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1 Disclaimer

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2 Abstract

The Virginia Center for Coal and Energy Research (VCCER) project, "Injecting Carbon Dioxide into Unconventional Storage Reservoirs in the Central Appalachian Basin, with an Emphasis on Enhanced Coalbed Methane Recovery (ECBM), to Validate Prior Geological Characterization," successfully completed two unique field projects: (1) a 510 ton scale 'huff-and-puff' carbon dioxide (CO2) injection into a legacy horizontal Chattanooga Shale well in Morgan County, Tennessee and (2) a 13,263 ton CO2 injection into 3 legacy coalbed methane (CBM) wells in Buchanan County, Virginia.

The results from this Morgan County shale injection test confirm the injectivity and storage potential of CO2 in organic shales formations while enhancing gas recovery. During the flowback phase, gas composition and flow rate were frequently monitored. Results indicated that there was a significant increase in gas flow rate during the first five months of the flowback phase and there was also a significant increase in gas quality, such that the percent composition of NGLs (natural gas liquids), including ethane, propane, and butane, increased.

The primary objective of the research is to test the injectivity of CO2 into unmineable coal seams and the potential for enhanced coalbed methane recovery (ECBM) by stressing the coals under continuous injection for a one-year period. The results from the Buchanan County ECBM test provided data to better understand the effect of matrix swelling, due to the adsorption of CO2 on the coal surface, on injectivity and ECBM. During the greater than 13,000-ton injection, injectivity was maintained and coal swelling reduced by injecting into multiple wells at a moderate injection rate. Flowback has recently commenced and will be instrumental in determining the ECBM potential of central Appalachian coals and identifying commercialization opportunities.

Table of Contents

1 Disclaimer ii

2 Abstract iii

3 Executive Summary 1

4 Acknowledgements 3

5 Contributing Authors 3

6 Project Management 4

6.1 Project Organization and Structure 4

6.2 Research Team and Responsibilities 5

6.3 NEPA and Permitting 7

6.4 Project Deliverables and Milestone Log 8

7 Risk Management 12

8 Shale Well CO_2 Injection Site: Morgan County, TN 22

8.1 Overview 22

8.1.1 Test Objectives 23

8.1.2 Geologic Background 23

8.1.3 Site Selection 24

8.1.4 Study Area 25

8.2 Geologic Characterization 26

8.2.1 Reservoir Geology 27

8.2.2 Gas Production Analysis 33

8.3 Preliminary Reservoir Modeling 34

8.3.1 Methodology 35

8.3.2 Model Parameters and Inputs 36

8.3.3 Sensitivity Analysis 38

8.3.4 History Match 38

8.4 Monitoring, Verification and Accounting Plan 39

8.5 Site Development and Operations 41

8.5.1 Site Development 41

8.5.2 Operations Permitting 43

8.5.3 CO2 Procurement 44

8.6 CO2 Injection Operations 44

8.6.1 Injection Results 44

8.7 Monitoring Results 48

8.7.1 Pre-injection baseline monitoring 48

8.7.2 Soaking Phase 50
8.7.3 Flowback Results 51
8.8 Post-Injection Reservoir Modeling 55
8.8.1 Methodology 55
8.8.2 Model Parameters and Inputs 56
8.8.3 Sensitivity Analysis 58
8.8.4 History Matching Results 58
8.9 Financial Analysis 62
8.10 Site Closure 64
8.11 Conclusions and Recommendations 65
8.11.1 Injectivity 65
8.11.2 CO2 storage 65
8.11.3 Enhanced hydrocarbon recovery 66
8.11.4 Recommendations 66
9 CBM Well CO_2 Injection Site: Buchanan County, VA 68
9.1 Overview 68
9.1.1 Oakwood Coalbed Methane Field 68
9.1.2 Geologic Background 69
9.1.3 Russell County ECBM Test 70
9.1.4 Site Selection 72
9.1.5 Study Area 79
9.2 Geologic Characterization 82
9.2.1 Regional Structure, Gas Content, and Stratigraphy of the Study Area 82
9.2.2 Lineaments 89
9.2.3 Stress Fields 91
9.2.4 Regional Gas Content Trends 95
9.2.5 Stratigraphy 96
9.2.6 Regional Coal Thickness Trends 99
9.2.7 Individual Seam Thickness and Gas Content Trends 99
9.2.8 Factors Impacting CBM Production 107
9.2.9 Over-Performing / Under-Performing Wells 108
9.2.10 Consistency of Coal Description and Variable Coal Quality 110
9.2.11 Summary of Geologic Characterization 111
9.2.12 Gas Content 112
9.3 Coal Testing 128
9.3.1 Targeted Coal Seams 128
9.3.2 Sample Processing 129

9.3.3 Gas Content Analysis 129
9.3.4 Coal Analytical Testing 145
9.3.5 Coal Pore Structure Testing 148
9.3.6 Methane adsorption isotherm testing 163
9.3.7 Carbon dioxide adsorption in coal: kinetics and equilibrium 164
9.3.8 Gas composition testing 185
9.4 Preliminary Reservoir Modeling 188
9.4.1 Preliminary Model Using COMET Software 189
9.4.2 Preliminary Model Using GEM Software for Russell County Injection Test 198
9.4.3 Single Well Model Using GEM for Buchanan County Injection Test (Model Set 1) 203
9.4.4 Twenty and Four-Well Models Using GEM for Buchanan County Injection Test (Model Set 2) 210
9.5 Monitoring, Verification and Accounting Plan 220
9.5.1 Approach 220
9.5.2 Design overview 221
9.5.3 Selected Technologies and Deployment 222
9.6 Site Development and Operations 227
9.6.1 Site Development 227
9.6.2 Permitting 264
9.6.3 CO2 Procurement 265
9.6.4 CO2 Injection Operations 266
9.7 Monitoring Results 273
9.7.1 Gas composition 273
9.7.2 Formation water composition 275
9.7.3 Tracers (gas and liquid) 275
9.7.4 Borehole liquid level measurement 276
9.7.5 Microseismic monitoring array 276
9.7.6 Surface deformation 278
9.7.7 Water Injection Test 280
9.7.8 Production Logging Tool 288
9.7.9 In-situ Spatial Distribution Determination Test 289
9.8 Post-Injection Reservoir Modeling 297
9.8.1 Reservoir Model with 20 Wells (1st Model) 298
9.9 Site Closure 313
9.9.1 Flow Back 313
9.9.2 Conversion of Injection Wells to Production Wells 314

9.9.3 Disposition of Monitoring Wells 314
9.9.4 Disposition of Pipeline 314
9.10 Conclusions and Recommendations 315
10 Outreach 317
10.1 Public Outreach Implementation 317
10.2 Communications Plan 319
11 Conclusions 320
11.1 Major Findings 320
11.2 Lessons Learned 321
11.2.1 Technical Challenges 321
11.2.2 Data Communication Challenges 323
11.3 Commercialization Opportunities 324
11.3.1 Enhanced Production from CBM and Shale wells 325
11.3.2 Recommended Research Initiatives 327
12 References 329
13 Appendix A – CBM Structure Maps 335
14 Appendix B – Regional Coal Thickness, Gas Content and Production Trends 346
15 Appendix C – CBM Injection Site: Seam Thickness, Perforations, Gas Content and Temperature 356
16 Appendix D – Buchanan No. 1 Mine – Hydraulic Fractures / Localized Structures 379
17 Appendix E – CBM Site Regional and Local Cross-Sections 389
18 Appendix F – Injection Skid Design 399
19 Appendix G – Permitting Documents 413
20 Appendix H – Wellbore Schematics 564
21 Appendix I – Injection Graphs 578
22 Appendix J – Production Logging 582
23 Appendix K – Flowback Logging 612
24 Appendix L – Outreach Materials 619
25 Appendix M – Commercialization Plan 634
25.1 Executive Summary 634
25.2 Introduction 637
25.3 Objective 1: Work summary with emphasis on commercialization challenges for unconventional storage reservoirs vs conventional EOR storage. 638
25.3.1 Overview of CBM Projects 638
25.3.2 Overview of Shale Gas Projects 639

25.3.3 Overview of U.S. Commercial scale projects 639
25.3.4 Differences between EOR and ECBM/ESGR..... 640
25.3.5 Methane production data from stimulated CBM and Shale wells 644
25.4 Objective 2: Recommend research initiatives that will advance the field work to the technology readiness level of systems verification in a relevant environment 648
25.5 Objective 3: Commercialization roadmap for unconventional storage reservoirs in Appalachia 649
25.5.1 Introduction 649
25.5.2 CBM/Shale well distribution in Appalachia..... 650
25.5.3 Permanence of CO_2 storage 652
25.5.4 CO_2 Sources in Appalachia 652
25.5.5 CO_2 from fossil fueled gasifiers and power plants 653
25.5.6 CO_2 from Industrial Sources..... 658
25.6 Roadmap Implementation 681
25.6.1 Commercialization Pathway – ECBM/ESGR Phase I (Budget Year 1) 682
25.6.2 Commercialization Pathway - ECBM/ESGR Phase II (Budget Years 2-??).. 684

FIGURES (IN REPORT)

Figure 6-1 Gantt Chart 5
Figure 6-2 Organizational Chart..... 6
Figure 8-1 Location Map 22
Figure 8-2 Chattanooga Shale Study Area 23
Figure 8-3 Chattanooga Shale Refined Study Area..... 26
Figure 8-4 Generalized Stratigraphic Column of Study Area 27
Figure 8-5 Overview of Regional Stratigraphic Cross Sections..... 28
Figure 8-6 Strike-Oriented Stratigraphic Correlation (A-A') 29
Figure 8-7 Dip-Oriented Stratigraphic Correlation (B-B') 29
Figure 8-8 Chattanooga Shale Thickness Map..... 31
Figure 8-9 Chattanooga Shale Structure Map 32
Figure 8-10 Chattanooga Shale Depth Map 33
Figure 8-11 Decline Curve Analysis, HW-1003..... 34
Figure 8-12 Plan view of the selected model 35
Figure 8-13 Cross-sectional view of the selected model..... 36
Figure 8-14 Gas production rate and BHP values of the history matched model with gas production 39
Figure 8-15 Shale Injection Site 40
Figure 8-16 MVA Well Layout 41
Figure 8-17 Shale Site Layout..... 42
Figure 8-18 Injection Wellhead with Tracer Tee 43
Figure 8-19 CO2 Injection Comparison..... 44
Figure 8-20 Monitoring parameters during the injection 45

Figure 8-21 Sulfur Hexafluoride Injection Schematic 46
Figure 8-22 Sulfur Hexafluoride Injection Wellhead Setup 46
Figure 8-23 Perfluorocarbon Tracer Injection Schematic 47
Figure 8-24 Perfluorocarbon Tracer Injection Wellhead Setup 48
Figure 8-25 CO2 and Tracer Injectate Phases 49
Figure 8-26 Wellhead Pressure during Soaking Phase 51
Figure 8-27 Total Gas Composition during Flowback Phase 51
Figure 8-28 Individual Hydrocarbon Chain Composition during Flowback Phase 52
Figure 8-29 Flowback Production versus Historical Production 52
Figure 8-30 Flowback Production versus Historical Production (zoomed to recent dates) 53
Figure 8-31 SF6 and PFT Concentrations during Flowback 53
Figure 8-32 Regression Analysis of Pre and Post Injection Flowrates 54
Figure 8-33 CO2 Retained through Regression Analysis 54
Figure 8-34 Model Geometry 56
Figure 8-35 CH4 and CO2 Composition for History Match versus Measured Data 59
Figure 8-36 C2H6, C3H8 and N2 Composition for History Match versus Measured Data 59
Figure 8-37 Cross-sectional view of SRV with CO2 global mole fraction during injection, shut-in, flowback and forecast 60
Figure 8-38 3D model for the SRV showing adsorbed CO2 during injection, shut-in, flowback and forecast 61
Figure 9-1 Index Map showing Location of CBM Study Area 68
Figure 9-2 Location of the Oakwood coalbed methane field within the Southwest Virginia Coalfield (modified after EIA, 2007; Nolde, 1995) 69
Figure 9-3 Generalized stratigraphic column for the Oakwood coalbed methane field. Shallow and deep reservoir zones are separated by the Basal Lee Sandstone (modified after Gilliland et al., 2013). 70
Figure 9-4 Locations of previous (orange) and active (green) CO2-ECBM field tests in the south Oakwood coalbed methane field of southwest Virginia 71
Figure 9-5 . Estimated ultimate recovery (EUR) for test well from 2009 CO2-ECBM test in Russell County, Virginia. The EUR for the well increased by 85 percent following the test with approximately 65 percent of the injected CO2 stored in the reservoir 72
Figure 9-6 Detailed CBM Characterization Study Areas, Virginia 73
Figure 9-7 Loup Creek Field Study Area, West Virginia 74
Figure 9-8 Central Appalachian Basin Sequestration Target and Feasible Areas 75
Figure 9-9 Injection area 76
Figure 9-10 Gas Production History for Injection Wells DD7, DD7A and DD8 79
Figure 9-11 Schematic Diagram of Structural and Stratigraphic Relationships – Buchanan No. 1 Mine – (Observed in October 2017) 84
Figure 9-12 Location of 2-D Seismic Line (after Sandia, 2013) 85
Figure 9-13 2-D Seismic Line: Synthetic Model generated with Time-to-Depth Ties and Formation Picks with location of Russell Fork Fault (green) on right; location of Enlarged View (yellow) for *Figure 4-4* shown on left (after Sandia, with North on left). 86
Figure 9-14 Enlarged View of Northern End of Seismic Line with Interpreted Fault Locations (after Sandia, image has been modified with reversed viewing direction, with North on the right) 87

Figure 9-15 Cross Sectional View of VP-3 Fault (see also Exhibit E9 in the Appendix) 88
Figure 9-16 Stress Diagram 95
Figure 9-17 Cross Section J1-J2, Illustrating splitting characteristics of the Pocahontas No.3 Seam 98
Figure 9-18 CBM Production in First 5 Years versus Completed Coal Thickness (21 Wells) 109
Figure 9-19 Apparatus for Measuring Desorbed Gas Volumes 118
Figure 9-20 CH-1-2014 and CH-1R-2014 Stratigraphic Sections 121
Figure 9-21 M-1 and M-2 (CBM-EE7A) Stratigraphic Sections 125
Figure 9-22 Apparatus for Measuring Desorbed Gas Volumes 135
Figure 9-23 CH-1-2014 and CH-1R-2014 Stratigraphic Sections 138
Figure 9-24 M-1 and M-2 (CBM-EE7A) Stratigraphic Sections 142
Figure 9-25 Nitrogen adsorption isotherms on central Appalachian coals at -196 °C: solid lines represent adsorption branch and dotted lines represent desorption branch 150
Figure 9-26 Meso-pore size distribution of coals 153
Figure 9-27 Carbon dioxide adsorption isotherms at 0 °C on central Appalachian coals: solid lines represent adsorption branch and dotted lines represent desorption branch 155
Figure 9-28 Micropore size distribution of coals 157
Figure 9-29 Specimen preparation for micro-CT and FSEM-EDS scanning 160
Figure 9-30 Micro-CT image for sample ① 161
Figure 9-31 FSEM image for subsample ② 161
Figure 9-32 FSEM image for subsample ③ 162
Figure 9-33 ESEM image for subsample ④ 163
Figure 9-34 Methane adsorption isotherms in different coals under reservoir temperatures: dotted lines represent Langmuir fitting curves, and solid symbols represents measured data 164
Figure 9-35 Relation between isothermal sorption content and time at 50℃ 165
Figure 9-36 Isothermal adsorption curves for bituminous and subbituminous coal at 50℃ 166
Figure 9-37 Measurement error of the pressure transducer 167
Figure 9-38 Linear relationship between t/Qt and t: stage (1) and stage (8) for bituminous 168
Figure 9-39 Linear relationship between t/Qt and t: stage (1) and stage (8) for sub-bituminous coal 168
Figure 9-40 Relationship between pressure and kinetics parameter Qe 170
Figure 9-41 Relationship between pressure and kinetics parameter k2 171
Figure 9-42 Isothermal adsorption curves and error analysis; Qtc is the predicted value using PSO value, Qtm is the measured test value. 172
Figure 9-43 Comparison between predicted values and measured test data 173
Figure 9-44 Generalized pore system in coal 173
Figure 9-45 Experimental data retrieved from Song et al. (2015), Ottiger et al. (2006); the dotted line is to connect data points for visualization. 175
Figure 9-46 The difference of CO2-coal sorption system before and after CO2 adsorption. 176
Figure 9-47 Fitting adsorption isotherms using dual-site Langmuir model for five coals; solid line: Gibbs excess fitting (equation (9)) and dotted line: absolute adsorption uptake (equation (6)) 180
Figure 9-48 Surface coverage (solid line, left axial) and the term (nmax-Vmax*ρ (P,T)) (dotted lines, right axial) with increasing pressure for both Chinese and Sulcis coals 180

Figure 9-49 Prediction of adsorption isotherms (black lines) beyond test data; left part: adsorption uptake as a function of pressure; right part: adsorption uptake as a function of bulk density. 181
Figure 9-50 Adsorption isotherms comparison between fitting data using three adsorption isotherms (dotted lines). Solid symbol represents test data. 182
Figure 9-51 Comparison of different isosteric heats of adsorption for scCO2 in coal: isosteric heat of adsorptions using ideal gas law (dotted lines) and real gas law (solid lines), and the gas phases are supercritical and liquid in the magnified area. 183
Figure 9-52 Density of liquid and scCO2; dotted line represents liquid carbon dioxide and solid line represents scCO2 183
Figure 9-53 CH4 concentration as a function of time 185
Figure 9-54 CO2 concentration as a function of time 186
Figure 9-55 C2H6 concentration as a function of time 186
Figure 9-56 H2S concentration as a function of time 187
Figure 9-57 C3H6 concentration as a function of time 187
Figure 9-58 C4H10 concentration as a function of time 188
Figure 9-59 C5H12 concentration as a function of time 188
Figure 9-60 CO_2 Plume (2 Injection Wells), End of Injection 192
Figure 9-61 CO_2 Plume (3 Injection Wells), End of Injection 192
Figure 9-62 CO_2 Plume (2 Injection Wells), 4 Years Post-Injection 193
Figure 9-63 CO_2 Plume (3 Injection Wells), 4 Years Post-Injection 194
Figure 9-64 ECBM Example, Well CC6A 195
Figure 9-65 ECBM Example, Well CC7 195
Figure 9-66 ECBM Example, Well CC7A 196
Figure 9-67 ECBM Example, Well CC8 196
Figure 9-68 ECBM Example, Well DD8A 197
Figure 9-69 ECBM Example, Well EE8 197
Figure 9-70 CBM Reserves and State of Depletion, Injection Test Site 198
Figure 9-71 Typical hydraulic fracture discretization 199
Figure 9-72 3-D view of model grid and wells. Legend shows the permeability in I direction 200
Figure 9-73 Face cleat permeability regions for single-well models and combined model 201
Figure 9-74 History match on gas and water rates for well BD-115 (RU-132) for the combined run. 202
Figure 9-75 CO_2 plume around injection well immediately after injection has been completed in the hydraulic fracture (3rd) model. 203
Figure 9-76 3D view of (A) 18-layer model and (B) 5-zone model with grid elevations 205
Figure 9-77 Different scenarios for the relative permeability curves to water and gas 206
Figure 9-78 Original Gas in Place in the Model and Initially Adsorbed Gas on the Coal Matrix for All Cases (C) 208
Figure 9-79 Original Water in Place for All Cases (C) 209
Figure 9-80 Relative permeability curves to water and gas as determined through history matching gas production for all the wells in the study area 212
Figure 9-81 Cumulative Gas Production per Layer Up to Year 2013 and (B) CO2 Adsorption per Layer during Injection and Post Injection Up to Year 2023 for Scenario S3 214

