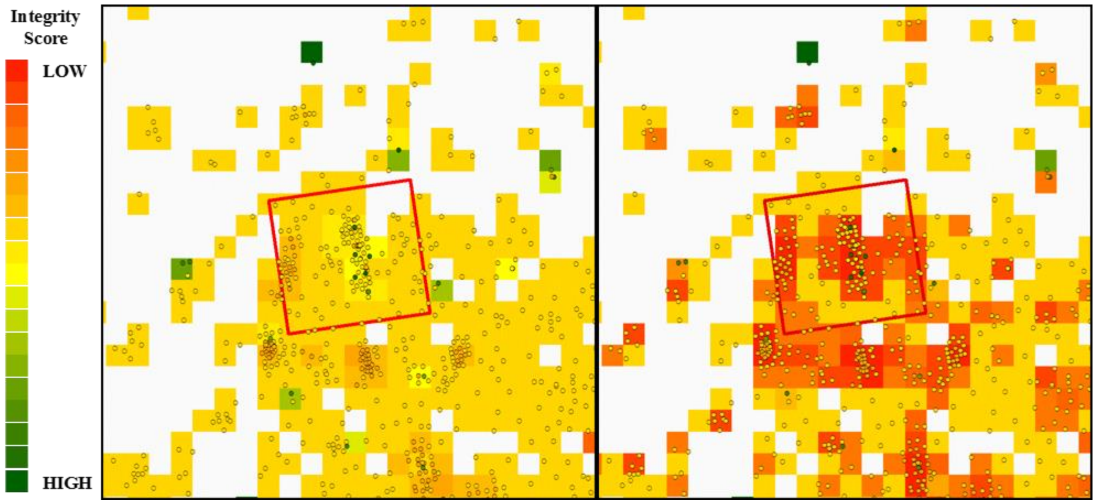
Figure 3-36 presents the average and weighted-average integrity scores for three candidate fields in Michigan, labeled the CAL (Calhoun), OTS (Otsego), and STC (Saint Clair) fields. The first of these fields (CAL) considers the Trempealeau as the confining layer, while the other two fields consider the Salina as the confining layer. This highlights how the methodology presented here allows for sites with different target confining layers to be evaluated together. For each field, Figure 3-36 shows the existing well locations, color coded according to well integrity, along with the surface area of the field, number of existing wells, average integrity score, and weighted-average integrity score. Screening with the weighted-average integrity score clearly suggests that the CAL field would be highest ranked among the three fields due to its significantly higher integrity score, which is driven by both a higher average integrity score and a lower well density.



Note: Well locations are color coded by integrity score.

Figure 3-36. Integrity Scores for Potential Storage Fields in Michigan, Relative to the Salina (OTS and STC fields) and Trempealeau (CAL field) Confining Layers

As a final illustration, Figure 3-37 presents the integrity scores at the finest spatial scale by zooming in on the STC field. Similar to the trends seen above in Figure 3-33 in Ohio, this figure shows the influence of well density—for example, reconsidering grid cells with reasonably favorable average integrity scores (yellow on the left panel) to be less favorable (red) when also considering well density (on the right panel).



Note: Well locations are color coded by integrity score. Left panel shows average integrity score; right panel shows weighted-average integrity score.

Figure 3-37. Finer-scale View of the STC Field in Michigan for 1-Square-Kilometer (3280 x 3280 feet) Grid Cells

4.0 Sustained Casing Pressure (SCP) Evaluation

SCP is considered a well integrity problem and is defined as pressure in any well annulus that is measurable at the wellhead and persistently rebuilds after bleed-down (Xu and Wojtanowicz, 2001; Combs et al., 2014). Often, SCP is a symptom of a loss of cement seal integrity or another barrier isolating the casing strings from one another (e.g., the casing head in the wellhead or the casing itself). In some wells, gas may enter a zone above the top of the cement column. While this type of event may be expected, it could also result in the migration of gas or fluids to undesirable geologic formations. Under these circumstances, at some location in the well, gas entered into or above the cement seal and traveled by a flow path up the annulus to the wellhead (Sminchak et al., 2013; Rocha-Valadez et al., 2014).

Often, SCP is investigated and assessed through limited testing, such as pressure bleed-down/build-up tests. A more complete picture of the source of the gas and the extent of any well integrity issue may be obtained by also analyzing the trapped gas and measuring the gas chamber volume in addition to measuring the pressure build-up**.**

Thirteen wells in the Appalachian Basin were analyzed using a complete suite of tests (bleed-down/build-up, gas analysis, and gas chamber volume) to identify the SCP issues associated with these wells. Wells which displayed SCP at some time in their history were selected for further analysis. The wells used in this analysis were drilled and completed over a wide range of dates (1940s to the present) and have a number of different casing and cement completion details. These different completion designs may result in different causes or different origins of SCP gas. The casing strings in these wells are cemented at various intervals, and they reflect a variety of well completions. Wellhead loggers were installed on the annulus port in the 13 wells; the wells were then vented so the rate of pressure build-up over time could be recorded. Gas samples were also collected from selected wells in an attempt to assess the source of the gas based on hydrocarbon signature. Once the pressure built back up to initial pressure, the volume of the gas was estimated with a flow meter. In general, the wells' pressure varied from 34 to 1,200 pounds per square inch (psi), indicating various source zones. Since the region has many different formations that produce gas, this may be expected, but it can complicate SCP analysis because the source of gas may not be clear.

4.1 SCP Field Data Collection Methods

4.1.1 Well Review and Selection

Over 1000 wells in three field areas in the Appalachian Basin were screened for well integrity issues by performing a historical review of the casing annulus pressure data; if the data indicated that a well's pressure issues would continue, the well was selected to be part of the study. The 13 selected wells were tested using a pressure bleed-down/build-up test, and gas samples were collected from the wells. In addition, the gas chamber volume (headspace above the top of the cement column) was measured in select wells.

The program field-tested 13 wells which fell into three fields:

- AB-1 SCP
- AB-2 to AB-5 SCP
- AB-6 to AB-13 SCP

4.1.2 Gas Sampling and Analysis

For each well involved in the study, a sample of the gas that accumulated in the annular space was collected when the annulus was at near-maximum pressure. Samples were collected in 300-millliliter pressure-rated cylinders (Figure 4-1). Appropriate fittings were used to connect the sampling cylinder to the casing valve on the well, and a Joule-Thomson apparatus was connected to the downstream side of the sampling cylinder to prevent condensation of heavier compounds in the sampling cylinder.

The cylinder was purged a minimum of five times by opening the inlet valve to allow gas to enter the cylinder, then closing the cylinder to trap the gas. The outlet valve on the sampling cylinder was opened to release the gas, and finally the valve was closed again to seal the cylinder.

Once the samples were collected, they were hand-delivered to the analytical laboratory for compositional analysis (N_2, H_2, CO_2, and C_1-C_7). The analytical results for the gas samples are presented in Table 4-1.

Figure 4-1. Collection of Annular Gas Sample at Test Well

Table 4-1. Analytical Results for Gas Samples Collected from Test Wells

Analyte	AB-1	AB-2	AB-3	AB-4	AB-5	AB-6	AB-7	AB-8	AB-9	AB-10	AB-11	AB-12	AB-13
	(mol %)												
Nitrogen (N_2)	1.485	2.322	3.039	0.388	6.063	4.599	4.424	7.963	3.958	3.497	3.631	5.881	3.667
Hydrogen (H_2)	NA	58.207	61.679	97.54	0.650	1.899	0.900	2.885	0.975	0.182	0.166	0.707	0.133
Carbon dioxide (CO_2)	0.012	0.002	0.009	0.021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Methane	88.760	35.332	31.28	1.674	83.343	83.104	83.266	80.048	78.625	83.640	81.503	82.915	83.499
Ethane	6.552	2.491	2.591	0.138	5.902	7.515	8.788	5.551	10.995	8.910	9.288	6.742	8.755
Propane	2.093	1.092	0.883	0.074	2.873	1.739	1.419	2.675	4.069	2.199	3.943	3.254	3.091
iso-butane	0.298	0.1	0.092	0.007	0.184	0.146	0.097	0.168	0.283	0.178	0.314	0.278	0.224
n-butane	0.511	0.255	0.214	0.036	0.659	0.666	0.728	0.542	0.782	0.878	0.749	0.692	0.494
iso-pentane	0.104	0.056	0.041	0.011	0.108	0.107	0.125	0.066	0.109	0.148	0.105	0.094	0.052
n-pentane	0.095	0.053	0.048	0.019	0.099	0.119	0.147	0.050	0.123	0.188	0.132	0.097	0.057
hexanes/plus	0.093	0.041	0.077	0.026	0.048	0.093	0.065	0.012	0.049	0.181	0.169	0.047	0.028
heptanes plus	NA	0.049	0.047	0.066	0.071	0.013	0.041	0.040	0.032	NA	NA	NA	NA

In general, the gas samples were composed primarily of methane (typically 78% to 88%), with the balance made up of nitrogen and light hydrocarbons. However, three samples (AB-2, AB-3, and AB-4) contained significant amounts of hydrogen. The composition of the gas samples demonstrates that the gas found in the annular space was not from the reservoir; rather, it entered the well from a different geologic zone. The specific geologic zone is uncertain based on the analytical results obtained from the gas samples. Wells AB-2 through AB-5 are not cemented to ground surface, so the gas may have entered the annular space through the 1,000 feet of borehole that is not encased by cement or another casing string. The elevated concentrations of hydrogen in AB-2, AB-3, and AB-4 are believed to be the result of a reaction with the casing caused by the cathodic protection system used on these wells.

4.1.3 Wellhead Pressure/Temperature Logging

A pressure bleed-down/build-up test was performed on each well involved in this study to evaluate the pressure-response curve related to the SCP. Before additional testing was performed, the baseline pressure was measured in an effort to determine the maximum pressure that the annulus would achieve. Table 4-2 presents the baseline pressure data for each well. The casing valve associated with annulus being tested was then opened to allow the pressure to bleed down to near-atmospheric condition, and a data-recording pressure/temperature gauge (Figure 4-2) was connected to the annular space to monitor the pressure recovery curve. Table 4-2 also presents the time required to bleed the pressure to atmospheric levels. The gauge remained attached to the well until the pressure rebounded to near-baseline conditions.

Table 4-2. Baseline Pressure Data for Test Wells

Well ID	Initial Pressure (psi)	Bleed-down Time
AB-1	1,200	NA
AB-2	95	3 minutes
AB-3	295	3 minutes
AB-4	34	30 seconds
AB-5	254	8 minutes
AB-6	619	4 minutes
AB-7	717	10 minutes
AB-8	263	2 minutes
AB-9	312	1 minute
AB-10	487	15 minutes
AB-11	338	13 minutes
AB-12	0 (open to atmosphere)	NA
AB-13	0 (open to atmosphere)	NA

Note: NA = not applicable.

Figure 4-2. Pressure/Temperature Recording Gauge

Typically, the data were recorded every minute; however, the sample rate does not need to be this frequent in order to analyze the data. Although pressure/temperature data were collected for up to several months, the majority of the pressure build-up typically occurred within the first days of monitoring. These are the critical data for performing SCP analysis.

4.1.4 Gas Flux/Vapor Space Analysis

The gas chamber volume was measured in 9 of the 13 wells. Four of the wells, AB-2 through AB-5, were constructed with limited cement in the annular space, and the gas chamber volume was not measured in these wells since cement integrity could not be quantified. In eight of the remaining nine wells, the annular space was bled down through a flow meter of the type shown in Figure 4-3 to determine the volume of the gas chamber; a valve at the outlet of the wellhead maintained a constant flow rate. Using the time required to blow the well down to near-atmospheric levels and the initial pressure, the gas chamber volume was calculated (Table 4-3). On the AB-1 well, a hot-wire, data-recording flow meter was used to determine the gas chamber volume. This meter measured and recorded the flow rate during the entire bleed-down period to provide a total volume released from the well. The total volume and the initial pressure were used with the Ideal Gas Law to determine the gas chamber volume (Equation 4.1). When calculating the volume, *n*, *R*, and *T* remain constant and the ideal gas law reduces to Equation 4.2:

$$PV = nRT \qquad \text{(Eq. 4.1)}$$

$$V_1 = (P_2 * V_2)/P_1 \text{ at high pressure and } V_1 = Vsc * Psc/(P_1 - P_2) \text{ at low pressure} \qquad \text{(Eq. 4.2)}$$

where P = pressure, V = volume, n = moles, R = Ideal gas constant, T = temperature, GCV_1 = gas combined volume, Vsc = molar volume standard condition, and Psc = standard condition pressure.

Figure 4-3. Flow Meter Used to Measure Gas Chamber Volume in Test Wells

Table 4-3. Gas Chamber Calculations and Volumes for Test Wells

Well ID	Flow Rate (L/min)	Flow Duration (min)	Initial Pressure (psi)	Final Pressure (psi)	Gas Chamber Volume (L)
AB-1	NA	NA	1,200	14.7	2.0
AB-6	105	3.48	596	14.7	9.0
AB-7	105	12.45	621	14.7	31
AB-8	105	1.26	261	14.7	7.4
AB-9	105	0.63	259	14.7	3.8
AB-10	105	41.68	414	110	NA
AB-11	105	37.83	296	14.7	197
AB-12	105	4.25	416	14.7	15.8
AB-13	105	4.07	567	14.7	11.1

For the nine wells tested, the gas chamber volume ranged from approximately 2.0 to 1,163 liters at STP; however, the initial pressures measured on the wells varied from 259 to 1,200 psi. An accurate gas chamber volume was not measured for AB-10 because the well started to produce liquid after bleeding down the well for approximately 42 minutes, indicating an artesian liquid flow. This violates the wellhead model assumption of constant liquid quantity in the annulus. SCP Methodology

The conventional diagnostic test for SCP is the bleed-down/build-up test, in which the gas pressure is bled off of the annulus and the resulting build-up is recorded. The base SCP pattern (Figure 4-4) consists of pressure increasing at a decreasing rate to an asymptotic pressure. Several researchers have detailed SCP analysis methods, primarily originating with Xu and Wojtanowicz (2001), who described a method to calculate cemented annulus permeability from SCP pressure observations. Huerta et al. (2009) proposed the use of this method for CO_2 storage well application.

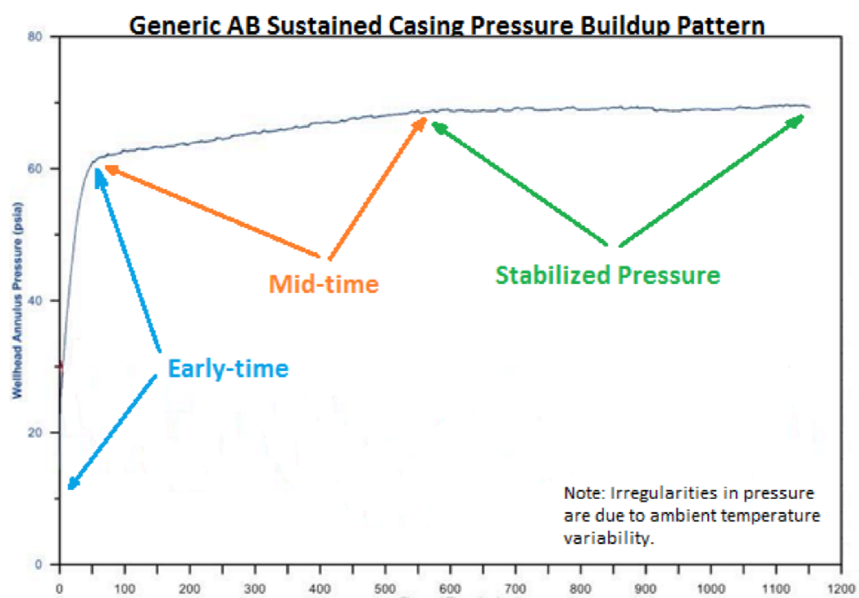
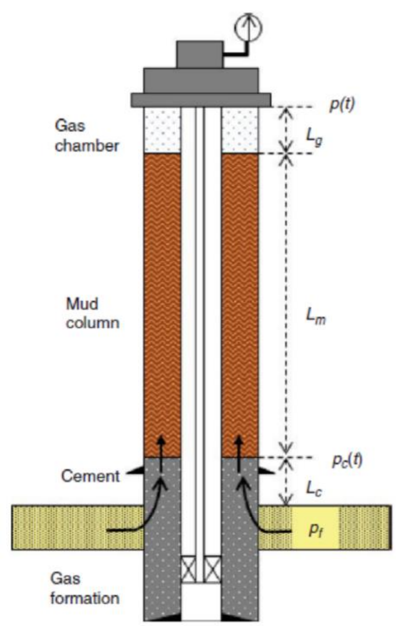


Figure 4-4. Idealized SCP Build-up Curve

The effective isolation of the injection zone and upper portion of the well is of great importance to a saline aquifer carbon sequestration project. Quantitative measurements of the effectiveness of the rock/cement/steel interface from in-situ, full-well-scale measurements are very rare. The Xu paper offered a potential avenue to obtain this valuable information.

Xu and Wojtanowicz (2001) developed a mathematical model to fit the SCP build-up of gas production wells from offshore fields in the Gulf of Mexico. They assumed a continuous Darcy-flow pathway within the cement portion and determined an equivalent permeability that best fit the observed base SCP pattern. The basic well elements are shown on Figure 4-5. A number of authors have extended or modified this basic cement permeability model, including Huerta et al. (2009), Tao et al. (2010), and Rocha-Valadez et al. (2014). In the course of field work performed for this project, a number of issues applying this model to actual field data were encountered:

1. The existing literature assumes that there is no hydrostatic gradient in the cement column. When applied to wells with short cement segments relative to the well depth, this assumption did not introduce much error. However, in some datasets (for example, AB-1) where the annulus is cemented nearly to surface, the hydrostatic gradient in the cement cannot be ignored.
2. If the source of gas that is causing the SCP is not specified (i.e., depth and pressure), then the permeability model cannot be applied. It is possible in some cases to estimate a range, as can be done with AB-1, but this introduces uncertainty and in some cases will preclude analysis.
3. The permeability model, applying Darcy flow equations derived for flow through porous media, may not be the best model for gas migration in a vertical rock/cement/steel system. This base model assumes that the flow resistance is proportional to the length of the cement column and inversely proportional to the annulus area. However, there is no evidence that these two assumptions are valid for a system that is normally thought to leak due to micro-annuli, cracks, voids and other defects that differ significantly from porous media.



Source: From Rocha-Valadez et al. (2014).

Figure 4-5. Cement/Mud Annular System

During this project effort, a simpler methodology was developed that did not require assumptions about the source of the gas or the geometry of the rock/cement/steel system. The cumulative effect of all the defects in the seal are represented by a hypothetical flow restriction, quantified as a flow factor (FF), located at the top of the cement. This simpler model has the advantage that it can indicate the character of the defect, providing diagnostic information not available if only a permeability flow model is assumed.

One aspect the wellhead model has in common with the traditional Xu model is the importance of the gas chamber volume measurement. Essentially, the gas chamber in the annulus serves as the “meter” for bleed-down/build-up tests. The observed gas rate, and therefore the calculated flow factor, is directly proportional to the gas chamber volume. In other words, for a given flow rate, pressure will build one-tenth as fast when the gas chamber volume is ten times bigger. Without a measurement of gas chamber volume, the flow factor cannot be determined.

4.1.5 Wellhead Model for SCP

The objective of developing the wellhead model is to quantitatively describe the base pattern of pressure build-up due to gas accumulation in cases where SCP is observed. The model assumes the following:

1. The increase in a casing pressure is the result of gas, which accumulates at the top of the casing and is referred to as the gas chamber.
2. Gas can enter the annulus either through defects in the cement or defects in the tubulars.
3. The source of the gas is at a constant pressure P1 which is equal to the observed asymptotic pressure Pasym. The source of gas is located at the top of the cement.
4. No gas leaves the gas chamber during a build-up.
5. The gas compressibility is in the range of $0.8 \le Z \le 1.1$.
6. The hydrostatic gradient in the gas chamber is zero.
7. The temperature of the gas chamber is constant.
8. The gas fluid properties of molecular weight, heat capacity ratio, and compressibility are constant and are normally evaluated at the average pressure and temperature over the range of the dynamic data.
9. If there is liquid between the gas chamber and the cement top, it is a compressible liquid which exerts a constant hydrostatic pressure.
10. The liquid, if present, is trapped and cannot leak out.
11. Gas which passes through an orifice transports immediately to the gas chamber; there is no dissolution, storage or evolution of gas in any liquid between the top of the cement and the gas chamber.

Table 4-4 summarizes the main parameters required to analyze SCP build-up. Most of these parameters are routinely measured during oil and gas field operations at little cost.

Table 4-4. Parameters Required for SCP Analysis Testing

Static Data Required Parameter	Oilfield Units	Comment
Asymptotic pressure	psia	The maximum SCP
Volume of gas chamber	cubic feet	None
Temperature of gas chamber	deg F	Usually the average temperature of the gas chamber
Gas compressibility Z in chamber	dim.	At the average of the minimum and asymptotic pressure
Gas molecular weight	lb/lbmol	None
Gas specific heat ratio k	dim.	None

Liquid volume	cubic feet	None
Initial true vertical liquid	feet	Vertical height of the liquid at the liquid density
Liquid compressibility	1/psi	None
Liquid density	lb/gallon	With vertical height above, defines liquid hydrostatic
Gas compressibility Z at source	dim.	At the average of the minimum and asymptotic pressures + hydrostatic of the liquid.
Cement top temperature	deg F	None

Note: psia = pounds per square inch absolute
deg F = degrees Fahrenheit
dim. = dimensionless
lb/lbmol = pounds per pound-mole

Dynamic Data Required

The dynamic data are the pressures observed as a function of time. The following specifications have been found practical for the application of this numerical method, along with the units used for implementation:

1. Data consist of :
    a. Delta time with random intervals (decimal days).
    b. Delta pressure over time (pounds per square inch absolute [psia]).
2. No more than 50 data points are required to describe the pressure increase pattern.
3. Time zero is the last observation before the pressure begins increasing.
4. Do not include any significant amount of asymptote data. For example, in Figure 4-6, the pressure asymptote is about 275 psia, which represents the end of the SCP dynamic data.

Figure 4-6 shows an example of SCP build-up data. The pressure build-up may occur over several hours or months. In general, early-time data may require fairly short monitoring interval (1 to 10 minutes) to capture rapid pressure build-up, but the later monitoring period may be coarser. In general, it is not necessary to capture the very small pressure changes at the end of the build-up pattern that are useful for determining far-field effects in reservoir pressure transient analysis. Since most wellhead loggers record ambient temperature, it is also useful to examine temperature trends because they may have an effect on fluid/gas in the annular space at the point of measurement (at the wellhead).

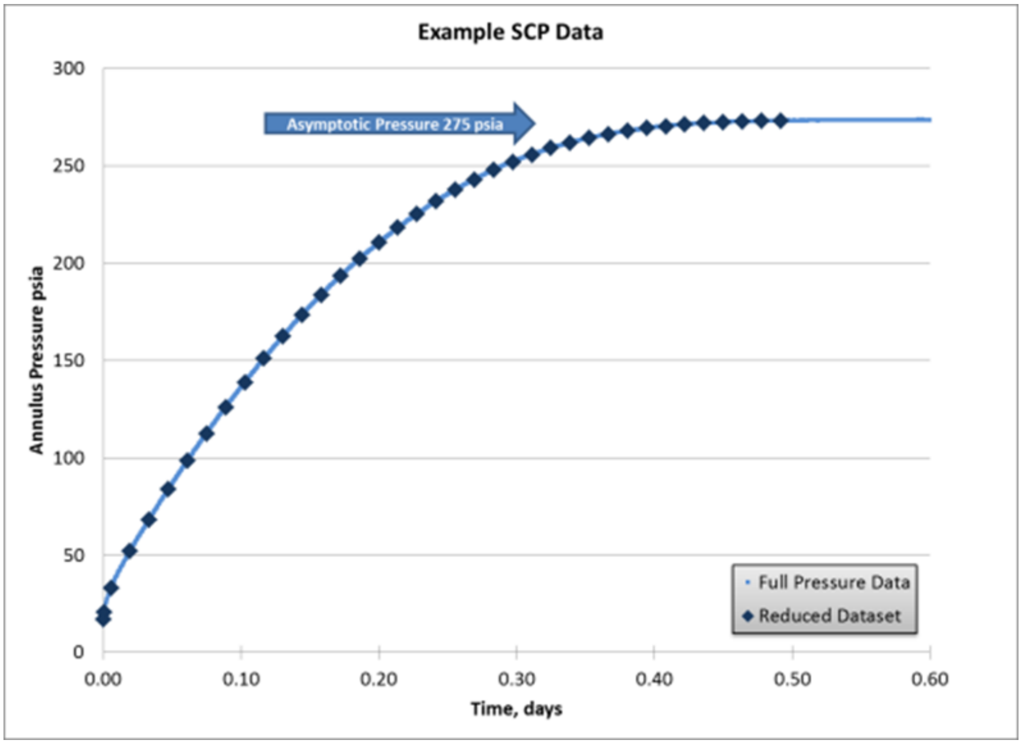


Figure 4-6. Example SCP Test Data (Wellhead Annulus Pressure)

Gas Accumulation from Dynamic Data

Using the real gas law to derive the equation for the change of pressure Pg with time in the gas chamber, the number of moles of gas entering the gas chamber during the *n*th time step is:

$$\Delta n^n = \frac{P_g^n V_g^n - P_g^{n-1} V_g^{n-1}}{ZRT_g} = \frac{P_{sc} q^n \Delta t}{RT_{sc}} \qquad \text{Eq. 4.3}$$

The cumulative moles of gas at *n*th time step in gas chamber are the sum of initial and leaked moles of gas:

$$n_t^n = n_i + \sum_{k=1}^{n} \Delta n^n = n_i + \frac{\sum_{k=1}^{n} P_{sc} q^k \Delta t}{RT_{sc}} \qquad \text{Eq. 4.4}$$

In the implementation, the time interval Δt is determined by the minimum difference between measured time steps. If there is liquid column in the annulus, the volume of gas chamber increases with time due to the compressibility of liquid. This effect is noticeable only when there is a very small initial gas chamber over a very large volume of compressible liquid. The gas law at *n*th time step is written as:

$$P_g^n \left(V_g^{n-1} + \Delta V_g^n \right) = n_t^n ZRT_g \qquad \text{Eq. 4.5}$$

The volume expansion of gas chamber is related to compressibility of liquid and pressure change:

$$\Delta V_g^n = -\Delta V_l^n = C_l V_l^{n-1} \left(P_g^n - P_g^{n-1} \right) \qquad \text{Eq. 4.6}$$

Equation Nomenclature

A	cross-section area of annulus, ft^2
A_o	orifice throat cross-sectional area, ft^2
C_d	discharge coefficient, dimensionless
C_l	compressibility of liquid, psi-1
FF	flow integrity factor, μm^2
FF_C	cement flow factor, μm^2
FF_T	tubular flow factor, μm^2
F_2	coefficient of subcritical flow, dimensionless
G_c	fluid gradient of cement portion, psi/ft
IRM	instant release metric, MSCF
K	specific heat ratio
K_e	effective permeability, md
L_c	length of cement column, ft
L_l	length of liquid column, ft
MW	molecular weight of gas, lbm/lbmol
N_i	initial moles of gas in gas chamber, mole
N_t	cumulative moles of gas in gas chamber, mole
P_1	upstream pressure of assumed orifice, psia
P_2	downstream pressure of assumed orifice, psia
P_{asym}	observed asymptotic pressure, psia
P_{cal}	calculated pressure, psia
P_{CF}	critical flow pressure, psia
P_f	formation pressure, psia
P_g	pressure of gas chamber, psia
P_{obs}	observed SCP, psia
P_{sc}	standard condition pressure (=14.7), psia
q	gas influx rate, SCF/D
r	pressure ratio across orifice, dimensionless
R	gas constant (= 10.731), ft3-psi/oR-lb-mol
SLM	sustained leakage metric, MSCFD
t	time, day
T_g	temperature of gas chamber, oR
TSC	standard condition temperature (=520), oR
V_g	volume of gas chamber, ft^3
$V_{g,a}$	volume of gas chamber at asymptotic pressure, ft^3
$V_{g,i}$	initial volume of gas chamber, ft^3
V_l	volume of liquid column, ft^3
Z	compressibility of gas, dimensionless
Δt	uniform time step, days
ρ_l	density of liquid, ppg

By combining equations n+2 and n+3, we can derive the gas pressure as (after Xu and Wojtanowicz (2001), Equation 1):

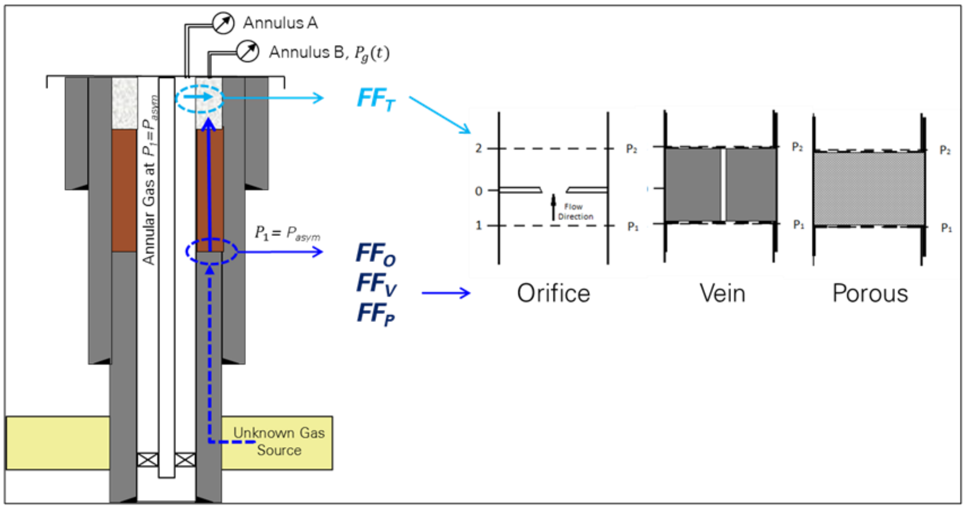
$$P_g^n = 0.5 \left[P_g^{n-1} - \frac{V_g^{n-1}}{C_l V_l^{n-1}} + \sqrt{\left(P_g^{n-1} - \frac{V_g^{n-1}}{C_l V_l^{n-1}} \right)^2 + \frac{4 n_t^n ZRT_g}{C_l V_l^{n-1}}} \right] \qquad \text{Eq. 4.7}$$

If liquid column does not exist and the volume of gas chamber is constant with time, gas pressure at surface is expressed as:

$$P_g^n = \frac{n_t^n ZRT_g}{V_g} \qquad \text{Eq. 4.8}$$

Gas Influx Rate

Orifice flow is commonly used to determine the mass rate from the orifice dimensions and the pressure drop. This is well suited to the SCP model because a higher-pressure source is flowing into a lower-pressure chamber. The schematic of gas flow passing through an orifice is shown in Figure 4-7.



Note: For gas migration through cement defects, upstream and downstream pressures are calculated by hydrostatic relationship. For gas movement through tubular defects, upstream and downstream pressures are inner production tubing pressure and pressure in gas chamber.

Figure 4-7. Simple Schematic of Assumed Orifice at (a) Top of Cement Column as Cement Defects and (b) Casing String as Tubular Defects

For the orifice flow character in the wellhead model, we assume a single orifice represents all defects in the cement section or the tubular container.

Methods for calculating flow through an orifice are well established in the petroleum industry for both measurement and pressure-relief purposes. For this development the methods of pressure-relief are best suited, so the point of departure is *API Standard 520 Part 1*. The standard theoretical framework of adiabatic isentropic flow of a gas for which PV^k is constant has proven adequate for surface process equipment. In this application, higher pressures may be encountered, particularly in very deep wells or unusual gas compositions (carbon dioxide, retrograde condensate). Therefore, the caution to check that the compressibility Z is between 0.8 and 1.1 is recommended.

For fundamental orifice flow in which the cross-sectional area of the throat is much less than upstream and downstream areas, the only remaining orifice physical dimension parameters are the throat area and a dimensionless correction factor such as C_d (Perry and Chilton 1973). We will replace all API correction factors with a single discharge coefficient C_d which we will consider a constant. This is reasonable for discharge areas much smaller than the inlet area and Reynolds Numbers above 4000. Reynolds Number will be lowest at the end of the accumulation, when the effect of any real variation in C_d will normally be imperceptible. Accordingly we can combine C_d with the discharge area A_o and propose a term orifice flow factor (FF_O) in square microns to quantify the overall severity of defects:

$$FF_O = 6.4516x10^8\, C_d\, A_o \qquad \text{Eq. 4.9}$$

The units of μm^2 result in convenient values for most normal SCP situations.

For orifice flow, if the downstream pressure is lower than the critical flow pressure, the flow rate is only dependent on the upstream pressure because the maximum wave velocity of a disturbance is the sonic velocity. The critical flow pressure for an isentropic flow is given by *API Standard 520 Part 1* (2014, section 5.6 equation 1 rearranged):

$$P_{CF} = P_1\left(\frac{2}{k+1}\right)^{\frac{k}{k-1}} \qquad \text{Eq. 4-10}$$

For the critical flow case, gas flow rate is only a function of the upstream pressure. Referring to *API Standard 520 Part 1* (2014, section 5.6 equation 3 rearranged with C_d replacing various K factors):

$$q = 4.7324x10^6\,.\,C_d A_o P_1\sqrt{k\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}\cdot\frac{1}{ZT_1 MW}} \qquad \text{Eq. 4-11}$$

Incorporating the flow factor into equation (A-9) gives, for critical flow:

$$q = 0.007335\,.\,FF_O\,.\,P_1\sqrt{k\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}\cdot\frac{1}{ZT_1 MW}} \qquad \text{Eq. 4-12}$$

Note that for a given set of gas properties, the critical flowrate is proportional to $\boldsymbol{P_1}$, which is a constant in the wellhead model:

$$q \sim FF_O P_1 \qquad \text{Eq. 4-13}$$

In SCP buildup, the downstream pressure increases. When the downstream pressure exceeds the critical flow pressure, the gas flow rate through the orifice depends on both upstream and downstream pressures, which can be expressed as in *API Standard 520 Part 1* (2014, section 5.6 equation 12 rearranged with C_d replacing various K factors) :

$$q = 6.6881X10^6\,\cdot\,C_d A_o\,\cdot F_2\sqrt{\frac{(P_1)(P_1-P_2)}{ZT_1 MW}} \qquad \text{Eq. 4-14}$$

Where F_2 is defined in *API Standard 520 Part 1* (2014, section 5.6 equation 18):

$$F_2 = \sqrt{\left(\frac{k}{k-1}\right)r^{\left(\frac{2}{k}\right)}\left[\frac{1-r\left(\frac{k-1}{k}\right)}{1-r}\right]}\ and\ r = \frac{P_2}{P1} \qquad \text{Eq. 4-15}$$

Incorporating the orifice flow factor into equation (A-11) gives, for subcritical flow:

$$\boldsymbol{q = 0.01038 \cdot FF_O \cdot F_2 \sqrt{\frac{(P_1)(P_1 - P_2)}{ZT_1 MW}}} \qquad \text{Eq. 4-16}$$

Note that for a given set of gas properties, the sub-critical flowrate is proportional to $\sqrt{\boldsymbol{P_1(P_1 - P_2)}}$:

$$q \sim FF_O \sqrt{P_1(P_1 - P_2)} \qquad \text{Eq. 4-17}$$

Gas Influx Rate for Vein Flow Character

For the vein flow character in the wellhead model, we assume a single pipe represents all defects in the cement. Admittedly, it use of a pipe to characterize a very long, very narrow vein is not correct, but our objective is the pressure function. Methods for calculating flow through pipes are well established in the petroleum industry. For this development we chose to the steady-state, isothermal flow pipeline equation from the *GPSA Engineering Data Book* (2004, equation 17-15):

$$q = 38.77 \left(\frac{T_{SC}}{P_{SC}}\right) E \sqrt{\frac{1}{f_f}} \sqrt{\frac{P_1^2 - P_2^2}{SL_m T_{avg} Z_{avg}}} d^{2.5} \qquad \text{Eq. 4-18}$$

Where E is an empirical efficiency constant, f_f is a friction factor, and S is the specific gravity of the gas. The pipeline dimensions are length L_m in miles and internal diameter d in inches. Re-arranging to group constants, vein dimensions, gas properties and the dynamic pressure parameters:

$$q = 38.77 \left(\frac{T_{SC}}{P_{SC}}\right) E \sqrt{\frac{1}{f_f}} \left(\frac{d^{2.5}}{L_m^{0.5}}\right) \sqrt{\frac{1}{S\, T_{avg} Z_{avg}}} \sqrt{P_1^2 - P_2^2} \qquad \text{Eq. 4-19}$$

We assume that the friction factor f_f is constant, and replace the constants and vein dimensions with a flow factor and proportionality constant selected to provide rough parity with the orifice flow factor in square microns:

$$q = \frac{FF_V}{192.4} \sqrt{\frac{1}{MW\, T_{avg} Z_{avg}}} \sqrt{P_1^2 - P_2^2} \qquad \text{Eq. 4-20}$$

Note that for a given set of gas properties, the flowrate is proportional to $\sqrt{P_1^2 - P_2^2}$:

$$q \sim FF_V \sqrt{P_1^2 - P_2^2}$$

Gas Influx Rate for Porous Character

For the porous flow character in the wellhead model, we begin with the derivation by Craft and Hawkins (1959, equation 6.15 on page 277) for steady-state, linear flow of gases:

$$q = 3.164\left(\frac{T_{SC}}{P_{SC}}\right)\frac{A\ k_e(P_1^2 - P_2^2)}{SL_p T_{avg} Z_{avg}\mu} \qquad \text{Eq. 4-21}$$

Re-arranging to group constants, Darcy path dimensions, gas properties and the dynamic pressure parameters:

$$q = 3.164\left(\frac{T_{SC}}{P_{SC}}\right)\frac{A\ k_e}{L_p}\frac{1}{T_{avg} Z_{avg}\mu}\ (P_1^2 - P_2^2) \qquad \text{Eq. 4-22}$$

The annular cross-sectional area *A* and the leak path length L_p are constant. We assume that the effective permeability k_e is constant, and replace the constants and Darcy path dimensions with a flow factor and proportionality constant selected to provide rough parity with the orifice flow factor in square microns:

$$q = \frac{FF_P}{2.242\ x\ 10^6}\ (P_1^2 - P_2^2) \qquad \text{Eq. 4-23}$$

Note that for a given set of gas properties, the flowrate is proportional to $P_1^2 - P_2^2$:

$$q \sim FF_P(P_1^2 - P_2^2)$$

Gas Migration Through Cement Defects. We assume that the defect is at the top of cement column. Upstream pressure is constant as it is the total of asymptotic pressure and pressure exerted by liquid column at the zero flow condition (A-13). The initial downstream pressure is calculated by the summation of initial gas pressure and hydrostatic pressure in both liquid and cement column. Initial conditions of upstream and downstream pressures are expressed as

$$P_1 = P_{asym} + 0.052\rho_l L_l \qquad \text{Eq. 4-24}$$

$$P_2 = P_G^0 + 0.052\rho_l L_l \qquad \text{Eq. 4-25}$$

After Xu and Wojtanowicz (2001, Equation 2), at n^th time step the upstream and downstream pressures are in forms of :

$$P_1^n = P_{asym} + 0.052\rho_l L_l = \text{constant} \qquad \text{Eq. 4-26}$$

$$P_2^n = P_g^{n-1} + 0.052\rho_l L_l \qquad \text{Eq. 4-27}$$

Gas Migration Through Tubular Defects. We assume the location of the defect is above any liquid level and that the source pressure is in an adjacent annulus or tubular string of known and relatively constant pressure. (A common example of this is the provision of gas lift gas on the "A" annulus, leading to SCP on the "B" annulus.)

$$P_1 = P_{asym} \qquad \text{Eq. 4-28}$$

$$P_2 = P_g^0 \qquad \text{Eq. 4-29}$$

At n[th] time step the upstream and downstream pressures are in forms of:

$$P_1^n = P_{asym} \quad \text{Eq. 4-30}$$

$$P_2^n = P_g^{n-1} \quad \text{Eq. 4-31}$$

The SCP-derived FF is calculated in square microns. For a given defect character, the coefficient which best matches the wellhead model to the observed pressure build-up data and gas chamber volume was used. Though the units are square microns for all characters, the flow factors are not interchangeable; for the same data, the flow factor (orifice) is not the same as the flow factor (porous).

With the Wellhead Model, the plot of rate versus time can provide an indication of the flow character as shown on Figure 4-8. The orifice model is characterized by constant rate early in the build-up followed by a decline to zero rate that ends abruptly. Data with this character suggests defects that are very close to the gas chamber. The vein model does not have a constant rate at the beginning, but ends abruptly at zero rate. This character suggests defects like cracks where the gas passes through a long narrow channel before reaching the gas chamber. The rate for the porous model is higher in early time and tapers to zero over a longer time frame. This character suggests the rate-limiting resistance could be porous cement or could be from a porous reservoir.

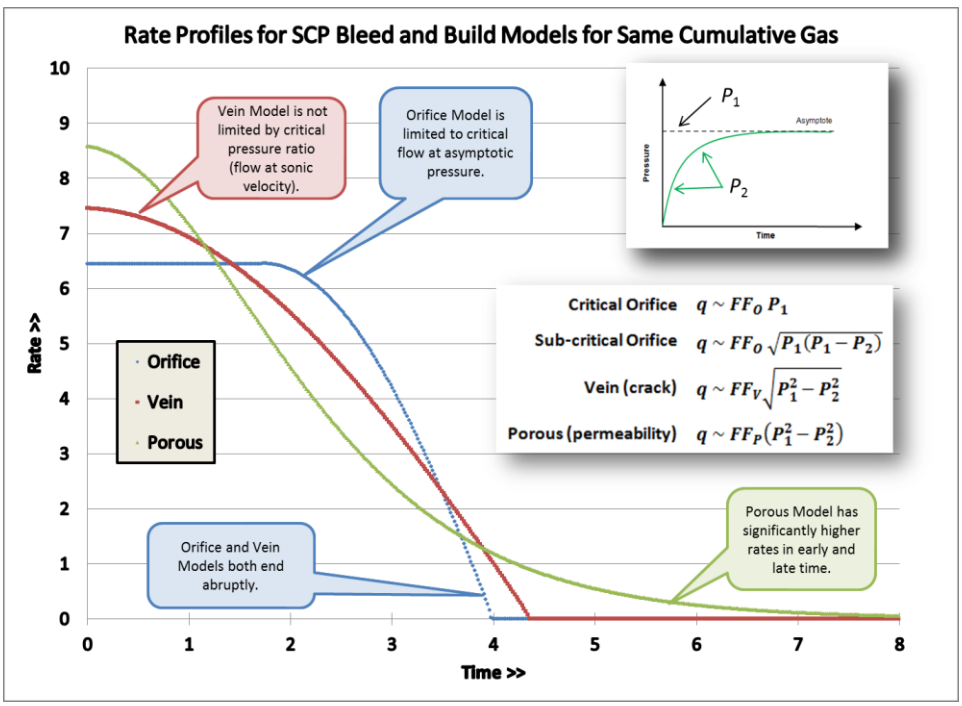


Figure 4-8. Rate Profiles for SCP Test for Same Cumulative Gas

Operational Metrics

Together, the asymptotic pressure P_{asym} and the appropriate factor FF_x generate the base SCP pattern that best matches the observed dynamic data. However, the flow factor is not directly useful in communicating the potential impact of the defective seal. We therefore introduce two associated metrics that are related to possible impacts.

First, the quantity of gas stored in the gas chamber could be released suddenly if the annulus was breached. The greater the gas chamber volume and the greater the asymptotic pressure, the greater the quantity of gas:

$$IRM = \frac{P_{asym}}{P_{sc}} \cdot \frac{V_{g,a}}{1000} \qquad \text{Eq. 4-32}$$

Secondly, a small leak could drop the annulus to atmospheric pressure. The sustained leakage metric, SLM, is appropriate rate equation evaluated with P_2 equal to atmospheric pressure. The units are thousands of standard cubic feet per day which is an appropriate scale for this metric.

For a case with orifice character, the maximum sustained release would be the critical rate through the hypothetical orifice:

$$SLM_O = \frac{0.007335}{1000}\, FF_O\; P_1 \sqrt{k \left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}} \frac{1}{ZT_1 MW}} \qquad \text{Eq. 4-33}$$

For a case with vein character, the maximum sustained release is:

$$SLM_V = \frac{FF_V}{192.4}\,\frac{1}{1000}\sqrt{\frac{1}{MW\, T_{avg} Z_{avg}}}\,\sqrt{P_1^2 - P_{atm}^2} \qquad \text{Eq. 4-34}$$

For a case with porous character, the maximum sustained release is:

$$SLM_P = \frac{FF_p}{2.242\ x\ 10^6}\frac{1}{1000}\left(P_1^2 - P_{atm}^2\right) \qquad \text{Eq. 4-35}$$

Well Site Description

This section summarizes the general well description, geology, and construction specifications for the wells monitored for SCP buildup. This information helps explain the nature of the casing pressure buildup.

4.1.6 AB-1 (WV Well)

4.1.6.1 Geology

In terms of geology, well AB-1 penetrated through the entire Paleozoic interval into Precambrian age rocks, but it was plugged back to the Cambrian Copper Ridge Dolomite. The well penetrated several gas-producing zones, especially the middle Devonian Marcellus Shale, which had significant gas shows. Otherwise, the well mostly penetrated low-permeability Cambrian rocks. The site was located near the Rome Trough, where rocks dip relatively steeply to the southeast. However, there are few geologic features in the general area.

4.1.6.2 Well Construction

Well AB-1 was constructed with six casing strings (Figure 4-9). The two deep casing strings and the surface casing strings were cemented to the surface. Some of the intermediate casing was cemented past the next casing string. Production casing was run to the wells' total depth and perforated across several hundred feet to facilitate gas injection.

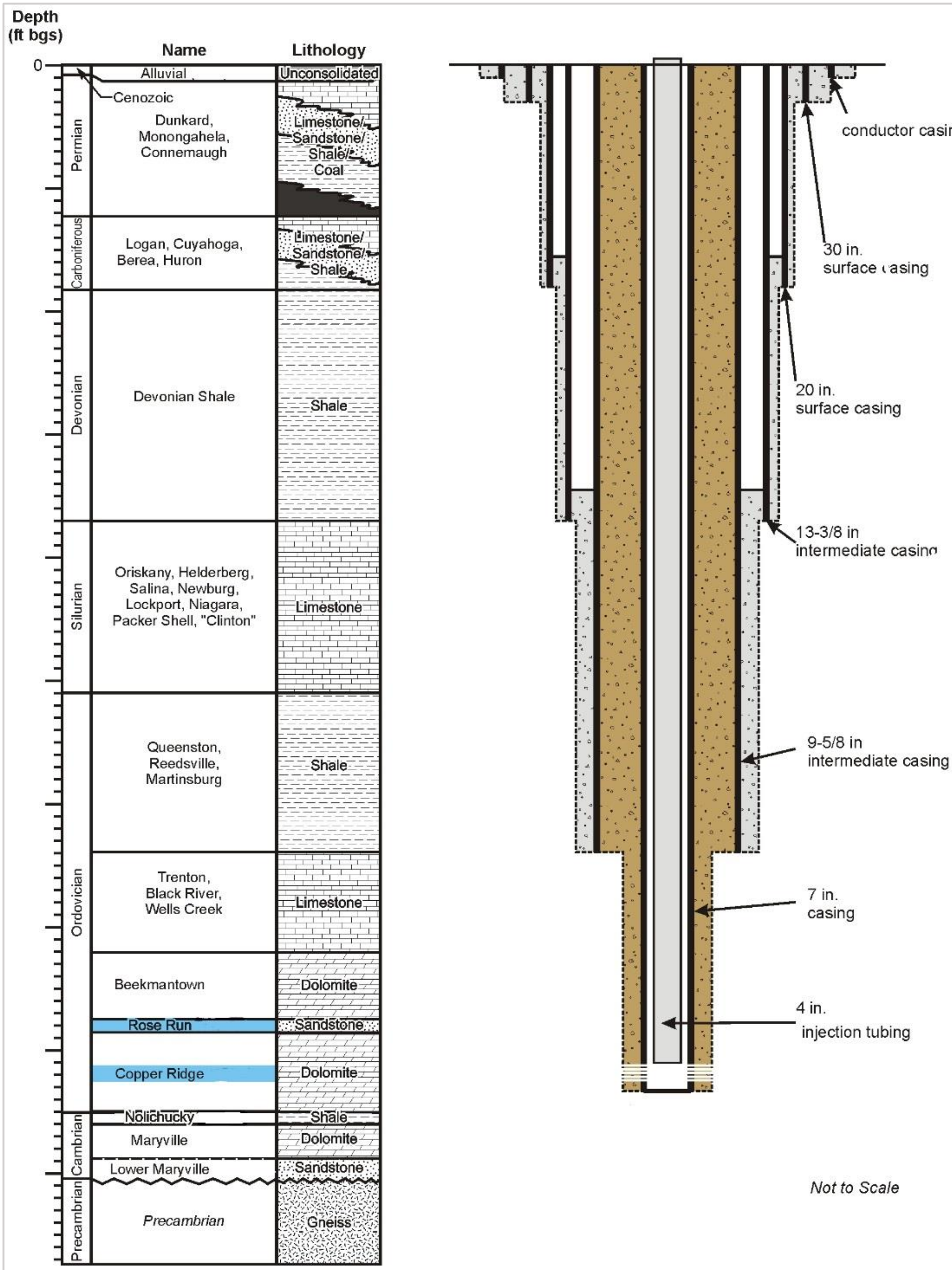


Figure 4-9. AB-1 Well Diagram and Geologic Column

4.1.6.3 Well History

Well AB-1 was a deeper well (greater than 8,000 feet) located in the central Appalachian Basin. The well was completed in the early 2000s as an exploration well. The well was operated for gas injection for about a year, but then it was shut in and eventually plugged and abandoned. The SCP testing was completed when the well was shut in. Overall, this well represents a newer, deep well with multiple casings cemented to the surface.

4.1.7 AB-2 through AB-5 (Guernsey County, Ohio)

4.1.7.1 Geology

Wells AB-2 through AB-5 are completed into the lower Devonian Oriskany Sandstone, which is a thin, localized field (Opritza, 1996; Patchen and Harper, 1996; Diecchio, 1985). In general, the wells are located in the western flank of the Appalachian Basin, where rocks dip gently to the east-southeast. The wells penetrate undifferentiated Pennsylvania-Mississippian rocks in the first few hundred feet. The local driller's 'Injun-Squaw' may have gas shows. At the top of the Devonian section, the Berea Sandstone may produce gas and/or water, and most wells run surface casing through the Berea. The deeper Devonian Shale units also contain mostly shale, with some gas zones in the lower interval. The Onondaga Limestone overlies the Oriskany and may have some hydrogen sulfide, which could cause corrosion.

4.1.7.2 Well Construction

Wells AB-2 through AB-5 were mostly completed with conductor, surface, and production casing (Figure 4-10). In general, the surface casing was run through the Berea Sandstone and cemented through the undifferentiated Pennsylvanian-Mississippian section. The production casing was cemented several hundred feet above the perforated zone into the lower Devonian rocks. The wells had an open-hole section in the upper Devonian shale. Many of the wells had some degree of well maintenance and repairs such as replacing sections of casing, cement squeeze jobs, and wellhead repairs.

4.1.7.3 Well History

Wells AB-2 through AB-5 were initially completed for production in the 1940s-1960s and later converted for gas storage. The wells have been operating for several decades and are subject to various levels of well maintenance. Overall, the wells are representative of older wells in the region, which have been exposed to subsurface conditions for 50+ years.

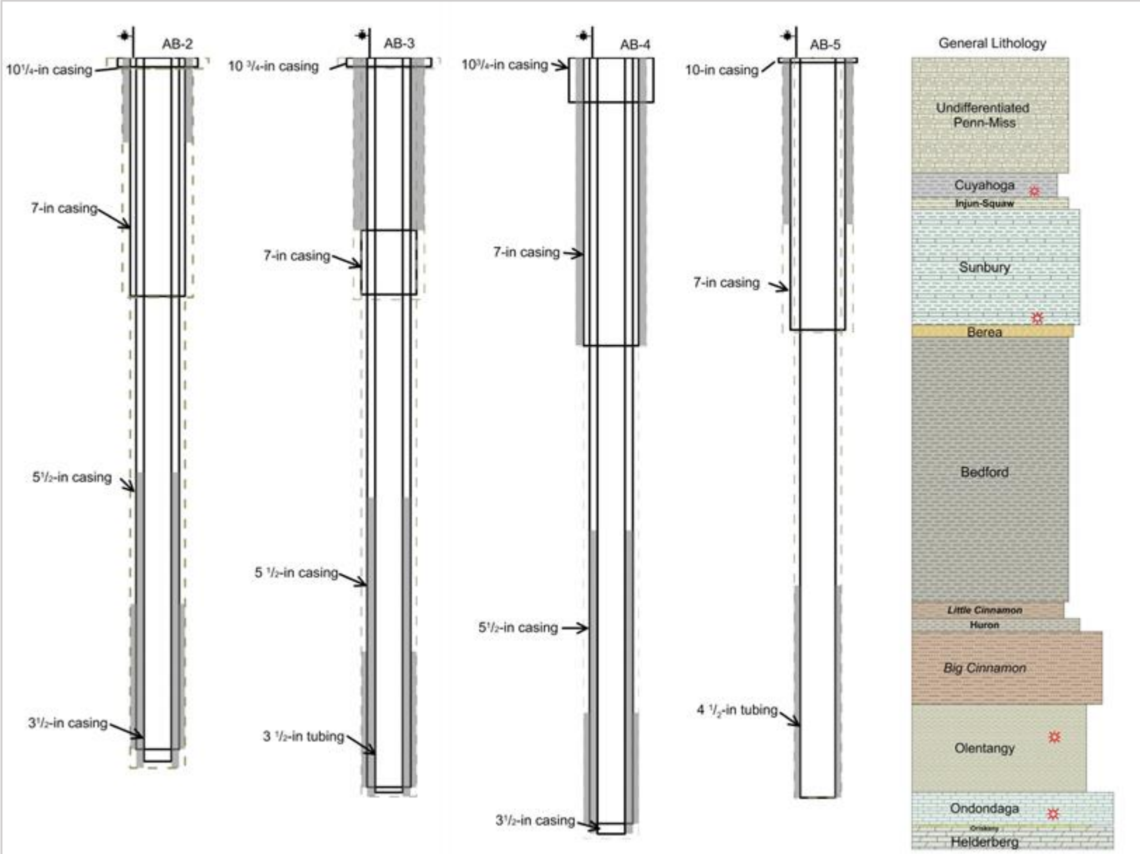


Figure 4-10. AB-2 through AB-5 Well Diagrams and Geologic Column

4.1.8 AB-6 through AB-12 (N. Canton, Ohio)

4.1.8.1 Geology

Wells AB-6 through AB-12 penetrate the Clinton and Medina Sandstones, which contains many hydrocarbon fields in the region. Rocks dip gently to the east-southeast in the northwest Appalachian Basin. Overall, the wells penetrate mainly Mississippian rocks in the first 50 to 100 feet, and most wells are cased off across the 'Big Injun' sandstone with conductor. The wells also case off through the Berea Sandstone. The wells penetrate a fairly thick section of Devonian shale into the Silurian carbonates, salts, and shales. The wells were completed in the Clinton and Medina Sandstones Overall, there are thousands of 'Clinton' wells across the Appalachian Basin, so the geology has been fairly well characterized (McCormac et al., 1996; Laughrey, 1984; Piotrowski, 1981).

4.1.8.2 Well Construction

Wells AB-6 through AB-12 generally contain two or three casing strings, as illustrated in Figure 4-11 for AB-6 through AB-9. The wells were cemented to surface across all casing strings. Three of the wells were newer, directional wells drilled off the same well pad as another well. As with most areas in the Appalachian Basin, there are several formations that can produce gas in intermediate zones. In this case, several intervals of Devonian Shale may produce natural gas.

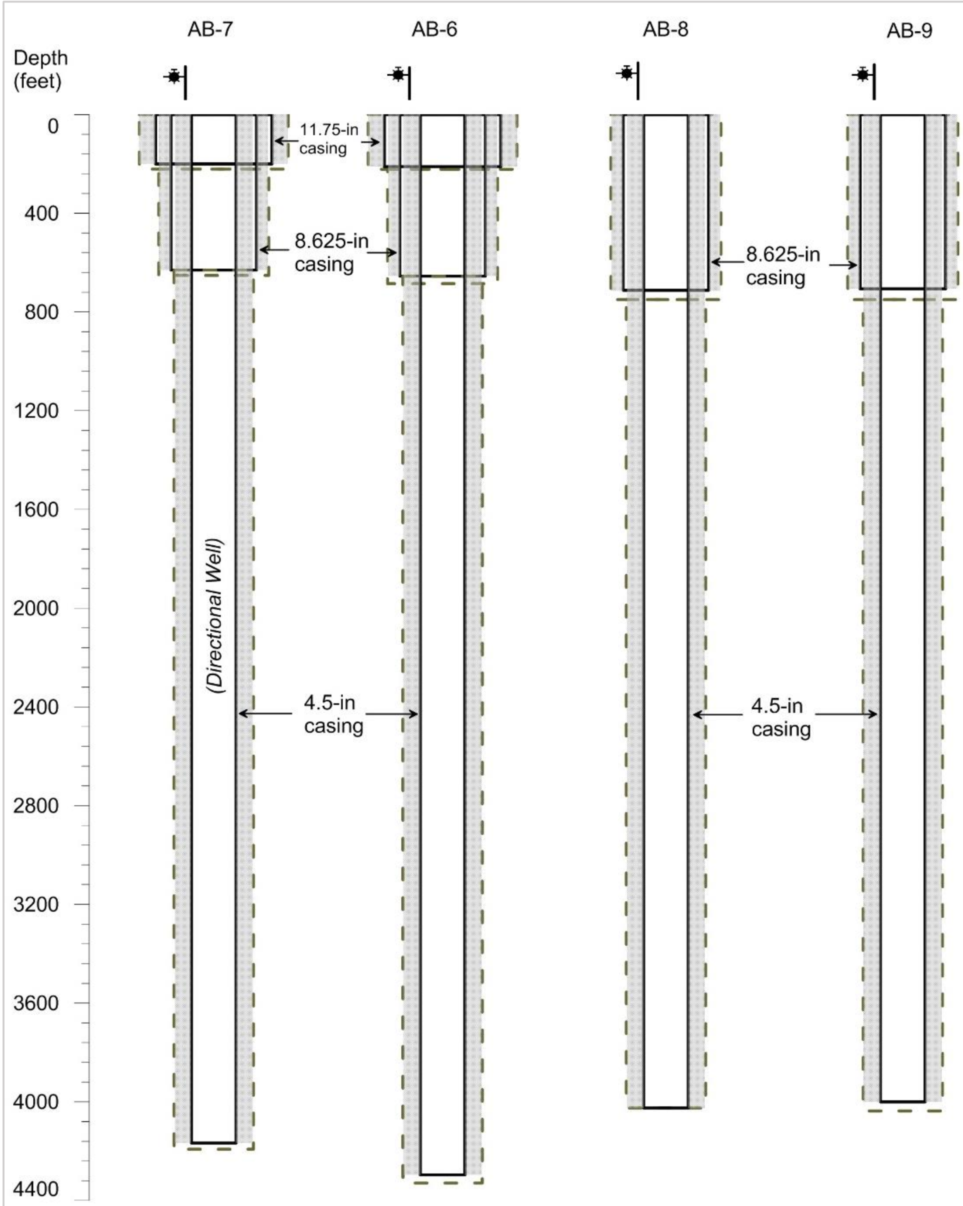


Figure 4-11. AB-6 through AB-9 Well Diagrams

4.1.8.3 Well History

Wells AB-6 through AB-12 were located in the northwestern Appalachian Basin. The wells were drilled from the early 1970s to the late 2000s. The wells were operated for gas storage operations. They are typical of many of the oil and gas wells drilled from the 1970s to 2000s in the Appalachian Basin, when the Clinton and Medina play was developed in the region. There are tens of thousands of these wells in the region. Many of these Clinton fields have been drilled on 40-acre spacing, and infill drilling is not unusual.

4.2 Field SCP Monitoring Results

4.2.1 AB-1

4.2.1.1 Pressure Analysis

AB-1, a gas injection well, exhibited SCP on the “A” annulus between the 9 $^5/_8$ -inch intermediate and 7-inch production casings. Injection into the well had ended and it was being prepared for P&A when the dynamic data were taken.

On March 3, 2014, the well was found with about 1,200 psia “A” annulus pressure. After gas samples were taken, this annulus was vented to the atmosphere, then shut in with a recording pressure gauge attached. Within two weeks, the pressure had stabilized and the gauge was removed after collecting 16 days of data (Figure 4-12). When the gauge was removed, a flow-rate meter was used to measure the quantity of gas in order to estimate the volume of the gas chamber. Using the ideal gas law, the gas chamber volume was found to be about 2 cubic feet. The pressure on the “B” annulus (9-5/8 inch:7 inch with Top of Cement (TOC) at 2,600 feet) was observed by operators and remained at a steady 25 pounds per square inch gage (psig) for the entire period. Figure 4-13 shows the reduced data curve and SCP model. The curve correlation coefficient of 0.98 suggests strong correlation to the model.

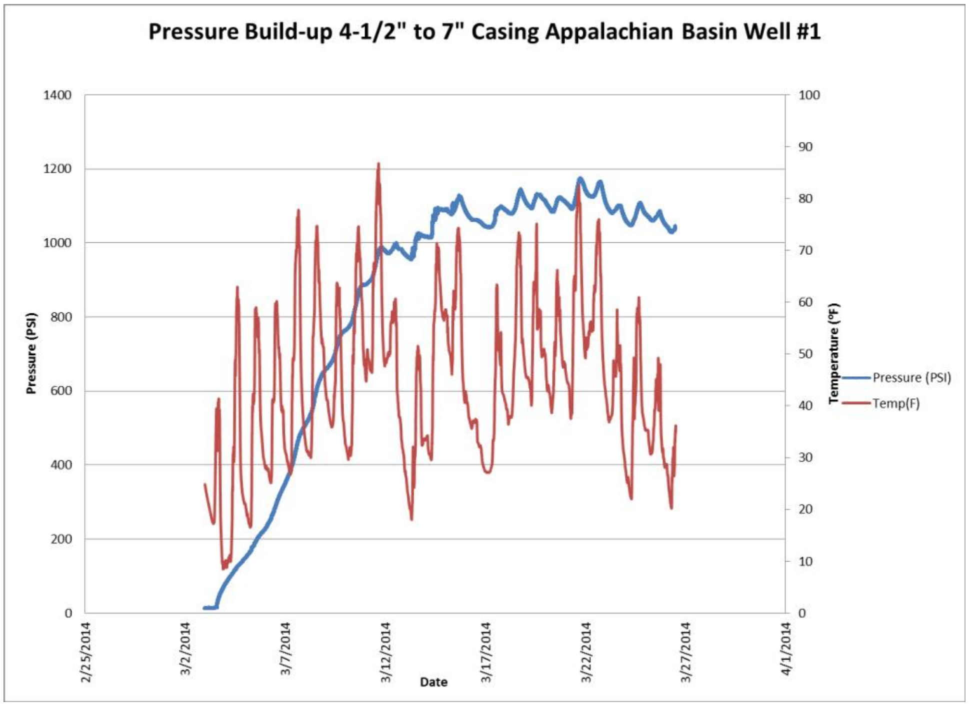


Figure 4-12. SCP build-up in AB-1.

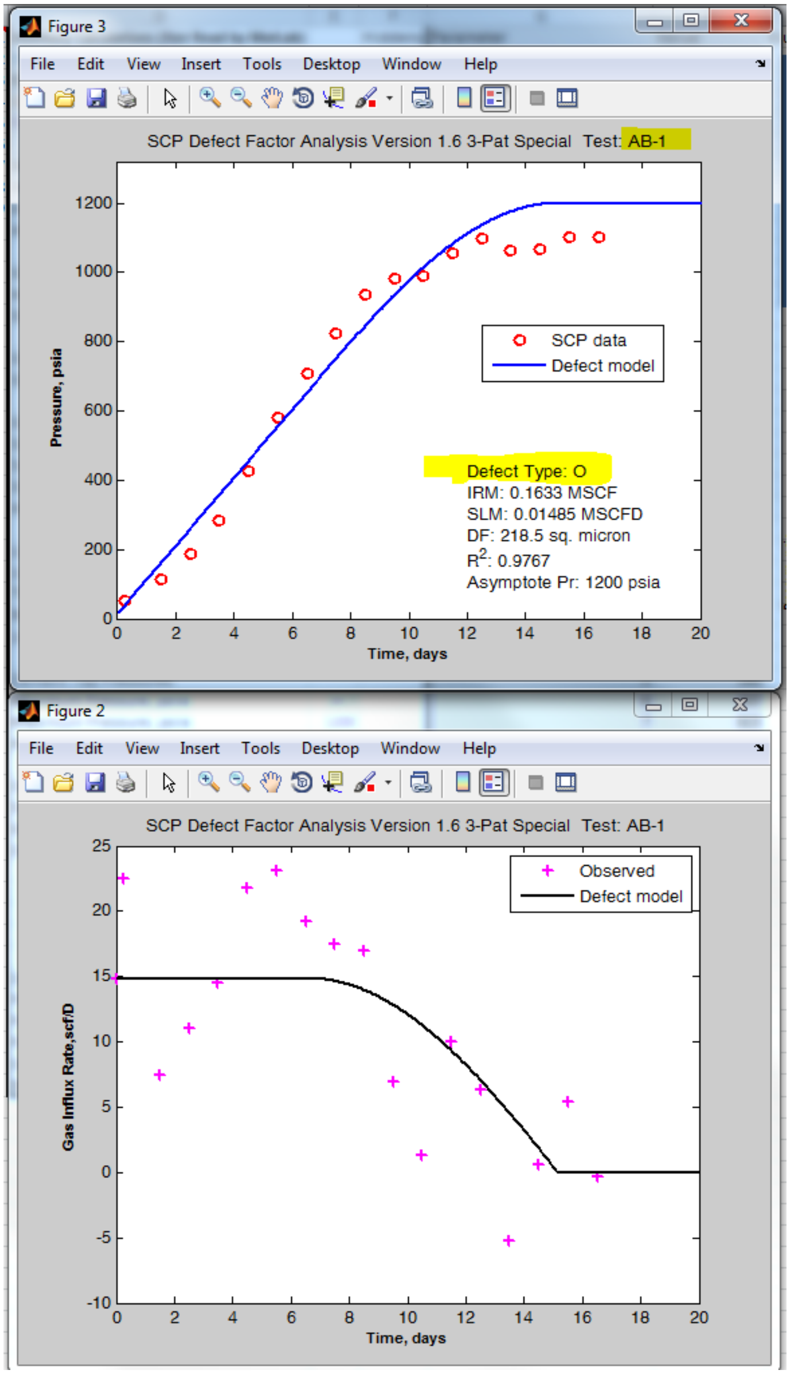


Figure 4-13. SCP well IF model for AB-1 test.

Input data for the IF calculation are shown in Table 4-5. Using the cement integrity equation, the well IF is 220 square microns. The precise source of the gas is not known; however, the gas analysis showed a natural gas signature (89% C_1, 7% C_2, 0.02% CO_2) in the annulus. Based on the composition, it is not sourced from the injection zone below 8,144 feet, and it is highly unlikely that the source is above the 7-inch casing string set at 6,300 feet.

Table 4-5. Input Parameters for Well AB-1 Cement IF Model

Parameter	Value
Integrity type (C or T)	C
Asymptotic pressure, psia	1,200
Initial volume of gas chamber, ft^3	2.00
Temperature of gas chamber, deg F	55
Gas compression Z in chamber, dim.	0.91
Gas molecular weight, lb/lbmol	16.04
Gas specific heat ratio k, dim.	1.31
Liquid volume, ft^3	0
Initial true vertical liquid, ft	N/A
Liquid compressibility, psi-1	N/A
Liquid density, ppg	N/A
Gas compression Z at source, dim.	0.91
Cement top temperature, deg F	55

Note: ft^3 = cubic feet
ppg = pounds per gallon

Using this range of possible sources, an attempt was made to analyze the SCP data with the porous cement model. A range of reasonable assumptions regarding source depth, source pressure, and the implied gradient in the cement path allowed cement permeability to be estimated in the traditional Xu manner.

The rock/cement/steel system in this well effectively sealed against the gas storage zone, as evidenced by the gas composition. The observed SCP was unrelated to the completed injection zone. In this case, the presence of SCP is not a reliable indicator of the quality of the cement seal at depth.

4.2.1.2 Gas Analysis

Two gas samples were collected from the annulus of well AB-1 on the same date. The mole percentages and specific gravities were averaged to represent both samples. The gas sample was dominantly methane (88%), with trace amounts of ethane. The gas composition is similar to gas produced from the Utica formation. The gas from the Utica could have migrated into the annulus. Figure 4-14 shows the gas composition for well AB-1.

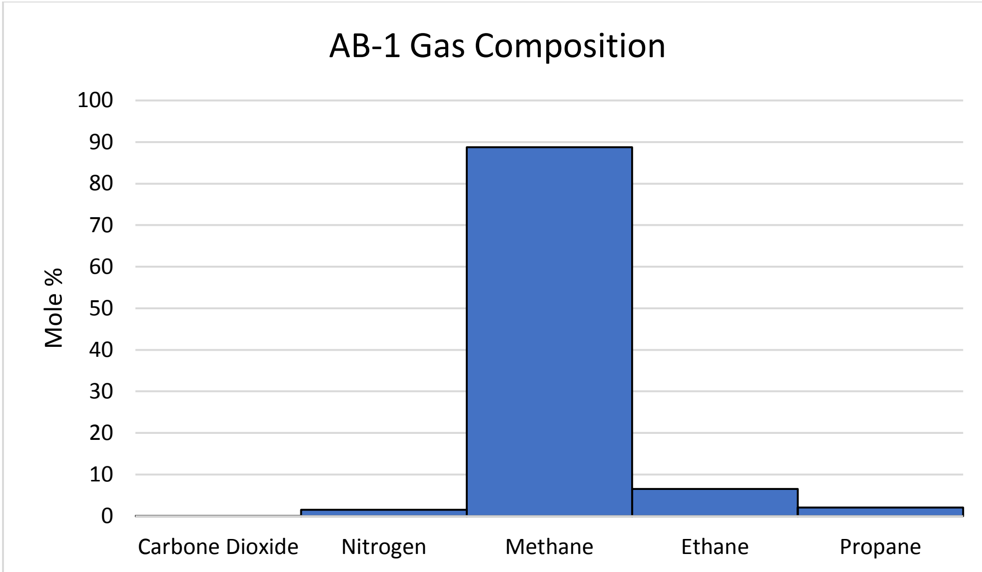


Figure 4-14. Gas Composition of Samples Collected at Well AB-1

4.2.2 AB-2 through AB-5

4.2.2.1 Pressure Analysis

Four wells in east-central Ohio were selected for SCP testing. All wells are currently storing pipeline-quality gas in the Oriskany formation at about a 3,000-foot depth, and have been doing so for a substantial period of time. The wells had a variety of different wellbore configurations, and not all annuli were accessible at the surface.

On November 5, 2013, a gas sample was taken from a selected annulus on each well. That annulus was then vented to atmospheric pressure and shut in with a surface memory gauge recording the pressure. The recording gauges remained in place until the third week in February. After the gauges were removed, an attempt was made to determine the fluid level in each tested annulus using an Echometer™. Finally, a second gas sample was taken on the AB-2 and AB-3 wells on April 7, 2014.

All four wells exhibited SCP; that is, after bleeding off, the annulus re-pressurized (Figures 4-15 through 4-18). As shown, the pattern included early rapid pressure build-up in the first 24 to 48 hours, followed by a mid-time segment in which pressure increased at a decreasing rate. Finally, on two of the wells, the pressure stabilized at a nearly constant value before the end of the observation period.

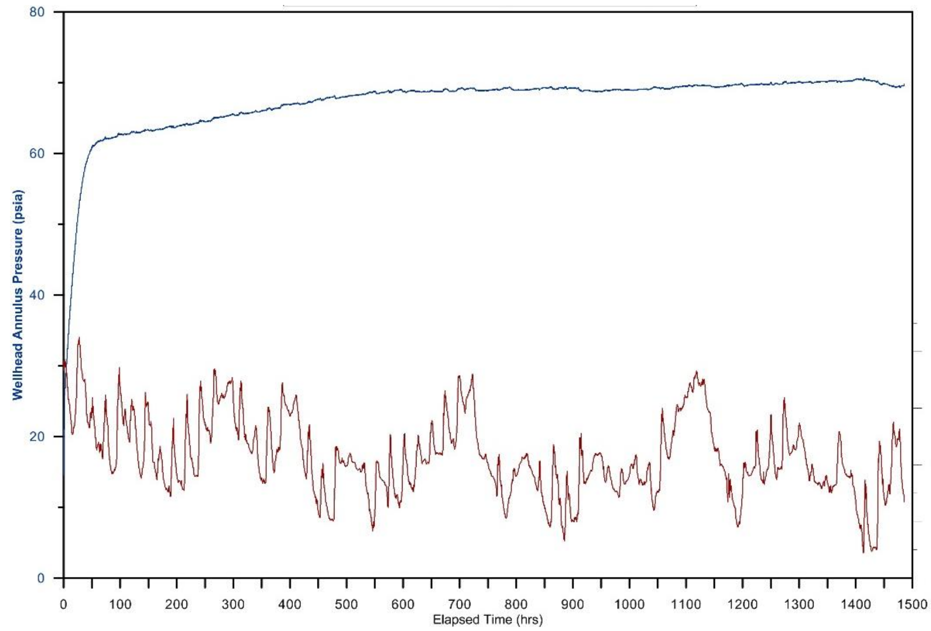


Figure 4-15. Field Test Data for Well AB-2

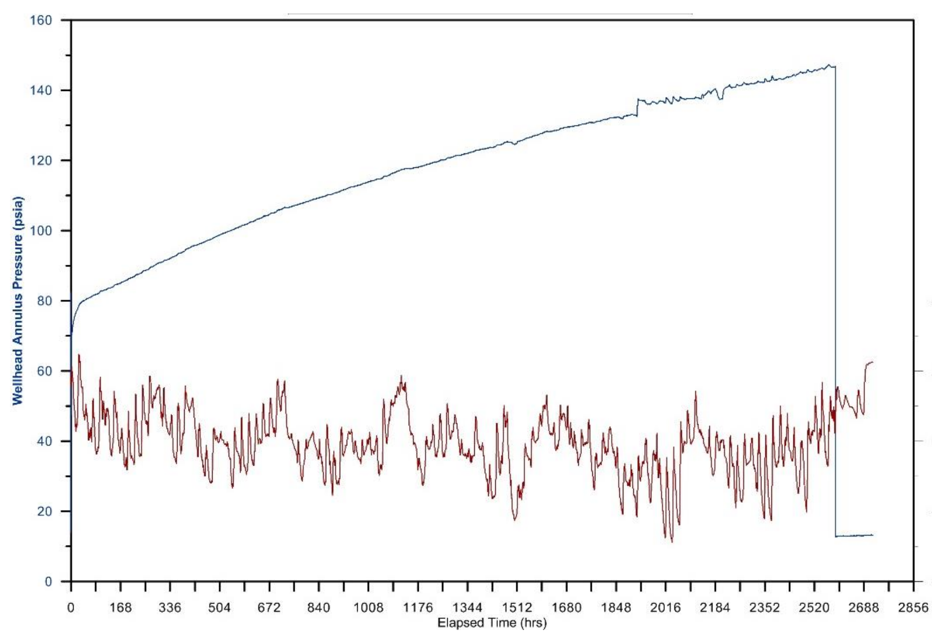


Figure 4-16. Field Test Data for Well AB-3

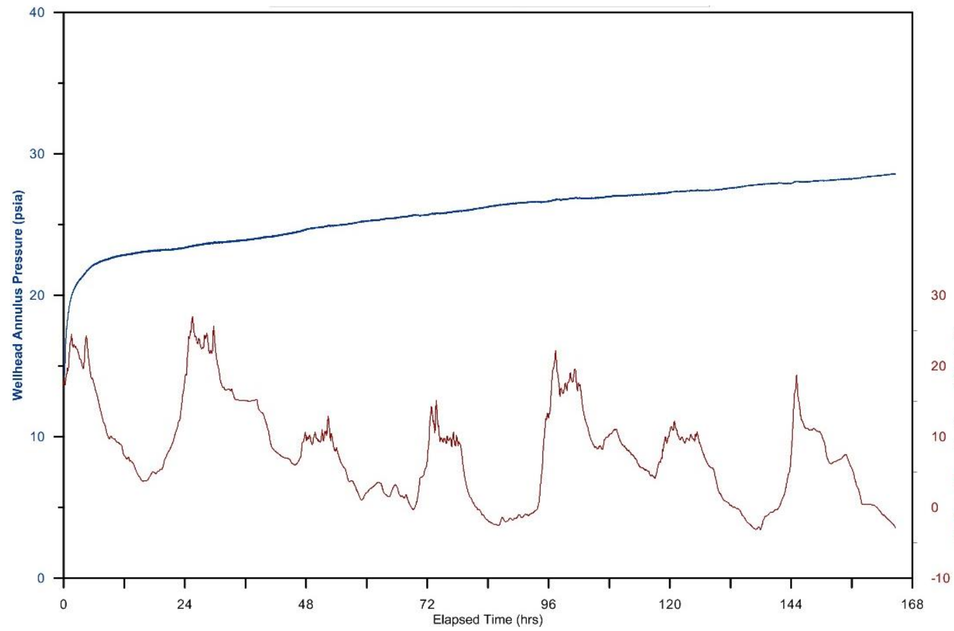


Figure 4-17. Field Test Data for Well AB-4

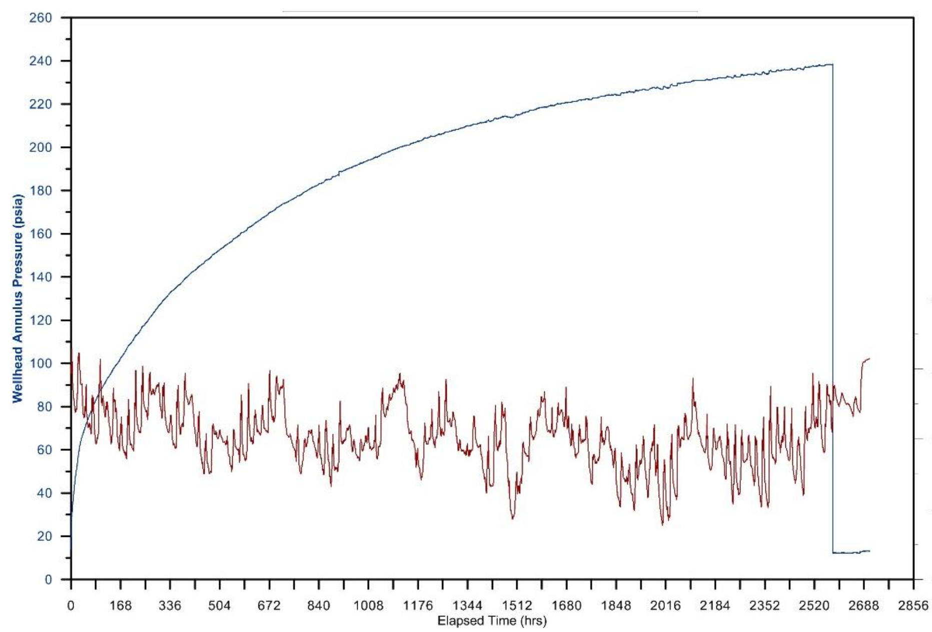


Figure 4-18. Field Test Data for Well AB-5

Analysis indicate gas is entering the measured annulus from some source. Three of the wells were predominantly hydrogen. The source cannot be determined with the information gathered. According to Stout and Schremp (1959), hydrogen is formed on the casing when cathodic protection is applied. Further investigation would be required to determine the actual source of the hydrogen.

Well AB-5, which was the only well with a large gas chamber, was the only well that did not show significant hydrogen. The composition of the gas recovered was consistent with a natural gas, not storage gas. The source of the gas is unknown; it may be unrelated to the cement seal across and above the injection zone.

Based on the observations of wells alone, SCP can occur and be influenced by factors other than the cement seepage from the completed zone. Given these alternative factors, it is clear that the presence of SCP is not a reliable indicator of the quality of the cement seal at depth for these tested wells.

4.2.2.2 Gas Analysis

Three gas samples were collected in the annulus of well AB-2 in the years 1992, 1999, and 2014. The mole percent of methane decreased from 78% to 35%, and the hydrogen increased from 12% to 58% from 1992 to 2014. The specific gravity (measured at 60ºF) decreased from 0.55 to 0.31. Contributions and changes of nitrogen, CO_2, ethane, and propane were minor. Figure 4-19 shows the changes in gas composition for well AB-2.

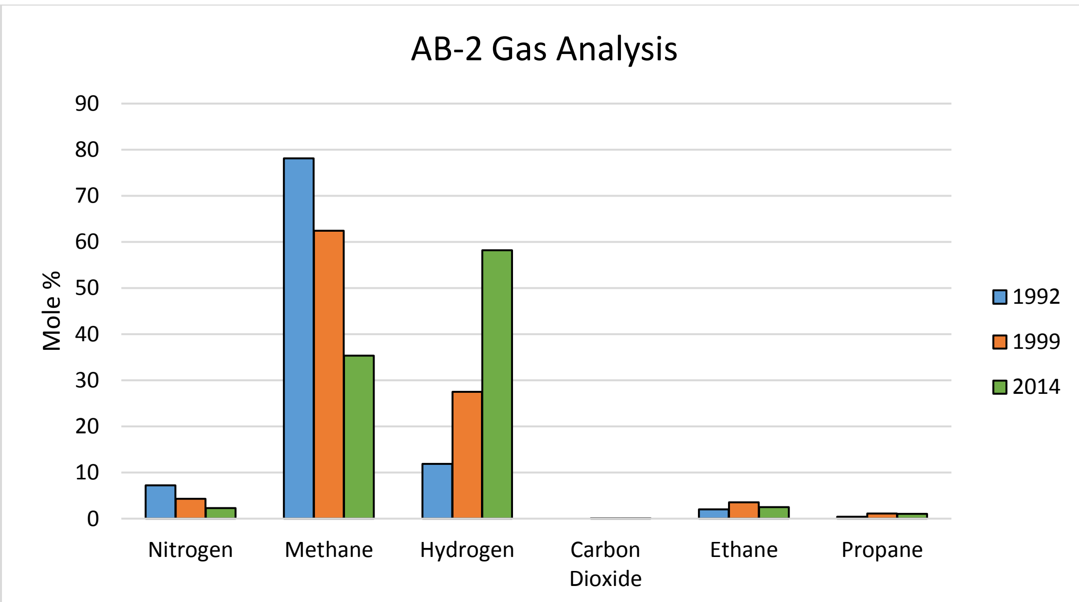


Figure 4-19. Gas Composition of Samples Collected at Well AB-2

4.2.3 AB-6 through AB-13

4.2.3.1 Pressure Analysis

Wells AB-6 to AB-13 were all natural gas storage wells completed into a sandstone formation at about a 4,000-foot depth. The eight wells tested were selected from a pool of about 800 well candidates on the basis that they were more prone to SCP than others. The sample set, therefore, is heavily biased toward problem wells. In all eight cases, the 'A' annulus (4-1/2-inch-long string inside 8-5/8-inch surface casing) was cemented to surface.

The wells were tested in Spring-Fall 2014. The wells exhibited SCP ranging from 300 to 700 psia. Figures 4-20 through 4-27 show the field testing data. Several of the tests were repeated to obtain repeat test data. Some of the wells appeared to show a pressure decrease after initial pressure build-up, which may be related to field operations or wellhead equipment.

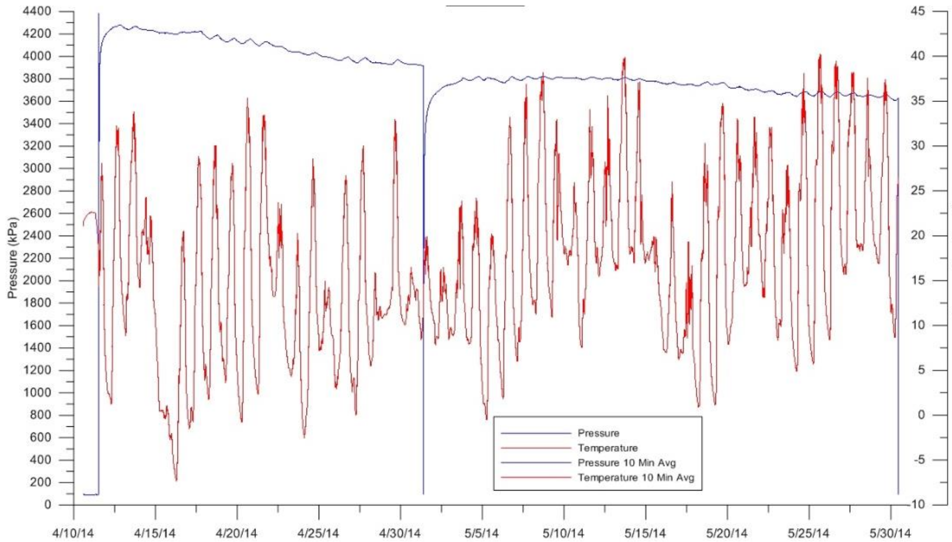


Figure 4-20. Field Test Data for Well AB-6

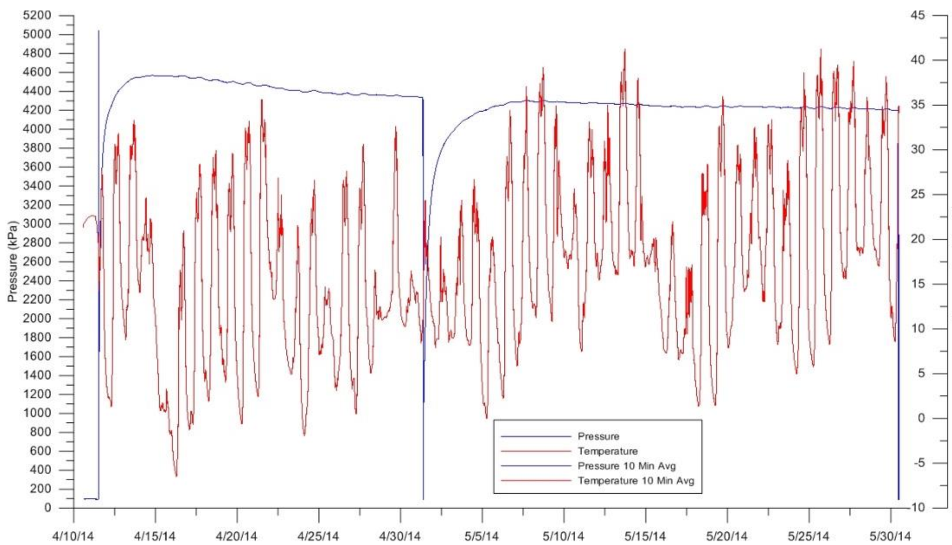


Figure 4-21. Field Test Data for Well AB-7

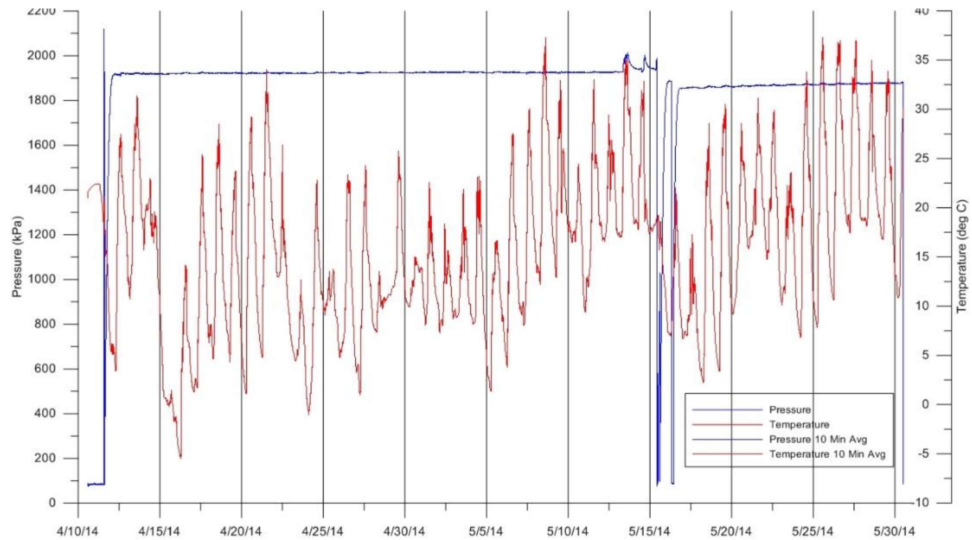


Figure 4-22. Field Test Data for Well AB-8

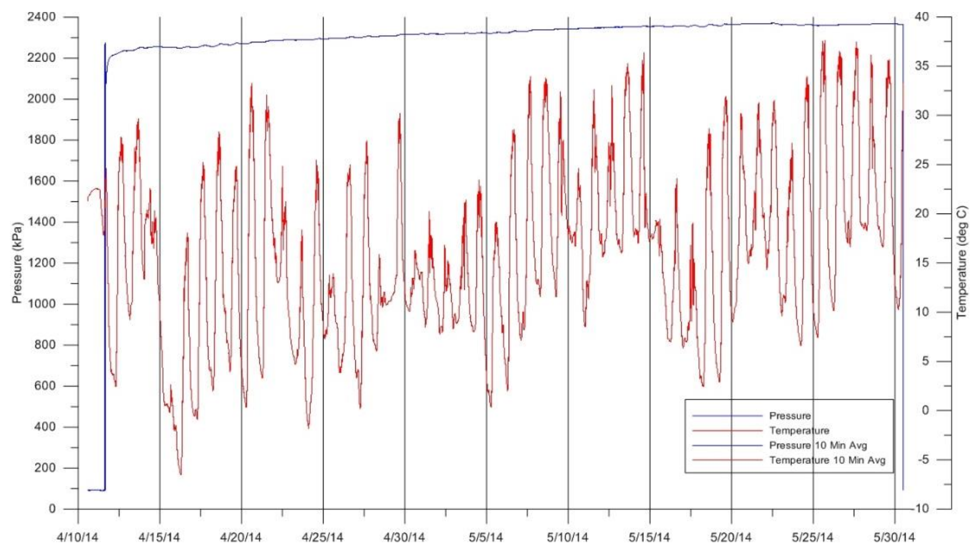


Figure 4-23. Field Test Data for Well AB-9

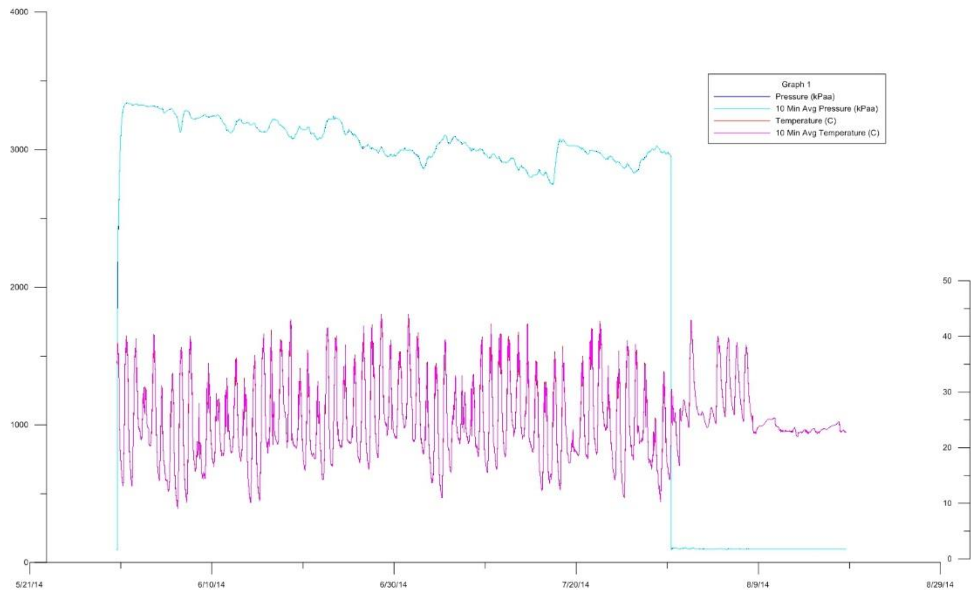


Figure 4-24. Field Test Data for Well AB-10

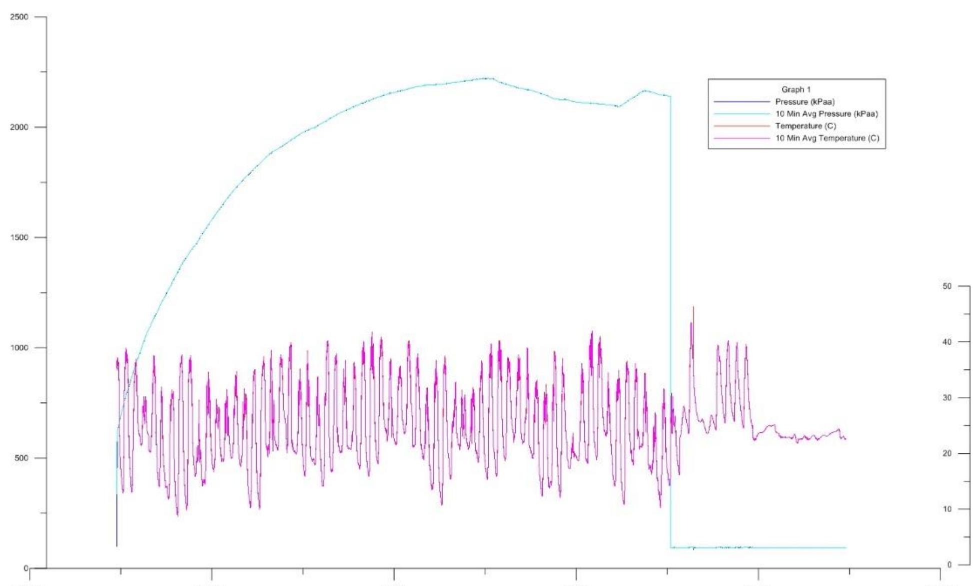


Figure 4-25. Field Test Data for Well AB-11

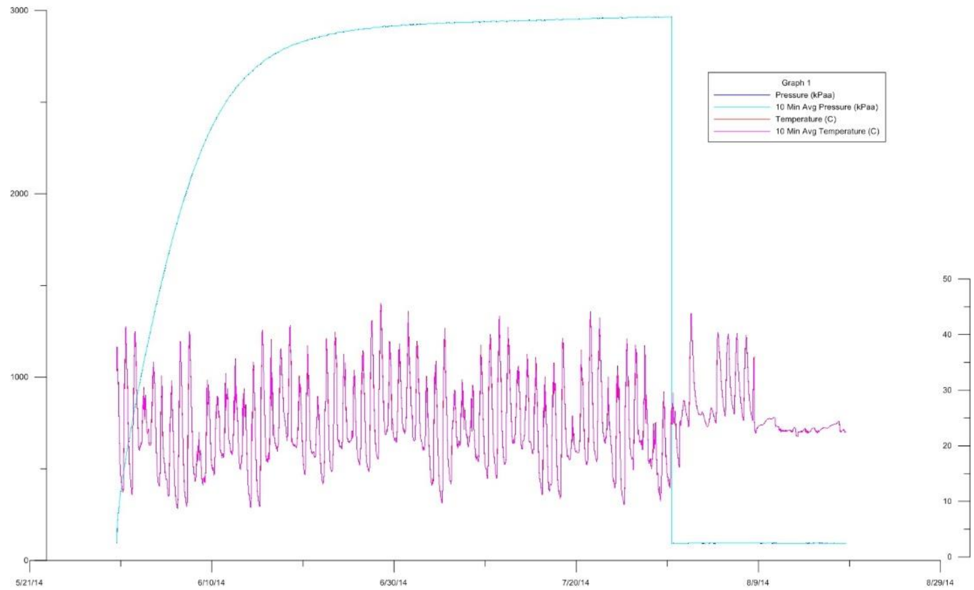


Figure 4-26. Field Test Data for Well AB-12

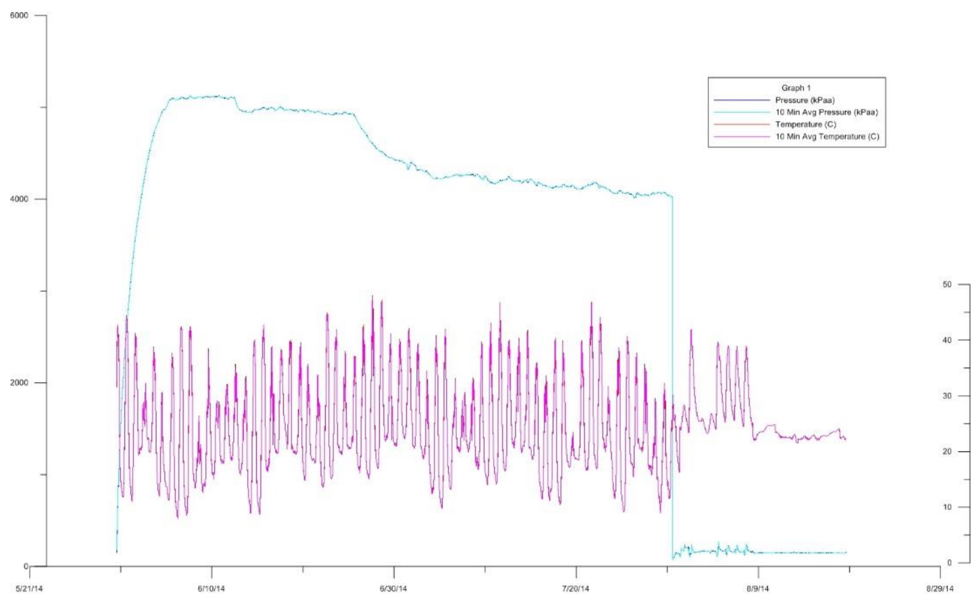


Figure 4-27. Field Test Data for Well AB-13

For six of the wells, analysis of the accumulated gas causing the casing pressure was not consistent with the gas composition from the completed zone. For these wells, the presence of SCP is not a reliable indicator of the cement seal at depth. On the final two wells, the accumulated gas composition was consistent with the gas in the completed zone. However, it is possible that the source gas leak path was in the wellhead. For seven of the tests, a flow factor was calculated, but there is no way to know whether the limiting flow resistance was the cement or the low-permeability source formation. The flow factors (orifice) ranged from 60 to 19,000 square microns, a variability of three orders of magnitude across a well set biased toward high flow factors.

Figures 4-28 through 4-34 show the well IF analysis for the pressure build-up in wells AB-6 to AB-13. Well AB-10 produced water and was removed from the analysis. Wells AB-11 and AB-12 appeared to reflect a mechanical disruption, possibly in the casing or wellhead equipment. Wells AB-10 and AB-13 had ragged declines after they reached maximum pressure and very different gas chamber volumes. Wells AB-6 and AB-7 also had a decline in pressure after reaching maximum SCP pressure, which may be related to nearby gas production. Wells AB-8 and AB-9 built up SCP very quickly, followed by a slow, minor increase in pressure. Many of the wells may have had pressure changes related to seasonal temperatures in the subsurface, cathodic protection, or other wellhead appurtenance issues. Therefore, analysis was based on general pressure build-up curves.

Calculated well IFs ranged from 60 to 19,000 square microns, reflecting a wide range of well integrity. The factors relate to the magnitude of the SLM; wells with a higher IF have larger SLM. The IRM was generally low (less than 200 cubic feet) and was more related to the gas chamber volume in the annulus.