Figure 9-82 CO_2 Adsorption Profile in gmole/ft^3 at Layer 4 for Scenarios (A) S1 Base, (B) S2 Skin and (C) S3 Hydraulic Fractures Scenario 215
Figure 9-83 Gas Mass Rate of Injected CO2 at Surface Conditions Versus Time for the Injection Scenarios L1 and L2 217
Figure 9-84 Overview of the MVA program for the CO2-ECBM test in Buchanan County, Virginia 221
Figure 9-85 Data acquisition schedule for the MVA program 223
Figure 9-86 Injection Skid 231
Figure 9-87 Control Valves 233
Figure 9-88 M-1 P9 Photo 1 237
Figure 9-89 M-1 P9 Photo 2 237
Figure 9-90 M-1 P9 Photo 3 238
Figure 9-91 M-1 P3 Photo 1 239
Figure 9-92 M-1 P3 Photo 2 239
Figure 9-93 M-1 P3 Photo 3 240
Figure 9-94 M-2 P9 photo 1 241
Figure 9-95 Packer for injection test 243
Figure 9-96 Downhole gauge carrier 244
Figure 9-97 Downhole gauge carrier 245
Figure 9-98 M-2 wellhead 247
Figure 9-99 Communication Equipment on C-1 Well 248
Figure 9-100 DD-7 Wellhead 257
Figure 9-101 CO2 huff-n-puff unit 258
Figure 9-102 CO2 Injection Rates by Well 267
Figure 9-103 CO2 Injection Pressure by Well 267
Figure 9-104 CO2 Injection Temperature by Well 267
Figure 9-105 CO2 Injectivity by Well 268
Figure 9-106 CO2 Injection Phase Diagram: Phase I 268
Figure 9-107 CO2 Injection Phase Diagram: Phase II 268
Figure 9-108 Gas Composition showing CO2 Breakthrough at DD8A 274
Figure 9-109 Tracer Detection Results 275
Figure 9-110 Reservoir-depth slices through combined TFI volumes for pre-injection survey (left) and early injection survey (right). 277
Figure 9-111 Persistence of the lateral distribution of high acoustic energy recorded pre-injection (left) and during injection (right) for the early injection microseismic survey. 278
Figure 9-112 Surface Deformation Result from ISBAS Processing 279
Figure 9-113 DD-8 and DD-8A Interwell Connectivity 281
Figure 9-114 Water Injection Test to Determine Gas Production from Individual Coal Seams 282
Figure 9-115 Echometer Results from the DD-8A Water Injection Test 284
Figure 9-116 a) coal thickness by zone. b) gas production by zone. c) gas production per foot of coal thickness by zone 285
Figure 9-117 a) CH4 composition by zone b) CO2 composition by zone c) ethane composition by zone 286
Figure 9-118 SF6 concentration by zone 287
Figure 9-119 CO2 Production by Zone 287
Figure 9-120 SF6 production by zone 287

Figure 9-121 Deployment of the DRRS 290
Figure 9-122 Raman peaks typical of (left) solution gas and (right) production gas. The x-axis is wavenumber, or energy, and the y-axis is photons collected at each energy. Solvation of the methane molecule by water molecules causes a decrease in wavenumber and slight broadening of the peak. 291
Figure 9-123 Methane spectra and response curve 291
Figure 9-124 Raman spectrum guide for analysis of gas species 292
Figure 9-125 DRRS logs of measured CO2, CH4, and onboard temperature and pressure: the solid line in the gas pressure logs indicates the measured Fraction composition while the dashed line indicates the absolute composition. 294
Figure 9-126 Structure map of Pocahontas 3 coal seam with well names and locations 298
Figure 9-127 Cleat permeability distribution 299
Figure 9-128 Cumulative gas and water production per well 300
Figure 9-129 Relative permeability curves used in the model (Adapted from Vasilikou, 2014) 300
Figure 9-130 Bottom-hole pressure (BHP) versus time for well W12 301
Figure 9-131 Cumulative gas production for each case 303
Figure 9-132 Cumulative gas mass (CO2 and CH4) 304
Figure 9-133 Produced and stored CO_2 mass 305
Figure 9-134 Global mole fractions (CO2) at layer 10 for each case study 306
Figure 9-135 Topographic map of the CO_2 injection area 307
Figure 9-136 Structure map of Pocahontas 10 coal seam with well names and locations (legend in ft) 307
Figure 9-137 Active fracture network around the injection wells (B) Cleat permeability values for one layer 309
Figure 9-138 Cumulative CO2 mass during injection for each injection well and 310
Figure 9-139 CO_2 plume in four coal seams for six different days 312
Figure 9-140 SF6 Plume in four coal seams for four different days 313
Figure 11-1 Russel County, VA CBM well production data 326
Figure 11-2 Morgan County, TN shale well production data 327
Figure 25-1 Morgan County, TN shale well production data 644
Figure 25-2 Morgan County, TN shale well CO_2 retention 645
Figure 25-3 Russell County, VA CBM well production data 646
Figure 25-4 Russell County, VA CBM well CO_2 retention 647
Figure 25-5 Low-cost CO_2 Emitters in Relation to Shale and CBM Gas-Producing Basins across the Appalachian Region 651
Figure 25-6 Artist's depiction of conceptual carbon capture facility at VCHEC 654
Figure 25-7 CO_2 Treatment Stages at Plant Barry 655
Figure 25-8 Petra Nova CO_2 capture and treatment facility 656
Figure 25-9 Coal Power Plants, Cement and Steel Plants across the Appalachian Region 657
Figure 25-10 Ammonia Plants and CO_2 Pipelines 660
Figure 25-11 Ethanol Plants and CO_2 Pipelines 661
Figure 25-12 Natural Gas Processing Plants and CO_2 Pipelines 662
Figure 25-13 Ethylene Oxide Plants and CO_2 Pipelines 663
Figure 25-14 Oil Refineries and CO_2 Pipelines 664
Figure 25-15 Cement Plants and CO_2 Pipelines 665

Figure 25-16 Steel Plants and CO_2 Pipelines 666
Figure 25-17 CO_2 emissions greater than 500,000 metric tons per year 667
Figure 25-18 CO_2 Capture Cost – Existing and Possible Future costs with Transformational capture Technologies 669
Figure 25-19 Low Cost Industrial CO_2 Emitters 670
Figure 25-20 Low Cost CO_2 Emitters in Central Appalachia 671
Figure 25-21 Ammonia Production Near Black Warrior Basin 672
Figure 25-22 Low cost Emitters in Northern Appalachia 674
Figure 25-23 NGP Facilities in Northern Appalachia in Relation to CBM / CMM Fields 676
Figure 25-24 NGP Facilities in Central Appalachia in Relation to CBM / CMM Fields 677
Figure 25-25 Northern Appalachia area of focus in Eastern Ohio 679
Figure 25-26 Northern Appalachia area of focus in West Virginia 680
Figure 25-27 Locations of CBM / CMM Fields in Northern and Central Appalachians 681

TABLES (IN REPORT)

Table 6-1 Task Responsibility by Research Team Organization and Point of Contact Information 7
Table 6-2 Deliverables 9
Table 6-3 Milestones Table 11
Table 7-1 Initial Identification of Significant Technical, Resource, and Management Risks 12
Table 7-2 Risks with Related Actions - CBM Test 14
Table 7-3 Risks with Related Actions - Shale Test 20
Table 8-1 CNX Gas Shale Injection Candidates 25
Table 8-2 Preliminary reservoir modeling parameters 37
Table 8-3 Injection well baseline composition (% of total gas stream) 49
Table 8-4 Gas component properties used in reservoir modeling 57
Table 8-5 Natural Gas and NGLs Spot Prices 62
Table 8-6 NGLs Conversion Factors (EIA, 2014b) 62
Table 8-7 Total Methane and NGLs in Flowback 63
Table 8-8 Flowback Value without the Soaking Phase 63
Table 8-9 Flowback Value with the Soaking Phase 63
Table 8-10 Total Flowback Value without the Soaking Phase 64
Table 8-11 Total Flowback Value with the Soaking Phase 64
Table 8-12 Total Net Flowback Value 64
Table 9-1 8 Wells within Area of Review 80
Table 9-2 14 Wells within Monitoring Area 80
Table 9-3 39 Wells outside of Monitoring Area 81
Table 9-4 Compilation of Paleo-Stress and Current (Horizontal) Stress / Structural Features 92
Table 9-5 Samples Collected from 4 Holes for Gas Content Analysis 116
Table 9-6 CH-1-2014 and CH-1R-2014 Gas Content Summary 122
Table 9-7 Summary of CH-1-2014 and CH-1R-2014 Quality 123
Table 9-8 CH-1-2014 Macroscopic Description 123
Table 9-9 Summary of M-1 Coalbed Gas Content 126
Table 9-10 Summary of M-1 Quality 126
Table 9-11 M-1 Macroscopic Descriptions 127

Table 9-12 Summary of M-2 Coalbed Gas Content 127
Table 9-13 Summary of M-2 Quality 128
Table 9-14 M-2 Macroscopic Descriptions 128
Table 9-15 Coal Samples Collected from CH-1-2014 Hole 129
Table 9-16 Samples Collected from 4 Holes for Gas Content Analysis 133
Table 9-17 CH-1-2014 and CH-1R-2014 Gas Content Summary 139
Table 9-18 Summary of CH-1-2014 and CH-1R-2014 Quality 140
Table 9-19 CH-1-2014 Macroscopic Description 140
Table 9-20 Summary of M-1 Coalbed Gas Content 143
Table 9-21 Summary of M-1 Quality 143
Table 9-22 M-1 Macroscopic Descriptions 144
Table 9-23 Summary of M-2 Coalbed Gas Content 144
Table 9-24 Summary of M-2 Quality 145
Table 9-25 M-2 Macroscopic Descriptions 145
Table 9-26 Coal analytical testing results for 15 coal samples 146
Table 9-27 BET specific surface of coal samples 154
Table 9-28 PSO model fitting data 169
Table 9-29 Fitting parameters (equation (9)) for coal samples 179
Table 9-30 Fitting parameters for Gibbs adsorption isotherms using three adsorption isotherms 182
Table 9-31 Wells Included in Reservoir Model 190
Table 9-32 Preliminary Reservoir Modeling Parameters 190
Table 9-33 Parameter range used as input in the CMOST model runs 199
Table 9-34 Set of Parameters Varied in Simulations for Cases C1 to C11 204
Table 9-35 Input Parameters for Modeling Hydraulic Fractures in Scenarios H1, H2, H3, H4 205
Table 9-36 Reservoir parameters and their values used in both models 206
Table 9-37 Input parameters for the combined and four-well models 212
Table 9-38 CO_2 Flowback at the Injectors and CO_2 Breakthrough at the Offset Well for the (S) Models for Projection Time to Year 2023 216
Table 9-39 Cumulative CH_4 Production for the (S) Models for the Base (S1), Skin (S2) and Hydraulic Fractures (S3) Scenarios for Projection Time to Year 2023 216
Table 9-40 Cumulative Gas Production (CGP) for All Wells for Cases: L1a, L1b, L2a, L1c 219
Table 9-41 CO_2 Flowback and Breakthrough for Cases: L1a, L1b, L2a, L1c 220
Table 9-42 Summary of monitoring technologies selected for the MVA program for the CO2-ECBM field test in Buchanan County, Virginia 223
Table 9-43 Potential Values for Flow, Pressure, and Temperature Downstream of the Leased Pumping and Heating Unit 229
Table 9-44 Core Hole Data from CH-1 235
Table 9-45 OPEN LOGS in CHARACTERIZATION, MONITOR WELLS & CORE HOLE 242
Table 9-46 DD-7 Perforation Assessment from Video Camera Logging 250
Table 9-47 DD-7A Perforation Assessment from Video Camera Logging 252
Table 9-48 DD-8 Perforation Assessment from Video Camera Logging 253
Table 9-49 Mechanical Integrity Test 256
Table 9-50 EPA Maximum Allowable Injection Pressures 261
Table 9-51 DD-7 270

Table 9-52 DD-7A 271
Table 9-53 DD-8 272
Table 9-54 Designated test zones for DRRS in three wells 293
Table 9-55 Model Inputs (Adapted from VCCER 2011, Vasilikou 2014) 299
Table 9-56 injection rates for base model" and "models with base model injection wells" 302
Table 9-57 Wells and seams used in the model 308
Table 9-58 Gas components and compositions used in the model 309
Table 9-59 CO_2 and SF6 injection data used in the model 310
Table 10-1 Stakeholders for public outreach 317
Table 10-2 Public meetings 318
Table 25-1 NETL breakeven cost for CO_2 capture for Ammonia, Ethanol and Natural Gas Processing 668

3 Executive Summary

The Virginia Center for Coal and Energy Research (VCCER) project, "Injecting Carbon Dioxide into Unconventional Storage Reservoirs in the Central Appalachian Basin, with an Emphasis on Enhanced Coalbed Methane Recovery, to Validate Prior Geological Characterization," assisted the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) in accomplishing the programmatic research goal of understanding the behavior, migration, and stability of carbon dioxide (CO2) in different depositional environments/classes of reservoirs throughout injection and post-injection periods.

Permanently sequestering carbon dioxide (CO2) in coal seams and gas-bearing shale formations is beneficial in that it can mitigate greenhouse gas emissions as well as enhance gas recovery in production wells. This is possible due to the sorption properties of the organic material within coals and shales and their greater affinity for CO2 over methane (CH4). The phenomenon of preferentially adsorbing CO2 while desorbing CH4 has been shown in unconventional coalbed methane reservoirs and shale formations.

Previous research studies conducted by the Southeast Regional Carbon Sequestration Partnership (SECARB) Phase II, Task 2 and Task 10, led by the VCCER and Marshall Miller & Associates (MM&A), have identified promising stacked storage reservoirs for CO2 storage in Central Appalachia and tested coal seam sequestration through a small, pilot scale field validation test. Results from two previous Southeast Regional Carbon Sequestration Partnership (SECARB) Phase II projects in Central Appalachia (2009) and the Black Warrior Basin (2010) report that CO_2 stimulation of coal bed methane wells can result in post-injection increases in gas production of 50% above pre-injection levels with greater than 50% of injected CO2 stored.

The previous studies form the basis for this project to inject up to 20,000 metric tons into unconventional stacked geologic formations in two locations: (1) ***the Chattanooga Shale in Morgan County, Tennessee*** and (2) ***the Oakwood coalbed methane (CBM) field, in southwestern Virginia***.

The geology of the Central Appalachian Basin is diverse and includes a variety of stacked storage opportunities. The recent characterization found that some of the most promising opportunities are in coal seams of Pennsylvanian age, tight sandstone formations of Mississippian age, and Devonian aged organic-rich shales. These formations were deposited in deltaic environments, and thus are subsets of reservoir classes recognized by the NETL/DOE to have high potential for geologic carbon sequestration. However, limited experience with injection into coal and organic-rich shale makes commercial potential uncertain at this time. The goal of the project was to reduce this uncertainty by designing and implementing characterization, injection, and monitoring activities to test these stacked formations and track the migration of CO2 throughout the injection and post-injection phases.

Chattanooga Shale Test in Morgan County, TN

The VCCER managed a field project to test the injectivity of CO2 into an unconventional shale reservoir and the potential for CO2-enhanced hydrocarbon recovery. The goal of this test was to inject at least 500 tons of CO2 into a legacy deep shale well in Appalachia to explore the potential for enhanced gas recovery from gas-bearing shale formations through a successful small-scale 'huff-and-puff' injection. This project used characterization, injection, and monitoring activities to test the treatment and enhanced recovery potential of the organic shale.

Approximately 510 short tons of CO2 were successfully injected into a horizontal production well completed in the Chattanooga Shale formation in Morgan County, Tennessee during March 2014. After the injection phase, the well was shut-in to allow for the CO2 to equilibrate within the target formation. After the 4-month soaking phase was completed, the well was flowed back and returned to normal production. During this flowback phase, gas composition and flow rate were frequently monitored. Results indicated that there was a significant increase in gas flow rate during the first five months of the flowback phase. There was also a significant increase in gas quality, such that the percent composition of NGLs (natural gas liquids), including ethane, propane, and butane, increased. The results from this injection test confirm the injectivity and storage potential of CO2 in organic shales formations while enhancing gas recovery. The ability to stimulate additional gas and gas liquids production from wet shales could provide additional revenues to justify CO_2 purchases. However, additional research, with larger CO_2 injections and multiple field projects, must be conducted before any reliable conclusions can be drawn on enhanced gas liquids production.

Coalbed Methane Test in Buchanan County, VA

A small-scale CO2 injection test was conducted in southwest Virginia to assess the storage and ECBM potential of CO2 in a stacked coalbed methane reservoir. This goal of the test was to inject up to 20,000 tons of CO2 into a coal reservoir of approximately 15-20 stacked coal seams. Phase I of the injection test was conducted from July 2, 2015 to April 15, 2016 where a total of 10,601 tons of CO2 was injected. Phase II of the injection was conducted from December 14, 2016 to January 30, 2017 where an additional 2,662 tons of CO2 was injected, for a total of 13,263 total tons of CO2 injected. Post-injection monitoring occurred through December 31, 2017 when the wells were returned to CNX Gas and returned to production. A customized plan was created to monitor CO2 injection activities, including surface, near-surface, and subsurface technologies.

The monitoring program for the CO2-ECBM test in Buchanan County, Virginia, has demonstrated success in characterizing the behavior of the coal reservoir in response to CO2 injection. The monitoring results and findings validate the design efforts and rationales for technology selection. Flowback of the wells commenced after the year long soaking phase and after the project ended. Results from the flowback will be instrumental in determining the ECBM potential of central Appalachian coals and commercialization opportunities.

4 Acknowledgements

The research team would like to acknowledge the US Department of Energy's National Energy Technology Laboratory for both funding and guiding this research.

The research team would like to thank CONSOL Energy and its subsidiaries CNX Gas and Knox Energy for donating producing wells to the project as well as donating personnel time and experience to help manage activities at both field sites.

The research team would like to thank the mineral and land owners who graciously donated wells and access to the surface for monitoring activities including Emory River, LLC and Harrison-Wyatt, LLC.

The research team would like to thank personnel from Praxair and Flo-CO2 who conducted the CO2 injection operations.

The research team would like to acknowledge the following groups for participating in this research project, including:

- Schlumberger
- Global Geophysical Services
- Oak Ridge National Laboratory
- University of Nottingham / British Geological Survey
- University of Tennessee
- University of Virginia
- Southern Illinois University
- Oklahoma State University

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6 Project Management

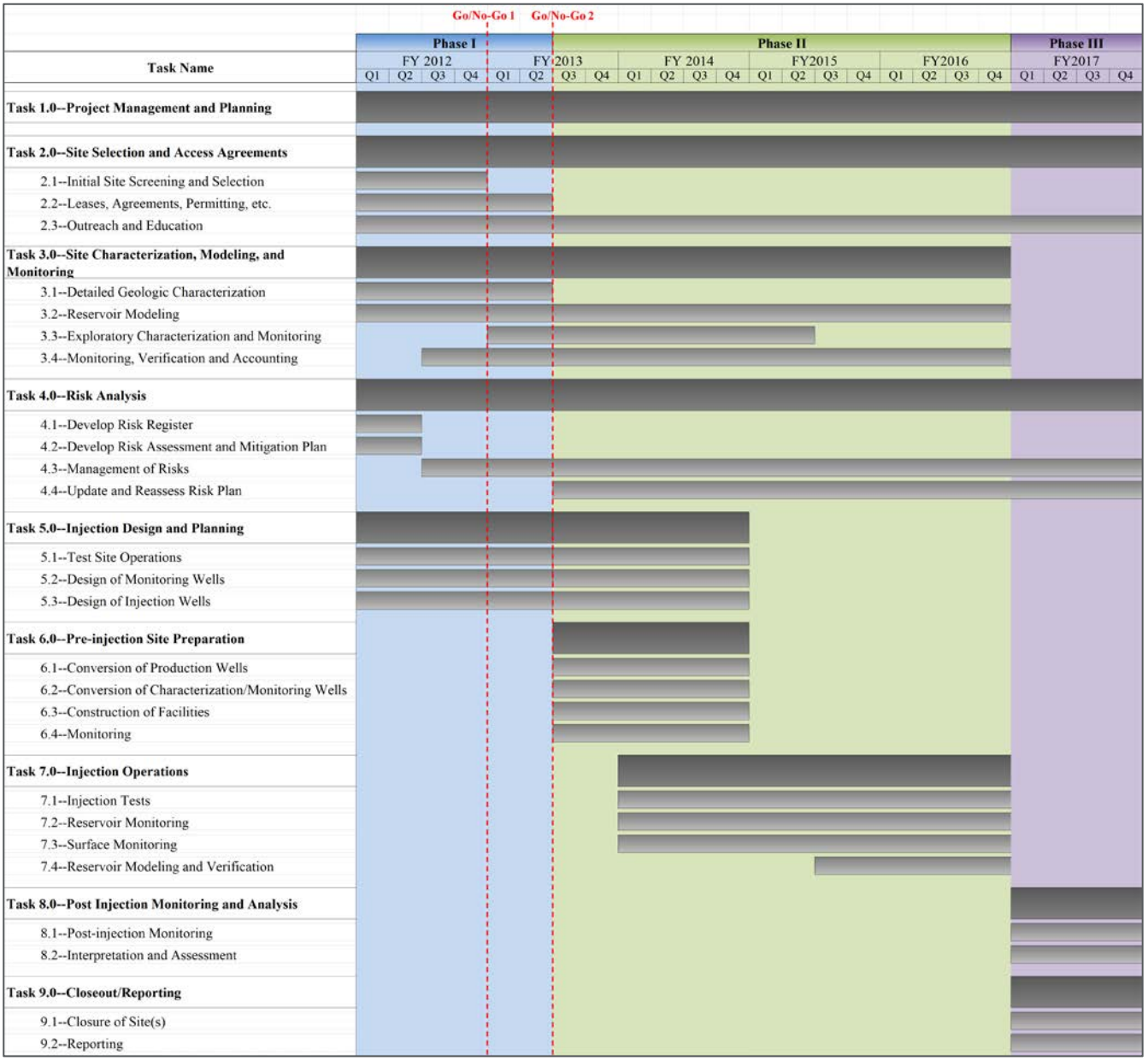
6.1 Project Organization and Structure

The Principal Investigator/Project Director (PI/PD) is Dr. Michael Karmis, Director of the VCCER and Stonie Barker Professor of Mining and Minerals Engineering at Virginia Tech. Nevada Davis, a post-award project specialist from Virginia Tech's Office of Sponsored Programs serves as the Financial and Contractual Officer, and Dr. Nino Ripepi, Assistant Professor of Mining and Minerals Engineering at Virginia Tech, provides overall technical project coordination.

The VCCER managed and administered the project into three phases consistent with three budget periods. Phase I/Budget Period 1 from October 1, 2011 to March 31, 2013. Phase II/Budget Period 2 from April 1, 2013 to January 31, 2017. Phase III/Budget Period 3 from February 1, 2017 to December 31, 2017.

The program is structured within nine key tasks as shown in the following Gantt chart (Figure 6-1). Task 1.0 will be implemented throughout all Phases of the project and is devoted to project management and planning and includes technical/financial oversight and reporting, financial management, and preparing and submitting required NEPA documentation. Task 2.0 consists of site selection, access agreements, and outreach and education. A 'go/no go' decision point was centered on the project being able to provide to DOE selected site(s) and all necessary documentation to move forward with drilling an exploratory well and subsequent injection to meet the project objectives. The project received approval to move beyond Task 2.0 from DOE based on the 'go/no go' decision point. Task 3.0 consisted of detailed geologic site characterization, modeling, and monitoring. Task 4.0 provided for a comprehensive risk analysis. Task 5.0 encompassed tasks required for injection design and planning. A 'go/no go' decision point marked the end of Phase I where injection of the CO2 will not commence until the research team and DOE have determined that subsurface conditions (proposed storage and sealing formations) have favorable properties that would allow for the injection and long-term storage of CO2, and all access agreements are finalized. With approval granted by DOE to move into Phase II pre-injection site preparation in Task 6.0 was completed a long with injection operations in Task 7.0. Phase III consists of Task 8.0, which provided for post-injection monitoring and analysis, and Task 9.0, which outlined closeout and reporting and includes the dissemination of project results.

Figure 6-1 Gantt Chart



6.2 Research Team and Responsibilities

To achieve the goals and objectives set forth in the project, VCCER issued subawards to: Marshall Miller & Associates (MM&A), CONSOL Energy Research (CONSOL), Virginia Department of Mines, Minerals and Energy (VaDMME), Southern States Energy Board (SSEB), GERALD R HILL PHD, Inc (HILL), Geological Survey of Alabama (GSA), Sandia Technologies (Sandia), and Det Norske Veritas (DNV). The research team has experience in a number of geological storage characterization studies and carbon sequestration injection pilots, both internationally and nationally under the Regional Carbon Sequestration Partnerships established by NETL/DOE. SSEB manages SECARB (the Southeast RCSP) and is actively engaged in CO2 capture and large scale Phase III CO2 storage projects. SSEB's experience and

expertise was leveraged and transferred to the project team. CONSOL Energy, gas lessee, supported the project at both project locations. An organizational chart depicting relationships among team members and identifying the primary point of contact (POC) for each organization is provided in Figure 6-2. Task responsibility by research team organization is outlined in Table 6-1.

Figure 6-2 'Organizational Chart' depicts flow down of contractual agreements from DOE/NETL to VCCER and its subawardees. The chart also represents the communication between all project team members and the project team members and DOE/NETL. The research team's primary points of contact are identified.

Figure 6-2 Organizational Chart

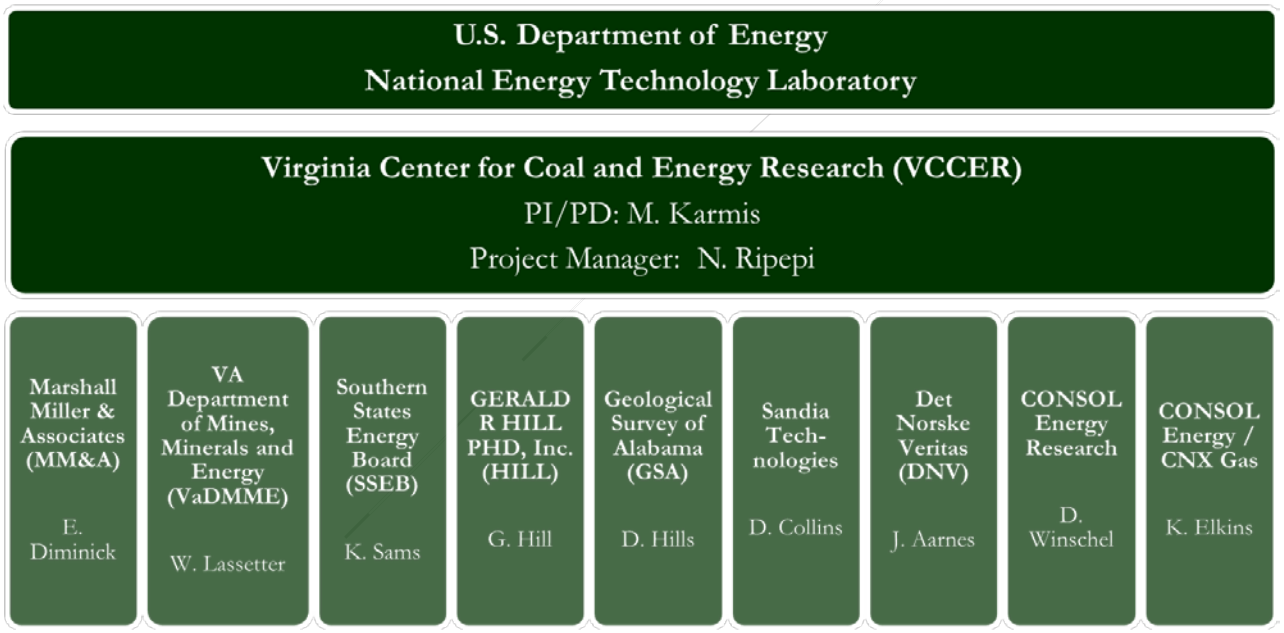


Table 6-1 Task Responsibility by Research Team Organization and Point of Contact Information

Research Team POC & Credentials	Organization	Task Number	Responsibility
Michael Karmis, Ph.D. Mining Engineering (engineer)	VCCER	All	Principal Investigator and Project Director
Nino Ripepi, Ph.D. Mining Engineering (engineer)	VCCER	All	Project Management and Technical Coordinator
Nevada Davis	Virginia Tech	1	Financial and Contractual Operations
Ed Diminick, M.S. Petroleum Engineer (engineer)	MM&A	2, 3, 5, 6, 7, 8, 9	Geologic Characterization, Reservoir Modeling, Injection Site Manager, Data Interpretation and Assessment
William Lassetter M.S. Hydrogeology (geologist)	VaDMME	2, 3, 8, 9	Geologic Characterization and Permitting
Kimberly Sams B.S. Geology (geologist)	SSEB	1, 2, 9	Outreach and Coordination with SECARB and NATCARB
Gerald Hill, Ph.D. Ph.D. Civil Engineering (engineer)	HILL	1, 2, 4	Project Integration
Denise Hills, M.S. Geology (geologist)	GSA	2, 3, 5, 6, 7, 8, 9	Geologic Characterization, MVA, Data Interpretation and Assessment
Daniel Collins, M.S. Geology (geologist)	Sandia Tech.	2, 3, 5, 6, 7, 8, 9	Well Design, MVA, and Field Services
Jorg Aarnes Dr. Scient / PhD Principal Consultant	DNV	4	Risk Analysis
Dick Winschel (engineer)	CONSOL Energy Research	2, 3, 5, 6, 7, 8, 9	Injection Design, MVA, Field Services
Kevin Elkins (Operations Manager)	CONSOL Energy / CNX Gas	5, 6, 7	Gas Lessee and Operator

6.3 NEPA and Permitting

DOE's procedures for implementing the National Environmental Policy Act (NEPA) required careful consideration of the potential environmental consequences of all proposed actions early in the planning process during the project. DOE must determine at the earliest possible time whether such actions

require preparation of an Environmental Assessment (EA), an Environmental Impact Statement (EIS), or are categorically excluded (CX) from further NEPA review. As part of the award process for the project, VCCER completed an Environmental Questionnaire that applied to the planning and site characterization steps being carried out under Phase I of the project. On 09/29/2011 VCCER received a categorical exclusion notice from DOE that authorized the project team to perform literature searches and to conduct preliminary site characterization at potential injection locations. Prior to conducting any site-specific development activities (e.g., infrastructure development, well drilling, or CO2 injection) it was necessary to complete an environmental questionnaire for each site. Information presented in the site specific environmental questionnaire was based upon Phase I tasks required for injection design and planning. A 'go/no go' decision point marked the end of Phase I.

In October 2012, the project team prepared its Permitting Action Plan. The plan was developed to encompass the NEPA and permitting actions that could be required for the CBM Test and Shale Test. To the extent possible the CBM and Shale field tests utilized existing infrastructure and wells. A list of permitting actions that could be required for the field tests included:

- NEPA compliance;
- Permits to survey well sites;
- Permit to build access road on private land from state or county roads;
- Permits to drill vertical characterization and monitoring wells and convert existing wells for CO2 injection;
- Permits to dispose of pit or produced fluids;
- Permits to drill ground water wells;
- Permit to construct CO2 pipeline;
- Permits to transport heavy equipment;
- Underground Injection Control permit for CO2 injection
- Permits to plug wells ; and
- Permit to build pipeline

6.4 Project Deliverables and Milestone Log

Project deliverables are listed in Table 6-2 in chronological order by Task Number. For a number of the deliverables, a separate document was provided for the CBM and Shale Tests respectively. However, the Project Management Plan, Site Selection and Access Agreements, Permitting Action Plan, Public Outreach Plan and Commercialization Plan included content related to both test locations. Completion dates are provided for all deliverables as well as the document type that was submitted to DOE/NETL.

Table 6-2 Deliverables

Budget Period	Fiscal Year	Task No.	Deliverable Description	Completion Date			Deliverable Type
				Combined Deliverable	*CBM Test Deliverable*	*Shale Test Deliverable*	
1	FY2012	1.0	Updated Project Management Plan	11/01/2012	---	---	File
1	FY2013	2.0	Site Selection and Access Agreements	11/30/2012	---	---	Report
1	FY2013	2.2	CO_2 Procurement Plan	---	6/9/2015	10/31/2013	Report
1	FY2013	2.2	Permitting Action Plan	11/30/2012	---	---	Report
1	FY2013	2.3	Public Outreach Plan	11/30/2012	---	---	Report
1	FY2013	3.0	Site Charac. and Modeling Plan	7/1/2013	---	---	Report
1	FY2013	3.1	Catalog of Well Logs File	2/25/2014	---	---	File
2	FY2013	3.3	Well Drilling and Installation Plan	---	6/9/2015	3/6/2014	Report
2	FY2013	3.4	MVA Plan	2/25/2014			Report
1	FY2013	4.2	Risk Assessment and Mitigation Plan	1/31/2013			Report
1	FY2013	5.3	Site Development, Operations, and Closure Plan	---	6/15/2015	3/6/2014	Report
2	FY2014	6.0	Implementation Status Report	---	6/15/2015	3/12/2014	Report
2	FY2014	7.0	Quick-look Report due 30 days after the initiation of injection	---	8/3/2015	4/18/2014	Presentation file
2	FY2014	7.0	Mid-term Status Report due 6 months after the initiation of injection	---	1/31/2016	---	Report
3	FY2015	8.2	Update Site Characterization / Conceptual Models Plan	12/31/2017	---	---	Report
3	FY2015	9.1	Project Closure and Status Report	12/31/2017	---	---	Report
3	FY2015	9.2	Commercialization Plan	12/31/2017	---	---	Report

Table 6-3 identifies the project milestones, completion dates, and the means by which the accomplishment of the milestones was verified. Each milestone relates to a task or multiple tasks in the statement of project objectives (SOPO). The milestones are quantitative and indicate progress toward accomplishing the project goals.

Table 6-3 Milestones Table

Fiscal Year	Task No.	Milestone Description	Completion Date			Verification Method
			Combined Deliverable	*CBM Test Deliverable*	*Shale Test Deliverable*	
FY2012	1.0	Project Award Negotiations Completed	09/30/2011			Countersigned Cooperative Agreement
FY2012	1.0	Subawards issued to Research Team	11/30/2011			Countersigned Subawards on File and Completed Status in Quarterly Report
FY2013	2.1	Site Selection	11/30/2012			Email/Memo to Contracting Officer
FY2013	2.2	Access Agreements in Place	11/30/2012			Email/Memo to Contracting Officer
FY2013	2.2 3.3	NEPA site work CX received or notice to conduct EA received		9/4/2013	9/4/2013	Approval/Authorization Received from DOE
FY2013	2.2	Authorization to Inject Received for First Field Site		6/18/2015	3/17/2014	Approval/Authorization Received from Regulator: Email/Memo to Contracting Officer
FY2013	6.0	First Field Site Ready for Injection		6/15/2015	3/13/2014	Email/Memo to Contracting Officer
FY2014	7.0	CO_2 Injection Begins at First Field Site		7/3/2015	3/19/2014	Email/Memo to Contracting Officer
FY2014	9.2	Resource Capacity Data Transferred to NATCARB and SECARB for Atlas V Update (2014)	5/16/2014			NETL SharePoint Site Transfer Confirmed by VCCER via Email to Contracting Officer
FY2014	7.0	CO_2 Injection Ends at First Field Site		1/31/2017	3/31/2014	Email/Memo to Contracting Officer
FY2015	9.2	Post-injection Open House Conducted	10/13/2017			Email/Memo to Contracting Officer and Photos
FY2015	9.1	CBM and Shale Test Sites Closed	11/30/2017			Email/Memo to Contracting Officer and Photos

7 Risk Management

The project team developed a comprehensive risk assessment and mitigation plan, including a risk register. The plan identified and ranked the potential occurrence of risks for each of the major activities and ranked the potential risk impact to the project as low, medium, or high. The project team managed these risks throughout the life of the project to ensure that they were planned for or mitigated during the performance period. The risk management method/procedure developed is expected to be effective in overcoming unexpected complications. The risks of failing to complete the project are limited and manageable due to the exceptional qualifications of the project team and real-world experience in conducting carbon sequestration field tests in the region, managing complex research and development programs and commercial operations, and communicating results. DNV and HILL supported the development of the project's risk assessment and mitigation plan utilizing experience gained from SECARB and other CCS projects. Support included assistance in identifying and ranking risks as well as providing periodic reviews and updates of the risk management plan through each Phase of the project.

An initial identification of significant technical, resources, and management risks was established for the project. It identifies categories of risk that have the potential to impede project progress. Initial risk management methods (RMM) designed to minimize the impacts from these issues are identified in Table 7-1.

Table 7-1 Initial Identification of Significant Technical, Resource, and Management Risks

Uncertain Future Event	Risk to Project	Risk Management Method	Risk Level
Cooperation of experts	Inadequate data collection, poor consensus	Numerous ways are planned to link with experts.	Low probability Low consequence
Cost share	Cost share must be harmonized temporally with federal spending	Cost share is committed by research partners.	Low probability Low consequence
Project cost tracking	Cost overruns and inability to track costs appropriately	Utilize established cost tracking and project controls utilized in similar on-going large scale capital projects	Low probability Low consequence

Uncertain Future Event	Risk to Project	Risk Management Method	Risk Level
Environmental Impacts	Environmental impacts to air, land, and water resources and potential impacts of waste production	The approach that will be taken and the existing facilities that will be used to support the project will minimize impacts to air, land, or water resources and waste production. The drilling of one characterization and one injection well will take place in an established natural gas field by a drilling company with experience in the area. Field disturbance will be minimized by utilizing the existing gas development infrastructure at the project location to accomplish the project objectives.	Low probability Medium consequence
Injection and Monitoring Well Availability	Meeting project metrics	If agreements at the primary injection site are not executed in a timely manner, the project team will move to the alternative site and attempt to execute agreements. If agreements are not in place by the end of Phase I, the project will not move to Phase II.	Low Probability High Consequence
Carbon Dioxide Availability	Meeting project metrics	If agreements are not in place from one of the three sources of CO_2 outlined in the narrative at the end of Phase I, the project will not move to Phase II.	Low Probability High Consequence
Staff availability	If staff are overcommitted to several projects, delays in completion may result	Participants are experienced in handling multiple projects. The participating partners and entities have considerable depth in professional staff with related experience.	Low probability Low consequence

An initial project meeting and risk management workshop was conducted May 22-23, 2012 and included key participants from the organizations selected to participate in the project as of the workshop date. During the May 2012 risk management workshop, DNV, with assistance from HILL, led in the update of the project's risk management methods, including the development of a draft risk registry. The initial workshop focused primarily on the draft risk registry for the CBM CO_2 injection test.

On May 21-22, 2013 HILL lead risk management workshops in Kingsport, TN that continued to focus on both the CBM Test and Shale Test. After the Kingsport risk workshop Hill worked with DNV to update

the combined CBM and Shale projects risk registry. Table 7-2 is a list of risks and actions for the CBM Test and Shale Test.