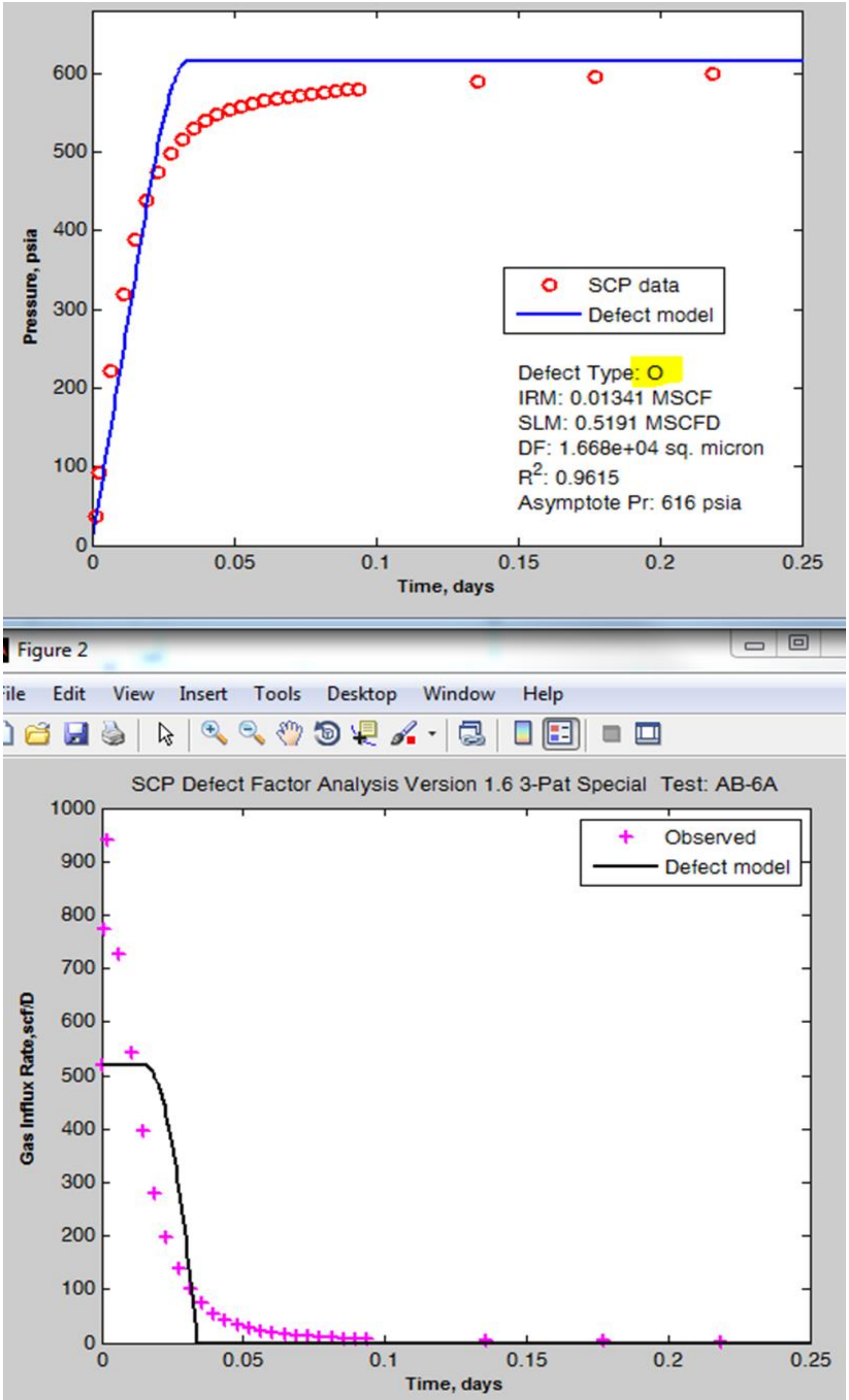


Figure 4-28. SCP Analysis for Well AB-6

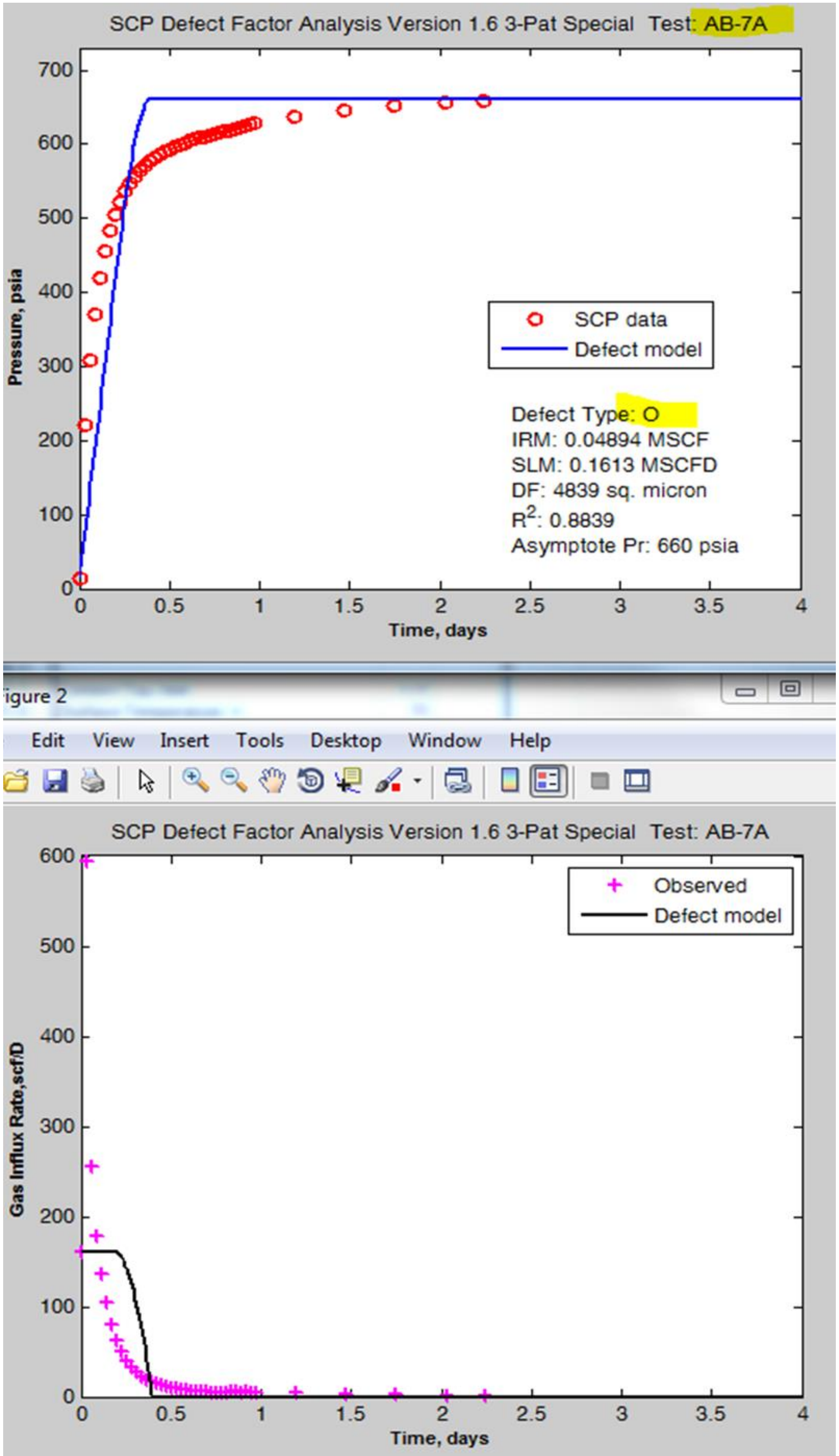


Figure 4-29. SCP Analysis for Well AB-7

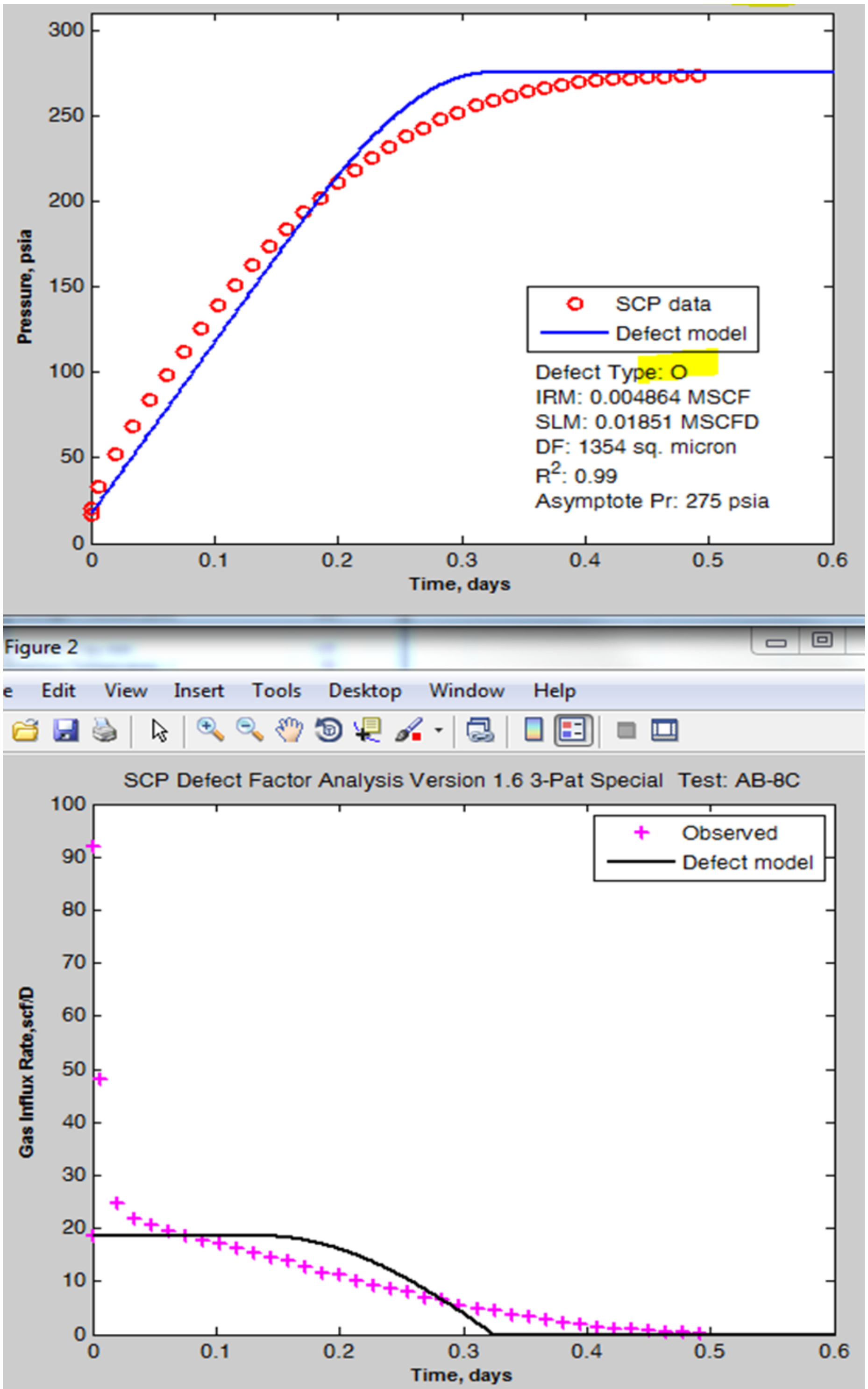


Figure 4-30. SCP Analysis for Well AB-8

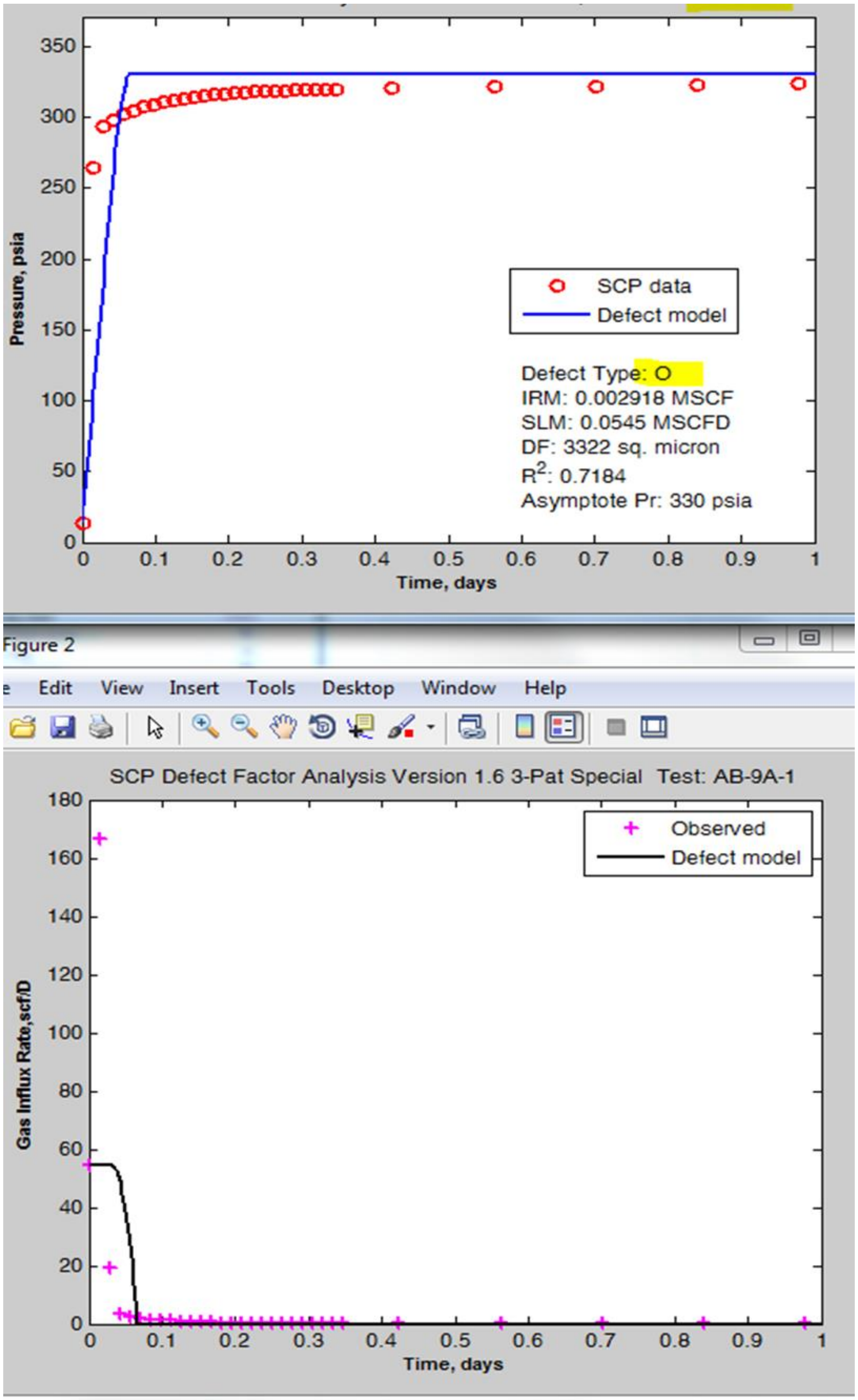


Figure 4-31. SCP Analysis for Well AB-9

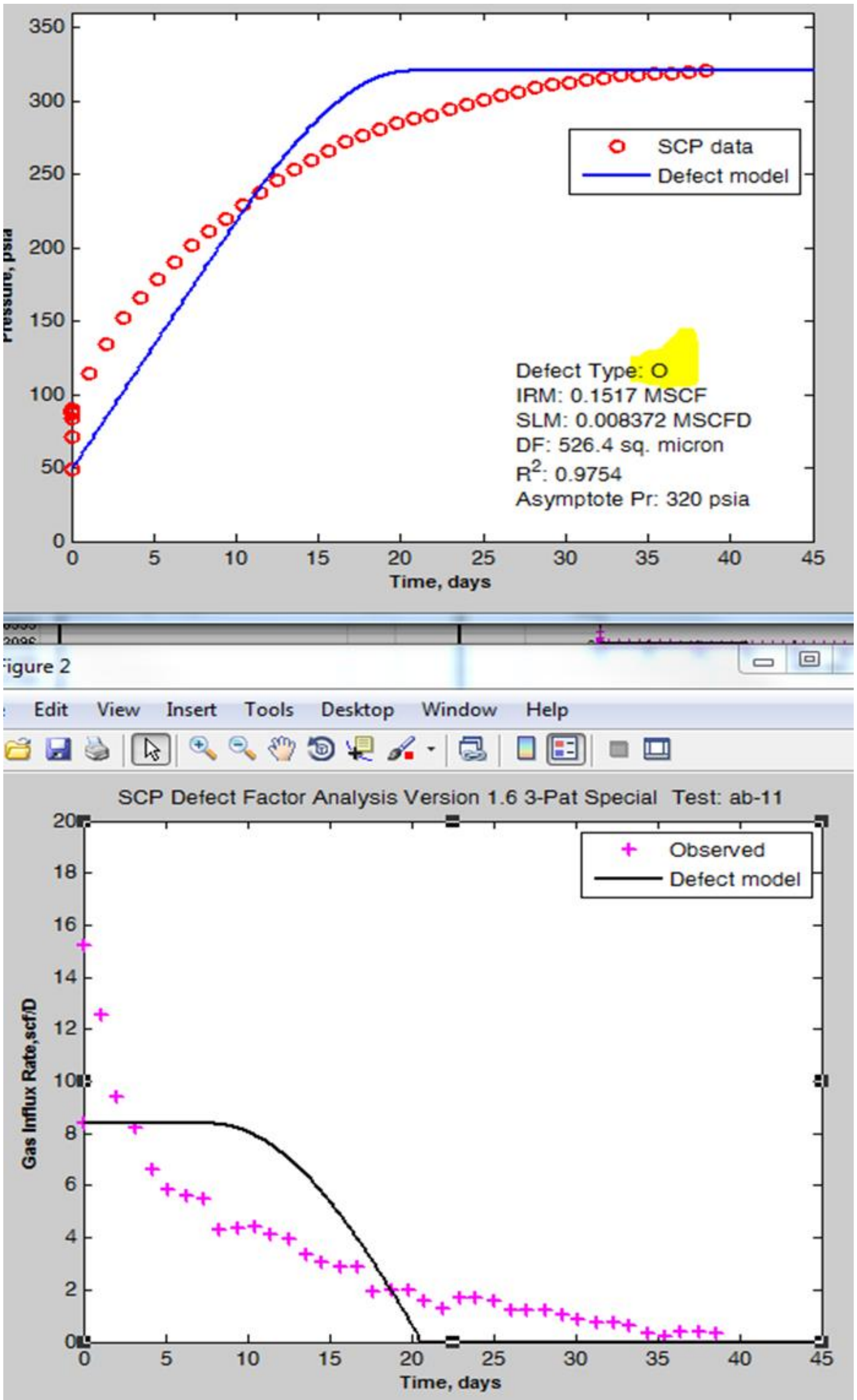


Figure 4-32. SCP Analysis for Well AB-11

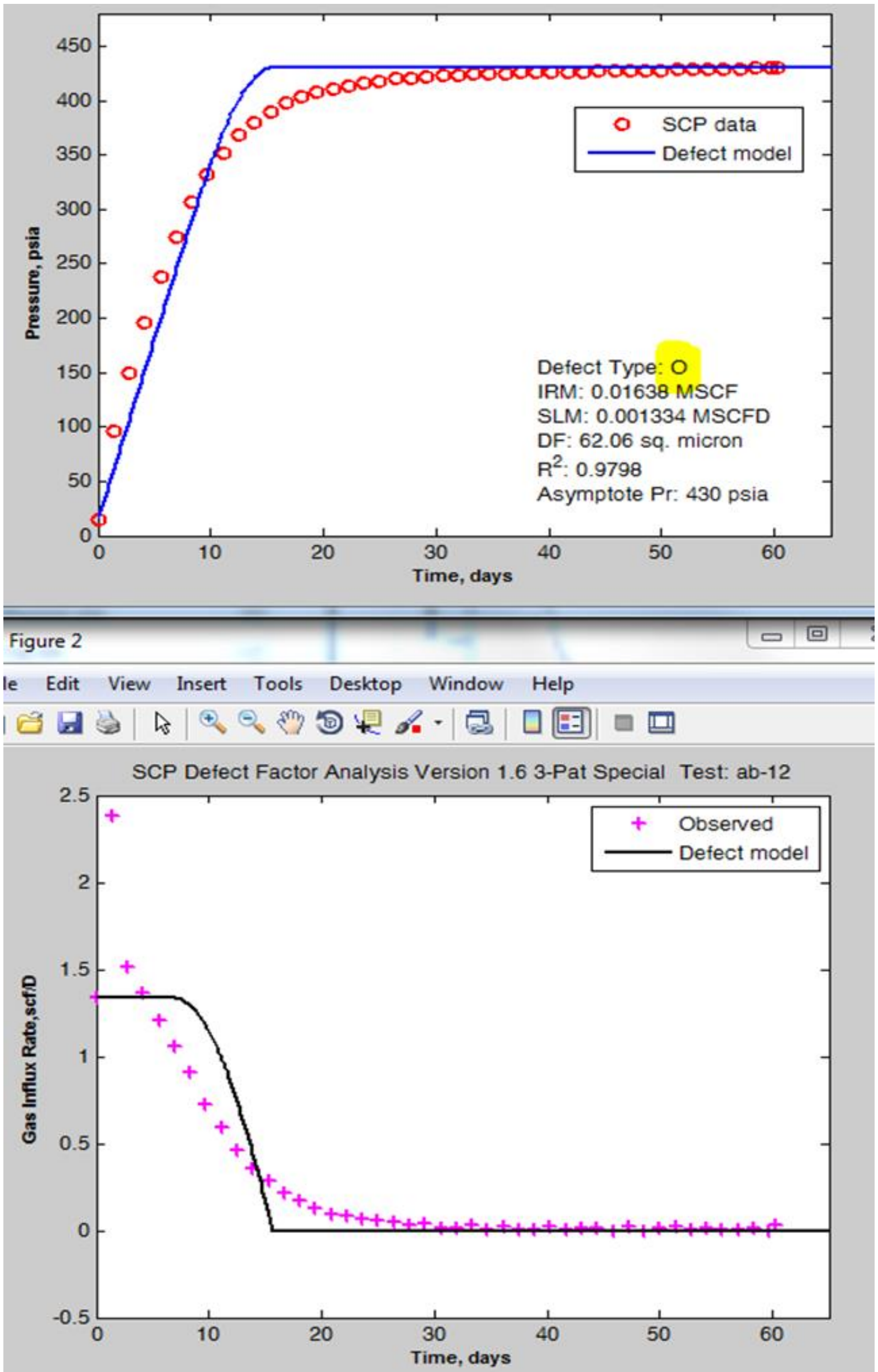


Figure 4-33. SCP Analysis for Well AB-12

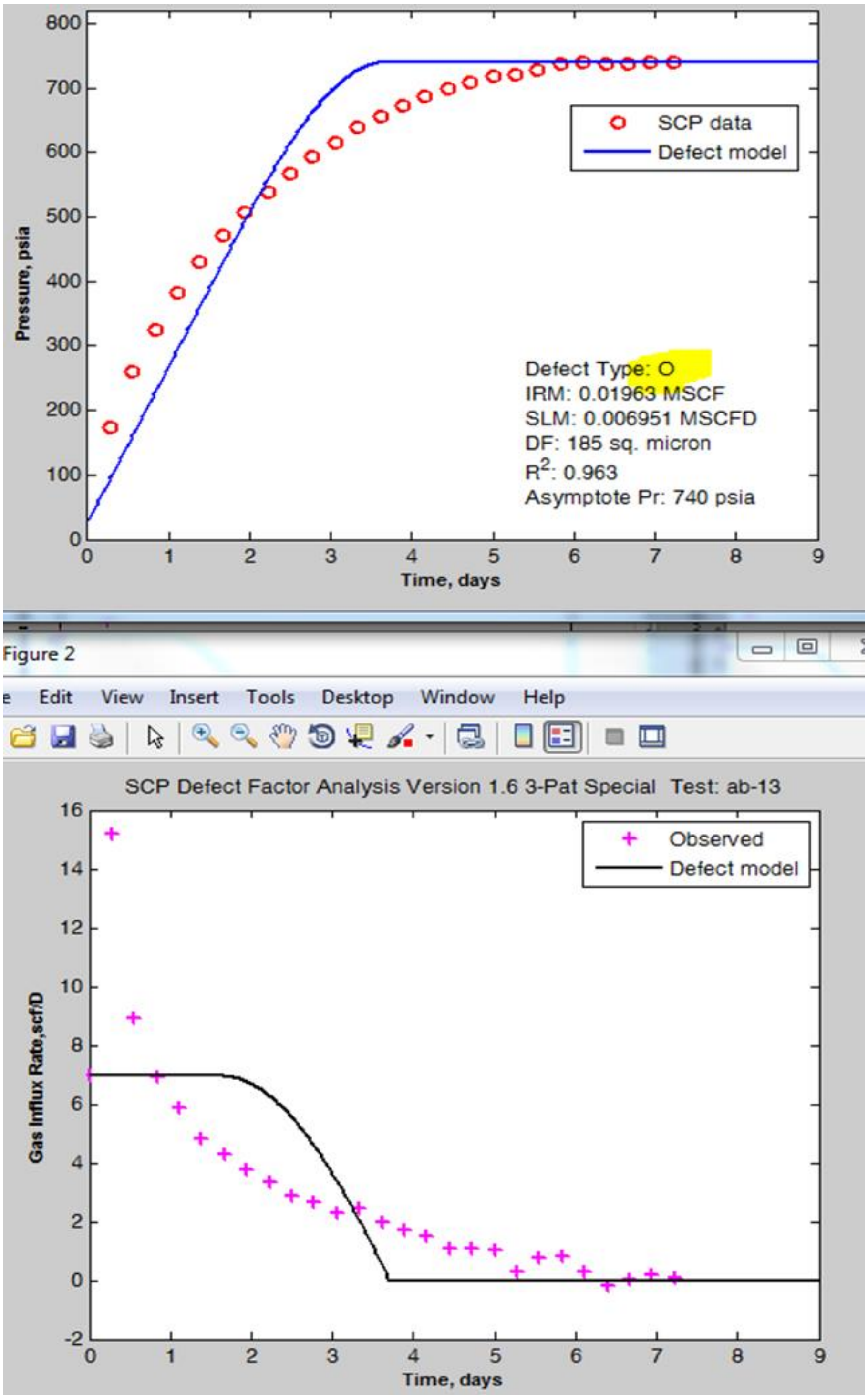


Figure 4-34. SCP Analysis for Well AB-13

4.2.3.2 Gas Analysis

Gas samples were collected in the annulus for wells AB-6 through AB-12. Historical gas samples for the storage gas was also provided. The storage gas is dominantly methane (>90%) with trace amounts of ethane and nitrogen. All wells had at least 7% less methane than the storage gas with elevated traces. Well AB-12 had 29% nitrogen which is significantly different than wells AB-6 through AB-11. Figure 4-35 compares gas compositions for wells AB-6 through AB-12 and the storage gas.

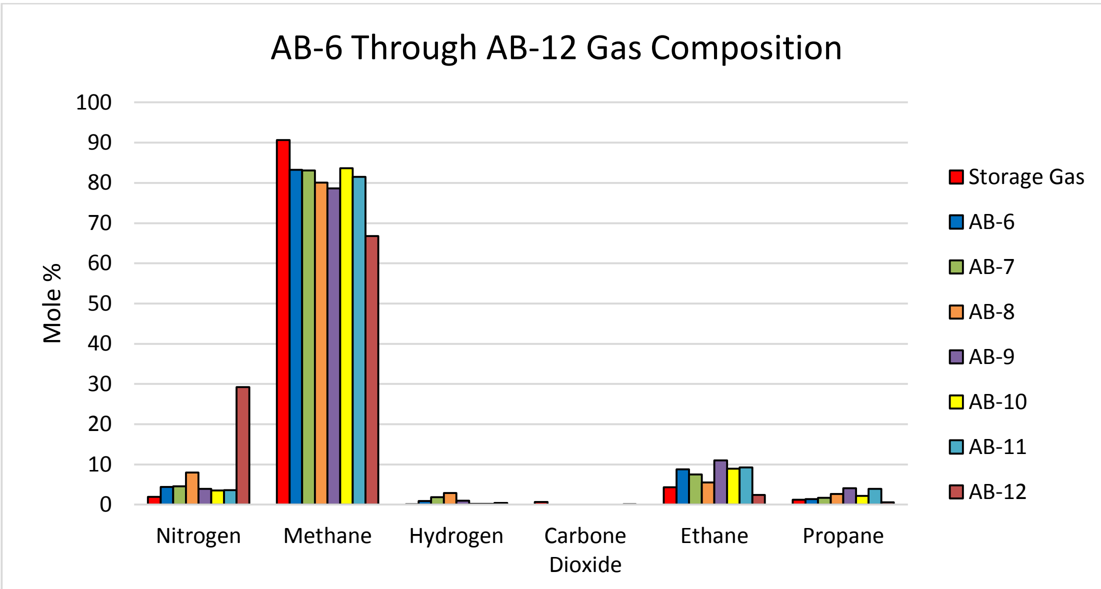


Figure 4-35. Comparison of Gas Compositions for Wells AB-6 through AB-12

All gas samples had higher specific gravities than the average gas storage specific gravity. This indicates the gasses collected from the annulus are more dense, or heavier, than the storage gas. Table 4-6 summarizes the specific gravity for each well.

Table 4-6. Specific Gravities of Gas Samples

Location	Specific Gravity
Storage Gas	0.623
AB-6	0.646
AB-7	0.637
AB-8	0.641
AB-9	0.682
AB-10	0.661
AB-11	0.679
AB-12	0.704

4.3 SCP Conclusions

A review of the SCP data clearly indicates that most of the wells exhibited a porous character rather than an orifice or vein character. This suggests that the rate-limiting step is of a porous character. Because the source of the gas is generally not the high-permeability completion zone but rather some high-pressure zone above the completion, we cannot tell with this data whether we are measuring the resistance of the cement or the source reservoir.

The orifice and porous flow factor and the derivative risk metrics for each test that could be analyzed are shown in Table 4-7. Flow factors have a wide range of 60 to 19,000 square microns, reflecting a large degree of variation in the magnitude of well integrity issues in these wells. The IRM for all wells was less than 200 cubic feet, which suggests that an instantaneous CO_2 release in these wells would not present highly hazardous conditions. The SLM was also fairly low at 500 cubic feet per day or less, suggesting even wells would have little potential to create hazardous conditions. However, over time leakage across many wells in a field would affect storage security.

Table 4-7. Summary of SCP Analysis Well Integrity Metrics

Well Integrity Metric	AB-1	AB-6	AB-7	AB-8	AB-9	AB-11	AB-12	AB-13
Asymptotic pressure (psia)	1,200	620	660	275	330	320	430	740
Flow factor – orifice (square micron)	220	17,000	4,800	1,361	3,300	500	60	190
Flow factor – porous (square micron)	160	19,000	7,300	4,100	10,000	1,400	100	200
IRM (MSCF)	0.16	0.01	0.05	0.005	0.003	0.2	0.002	0.02
SLM (MSCFD)	0.015	0.6	0.2	0.02	0.05	0.008	0.001	0.007

Note: MSCF = thousand standard cubic feet
MSCFD = thousand standard cubic feet per day

In 11 of the 13 tests, there is no indication that gas from the completed zone is the source of the SCP. In these cases, the presence of SCP is not a reliable indicator of the quality of the cement seal at depth. The gas source in the two remaining tests could be either the completed zone or a surface mechanical leak. We can conclude that the presence of SCP in a well does not necessarily indicate that cement above the completed zone is leaking.

For the nine wells that were cemented to surface, there exists a flow path that includes at least 400 to 800 feet of top-hole cement, assuming the surface casing of these annuli is intact. Since the character of the flow rate profile in all cases looks more like a porous model and less like an orifice model, there are two end members with a combination possible:

1. It is possible that the imperfections in the cement system are acting like a porous flow path. In this case, the cement is a barrier and is the rate-limiting resistance in the system.
2. It is possible that the rate-limiting resistance is the flow from an overpressure shale source and the cement at this level is not providing any significant resistance to flow.

As a result, the rate-limiting flow path may be the source rock, in which case the cement seal at the top of the well may be of lower quality than the 60 to 19,000 square microns observed.

5.0 Well Integrity Evaluation

5.1 Cement Integrity Evaluation

The objective of the cement integrity evaluation was to review methods used to cement oil and gas wells in the region, determine materials and additives used for cementing, and assess cement quality in wells based on a systematic evaluation of CBLs. Together, these efforts better define the wellbore integrity issues related to cement in wells in the region.

5.1.1 Well Cementing Practices in the Region

Well cementing practices may affect the quality of cement emplaced in wells. Overall, cementing methods in the Midwest United States have improved with drilling technologies. Cement slurry density can drastically affect the compressive strength of cement, which can result in variances of the bond quality on the CBL. Until the advent of the recirculating cement mixer in the 1970s, most oilfield cement was mixed and placed with jet mixers (Figure 5-1).

Note: The primary hose on the right side of the jet mixer hydrates the cement and sends it up to the mixing tank on the side of the pump truck. The auxiliary hose on the left side of the jet mixer is used to add extra water to the mix to decrease the slurry density. The red steel line to the left of the jet mixer takes the slurry to the suction tub; from there, the downhole pump picks it up and pumps it down the casing being cemented.

Figure 5-1. Jet Cement Mixer (on ground below bulk truck, right side of photo)

With this system, the dry bulk cement was gravity-fed into a hopper positioned directly above a high-velocity jet mixer. The jet mixer would create a high-velocity stream of water which would aspirate the cement and instantly hydrate it. A second (auxiliary) water line was attached to the mixer downstream of the jet; this line was used to add more water to the slurry to decease the cement slurry density. To achieve the desired density, the operator would take samples of the slurry from the suction tub and weigh it with a cement scale. Based on the measured cement density, the cementing operator would tell the pump truck operator to add or decrease water to the mix using the auxiliary hose to reach the desired density. However, all of the cement slurry that was mixed prior to reaching the desired density was usually pumped downhole. In some cases, operators would pump the initial slurry volume into a pit until the slurry had reached its desired density, but in the majority of jobs, that was not the case. Therefore, on most jobs, the first part of the cement slurry would exhibit lesser quality bond on the CBL.

Another factor possibly affecting the consistency of the cement slurry density with this type of mixing system was how well the operator on the bulk truck could maintain the level of the bulk cement in the hopper. The bulk cement would feed into the jet mixer at different rates, depending upon the amount of cement in the hopper—the less cement in the hopper, the less the slurry density.

The introduction of the recirculating cement mixer in the 1970s eliminated many of the problems associated with inconsistent cement slurry density (Figure 5-2). The recirculating mixer recirculates the slurry until the predetermined slurry density is reached, and the slurry is then pumped downhole. The recirculating mixers are equipped with densimeters, which give a constant, real-time readout of slurry density.

With the recirculating cement mixer, dry bulk cement is transferred pneumatically to a “cyclone tank” on the pump truck. The cement is then transferred to a mixing tub, where it is mixed with water. The slurry is then pumped through the densimeter to determine whether its density has reached the acceptable preset level. If the density is acceptable, the slurry is transferred to the high-pressure downhole pump; otherwise, it is sent back to the mixing tank. A computer controls the inflow of water and cement to the mixing tub and controls the valves at the densimeter to direct the slurry to the downhole pump or back to the mixing tub. This system results in a much more consistent cement slurry density and better overall bond quality on the CBL.

Note: Dry bulk “cyclone tank” is located on top of the rear end of the truck. The mixing tub (red tank behind the piping) is located directly below the cyclone tank. The high-pressure downhole pump is located above the rear tires.

Figure 5-2. Recirculating Cement Pump Truck

5.1.2 Cement Materials and Additives

For Ohio, information on cement materials and additives used for casing string cement intervals was obtained from the Ohio RBDMS on oil and gas wells. For individual casing strings, the database lists fields on cement class, sacks, yield, gel viscosity, and duration. Data are in various stages of completeness, so many of the database fields are not listed. However, the data provide a summary of cement used over time in oil and gas wells in Ohio.

Cement materials and additives were not readily available from Michigan databases. Therefore, data from P&A records were utilized to evaluate cement materials and additives. It may be expected that materials used to cement casing were similar to those used to set plugs.

The ODNR maintains a database of all catalogued and publicly available information on well sections within the state. The cement inspection database, which contains all data on the process and timing of the cementation of wellbores, is useful for delineating how often certain types of cement are used downhole, the frequency with which certain additives are applied during the process of wellbore cementation, and the frequency with which cement type is simply listed in reference to particular individual well sections.

The cement inspection database lists 429,286 individual well sections. Each well section does not represent the entirety of a single well with a unique API number, but rather specific intervals within a single well such as production or surface casing. Still, given this large number of detailed sections, a relatively small amount of information is listed overall. Table 5-1 lists all types of base cement used for individual well sections.

Table 5-1. Base Cement Types Listed in Ohio Casing String Records

Class	Number of Well Sections	Percentage
A	12,872	43.23
B	21	0.07
C	12	0.04
FC	530	1.78
G	13	0.04
H	254	0.85
Portland	1,234	4.14
Other	3,349	11.25
Unknown	11,492	38.59
Total	**29,777**	**100**

While only 29,777 out of the 429,286 records list cement type (7%), the data likely reflect typical materials used for cement jobs. As expected, Class A is the most commonly used base cement type. Class A cement is useful in surface settings to a depth of 6,000 feet, making it the easiest and most generic type of cement used for the purpose of wellbore cementation. Class A and Portland cement are also listed in Table 5-1; these terms, which are interchangeable, refer to generally the same cement mixture as Class A cement. Portland cement is simply a common, commercially available cement rated by the American Society for Testing and Materials (ASTM) as a ‘Type 1’ or ‘Class A’ cement. If all variations of Class A style cement are combined, it is used in 48.2% of all well sections. Types B and C

(ASTM Types 2 and 3, respectively) are useful in situations where downhole sulfate resistance is necessary for proper cementation. Cement types are subdivided further; the formula of Class G, a newer and specialized version of Class A cement, is intended to reduce drying shrinkage and improve tensile strength of the cement column.

Similarly, cement additives are diverse in type and application. Typically, a basic cement type without additives will not be sufficient to provide the unique variability required in a cement job to allow for adequate bonding and overall integrity. Table 5-2 shows the various types of common additives listed in the ODNR oil and gas database.

Table 5-2. Cement Additives Listed in Ohio Casing String Records

Material	Well Sections	Percentage
2% $CaCl_2$	2,011	22.23
3% $CaCl_2$	574	6.34
$CaCl_2$ (% unknown)	2,325	25.70
Salt	283	3.13
Gel	2,624	29.00
Cotton Seed Hull	585	6.47
Bentonite	208	2.30
Flo-seal	136	1.50
Cello-Flake	45	0.50
C-41P	175	1.93
Gypsum	57	0.63
Anti-Foam	25	0.28
Total	**9,048**	**100**

Again, a low number (9,048) of additive records exist out of the total well section database (less than 2%). Many of these well sections contain more than one type of additive as well. Calcium chloride ($CaCl_2$) is the most commonly used additive, as it is useful in shallow pipe settings and for plugging. It is an accelerant used to reduce the wait time required for cement to solidify. It also provides early strength in the cement column to decrease the chances of a poor cement bond. Often, a wellbore environment will require the opposite: a cement retarder to allow a slower dry time in order to be able to properly place the cement downhole. Salt is often used for this purpose. Salt also offers the added benefit of increasing the density of the mix, which mitigates the effects of a large amount of pressure being applied to the cement column as it is setting.

Occasionally, a salty gel is introduced (attapulgite). This gel offers the benefit of salt with regard to water retention and slower curing time, while decreasing the density. Most gels are used in this manner, to provide certain chemicals while maintaining a consistency that allows for overall density reduction.

In the realm of unique solutions, various materials such as cotton seed hulls can be introduced to the wellbore that has lost circulation. Without circulation, it is very difficult to properly cement a wellbore. Bentonite also serves this purpose, as do various additives that are trademarked for their specific composition and are sold commercially, such as Flo-seal and Cello-Flake (though shredded newspaper has been known to be used in a pinch).

Overall, the diverse range of cement additives reflects the many environmental conditions that exist in a well at any given time, and highlights how complicated a proper cement job can be when conditions are so variable and relatively unknown at depth. Varying conditions pose a variety of challenges, whether there is the need for a density increase or reduction; the need for a highly salty cement to prevent super-saline water from penetrating the cement as it is curing; or simply the need to reduce the wait time of drying cement.

Because of the wide range of variability involved in a particular cement mix, as well as detailed calculations that are often required to determine specifically what cement is needed on any given location, it becomes difficult to properly assess both the cement inputs for any given wellbore and the accuracy with which the wellbore was cemented by the operator. Access to cement bond and well files are a pre-requisite for a robust analysis of wellbore integrity conditions, which precludes such analysis over a large area. When smaller area is under consideration, access to detailed well data can be negotiated, enabling the needed well-by-well evaluation necessary to determine well integrity and required actions. Cement Plugs

Cement materials and additives were also summarized based on information listed in plugging and abandonment records to determine materials typically used to plug wells. This information provides a basis for evaluating cement resistance to CO_2 in the subsurface. Data were obtained under the data collection and analysis task. For Ohio, data were tabulated from the RBDMS database on plugged wells. For Michigan, data were tabulated from a 1,730-well subset compiled from permit records.

Table 5-3 summarizes materials and additives listed for cement plugs in Ohio. A total of 20,767 plugs are listed in the database, and 16,205 are listed as cement plugs. Plugs are mostly listed as Class A cement, which was likely standard Portland cement. Additives are listed for 7,561 plugs, with a fairly even distribution across the state (Figure 5-3). The most common additive listed in the plugs is gel (in 6,006 plugs) with an average volume of 2.7% and Bentonite (in 1,010 plugs), which are generally equivalent materials. Calcium chloride was listed as an additive in 773 wells at an average of 2.5%. Other materials listed included fire clay, POZ mix, 9 sack grout, salt, and other materials. Lost circulation material was generally not considered a cement additive in the plugging records, so there may not have been a requirement to record it.

Table 5-3. Summary of Cement Plug Additives in Ohio

Parameter	Stat	Unit
Total Records	20,767	#
Total Plugs	20,767	#
Cement Plugs	16,205	#
Class A	15,094	#
Clay Plugs	3,665	#
Plugs with Additives	7,561	#
Plugs with Gel	6,006	#
Avg Gel%	2.7	%
Plugs with $CaCl_2$	773	#
Avg $CaCl_2$%	2.5	%
Plugs with Bent.	1,010	#
Avg Bent%	3.4	%
Fire Clay	800	#
POZ mix	557	#
9 Sack Grout	502	#
Salt	357	#
Other	82	#

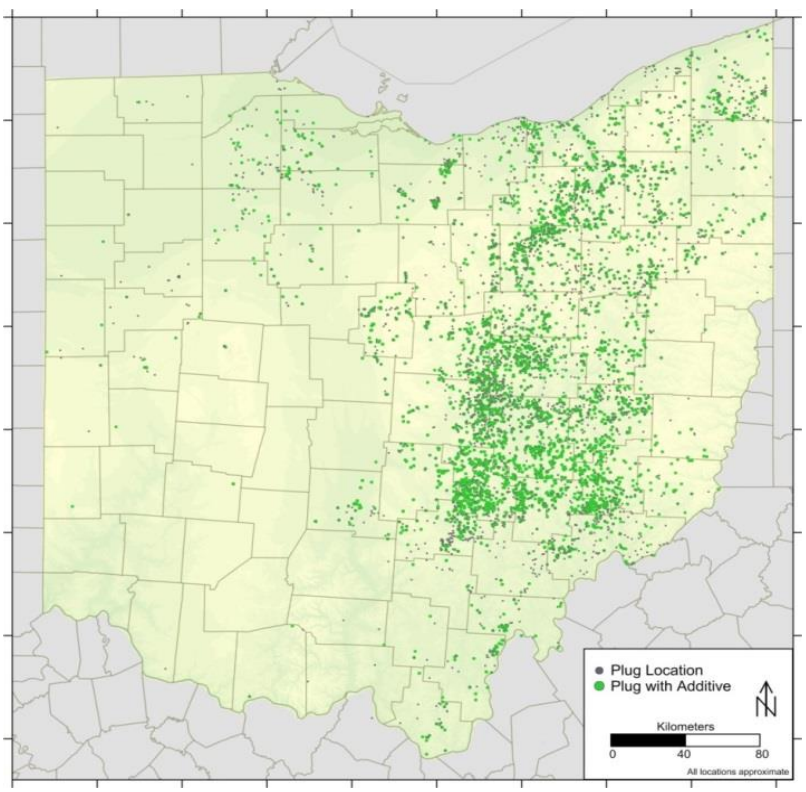


Figure 5-3. Locations of Plugs with Additives in Ohio

Table 5-4 summarizes cement materials and additives listed for cement plugs in Michigan. About 63% of the plugs were cement, and 26% were listed as mud. In general, plugging and abandonment forms did not explicitly require reporting of additives used in cement plugs. As such, most of the additive information was present in more recent records where a cement job was completed by a service company. Only 69 records reviewed listed cement additives for plugs (Figure 5-4). The most common additive was $CaCl_2$ accelerant, listed in 51 plugs at an average of 2.6%. Lost circulation material was listed in 36 plugs. Other additives include Baroco clay, gel, sulf-x, and POZ mix.

Table 5-4. Summary of Cement Plug Additives in Michigan

Parameter	Stat	Unit
Total Records*	1,730	#
Total Plugs	5,055	#
Cement Plugs	3,178	#
Class A	124	#
Clay Plugs	182	#
Mud Plugs	1,332	#
Plugs with Additives	69	#
Plugs with LCM	36	#
Plugs with CaCl	51	#
Avg CaCl%	2.6	%
POZ mix	10	#
Plugs with Gel	2	#

*Based on 5% subsample set of all plugged wells.

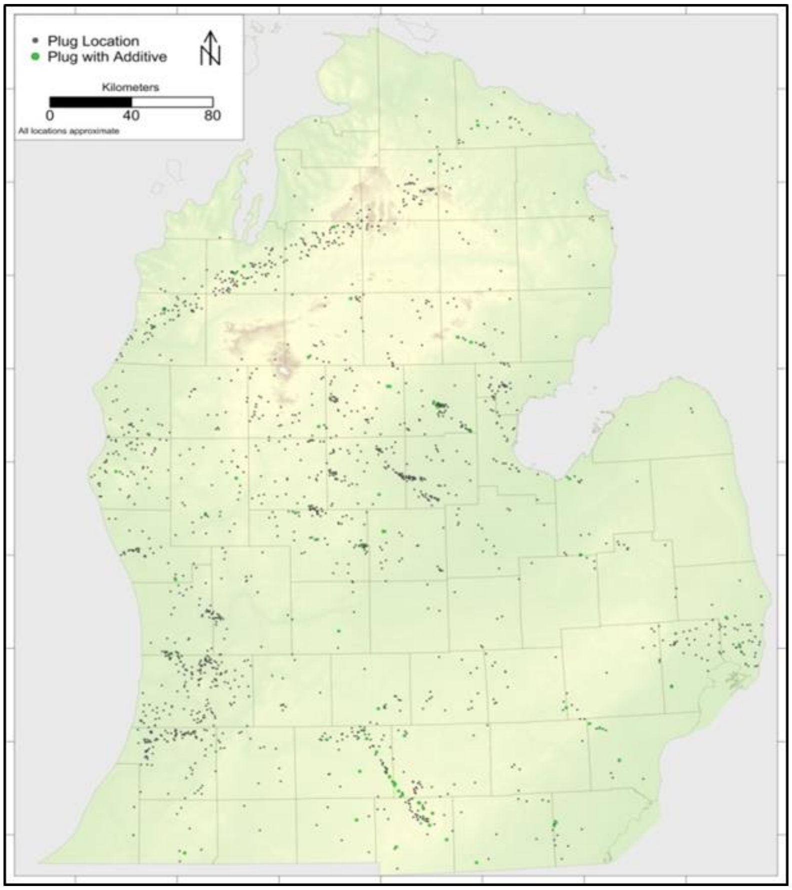


Figure 5-4. Locations of Plugs with Additives in Michigan

5.1.3 CBL Analysis

5.1.3.1 CBL Data Collection

There are 1,720 CBLs available in Michigan and 1,060 in Ohio. Ten percent (10%) of the available CBLs were analyzed plus the CBLs which fell into the local-scale CBL study areas, totaling 394 for Michigan and 306 for Ohio. Of the 700 analyzed CBLs, 56 were assigned to multiple interpreters to compare and assess the quality of the analysis process. Figure 5-5 shows the distribution of the CBLs that are available in Michigan and Ohio with the 10% subset selected.

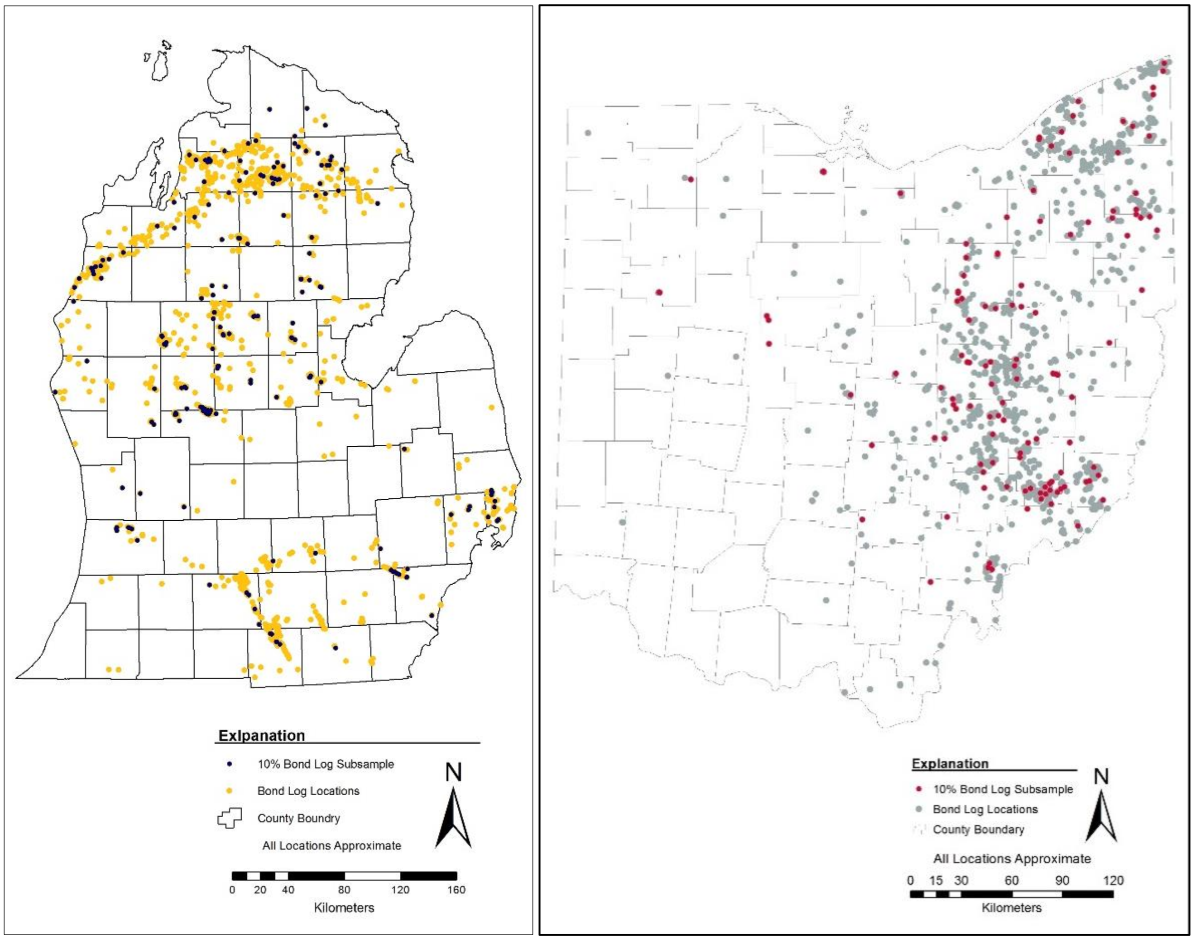


Figure 5-5. Available CBLs and the 10% Subset in Michigan (left) and Ohio (right)

5.1.3.2 CBL Evaluation Methodology

5.1.3.2.1 Technical Basis

CBLs are often exclusively interpreted qualitatively; however, there are quantitative interpretation methods. There are no flawless wireline log interpretation methodologies, so Battelle selected an analysis approach at the start of this task. Based on industry acceptance and ease of use, Battelle selected the Bond Index Method (Bigelow, 1990) to quantitatively analyze the CBLs. This method is based on the principle in Equation 5.1:

$$Bond\ Index\ (Percent\ Bonded) = \frac{Attenuation\ Measured\ Bond\ Index}{Maximum\ Attenuation} \qquad \text{(Eq. 5.1)}$$

By assigning a percentage value, some degree of differences between log types could be accounted for. This technique also allowed for standardizing the interpretation technique across multiple interpreters.