Table 7-2 Risks with Related Actions - CBM Test

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
R-0002		**CBM test - Unusually large CO_2 release during unloading and storage in four 60-ton vessels near injection site.**		
	A-0014	CBM - Monitor unloading diligently		
	A-0015	CBM - Inspection of valves and vessels		
	A-0016	CBM - Protect/lock valves		
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Emergency philosophy and procedures	Ed Diminick	MM&A
	A-0020	CO_2 loading/unloading procedures		
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0101	Identify escape routes		
	A-0102	Review wind socks		
	A-0103	Implement procedure with daily HASP planning before work occurs.		
R-0003		**CBM test - Unusually large CO_2 release during storage in four 60 ton vessels**		
	A-0015	CBM - Inspection of valves and vessels		
	A-0016	CBM - Protect/lock valves		
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Emergency philosophy and procedures	Ed Diminick	MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0090	Reduce on-site personnel to only CO_2 operator and site supervision/engineer.		
R-0004		**CBM test - Unusually large CO_2 release during transfer to two 50 ton vessels at injection well DD7, and possibly release and ignition of diesel from transfer truck.`**		**TBD Transfer company**
	A-0014	CBM - Monitor unloading diligently		
	A-0015	CBM - Inspection of valves and vessels		
	A-0016	CBM - Protect/lock valves		
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0019	Road use protocol	Kevin Elkins	CNX-Gas
	A-0020	CO_2 loading/unloading procedures		
	A-0021	Road maintenance procedures	Kevin Elkins	CNX-Gas
	A-0022	Fire extinguisher in truck.		TBD Transfer company
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0104	Use site supervision to review transfer practices.		
R-0005		**CBM test - Unusually large CO_2 release during storage in two 50 ton vessels at DD7**		
	A-0015	CBM - Inspection of valves and vessels		
	A-0016	CBM - Protect/lock valves		
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0024	Safety distances		
	A-0090	Reduce on-site personnel to only CO_2 operator and site supervision/engineer.		
R-0006		**CBM test - Failure or unplanned down-time of tri-plex pump creates project delays**		
	A-0025	CBM - Regular maintenance of pump		
	A-0026	Maintain purity of CO_2 stream		
R-0007		**CBM test - Failure or unplanned downtime of heater creates project delays**		
	A-0027	Spare heater/alternative heater		
	A-0028	Evaluate liquid injection		
R-0008		**CBM test - Release and ignition of propane causing harm to people or knock-on effects to CO_2 vessels, DD7 and tri-plex pump.**		
	A-0015	CBM - Inspection of valves and vessels		

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0024	Safety distances		
	A-0029	Explosive atmosphere protection		
R-0009		**CBM test - Unusually large CO_2 release along pipeline distribution system**	**Ed Diminick**	**Cardno MM&A**
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0030	Pressure monitoring and control system	Ed Diminick	Cardno MM&A
R-0010		**CBM test - Internal or external corrosion of pipeline requiring corrective action.**	**Ed Diminick**	**Cardno MM&A**
	A-0026	Maintain purity of CO_2 stream		
	A-0031	CO_2 purity monitoring	Ed Diminick	Cardno MM&A
R-0011		**CBM test - Pipeline construction delay affects project schedule (Milestone Log)**	**Ed Diminick**	**Cardno MM&A**
	A-0033	Communication with suppliers	Ed Diminick	Cardno MM&A
	A-0034	Procedures for acceptance check of equipment	Ed Diminick	Cardno MM&A
R-0012		**CBM test - Lack of communication protocols between field team members leads to system downtime.**	**Ed Diminick**	**Cardno MM&A**
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0032	Operational procedures and communication protocol	Ed Diminick	Cardno MM&A
	A-0105	Ensure oversight and review of CO_2 supply, injection process and HASP.	Ed Diminick	Cardno MM&A
R-0013		**CBM test - Leakage along existing or new wellbores due to inadequate well integrity**	**Ed Diminick**	**Cardno MM&A**
	A-0003	CBM - Redistribute injection among wells	Ed Diminick	Cardno MM&A
	A-0004	Stop injection in one (or more - CBM) well(s)	Ed Diminick	Cardno MM&A
	A-0005	Repair well(s)	Ed Diminick	Cardno MM&A
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
	A-0091	Diagnose extent of leakage	Ed Diminick	Cardno MM&A
R-0014		**CBM test - CO_2 migration outside area of review along transmissive faults or natural fractures.**	**Ed Diminick**	**Cardno MM&A**
	A-0002	Appropriate site selection	Nino Ripepi	Virginia Tech.
	A-0004	Stop injection in one (or more - CBM) well(s)	Ed Diminick	Cardno MM&A
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
R-0015		**CBM test - Leakage through faults or fractures in seals**	**Ed Diminick**	**Cardno MM&A**
	A-0002	Appropriate site selection	Nino Ripepi	Virginia Tech.
	A-0003	CBM - Redistribute injection among wells	Ed Diminick	Cardno MM&A
	A-0004	Stop injection in one (or more - CBM) well(s)	Ed Diminick	Cardno MM&A
	A-0006	Lower injection pressure	Ed Diminick	Cardno MM&A
	A-0082	Perform microseismic monitoring	Nino Ripepi	Virginia Tech.
	A-0091	Diagnose extent of leakage	Ed Diminick	Cardno MM&A
R-0016		**CBM test - Injectivity insufficient to inject 7 kt in three wells over 1 year.**	**Nino Ripepi**	**Virginia Tech.**
	A-0007	Change injection pressure	Ed Diminick	Cardno MM&A
	A-0008	Start injection with slow rates	Ed Diminick	Cardno MM&A
R-0017		**CBM test - Lower capacity than required for 7kt.**	**Nino Ripepi**	**Virginia Tech.**
	A-0002	Appropriate site selection	Nino Ripepi	Virginia Tech.
R-0018		**CBM test - Monitoring program unable to track movement of CO_2 and demonstrate containment**	**Nino Ripepi**	**Virginia Tech.**
	A-0009	Detect CO_2 breakthrough in monitoring wells.	Nino Ripepi	Virginia Tech.
	A-0010	Use history matching to calibrate models.	Nino Ripepi	Virginia Tech.
	A-0011	Use wells (and geophysical monitoring for CBM) to image CO_2 plume.	Nino Ripepi	Virginia Tech.
	A-0012	Develop robust MVA plan to meet these objectives with sufficient response time for implementing contingency options.	Nino Ripepi	Virginia Tech.
	A-0013	Escalate monitoring program if lack of resolution / sensitivity is suspected.	Nino Ripepi	Virginia Tech.
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
R-0019		**CBM test - Size/direction of plume expansion not consistent with baseline monitoring and predictions.**	**Nino Ripepi**	**Virginia Tech.**
	A-0007	Change injection pressure	Ed Diminick	Cardno MM&A
	A-0008	Start injection with slow rates	Ed Diminick	Cardno MM&A

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
	A-0009	Detect CO_2 breakthrough in monitoring wells.	Nino Ripepi	Virginia Tech.
	A-0010	Use history matching to calibrate models.	Nino Ripepi	Virginia Tech.
	A-0011	Use wells (and geophysical monitoring for CBM) to image CO_2 plume.	Nino Ripepi	Virginia Tech.
	A-0107	Identify and isolate coal seam causing breakthrough	Ed Diminick	Cardno MM&A
R-0020		**CBM test - Delayed baseline characterization infers delay in start-up of injection.**	**Nino Ripepi**	**Virginia Tech.**
	A-0083	Modify access agreements	Michael Karmis	Virginia Tech.
	A-0084	Separate CX for characterization	Nino Ripepi	Virginia Tech.
R-0021		**CBM test - Baseline insufficient to differentiate indicators of CO_2/formation fluid/gas migration**	**Nino Ripepi**	**Virginia Tech.**
	A-0085	Utilization of tracers for monitoring the extent of CO_2 migration.	Nino Ripepi	Virginia Tech.
R-0023		**CBM test - Leaky packer**	**Ed Diminick**	**Cardno MM&A**
	A-0038	Attempt to reset packer or pull packer and replace	Ed Diminick	Cardno MM&A
R-0024		**CBM test - Leaking tubing**	**Ed Diminick**	**Cardno MM&A**
	A-0039	Pull tubing and replace bad joint.	Ed Diminick	Cardno MM&A
	A-0040	Use fiberglass lined tubing to prevent holes for CBM wells	Ed Diminick	Cardno MM&A
R-0025		**CBM test - Casing leak**	**Ed Diminick**	**Cardno MM&A**
	A-0041	Mechanical Integrity Test prior to injection.	Ed Diminick	Cardno MM&A
	A-0086	Monitor casing annulus at regular intervals on an ongoing basis.	Ed Diminick	Cardno MM&A
	A-0087	Repair casing	Ed Diminick	Cardno MM&A
R-0026		**CBM test - Loss of monitoring well during drilling**	**Ed Diminick**	**Cardno MM&A**
	A-0088	Use driller experienced in area		
R-0027		**CBM test - Tool fishing**	**Ed Diminick**	**Cardno MM&A**
	A-0042	Retrieve tools using service rig	Ed Diminick	Cardno MM&A
	A-0043	Tool fishing insurance	Ed Diminick	Cardno MM&A
R-0028		**CBM test - Delayed reporting/deliverables/milestones leading to action by DOE**	**Nino Ripepi**	**Virginia Tech.**
	A-0044	Contractual arrangements with subcontractors regarding reporting requirements.	Nino Ripepi	Virginia Tech.
	A-0045	VCCER will assist, if needed, with reporting to regain schedule slippage	Nino Ripepi	Virginia Tech.
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech.
R-0029		**CBM test - Lack of availability of 10-ton trucks**		**TBD Transfer company**
	A-0046	CBM - Assess contingency options for CO_2 delivery at DD7	Nino Ripepi	Virginia Tech.
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech.
R-0030		**CBM test - Third party damage to equipment, pipeline, pumps or wellheads**	**Kevin Elkins**	**CNX-Gas**
	A-0047	Bury pipeline and identify ROW with appropriate safety markers	Kevin Elkins	CNX-Gas
	A-0048	Supervision of injection site during injection period.	John Guoynes	CNX-Gas
	A-0089	Implement wellhead safeguards and perimeter control	John Guoynes	CNX-Gas
	A-0106	Security planning and monitoring	John Guoynes	CNX-Gas
	A-0108	Install gate at lower road	Kevin Elkins	CNX-Gas
R-0031		**CBM test - Lack of personnel availability**	**Nino Ripepi**	**Virginia Tech.**
	A-0049	Develop contingency plans for replacing key project personnel.	Nino Ripepi	Virginia Tech.
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech.
R-0032		**CBM test - Extreme weather causing interruptions in injection operations**	**Nino Ripepi**	**Virginia Tech.**
	A-0050	Prepare plans for securing and protecting equipment/instruments based on severe weather forecast.	Nino Ripepi	Virginia Tech.
	A-0051	Implement protocol for suspending operations if necessary.	John Guoynes	CNX-Gas
	A-0052	Prepare plans for timely snow removal and road repair.	John Guoynes	CNX-Gas
R-0033		**CBM test - Failure to start injection by Q2 2014.**	**Nino Ripepi**	**Virginia Tech.**
	A-0053	Good communication with permitting agency.	Ed Diminick	Cardno MM&A
	A-0054	Submit permit applications early.	Ed Diminick	Cardno MM&A
	A-0055	Seek to conclude contract negotiations early	Nino Ripepi	Virginia Tech.
R-0034		**CBM test - High budget overruns due to unforeseen technical or commercial challenges results in alteration of scope.**	**Michael Karmis**	**Virginia Tech.**
	A-0056	Utilize established cost tracking and project controls utilized in similar on-going large scale capital projects.	Michael Karmis	Virginia Tech.
	A-0057	CBM - Reduce purchased volumes of CO_2.	Michael Karmis	Virginia Tech.
	A-0058	Revise monitoring program	Nino Ripepi	Virginia Tech.
	A-0066	Periodic financial statement vs project progress	Margaret Radcliffe	Virginia Tech.

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
R-0035		**CBM test - Delayed return of wells to CNX Gas**	**Michael Karmis**	**Virginia Tech.**
	A-0092	Extend access agreements to wells	Michael Karmis	Virginia Tech.
R-0036		**CBM test - Cost of CO_2 exceed expectations**	**Michael Karmis**	**Virginia Tech.**
	A-0057	CBM - Reduce purchased volumes of CO_2.	Michael Karmis	Virginia Tech.
	A-0093	Consider alternative vendors	Michael Karmis	Virginia Tech.
R-0038		**CBM test - Public opposition, claims that may delay or stop project**	**Michael Karmis**	**Virginia Tech.**
	A-0059	Implement an aggressive outreach program, including open houses.	Michael Karmis	Virginia Tech.
	A-0095	Initial meetings and briefings for regulators and public officials.	Michael Karmis	Virginia Tech.
R-0041		**CBM test - Delay in issue of Class II UIC permit**	**Ed Diminick**	**Cardno MM&A**
	A-0063	CBM - Keep open communication with EPA Region 3 and allow extra time for decision	Ed Diminick	Cardno MM&A
R-0044		**CBM test - Delay in issue of state permits**	**Ed Diminick**	**Cardno MM&A**
	A-0064	Allow plenty of extra time when preparing and submitting documents for state permits in order to address any discrepancies	Ed Diminick	Cardno MM&A
R-0050		**Shale test - Unplanned CO_2 release during unloading in two 60-ton vessels near injection site**		
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0020	CO_2 loading/unloading procedures		
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0070	Shale - Monitor unloading diligently		
	A-0071	Shale - Inspection of valves and vessels		
	A-0072	Shale - Protect / lock valves		
R-0051		**Shale test - Unplanned CO_2 release during storage in two 60 ton vessels**		
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0024	Safety distances		
	A-0071	Shale - Inspection of valves and vessels		
	A-0072	Shale - Protect / lock valves		
	A-0081	Vent CO_2 at storage vessels to maintain CO_2 in liquid phase		
R-0052		**Shale test - Failure or unplanned down-time of pump creates project delays**		
	A-0026	Maintain purity of CO_2 stream		
	A-0073	Shale - Regular maintenance of pump		
	A-0098	Ensure authorized personnel have immediate access to parts warehouse.		
R-0053		**Shale test - Failure or unplanned downtime of heater creates project delays**		
	A-0027	Spare heater/alternative heater		
	A-0028	Evaluate liquid injection		
R-0054		**Shale test - Release and ignition of propane causing harm to people or knock on effects to CO_2 vessels and pump**		
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0024	Safety distances		
	A-0029	Explosive atmosphere protection		
	A-0071	Shale - Inspection of valves and vessels		
R-0055		**Shale test - Plume breakthrough at 3rd party production wells.**	**Nino Ripepi**	**Virginia Tech.**
	A-0007	Change injection pressure	Ed Diminick	Cardno MM&A
	A-0008	Start injection with slow rates	Ed Diminick	Cardno MM&A
	A-0009	Detect CO_2 breakthrough in monitoring wells.	Nino Ripepi	Virginia Tech.
	A-0011	Use wells (and geophysical monitoring for CBM) to image CO_2 plume.	Nino Ripepi	Virginia Tech.
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
	A-0099	Stop injection if third party objects	John Guoynes	CNX-Gas
R-0056		**Shale test - Failure to start Shale Test Injection by CY-Q4 2013**	**Nino Ripepi**	**Virginia Tech.**
	A-0053	Good communication with permitting agency.	Ed Diminick	Cardno MM&A
	A-0055	Seek to conclude contract negotiations early	Nino Ripepi	Virginia Tech.
	A-0074	Shale - Allow plenty of extra time to seek authorization from state for well stimulation	Ed Diminick	Cardno MM&A

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
R-0059		**Shale test - Third party damage to equipment, pumps or wellheads**	**John Guoynes**	**CNX-Gas**
	A-0048	Supervision of injection site during injection period.	John Guoynes	CNX-Gas
	A-0089	Implement wellhead safeguards and perimeter control	John Guoynes	CNX-Gas
	A-0106	Security planning and monitoring	John Guoynes	CNX-Gas
R-0062		**Shale test - Ability to successfully monitor with a Huff and Puff**	**Nino Ripepi**	**Virginia Tech.**
	A-0080	Shale - Deploy instrumentation and sampling procedures to double check results and provide a back-up to primary instrumentation	Nino Ripepi	Virginia Tech.
R-0063		**Shale test - Lack of communication protocols between field team members leads to system downtime.**	**Ed Diminick**	**Cardno MM&A**
	A-0018	Emergency philosophy and procedures	Ed Diminick	Cardno MM&A
	A-0023	Arrange Emergency response training		TBD Trainer
	A-0032	Operational procedures and communication protocol	Ed Diminick	Cardno MM&A
	A-0100	Provide clear supervision and oversight	Ed Diminick	Cardno MM&A
R-0064		**Shale test - Leakage along existing or new wellbores due to inadequate well integrity.**	**Ed Diminick**	**Cardno MM&A**
	A-0003	CBM - Redistribute injection among wells	Ed Diminick	Cardno MM&A
	A-0005	Repair well(s)	Ed Diminick	Cardno MM&A
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
	A-0091	Diagnose extent of leakage	Ed Diminick	Cardno MM&A
R-0065		**Shale test - CO_2 migration outside area of review along transmissive faults or natural fractures.**	**Ed Diminick**	**Cardno MM&A**
	A-0002	Appropriate site selection	Nino Ripepi	Virginia Tech.
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
R-0066		**Shale test - Leakage through faults or fractures in seals**	**Ed Diminick**	**Cardno MM&A**
	A-0002	Appropriate site selection	Nino Ripepi	Virginia Tech.
	A-0003	CBM - Redistribute injection among wells	Ed Diminick	Cardno MM&A
	A-0004	Stop injection in one (or more - CBM) well(s)	Ed Diminick	Cardno MM&A
	A-0006	Lower injection pressure	Ed Diminick	Cardno MM&A
	A-0091	Diagnose extent of leakage	Ed Diminick	Cardno MM&A
R-0067		**Shale test - Injectivity insufficient to inject 300 tons in 1 well over 1 month.**	**Nino Ripepi**	**Virginia Tech.**
	A-0109	Reduce injection volumes and/or extend injection period	Nino Ripepi	Virginia Tech.
R-0068		**Shale test - Monitoring program unable to detect lateral extent of injected CO_2 and demonstrate containment.**	**Nino Ripepi**	**Virginia Tech.**
	A-0010	Use history matching to calibrate models.	Nino Ripepi	Virginia Tech.
	A-0012	Develop robust MVA plan to meet these objectives with sufficient response time for implementing contingency options.	Nino Ripepi	Virginia Tech.
	A-0013	Escalate monitoring program if lack of resolution / sensitivity is suspected.	Nino Ripepi	Virginia Tech.
	A-0068	Employ best management practices for CO_2 injection and monitoring	Ed Diminick	Cardno MM&A
	A-0110	Detect CO_2 breakthrough in offset producing wells	Nino Ripepi	Virginia Tech.
	A-0111	Use wells and tracers to image CO_2 plume	Nino Ripepi	Virginia Tech.
R-0069		**Shale test - Delayed baseline characterization infers delay in start-up of injection**	**Nino Ripepi**	**Virginia Tech.**
	A-0083	Modify access agreements	Michael Karmis	Virginia Tech.
	A-0084	Separate CX for characterization	Nino Ripepi	Virginia Tech.
R-0070		**Shale test - Baseline insufficient to differentiate indicators of CO_2/formation fluid/gas migration**	**Nino Ripepi**	**Airgas**
	A-0085	Utilization of tracers for monitoring the extent of CO_2 migration.	Nino Ripepi	Virginia Tech.
R-0071		**Shale test - Leaky Packer**	**Ed Diminick**	**Cardno MM&A**
	A-0038	Attempt to reset packer or pull packer and replace	Ed Diminick	Cardno MM&A
R-0072		**Shale test - Leaking tubing**	**Ed Diminick**	**Cardno MM&A**
	A-0039	Pull tubing and replace bad joint.	Ed Diminick	Cardno MM&A
R-0073		**Shale test - Casing leak**	**Ed Diminick**	**Cardno MM&A**
	A-0041	Mechanical Integrity Test prior to injection.	Ed Diminick	Cardno MM&A
	A-0086	Monitor casing annulus pressure at regular intervals on an ongoing basis.	Ed Diminick	Cardno MM&A
	A-0087	Repair casing	Ed Diminick	Cardno MM&A
R-0074		**Shale test - Tool fishing**	**Ed Diminick**	**Cardno MM&A**
	A-0042	Retrieve tools using service rig	Ed Diminick	Cardno MM&A
	A-0043	Tool fishing insurance	Ed Diminick	Cardno MM&A