Battelle also used a standard approach to identify the log TOC on each log. Starting at the top of the logged interval, interpreters identified the first largely contrasting interval. This depth was then compared to the Calculated Top of Cement (CTOC). CTOC was derived by first calculating the volume of the annular space (the space between the casing and the borehole) by subtracting the area of the casing from the area of the borehole and multiplying by depth. Then, the volume of cement was determined by finding the number of sacks of cement used, referencing the well construction and completion records. The number of sacks of cement was converted to cement volume based on the type of cement used (Table 5-5).

Table 5-5. Slurry and Cement Yields

Cement Type	Additives	Mix Water (gal / sack)	Slurry Yield (cu ft / sack)
Class A Neat	None	5.2	1.18
Class A	2% Gel	6.5	1.36
Class A	10% salt	5.2	1.2
Class A	2% CaCl	5.2	1.18
'Light"	Varies, usually contains gel	7.7	1.54
'Light"	10 lbs./sack Gilsonite	7.7	1.7
50/50 Pozmix	Neat	5.75	1.26
50/50 Pozmix	10% Salt	5.75	1.29
Thixotropic	10 lbs/sack Cal Seal	5.2	1.24
Thixotropic	10 lbs Cal Seal, 2% Gel. 2% CaCl	6.5	1.36

If a large discrepancy was found between log TOC and CTOC, the log and well data were re-examined to check for errors.

5.1.3.2.2 Interpretation Tool

To continue standardizing the approach to CBL interpretation, Battelle developed a CBL interpretation tool that was used to evaluate well cement quality. The techniques discussed above were integrated into a Visual Basic for Applications (VBA)-based Excel spreadsheet.[1] The spreadsheet was programmed to make and output calculations based on user input of relevant well data.

To populate the spreadsheet, basic well information was researched using publicly available well permit files. Figure 5-6 shows the information required. In cases where information was unavailable, either estimated values were entered (labeled as estimated) or the information was left blank.

Well Information

API Number	Well name	Latitude	Longitude	Spud Date	Log TVD (ft.)	Log MD (ft.)	Hole Diameter (in)	Casing Diameter (in)	Cement amount (sx)	Slurry Yield	Classification

Figure 5-6. Well Information Required by the Interpretation Tool

Information specific to the CBL was entered next. Figure 5-7 shows the information required. In cases where information was unavailable, either estimated values were entered (labeled as estimated) or the information was left blank.

[1] VBA (Visual Basic for Applications) is a programming language accessible within Microsoft Excel.

Log Information

Log Date	Log Interval Top (ft.)	Log Interval Bottom (ft.)	Free Pipe Interval, MD (ft.)	Free Pipe Interval Log Reading (mV)	Depth 100% bond, MC (ft.)	100% Bond Log Reading (mV)	Log TOC	Logged Under Pressure

Figure 5-7. Log Information Required by the Interpretation Tool

The last step of the process was to interpret the CBL. The interpretation process consisted of the following steps:

1. The logged interval of the well was examined.
2. Intervals of approximately 20 or more feet of consistent log output data values were marked as an interval.
3. Interval top, bottom, and log output readings were recorded in the spreadsheet table (Figure 5-8).
4. “Fast formation” behavior or other relevant comments were recorded in the table.

Well Log Interval Information

Bond at IOI Top	Bond IOI Bottom	IOI Reading (mV)	Bond Index	Fast Formation?	Comments

Note: IOI = interval of interest.

Figure 5-8. Interpretation Section of the Evaluation Tool

5.1.3.2.3 Statistical Dataset

Battelle determined a set of calculated values which are most relevant to cement quality obtained from CBL analysis. This selected set of calculated values was used to create a statistically valid dataset that could be analyzed for the subset of wells in the study area. Table 5-6 shows the selected dataset of calculated values, including a brief description of each parameter.

Table 5-6. Values Calculated by the Evaluation Tool for Statistical Analysis

Statistical Value	Description
Min	Minimum bond index value in the well
Max	Maximum bond index value in the well
Weighted Average (Total)	Weighted average of the bond index in the well based on the total interval interpreted
Weighted Average (TOC)	Weighted average of the bond index in the well based on the interval between the interpreted TOC and the bottom depth interpreted
0 – 20%	The total footage in the well that has a bond index between 0% and 20%
20 – 50%	The total footage in the well that has a bond index between 20% and 50%
50 – 80%	The total footage in the well that has a bond index between 50% and 80%
80 – 100%	The total footage in the well that has a bond index between 80% and 100%
CTOC	The TOC as calculated from the bit size, casing size, number of sacks of cement, and cement yield
TOC Difference	The difference, in feet, between the calculated and interpreted TOC.

5.1.3.3 CBL Evaluation

5.1.3.3.1 Instructions

Battelle used 11 interpreters to evaluate the CBLs. Their expertise ranged from professionals with significant CBL interpretation experience to interpreters with no prior oilfield experience. Each interpreter was taught in a one-on-one session how to use the tool, retrieve and record information from the well permit files, and evaluate CBLs. As questions and issues arose during analysis, less experienced interpreters were supported by the more experienced interpreters.

5.1.3.3.2 Beta Testing

To first evaluate the effectiveness of the tool and method, a test case was implemented using 22 CBLs in Guernsey County, Ohio. Four Battelle staff members interpreted these CBLs; 10 of the logs were interpreted by multiple staff members, providing analysis overlap within the test case log subset. The statistics showed reasonable interpretation consistency across the four interpreters. Minor problems were found within the tool; these problems were addressed.

5.1.3.3.3 Implementation

A subset of the CBLs dataset was interpreted by multiple staff members, providing analysis overlap and helping to verify the standardization of tool use and log interpretation. Table 5-7 shows a sample set of results from some of the overlapping wells, indicating reasonable consistency among the staff members.

Table 5-7. Statistical Output for Subset of Wells Showing Consistency between Interpreters

API	Well Name	Spud Date	Classification	Log Date	TD	Min	Max	W Ave T	W Ave TOC	TOC Log	TOC Calc	TOC Diff	Interpreter	IntDate
2108121780														
	Alto #3	8/21/1959	Open	8/18/1994	3966	0.10	1	0.66	0.78	610	-4974	-5584	BG	
	LPG Storage #3	8/21/1959	Open	8/18/1994	3675	0	1	0.66	0.8	600	-5265	-5865	O.B	
	alto lpg storage #3	8/21/1959	Open	8/18/1994	3675	0	1	0.65	0.79	650	-5265	-5915	AJH	12/17/2013
2105133628														
	Cottrell-Heck #2	3/30/1980	Abandoned	4/17/1980	2268	0.48	1	0.36	0.87	1326	1265	-61	BG	
	Cottrell-heck #2	3/30/1980	Open	4/17/1980	2268	0	1	0.46	0.88	1320	1265	-55	O.B	
	cottrell-heck 2	3/30/1980	Open	4/17/1980	2268	0	1	0.34	0.84	1330	1168	-162	AJH	12/17/2013
3415124666														
	E & M Harrold #2	10/12/1990	Open	12/4/1990	6611	0.09	1	0.61	0.71	6345	5273	-1072	WAK	12/23/2013
	E&M Harold#2	10/12/1990	Open	12/4/1990	6611	0	1	0.43	0.51	6345	5273	-1072	AJH	12/16/2013
	Harold #2 3369-001	10/12/1990	Open	12/4/1990	6611	0	1	0.57	0.66	6344	5273	-1071	O.B	
3407525452														
	Mast I & E #1	8/24/2006	Open	10/5/2006	4180	0	1	0.63	0.84	3556	2301	-1255	WAK	12/20/2013
	MAST I&E #1	8/24/2006	Open	10/5/2006	4182	0	1	0.78	0.91	3456	2191	-1265	AJH	12/16/2013
	Mast I&E #1	8/23/2006	Open	10/5/2006	4199	0	1	0.78	0.54	3456	2192	-1264	O.B	
3411124138														
	Yonak #1	10/4/2007	Open	1/10/2008	2660	0.10	1	0.49	0.55	816	252	-564	WAK	12/23/2013
	yonak 1	10/4/2007	Open	1/10/2008	2660	0	1	0.37	0.96	816	224	-592	AJH	12/16/2013
	Yonak 31	10/4/2007	Open	1/10/2008	2660	0	1	0.63	0.66	815	252	-563	O.B	

The overall statistics from each interpreter were synthesized into two master spreadsheets: one for Michigan and one for Ohio. These data were then screened for any statistical outliers. If unusual values (such as non-numerical answers, bond index of over 100%, or significant differences between CTOC and TOC) were found, these wells were revisited and corrected where applicable. If errors could not be resolved, non-uniform well information was removed from the dataset.

5.2 Regional CBL Analysis

All analyzed CBLs for Michigan and Ohio were compiled into two datasets to determine whether any factors influence the cement quality in a wellbore and, if so, whether to use these criteria as “red flags” when assessing a potential CO_2 study area. The age of the well, the season in which the well was completed, the total depth of the well, and the thickness of the cement column were statistically compared to cement quality. These factors were chosen because these data are typically recorded in the well records and are important for assessing wellbore integrity for CO_2 storage. For example, the depth of the well is important to establish the quality of cement within the confining layers.

Three categories were determined to represent the cement quality in a wellbore:

1. high cement quality, which has a cement bond index of 80% or greater as determined from an industry standard,
2. moderate cement quality, which has a cement bond index less than 80% but greater than or equal to 60%, and
3. low cement quality, which has a cement bond index less than 60% indicating a need for more detailed assessment or corrective action

The footage of cement in each category was divided by the total cement column to calculate the percentage of cement that fell into each category.

5.2.1 Michigan

5.2.1.1 Data Distribution

The Michigan dataset consisted of 394 CBLs analyzed with the statistical output. Very few wells were drilled prior to 1950, and only a few wells were drilled in the 2010s (the dataset is from 2012). There are three spikes in the number of wells drilled: one in the 1960s, the second in the 1980s, and the third in the 2000s, which corresponds to drilling surges in Michigan. More wells were drilled in the summer months (June-August) than any other season, with winter months (December-February) showing the fewest number of wells drilled. Figure 5-9 shows the distribution of completed wells, by decade and by season, from the 1930s through the 2000s.

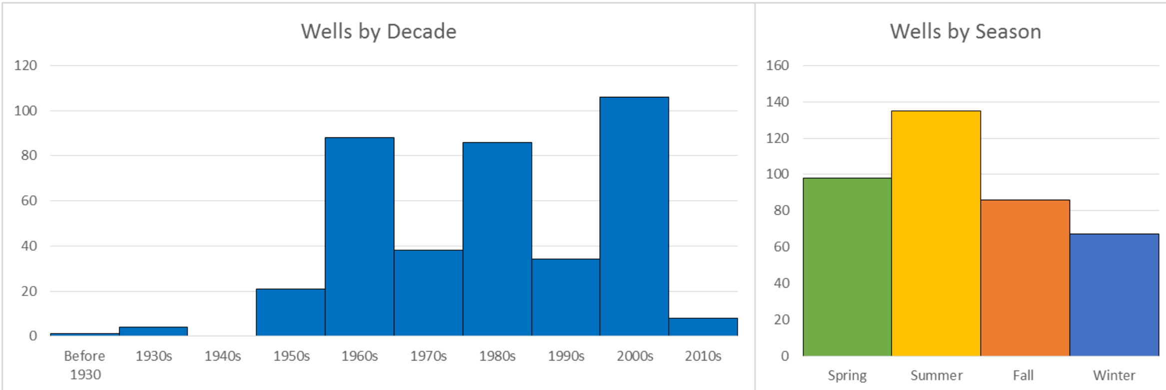


Figure 5-9. Distribution of Completed Wells by Decade and by Season, 1930s-2000s (Michigan dataset)

Eighty-eight percent (88%) of the wells reached a total depth of less than 5,000 feet, with a spike of wells between 1,000 and 2,000 feet deep. Fifty percent (50%) of the wells have a total cement column thickness of less than 2,000 feet, and 42% of the wells were cemented to the surface. Figure 5-10 shows the well distribution by total depth (top), cement column thickness (middle), and percent of wellbore which has been cemented (bottom).

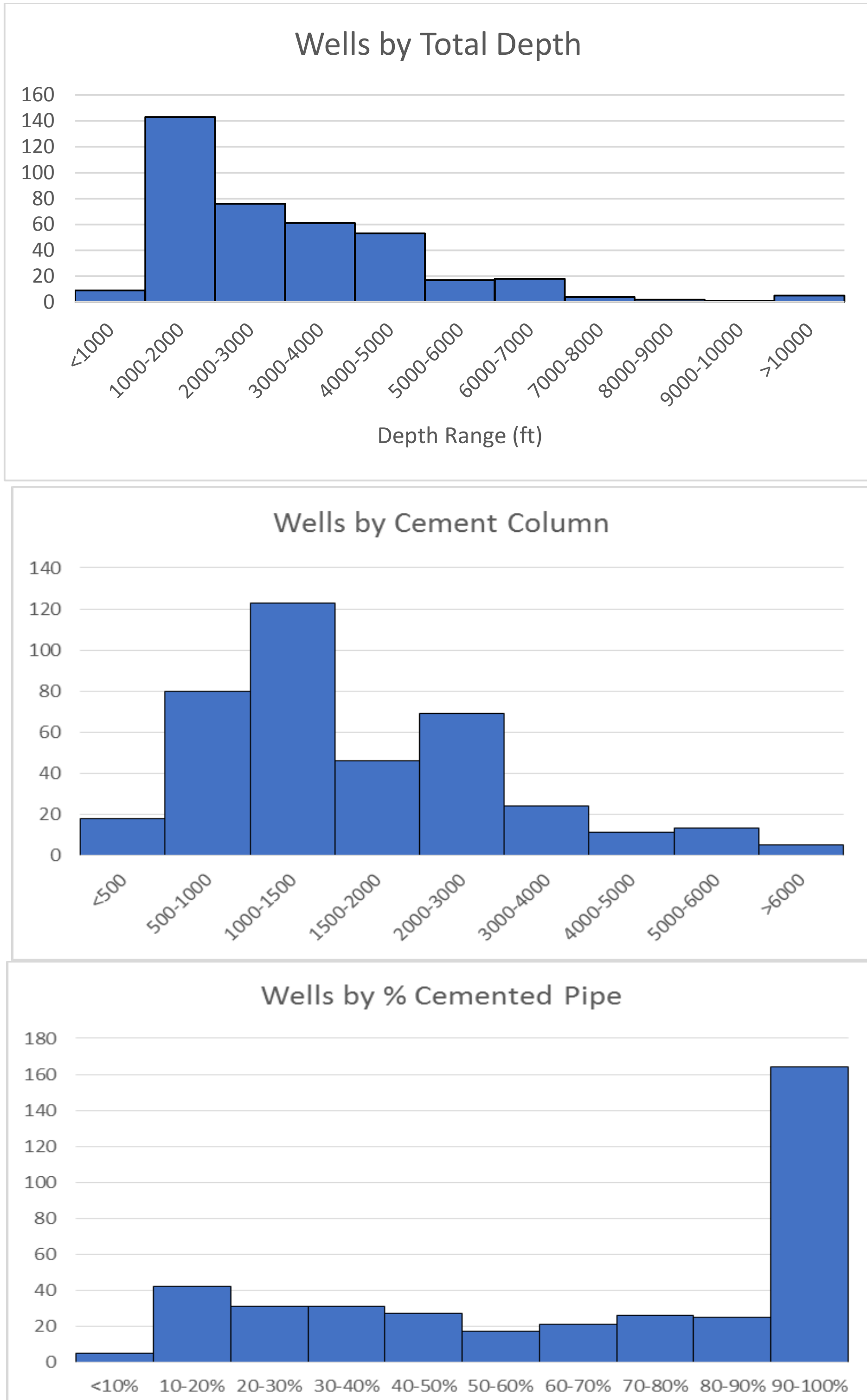


Figure 5-10. Distribution of Wells by Total Depth (top), Cement Column Thickness (middle), and Percent Cemented Pipe (bottom) (Michigan dataset)

5.2.1.2 Cement Quality Results

The majority of the wells (67%) have an average cement bond index between 80% and 100%, which falls into the high-cement-quality category. Only 15% of wells fell into the low-cement-quality category. On average, the footage of high cement quality was around 1,100 feet, while the average low-cement-quality footage was 219 feet. The resulting histogram (Figure 5-11) shows the distribution of wells that fell into each cement quality category.

Geospatially, clusters of wells with low-quality cement correlate with high well density. Figure 5-12 shows the cement quality categories at each well location.

5.2.1.3 Cement Factor Analysis

A series of graphs, boxplots, and classification trees were produced to look for any correlations between cement factors and cement quality in Michigan wells. The age of a well, the season a well was completed, and the depth of a well had no correlation with the cement quality. The thickness of the cement column, calculated by taking the difference from TOC and total depth, showed a slight correlation. The weighted histogram in Figure 5-13 shows the three cement quality categories for different ranges of cement column thickness. As the cement column thickens, the number of high-quality cement (green) wells decreases and the number of low-quality cement (orange) wells increases.

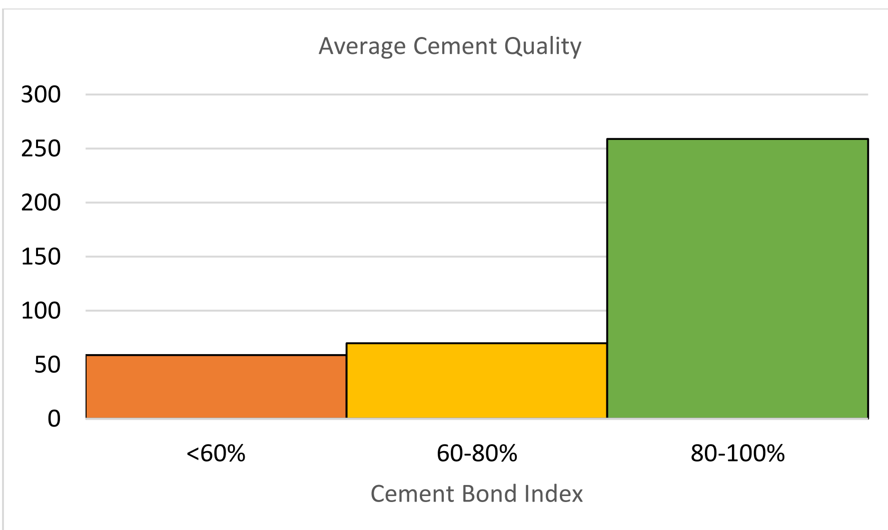


Figure 5-11. Distribution of Wells by Cement Quality Category (Michigan)

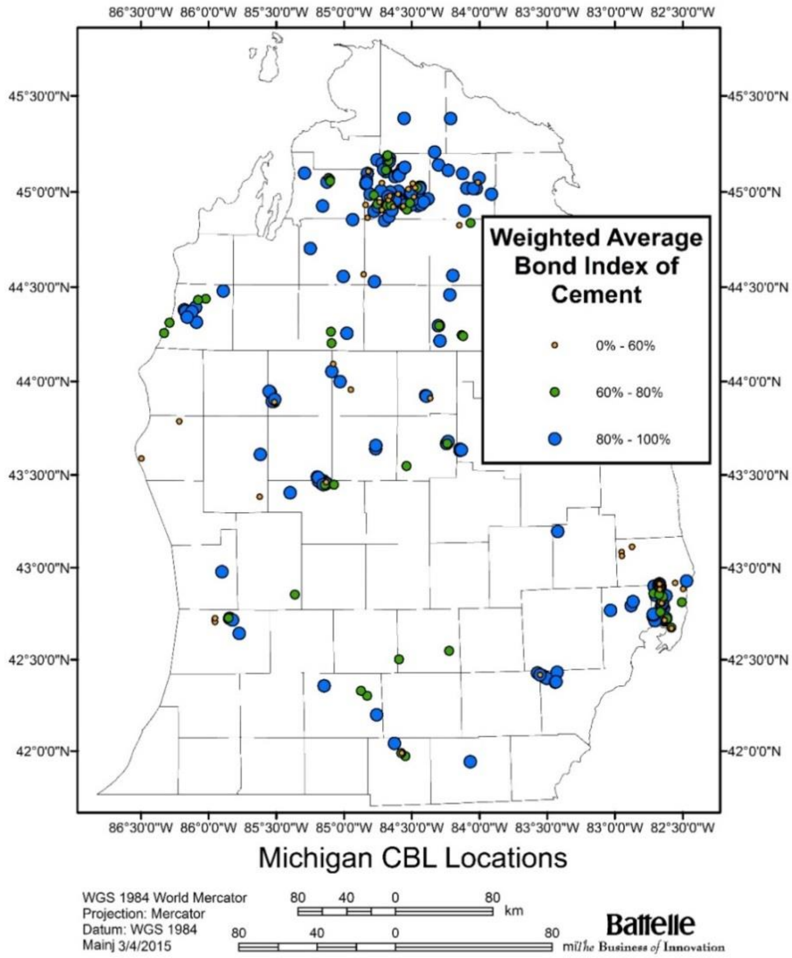


Figure 5-12. Locations of Michigan Wells Analyzed, by Cement Quality Category (Michigan dataset)

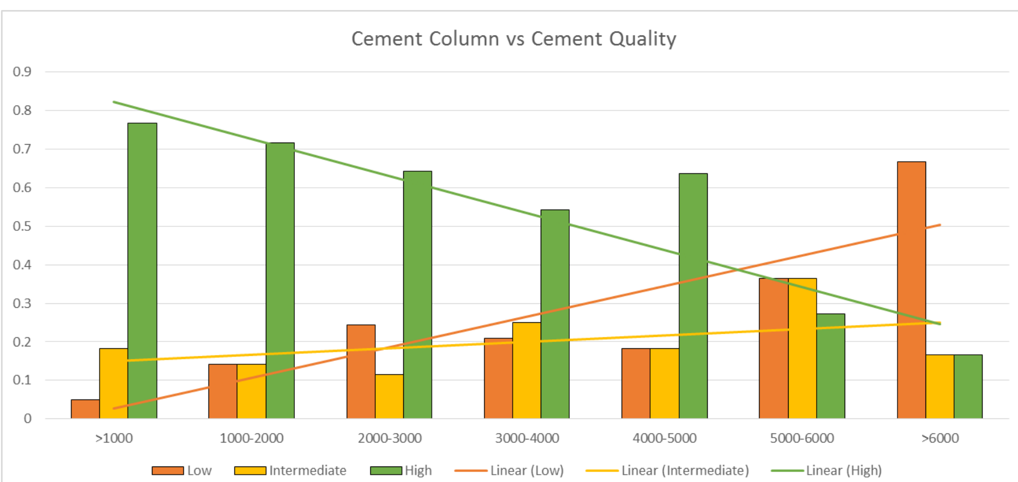


Figure 5-13. Distribution of Cement Quality Categories for Different Ranges of Cement Column Thickness (weighted) (Michigan dataset)

5.2.2 Ohio

5.2.2.1 Data Distribution

The Ohio dataset consisted of 306 CBLs analyzed with the statistical output. Very few wells with CBLs were drilled prior to the 1970s or after 2010 (the dataset is from 2012). Fifty-two percent (52%) of the wells were completed in the 2000s, with a smaller spike in the 1980s. Slightly more wells were completed in the fall than in any other season; the fewest were completed in the winter. Figure 5-14 shows the distribution of completed wells, by decade and by season.

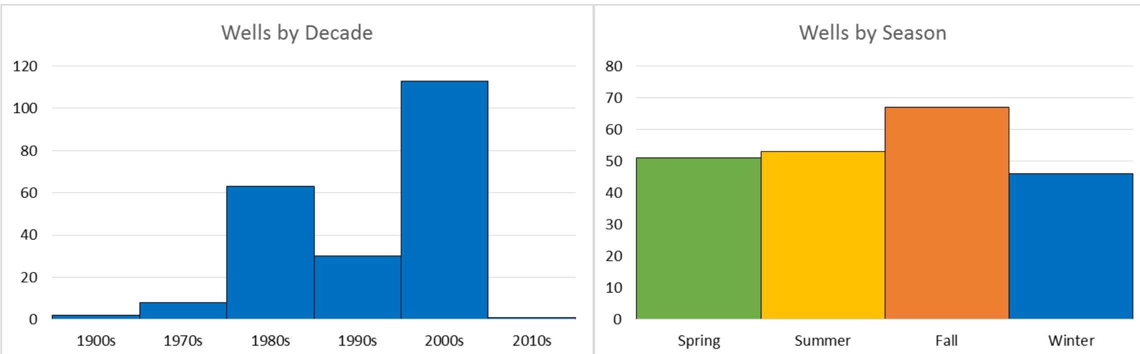


Figure 5-14. Distribution of Completed Wells by Decade and by Season, 1970s-2000s (Ohio dataset)

No wells were drilled to a total depth of less than 1,000 feet, and very few were greater than 8,000 feet deep. Thirty-five percent (35%) of the wells were in the 6,000- to 7,000-foot range, and 88% of the wells were drilled shallower than 7,000 feet. Forty-six percent (46%) of wells had a cement column with a total thickness of between 500 and 1,000 feet; very few wells had a thickness greater than 4,000 feet. Forty percent (40%) of the wells had wellbores that were 10% to 20% cemented. Only 1% of wells were cemented to the surface. Figure 5-15 shows the distribution of total depth (top), cement column thickness (middle), and % cemented pipe (bottom).

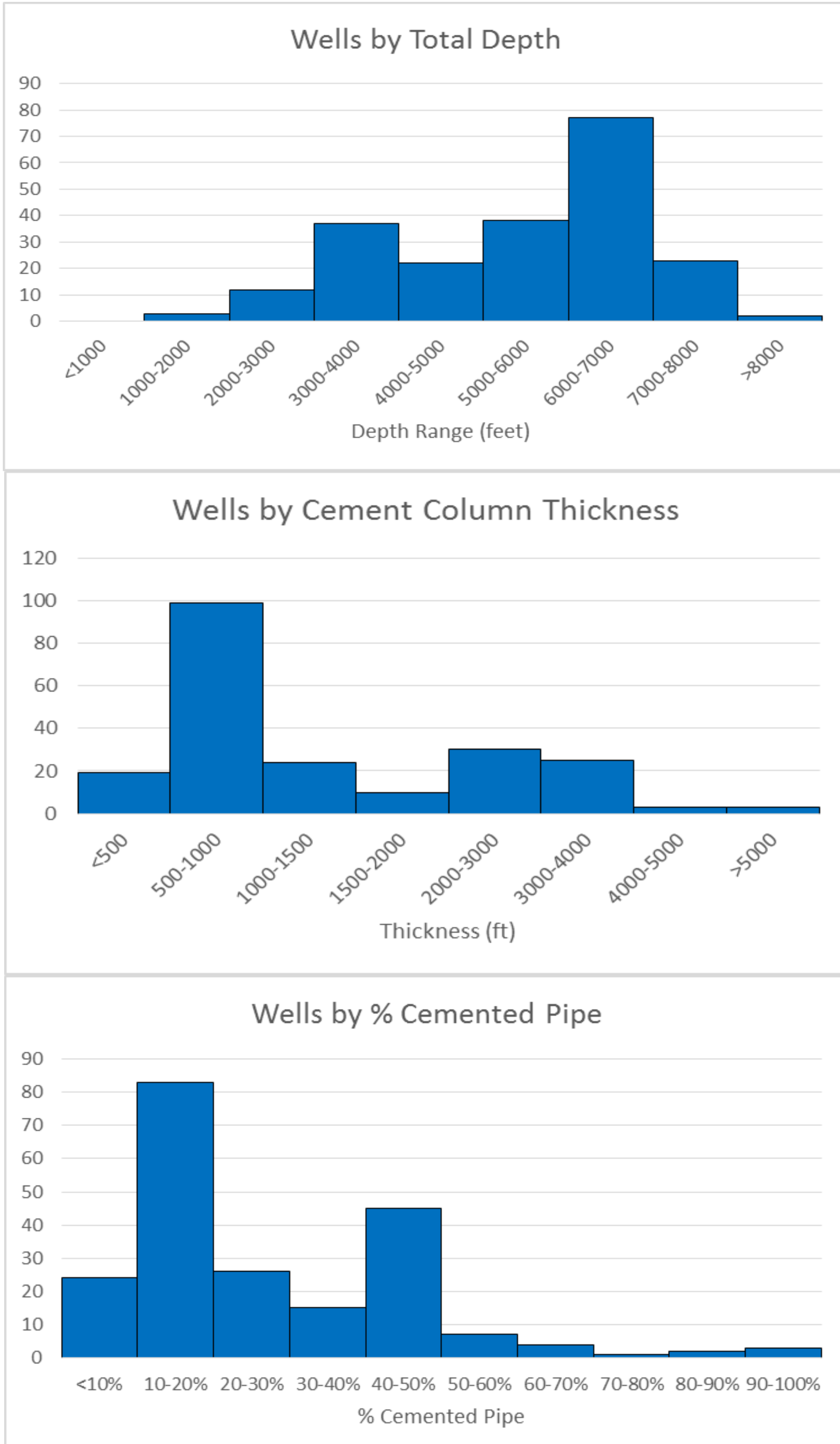


Figure 5-15. Distribution of Wells by Total Depth, (top), Cement Column Thickness (middle), and Percent Cemented Pipe (bottom) (Ohio dataset)

5.2.2.2 Cement Quality Results

The majority of the wells (66%) have an average cement bond index between 80% and 100%, which falls into the high-cement-quality category. Only 13% of wells fell into the low-cement-quality category. On average, the footage of high cement quality was around 560 feet, while the average low-cement-quality footage was 135 feet. The resulting histogram (Figure 5-16) shows the distribution of wells that fell into each cement quality category.

There is a streak of wells with low-quality cement in northern Muskingum County (Figure 5-17). This set of wells is in the Muskingum/Coshocton study area and is discussed in more detail in Section 5.3.2.

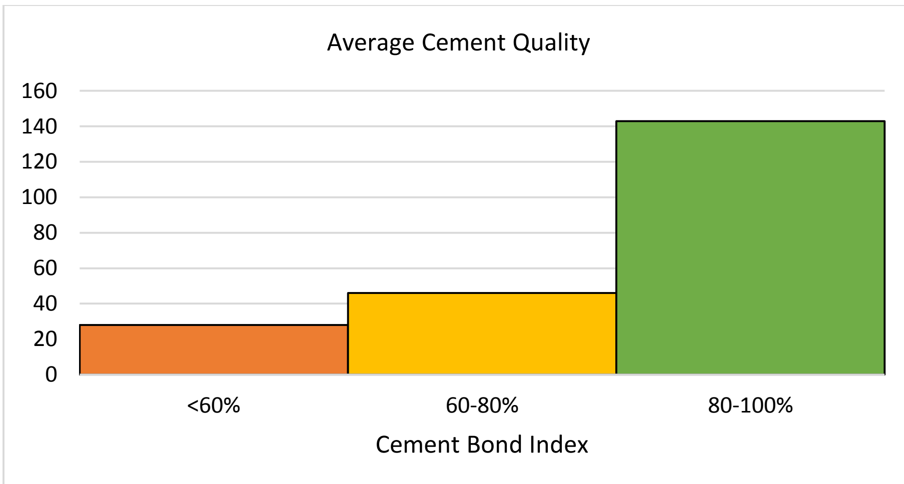


Figure 5-16. Distribution of Wells by Cement Quality Category (Ohio dataset)

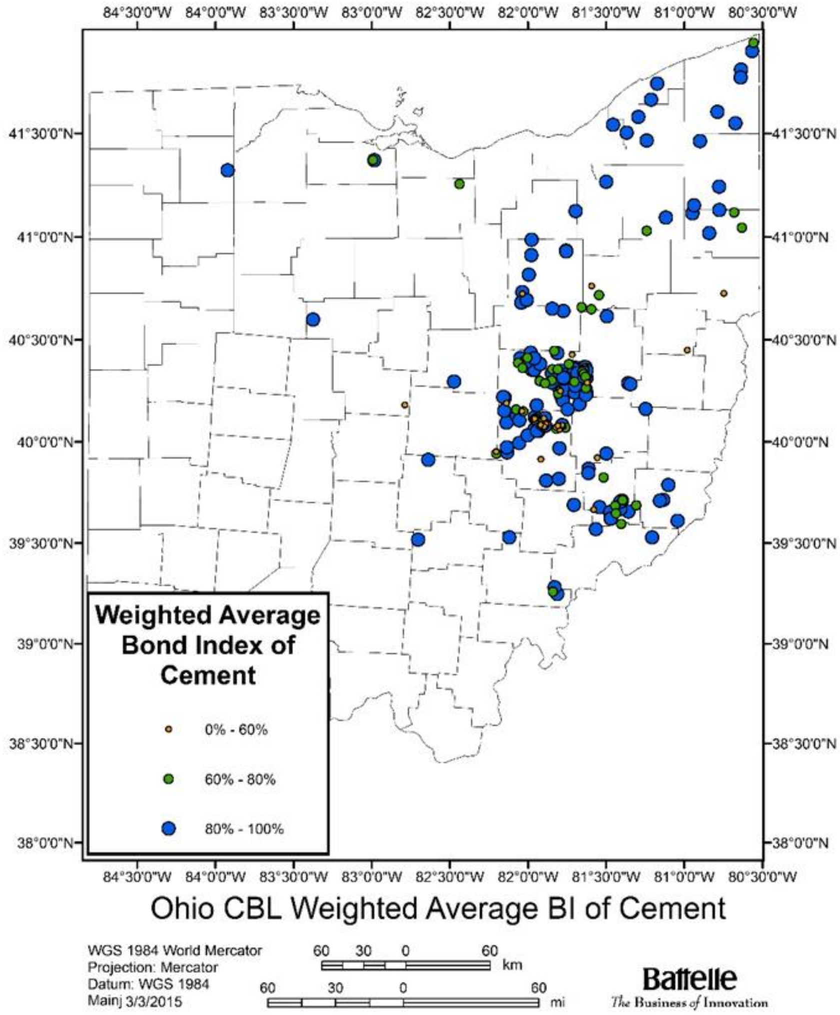


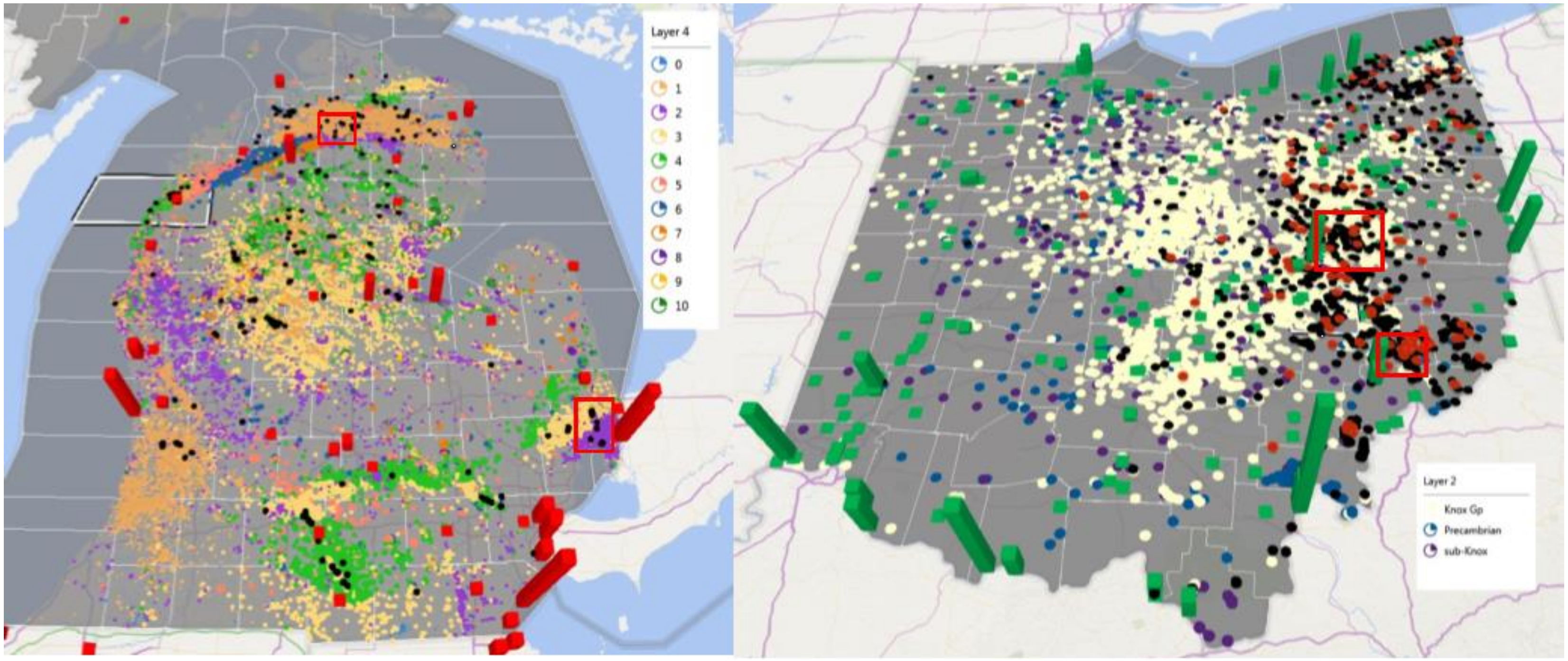
Figure 5-17. Locations of Ohio Wells Analyzed, by Cement Quality Category (Ohio dataset)

5.2.2.3 Cement Factor Analysis

A series of graphs, boxplots, and classification trees were produced to look for any correlations between cement factors and cement quality in Ohio wells. The age of a well, the season a well was completed, the depth of a well, and the thickness of a well's cement column had no correlation with the cement quality.

5.3 Local-Scale CBL Study Areas

Local study areas were chosen to assess wellbore integrity at hypothetical CO_2 storage areas in Ohio and Michigan. A series of maps were created plotting oil and gas wells with recorded depths, wells with CBLs, and locations of CO_2-emitting facilities with approximate emission amounts. Areas with deep wells, available CBLs, and close proximity to CO_2-emitting facilities were of most interest. Five study areas, two in Michigan and three in Ohio, which met the criteria were selected. Figure 5-18 has combined maps for Michigan and Ohio showing well locations by depth, available CBLs, and relative amounts of emissions from CO_2-emitting facilities.



Note: Colored dots indicate well depth; black dots indicate wells with CBLs; columns indicate relative amounts of emissions from CO_2-emitting facilities. Squares indicate study areas.

Figure 5-18. Diagram illustrating locations of Oil and Gas Wells in Michigan (left) and Ohio (right) by Depth, Available CBLs, and CO_2-emitting Facilities

The sizes of the study areas (except for Guernsey County, Ohio) were determined by estimating the volume needed to store 3.5 million tons of CO_2 per year for 20 years. The thickness and porosity of the storage formation were used in the analysis, along with the density of CO_2 and a variety of efficiency factors (E-factors). Table 5-8 lists the criteria used and the resulting study area sizes. Guernsey County, Ohio, was predetermined from a dataset provided by NiSource to evaluate the gas storage wells in an old storage site.

Table 5-8. Factors used to Estimate Study Area Sizes (Ohio and Michigan)

Study Area	Formation	Thickness (meters)	Porosity	CO_2 Density (g/cc)	Resulting Area (kilometers)
Ohio Counties					
Guernsey	Oriskany	ND*	ND	NA*	NA
Muskingum/ Coshocton	Copper Ridge to Mt. Simon	35	6.50%	0.794	15x15
Noble	Copper Ridge to Mt. Simon	35	6.50%	0.794	15x15
Michigan Counties					
Otsego	Niagara	125	12%	0.794	6x6
St. Clair	Niagara	125	12%	0.794	6x6

***ND = not determined
NA = not applicable
g/cc = grams per cubic centimeter

5.3.1 Guernsey County, Ohio

Of 48 wells within the storage field in Guernsey County, 13 contain CBL data. The majority of these wells are between 3,250 and 3,500 feet deep, with one well reaching a depth of 4,590 feet. Wells were completed between 1929 and 1973; most were completed between 1934 and 1956. The Oriskany Sandstone is the storage formation, with the Onondaga Limestone as the confining layer. Above this lies the undifferentiated Devonian shales, which includes the Bedford, Huron, and Olentangy, and provides a secondary confining layer. Figure 5-19 shows an example wellbore with the general stratigraphy of the area.

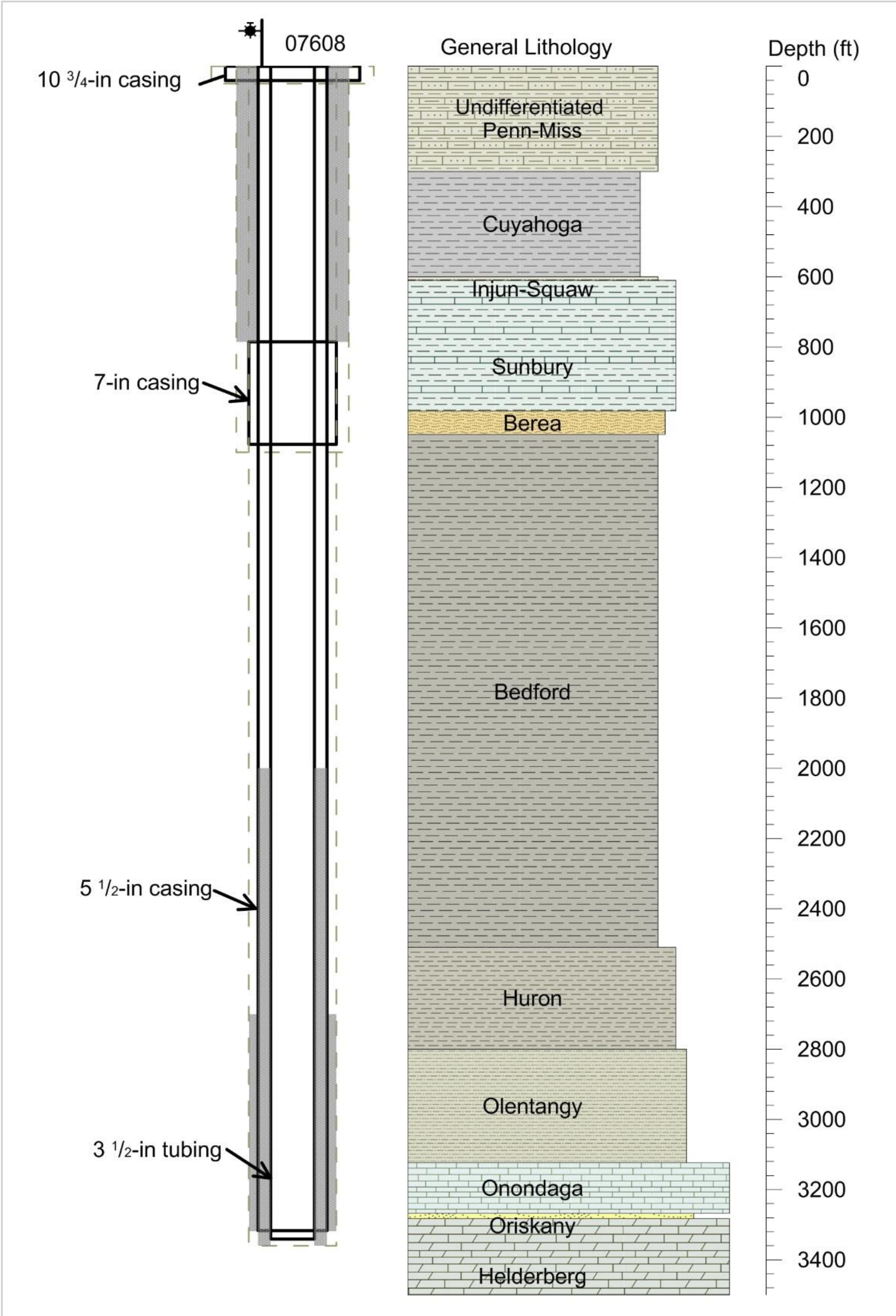


Figure 5-19. Generalized Wellbore with Stratigraphy in the Guernsey County, Ohio, Study Area

Individual CBL analyses were computed in order to determine the average percentage of cement bonding that occurs within a specific wellbore, as detailed in Section 5.1.5 The results of this analysis are shown in Figure 5-20, which indicates that 7 of the 13 wells in this study area have an average cement bond of 80% or greater. The results are mapped in Figure 5-21 to determine if there are any geospatial trends associated with wells with low cement quality.

Total footages for each cement quality category were calculated to show the amount of feet in each category for all wellbores. Figure 5-22 shows that while only 7 of the 13 wells had an average cement bond of 80% to 100%, a significant majority of the total bonded footage within the Guernsey County study area has a cement bond of 80% to 100%. The wells with portions of low cement quality had sufficient footages of high cement quality (50 feet of 80% or better) to provide a sufficient seal.

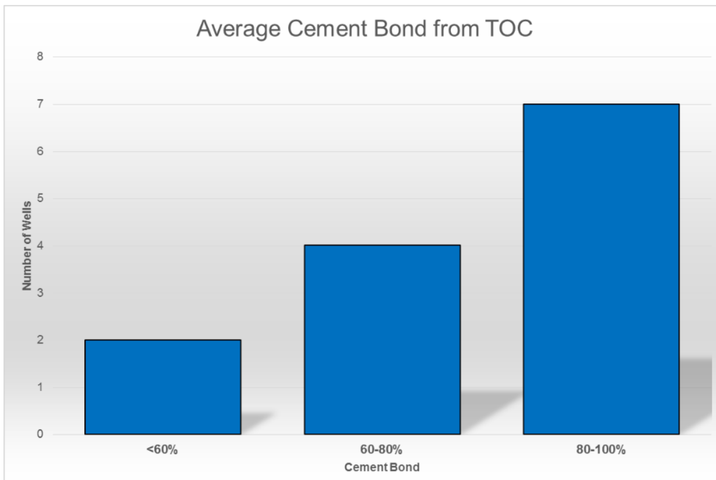
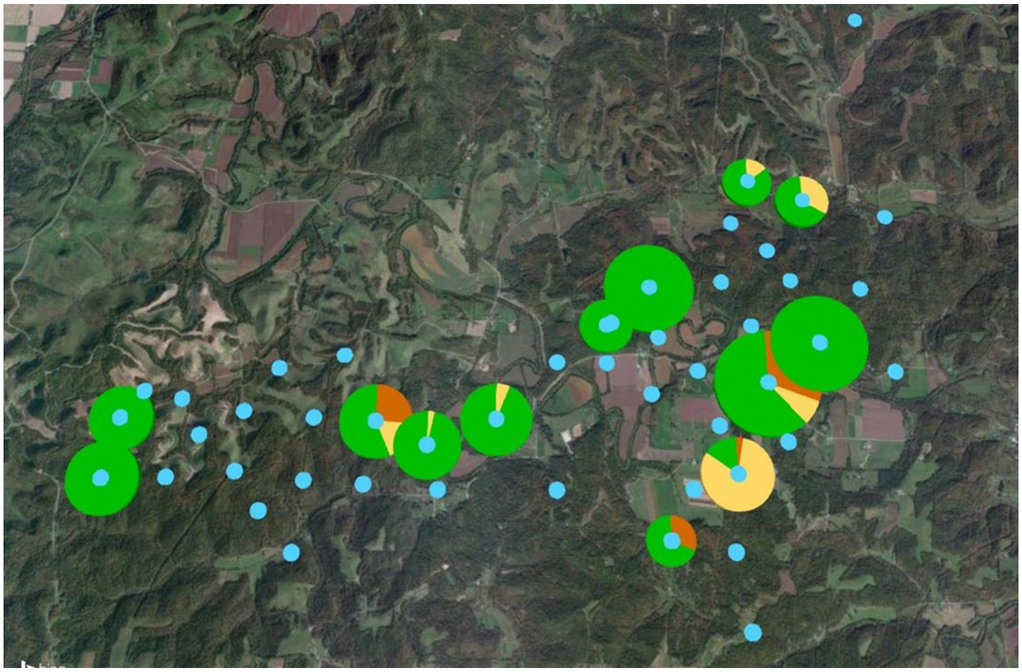


Figure 5-20. Cement Quality (Average Cement Bond Percentage) for Wells in the Guernsey County, Ohio, Study Area



Note: Green indicates high cement quality, yellow is moderate, and orange is low.