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
R-0075		**Shale test - Delayed reporting / deliverables / milestones leading to action by DOE**	**Nino Ripepi**	**Virginia Tech.**
	A-0044	Contractual arrangements with subcontractors regarding reporting requirements.	Nino Ripepi	Virginia Tech.
	A-0045	VCCER will assist, if needed, with reporting to regain schedule slippage	Nino Ripepi	Virginia Tech.
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech.
R-0076		**Shale test - Lack of personnel availability**	**Nino Ripepi**	**Virginia Tech.**
	A-0049	Develop contingency plans for replacing key project personnel.	Nino Ripepi	Virginia Tech.
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech.
R-0077		**Shale test - Extreme weather causing interruptions in injection operations**	**Nino Ripepi**	**Virginia Tech.**
	A-0050	Prepare plans for securing and protecting equipment/instruments based on severe weather forecast.	Nino Ripepi	Virginia Tech.
	A-0051	Implement protocol for suspending operations if necessary.	John Guoynes	CNX-Gas
	A-0052	Prepare plans for timely snow removal and road repair.	John Guoynes	CNX-Gas
R-0078		**Shale test - High budget overruns due to unforeseen technical or commercial challenges results in alteration of scope.**	**Michael Karmis**	**Virginia Tech.**
	A-0056	Utilize established cost tracking and project controls utilized in similar on-going large scale capital projects.	Michael Karmis	Virginia Tech.
	A-0057	CBM - Reduce purchased volumes of CO_2.	Michael Karmis	Virginia Tech.
	A-0058	Revise monitoring program	Nino Ripepi	Virginia Tech.
	A-0066	Periodic financial statement vs project progress	Margaret Radcliffe	Virginia Tech.
R-0079		**Shale test - Delayed return of wells to CNX Gas**	**Michael Karmis**	**Virginia Tech.**
	A-0092	Extend access agreements to wells	Michael Karmis	Virginia Tech.
R-0081		**Shale test - Public claims and opposition, unrelated to permits, delay or stop project.**	**Michael Karmis**	**Virginia Tech.**
	A-0059	Implement an aggressive outreach program, including open houses.	Michael Karmis	Virginia Tech.
	A-0095	Initial meetings and briefings for regulators and public officials.	Michael Karmis	Virginia Tech.
R-0086		**Shale test - CO_2 not available for injection tests**	**Michael Karmis**	**Virginia Tech.**
	A-0093	Consider alternative vendors	Michael Karmis	Virginia Tech.
R-0087		**Secure Location to Store CO_2 for CBM Test**	**Jason Bragg**	**Consol Energy**

Table 7-2 provides an identification number for each listed risk and related actions to be taken. The initial listing of risks (from Table 2) carry risk registry numbers R-0001a – R-0001h. The RMM of the initial Table 7-2 listing carry action numbers RMM-001 – RMM-006. Risks identified in the 2012 and 2013 CBM & Shale risk workshops carry risk registry numbers beginning with R-0002. Actions identified in the risk management workshops carry numbers A-0002 and up. Risk owners' names and organizations are included, as well as the names and organizations for individuals responsible for each related action.

During 2013 various agreements and approvals were obtained and it became clear that the Shale Test would be conducted before the CBM Test. In late 2013 FLO-CO2 was selected to perform the CO2 injection. Key members of the Shale Test team reconvened on January 30, 2014 in Knoxville, TN, to review the risk registries for the Shale Test prior to conducting any on-site activities that extend beyond site characterization. DNV and HILL facilitated the risk workshop and produced an updated risk registry specific to the Shale Test. Table 7-3 is a listing of risks and related actions that was developed for the Shale Test.

Table 7-3 Risks with Related Actions - Shale Test

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
R-0050		**Abnormal CO2 release during unloading in vessel near injection site**	**Alan Houk**	**Flo CO2**
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Develop emergency philosophy and procedures	Ed Diminick	MM&A
	A-0070	Monitor unloading diligently	Alan Houk	Flo CO2
	A-0071	Inspection of valves and vessels	Alan Houk	Flo CO2
	A-0072	Protect / lock valves	Alan Houk	Flo CO2
	A-0112	Document CO2 loading/unloading procedures	Alan Houk	Flo CO2
	A-0113	Arrange relevant emergency response training	Ed Diminick	MM&A
R-0051		**Abnormal CO2 release during storage in vessel**	**Alan Houk**	**Flo CO2**
	A-0017	Lay-out review	Nino Ripepi	Virginia Tech.
	A-0018	Develop emergency philosophy and procedures	Ed Diminick	MM&A
	A-0071	Inspection of valves and vessels	Alan Houk	Flo CO2
	A-0072	Protect / lock valves	Alan Houk	Flo CO2
	A-0113	Arrange relevant emergency response training	Ed Diminick	MM&A
	A-0114	Determine and document safety distances	Alan Houk and Kevin Elkins	Flo CO2 and CNX Gas
	A-0115	Vent CO2 at storage vessels to maintain CO2 in liquid phase	Alan Houk	Flo CO2
R-0052		**Failure or unplanned down-time of pump creates project delays**	**Alan Houk**	**Flo CO2**
	A-0073	Regular maintenance of pump	Alan Houk	Flo CO2
	A-0118	Maintain purity of CO2 stream	Alan Houk	Flo CO2
R-0053		**Failure or unplanned downtime of heater creates project delays**	**Alan Houk**	**Flo CO2**
	A-0117	Assess possibility for injecting liquid CO2 in case of loss of heating.	Ed Diminick	MM&A
R-0054		**Release and ignition of propane causing harm to people or knock on effects to CO2 vessel and pump**	**Alan Houk**	**Flo CO2**
	A-0018	Develop emergency philosophy and procedures	Ed Diminick	MM&A
	A-0071	Inspection of valves and vessels	Alan Houk	Flo CO2
	A-0113	Arrange relevant emergency response training	Ed Diminick	MM&A
	A-0114	Determine and document safety distances	Alan Houk and Kevin Elkins	Flo CO2 and CNX Gas
	A-0116	Explosive atmosphere protection	Alan Houk	Flo CO2
R-0055		**Plume breakthrough at 3rd party production wells.**	**Nino Ripepi**	**Virginia Tech.**
	A-0099	Stop injection if third party objects	John Guoynes	CNX-Gas
R-0059		**Third party damage to equipment, pumps or wellheads**	**John Guoynes**	**CNX-Gas**
	A-0048	Supervision of injection site during injection period.	John Guoynes	CNX-Gas
	A-0089	Implement wellhead safeguards and perimeter control	John Guoynes	CNX-Gas
	A-0106	Security planning and monitoring	John Guoynes	CNX-Gas
R-0062		**Ability to successfully monitor with a Huff and Puff**	**Ed Diminick**	**MM&A**
	A-0080	Deploy instrumentation and sampling procedures to double check results and provide a back-up to primary instrumentation	Nino Ripepi	Virginia Tech.
R-0063		**Lack of communication protocols between field team members leads to system downtime.**	**Ed Diminick**	**MM&A**
	A-0018	Develop emergency philosophy and procedures	Ed Diminick	MM&A
	A-0032	Operational procedures and communication protocol	Ed Diminick	MM&A
	A-0100	Provide clear supervision and oversight	Ed Diminick	MM&A
	A-0113	Arrange relevant emergency response training	Ed Diminick	MM&A
R-0064		**Leakage along existing wellbores due to inadequate well integrity.**	**Ed Diminick**	**MM&A**
	A-0005	Repair well(s)	Ed Diminick	MM&A
	A-0091	Diagnose extent of leakage	Ed Diminick	MM&A
R-0065		**Early breakthrough at CO2 monitoring well**	**Ed Diminick**	**MM&A**
	A-0002	Appropriate site selection	Nino Ripepi	Virginia Tech
	A-0068	Employ best management practices for CO2 injection and monitoring	Ed Diminick	MM&A
R-0066		**CO2 Migration into St. Louis Limestone**	**Ed Diminick**	**MM&A**
	A-0004	Stop injection in one (or more - CBM) well(s)	Ed Diminick	MM&A
	A-0091	Diagnose extent of leakage	Ed Diminick	MM&A
R-0067		**Injectivity insufficient to inject 300 tons in 1 well over 1 month.**	**Nino Ripepi**	**Virginia Tech**
	A-0109	Reduce injection volumes and/or extend injection period	Nino Ripepi	Virginia Tech

Id-H	Id-A	Name	Risk owner / Action responsible	Organization
R-0070		**Baseline insufficient to differentiate indicators of CO2/formation fluid/gas migration**	**Nino Ripepi**	**Virginia Tech**
	A-0085	Utilization of tracers for monitoring the extent of CO2 migration.	Nino Ripepi	Virginia Tech
R-0075		**Delayed reporting / deliverables / milestones leading to action by DOE**	**Nino Ripepi**	**Virginia Tech**
	A-0044	Contractual arrangements with subcontractors regarding reporting requirements.	Nino Ripepi	Virginia Tec.
	A-0045	VCCER will assist, if needed, with reporting to regain schedule slippage	Nino Ripepi	Virginia Tech
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech
R-0076		**Lack of personnel availability**	**Nino Ripepi**	**Virginia Tech**
	A-0049	Develop contingency plans for replacing key project personnel.	Nino Ripepi	Virginia Tech
	A-0065	Requirements not constrained by a single participant or event	Michael Karmis	Virginia Tech
R-0077		**Extreme weather causing interruptions in injection operations**	**Nino Ripepi**	**Virginia Tech**
	A-0050	Prepare plans for securing and protecting equipment/instruments based on severe weather forecast.	Nino Ripepi	Virginia Tech
	A-0051	Implement protocol for suspending operations if necessary.	John Guoynes	CNX-Gas
	A-0052	Prepare plans for timely snow removal and road repair.	John Guoynes	CNX-Gas
R-0079		**Delayed return of wells to CNX Gas**	**Michael Karmis**	**Virginia Tech**
	A-0092	Extend access agreements to wells	Michael Karmis	Virginia Tech
R-0081		**Public claims and opposition, unrelated to permits, delay or stop project.**	**Michael Karmis**	**Virginia Tech**
	A-0059	Implement an aggressive outreach program, including open houses.	Michael Karmis	Virginia Tech
	A-0095	Initial meetings and briefings for regulators and public officials.	Michael Karmis	Virginia Tech
R-0089		**Delay in start-up of injection due to delay in VT approval of procurement process**	**Nino Ripepi**	**Virginia Tech**
R-0090		**Delay in start-up of injection due to delay in authorization to inject from DOE**	**Nino Ripepi**	**Virginia Tech**
R-0091		**Delay in start-up of injection due to delay in transfer of well to Cardno MM&A**	**Ed Diminick**	**MM&A**
R-0092		**Availability of rig for pulling tubing prior to injection**	**Ed Diminick**	**MM&A**
R-0093		**Truck accident on the county road or 0.6 miles lease road**	**Alan Houk**	**Flo CO2**
	A-0119	Follow CNX procedures for CB radio	Alan Houk	Flo CO2
R-0094		**Flow back creates H&S impact on site**	**Ed Diminick**	**MM&A**
R-0095		**Environmental damage from fuel or oil spills assuming safeguards are implemented**	**Alan Houk**	**Flo CO2**
	A-0120	Put down pig matting	John Dales	P&C
R-0096		**Injuries or health effects from operation of valves on storage and pumping equipment or low temperature equipment/fluids**	**Alan Houk**	**Flo CO2**
	A-0121	Training (execute training for all personnel and ensure adherence to CNX and Flo CO2 company procedures)	Alan Houk	Flo CO2
R-0097		**Injuries or health effects from operation of valves or low temperature equipment/fluids during flow back operation**	**John Dales**	**P&C**
R-0098		**Availability of sufficient CO2 for desired rate of injection**	**Alan Houk**	**Flo CO2**
	A-0122	Satellite communication with drivers and plant operators.	Alan Houk	Flo CO2
R-0099		**CO2 concentration exceeds pipeline specs for flow back**	**Ed Diminick**	**MM&A**
R-0100		**Lack of required training or complience with training**	**Ed Diminick**	**Flo CO2**

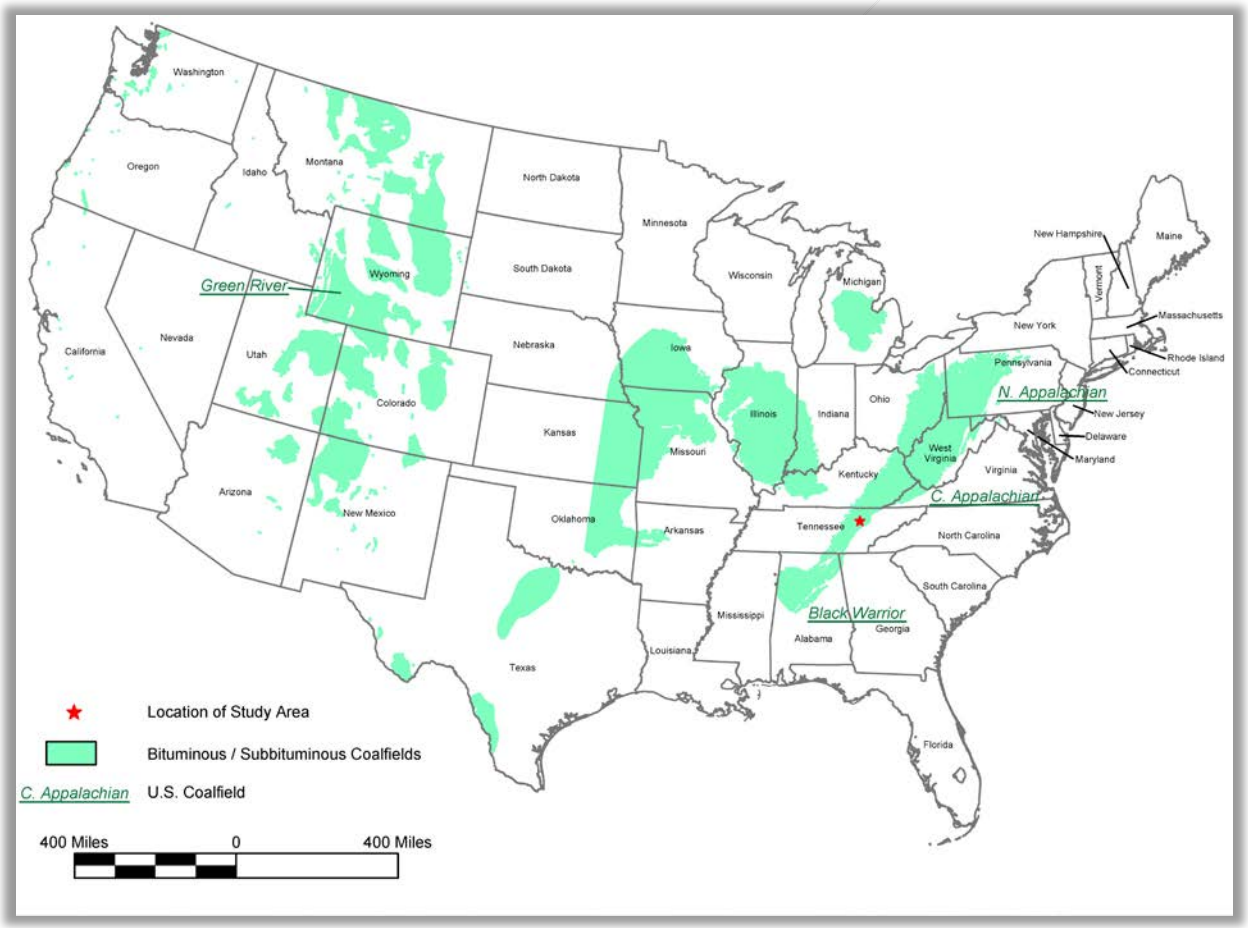
Jerry Hill (HILL), Nino Ripepi (VT) and Ed Diminick (MM&A) participated in both conference calls as well as in person meetings to review risks on the risk register throughout the life of the project. This group made the determination when to close out specific risks. On August 21, August 25, October 13 and November 2, 2017 the group met to close out all risks related to the both the Shale and CBM field sites.

8 Shale Well CO_2 Injection Site: Morgan County, TN

8.1 Overview

The Shale well CO_2 injection site in Morgan County, Tennessee is one of two locations in which CO_2 injection has recently been tested (see *Figure F1* in the *Appendix* of this report). In March 2014, CO_2 was injected into a horizontal well (HW-1003) within the Devonian Chattanooga Shale formation (Figure 8-1).

Figure 8-1 Location Map



8.1.1 Test Objectives

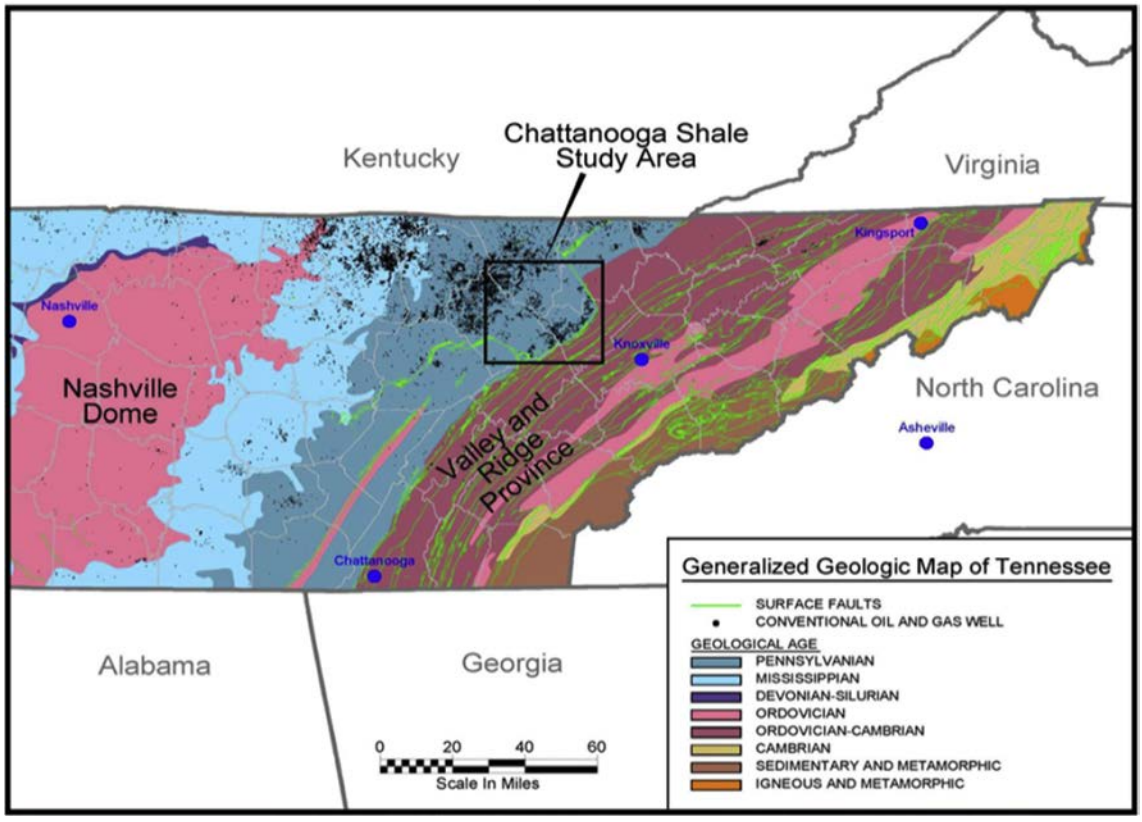
The objective of this project was to design and implement injection and monitoring activities of approximately 500 metric tons of CO2 into a legacy organic shale well in Central Appalachia to test the injectivity and Enhanced Gas Recovery (EGR) potential through a CO2 huff and puff test.

8.1.2 Geologic Background

The CO_2 injection target of this investigation is located within the USGS 7.5-minute Gobey Quadrangle of Morgan County, Tennessee within a deep shale formation commonly referred to as the Devonian Chattanooga Shale.