Figure 5-21. Wells in the Guernsey County, Ohio, Study Area with CBL Results

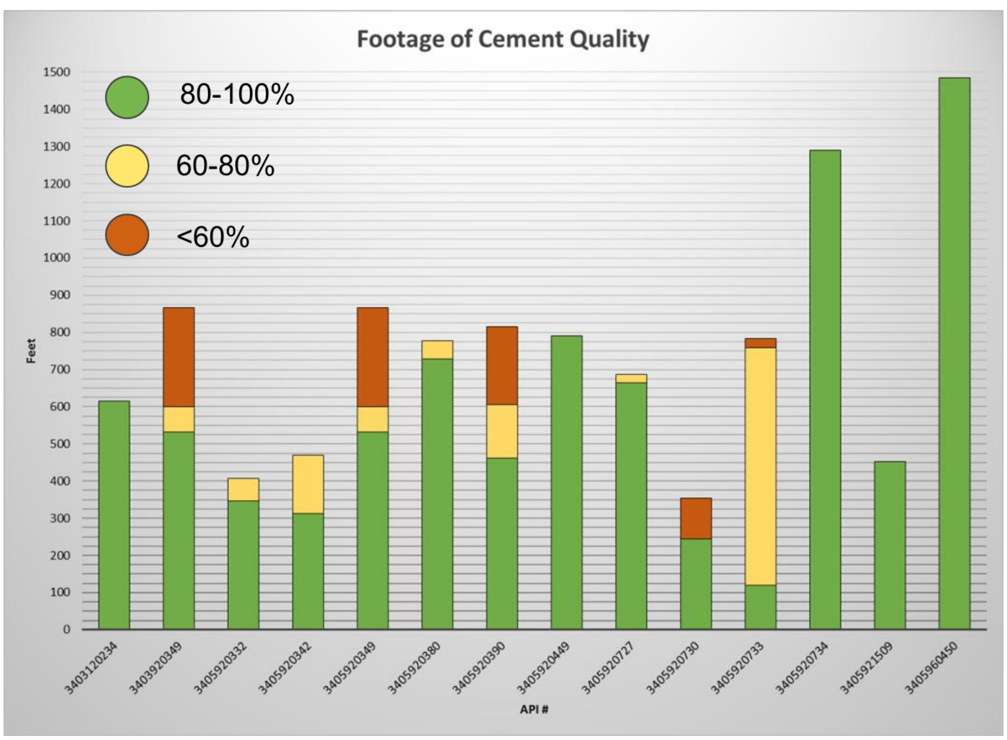


Figure 5-22. Total Footage of Cement Bonds by Specific Bond Percentages, Guernsey County, Ohio, Study Area

Position of cement in depth was evaluated by plotting wellbores, cement in depth, and the local stratigraphy extracted from well records. In order to prevent leakage from the storage zone (Oriskany), there needs to be sufficient cement in or above the confining layer(s). Figure 5-23 shows that 10 wells have high-quality cement within the primary confining layer (Onondaga). The remaining three wells have high-quality cement just above the Onondaga, which falls into the secondary confining layer (undifferentiated Devonian shale).

Overall, in the Guernsey County study area, we interpret that a majority of the wells have sufficient bond percentages and total footage of cement bonds. No conclusion can be drawn as to the potential for formations or residual effects to allow for a poor bonding percentage (less than 60%). Further analysis may be required, especially within the southeast corner of this study area, to look for correlations between percent bond index and certain conditions such as formations, cement type and timing, or any residual effects.

5.3.2 Muskingum/Coshocton County, Ohio

Within the Muskingum/Coshocton County study area, 314 wells have penetrated the Queenston shale or deeper. Of these wells, 114 have CBL data available. The wells are between 3,434 and 7,381 feet deep; the majority have a total depth exceeding 5,800 feet. Wells were completed between 1900 and 2011, with the majority being completed after 1988. The storage zone is the Copper Ridge Dolomite to Mt. Simon Sandstone; the Black River Group is the confining layer.

Individual analyses were completed on the CBLs to determine overall wellbore integrity. Figure 5-24 shows the 114 wells subdivided into three categories of cement quality. The data show that just over half of the wells in this study area contain an average cement bond of greater than or equal to 80%, or high cement quality.

The CBL results were mapped to determine if there were any geospatial trends in the study area with respect to cement quality. Figure 5-24 shows the CBL results and locations of wells by cement quality category. That figure shows a line of wells with low cement quality (weighted average bond index less than 60%) running roughly northwest-southeast.

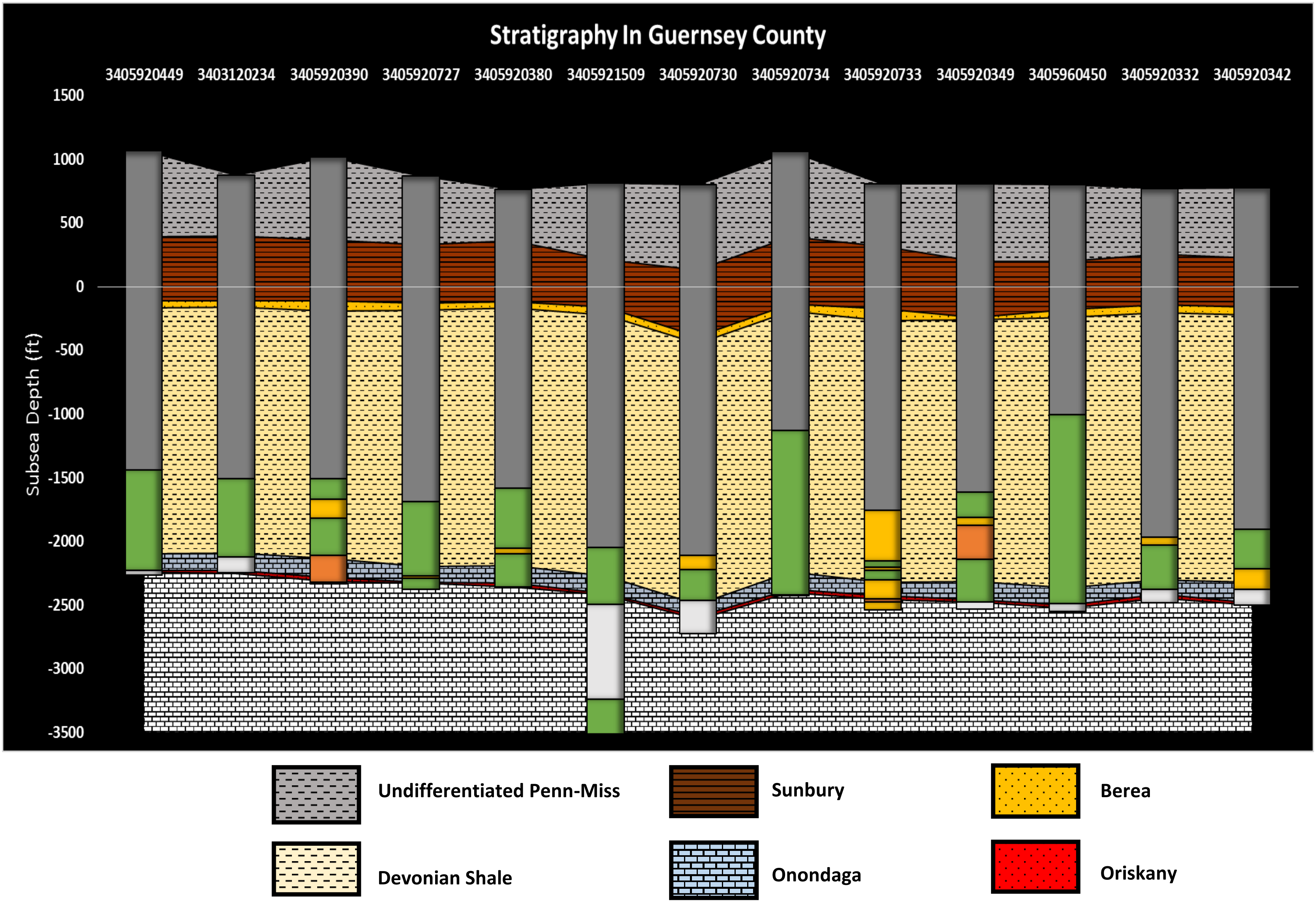
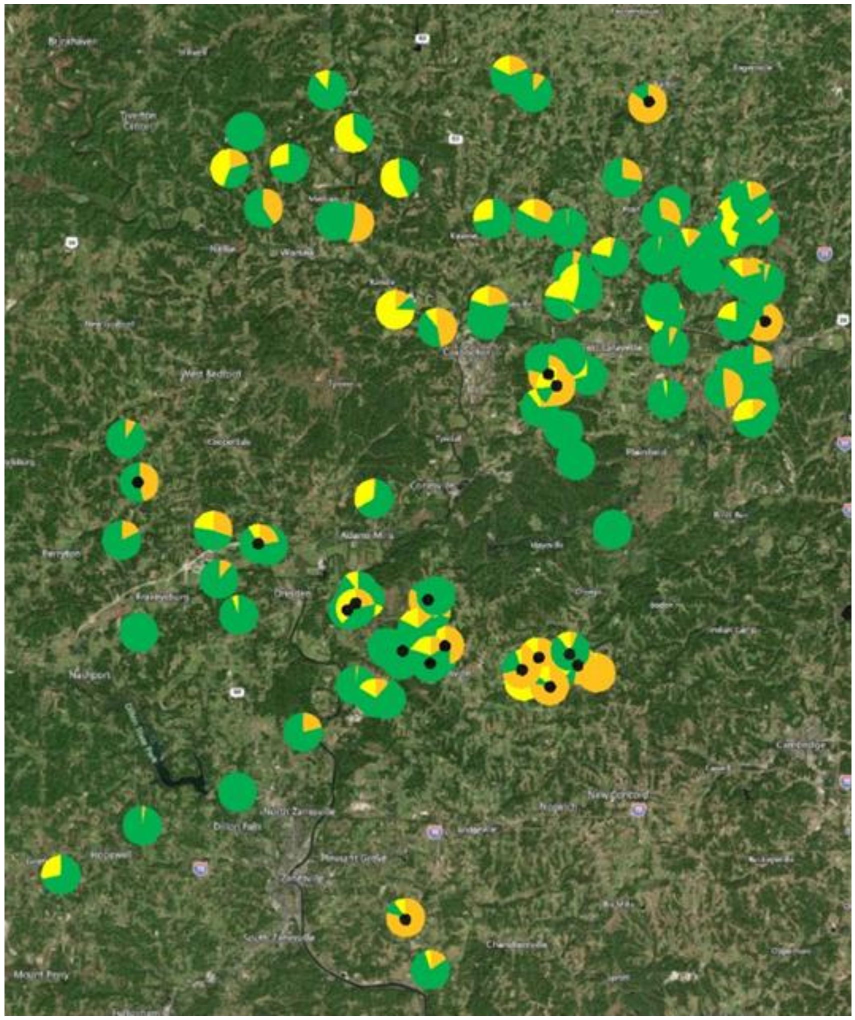


Figure 5-23. Cement Quality of Guernsey County, Ohio, Wells in Subsea Depth Plotted over Local Stratigraphy



Note: Green indicates high cement quality, yellow is moderate, and orange is low.

Figure 5-24. Wells in the Muskingum/Coshocton County, Ohio, Study Area with CBL Results

The cluster of wells in Muskingum County shows a trend of poor cement bonding. These wells were selected for further analysis to assess how the cement was interacting with the subsurface stratigraphy. Figure 5-25 shows 11 wells and their corresponding cement intervals as they are positioned in the subsurface. Of note is the Black River Group in green, selected to perform as the confining layer to the Copper Ridge Dolomite storage zone (orange).

The stratigraphy correlation displays a clear trend of low cement quality within the Black River Group. These wells may not provide a sufficient seal for CO_2 storage and would be considered a risk that could be mitigated through additional assessment and possible corrective action. Overall, the data indicate that a majority of wells within this study area contain proper cement conditions of greater than 80%.

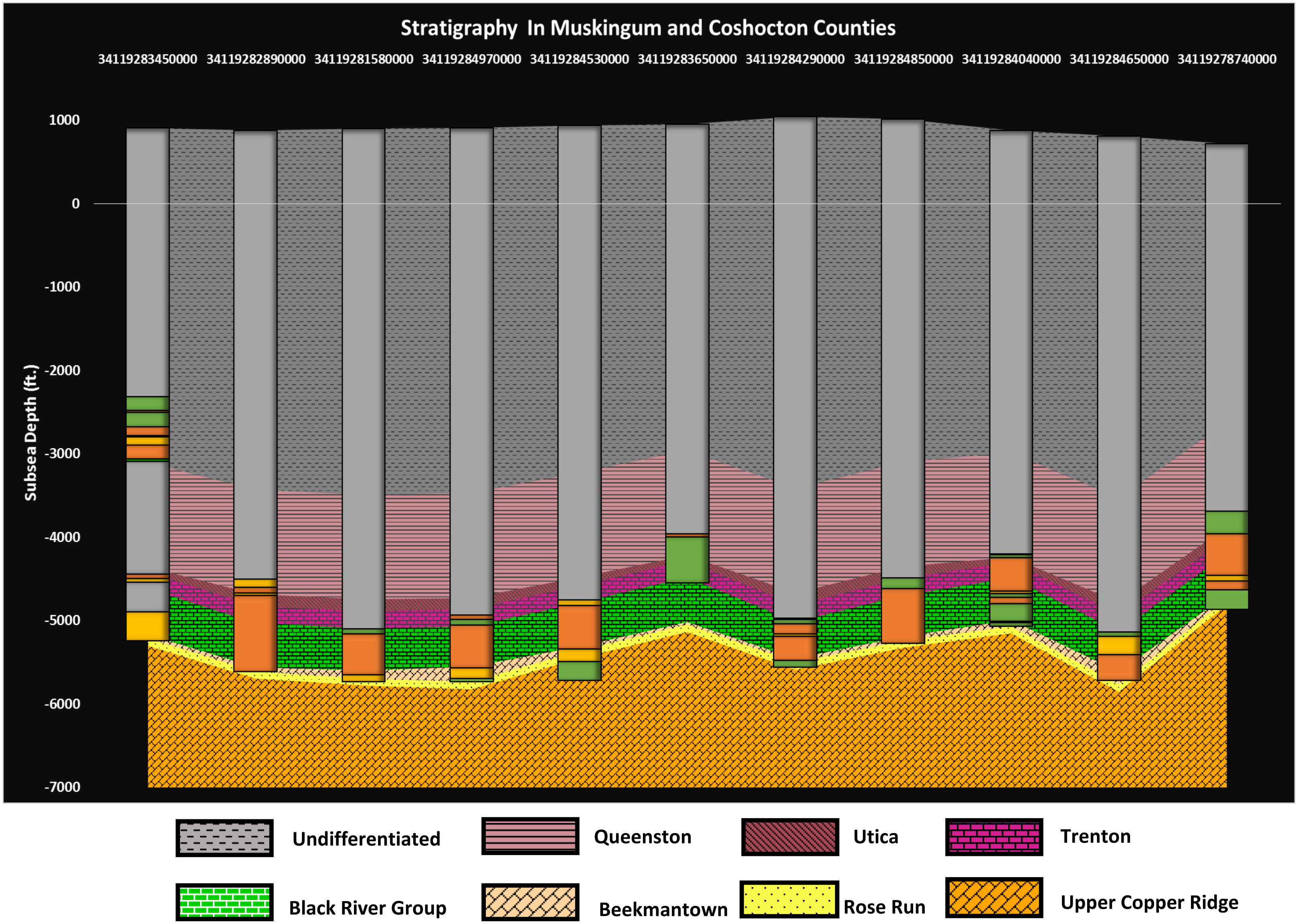


Figure 5-25. Low-cement-quality Muskingum/Coshocton County, Ohio, Wells in Subsea Depth Plotted over Local Stratigraphy

5.3.3 Noble County, Ohio

The same selection criteria and analysis methods were applied to Noble County; however, there was only one CBL with a total depth in Queenston Shale or deeper. With a single data point, no further action could be taken to analyze this particular study area for wellbore integrity.

5.3.4 Otsego County, Michigan

Within the Otsego County study area, 154 wells reach total depth in the Dundee Limestone or deeper. The wells were completed between 1969 and 2008, with the majority of wells being completed later than 1988. There were 87 wells with CBL data available; of these, only 22 penetrated the Dundee or deeper. The majority of wells with CBLs reached a total depth of less than 2,500 feet. The Niagara dolomite is the storage zone, with the Salina group as the confining layers. Figure 5-26 shows the generalized stratigraphy for the study area.

Name	Lithology	Legend
Glacial Drift	Gravel,sand,silt, clay	
Undifferentiated	Sands and shales	
Antrim	Shale	
Traverse	Limestone	
Bell	Shale	
Dundee	Limestone	
Detroit River	Carbonate,Salt,Anhydrites	
Bois Blanc	Carbonate	
Bass Islands	Carbonate	
Salina G	Carbonate	
Salina F	Salt	
Salina E	Carbonate	
Salina D	Carbonate	
Salina C	Shale	
Salina B	Carbonate	
Salina B salt	Salt	
A-2 Carbonate	Carbonate	
A-2 Evaporite	Salt	
A-1 Carbonate	Carbonate	
Niagara	Dolomite	

Figure 5-26. Generalized Stratigraphy for Otsego County and Saint Clair County, Michigan

Individual analyses were completed on the CBLs to determine overall wellbore integrity. Figure 5-27 shows the 87 Otsego County wells subdivided into three categories of cement quality. The data show that the majority of the wells in this study area have an average cement bond of greater than or equal to 80%, or high cement quality. Also worth noting is that half of the wells were cemented to surface.

An aerial analysis was conducted to determine if any trends could be found within wells that contain poor cement conditions (less than 60% average cement bond). Figure 5-28 shows all of the wells in the Otsego County study area, with black dots indicating wells with an average bond index less than 60%. Most of the wells with low cement quality are clustered in the southern section of the study area and were selected for further analysis.

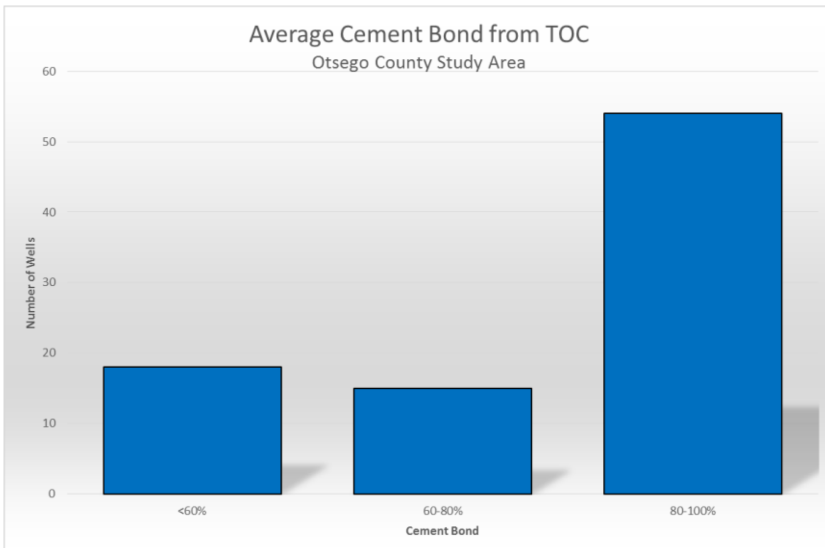
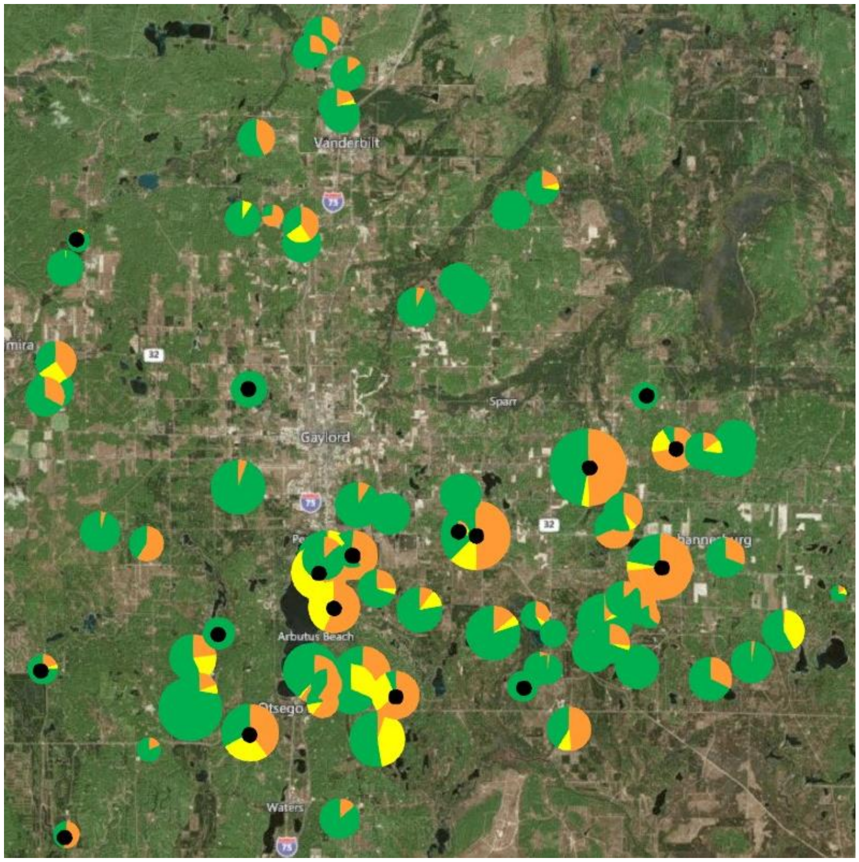


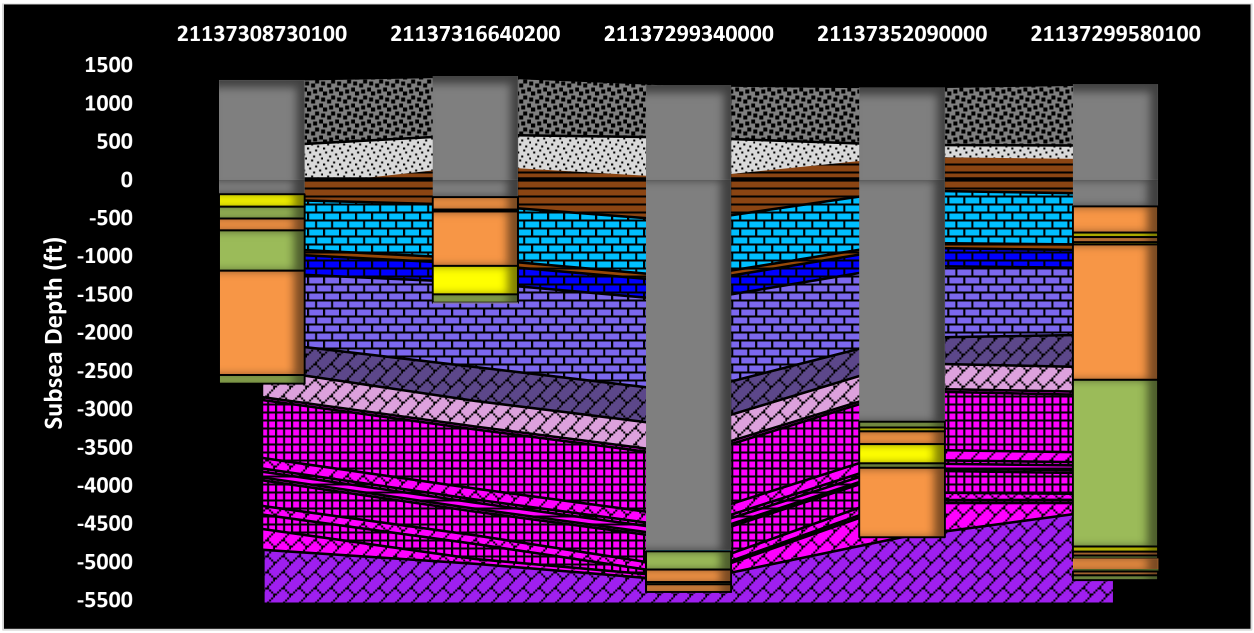
Figure 5-27. Cement Quality (Average Cement Bond Percentage) for Wells in the Otsego County, Michigan, Study Area



Note: Black dots indicate low-quality-cement wells (average bond index of < 60%). Green is high cement quality, yellow is moderate, and orange is low.

Figure 5-28. Wells in the Otsego County, Michigan, Study Area with CBL Results

Figure 5-28 shows that 18 Otsego County wells had an average bond index of less than 60%. Only five of these wells reached a total depth within the confining layers or deeper (Figure 5-29). Two wells were not logged to total depth, so no conclusions about the cement quality in the confining layers could be drawn. Well 21137299340000 has alternating layers of high-quality and low-quality cement. It has 240 feet of high-quality cement within the Salina group, which satisfies industry standards. Well 21137352090000 has alternating layers of high-, moderate-, and low-quality cement. There are two intervals of high-quality cement in that well, one 74 feet thick and the other 60 feet thick. Well 21137299580100 has 2,180 feet of high-quality cement across the Salina group. Even though these three wells have low-quality cement present, there is enough footage of high-quality cement to create a sufficient seal within the confining layers. Figure 5-29 shows the resulting cement quality in depth for the five wells, with local stratigraphy in the background.



Note: See Figure 5-26 for stratigraphy and coordinating legend.

Figure 5-29. Cement Quality of Otsego County, Michigan, Wells in Subsea Depth Plotted over Local Stratigraphy

5.3.5 St. Clair County, Michigan

Of 155 wells in the St. Clair County study area, 86 have available CBLs. The wells were completed between 1958 and 2004, with the majority of wells completed in the late 1960s. The wells ranged from 1,976 to 9,155 feet deep; most of the wells were less than 4,000 feet deep. The storage zone is the Niagara Dolomite with the Salina Group as the confining layers. The generalized stratigraphy for the Otsego County study area (see Figure 5-26) is the same for the St. Clair study area.

More than half of the St. Clair County wells have an average cement bond of 80% or greater. Just like the Otsego County study area, the majority of wells were cemented to surface. Figure 5-30 shows the results of the CBL analysis for the St. Clair County wells. The map view (Figure 5-31) does not show any trend or clustering of low-quality wells. The 15 wells with an average bond index of less than 60% were further analyzed to determine the quality of cement in the confining layers.

Most of the wells with low cement quality have at least 50 feet of cement of 80% or better bond index within the Salina group (Figure 5-32, pink). Three wells did not meet the industry standard. Wells 21147559040000 and 21147575870000 do not have any high-quality cement; well 21147261230000 has a maximum of 22 feet of high-quality cement. These three wells would be high-risk wells in the St. Clair County study area and would require more detailed assessment or corrective action if they were to be used for CO_2 storage. Figure 5-32 shows the resulting cement quality in depth for the 15 wells with low-quality cement in St. Clair County.

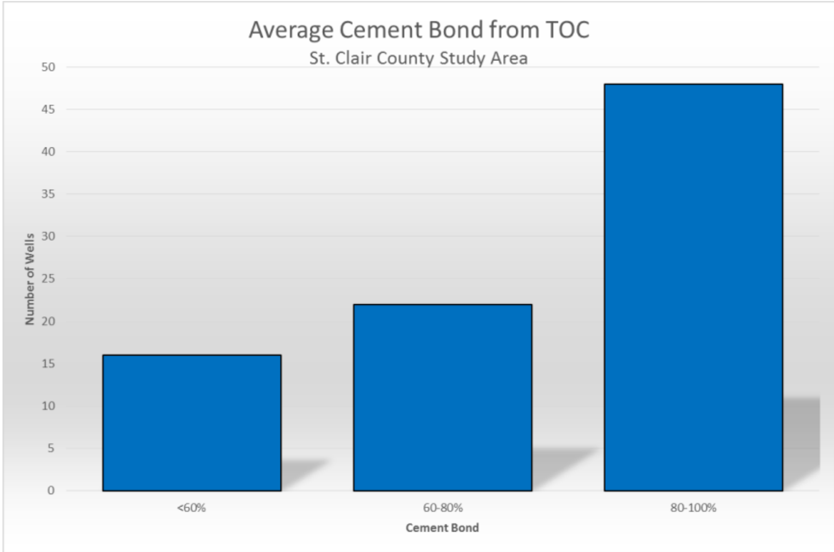
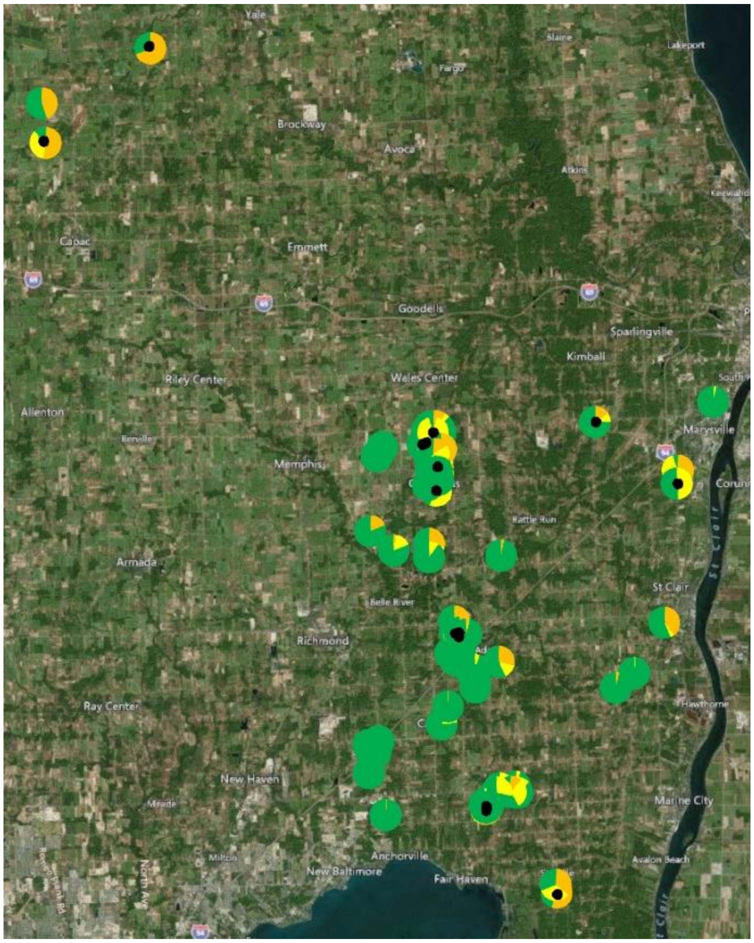
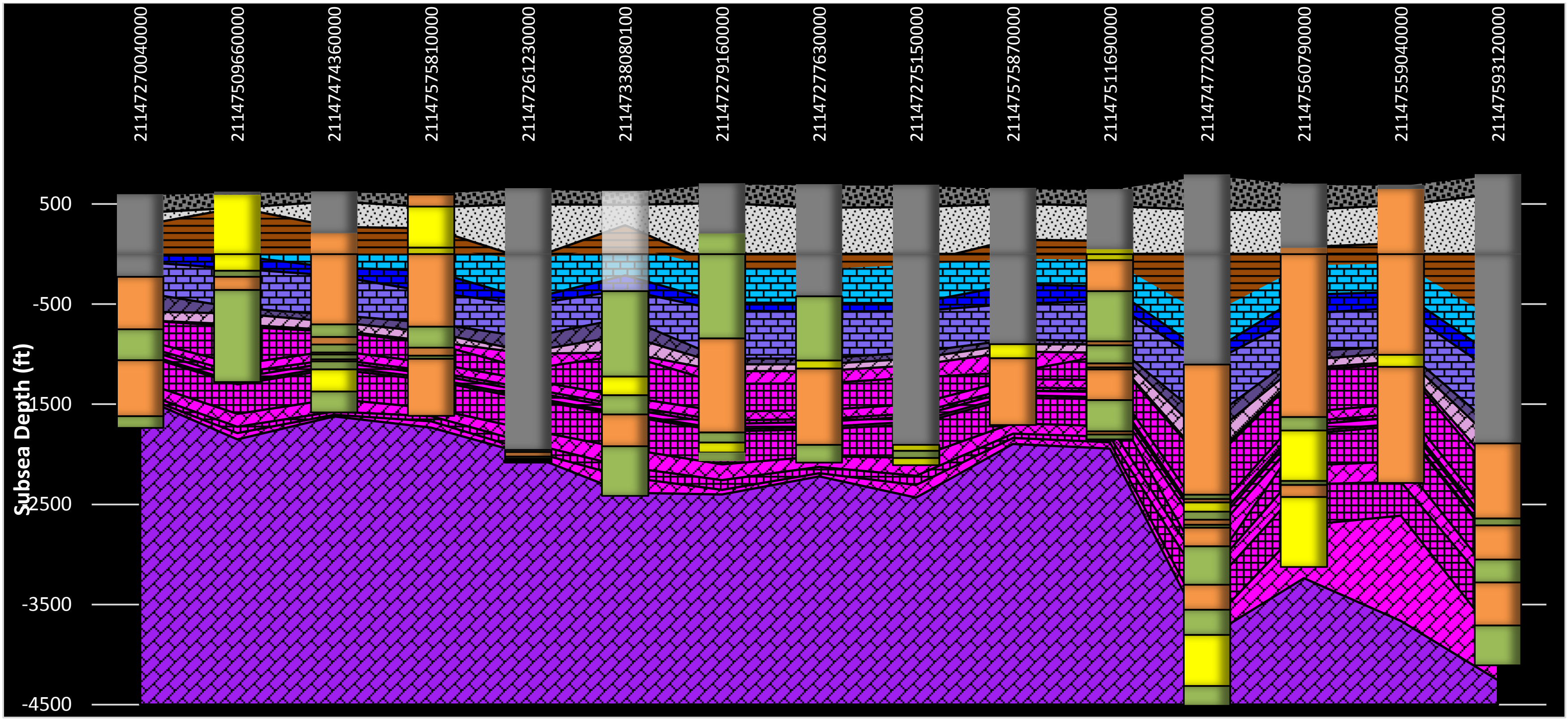


Figure 5-30. Average Cement Bond for Wells in the St. Clair County, Michigan, Study Area



Note: Black dots indicate low-quality-cement wells (average bond index of less than 60%). Green indicates high cement quality, yellow is moderate, and orange is low.

Figure 5-31. Wells in St. Clair County, Michigan, Study Area with CBL Results



Note: See Figure 5-26 for the stratigraphy and coordinating legend.

Figure 5-32. Low-cement-quality St. Clair County, Michigan, Wells in Subsea Depth Plotted over Local Stratigraphy

5.4 Well Casing Evaluation

Well casing was evaluated in relation to potential for CO_2 storage in the region. Well construction methods and casing materials were reviewed for conditions that may contribute to CO_2 migration along existing oil and gas wells. In addition, casing inspecting methods were summarized as they apply to evaluating the condition of casing in oil and gas wells.

5.4.1 Well Construction in the Region

Well construction practices in the Midwest United States have progressed with drilling technologies and regulations. Review of well records provides evidence of the increase in documentation and records related to oil and gas wells. To depict the development of drilling technologies in the study areas, key historical events related to drilling technology were summarized.

Figure 5-33 shows historical events in the Michigan oil and gas industry. As shown, the first oil well was drilled in Michigan in 1886 in the Dundee group in Port Huron, St. Clair County. Saginaw Field, Michigan's first commercial oil field, was developed in 1925. In 1927, Michigan began requiring drilling permits and approval to plug and abandon wells. In 1939, the Oil and Gas Act was passed in Michigan, which mandated filing of well records and reports. This was followed by development of major fields like the Antrim (1940) and Albion-Scipio (1957), and the northern Silurian reef trend (1969). More recently, regulations were instituted to require reporting and monitoring related to hydraulic fracturing.

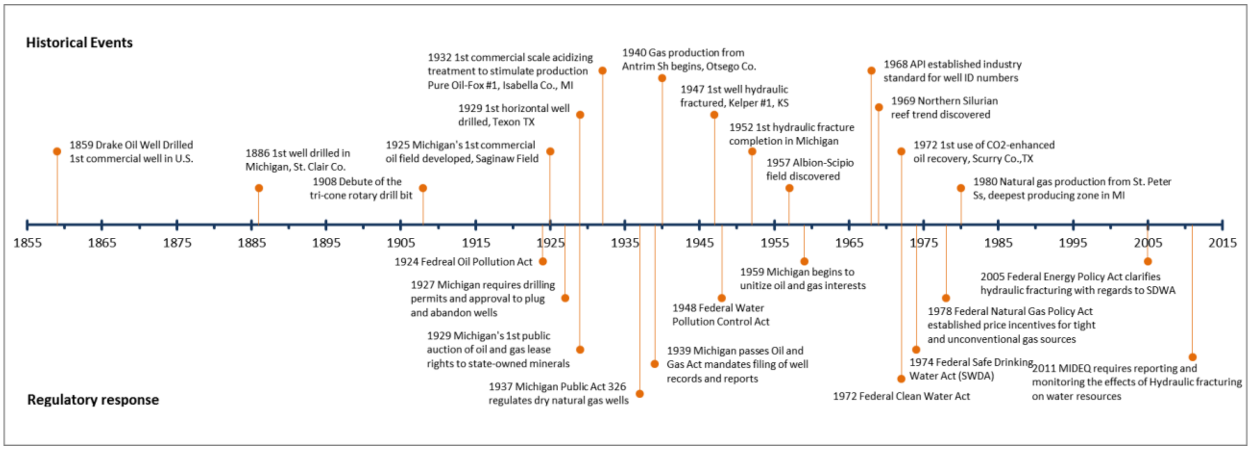


Figure 5-33. Historical Timeline of Oil and Gas Developments in Michigan

Figure 5-34 summarizes historical events in the Ohio oil and gas industry. The first commercial oil well was drilled in Ohio in 1860. Several major oil fields were developed in the late 1800s, including the Lima oil field. Due to these developments, Ohio was one of the first states to require wells to be cased when drilled and plugged when abandoned, in 1883. In 1933, Ohio began requiring completion records for all wells drilled in the state. Several major oil fields were discovered in Ohio, including the Morrow County fields in the 1960s, which led to well spacing regulations. In 1974, Ohio enacted preliminary and final restoration requirements. Similar to other areas of the United States, regulations have recently been instituted to require reporting and monitoring related to hydraulic fracturing.

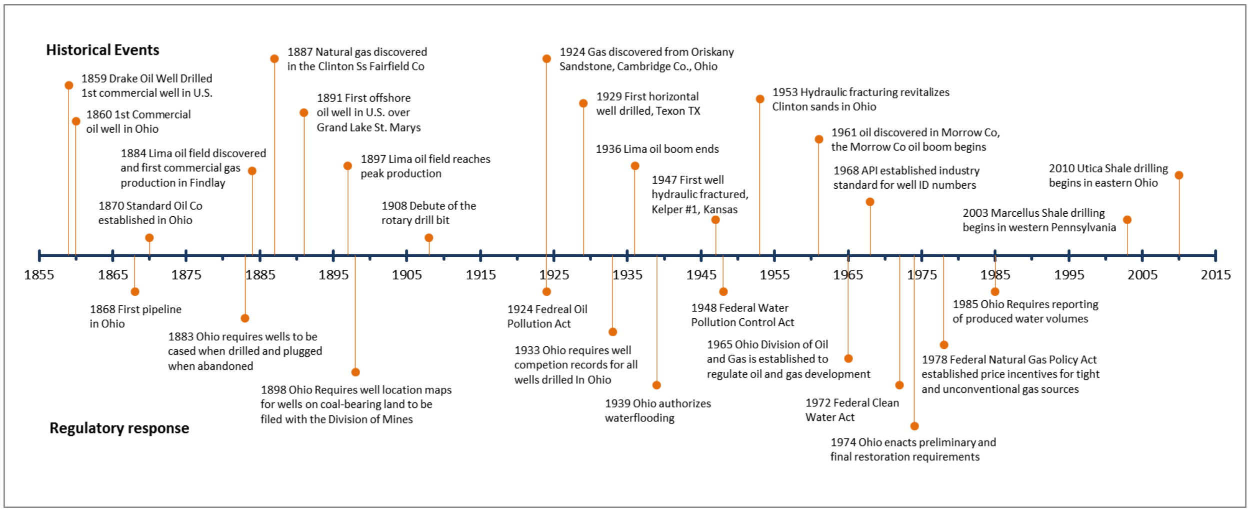


Figure 5-34. Historical Timeline of Oil and Gas Developments in Ohio

5.4.2 Casing Materials

Well casing is used in oil and gas wells to stabilize the borehole, prevent unconsolidated material from entering the borehole, reduce corrosion, and protect underground aquifers. While there are some instances of wood, stone, or concrete casing in very old wells in the region, most wells use carbon steel casing. Casing and tubing are classified by API type of steel (H-Q) and minimum yield strength (40,000 to 125,000+ psi). In general, higher grades of steel are designed for deeper wells, higher temperatures, higher pressures, and corrosion resistance. Many grades of steel are designed to be more ductile to prevent brittle failure from hydrogen sulfide (H_2S) gas.

Well completion records in the region list well casing diameter for each casing run, but not much detail is provided on the grade of casing unless a job ticket is included. API grade H-40 or J-55 casing is most prevalent in the region, because it is suitable for most depth, temperature, and fluid conditions encountered. Various casing sizes are used, depending on field properties. Overall, 8 5/8-inch diameter surface casing and 4 1/2-inch diameter production casing were typical for Ohio wells. In Michigan, 9 5/8-inch diameter surface casing and 5 1/2-inch diameter production casing were typical construction designs. However, many different well designs have been used in the region. Wells may have two to six or more strings of casing at various depths. Many ‘dry hole’ wells did not set production casing, and many wells have sections where casing was pulled after plugging. These conditions may affect CO_2 storage security and are best evaluated on a well-by-well, site-specific basis.

In relation to CO_2 storage, existing oil and gas well casing may be affected if it comes in contact with CO_2 or CO_2/water mixture in the subsurface. CO_2 is referred to as “sweet gas” when encountered in the oil and gas industry and can cause pitting and pinhole leaks in casing, joints, tubing, and packers. API grade of L-80 or greater is recommended for these applications. Nitrogen dioxide (NO_2) and sulfur dioxide (SO_2) may result in a similar acidic corrosion process, and the same grade of steel may be sufficient for these compounds as well. Other options for corrosion resistance include alloy plating (nickel, chrome, etc.), polymer coatings, stainless steel, and fiberglass casing.

Table 5-9 summarizes casing/tubing materials for CO_2 storage applications. These options are typically more expensive and more difficult to handle in the field and are susceptible to damage due to scrapes, nicks, and scratches. Many operators use common steel grades (J-55) with few problems so long as they produce or inject relatively pure CO_2. However, some enhanced oil recovery (EOR) fields encounter significant corrosion when injecting water alternating CO_2 gas.

Table 5-9. Casing/Tubing Materials, Applications, and Limitations

Material	Type	Applications	Limitations
Carbon and Low-Alloy Steel	Hardness <HRC 22	"Dry" CO_2 transmission, shallow casing (i.e., conductor casing).	Brittle at temperatures < -20°F. Corrodes in presence of wet CO_2 or H_2S. Corrodes more rapidly when CO_2 partial pressure exceeds 15 psia or temperature > 300°F.
Stainless Steel (Martensitic)	Hardness <HRC 22 (AISI 410; 9Cr/1Mo)	"Dry" or "wet" CO_2 transmission.	Oxygen, H_2S, H_2O, increasing partial pressures of CO_2, or Cl rapidly increase corrosion rates, especially at temperatures > 200°F.
Stainless Steel (Austenitic)	Hardness < HRC 22; 35 (AISI 304, 316; Nitronic-50)	"Dry" or "wet" CO_2 transmission.	Oxygen, H_2S, H_2O, and Cl increase corrosion rate, especially at temperatures > 150°F.
Bimetallic	Carbon steel outer, corrosion-resistant inner (Alloy 625)	Inexpensive carbon steel handles stresses, is protected from corrosion by liner. Cheaper than high-alloy steel pipe.	Segments must be joined by special welding technique. Very susceptible to problems (including galvanic corrosion) if holes form in liner.
Other Internally-coated Carbon Steel	Phenolics, epoxy-phenolics, glass epoxies, nickel	Provides extra protection to inexpensive steels (alternative to more expensive material).	Only effective when not damaged (i.e., scratched). Damaged areas will corrode quickly.
Fiberglass	–	Can be used alone or as an outer covering to protect carbon steel from corrosion.	Pure fiberglass may not withstand high pressures, can be brittle when cold, and its length can vary dramatically with temperature.
Fiberglass-Reinforced Plastic	Polyester/glass, epoxy/glass	Currently used in natural CO_2 production and oil-field injection.	CO_2 swells and alters resin, worse at increasing pressures. Results in brittleness, delamination. H_2S limits service temperatures. Length varies dramatically with temperature.

5.4.3 Casing Evaluation

Casing inspections may be required on a regular basis for some deep wells (typically injection wells) or before plugging and abandoning a well. There are numerous ways to inspect the condition of the casing string, but most methods fall into a physical test (pressure testing) or wireline deployment. This section describes the inspection methods that are most frequently used.

5.4.3.1 Physical Techniques

Physical techniques are essentially limited to pressure testing of the casing string. The casing string is usually filled with fluid and pressurized to a specified pressure (often in the range of 250 to 1,000 psi). The string is then sealed and isolated, and the pressure is monitored for a specified length of time (often 30 minutes). A successful test (indicating that the casing string is sound) is defined by a pressure decrease that is less than a certain percentage of the starting pressure. If this test is performed as a regulatory requirement, the starting pressure, the duration of the test, and the allowable pressure loss are often prescribed. Typically, these tests are performed on the entire casing string, but they can be performed over discrete intervals in order to check specific zones of the casing string.

5.4.3.2 Wireline Techniques

Wireline casing-inspection logs can be divided into those that collect physical data and those that collect electronic data. Examples of both include cased-hole caliper (physical) and flux leakage tools (electronic). These commonly used casing-inspection logs and the data generated by each log are described in this section.

Cased-Hole Caliper Tools

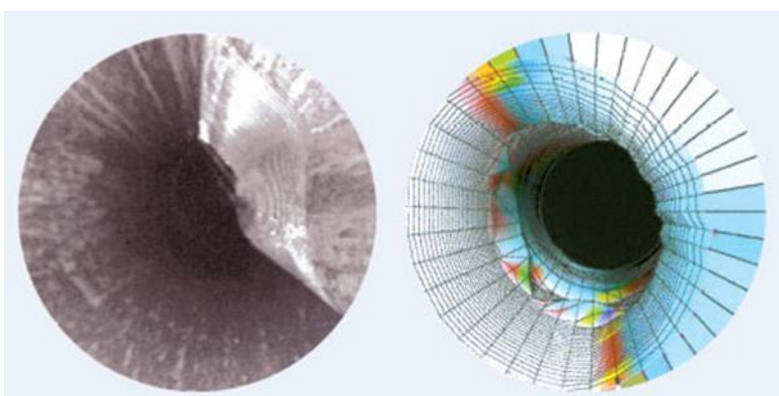
Multifinger calipers can be wireline- or slickline-deployed, depending on the type of tools. Wireline-deployed tools provide real-time data; the slickline tools have data-logging capabilities incorporated in the tools. Multifinger calipers are used to identify changes in the inside diameter of tubulars that may indicate wear and corrosion. They are also used to monitor tubular deformation. These logging tools can have up to 80 spring-loaded feelers or fingers, depending on the nominal casing diameter (Figure 5-35). Different multifinger caliper tools can log casing sizes from 4 to 20 inches. Smaller tools are available for tubing inspection. Each hardened finger can measure the internal casing diameter with a radial resolution of a few thousandths of an inch and a vertical resolution of a few hundredths of an inch, with measurements being collected many times per second from each finger. A finger extends where it encounters a pit or hole and retracts where there is scale or other buildup present or if there has been partial collapse.

A potential disadvantage is that the fingers can damage the casing; however, modern electronic tools have a very low finger pressure to avoid this problem. The tool also indicates which finger is the one on the highest side of the well. Moreover, fingers can be grouped azimuthally. All these data can be combined with the measured diameter to produce a three-dimensional (3-D) picture of the casing, including cross-sectional distortions and changes in the trajectory of the well axis as small as 0.01°.

Source: From Baker-Hughes.

Figure 5-35. Example of a Multifinger Caliper Tool

Multifinger tools often contain an inclinometer so that tool deviation and orientation can be recorded. If these pieces of data are known, modern multifinger calipers can produce detailed images of the casing condition. These data can be used to map the trajectory of the wellbore and quantify casing deformation. For example, digital images of the casing deformation can be produced for a well. In addition, if repeat logging is performed with these tools over time, the images can be used to measure the rates of corrosion or scale buildup. Modern multifinger calipers can provide images similar to those provided by a downhole camera, but with an additional capability: the electronic images can be rotated and inspected from any angle. Artificial colors are used to bring out anomalies. An example of data output from a multifinger caliper is provided in Figure 5-36.



Source: easternutd.com

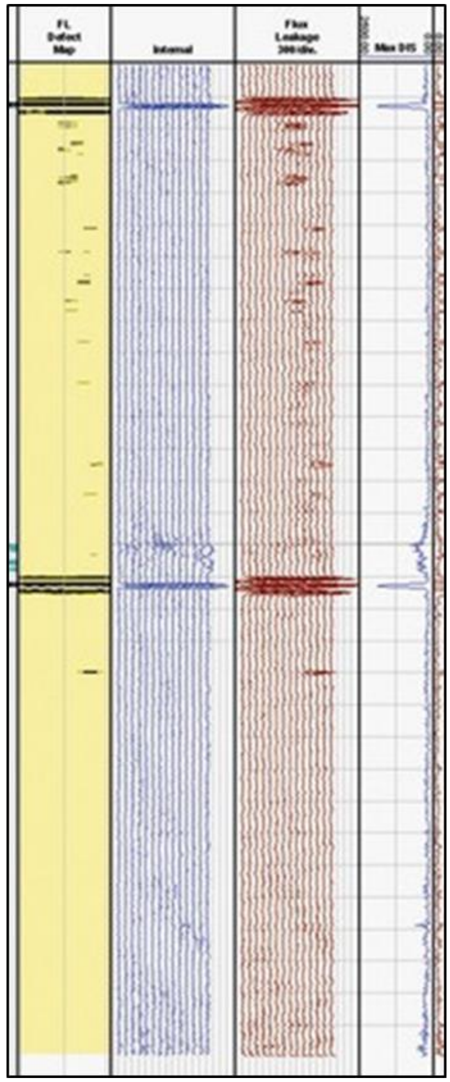
Figure 5-36. Processed Data from a Multifinger Caliper Logging Tool

Flux-Leakage Tools

Flux leakage is a semi-quantitative logging method that produces a strong magnetic field to identify and, to a certain extent, quantify spots of corrosion on both the inner and the outer surfaces of the casing. An electromagnet creates a low-frequency or a direct-current magnetic field that is held close to the inner surface of the casing. Magnetic flux is concentrated within the casing close to the magnetic saturation level. The tool contains spring-loaded, coil-type, pad-mounted sensors that are run close to the casing during logging. Where casing corrosion is encountered, the magnetic flux lines flare out from the casing, appearing as if they are leaking from the casing. The primary sensors pass through this magnetic flux field and measure the induced voltage. The amplitude and spatial extent of the sensor response are related to the volume and shape of the corrosion-induced metal loss, and can be used to estimate size of the defect.

Figure 5-37 shows generic output from a flux-leakage tool. The primary sensor flux measurement cannot distinguish between internal and external casing defects, but some tools use an additional higher-frequency eddy-current measurement. The eddy-current measurement is a shallower measurement that responds only to casing flaws on the inner wall. When the eddy-current measurement is combined with the magnetic flux measurement, inner wall defects can be distinguished from defects along the outer wall of the casing.

Magnetic flux-leakage tools can be used to identify localized casing defects such as corrosion patches, pits, and holes with areas as small as 0.2 inch on both the inside and the outside of the pipe. However, the tool cannot detect large areas of corrosion. Also, this tool cannot detect scale that is non-magnetic. Further, the coil-sensor response is sensitive to logging speed, and this sensitivity makes quantitative interpretation more difficult.



Source: Baker-Hughes

Figure 5-37. Example of Data Output from a Flux-Leakage Tool

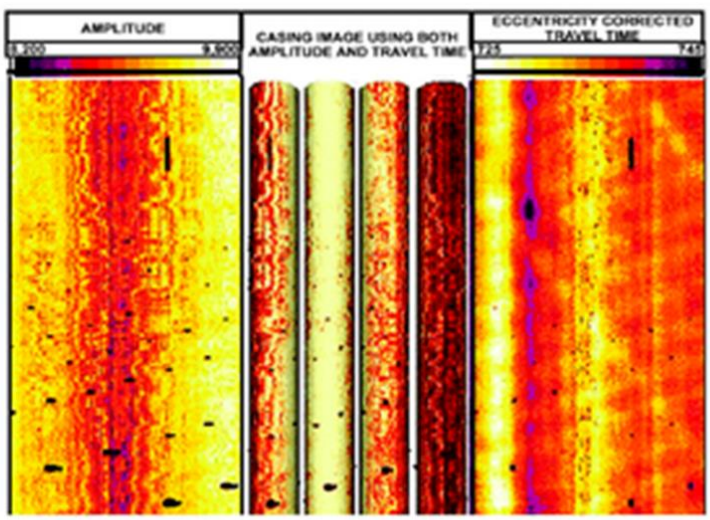
Electromagnetic Phase-Shift Tools

Electromagnetic phase-shift tools use a transmitter coil that generates a low-frequency alternating magnetic field, which couples to a receiver coil, and the eddy currents pass through the casing and formation. When these currents pass through the casing, a phase shift occurs. The phase-shifted field is superimposed on the transmitted field, and both (combined) fields are detected by the receiver coil. The phase shift between the transmitted and received signals is related to the thickness, electrical conductivity, and magnetic permeability of the casing. If the last two are known, the casing thickness can be determined. Higher phase shifts indicate a higher casing thickness, all other things being equal.

The electromagnetic phase-shift technique provides an estimate of casing thickness across approximately 1 foot of casing length, so its spatial resolution is weaker than other methods because electromagnetic phase-shift tools make measurements that are averages around the circumference of the pipe. However, because this tool has a higher spatial resolution, it is best used to investigate larger-area corrosion and gradual thinning of the casing. With this tool, the sensors do not need to be in close proximity to the casing, so a single tool can examine a range of casing sizes.

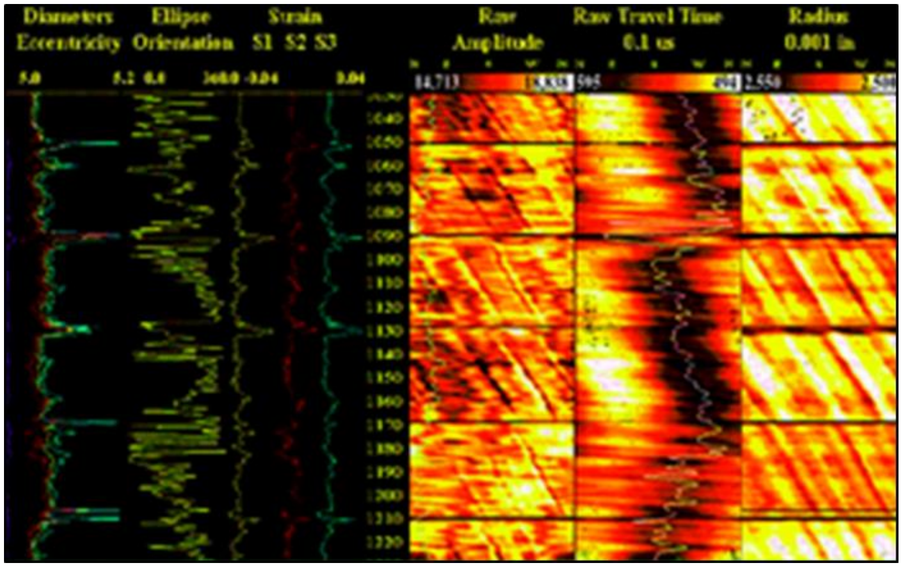
Ultrasonic Tools

Ultrasonic tools use an ultrasonic emitter and a transducer array to analyze the condition of the casing. Casing inspection and monitoring applications include corrosion detection, identification of internal and external damage or deformation, and casing thickness analysis. The amplitude and travel time of the echoed ultrasonic waves provide images that show the condition of the inside casing surface (e.g., buildup, defects, and roughness such as pitting and gouges) (Figure 5-38), and travel-time and resonant-frequency analysis provide casing thickness (Figure 5-39). The acoustic caliper generated from the pulse/echo travel time provides the casing inside diameter (an average of all transducers or a single circumferential scan). An estimate of casing ovality is obtained using only the maximum and minimum measurements. Then, if the nominal value of the outside casing diameter is assumed, changes in thickness can be calculated and internal defects identified. Frequency analysis determines the casing resonant frequency from the acoustic waveform; casing thickness is inversely related to the resonant frequency.



Note: Left image is based on an amplitude reading; center image provides 3-D images of the casing quadrants; right image is based on corrected time travel of the ultrasonic waves.
Source: SPE

Figure 5-38. Example of an Ultrasonic Casing Evaluation Log Showing Holes in the Casing



Source: Baker-Hughes

Figure 5-39. Example of an Ultrasonic Log Data Depicting Casing Thickness

Noise and Temperature Logs

Noise and temperature logs are relatively simple logs that can provide information about the depth of a hole in the casing. The noise log essentially uses a microphone-equipped logging tool that "listens" for fluid movement, and the temperature log is equipped with a thermometer that senses small changes in the temperature of the fluid it is passing through (Figure 5-40). Often, when a leak occurs in the casing, the fluid or gas moving into the well is depressurized and is cooled. As these tools pass by a leak in the casing, there may be an audible sound from the fluid moving into the well accompanied by a zone of lower temperature. These tools, however, cannot detect corrosion or small defects in the casing that have not penetrated through the casing wall.

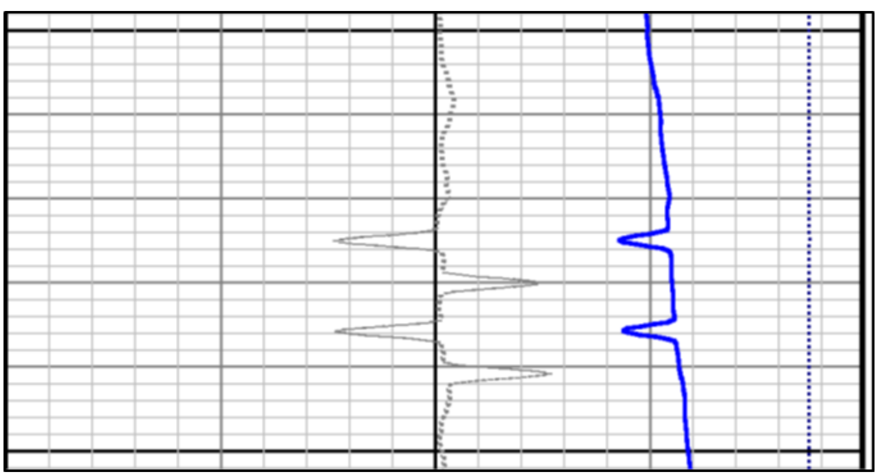


Figure 5-40. Example of a Temperature Log Showing Small Deflections in Temperature

5.5 Hydrologic Conditions

Over time, subsurface hydrologic conditions may lead to corrosion or physical damage of wellbore materials and interactions with CO_2 storage zones. To determine possible effects on wellbore integrity, subsurface hydrologic conditions at six local study areas in Ohio and Michigan were examined.

5.5.1 CO_2 Storage Zones

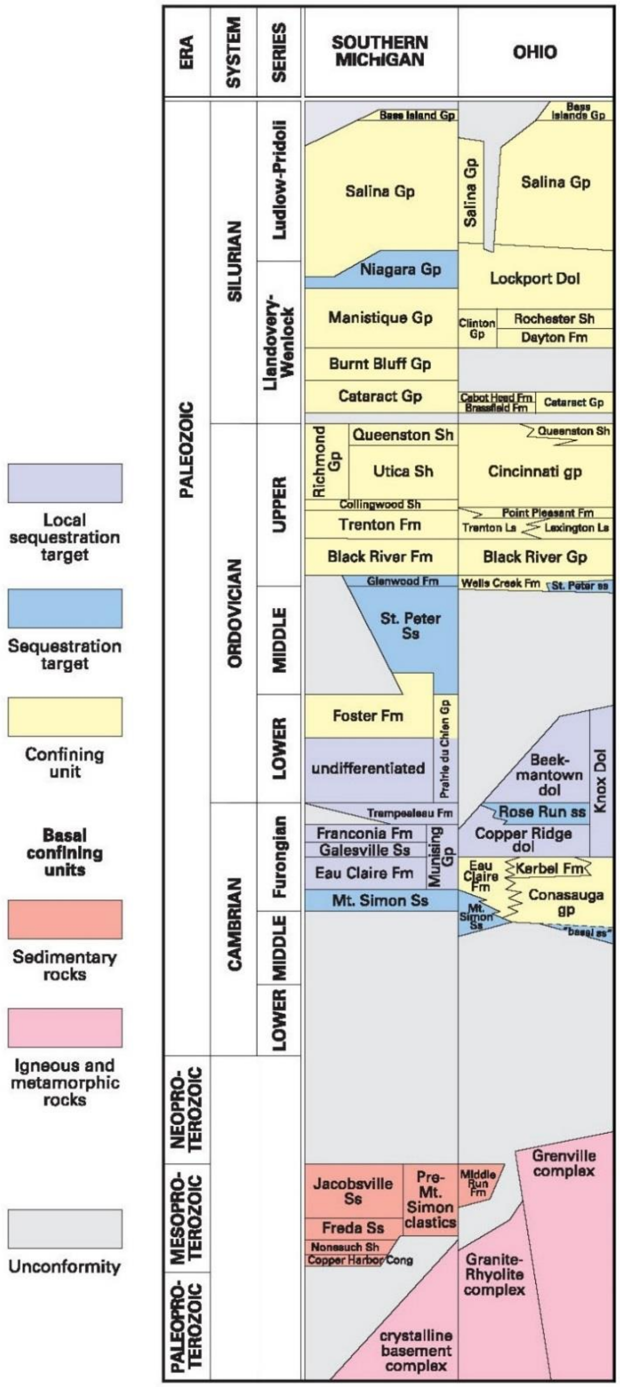
There are many potential storage zones in the Midwest United States (Wickstrom et al., 2005). These zones are located at various intervals with sequences of Paleozoic age rocks in the region (Figure 5-41). The CO_2 storage zones investigated in this study were related to the six local study areas in Ohio and Michigan, including the Cambrian basal sandstones-Cambrian Copper Ridge Dolomite, the Silurian Clinton and Medina sandstones, and the Silurian Niagara Group and Lockport Dolomite (Figure 5-42). These study areas represent realistic test cases for evaluating wellbore integrity in relation to CO_2 storage applications. Examination of the hydrologic factors builds on work to examine wellbore conditions in these areas as summarized in Section 2.0. The geologic characteristics of the storage zones are summarized in the following sections.

5.5.1.1 Cambrian Basal Sandstone Interval

At the base of the Michigan and Ohio sedimentary sequence, unconformably overlying the Precambrian basement, there are two major Cambrian-age sandstone units: the Mt. Simon sandstone and the unnamed Conasauga sandstone. The Mt. Simon lies at depths from 2,000 feet on the Ohio-Indiana platform to about 15,000 feet in the center of the Michigan Basin. In the Michigan Basin, the Mt. Simon reaches thicknesses greater than 1,300 feet. In eastern Ohio, the Mt. Simon ranges in thickness from 50 to 300 feet. The Mt. Simon pinches out eastward and is replaced by the unnamed Conasauga sandstones in central and eastern Ohio (Wickstrom et al., 2005; Barnes et al., 2009). The Mt. Simon Sandstone grades upward into the overlying Eau Claire Formation. The Eau Claire, along with the overlying upper Cambrian strata, is considered a regional confining zone (Barnes et al, 2009; Medina et al., 2010).

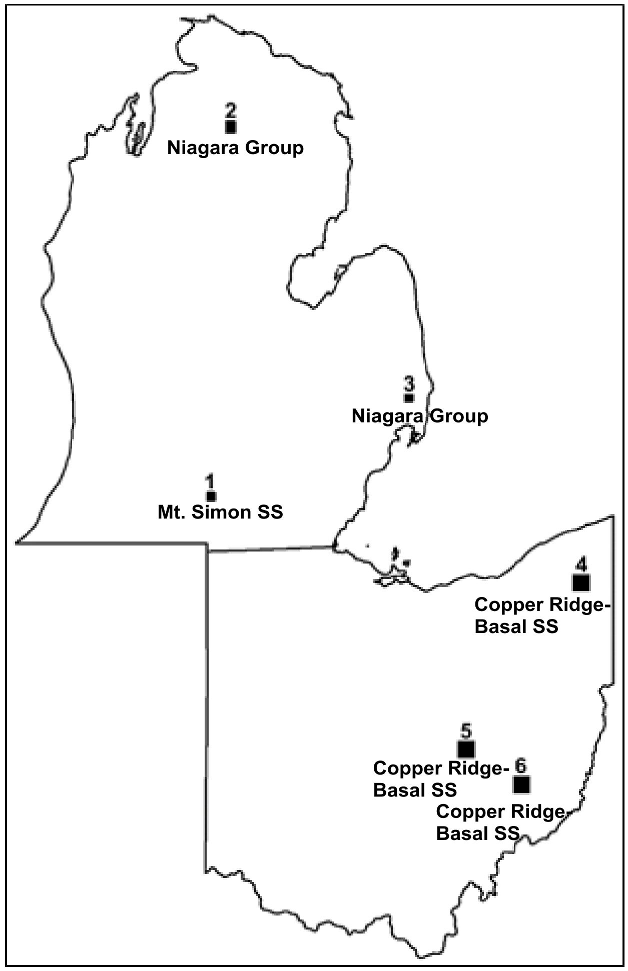
5.5.1.2 Copper Ridge Dolomite

The Copper Ridge Dolomite in Ohio has recently been recognized as a potential long-term storage reservoir for CO_2. Regional geologic analysis conducted by Battelle has shown the Copper Ridge to have moderate to significant porosity and permeability and potential areal extent and thickness to justify interest as possible CO_2 reservoir. In the western region of the study area, where the Copper Ridge is truncated by the Knox unconformity, the unit can develop secondary porosity, especially in topographically high erosional remnants.



Note: Modified from Wickstrom et al., 2005.

Figure 5-41. Regional Stratigraphic Correlation Chart of Southern Michigan and Ohio Showing Potential CO_2 Storage Zones and Confining Units



Note: 1) South-central Michigan, 2) northern Michigan, 3) eastern Michigan, 4), northeastern Ohio, 5) central-eastern Ohio and 6) eastern Ohio.

Figure 5-42. Locations of the Six Test Areas in Michigan and Ohio

5.5.1.3 Silurian Clinton Sandstones

The Silurian Clinton Sandstone thickness from the base of the Dayton Formation to the top of the Queenston Shale ranges from 170 to 200 feet, with an average gross thickness of 110 feet (Riley et al., 2010). Historically, the Silurian Clinton has been an important oil and gas producer in Ohio since "Clinton" gas was discovered in 1887 near Lancaster, Ohio (McCormac et al., 1996).

5.5.1.4 Silurian Niagara Group and Lockport Dolomite

In Michigan, the Silurian Niagara Group is characterized by two linear trends of pinnacle reef development. Pinnacle reefs are localized carbonate structures, conical in shape, that act as a trap for hydrocarbons in the subsurface (Tolle et al., 2008). These pinnacle reefs developed along two linear trends: one along the northern part of the Michigan Basin and the other along the southern part. More than 1,100 reefs have been identified in the northern and southern trends at depths ranging from 3,000 to 7,000 feet (Grammer et al., 2009). Even though pinnacle reefs are localized in nature, they can be laterally extensive and several hundred feet thick. These reef formations have been important oil and gas producers since their discovery in 1952 and are currently undergoing exploration and extraction (Wickstrom et al., 2005). The Lockport Dolomite in Ohio is a potential CO_2 storage zone in the eastern part of the state. Porosity zones are often associated with patch reef development within the Lockport interval (Janssens, 1977). The Lockport ranges in depth from -1,500 to -6,500 feet below sea level and ranges in thickness from 150 to 350 feet. The Niagara Group and Lockport Dolomite are overlain by the Salina Group, an intercalated interval of carbonates and evaporites. The Salina Group is a regionally thick and competent confining zone (Wickstrom et al., 2005).

5.5.2 Subsurface Conditions

Six test areas were chosen in the Michigan-Ohio region (see Figure 5-42) to study wellbore integrity impacts on CO_2 storage reservoirs. Three test areas were picked for each state based on geologic layers with suitable depth, thickness, and porosity to accommodate a large-scale CO_2 storage project. The potential storage reservoirs investigated were the Mt. Simon sandstone (test area 1), Niagara Group pinnacle reefs (test areas 2 and 3), and the Copper Ridge Dolomite to basal sandstone interval (test areas 4, 5, and 6). Conditions in overlying layers may also affect wellbore integrity in shallower intervals, but the storage zone and immediate confining layers are most important to evaluate CO_2 storage processes.

Table 5-10 lists the subsurface hydrological conditions for each test area. Data for the table were compiled from Battelle program data, the ODNR, and the Michigan DEQ. Many of the parameters are difficult to measure at depth, so all values should be considered approximate.

Table 5-10. Subsurface Hydrologic Conditions of Wellbore Integrity Test Areas in Michigan and Ohio

Formation Properties	Test Area					
	1	2	3	4	5	6
Reservoir	Mt. Simon SS	Niagara Group		Copper Ridge-Basal SS		
Depth (feet)	5,600	6,000	3,000	7,000	6,000	7,700
Thickness (feet)	300	150-700	412	500	970	1,100
Initial Reservoir Pressure (psi)	2,700	3,000	2,500	3,400	2,900	3,800
Temperature (ºF)	112	108	108	127	127	127
Porosity (%)	12	3-12	3-12	0.9-10	0.9-10	0.9-10
Salinity (mg/L)	225,000	400,000	350,000	250,000+	250,000+	250,000+
Confining unit	Eau Clair Fm	Salina Gp		Beekmantown to Black River		

Note: All values are approximate.

Overall, the hydrologic conditions in the test areas reflect general conditions in the Midwest United States. Formation depths range from 3,000 to 7,700 feet, and there are not many reservoirs at extreme depths. Similarly, reservoir pressures are slightly greater than hydrostatic pressure due to high-salinity formation fluids. Highly over-pressured zones are not common in the region. However, some depleted oil and gas zones may be depressurized due to historical production. Reservoir temperatures are also fairly moderate, with no extreme temperatures that would require special well materials. Rock formations include well-lithified shale, carbonates, and sandstones. Salt layers above Niagara Group reservoirs may affect casing and cement because the salt may wash out during drilling, be difficult to cement, and plastically deform and collapse casing. A major hydrologic factor that may affect well integrity in the study area is the highly saline nature of formation brines. As shown, these brines may have salinity up to 400,000+ milligrams per liter (mg/L) which will require detailed consideration in the design of any well integrity repairs.

6.0 CO_2 Storage Assessment

6.1 Well Integrity Remediation

To provide a better understanding of the steps necessary to address wellbore integrity issues for CO_2 storage sites in the Midwest United States, remediation methods for wellbores were examined. The analysis included review of the methods related to U.S. Environmental Protection Agency (USEPA) corrective action requirements. In addition, corrective action costs were analyzed. This information was used to provide cost estimates for the test study area analysis.

6.1.1 Corrective Action Guidance

The USEPA UIC Class VI rule states that the operator of a proposed Class VI injection well must verify the integrity of all wellbores that penetrate the injection zone or the confining zone. Therefore, once an operator has determined which wells have not penetrated the confining zone, those wells can be disregarded. The operator must then identify and evaluate all wells within the AoR that do penetrate the confining or injection zone.

The operator of a proposed Class VI injection well then needs to determine that each well shown to be plugged and abandoned was plugged properly to prevent movement of the CO_2 and other fluids that may endanger underground sources of drinking water (USDWs). The operator must also determine that the materials used to plug the well are compatible (will not degrade) in the presence of the CO_2 stream. Corrective actions will be required for those wells that are considered to be high risk for leakage (i.e., poor condition of cement, poor maintenance, and penetration into the oil reservoir and confining zones). The corrective action plan may involve either remediation or monitoring for leakage at the well. Note, while operators may perform additional corrective actions as part of their own risk mitigation strategies, these actions are beyond the current scope of these case studies and are not included here.

6.1.2 Corrective Action Costs

To provide a better understanding of the level of effort necessary to locate, test, monitor, and/or repair wellbores in the Midwest United States in preparation for CO_2 storage, cost estimates were generated for corrective action categories. These estimates were utilized in the test study area analysis to provide a range of potential corrective action costs for typical sites in the region. Costs were determined for site reconnaissance, well testing, and P&A.

6.1.2.1 Site Reconnaissance

To locate abandoned wells within the AoR, the operator should:

- Interview local residents and property owners to see if they are aware of any wells that are not of record.
- Conduct a visual inspection of the area for signs of old well activity.
- Consult with oilfield workers, consultants, and service companies that might have information that is not of record.

- Look for distinguishing surface features such as old standard derricks, abandoned roads, old brine pits, well casing or drilling equipment, vegetation stress, and old foundations for surface production equipment.
- Examine aerial photographs and satellite images for signs of old wells.

The operator can also use geophysical techniques such as ground-penetrating radar (GPR), magnetic surveys, and electromagnetic (EM) methods to supplement other methods of locating old wells. Another technology, Light Detection and Ranging (LiDAR), is capable of mapping physical features that can reveal signs of old well construction. The pros and cons of each method are as follows:

- **Ground-penetrating radar**. Unlike other geophysical methods, GPR does not rely on the presence of steel or iron in the wellbore, so it can be used to detect open boreholes and non-metallic materials. GPR uses high-frequency radio waves to measure EM energy. GPR is not recommended for surveying large areas because the search grid is of such small spacing, but it can be used after other sorts of surveys to precisely locate a wellbore.
- **Magnetic surveys**. Magnetic surveys might not be dependable in areas with significant development or where casing was removed from the well during plugging operations, where casing is severely corroded, or where non-metallic materials were used in the construction of the well. Airborne magnetic surveys work well on abandoned wells constructed with at least 200 feet of 8-inch casing or larger.
- **EM methods**. EM methods are non-invasive and can be effective to depths of a few meters to several hundred meters, depending on the size of the array. EM methods often used to detect wellbores include frequency-domain and time-domain EM surveys. Both the transmitter and receiver are located above the ground surface. EM methods can also detect anomalous fluids associated with leakage from wellbores, especially the time-domain method.
- **LiDAR**. LiDAR is an optical remote sensing technology that can measure the distance to a target by illuminating the target with laser light and analyzing the backscatter. The technology utilizes a narrow laser beam (of ultraviolet, visible, or near infrared light) to create an incredibly high-resolution map of physical features. The data collected using LiDAR can be used to form digital elevation models and detailed topographic maps of the Earth's surface in open fields and under dense tree canopy. These maps, enhanced through other cartographic techniques, provide an overview of broad, continuous features that may be indistinguishable on the ground (DOE-NETL, 2013).

The cost of site reconnaissance can vary significantly, depending on the length of time and the type of reconnaissance tool required. To estimate costs, several operators were surveyed for costs they would budget for well service activities. The operators included two exploration and production (E&P) companies and a gas storage company. In addition, costs for equipment necessary to support the corrective action activities were compiled. As with many service items, these costs may vary substantially with demand and other economic factors. Table 6-1 summarizes estimated costs for site reconnaissance activities.

Table 6-1. Estimated Costs for Site Reconnaissance

Description	Cost
Conduct a visual inspection of the area for evidence of old wells such as abandoned roads, concrete base, brine pits, piping, cable, old rig parts, vegetative stress	$1,000
Consult with local residents and property owners to see if they are aware of any wells that are not of record	$1,000
Examine aerial photographs and satellite images for signs of old wells	$1,000
Perform geophysical survey(s)	$5,000

*costs estimated in 2015 dollars.

6.1.2.2 Field Testing of Wells

After all records have been reviewed, wells that cannot be shown to have good integrity must be evaluated through field testing. If the CO_2 plume is not expected to reach the well in the near future, evaluation and corrective action may be addressed in phases. The UIC director can require that existing plugs be drilled out if their integrity cannot be determined. The casing and cement must be evaluated. Tools used to evaluate the cement and casing include, but are not limited to, those listed in Table 6-2. Again, costs were estimated based on survey of operators and previous field work by Battelle.

Table 6-2. Estimated Costs for Well Testing

Tool	Cost
Multi-finger caliper log	$15,000
Sonic scanner	$25,000
Ultrasonic imaging tool	$30,000
Cement evaluation tool	$15,000
Radioactive tracer survey	$20,000
Cased hole dynamic tester	$25,000
Modular sidewall coring tool	$50,000

*costs estimated in 2015 dollars

The USEPA recommends that casing and cement tests be run sequentially, from the simplest and least destructive to the more complicated and destructive tests. If tests detect flaws such as degraded cement bond, corrosion, microannuli, channels between cement and casing or cement and formation, or missing cement, Class VI rules require corrective action.

6.1.2.3 Monitoring for Leakage at Abandoned Wells

Monitoring should be designed so that it is sensitive to a leakage signal. Monitoring equipment should be selected only if its CO_2 detection thresholds can accurately confirm the effectiveness of CO_2 storage. Key project-specific parameters that are indicative of leakage, and appropriate ranges for those parameters, should be determined such that if the parameter is detected above the appropriate range of values, exceedances are indicative of leakage.

Depending on site-specific conditions, the monitoring approach may include baseline monitoring to establish pre-injection levels. Before injection begins, data should be measured and collected for a sufficiently long period of time to ensure that they are representative of site conditions. For the purpose of developing cost estimates for this case study, Table 6-3 summarizes typical costs associated with surface flux monitoring.

Table 6-3. Estimated Costs for Well Monitoring

Description	Cost
Surface flux monitoring equipment	$19,000
SCP monitoring	$6,000

*costs estimated in 2015 dollars

Upon review of records for an area, if specific existing wells (wells that have not been abandoned) are thought to potentially exhibit sustained casing issues, the step-wise approach should be used to evaluate the condition of the well. The steps are aimed at identifying the presence of SCP and determining the potential problems or risk that the SCP presents.

If a well potentially exhibits SCP, the first step is to measure its extent. SCP is quantified by measuring the pressure level in the annular space after the well has been allowed to accumulate gas. This step provides a baseline measurement. Following the pressure measurement, a sample of the annular gas should then be collected for compositional analysis (CO_2, O_2, N_2, H_2, C_1 through C_6+). The analytical results for this sample can provide the origin of the gas in the annulus. After the sample has been collected, the annular space should be bled down to near-atmospheric conditions, and a data-logging pressure/temperature gauge should be connected to the well to monitor pressure build-up in the annulus.

A data-logging pressure/temperature gauge can be connected to the annular space at the wellhead to monitor the pressure rebound after the well has been bled down. The data from this monitoring are used to determine the type and severity of a leak occurring in the well. Generally, a rapid build-up of pressure over time would suggest a larger leak, all other factors being the same. Another method for determining the type of leak is to measure the chamber volume (the open casing above the TOC) in the test well. Often the pressure will increase at a lower rate in wells that have a large chamber volume.

Using the pressure build-up and the chamber volume together provides a means to quantitatively calculate the leakage into the well through three separate leakage pathways: orifice flow, vein flow, and porous flow. The pressure increase rate is plotted over time to determine the flow pathway into/through the well. These data can then potentially be used to evaluate remedial actions for the well.

6.1.2.4 Plugging of Wells

A well requires plugging if records indicate that it was not plugged, was plugged improperly, or was not plugged so as to prevent migration of CO_2 or other liquids into the USDW. In addition, if a plugged well does not have a plug across the confining zone, one is required to be set there. If records indicate that there are no plugs below the USDW or other permeable formation to prevent cross-flow of fluids, additional plugs may be required. If evaluation techniques indicate the presence of cracks, channels, or annuli in the plug, the USEPA recommends replacing it. In addition to the confining zone plug, it is recommended that plugs be set across the bottoms of any casing strings and across all USDWs.
Table 6-4 summarizes the general costs for plugging wells as of mid-2015. Costs were estimated based on feedback from two E&P companies and a gas storage company.

Table 6-4. Estimated Costs for Plugging

Description	Cost
Rig	$40,000
Cement plugs (five)	$20,000
Ancillary equipment	$15,000
Restoration	$10,000

6.1.2.5 Remedial Cementing of Wells

If a well was properly plugged but the records or testing indicates that the cement surrounding the wellbore has failed or has cracks, channels, or annuli that could allow migration of CO_2, the USEPA recommends performing remedial cementing. Remedial cementing should focus on two key areas: depths corresponding to the injection zone, and depths through any other permeable zones.

Remedial cementing is performed through squeeze cementing, where the cement is placed into the affected area. Cement squeezes can be performed using either the tubing and packer method or the bradenhead method. The tubing and packer method allows the targeted area to be isolated from the rest of the well. The bradenhead method isolates only the area below the targeted area and is used only if the casing above the area to be cemented is strong enough to withstand the squeeze pressure. The cement used to remediate abandoned wells might vary, but all cements must be compatible with the CO_2 stream. Table 6-5 summarizes remedial cementing costs. These costs were estimated based on information from two E&P companies and a gas storage company.

Table 6-5. Estimated Costs for Remedial Cementing

Description	Cost
Rig	$40,000
Perforating	$5,000
Squeeze job (tubing and packer)	$25,000
Squeeze job (bradenhead)	$20,000
Ancillary equipment	$15,000
Pressure testing	$5,000
Restoration	$10,000

6.1.2.6 Re-entry, Drill-out, and Plugging of Wells

Existing plugs may need to be drilled out if they cannot be determined to have good integrity. If the CO_2 plume is not expected to reach the well in the near future, evaluation and corrective action may be addressed in phases. If the operator cannot determine how a well was plugged from a search of the records, the operator may be required to re-enter the well, drill out plugs to a specified depth, and set plugs as recommended by the USEPA. Table 6-6 summarizes estimated costs for well re-entry, drill-out, and plugging. Costs were also estimated based on information from two operators and a gas storage company.

Table 6-6. Estimated Costs for Well Re-entry, Drill-out, and Plugging

Description	Cost
Rig, drill pipe, power swivel, mud pumps	$100,000
Cement (five plugs)	$20,000
Ancillary equipment	$15,000
Restoration	$10,000

6.2 CO_2 Storage Siting

Wellbore integrity may be a significant factor in siting a CO_2 storage project. To assist in site selection and planning, guidance on wellbore IFs related to site selection and UIC Class VI permitting requirements was analyzed.

6.2.1 Site Selection and Screening

The condition of wellbores at potential CO_2 storage sites should be considered in site selection and screening. Source location, geologic framework, surficial factors, reservoir capacity, source/sink analysis, pipeline routing, and operating limitations are factors for developing transport and injection scenarios for CO_2 storage applications. Wellbore integrity can be a major issue for site preparation, operations, and post-injection site closure.

The Midwest United States may have tens to thousands of legacy oil and gas wells present in areas suitable for implementing industrial-scale CO_2 storage. However, many of these wells may not penetrate the storage zone or containment layers. Therefore, methods designed to summarize well integrity indicators may be useful in the site screening process (see Section 3.0). More detailed review of well records may provide information on the condition of wells in the project areas and necessary corrective actions.

6.2.2 UIC Class VI Permit Requirements

The USEPA UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidelines set the minimum federal technical criteria for Class VI injection wells for the purpose of protecting USDWs. The Class VI rule and related documents can be found at USEPA (2012). The rule requires that the AoR around a proposed carbon storage project be delineated using a computational model and that the AoR be re-evaluated periodically during the injection lifetime of the project. For this study, it was assumed that the CO_2 storage operator has already determined the injection zone, the confining zone, and the dimensions of the AoR.

The first step the operator of a proposed Class VI injection well must take is to identify all of the existing wells within the AoR. The next step is to gather all of the information about the wells via public and industry records.

The UIC Class VI rule states that the operator of a proposed Class VI injection well must verify the integrity of all wellbores that penetrate the injection zone or the confining zone. Therefore, once an operator has determined which wells have not penetrated the confining zone, those wells can be disregarded. The operator must then identify and evaluate all wells within the AoR that do penetrate the confining or injection zone.

6.2.3 Penetration of Confining Zone

The operator of a proposed Class VI injection well must identify all wells that penetrate the confining zone(s), whether producing, plugged, or idle. The operator must also determine if plugged wells were properly plugged to regulatory standards using appropriate materials.

6.2.4 Historical Research

Most deep wells that penetrate the confining zone are oil and gas wells. It is recommended that a records search be the first step in well identification. Historical records will usually show the age and types of wells that were drilled in a given area and may also provide information on typical completion and construction methods. A search of all public (regulatory) records will provide a list of known abandoned wells. The operator of a proposed Class VI injection well should review the date drilled, well type, depth, construction methods, completion methods, P&A records, and any other data of record. The operator should be aware that many older wells might not be of record. In addition to public records, some private data compilation services maintain detailed databases for oil and gas exploration, including well locations and P&A information.

6.2.5 Assessment of Identified Abandoned Wells

The operator of a proposed Class VI injection well must determine which abandoned wells in the AoR have been improperly plugged; these wells may allow fluid movement and therefore may endanger USDWs. To prevent fluid movement, abandoned wells should have a cement plug through the primary confining zone and across the injection zone/confining zone contact. The USEPA also recommends that a cement surface plug be set. The UIC director might also require additional plugs, depending upon the site-specific circumstances.

6.2.6 Review of Abandoned Well Plugging

A well record review can reduce the number of identified wells that may need to be evaluated through future field testing. Well abandonment records of recently plugged wells may be used to reduce the number of identified wells needing additional follow-up field investigations under certain conditions:

- The records make no mention of difficulties encountered during plugging operations.
- The records indicate that the holes are cased.
- The records indicate that the wells have properly placed plugs and cement to isolate the injection zone from other fluid-containing zones.

If records are incomplete or indicate that the plugging was not sufficient to isolate the injection zone from other fluid-containing zones, follow-up field investigations should be performed.

Wells with no records will require a field investigation to determine the quality of plugging as set forth in the Class VI rules. As an alternative, the operator can choose to plug any questionable abandoned wells rather than go through an evaluation process.

Key elements of the review process are:

1. Well depth and completion
2. Well abandonment date
3. Type of hole (open or cased)
4. Location of the plugs

5. Casing and cementing records
6. Records of mechanical integrity test of logs performed
7. Well deviation

If the well completion depth is above the confining zone, additional action may not be required. The date of abandonment may provide information as to the adequacy of the plugging job. Whether the well was abandoned with casing or as on open hole is an important consideration in determining the likelihood that the well might act as a conduit for fluid movement. Cement plugs are considered superior to mechanical plugs for preventing the movement of fluids into or between USDWs. The USEPA recommends that cement plugs be located across the bottom of any casings and at the base of the lowermost USDW.

Records should be checked for problems that occurred during drilling and construction. Such problems include loss of circulation, stuck pipe while running the casing, excessive pressure during the cement job, pressure bleed-off after landing the plug, improperly centralized casing, or improper removal of drilling mud prior to the cement job. Mechanical tests such as pressure tests, noise logs, temperature surveys, or cement evaluation logs should be used to locate leaks, which must be repaired. Mud logs and caliper logs can be used to find weak or unstable formations. Casing inspection logs (corrosion logs) can be useful in locating trouble areas. Deviated holes can also be the cause of integrity loss. Records should also be checked to make sure that proper casing design and cementing practices were used in the construction of the well.

6.2.7 Plan for Corrective Action

Operators must perform corrective action on all improperly plugged wells that penetrate the confining zone to ensure that they do not serve as conduits for fluid movement into USDWs. If the AoR is large and the number of wells requiring corrective action is high, the USEPA will allow the operator to submit a phased plan for corrective operations. The first phase should include all wells that fall within the modeled CO_2 plume during the first year of injection operations. Later phases should include wells that would fall within the model's CO_2 plume for years two, three, four, and beyond, until all wells requiring corrective action have been addressed. The operator must document how the corrective action will be performed; what the schedule for corrective action will be, and what corrective actions will be phased. The guidelines suggest including a table that lists all wells identified in the AoR that require corrective action, the scheduled date for the corrective action, and the planned methods to be used. Well schematics are recommended.

The USEPA requires that the operator re-evaluate the AoR delineation once every five (5) years to ensure that the initial model predictions are adequate for predicting the extent of the CO_2 plume. The first step in the AoR re-evaluation process is to compare monitoring data to the original model predictions. If the monitoring data and the model predictions differ significantly, the operator is required to re-evaluate the AoR and amend the corrective action plan.

7.0 Local-Scale CO_2 Storage Test Study Area Analysis

Six study areas were selected to complete a systematic assessment of wellbore integrity using regulatory and industry information. Well records, plugging records, and CBLs were reviewed in accordance with USEPA guidelines and recommendations to determine the overall wellbore integrity of the area. A cost analysis of well procedures was combined with the corrective actions to determine real-world level of effort necessary to address existing boreholes at hypothetical CO_2 storage study areas in Ohio and Michigan.

7.1 Site Selection

Six study areas, three in Michigan and three in Ohio, were selected to represent different scenarios for potential CO_2 storage sites. Maps were created plotting oil and gas wells with recorded depths, wells with CBLs, and locations of CO_2-emitting facilities along with approximate emission volumes. Areas with deep wells, available CBLs, and close proximity to CO_2-emitting facilities were of most interest. The study sites ranged from very few wells (22) to many wells (more than 1,200) with varying depths, ages, and status. The Michigan study areas are in Otsego County, Saint Clair County, and Calhoun County. The Ohio study areas are in Muskingum/Coshocton Counties, Noble County, and Trumbull County. Figure 7-1 shows the locations of each study area.

The size of each study area was selected by calculating the CO_2 storage capacity and assuming 3.5 million tons/year for 20 years of injection (a total of 70 million tons). Characteristics of the storage formation were used along with assumed efficiency factors to roughly estimate the area needed to store 70 million tons of CO_2. The thickness, porosity, and CO_2 density were used as determined from literature and wireline logs.

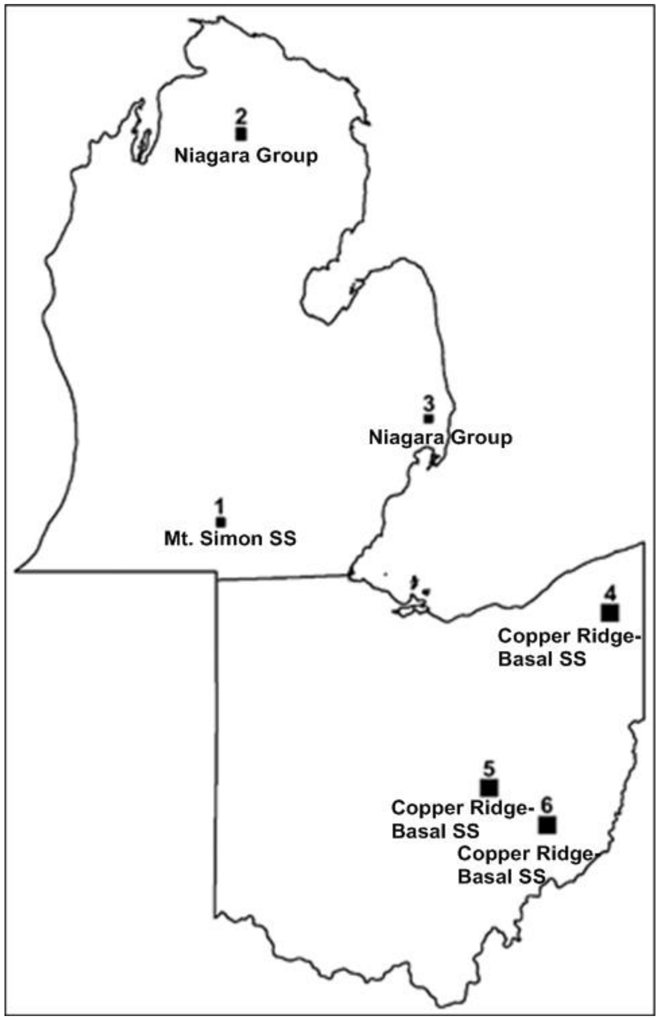


Figure 7-1. CO_2 Storage Study Area Locations

7.2 Corrective Action

Corrective action guidelines were created based on the type of well, well status, and condition of the well. These guidelines follow USEPA guidelines and requirements for Class VI wells (CO_2 storage). Table 7-1 lists the possible corrective actions, and Table 7-2 shows which corrective action should be used under which scenario. Figure 7-2 demonstrates the process used to arrive at the appropriate corrective action based on well information.

Table 7-1. Summary of Corrective Action Options

Corrective Action	Description
Inspect wellhead	Visually locate wellhead
Test well	Test well condition with wellhead pressure testing
Monitor wellhead	Monitoring wellhead for CO_2 leakage with surface methods or sample active well for CO_2
Add plugs to well	Re-enter and add plugs to well
Re-enter and plug	Re-enter well and plug well

Table 7-2. Corrective Actions and Scenarios for their Use

Corrective Action	Well Status Scenario
Inspect wellhead	Producing wells, P&A wells
Test well	P&A w/ no records
Monitor wellhead	Domestic well w/ no records, historical producer, active well in storage zone
Add plugs to well	Unplugged well
Re-enter and plug	Unplugged well or well that demonstrates leakage during CO_2 storage period

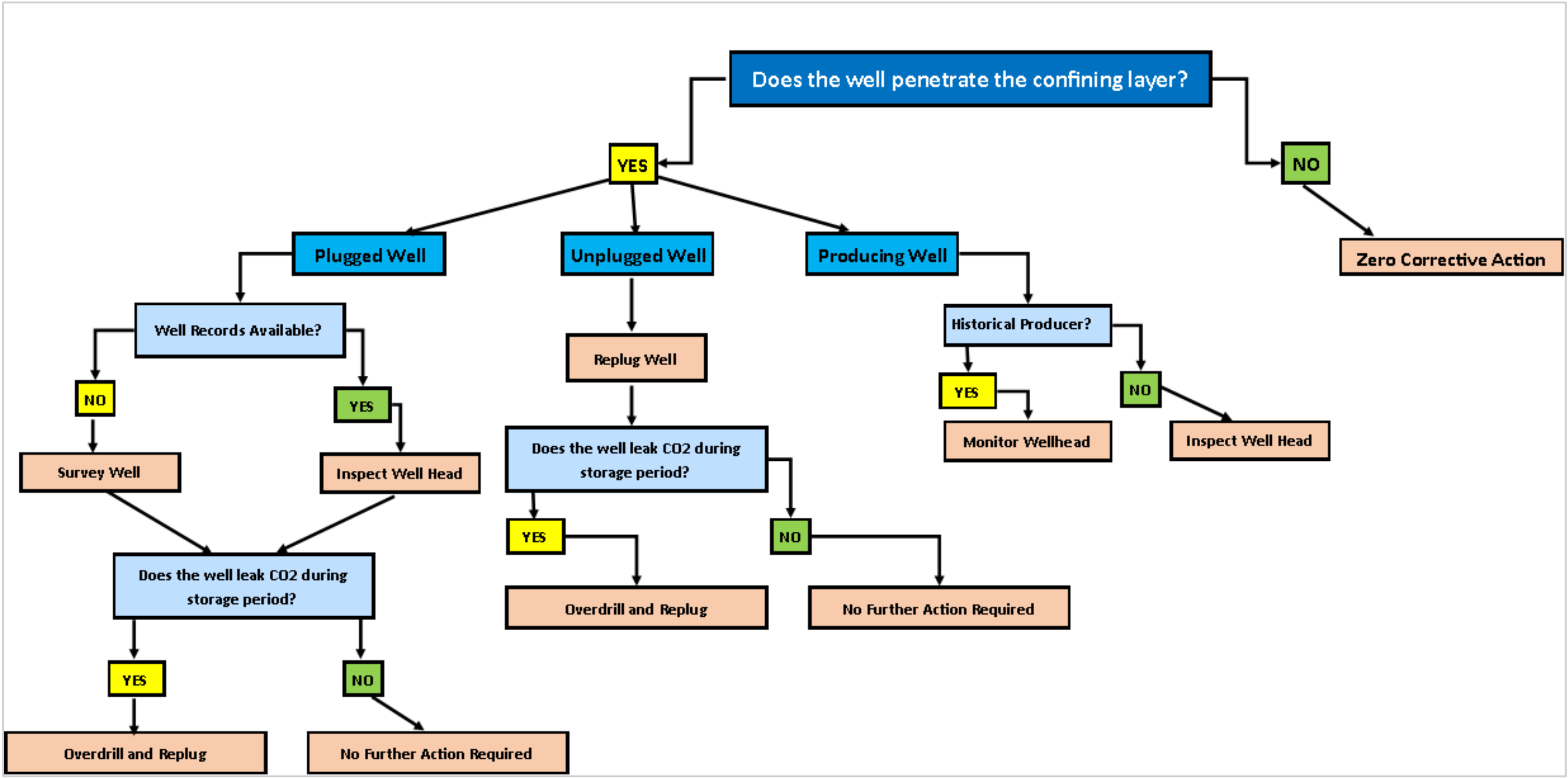


Figure 7-2. Corrective Action Process

7.3 Ohio Study Areas

7.3.1 Geologic Setting

The three Ohio test study areas are located in the Upper Ohio River Valley Region of eastern Ohio, which overlies the western flank of the northern Appalachian Basin. All of the Ohio study areas lie within the Appalachian Plateau Province. In this province, erosion has subdued the uplifted landscape into hilly upland areas. The flatter landforms of the Central Lowlands Province, formed from multiple Pleistocene glaciations, are located to the west. Sedimentary rocks of eastern Ohio are within the western margin of the Appalachian Basin, and were deposited during the Paleozoic Era. The preserved thickness of these rocks ranges from about 2,800 feet on the Findlay Arch to about 25,000 feet near the Allegheny structural front.

In eastern Ohio, the zones of interest consists of Cambrian to lower Ordovician sedimentary rock bounded above by the Knox unconformity and below by the Precambrian unconformity surface. The stratigraphy of the formations of interest indicates shallow-water deposition consisting primarily of sandstones and bioclastic carbonates. Lithostratigraphic units making up the sequence are (in descending order) the Knox Dolomite, Kerbel Formation, Conasauga group, and Mt. Simon or Basal Sandstone.

The Knox Dolomite ranges in age from Upper Cambrian to Lower Ordovician. The unit consists of dolostones and dolomitic sandstones deposited in tidal flat to shallow marine environments that were subjected to periodic subaerial exposure. In Ohio, the Knox is informally subdivided into (in descending order of increasing depth) the Beekmantown dolomite, Rose Run sandstone, and Copper Ridge dolomite (Janssens, 1973; Riley et al., 2002; Ryder et al., 2008; Baranoski et al., 2002; Wickstrom et al., 2011).

The storage zones of interest in Ohio include a series of stacked reservoirs from the Copper Ridge down to the Basal Sandstone. The storage zones consist of vugular dolomite and sandstones. The confining layers consist of a thick package of shales and carbonates including the Queenston, Utica, and Black River Group. Figure 7-3 shows a simplified stratigraphic column for a well in Coshocton County, Ohio.

7.3.2 Underground Drinking Water

The underground drinking water in most portions of eastern Ohio is found in the lower Pennsylvanian and upper Mississippian sandstones, carbonates, and unconsolidated surficial deposits. Most of the water wells are drilled shallower than 400 feet deep, with isolated exceptions at locations of valley fill. Thousands of feet of rock lie between any source of underground drinking water and potential CO_2 storage zones. The underground drinking water zone is included in the undifferentiated zone on all plugging charts. The top and base were recorded from well records and drilling records. Figure 7-4 shows an example map from Coshocton County with the source of drinking water, location of water wells, and the depth of the water wells.

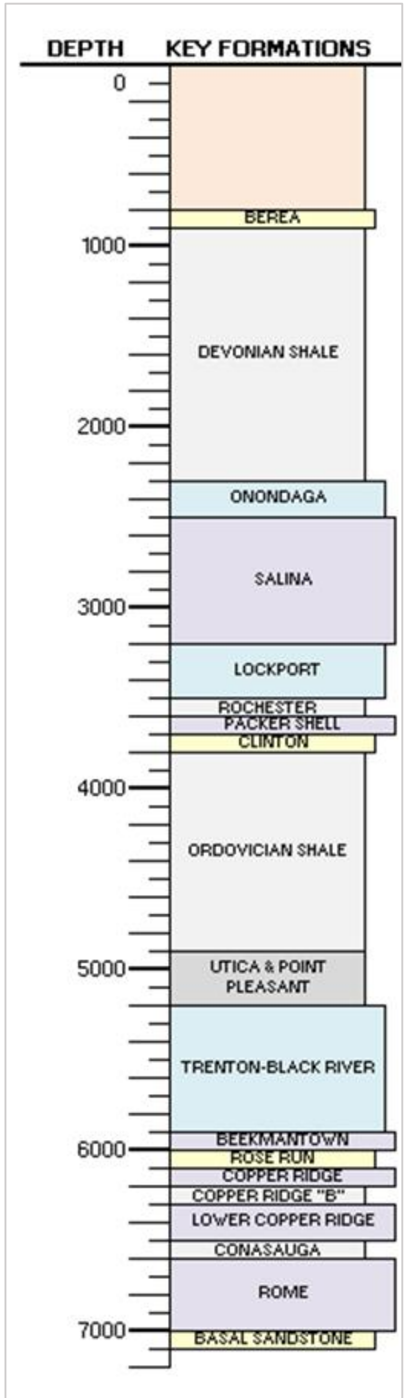
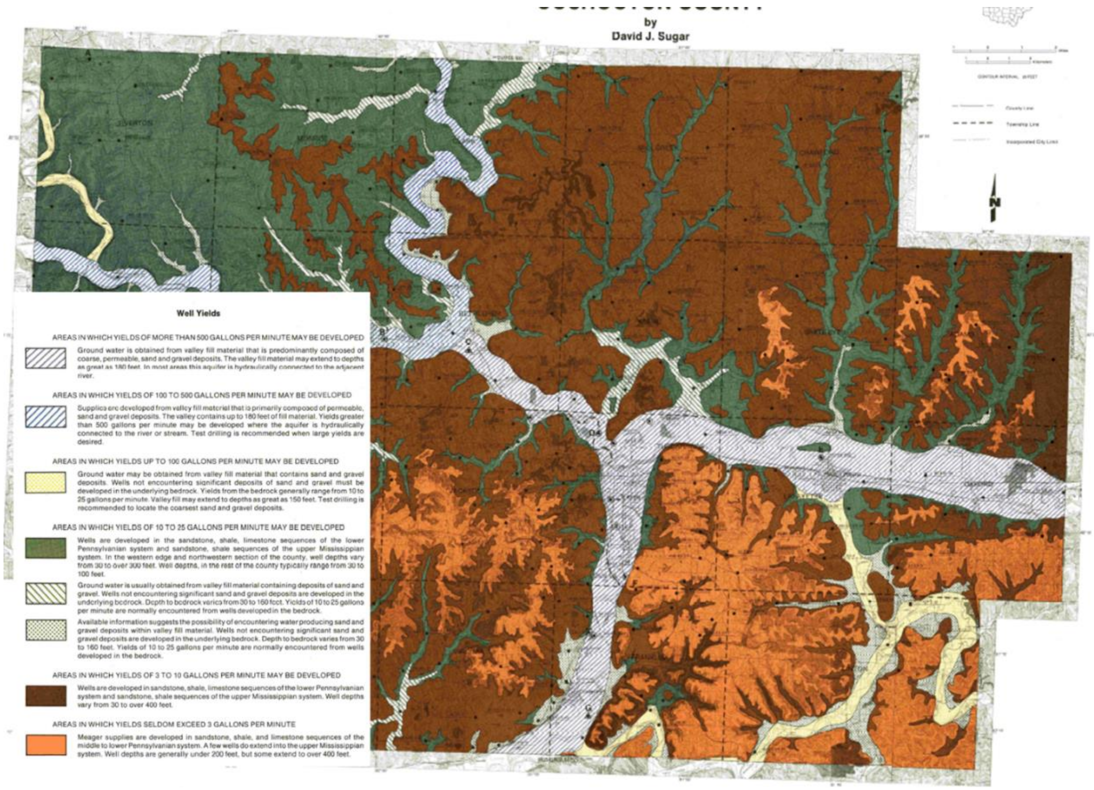


Figure 7-3. Example Stratigraphic Chart from Coshocton County, Ohio



Source: OhioDNR.gov.