The broader Chattanooga Shale study area is located in north-central Tennessee, and encompasses portions of Anderson, Campbell, Morgan, and Scott Counties, and is within the Cumberland Plateau Region. Rocks of Pennsylvanian (coal-bearing) through Mississippian (shales and limestones) age are found at the surface and subsurface, overlying the Devonian strata (Figure 8-2) which is the target of this injection site.

Figure 8-2 Chattanooga Shale Study Area



8.1.3 Site Selection

The analyses of primary and alternative options for EGR sites were conducted previously in the regional Phase I and Phase II SECARB geologic characterization studies. The original study area for Devonian-aged shale was conducted in southwest Virginia, southern West Virginia and Eastern Kentucky. However, assessment continued in this project of the Chattanooga Shale formation (Devonian in age) located in north-central Tennessee.

CONSOL Energy (CONSOL) is the host company for both the primary sequestration test in coalbed methane wells in Virginia as well as the smaller shale test. CONSOL's operating company in Tennessee, Knox Energy (KNOX), has a large acreage position in Anderson, Morgan, and Scott counties and has drilled more than 141 Chattanooga Shale wells in the region. Chattanooga Shale wells drilled by Knox and Atlas are indicated by the yellow and green dots, respectively (see *Map F2* in the *Appendix*).

Knox conducted an internal land review of the prospective area and provided six potential CO2 injection well candidates within the shale study area. The technical review of the six specific shale wells provided by Knox indicated favorable injection well candidates in terms of well integrity, existing infrastructure, surface logistics, and site access. The prospective wells were all located in a sparsely-populated and mountainous area.

During the site selection process, Knox identified Emory River, LLC (Emory), a company with large land and mineral holdings within the prospective test area. The research team reviewed Emory's ownership position relative to the findings of the technical assessment. The team determined that there were numerous horizontal shale wells located entirely on Emory mineral tracts, that contained the geological and injectivity characteristics required for the proposed test. The selected injection well was also located on a surface tract owned by Emory, thereby eliminating the need to obtain mineral and surface access agreements from different owners.

Emory's management were presented with the proposed injection test details and they expressed their solid support for the project. It was also explained that the converted shale well, to be used as a CO2 injection well, would not generate revenue for the expected 5 to 6 months required for injection testing and subsequent shut-in monitoring. The research team agreed that the well converted for use as a CO2 injection well would be returned to Knox and could be converted back to producing well status following the injection and shut-in periods.

Knox provided a list of six horizontal well candidates (see *Table 8-1* below), located in Anderson and Morgan Counties, Tennessee as well as technical data, including: production start dates, lateral lengths, number of completion stages, historic production, gas quality, current gas production rate, and availability of offset wells for plume monitoring.

The gas reserves projected to be recovered from the six wells varied from 147 MMcf to 509 MMcf as shown in the decline curves in the Appendix, and the daily gas production rate at the time of review

ranged from 17 to 64 MCFD. These were average production wells, but all had favorable mineral and surface ownership conditions. Site access and logistics for delivering CO2 were determined to be a significant factor because of the steepness of the terrain. Access to two well sites required one or two creek crossings that the project team wanted to avoid. One lease road involved three steep grades that the transport trailers would not be able to climb without the use of a dozer pulling it so it was eliminated. The lease road to a fourth well could not be fully assessed, but the section that was inspected was very narrow and deemed to be unacceptable. Only one well had easier access than the HW-1003 well, but it was the poorest performing well in terms of cumulative production. Because these sites were built for horizontal well drilling operations, each site is large with plenty of space for storage tanks, pumping equipment, and crew living quarters. MM&A, Virginia Tech, Knox and FloCO2, the CO2 supplier, representatives inspected the HW-1003 well pad and determined that it had suitable size and road access for transport trailers to turn around and make CO2 deliveries and would be sufficient for installation of necessary CO2 tanks, injection pump skid, heater and measurement equipment.

Therefore, based on the mineral and surface ownership, surface logistics, and site access, the HW-1003 well was selected to be a good injection-well candidate by the technical team. Table 8-1 below shows the wells that were considered with projected reserves, initial production after completion, recent production (at time of selection) data and notes regarding logistics.

Based on production and completion data provided by Knox for the six horizontal-well candidates, all but one (CH-2024) of the six Chattanooga Shale candidates was deemed to possess adequate injection and logistical characteristics to facilitate a small CO_2 injection test. Ultimately, horizontal well HW-1003 was selected as the test well site.

Table 8-1 CNX Gas Shale Injection Candidates

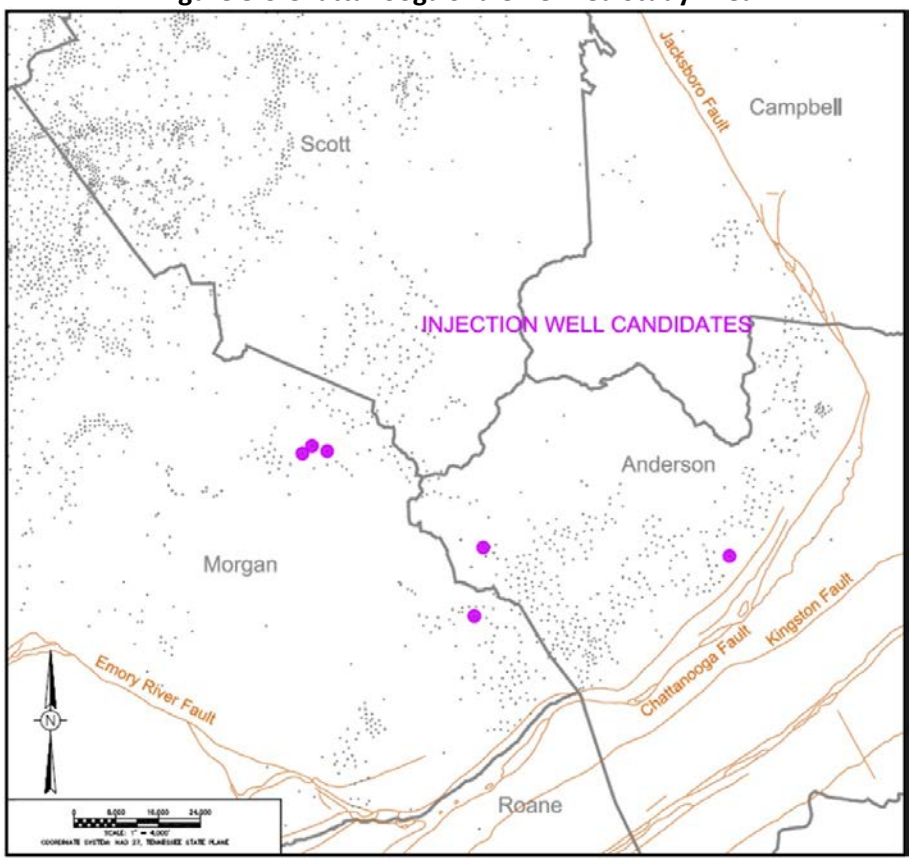
Well ID	County/State	Formation	Well Type	EUR (MMCF)	Initial Production (MCFD)	Recent Production (MCFD)
CH-1005	Morgan, TN	Chattanooga	Horizontal	405	213	49
CH-1008	Anderson, TN	Chattanooga	Horizontal	509	210	64
CH-2024	Anderson, TN	Chattanooga	Horizontal	157	83	29
HH-1003	Morgan, TN	Chattanooga	Horizontal	241	118	30
HH-1006	Morgan, TN	Chattanooga	Horizontal	357	347	63
HW-1003	Morgan, TN	Chattanooga	Horizontal	147	149	17

8.1.4 Study Area

The study area is bounded to the east by the Pine Mountain thrust sheet, and to the south by the Valley and Ridge Province, a region of complex faulting and folding containing rocks of Mississippian through Cambrian age. The primary structural features located adjacent to the study area include the: Jacksboro

fault, the Chattanooga fault, the Kingston fault, and the and the Emory River fault (Figure 8-3 and Map F5 in the Appendix).

Figure 8-3 Chattanooga Shale Refined Study Area

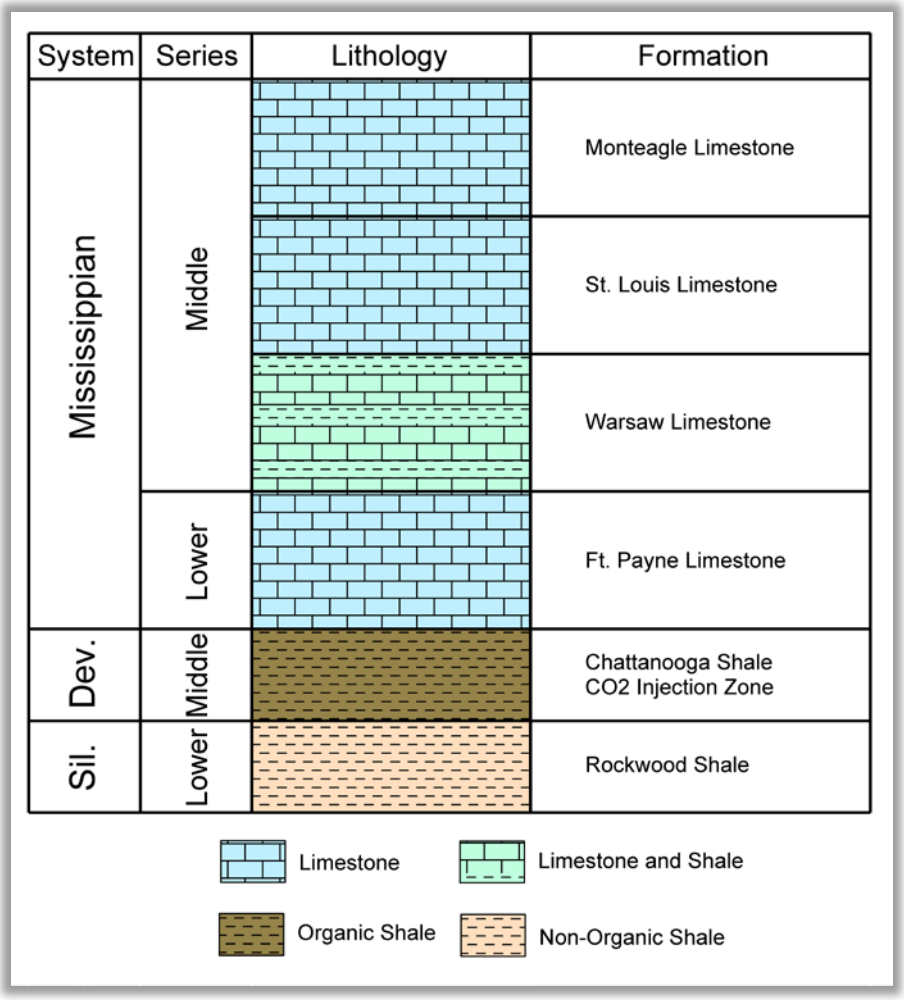


8.2 Geologic Characterization

Objectives of this investigation include: collection, processing, and analysis of all available gas well, geologic, production, and regulatory data to characterize a potential CO_2 injection test site in deep shale formations, and to perform preliminary reservoir modeling to ensure favorable injection and storage capabilities. Data for the Chattanooga shale study is comprised of well location databases, geophysical logs, reservoir thickness data, reservoir quality data, and completion reports.

A geologic assessment for the study areas was completed, including: stratigraphic analysis (Figure 8-4), structural interpretation and mapping, reservoir thickness mapping, and summation of reservoir depth mapping. Shale gas production data from the **Tennessee Division of Geology (*TDG*)**, (as well as data from CNX Gas) primarily for horizontal wells drilled in the target shale formation, was also reviewed and processed.

Figure 8-4 Generalized Stratigraphic Column of Study Area



The first oil production within the study area occurred in 1924 from the Boone Camp field located in Morgan County. Several additional oil and gas fields were discovered and developed in the 1940s within the study area, primarily in the Mississippian-age Fort Payne Formation. The Fort Payne oil and gas fields, producing from Waulsortian carbonate mud mounds, trend southwest to northeast through the study area in northern Morgan and Scott counties.

Development in the underlying Chattanooga Shale in this area began in 2002 with vertically-drilled wells. The Chattanooga Shale gas play was initiated by CNX Gas and later joined by Atlas Energy in drilling more than 141 and 479 Chattanooga Shale wells, respectively. CNX Gas initiated horizontal development in the Chattanooga Shale in 2008 and to date has drilled and completed more than 67 horizontal wells within the study area.

8.2.1 Reservoir Geology

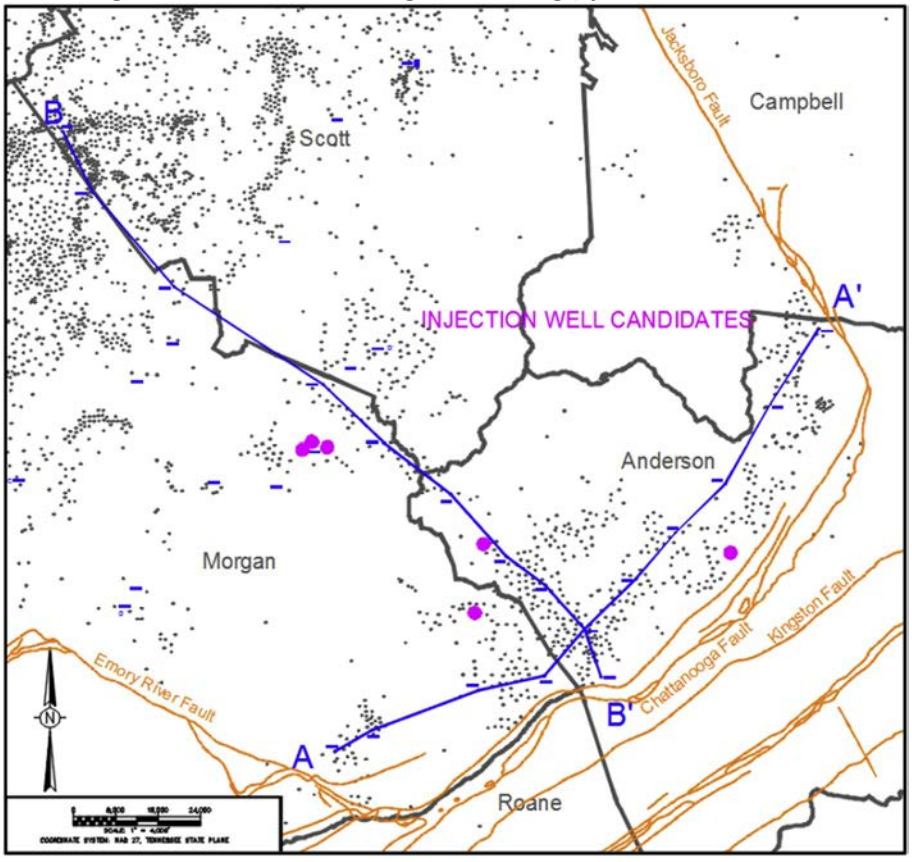
In order to conduct the initial geologic assessment and characterize the Chattanooga Shale reservoir within the study area, approximately 90 geophysical logs penetrating the formation were procured.

This primary data set was supplemented with formation top and thickness data provided by a database obtained from the TDG; surface faults were delineated in the study area by processing GIS shape files also from the TDG. The Chattanooga Shale and adjacent formations were correlated on the geophysical logs and reservoir thicknesses and depth were determined.

Using the drilling and geophysical log data indicated above, multiple regional stratigraphic cross sections were developed across the Chattanooga Shale study area; a small portion of one of those sections is included herein (Figure 8-5 and *Exhibit 7* in the *Appendix*). The datum used for the cross sections is the top of the Chattanooga Shale.

Chattanooga Shale data derived from the TDG spreadsheets were subsequently merged with the log data to develop a master database for the study area.

Figure 8-5 Overview of Regional Stratigraphic Cross Sections



Stratigraphy

Data from the TDG that identified wells with available scanned geophysical logs was reviewed, and logs were downloaded and processed for the Chattanooga Shale injection candidates (and nearby wells). These logs were analyzed in order to determine the thickness, depth, and log characteristics of the shale reservoir. In addition, potential seals and trapping mechanisms were also reviewed and assessed by preparing stratigraphic cross sections (see *Figure 8-6, 8-7, A1-A2* in the *Appendix*).

Figure 8-6 Strike-Oriented Stratigraphic Correlation (A-A')

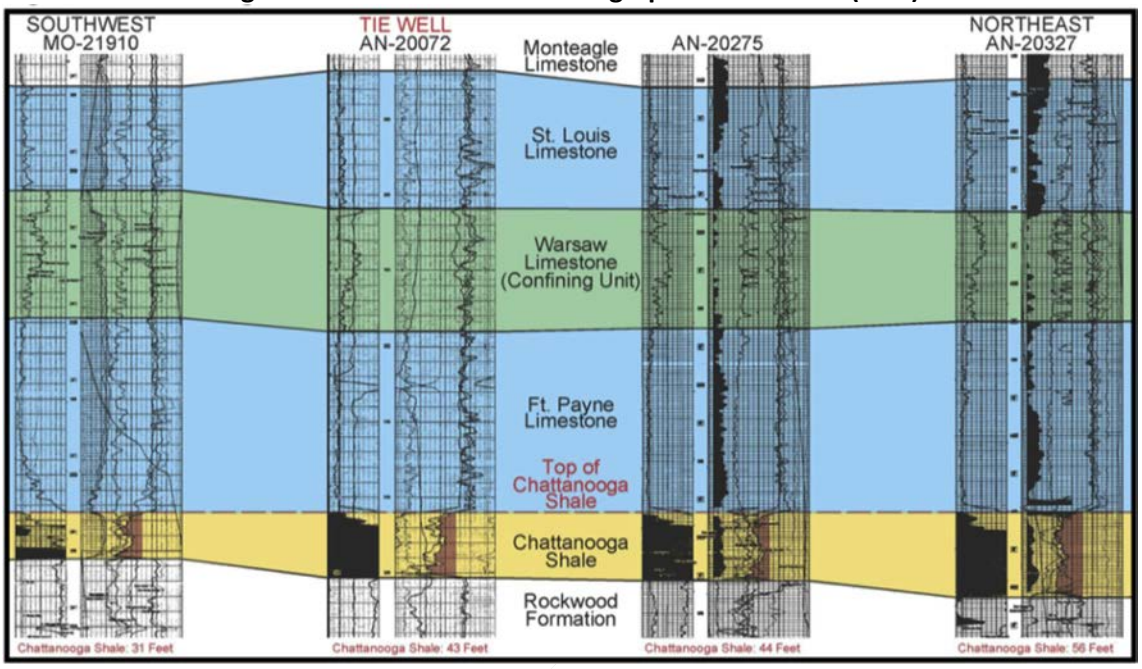
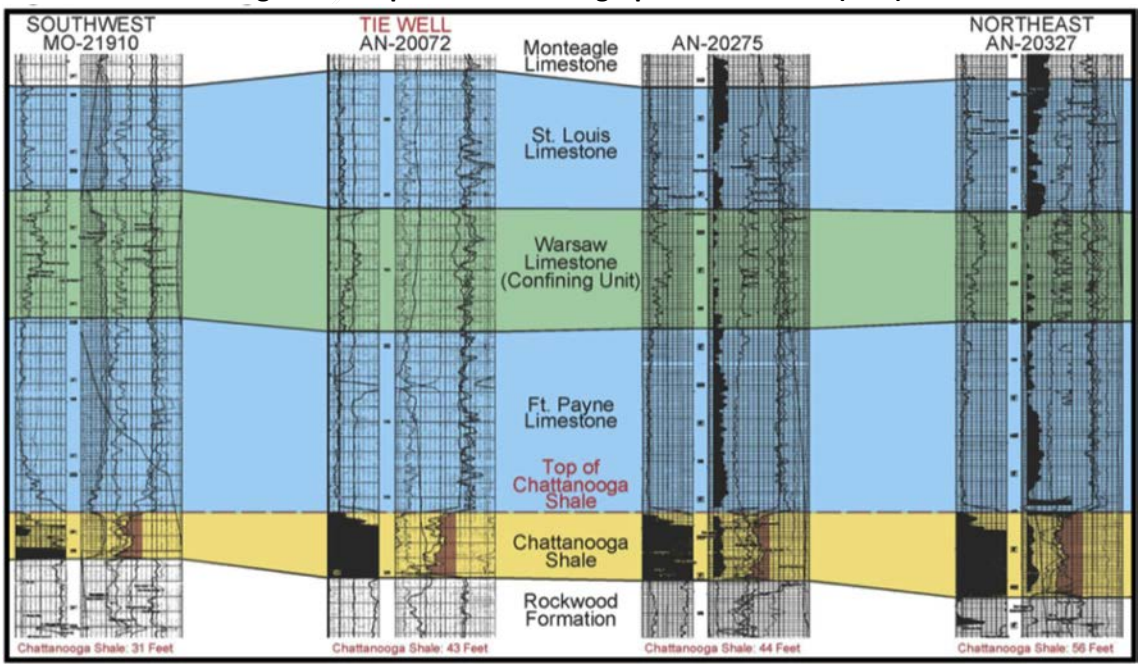


Figure 8-7 Dip-Oriented Stratigraphic Correlation (B-B')



Overlying Stratigraphic Seals

Four confining units identified in the study (Figure 8-2) include overlying the Chattanooga Shale (in descending stratigraphic order) include the following:

- Monteagle Limestone
- St. Louis Limestone
- Warsaw Limestone
- Fort Payne Limestone

The primary confining unit is the Warsaw Limestone (shaded green), which is generally comprised of shale and argillaceous carbonate rocks. These formations contain approximately 500 feet (composite thickness) of low porosity and low permeability limestone. A log analysis was conducted in representative horizons of each of these formations to determine average porosity values.