Figure 7-4. Underground Drinking Water Sources in Coshocton County, Ohio

7.3.3 Test Areas

7.3.3.1 Trumbull County, Ohio

7.3.3.1.1 Test Area Definition

The Trumbull County study area encompasses 357 oil and gas wells which primarily target the Cataract Group. The potential storage zone in this study area is the Copper Ridge Dolomite down to the Basal Sandstone, with the Queenston Shale to Black River Group as the confining layers. The selected study area is 15 x 15 kilometers based on the parameters listed in Table 7-3, which were selected using wireline data and literature. Figure 7-5 shows the location of the Trumbull County study area.

Table 7-3. Parameters Used to Estimate the Size of the Trumbull County, Ohio, Study Area

Formation: Copper Ridge-Basal SS		
Depth	7050	feet
Thickness	115	feet
Porosity	0.065	fraction
Pressure	3,385	psi
Salinity	250,000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

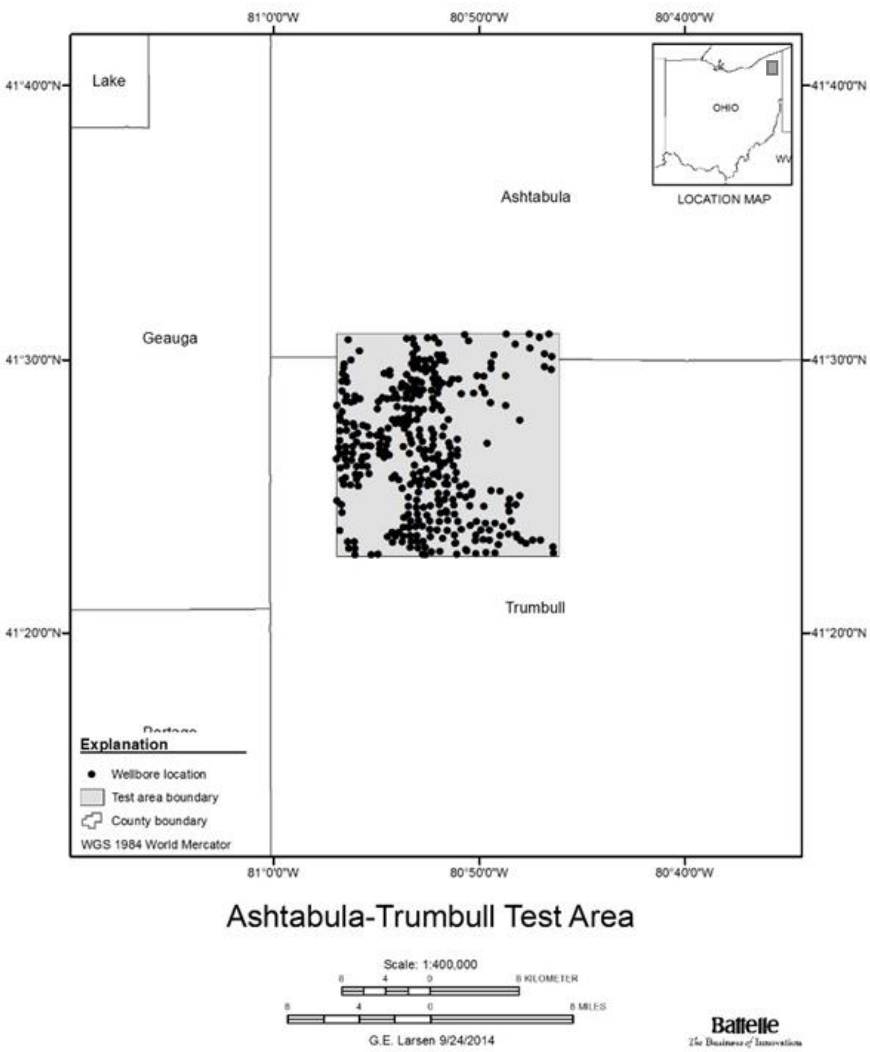


Figure 7-5. Location of the Trumbull County, Ohio, Study Area

7.3.3.1.2 Well Status Survey

All of the wells in the Trumbull County study area were drilled shallower than 4,200 feet. No wells penetrated the storage zone and/or the confining layers. The 3-D view in Figure 7-6 shows that no wells were drilled deep enough to penetrate the storage zone.

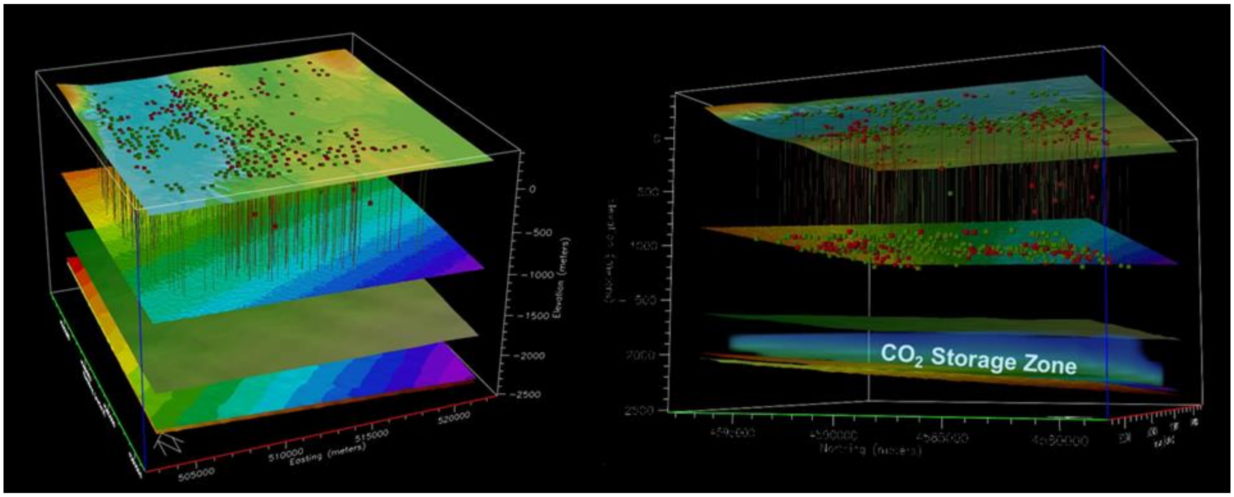


Figure 7-6. 3-D View of Wells in the Trumbull County, Ohio, Study Area

There are 76 plugged wells in the Trumbull County study area. The number of plugs in each well ranged from one to five, with the average being four. All but two of the wells had at least four plugs between the storage zone and the surface. Figure 7-7 shows the locations of plugs in depths for all 76 wells.

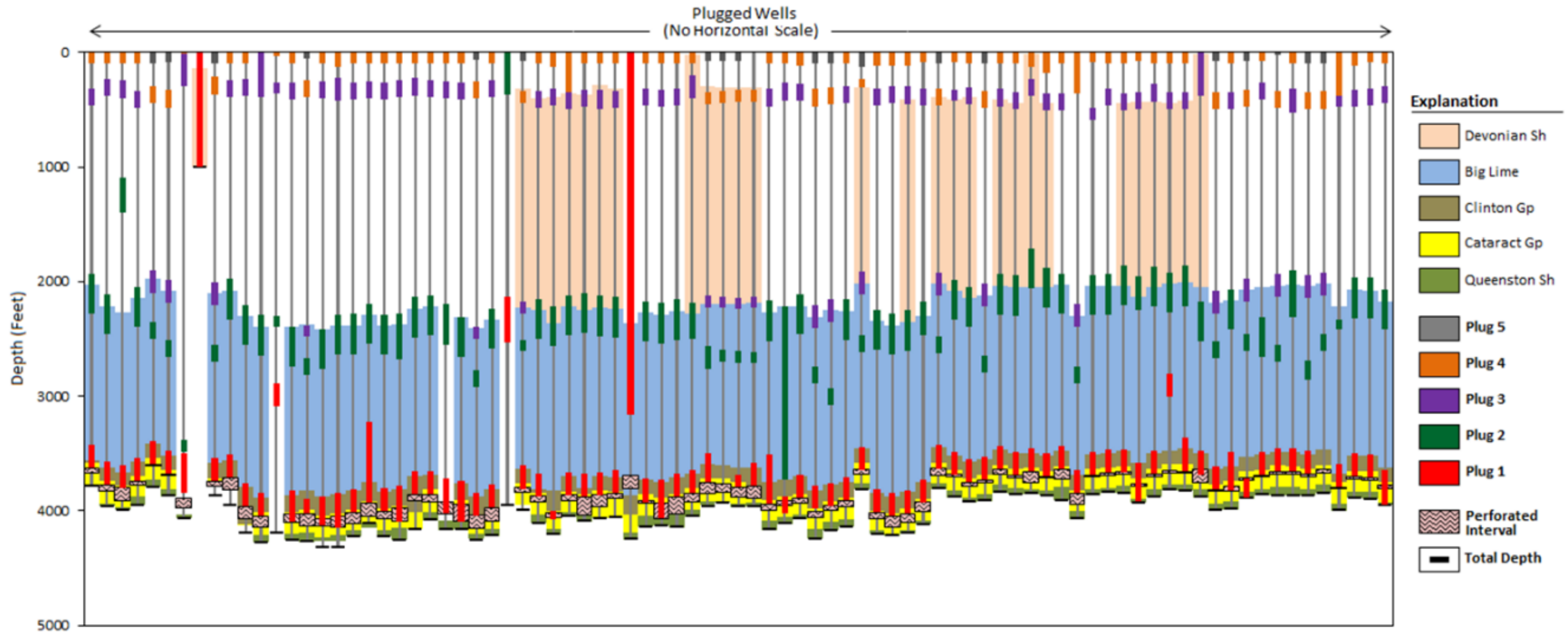


Figure 7-7. Plugging Chart for Wells in the Trumbull County, Ohio, Study Area

7.3.3.1.3 Corrective Action Analysis

Because no wells penetrated the confining layers and storage zone, zero corrective action is needed.

7.3.3.2 Muskingum/Coshocton County, Ohio

7.3.3.2.1 Test Area Definition

The Muskingum/Coshocton County study area encompasses 1,221 oil and gas wells which primarily target the Clinton-Cataract group. There are 12 nearby CO_2-emitting facilities which are high producers. The selected study area is 49,200 x 49,200 feet based on the parameters listed in Table 7-4, which were selected using wireline data and literature. The targeted storage formations are the Copper Ridge Dolomite down to the Basal Sandstone, with the Queenston Shale to the Black River Group as the confining layers. Figure 7-8 shows the location of the study area.

Table 7-4. Parameters Used to Estimate the Size of the Muskingum/Coshocton County, Ohio, Study Area

Formation: Copper Ridge-Basal SS		
Depth	7050	feet
Thickness	115	feet
Porosity	0.065	fraction
Pressure	3,385	psi
Salinity	250,000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

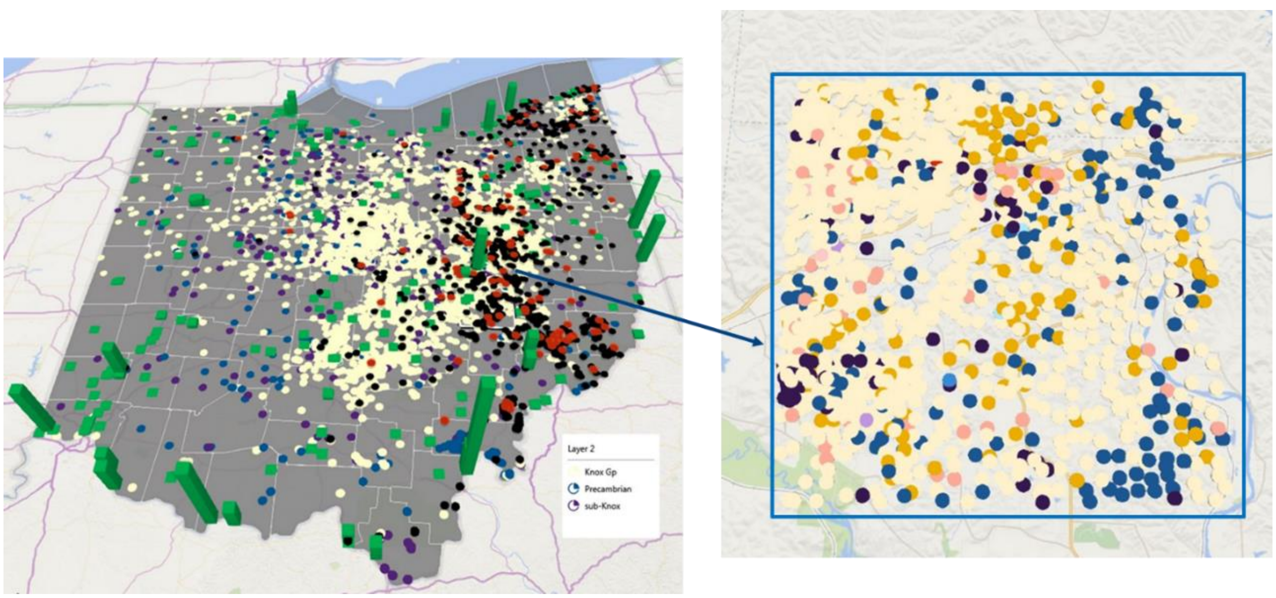
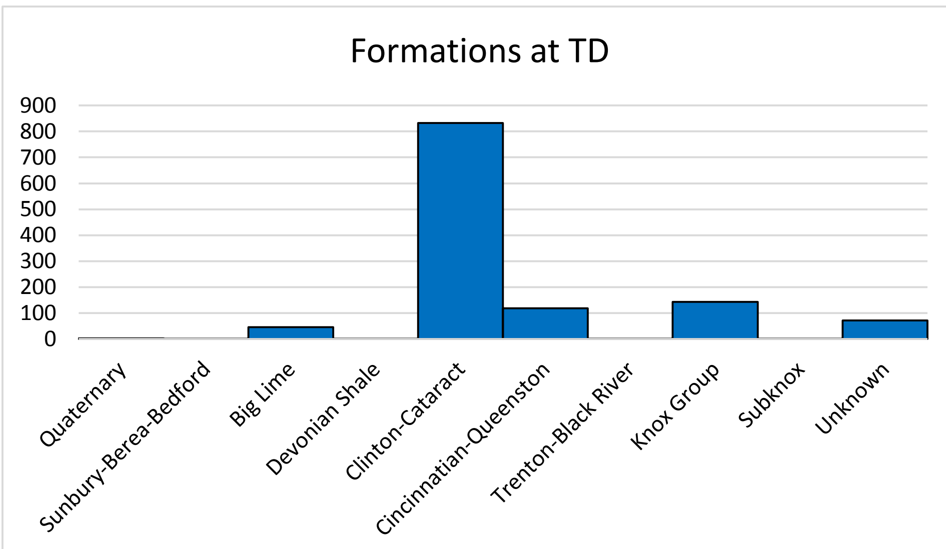


Figure 7-8. Location of the Muskingum/Coshocton County, Ohio, Study Area

7.3.3.2.2 Well Status Survey

There are 302 wells of interest in the study area which either penetrate the confining layers or have unknown depths. Of that total, 53% have been plugged and 42% are currently producing. There are nine historical producers within the study area and five domestic wells. Figures 7-9 and 7-10 summarize the formations reached at total depth of all 1,221 wells and the status for the wells of interest.

Detailed plugging records were available for 94 wells in the study area which penetrate the Queenston Shale or deeper. The number of plugs in each well ranged from one to eight, with an average of five. All wells have at least one plug in the confining layers and at least three plugs between the storage zone and the surface. Figure 7-11 shows the locations of the plugs in depth for each well.



Note: TD = total depth.

Figure 7-9. Histogram of the Formations Reached at Total Depth, Muskingum/Coshocton County, Ohio

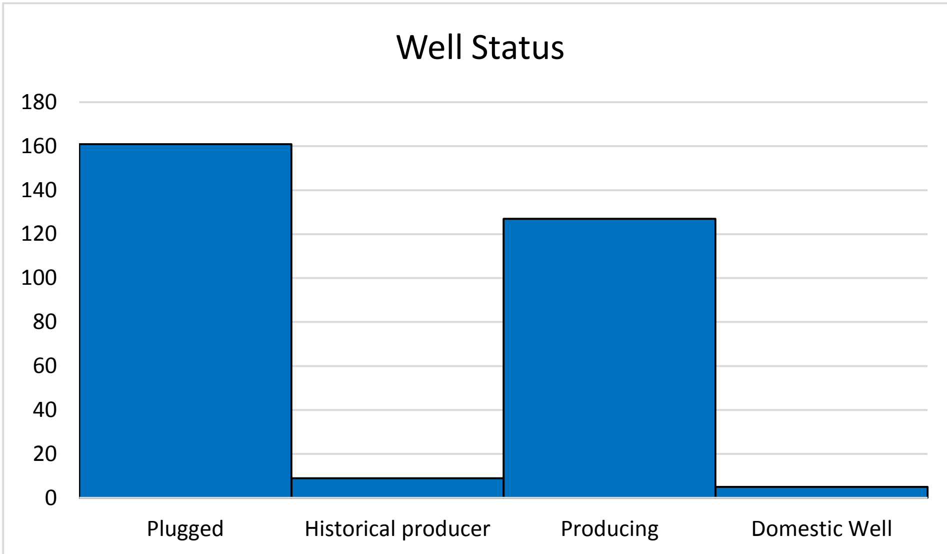


Figure 7-10. Histogram of Status for the Wells of Interest Muskingum/Coshocton County, Ohio

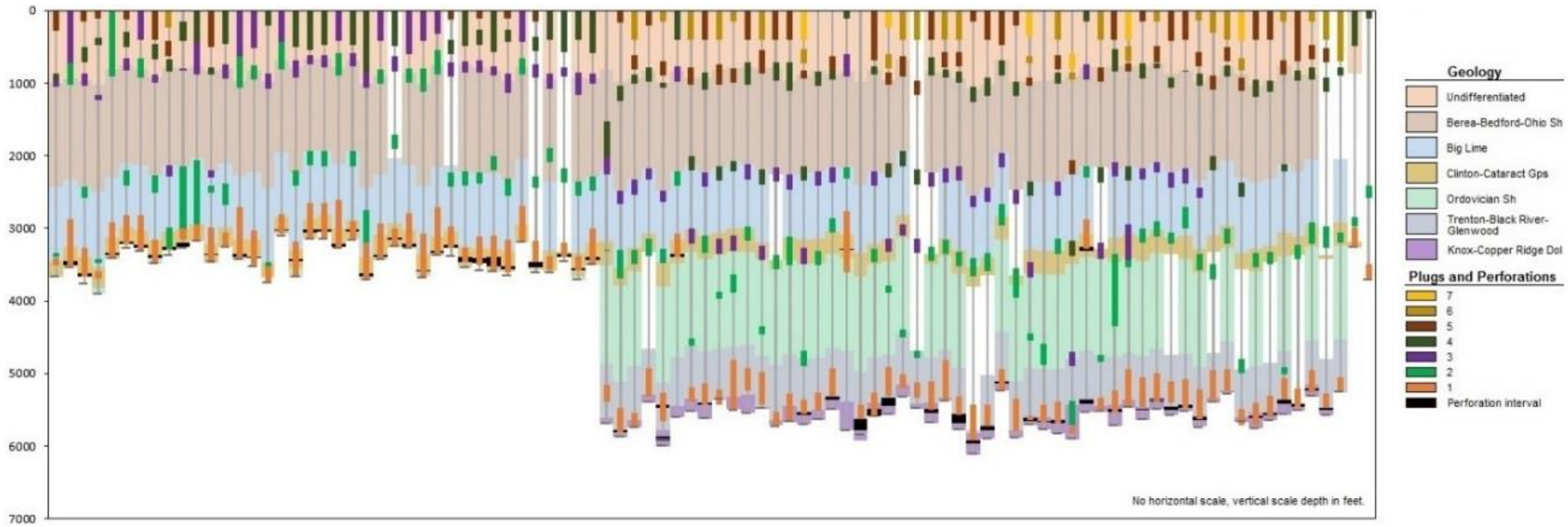


Figure 7-11. Plugging Chart for Wells in the Muskingum/Coshocton County, Ohio, Study Area

7.3.3.2.3 Corrective Action Analysis

Of the 1,221 wells in this study area, 919 do not require any corrective action because they are drilled shallower than the confining layers. The plugged and producing wells only require the wellhead to be located and inspected. The nine historical producing wells need to be monitored for leaks. Table 7-5 summarizes the recommended corrective actions. Figure 7-12 maps the locations of wells which require corrective action.

Table 7-5. Summary of Recommended Corrective Actions, Muskingum/Coshocton County, Ohio, Study Area

Corrective Action	Count
Zero corrective action	919
Inspect wellhead	293
Survey well	0
Monitor wellhead	9
Replug well	0
Overdrill & plug	0
Total # of wells	1,221

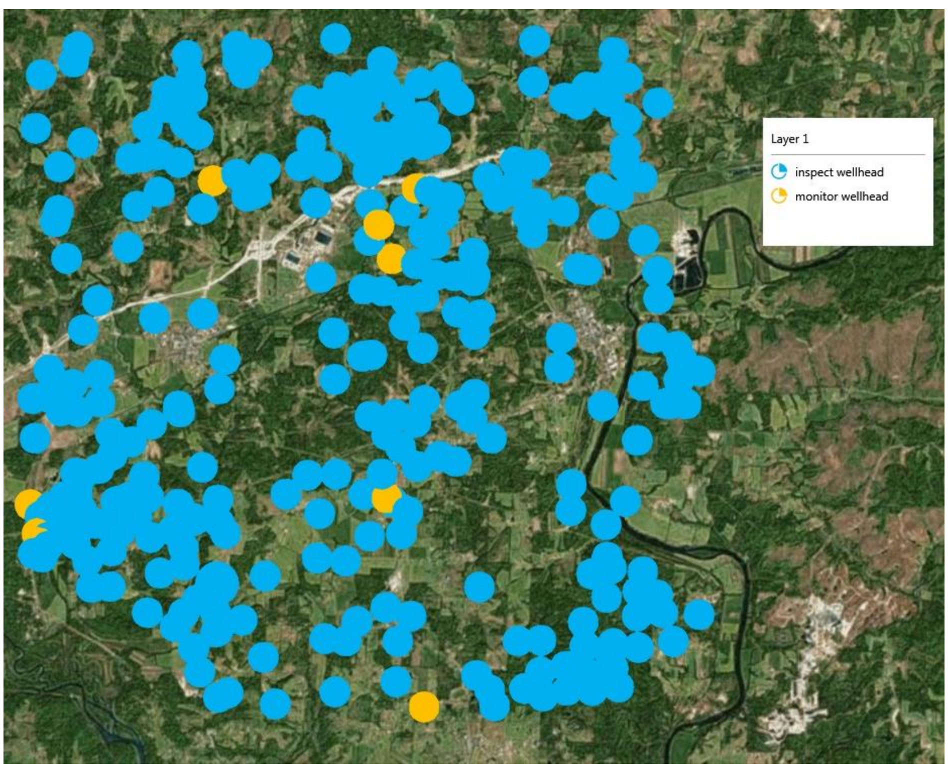


Figure 7-12. Well Locations in the Muskingum/Coshocton County, Ohio, Study Area Requiring Wellhead Inspections (blue) and Monitoring (yellow)

7.3.3.3 *Noble County, Ohio*

7.3.3.3.1 Test Area Definition

The Noble County study area encompasses 868 oil and gas wells which primarily target either the Berea sandstone or the Queenston Shale. There is one nearby CO_2-emitting facility which produces 3.7 million tons of CO_2 (USEPA, 2013). The selected study area is 49,200 x 49,200 feet based on the parameters listed in Table 7-6, which were selected using wireline data and literature. Figure 7-13 shows the location of the Noble County study area.

Table 7-6. Parameters Used to Estimate the Size of the Noble County, Ohio, Study Area

Formation: Copper Ridge Dol-Basal Ss		
Depth	7050	feet
Thickness	115	feet
Porosity	0.065	fraction
Pressure	3,385	psi
Salinity	250,000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

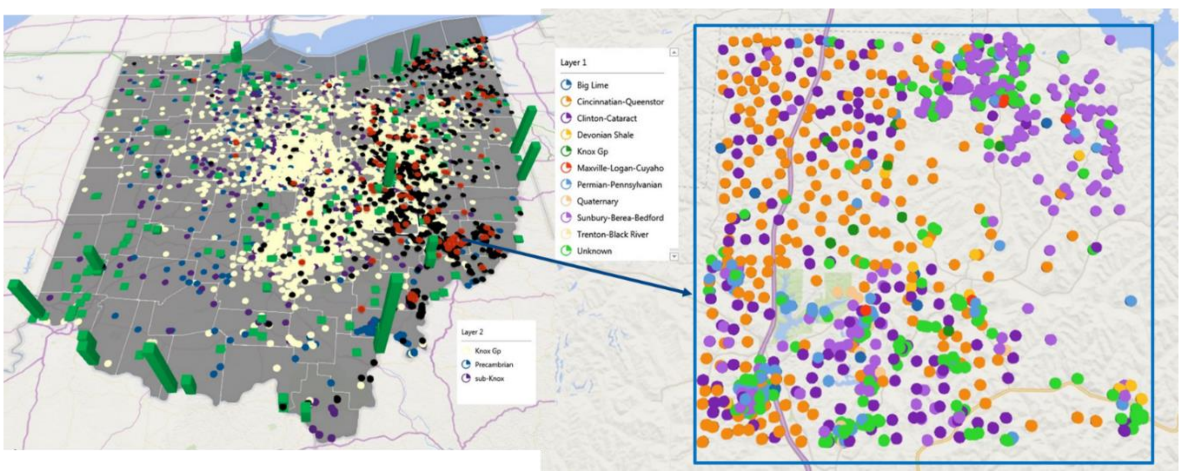
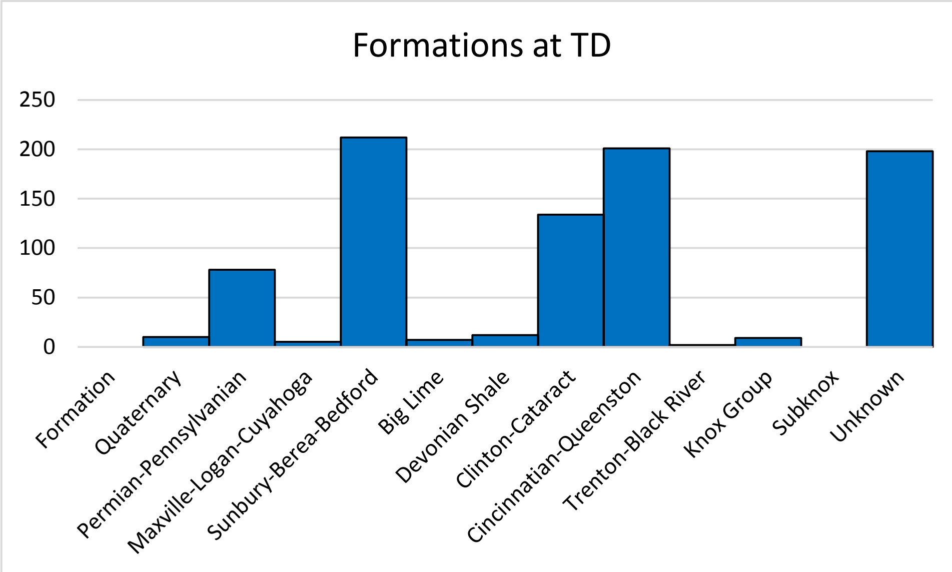


Figure 7-13. Location of the Noble County, Ohio, Study Area

7.3.3.3.2 Well Status Survey

There are 240 wells of interest in the study area which either penetrate the confining layers or have unknown depths. Of that total, 55% have been plugged and 44% are currently producing or active. There are four historical producers within the study area. Figures 7-14 and 7-15 summarize the formations reached at total depth of all wells and the status for the wells of interest.



Note: TD = total depth.

Figure 7-14. Histogram of Formations Reached at Total Depth, Noble County, Ohio

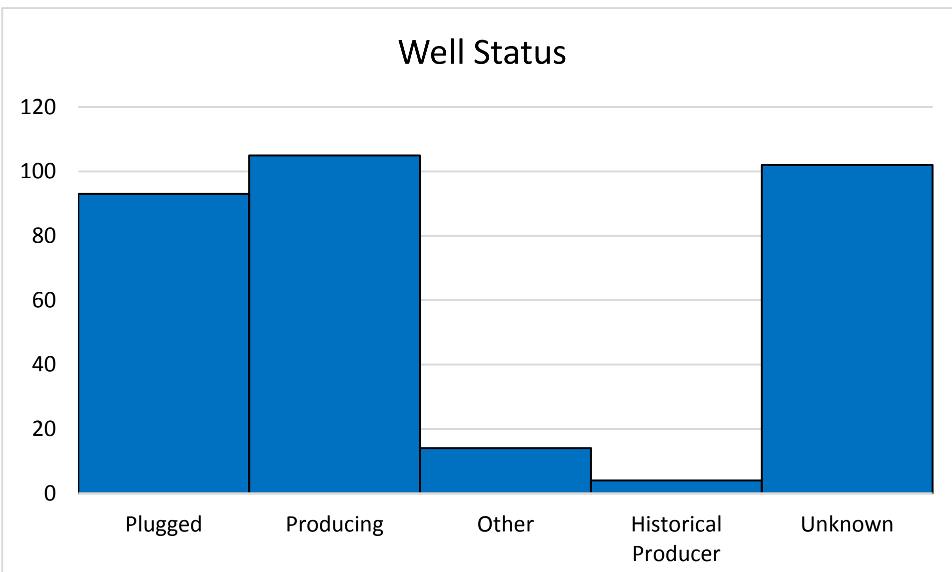


Figure 7-15. Histogram of Status for the Wells of Interest, Noble County, Ohio

Detailed plugging records for 68 wells were available in the study area. However, there were four wells which were confirmed to be plugged but did not have any plugging records. Within the study area, 21 wells were permitted to be plugged or are in the process. The number of plugs in each well ranged from one to six, with an average of four. More than a dozen wells do not have plugs set in the confining layers but do have plugs set in shallower layers. All but one well has multiple plugs between the confining layers and the USDW. Figure 7-16 shows plug locations in depth with respect to formations.

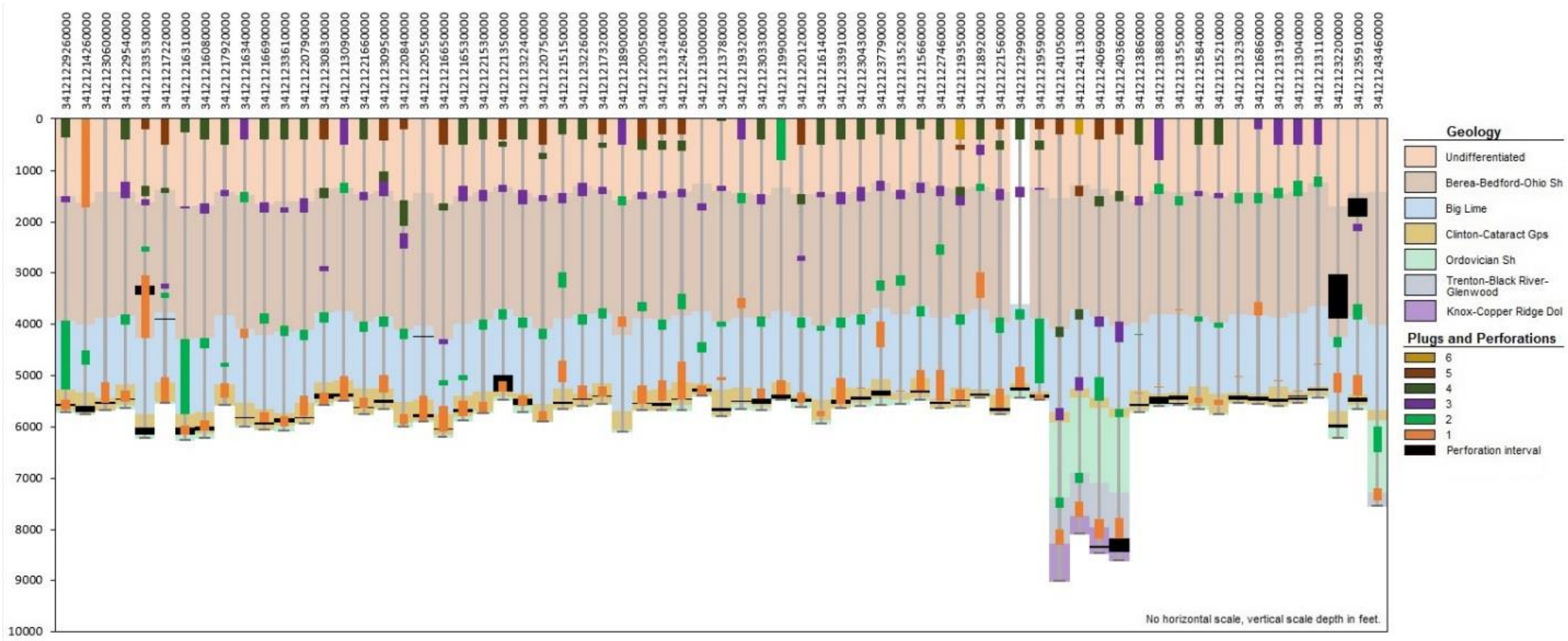


Figure 7-16. Plugging Chart for Wells in the Noble County, Ohio, Study Area

7.3.3.3.3 Corrective Action Analysis

Out of a total of 868 wells, 629 do not require any corrective action because they did not penetrate the confining layers. The wells with plugging records and the wells which are currently producing only require to have the wellhead checked. The four wells that were plugged with no plugged records are recommended to be surveyed. The wells which have plugs in shallower layers but not in the confining layers would be required to have additional plugs set. The historical producers need to be monitored, and 16 wells need to be overdrilled and plugged. Table 7-7 summarizes the recommended corrective actions for the wells in the Noble County study area.

Table 7-7. Summary of Recommended Corrective Actions, Noble County, Ohio, Study Area

Corrective Action	Count
Zero corrective action	629
Inspect wellhead	193
Survey well	26
Monitor wellhead	4
Replug well	0
Overdrill & plug	16
Total # of wells	868

7.4 Michigan Study Areas

7.4.1 Geologic Setting

There are two storage zones of interest in Michigan: the Niagaran Reefs and the Mt. Simon Sandstone. The Silurian Niagaran Reefs are part of an extensive paleo shallow shelf carbonate depositional system. The trend of pinnacle reefs forms a circular belt along the platform margin that rings the Michigan Basin. The pinnacle reefs range from 2,000 feet to more than 6,000 feet deep; most of the oil- and gas-producing reefs along the northern trend are at depths of approximately 3,500 to 5,500 feet. While individual reef complexes are localized (averaging 50 to 400 acres in area), they may be up to 2,000 acres in areal extent and 150 to 700 feet in vertical relief with the steeply dipping flanks. Reef height, pay thickness, burial depth, and reservoir pressure increase towards the basin center (Gill, 1979). The Otsego County study area falls in the northern reef trend and Saint Clair County falls in the southern reef trend. Both trends consist of porous and permeable dolomite and limestone. The confining layers are subdivisions of the Salina Group, which is composed of interlayered tight dolomite, evaporites, and shales. Figure 7-17 shows a simplified stratigraphy column of Michigan formations of interest.

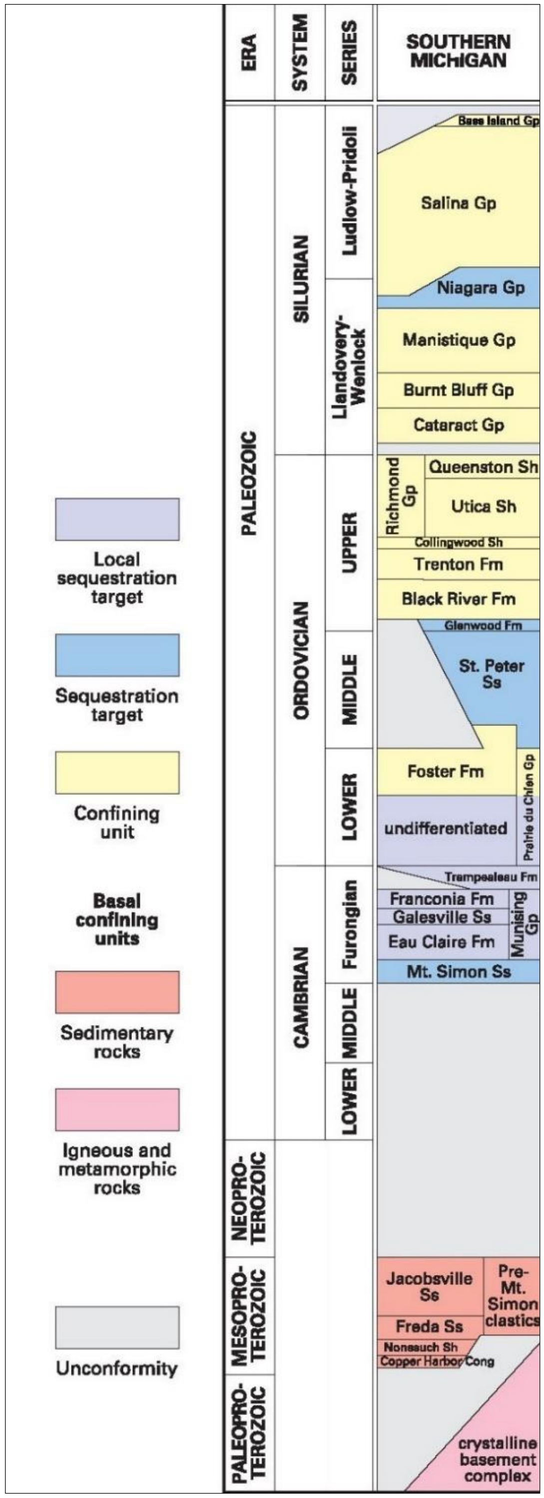


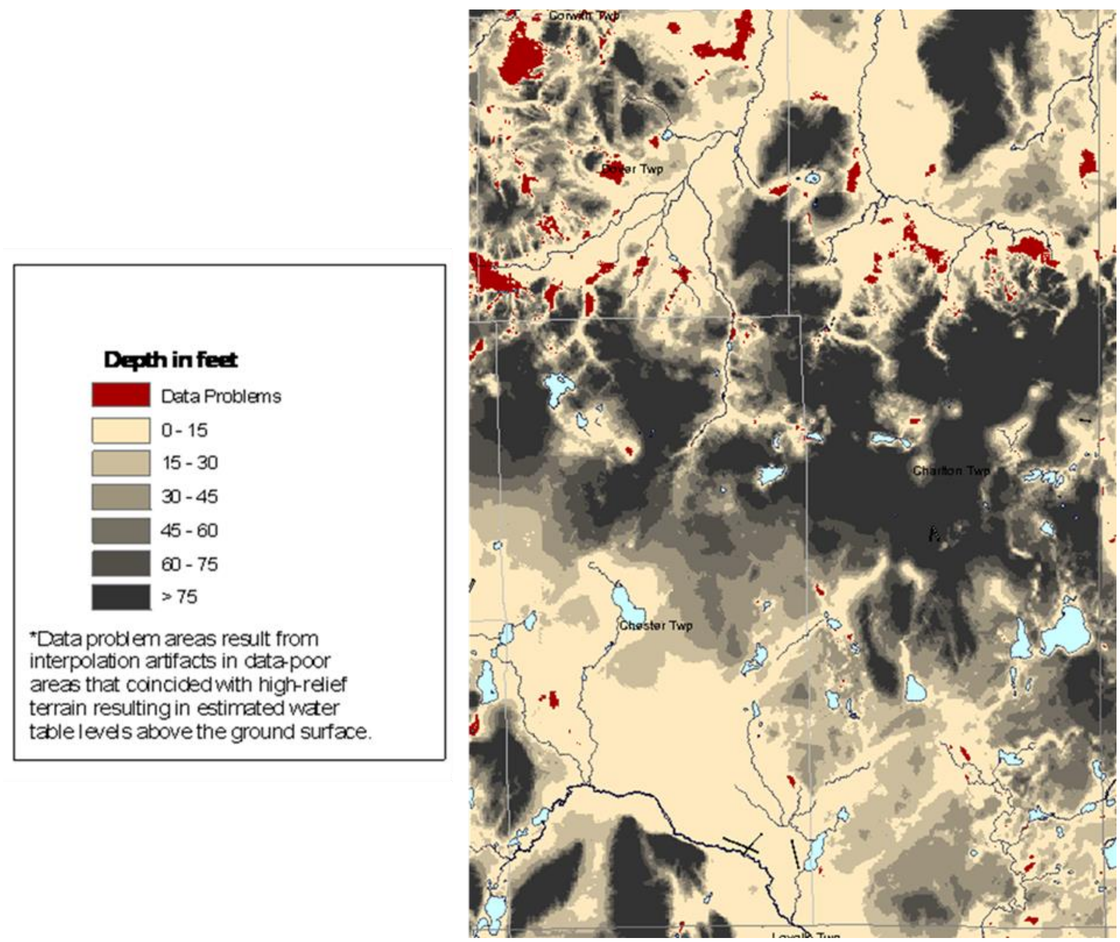
Figure 7-17. Simplified Stratigraphy Column of Michigan Formations of Interest

The Mt. Simon Sandstone was deposited during the Cambrian Period. It unconformably overlies the Precambrian basement. The thickness, textures, and depth change throughout the region. In Calhoun County, the storage zone is about 300 feet thick with a depth around 5,500 feet and an average porosity of 12%. The confining layers are in the Cambrian Eau Claire Formation, which consists of tight dolomite and shales.

7.4.2 Underground Drinking Water

The Glacial Drift is the only source of underground drinking water in Michigan. The thickness of this formation varies from 200 feet to greater than 1,000 feet. The depth to the Glacial Drift also varies from the surface to greater than 75 feet below the surface. Figure 7-18 demonstrates how the Glacial Drift varies over Dover, Chester, and Charlton Townships in Otsego County.

The depth to the base of the Glacial Drift was recorded for each well using driller logs. These data have been marked on the plugging charts to determine if there are sufficient plugs to prevent leakage into the Glacial Drift at each well site.



Source: Michigan.gov.

Figure 7-18. Depth to the Glacial Drift (underground drinking water source) in Otsego County, Michigan

7.4.3 Test Areas

7.4.3.1 Otsego County, Michigan

7.4.3.1.1 Test Area Definition

The Otsego County study area encompasses 446 oil and gas wells which primarily target either the Niagaran reef system or the shallower shale plays. There is one nearby CO_2-emitting facility which produces 3.7 million tons of CO_2 (USEPA, 2013). The selected study area is 19,700 x 19,700 feet based on the parameters listed in Table 7-8, which were selected using wireline data and literature. Figure 7-19 shows the location of the Otsego County study area.

Table 7-8. Parameters Used to Estimate the Size of the Otsego County, Michigan Study Area

Formation: Niagara		
Depth	6200	feet
Thickness	400	feet
Porosity	0.12	fraction
Pressure	2500	psi
Salinity	350000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

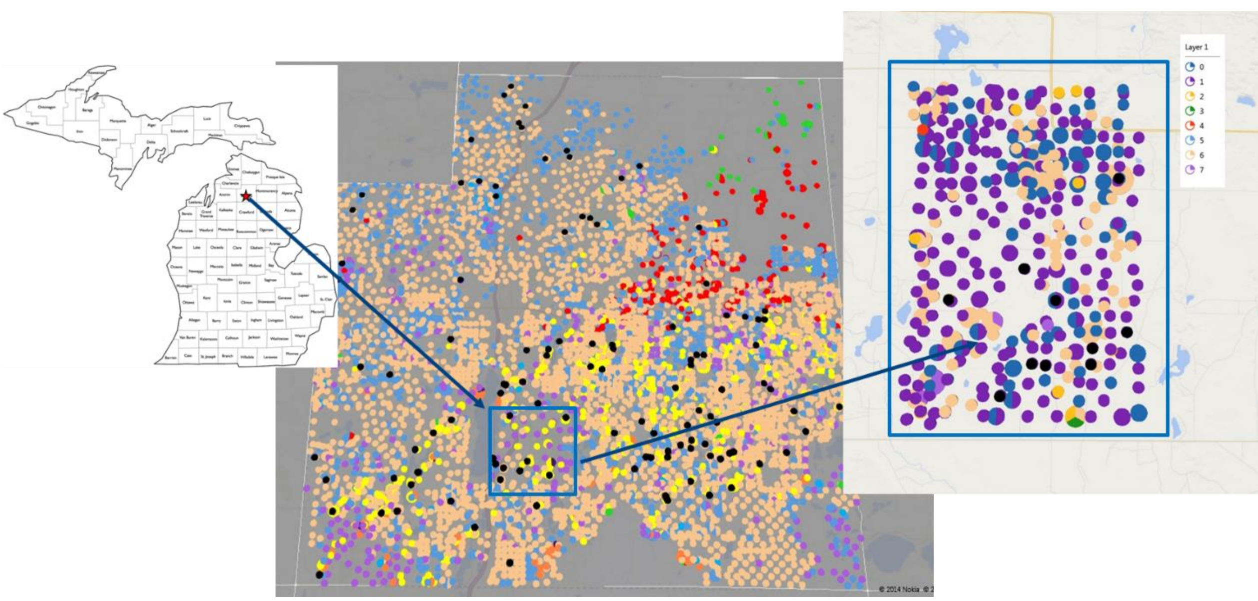


Figure 7-19. Location of the Otsego County, Michigan Study Area

7.4.3.1.2 Well Status Survey

The majority of wells in the Otsego County study area were drilled shallower than 2,000 feet with the second highest number of wells being drilled between 6,000 and 7,000 feet deep. Of the 446 total wells, 133 wells of interest penetrated the storage zone and/or the confining layers. Of that total, 115 wells (86%) were plugged and abandoned, with 13% currently active or producing. Table 7-9 summarizes the recorded deepest formations for wells in Otsego County, and Figure 7-20 shows well depths in Otsego County. Figure 7-21 shows the status of the 133 wells of interest that penetrated the storage zone and/or the confining layers.