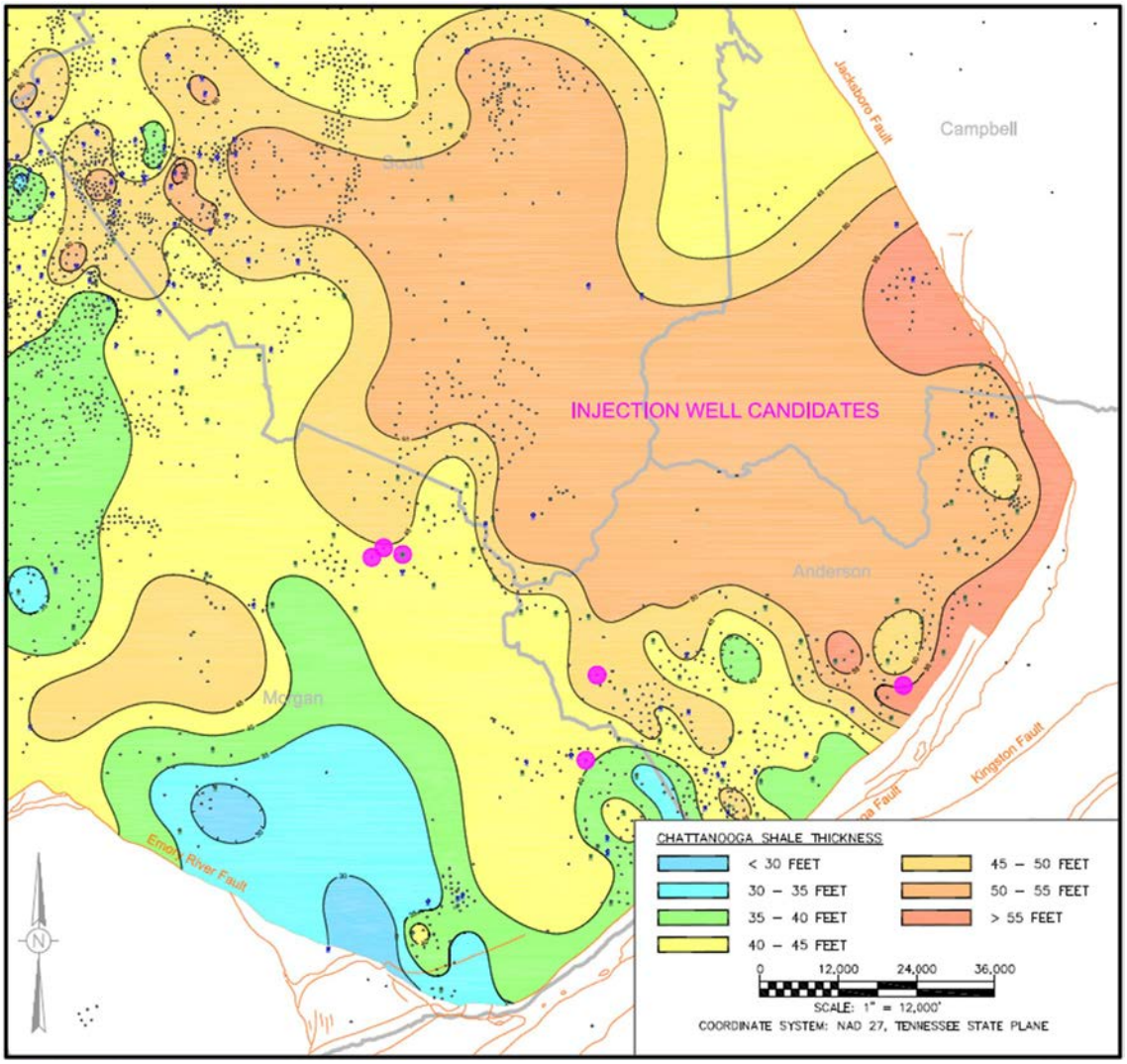
In well HW-1003, the average calculated porosities for the Fort Payne, Warsaw, St. Louis, and Monteagle formations are: 1.1, 1.8, 1.0, and 1.1 percent, respectively. Although the permeability values for these formations cannot be calculated directly from the log analysis, porosity values in this range indicate very low reservoir permeability and no significant potential for gas leakage. Based on these results, the overlying limestone units will provide excellent seals for the small-scale CO_2 injection test.

Reservoir Thickness

The Chattanooga Shale reservoir thickness (Figure 8-8 and *Figure F3* in the *Appendix*) was determined from geophysical logs and supplemented with additional thickness control points derived from the TDG geologic database. The Chattanooga Shale reservoir thickness ranges from 29 to 59 feet across the study area. The thickest shale occurs in an area adjacent to the Chattanooga and Jacksboro faults (red shaded area). The Chattanooga Shale generally thins to the southwest, an area where the shale thickness is less than 35 feet (blue shaded area).

Moreover, a siltstone facies has been identified in the upper portion of the Chattanooga Shale (*Figure F4*) and mapped where present across the study area. It appears that the source for the siltstone was derived from the west, potentially from rocks exposed along the Nashville Dome. The Chattanooga Shale is approximately 46 feet thick at horizontal well HW-1003.

Figure 8-8 Chattanooga Shale Thickness Map



Structural Interpretation and Depth

The structure map (*Map F5* in the *Appendix*) demonstrates that the Chattanooga Shale regionally strikes to the northeast and dips to the southeast within the study area. The primary structural features delineated by the mapping include the Chattanooga fault, the Wartburg Basin, the Emory River fault, and the Jacksboro fault.

Based on limited geological mapping, only small-scale folds interrupt the regional dip to the southeast. The most prominent anticlinal nose occurs adjacent to the Chattanooga fault in Anderson County where the strike of the fault exhibits a marked change in orientation; no faults were identified by subsurface mapping.

The Chattanooga Shale (Figure 8-9, Figure 8-10 and *Map F6* in the *Appendix*) is deepest in Anderson County, where it lies more than 5,220 feet below the surface. The shale is shallower to the northwest,

where it lies less than 1,400 feet below the surface. The top of the Chattanooga Shale is approximately 2,550 feet deep at horizontal well HW-1003.

Figure 8-9 Chattanooga Shale Structure Map

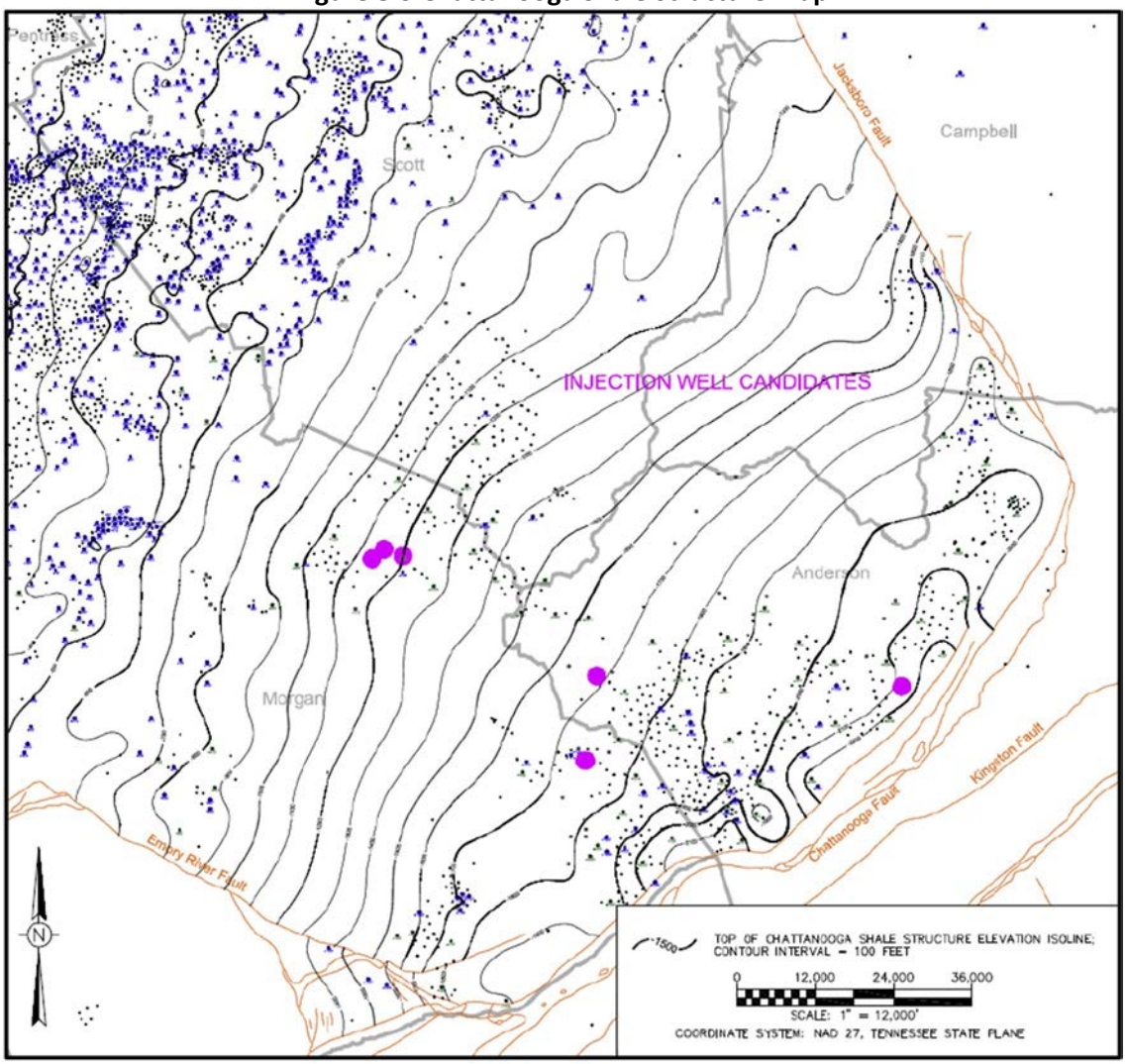
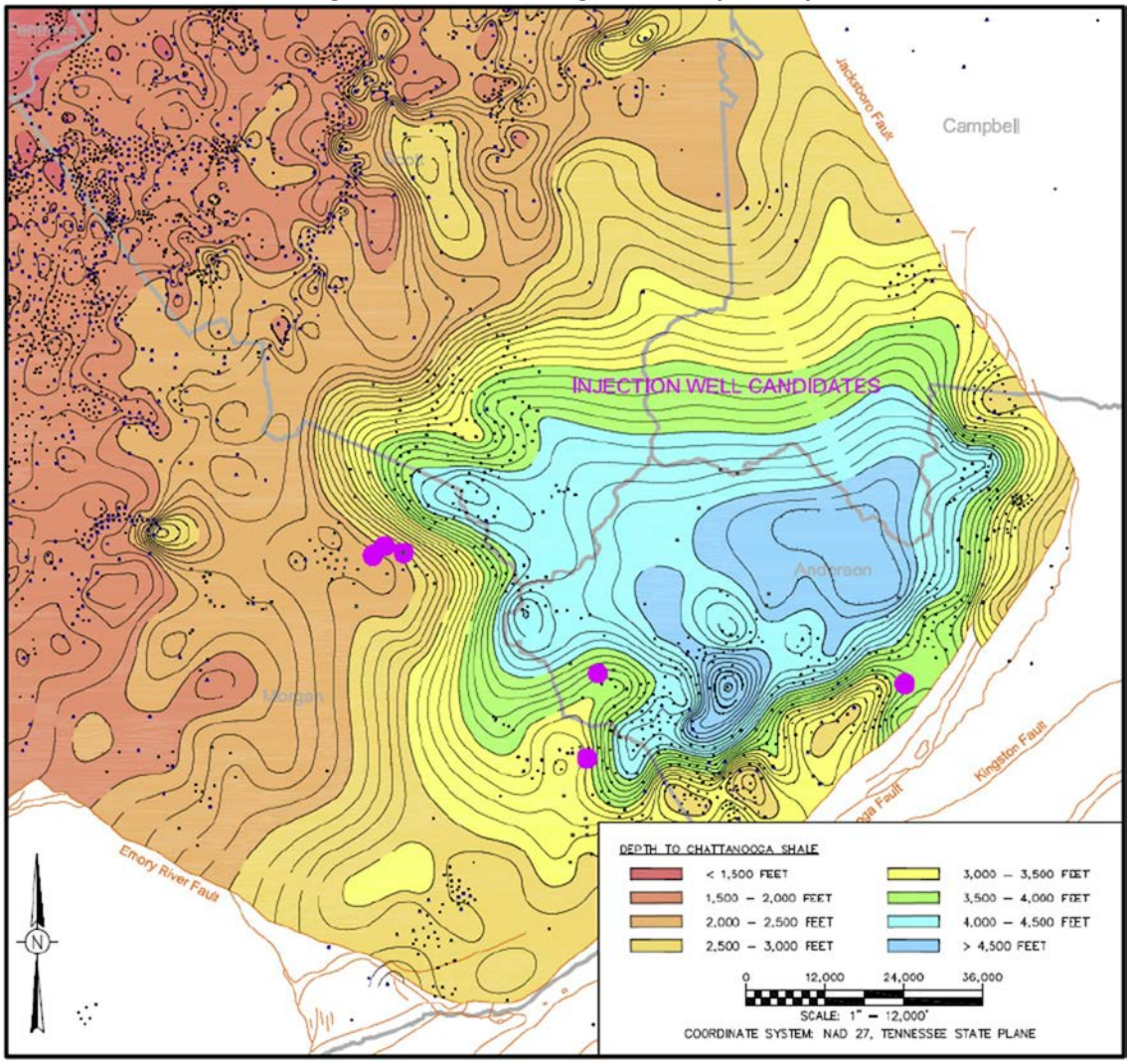


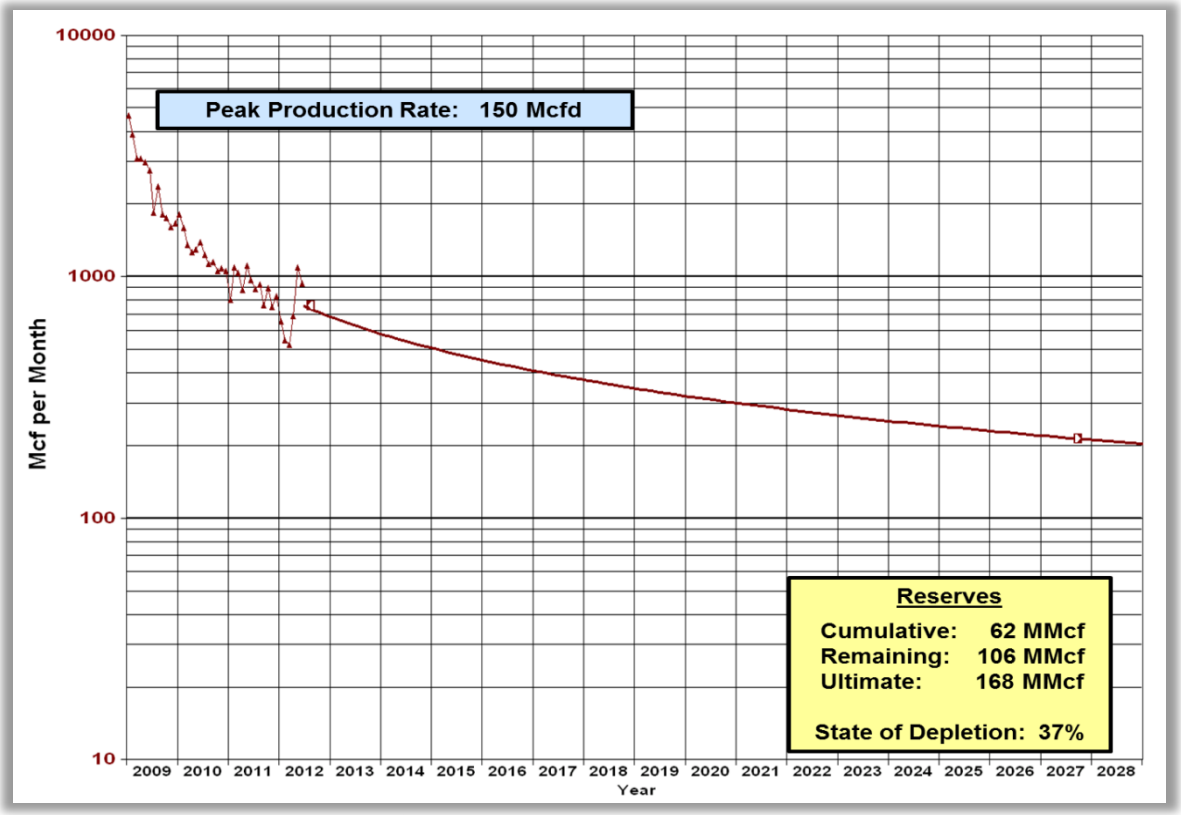
Figure 8-10 Chattanooga Shale Depth Map



8.2.2 Gas Production Analysis

Production data provided by Knox for the six horizontal-well injection candidates was reviewed, from which decline-curve analysis was performed on well HW-1003 (Figure 8-11) to determine the cumulative production, remaining reserves, estimated ultimate gas recovery (*EUR*), and state of depletion.

Figure 8-11 Decline Curve Analysis, HW-1003



Estimated peak production rate for this well was 150 thousand cubic feet per day (*Mcf/d*); with remaining reserves estimated at 106 million cubic feet (*MMcf*), and an EUR of 168 MMcf. Based on peak production rate, the EUR, and calculated state of depletion, HW-1003 was deemed to have favorable injection and reservoir characteristics to support the 500 metric tons CO_2 injection test.

Knox provided the natural gas component analysis for well HW-1003. The primary gas components indicate a high thermal content (1,160 British thermal units per standard cubic foot) in the Chattanooga Shale, and a reservoir with the potential to produce some hydrocarbon liquids.

Injection of CO_2 into the reservoir may result in a lowering of the viscosity of liquids contained in the low permeability shale, thus potentially liberating the heavier hydrocarbon components. In addition, as the liquids are liberated, the relative permeability to gas should increase, potentially resulting in enhanced gas production.