Table 7-9. Recorded Deepest Formations for all Wells in the Otsego County, Michigan Study Area

Deepest Formation	Count
Glacial Drift	1
Sunbury	1
Antrim	143
Traverse Group	62
Detroit River Group	3
Dundee	5
Bass Islands	1
Salina	1
A Two	1
Niagara	125
Clinton	5
Unknown	99
Total # of Wells	446

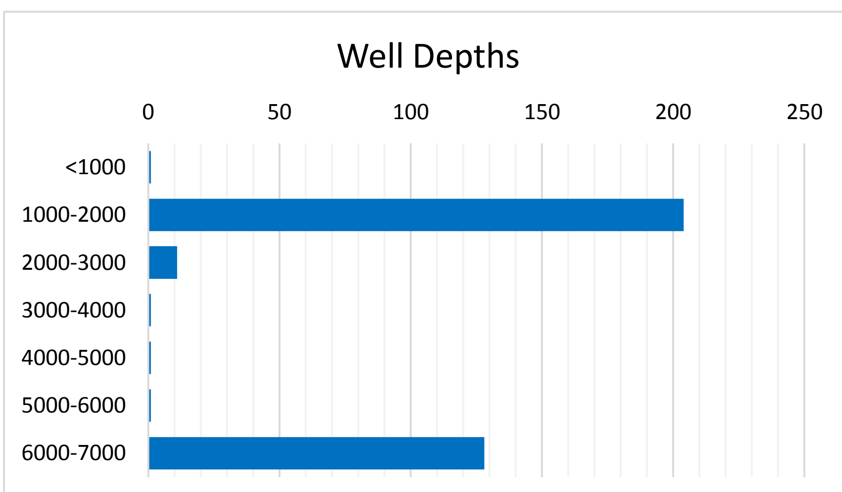


Figure 7-20. Well Depths in the Otsego County, Michigan Study Area

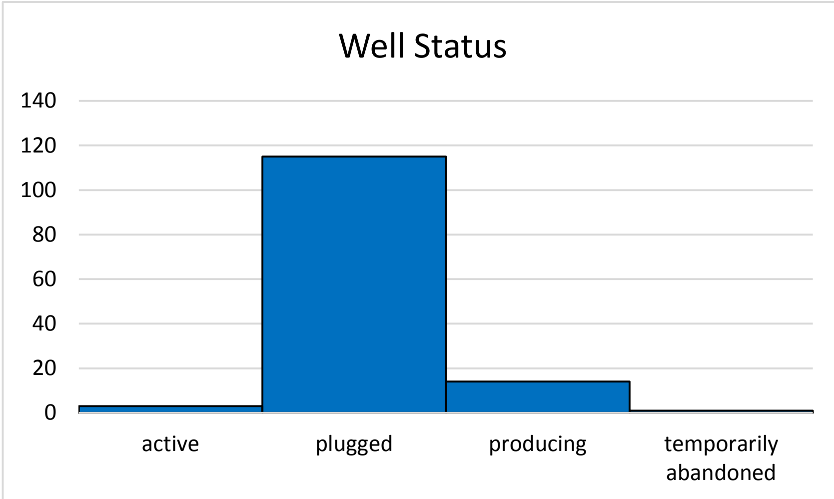
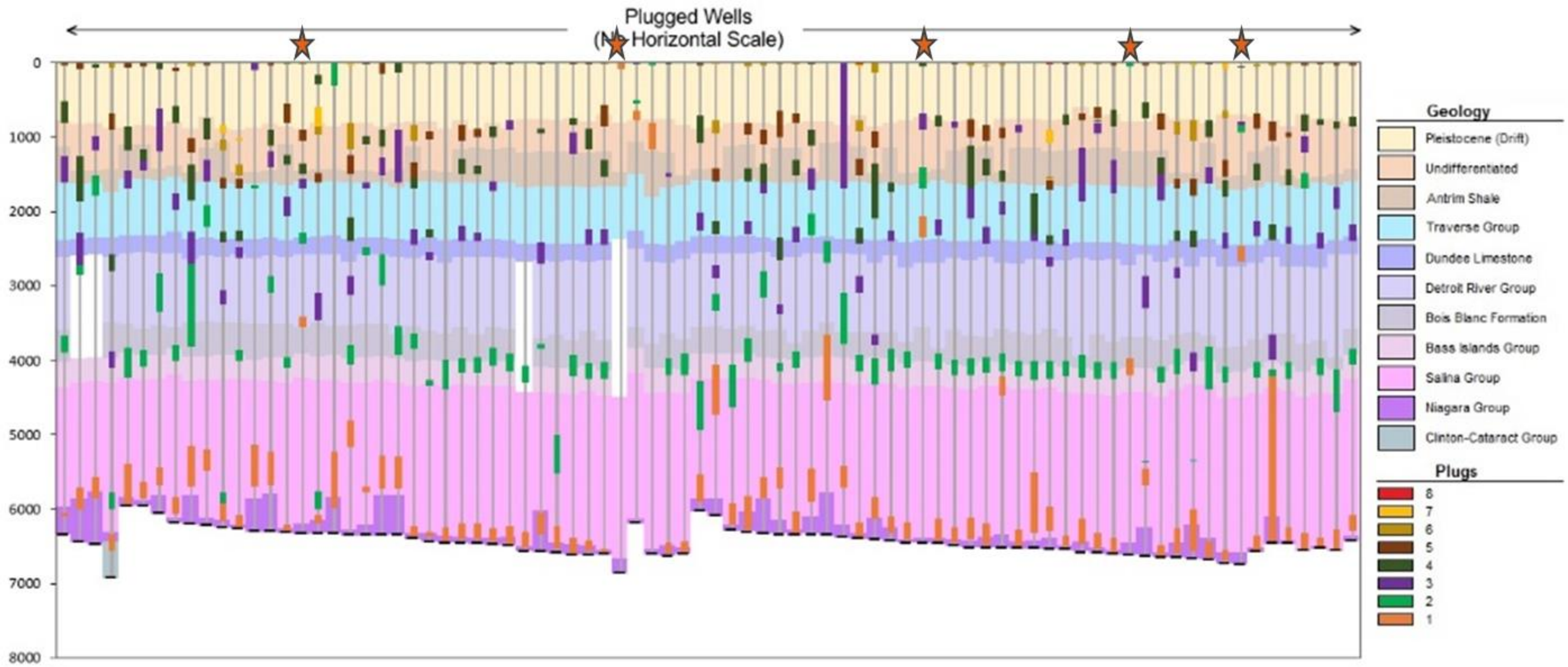


Figure 7-21. Status of the 133 Wells of Interest in the Otsego County, Michigan Study Area

Of the 115 plugged wells, 82 had available plugging records to review. The number of plugs in each well ranged from one to eight, with an average of five. Seven wells did not have a plug in the Salina Group or Niagara, but all wells had at least one plug between the storage zone at the USDW. Figure 7-22 shows plugs in depth in all 82 wells. The red stars denote wells that would need to be remediated if this site were to be used for CO_2 storage.



Note: Red stars denote wells that do not have adequate plugs and would need to be remediated if this site were to be used for CO_2 storage.

Figure 7-22. Plugging Chart for Wells in the Otsego County, Michigan, Study Area

7.4.3.1.3 Corrective Action Analysis

Based on the corrective action flow chart shown in Figure 7-2, the Otsego County study area has 313 wells which would require no corrective action because they reached a total depth shallower than the confining layers. All 123 wells that penetrate the confining layer or deeper would require wellhead inspection. Based on the well status, history, and plugging records, ten wells would need to be replugged or have additional plugs set to reduce the risk of CO_2 migration through the wellbore. Figure 7-23 shows the locations of wells which need to be inspected (green) and those that require replugging (orange). Table 7-10 summarizes the necessary corrective action needed to prepare the Otsego County study area for a CO_2 storage site.

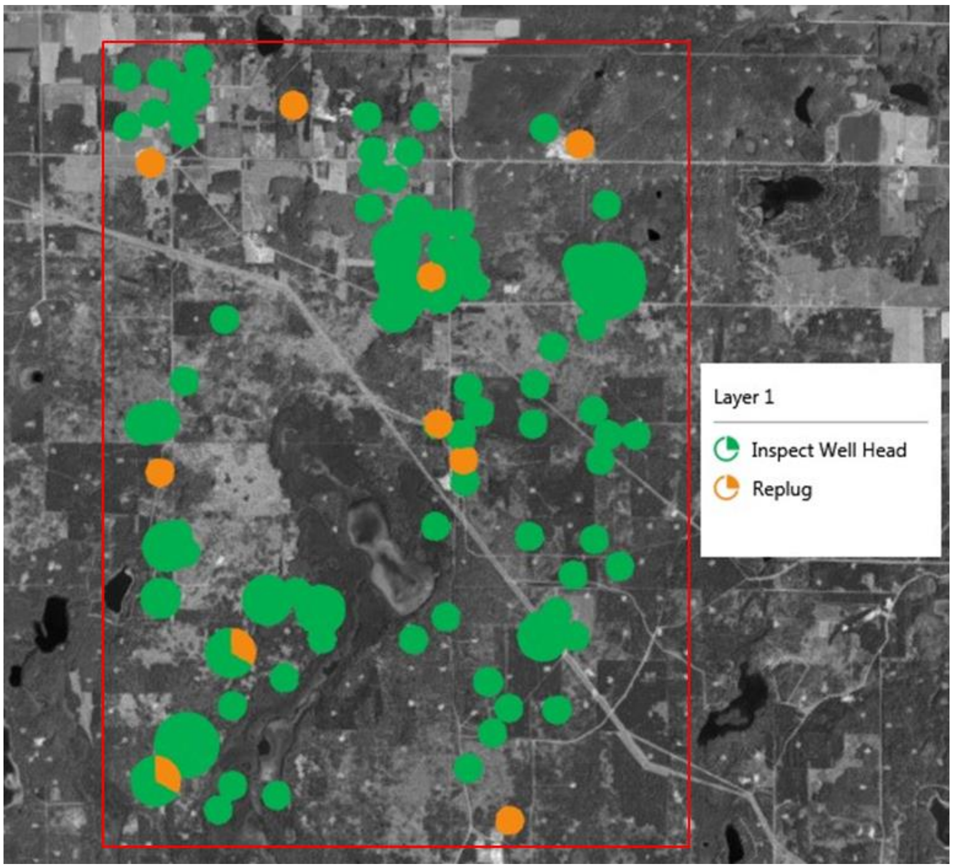


Figure 7-23. Well Locations Requiring Corrective Actions

Table 7-10. Summary of Required Corrective Actions for Wells in the Otsego County Study Area

Corrective Action	Count
Zero corrective action	313
Inspect wellhead	123
Survey well	0
Monitor wellhead	0
Replug well	10
Overdrill & plug	0
Total	446

7.4.3.2 St. Clair County, Michigan

7.4.3.2.1 Test Area Definition

The Saint Clair County study area encompasses 155 oil and gas wells which primarily target the Niagara reef system. There are four nearby CO_2-emitting facilities, one of which produces more than 10 million tons of CO_2 (USEPA, 2013). The selected study area is 19,700 x 19,700 feet based on the parameters listed in Table 7-11, which were selected using wireline data and literature. Figure 7-24 shows the location of the study area.

Table 7-11. Parameters Used to Estimate the Size of the Saint Clair County, Michigan Study Area

Formation: Niagara		
Depth	6200	feet
Thickness	400	feet
Porosity	0.12	fraction
Pressure	2500	psi
Salinity	350000	ppm
Temperature	52.8	Celsius
CO_2 Density	0.794	g/cc

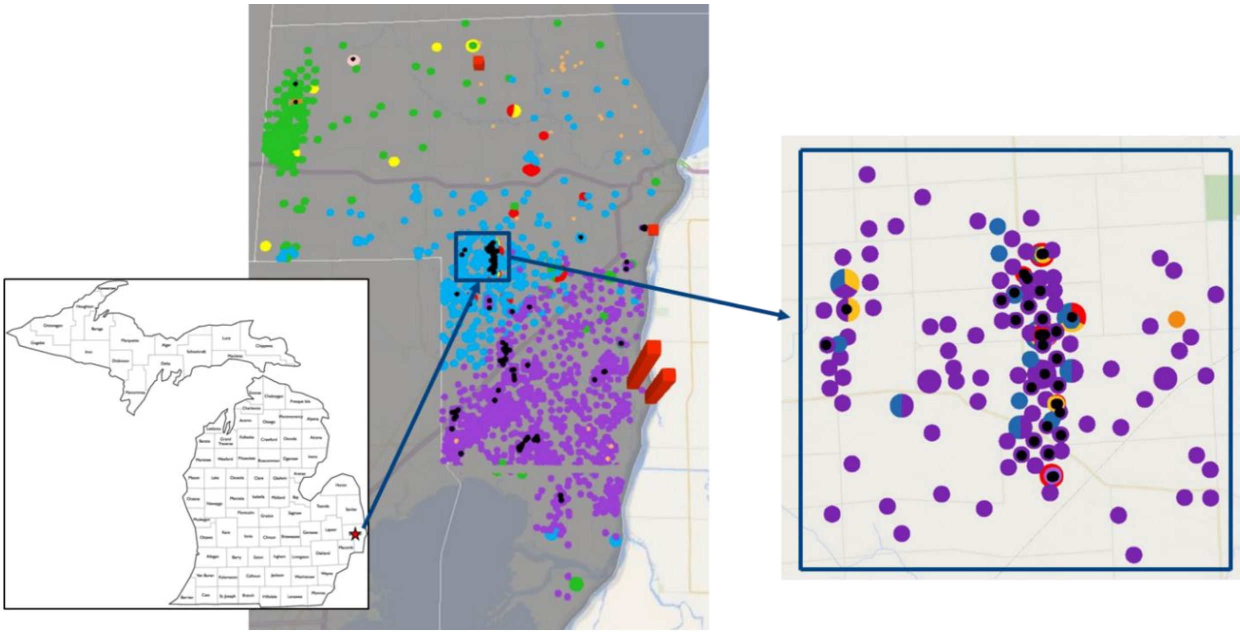


Figure 7-24. Location of the Saint Clair County, Michigan Study Area

7.4.3.2.2 Well Status Survey

The majority of wells in the Saint Clair County study area were drilled between 3,000 and 4,000 feet deep. Table 7-12 and Figure 7-25 summarize the formations and the depths reached at the total depth of the well. Of the 155 total wells, 145 wells penetrated the storage zone and/or the confining layers. Of that total, 107 wells (74%) were plugged and abandoned, with 23% currently active or producing. Figure 7-26 summarizes the status of all of the wells of interest in the Saint Clair County study area.

Table 7-12. Formations Penetrated at Total Depth of the Wells in the Saint Clair County, Michigan Study Area

Formation	Count
Bedford	1
Salina	2
A Two	1
A One	11
Niagara	112
Clinton	9
Manistique	1
Unknown	18
Total # of Wells	155

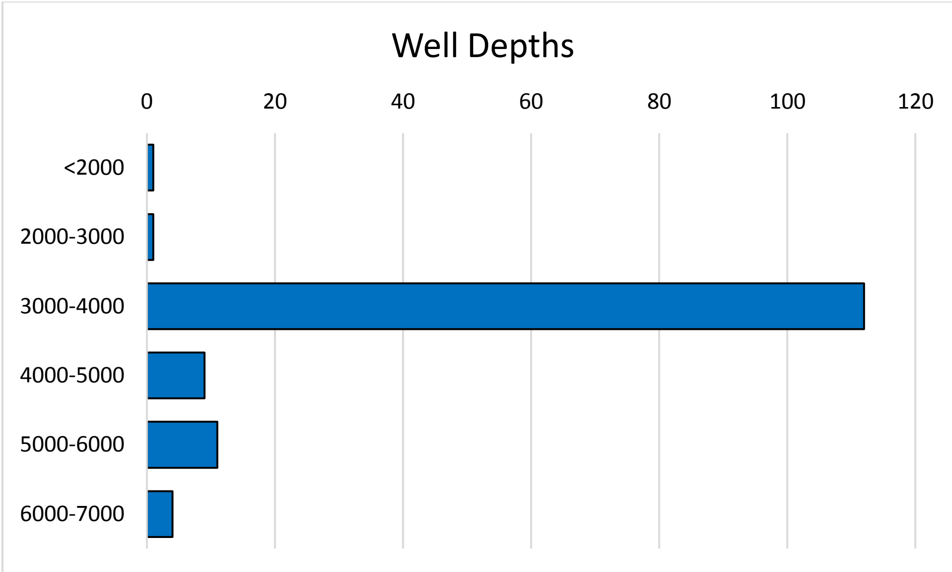


Figure 7-25. Well Depths in the Saint Clair County, Michigan Study Area

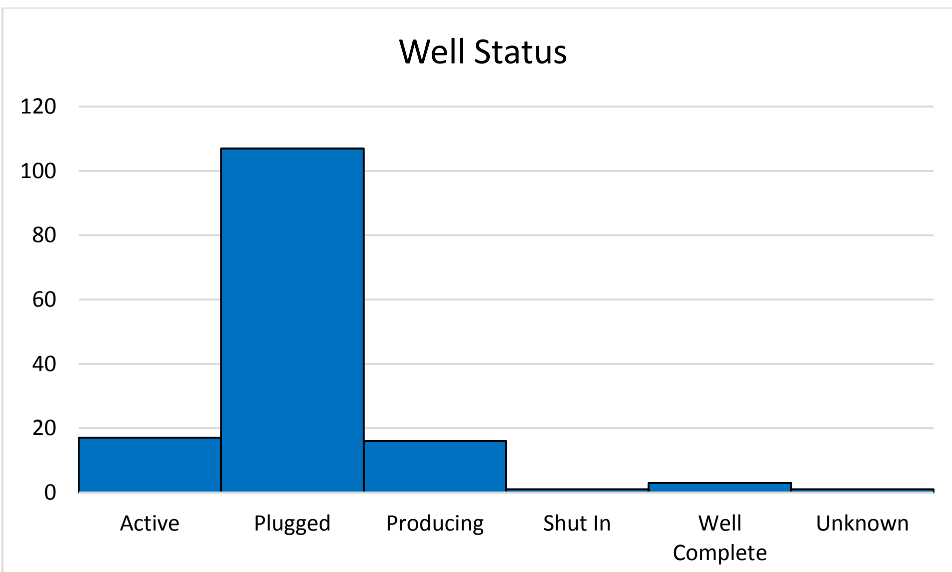


Figure 7-26. Status of the 145 Wells of Interest in Saint Clair County, Michigan Study Area

Within the study area, 107 plugged wells penetrate the storage zone and/or confining layers, of which 88 had detailed plugging records available. The number of plugs in each well ranged from two to seven, with an average of three. All wells had at least one plug in the Niagara or Salina Group, and all wells had at least two plugs between the storage zone and the USDW. Figure 7-27 shows plugs in depth in all 88 wells.

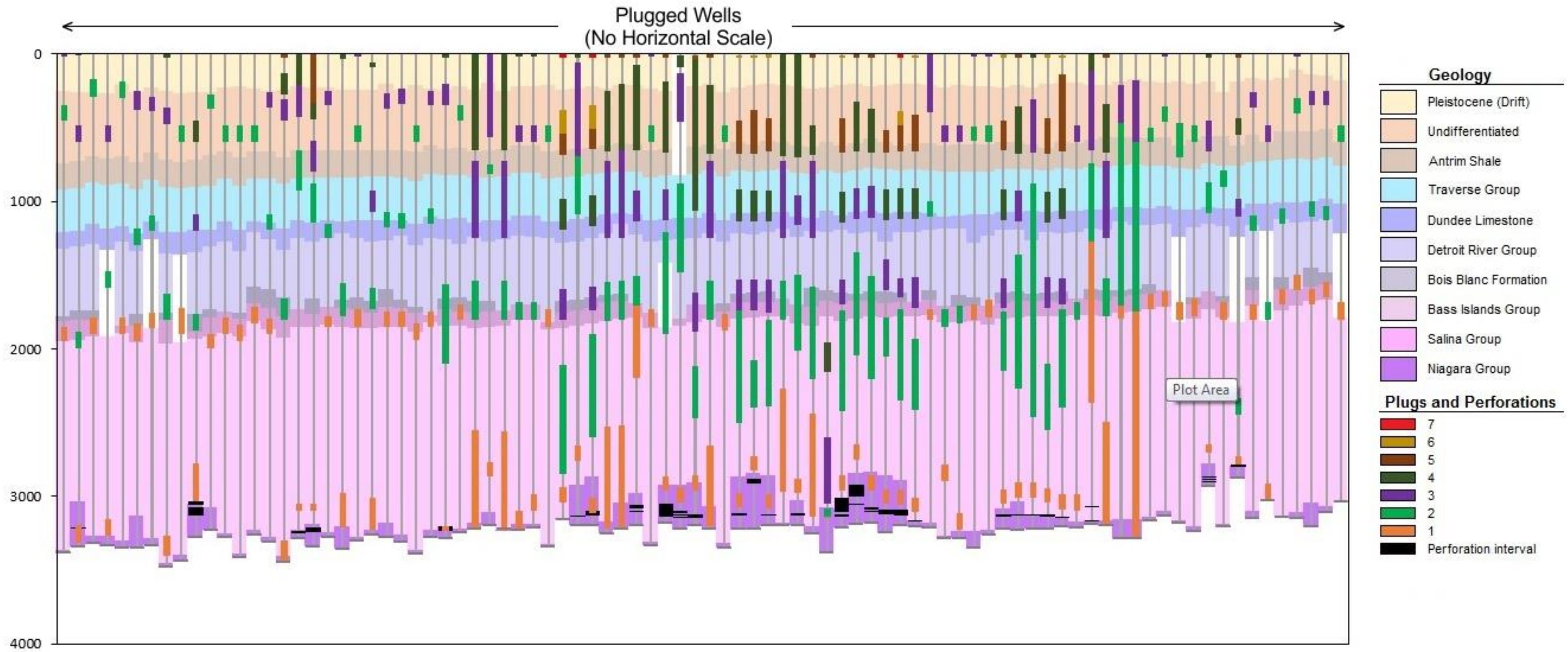


Figure 7-27. Plugging Chart for Wells in the Saint Clair County, Michigan Study Area

7.4.3.2.3 Corrective Action Analysis

Based on the corrective action flow chart (see Figure 7-2), nine wells in the Saint Clair County study area require no corrective action because they reached a total depth shallower than the confining layers. Another 127 wells are properly plugged and only require to have the wellhead inspected. Based on the well status, history, and plugging records, 18 wells need to be plugged because they are currently active. One well has very little information available and should be surveyed and monitored.

Figure 7-28 shows the locations of wells that need to be inspected (green), the well that needs to be surveyed (yellow), and those that require plugging (orange). Table 7-13 summarizes the corrective actions needed to prepare the Saint Clair County study area for a CO_2 storage site.

Figure 7-28. Well Locations in the Saint Clair County, Michigan Study Area that Require Wellhead Inspection (green), Plugging (orange), and a Survey (yellow)

Table 7-13. Summary of Required Corrective Actions for Wells in the Saint Clair County Study Area

Corrective Action	Count
Zero corrective action	9
Inspect wellhead	127
Survey well	1
Monitor wellhead	0
Replug well	18
Overdrill & plug	0
Total # of wells	155

7.4.3.3 Calhoun County, Michigan

7.4.3.3.1 Test Area Definition

The Calhoun County study area encompasses 22 oil and gas wells which primarily target the Trenton-Black River Formations. The potential storage zone in this study area is the Mt. Simon Sandstone, with the Copper Ridge Dolomite as the confining layer. The selected study area is 23,000 x 23,000 feet based on the parameters listed in Table 7-14, which were selected using wireline data and literature. Figure 7-29 shows the location of the study area.

Table 7-14. Summary of Parameters Used to Estimate the Size of the Calhoun County, Michigan Study Area

Formation: Mt. Simon		
Depth	5600	feet
Thickness	330	feet
Porosity	0.12	fraction
Pressure	2,500	psi
Salinity	225,000	ppm
Temperature	44.4	Celsius
CO_2 Density	0.756	g/cc

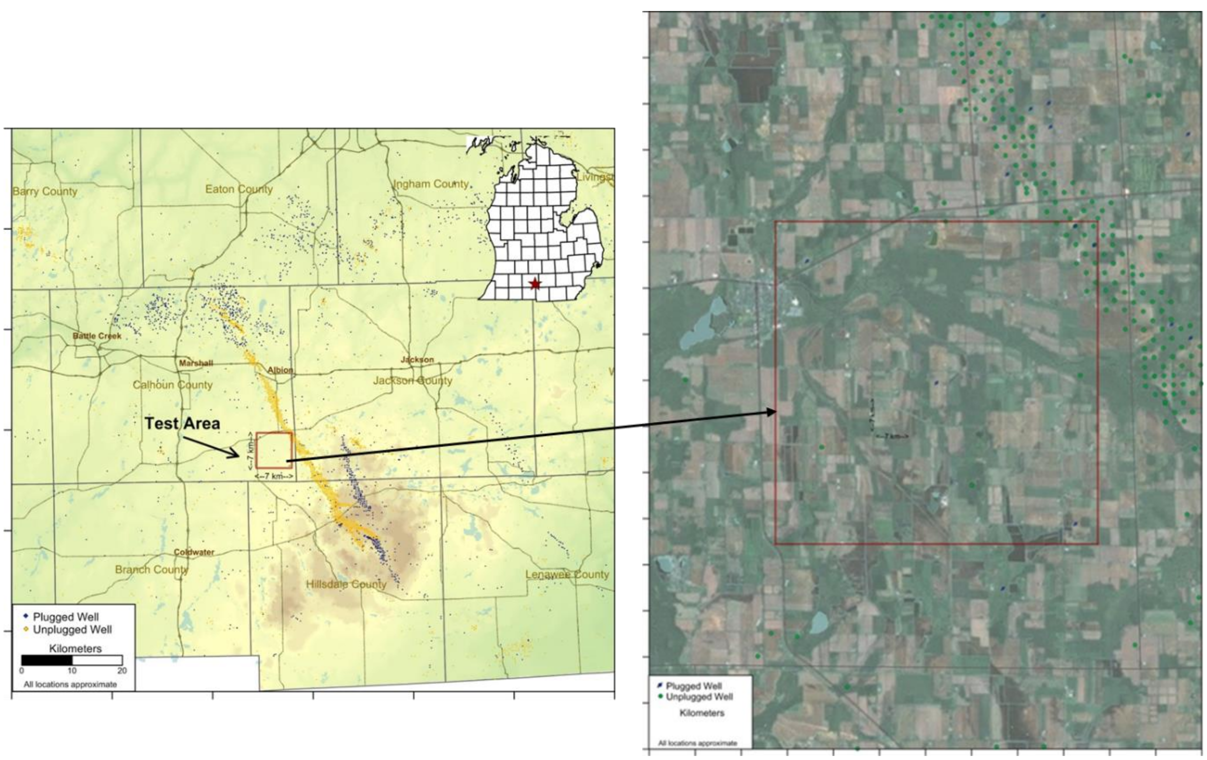


Figure 7-29. Location of the Calhoun County, Michigan Study Area

7.4.3.3.2 Well Status Survey

The 22 wells in the study area are all plugged and do not penetrate the targeted storage zone and/or confining layers. The number of plugs in each well ranges from three to six, with an average of four. All wells have at least three plugs between the storage zone and the USDW. Figure 7-30 shows all the plugs in depth.

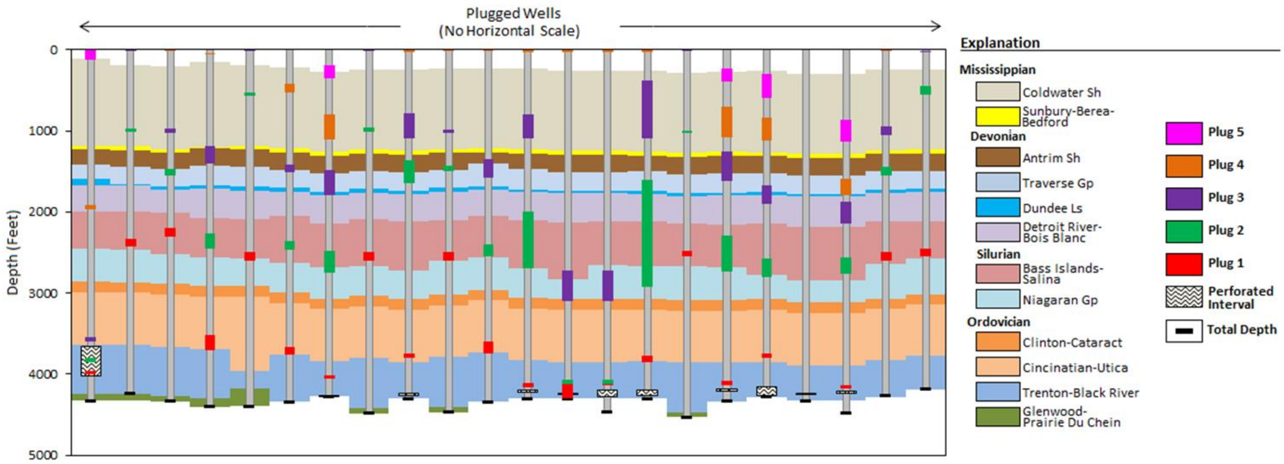


Figure 7-30. Plugging Chart for Wells in the Calhoun County, Michigan Study Area

7.4.3.3.3 Corrective Action Analysis

Zero corrective action is required for this study area, because no wells penetrate the confining layer of the Mt. Simon storage zone. In general, the Mt. Simon is about 1,500 feet deeper than the wells in the test study area.

8.0 Conclusions

The condition of legacy oil and gas wells in the Midwest United States was evaluated through analysis of well records, well plugging information, CBL evaluation, SCP field monitoring, and hypothetical CO_2 test areas to provide a realistic description of wellbore IFs. The research included state-wide review of oil and gas well records for Ohio and Michigan along with more detailed testing of wells in Ohio. Results concluded that oil and gas wells are clustered along fields in areas. Many of the deep saline formations being considered for CO_2 storage have few wells that penetrate the storage zone or confining layers. Research suggests that a variety of well construction and plugging approaches have been used over time in the region. Well status, condition, CBLs, and plugging records were used to estimate corrective actions necessary to prepare the test areas for CO_2 storage.

This project generated several useful tools and methodologies for examining wellbore IFs for CO_2 storage:

- a database of over 4 million fields on well integrity parameters in the study areas,
- a systematic CBL evaluation tool for rating cement in boreholes,
- SCP field monitoring procedure and analysis methodology,
- a process for summarizing well integrity at CO_2 storage fields,
- a statistical analysis of well integrity indicators, and
- an assessment of practical methods and costs necessary to repair/remediate typical wells in the region based on assessment of six test study areas.

Together, these products provide practical tools for supporting CO_2 storage applications in the region (and other locations). The tools may be applied to individual wells, but they appear to be more useful in evaluating many wells for trends based on spatial location, well age, well depth, and/or geologic formations. Project results may benefit both CO_2 storage and improved oil recovery applications. A study of wellbore integrity is a useful precursor to support development of geologic storage in the Midwest United States, which has some of the oldest oil and gas wells in the world. This study sheds more light on the actual well conditions (rather than the perceived condition) of historic oil and gas wells in the Midwest.

Project results suggest major implications for CO_2 storage projects in the Midwest United States; these issues are discussed in Sections 8.1 through 8.6.

8.1 Well Record Data Analysis

A database of over 4 million well records for Ohio and Michigan was compiled. Input data included records on well construction, well status, and plugging methods. Data suggests that 102,246 of the 207,892 wells in Ohio (49%) are plugged and 34,587 of the 53,800 wells in Michigan (64) are plugged. P&A details were also collected for a 5% subsampling for Michigan and Ohio. CBLs were reviewed for the Michigan and Ohio study areas. Records indicated that 1,720 CBLs were available for Michigan and 1,060 CBLs were available for Ohio. These records were randomly subsampled to obtain 10%, or 278, of the logs. The 10% subset was acquired and collated with well records for further analysis. The logs were reviewed with a systematic cement bond evaluation tool to assess the quantity and quality of cement in the well. Statistics were used to evaluate population and spatial trends in the datasets. These data provide a better description of well status, plugging quality, and geographic distribution.

8.2 Well Integrity Evaluation

The condition of oil and gas wells in the region was evaluated based on well records. Cement integrity was analyzed based on the amount of cement in the well casing as indicated by CBLs and plugging records. Well casing was surveyed for materials, construction methods, and options for surveying casing. Finally, hydrologic conditions in the subsurface were reviewed for the study areas in relation to the potential to affect wellbore integrity.

8.2.1 Cement Integrity

Well cementing practices were adopted in the region in the 1920s, driven by regulations and drilling technology. Overall, review of the well records suggests that many cementing advances were driven by oil and gas regulations. Review of materials used for well completion and plugging suggests that mostly Class A cement was used for nearly all wells. Cement additives were mainly CaCl accelerant, gel, salt, and lost circulation material. Plugging records suggest that a significant portion of wells in Michigan were plugged with mud. Approximately 18% of the plugs in Ohio were listed as clay.

To investigate the emplacement of cement in oil and gas wells in the study area, a 10% subset of available CBLs from Ohio and Michigan was analyzed using a systematic evaluation method. The method classified cement intervals based on bond index, so the cement bond may be analyzed with a more standardized method.

Michigan CBL Analysis - Based on the evaluation tool results on 394 CBLs from Michigan, it was determined that 67% of wells in Michigan had an average cement bond index between 80% and 100%, which falls into the high-cement-quality category. Approximately 15% of the wells fell into the low-cement-quality category, pointing to a need for additional review and potential corrective action. Based on the CBL index, a series of graphs, boxplots, and classification trees were produced to look for any correlations between cement factors and cement quality in Michigan wells. The age of a well, the season a well was completed, and the depth of a well had no correlation with the cement quality.

Ohio CBL Analysis - A total of 306 CBLs were analyzed for Ohio. It should be noted that very few wells were drilled prior to the 1970s or after 2010 (the dataset is from 2012). Results indicated that the majority of wells (66%) have an average cement bond index between 80% and 100%, which falls into the high-cement-quality category. Only 13% of wells fell into the low-cement-quality category that may require additional analysis or corrective action. On average, the footage of high cement quality was around 560 feet, while the average low-cement-quality footage was 135 feet. Cement quality did not appear to correlate with age, season of the cement job, depth, or thickness.

8.2.2 Casing Integrity

Well casing may be a wellbore IF in CO_2 storage zones. Similar to well cementing, well construction methods appear to be related to drilling technology, local practices, and regulations. API grade H-40 or J-55 casing was most prevalent in the region, because it is suitable for most depth, temperature, and fluid conditions encountered. Various casing sizes were used, depending on field properties. Overall, 8 5/8-inch diameter surface casing and 4 1/2-inch diameter production casing were typical for Ohio wells, and 9 5/8-inch diameter surface casing and 5 1/2-inch diameter production casing were typical for Michigan wells. Many different well designs have been used in the region, and wells may have 2 to 6+ strings of casing at various depths. Many ‘dry hole’ wells did not set production casing, and many wells have sections where casing was pulled after plugging. These conditions may affect CO_2 storage security, because there are many inactive wells with no casing across large intervals.

To assess casing conditions, physical and wireline methods are available. Physical methods include pressure testing the casing string with fluid to determine if there any leaks. Wireline methods include cased-hole caliper logs, flux leakage tools, EM phase-shift tools, ultrasonic tools, and noise and temperature logs. Most of these methods are employed only when an operator has a problem with a well. In addition, when applied, these tools are used to investigate a particular problem which requires knowledge of the context behind the operation. Consequently, evaluating casing conditions based on well inspection records over a broad area is not feasible. Hydrologic Conditions

Subsurface hydrologic conditions may affect wellbores over time and interactions with CO_2 storage zones. Temperatures, fluid pressures, salinity, and oil/gas/water ratios may vary considerably across the Midwest United States. To review these conditions, we summarized the hydrologic conditions at six local study areas. Formation temperature, salinity, pressure, and fluid composition were tabulated for these areas. Overall, the review indicated that one of the main factors that may affect pre-existing wellbore integrity was highly saline (more than 100,000 mg/L) formation water, which may create corrosive environments with CO_2. Most depleted oil and gas reservoirs may be depressurized due to historical production. Finally, many areas in the region have thick salt layers that are difficult to cement across and may exhibit ductile deformation that could damage well components.

8.3 Statistical Analysis of Wellbore Integrity Indicators

If a carbon storage project must be placed in an area with pre-existing wells, a methodology was developed to rate existing wellbores based on well age, depth, geologic formations penetrated, and well status. The method was applied to Ohio and Michigan study areas to help screen areas for potential CO_2 storage fields. The method also provided an integrity score for specified areas. This rating can be used to compare specific candidate storage fields. Average and weighted-average integrity scores were calculated for three candidate fields in Ohio and three in Michigan to illustrate the process. For example, the weighted average integrity indicator for the example sites in Ohio ranged from 4.5 to 11.6; the site with the higher rating would likely have fewer well integrity issues for CO_2 storage applications.

8.4 Well Integrity Remediation Guidance

To provide remediation guidance on wellbore integrity issues in the Midwest United States, corrective action options and USEPA Class VI UIC requirements were reviewed. The review provided guidance on well plugging, monitoring, and well testing for CO_2 storage applications. These methods offer customized options for addressing legacy oil and gas wells in the region. The methods aid in determining the depth location in the well and the nature and severity of potential defects. The information may be used to make a more cost-effective well repair. Overall, the remediation guidance determined that multiple options may be suitable, depending on the conditions in a wellbore. For locations in the Midwest, several factors suggest that well testing or monitoring may be suitable rather than more expensive well re-plugging or squeeze jobs.

To assist in site selection and planning, wellbore IFs related to site selection and UIC Class VI permitting requirements were analyzed. Wellbore integrity may be a key factor for CO_2 storage application, and it should be included in the site selection and screening process. The statistical indicator of the wellbore integrity method may be used in the site screening process as a measure of wellbore problems. USEPA Class VI regulations require identification of wells in the CO_2 storage zone AoR, which may be several hundred square kilometers for industrial-scale projects in the Midwest. Some of the methods for identifying and testing wells may be challenging if the well locations are uncertain or if the wells have been plugged and abandoned to below surface. The option to re-evaluate the AoR every five years does provide the operator with flexibility to progressively address more wells as a CO_2 storage project proceeds.

8.5 SCP Testing

To better understand the subsurface conditions in typical wells in the region, 13 wells in the Appalachian Basin were tested with SCP methods (bleed-down/build-up, gas analysis, and gas chamber volume). The objective of the testing was to identify the SCP issues associated with these wells. The wells were selected based on displaying SCP at some time in their history, so they represent a subset with substantial bias rather than all oil and gas wells in the region. The wells used in this analysis were drilled and completed over a wide range of dates (1940s to the present) and have a number of different casing and cement completion details. In the testing, it was determined that the completion designs resulted in different causes or different origins of SCP gas. The casing strings in these wells were cemented at various intervals, and they reflect a variety of well completions.

A SCP testing methodology was developed to measure the sum effect of defects in the wells. The testing procedure involved installing wellhead loggers on the annulus port in the 13 wells, then venting the port so the rate of pressure build-up over time could be recorded. Gas samples were also collected from selected wells in an attempt to assess the source of the gas based on hydrocarbon signature. Once the pressure built back up to initial pressure, the volume of the gas chamber was estimated with a flow meter and the change in pressure. In general, the wells' pressure varied from 34 to 1,200 psi, indicating various source zones. Because the region has many different formations that produce gas, this may be expected, but it complicates SCP analysis because the source of gas may not be clear.

The SCP test involves a direct measurement on wells, so there are no assumptions or interpretations to obscure results. The SCP test procedure provides a well FF, which may be used to evaluate conditions in multiple wells. The methodology also estimates SLM and IRM. These metrics are useful in CO_2 storage applications to understand the potential for CO_2 migration from wells.

Overall, all the wells had good zonal isolation, and there was no indication that gas from the reservoir zone was migrating through the annulus. However, there was evidence for gas moving into the wellbore from intermediate zones. Thus, for this set of wells, this investigation concluded that the presence of SCP is not a reliable indicator of a poor seal above the producing/injecting formation. In 11 of the tests, the gas causing the SCP was not from the producing/injecting formation. In the other two, it is not possible with the data collected to determine the source of the gas. Therefore the presence of SCP in a well does not necessarily indicate that cement above the completed zone is leaking. The character of flow for the wells in this study was "porous," which means it was most consistent with a Darcy-derived flow function. As a result, it was not possible to determine whether the calculated flow factor was due to the resistance of the cement or the source formation.

These 13 wells represent a limited sampling, biased toward wells that exhibit SCP, in only three geographic areas. In this sample set, the range of variability in the flow factor is about three orders of magnitude. The wells represent about 1% of the candidate population. In order to be able to make any statistical inferences about cement quality in large populations of existing wells, a much larger and more diverse dataset would be required. In the case of any individual well, diagnosis of the location and cause of the SCP would require more investigation, but the initial screening using the wellhead model can quantify the level of risk, prioritize the well relative to others, and focus any subsequent testing.

8.6 CO_2 Storage Siting Guidance

To provide more detailed information on cementing in the region, six local-scale study areas were investigated in more detail. The study areas were based on general, industrial-scale CO_2 storage application, so the areas ranged from 6 x 6 kilometers to 15 x 15 kilometers. Overall, these study areas had 48 to 314 wells that penetrated major CO_2 storage zones or immediate confining layers. Detailed analysis was useful in determining areas where wells had lower cement bond quality. In addition, the tool provided information on certain geologic intervals where cement bond have less quality and on zones that were not cemented entirely.

The six study areas demonstrated a range of scenarios, from sites that required zero corrective action to sites that required over-drilling and re-plugging. Sites that have hundreds of oil and gas wells, such as Trumbull County and Muskingum/Coshocton Counties, Ohio, could still be good candidates for CO_2 storage because most of the wells do not penetrate the confining layers and only require inspections. Table 8-1 summarizes the corrective action analysis for each study area and ties in the cost analysis to give overall cost estimates to prepare a site for CO_2 storage.

Table 8-1. Summary of CO_2 Storage Test Study Areas

Corrective Action		Michigan			Ohio		
		Calhoun	*Otsego*	*Saint Clair*	*Trumbull*	*Musk/ Cosh*	*Noble*
Total # of Wells		*22*	*446*	*155*	*357*	*1,221*	*868*
Zero Corrective Action		22	313	9	357	919	629
Inspect Well Head		0	123	127	0	293	193
Test Well		0	0	1	0	0	26
Monitor Wellhead		0	0	0	0	9	4
Add Plugs to Well		0	10	18	0	0	0
Re-enter & Plug		0	0	0	0	0	16
Corrective Action	***Cost Per Well***	**Michigan**			**Ohio**		
		Calhoun	*Otsego*	*Saint Clair*	*Trumbull*	*Musk/ Cosh*	*Noble*
Total # of Wells		*22*	*446*	*155*	*357*	*1,221*	*868*
Zero Corrective Action	$0	$0	$0	$0	$0	$0	$0
Inspect Well Head	$400	$0	$49,200	$50,800	$0	$117,200	$77,200
Test Well	$25,000	$0	$0	$25,000	$0	$0	$650,000
Monitor Wellhead	$20,000	$0	$0	$0	$0	$180,000	$80,000
Add Plugs to Well	$75,000	$0	$750,000	$1,350,000	$0	$0	$0
Re-enter & Plug	$145,000	$0	$0	$0	$0	$0	$2,320,000
Test Study Area Cost Estimate		$0	$799,200	$1,425,800	$0	$297,200	$3,127,200

Overall, the test study area analysis suggests that for industrial-scale CO_2 storage projects in the Midwest United States, the corrective action level of effort would cover a wide range. Some sites may require no action, because no wells penetrate the storage zone or immediate confining layer. In other areas, there may be over 1,000 wells in a typical AoR. At these sites, it may be necessary to perform some level of corrective action on many wells. Cost estimates for the six sites ranged from $0 to $3,000,000 to address wellbore integrity issues. Sites with many unplugged or poorly plugged wells had the highest estimated corrective action costs. Sites with several hundred wells requiring well inspection or testing also had fairly high corrective action costs due to the high number of wells.

9.0 Technology Transfer

Technology transfer efforts included technical presentations, development of informational products, and project team meetings. The project benefited from several technical advisory committee meetings with BP Alternative Energy, NiSource-Columbia Gas Pipeline Group, and DOE-NETL. Data generated from the project were uploaded to the DOE-NETL Energy Data Exchange web site. Project methodology on CBL analysis was directly applied to the Midwest Regional Carbon Sequestration Partnership (MRCSP) field site risk assessment. At this CO_2 storage site, wellbore leakage was identified as the primary leakage pathway, so the methods developed under this project were very useful. The SCP methodology was used at several BP sites to examine well integrity. Mark Moody gave a Society of Petroleum Engineers (SPE) workshop presentation on SCP testing. The project was also useful for more indirect interactions related to the National Risk Assessment Partnership, DOE-NETL CO_2 Storage Program Best Practices Manuals, and other research on CO_2 storage. Technology transfer activities are summarized as follows:

9.1 Technical Advisory Meetings

- A project overview was given to the ODSA OCDO technical advisory committee on 27 September 2012, in Columbus, Ohio. The committee voted to approve the project.
- A brief project overview was provided at the MRCSP Annual Partners meeting in Independence, Ohio, on 30 October 2012.
- A project kickoff meeting was held at the DOE-NETL Pittsburgh office on 10 January 2013. At the meeting, Mark Moody presented an overview of the project for NETL research staff and project managers.
- A project team meeting was held between Battelle, BP Alternative Energy, and NiSource on 18 February 2013 at the Battelle Columbus Office. Topics of the meeting included project status, well record collection, SCP analysis, and NiSource/Columbia gas storage operations.
- A project review was presented by Mr. Mark Moody at the DOE Carbon Storage R&D Project Review Meeting in Pittsburgh, Pennsylvania, on 22 August 2013.
- A project review was presented by Mr. Mark Moody at the PTTC-EFD Wellbore Integrity Workshop in Pittsburgh, Pennsylvania, on 4 September 2013.
- A technical advisory group meeting was held on 12 March 2014, at Battelle Columbus, Ohio, office. The meeting was attended by BP Alternative Energy (Nigel Jenvey, Brian Dotson), NiSource-Columbia (Andrew Theodos, Jason Martin), DOE-NETL (Bill O'Dowd), ODSA OCDO (Greg Payne) and the Battelle project team members. Topics included project review, well record collection, well record analysis, SCP analysis, well integrity evaluation, study test area assessment, and CO_2 storage assessment.
- A technical advisory group meeting was held on 19 November 2014, at Battelle Columbus, Ohio, office. The meeting was attended by BP Alternative Energy (Nigel Jenvey, Bryan Dotson), NiSource-Columbia (Andrew Theodos, Jason Martin), DOE-NETL (Bill O'Dowd), ODSA OCDO (Greg Payne, Erin Hazelton, Bob Brown), and the Battelle project team members. Topics included project review, SCP analysis, CBL analysis, WBI statistical evaluation, well record analysis, study test area analysis, and CO_2 storage assessment.
- A technical advisory group meeting was held on 20 May 2015, at Battelle Columbus, Ohio, office. The meeting was attended by BP Alternative Energy (Nigel Jenvey), NiSource-Columbia (Andrew Theodos, Jason Martin), DOE-NETL (Bill O'Dowd), ODSA OCDO (Greg

Payne, Bob Brown), and the Battelle project team members. Topics included project review, SCP analysis, CBL analysis, WBI statistical evaluation, well record analysis, study test area analysis, and CO_2 storage assessment.

- Several meetings were also held with regional operators to discuss SCP monitoring opportunities.

9.2 Presentations at Professional Conferences

- A presentation was given by J.R. Sminchak at the Groundwater Protection Council 2013 UIC Conference, 22-24 January 2013: Abstract 18: Systematic Assessment of Wellbore Integrity for CO_2 Geosequestration in the Midwestern U.S. - Joel Sminchak, Neeraj Gupta, and Mark Moody.
- Investigation of Wellbore Integrity Factors in Historical Oil and Gas Wells for CO_2 Geosequestration in the Midwestern U.S., Joel Sminchak, Mark Moody, Andrew Theodos, Glenn Larsen, and Neeraj Gupta, GHGT-12, Austin, Texas, 5-9 October 2014.
- Systematic Assessment of Wellbore Integrity for Geologic Carbon Storage Using Regulatory and Industry Information, Mark Moody, DOE-NETL Carbon Storage R&D Project Review Meeting, Pittsburgh, Pennsylvania, 12-14 August 2014.
- Delineation of Wellbore Integrity Conditions for CO_2 Storage in the Midwestern U.S. with Historical Oil and Gas Wells Records (Poster), Joel Sminchak, Mark Moody, and Glenn Larsen, DOE-NETL Carbon Storage R&D Project Review Meeting, Pittsburgh, Pennsylvania, 12-14 August 2014.
- Sustained Casing Pressure Diagnosis Using the Wellhead Model, Bryan Dotson, Mark Moody, and Matthew Place, SPE/CSGM Gas Migration Challenges – Identification and Treatment Workshop, 13-14 May 2015, Banff, Alberta, Canada.
- Impact of Wellbore Integrity on CO_2 Storage Site Suitability in Oil and Gas Producing Areas, Joel Sminchak, Mark Moody, Autumn Haagsma, and Glenn Larsen. 14th Annual CCUS Conference, Pittsburgh, Pennsylvania, April 28-May 1, 2015.
- Utilizing Cement Bond Logs to Evaluate Wellbore Integrity for CO_2 Storage, Autumn Haagsma, Joel Sminchak, Mark Moody, Jacqueline Gerst, Andrew Burchwell, and Joel Main. 14th Annual CCUS Conference, Pittsburgh, Pennsylvania, April 28-May 1, 2015.
- Utilizing Cement Bond Logs to Evaluate Wellbore Integrity on Local and Regional Scales, Andrew Burchwell, Autumn Haagsma, Mark Moody, Jackie Gerst, and Joel Sminchak, AAPG Eastern Regional Meeting, 20-23 September 2015, Indianapolis, Indiana.
- Sustained Casing Pressure Diagnosis with Extended Data Collection, Matt Place, Glenn Larsen, Bryan Dotson, Nigel Jenvey, and Mark Moody, SPE Eastern Regional Meeting, 13-15 October 2015, Morgantown, West Virginia.
- Approach for Assessing Wellbore Integrity to Prioritize Study Areas for Potential Siting of a Carbon Dioxide Repository, Bruce Buxton, Neeraj Gupta, Mark Moody, Joel Sminchak, and Stephanie Weber, SPE Eastern Regional Meeting, 13-15 October 2015, Morgantown, West Virginia.
- Utilizing Cement Bond Logs to Evaluate Wellbore Integrity on Local and Regional Scales. Autumn Haagsma, Andrew Burchwell, Mark Moody, Jackie Gerst, and Joel Sminchak, SPE Eastern Regional Meeting, 13-15 October 2015, Morgantown, West Virginia.

9.3 Paper Publications

J.R. Sminchak, Mark Moody, Andrew Theodos, Glenn Larsen, and Neeraj Gupta. 2014. Investigation of wellbore IFs in historical oil and gas wells for CO_2 geosequestration in the Midwestern U.S. Energy Procedia (2014), pp. 5787-5797. http://dx.doi.org/10.1016/j.egypro.2014.11.611

Three papers are currently in progress for a special issue of *Greenhouse Gases: Science and Technology* on wellbore integrity and CO_2 storage:

- Systematic Wellbore Integrity Evaluation of CO_2 Storage Sites in the Michigan Niagaran Reefs, Autumn Haagsma (Battelle)
- Wellbore Integrity Factors for CO_2 Storage in Oil and Gas Producing Areas in the Midwest United States, Joel Sminchak and Mark Moody (Battelle)
- Sustained Casing Pressure Diagnosis with Extended Data Collection to Support CO_2 Storage Projects, Matthew Place and Brian Dotson (Battelle/BP Alternative Energy)

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Acronyms and Abbreviations

AoR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
CaCl	calcium chloride
CBL	cement bond log
CCUS	carbon capture, utilization, and storage
CO_2	carbon dioxide
CTOC	calculated top of cement
DEQ	Department of Environmental Quality
DOE	Department of Energy
DTD	total depth recorded by driller
E&P	exploration and production
EM	electromagnetic
EOR	enhanced oil recovery
FOA	Funding Opportunity Announcement
g/cc	grams per cubic centimeter
GPR	ground-penetrating radar
H_2S	hydrogen sulfide
IF	integrity factor
IOI	interval of interest
IRM	instant release metric
LiDAR	Light Detection and Ranging
LTD	total depth recorded by logger
mg/L	milligrams per liter
MRCSP	Midwest Regional Carbon Sequestration Partnership
MSCF	thousand standard cubic feet
MSCFD	thousand standard cubic feet per day
NETL	National Energy Technology Laboratory
NO_2	nitrogen dioxide
OCDO	Ohio Coal Development Office
ODNR	Ohio Department of Natural Resources
ODSA	Ohio Development Services Agency
P&A	plugging and abandonment
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gage
RBDMS	Risk Based Data Management System
SCP	sustained casing pressure
SLM	sustained leakage metric
SO_2	sulfur dioxide
SPE	Society of Petroleum Engineers
TD	total depth
TOC	top of cement

Acronyms and Abbreviations (cont)

TVD	total vertical depth
UIC	underground injection control
USDW	underground source of drinking water
USEPA	U.S. Environmental Protection Agency
VBA	Visual Basic for Applications