8.3 Preliminary Reservoir Modeling

Computer Modeling Group Ltd.'s GEM software, a compositional and unconventional reservoir simulator, was utilized for reservoir modeling. A dual porosity-dual permeability model which is generally used for shale gas production was assigned. In dual porosity-dual permeability models, porosity and permeability are defined in both matrices and fractures. Shale has both Darcy flow and diffusion in matrix while it has Darcy flow and Non-Darcy flow in fractures.

A preliminary model was developed based on regional geologic data, allowing the research team to obtain initial estimates of the stimulated reservoir volume (SRV) around the horizontal well due to hydraulic fracturing treatment. Various values were set for unknown reservoir parameters to see their influence on gas production. The following section focuses on the preliminary reservoir model with associated regional geologic input to perform a sensitivity analysis.

8.3.1 Methodology

Multiple modeling scenarios were simulated to investigate various reservoir parameters' influences on gas production, original gas in place, gas recovery and bottom-hole pressure (BHP). In the sensitivity analysis, various values were assigned for grid refinement of the SRV, fracture spacing, fracture porosity, fracture network permeability, and dimensions of the SRV (i.e., the half-length of the fracture network, the number of layer formations in the SRV and the width of each stimulated stage). Details of this study can be found in Keles and Ripepi (2014 and 2016).

For the history matching exercise, multiple scenarios were run based on the sensitivity analysis results mentioned above, a best match was found to be a model having 350 ft half-length and five layers. This model cuts through two layers of Fort Payne and Chattanooga Shale Formations and one layer of Sequatchie Shale Formation, and 1150 ft of total width (that is, stage 1 and 4: 250 ft, Stage 2: 350 ft, Stage 3: 300 ft). Figures 8-12 and 8-13 illustrate the plan and cross-sectional view of the model geometry with SRV dimensions. The volume of the stimulated reservoir was calculated as 84.4E+06 scf. Effective permeability was set as 20 mD in this model.

Figure 8-12 Plan view of the selected model

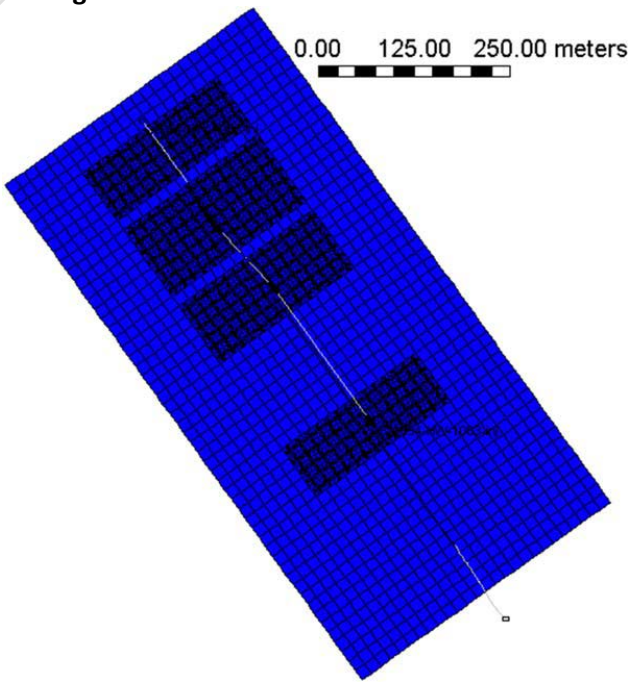
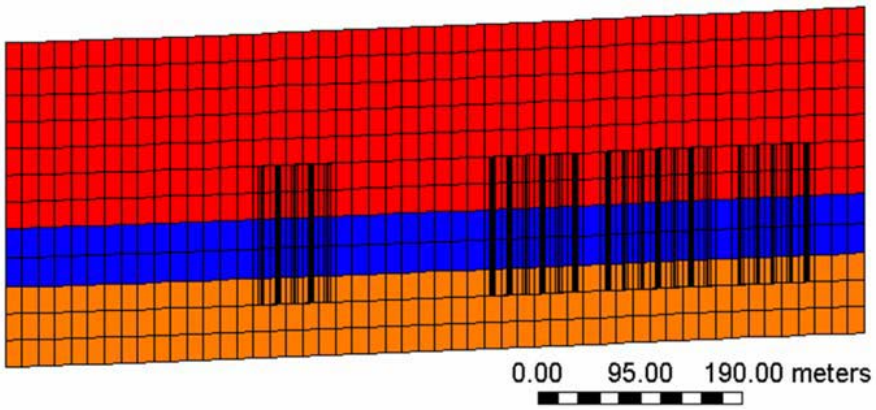


Figure 8-13 Cross-sectional view of the selected model



8.3.2 Model Parameters and Inputs

Limited publicly-available data exist pertaining to reservoir characteristics proximal to the proposed Chattanooga Shale injection test well. In comparison to CBM reservoirs, organic shale reservoirs exhibit different physical and geochemical characteristics that present challenges in reservoir modeling. Approaches to address these various challenges are summarized below.

> ***Gas Storage Mechanisms:*** Organic shale reservoirs store gas molecules both in the free (compressed) and adsorbed states within the internal shale matrix. Standard coalbed methane reservoir modelling software assumes an adsorbed state for stored gas within coal pores. Organic shales initially release free gas in early stages of production, and over time, as the free gas becomes depleted and the reservoir pressure drops, gas desorbs from the shale's pore surfaces.

> ***Degree of Fracturing:*** Organic-rich shale reservoirs typically contain joint systems (primary and secondary sets), believed to possess a moderate degree of predictability based on regional fracture trends. The joint spacing in organic shale reservoirs is typically measured in feet or tens of feet (DOE Report No. DE85008608, 1985). While this reservoir permeability and productivity challenge to shale gas operators can often be overcome by drilling long horizontal laterals perpendicular to the primary fracture set with large, multiple-stage fracture stimulations, the physical distribution and spacing of in-situ natural fractures present a challenge in reservoir modelling.

Reservoir Modeling Inputs

The primary model developed by technical team consisted of 12-layers with three formations including the Fort Payne, Chattanooga shale and Sequatchie shale formations. Modeling inputs were obtained from multiple resources. Structure and isopach maps of Chattanooga shale formations were used to create the model structure. In the reservoir model, the Fort Payne formation was modeled lying above the Chattanooga formation with 140 ft thickness and Sequatchie formation was modeled lying underneath the Chattanooga formation with 60 ft thickness. The average thickness of the entire model was aprroximately 245 ft. Reservoir properties for reservoir modeling inputs were determined using

interpretations from log data from vertical wells near the injection well. The shape of the stimulated volume was estimated using another horizontal well's micro seismic data that monitored a similar hydraulic fracture treatment. This horizontal well similarities with the HW-1003 well in terms of gas production rate, cumulative gas production, and both wells are completed in the same geological formations. Pertinent reservoir modeling inputs are summarized below in Table 8-2.

Table 8-2 Preliminary reservoir modeling parameters

Parameter		Fort Payne Formation	Chattanooga Shale	Sequatchie Shale	Source
Matrix Porosity		0.015[1]	0.061	0.066	Corelab (2009)
Matrix Permeability (mD)		4.61E-06[2]	4.61E-06	2.46E-06	Corelab (2009)
Langmuir Volume (CH_4) (scf/ton)		0.01[2]	139.48	16.1	Corelab (2009)
Langmuir Pressure (CH_4) (psi)		667.33[2]	667.33	1329.81	Corelab (2009)
Water Saturation		0.300	0.354	0.438	Corelab (2009)
Rock Density (lb/scf)		169.18	153.30	166.83	Corelab (2009)
Reservoir Temperature (°F)		62			Miller (2014)
Water Table Level (ft)		1210			Miller (2014)
Pressure Gradient (psi/ft)		0.31			Miller (2014)
	[1] Porosity of the Fort Payne formation was determined from Atlas wells data (Miller, 2014) [2] Assumed				

The grid model was oriented so that the horizontal part of the well was parallel with the j-direction (i.e., N 35°E). Grid blocks were modeled as squares with X and Y dimensions of 50 feet. In the shale formation fracture permeability is very low and gas and water transportation is not possible without a fracture network. The fracture network was assigned to shale gas reservoir models by defining the SRV in the model and grid block in those volumes were refined. In the SRV refined grid, grid size increases logarithmically from the center to the boundary of the cellblock. Smaller grids would generate more accurate results though it increases the computation requirements. The technical team performed a sensitivity analysis to identify the optimal refined grid size to achieve more accurate results and minimize the processing time and computer space needed.

HW-1003 well commenced gas production in January 2009. Neither water nor oil was produced from the well. In the sensitivity analysis only one-year of production data was used in order to be able to compare additional values for selected parameters in a reasonable time. The gas production data was made available from 8 January 2009 till 31 July 2013. After that day, decline-curve analysis was performed to predict forecast production until 13 March 2014, which is the date of shut-in for the production well. The production data and decline curve analysis were used to match the historic data.

8.3.3 Sensitivity Analysis

The following conclusion was derived from the sensitivity analysis: selecting an optimum number of grid refinements is an important parameter because it influences the results of the entire simulation. In this study, the optimum number of grid refinement where computation time can be minimized was seven.

As fracture spacing increased, fracture porosity decreased, and decreasing porosity, decreased the original gas in place. This change was taken as negligible. Changing fracture spacing and fracture porosity did not influence gas production, BHP, or gas recovery remarkably.

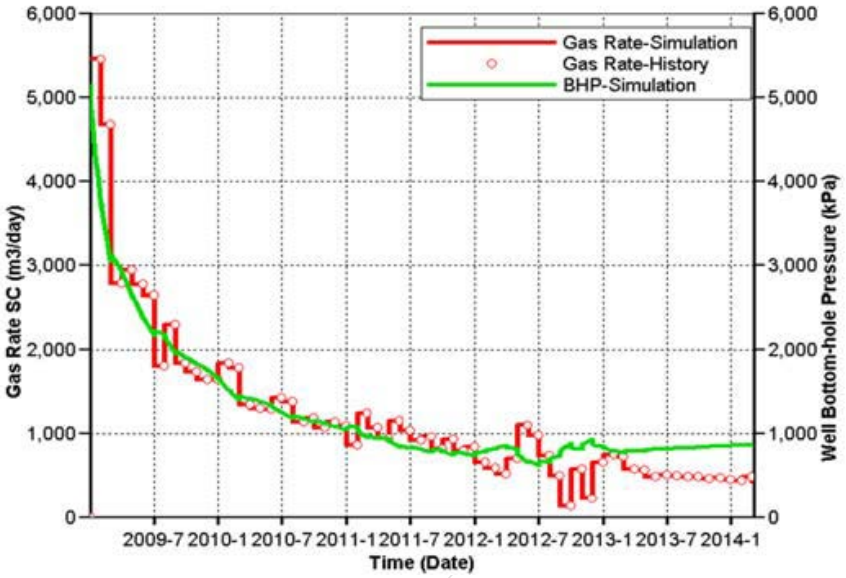
The conductivity of the actual fracture was equal to the conductivity in the model fracture blocks. When primary constraint was gas rate, BHP increased as the fracture network permeability increased, but after a certain point the change in permeability no longer influenced the BHP. When primary constraint was BHP, increasing fracture permeability increased cumulative gas production and gas recovery, but after a certain point again the increase in permeability did not affect the production because the well had reached its maximum production capacity.

When primary constraint was defined as gas rate, as the volume of the network fracture (SRV) was decreased, BHP also decreased. The SRV dimension could be changed in three ways: by changing half-length of the SRV, the number of layers included in SRV or the width of each stage. When the fracture network volumes and fracture permeability values in horizontal directions (i.e., I and J directions) were equal, changing just the half-length or just the width had the same influence on BHP. If the number of layers included in SRV was in the deeper formations, the BHP was higher since the reservoir pressure was also higher in deeper formations.

8.3.4 History Match

There are multiple solutions that could match both gas production and BHP data at the same time. In this study, the model having 20 mD effective permeability, 350 ft half-length and 84.4E+06 scf SRV was chosen because it matched the gas rate through the full production and the BHP range expected before the well was shut-in (Figure 8-14). Before shut-in, BHP was calculated as 143 psi, which is in the acceptable range (i.e., 100–150 psi).

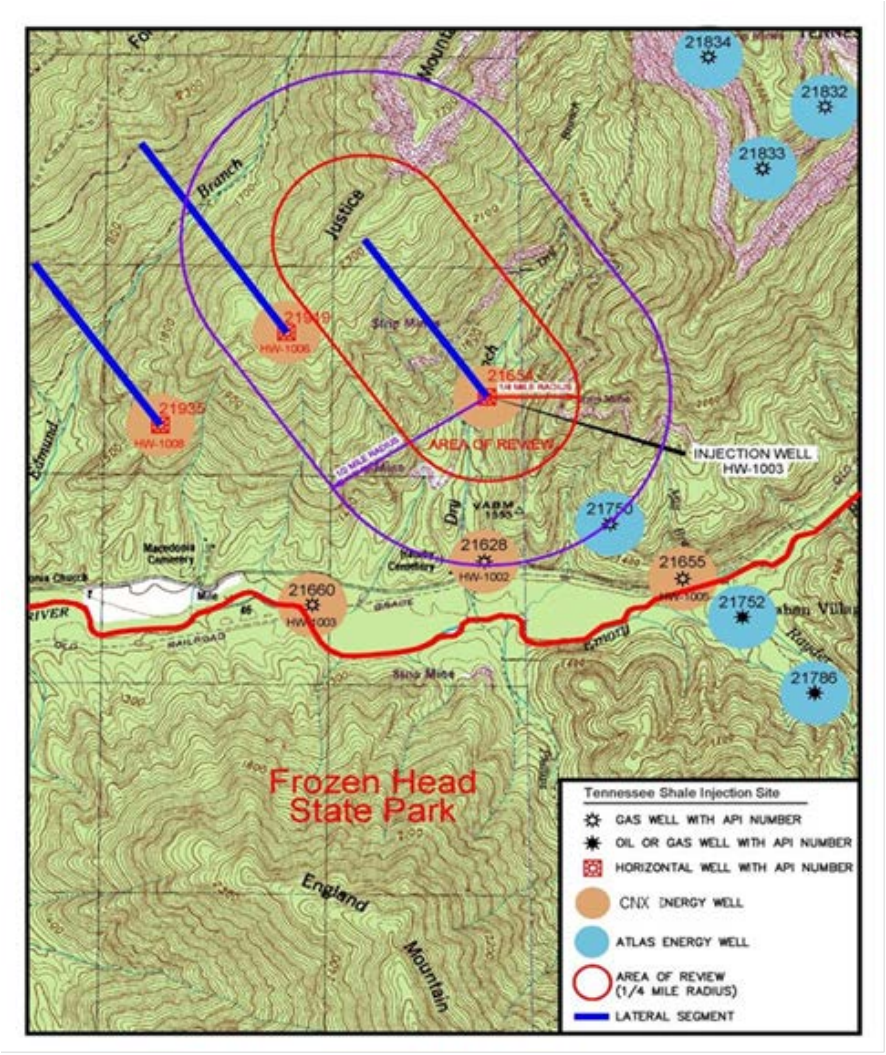
Figure 8-14 Gas production rate and BHP values of the history matched model with gas production history



8.4 Monitoring, Verification and Accounting Plan

The Monitoring, Verification, and Accounting (MVA) program for the shale test is scaled back when compared to the CBM test, in accordance with the smaller injection size and short test duration. Gas, oil, condensate and water sampling will be collected at offset production wells, which will also be monitored for production rates and pressures. A small-scale injectate tracer study using multiple tracer gases will be conducted. The quarter-mile perimeter around the injection well lateral shown in Figure 8-15 was established as an area of review, which represents the anticipated boundary of the injected CO2 plume (as indicated by preliminary reservoir modeling) for the shale test in Morgan County, Tennessee.

Figure 8-15 Shale Injection Site

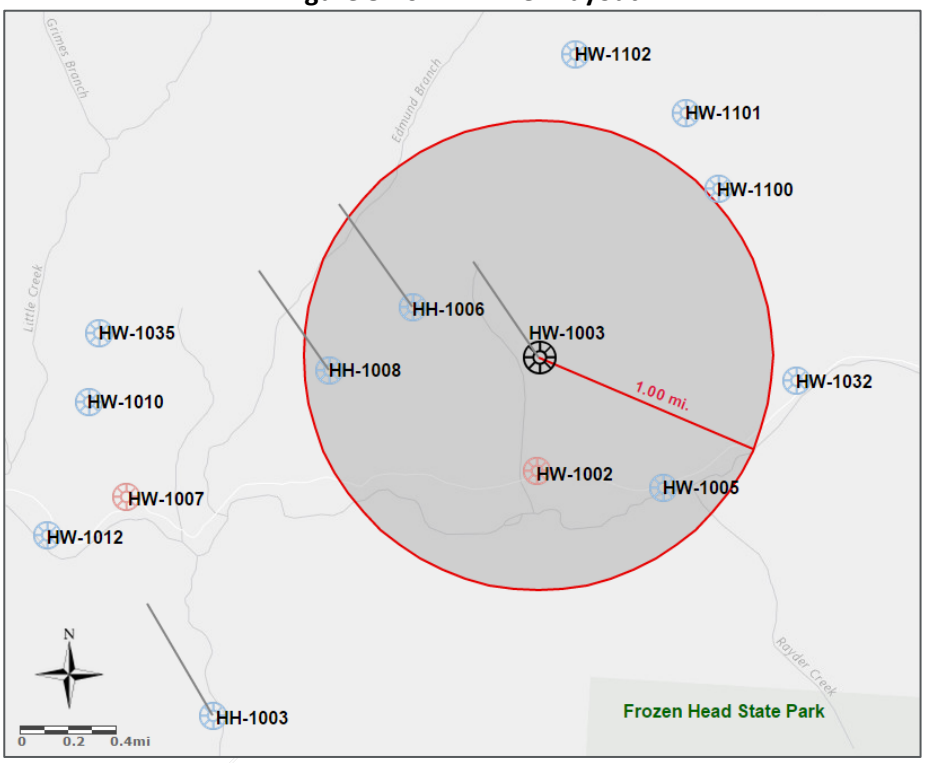


As part of the MVA program for the injection test, thirteen nearby offset production wells were selected as monitoring wells (Figure 8-16). These wells are owned and operated by Knox (CNX Gas) and Atlas Energy and consist of three horizontally drilled wells completed in the Chattanooga Shale (HW-1003, HH-1006, HH-1008, HH-1003), eight vertically drilled wells completed in the Chattanooga Shale (HW-1102, HW-1101, HW-1100, HW-1032, HW-1005, HW-1035, HW-1010, HW-1012), and two vertically drilled wells completed above the Chattanooga Shale (HW-1002 and HW-1007). The wells that were completed in the Chattanooga shale formation are denoted by a blue symbol while those completed out of formation are denoted by a red symbol.

Gas composition, historical gas production, and wellhead pressure were taken from each of these offset production wells prior to injection as a baseline study. Any changes in flow rate, pressure, or gas composition, including hydrocarbons and CO2 would give an indication of either CO2 breakthrough at these wells or enhanced gas recovery as a result from the injection. Choosing two wells that were not

completed in the Chattanooga Shale (HW-1002 and HW-1007) would provide confirmation of any vertical movement of the CO2 plume out of zone.

Figure 8-16 MVA Well Layout



8.5 Site Development and Operations

8.5.1 Site Development

Knox directed the site preparation and initial well work to have the HW-1003 ready for injection operations. Well HW-1003 was an existing shale gas production well with 2-3/8" production tubing set inside 4-1/2" production casing. A well service rig operated by Griffith Well Services was contracted to pull the production tubing out of the well on March 12 and 13, 2014. Once the tubing was removed, a new 5,000 pounds per square inch (psi) master valve was installed on the wellhead. On March 14, Armes Excavating spread 110 tons of gravel and graded the site so it was suitable for the 70-ton storage tank and daily tractor-trailer deliveries of CO2.

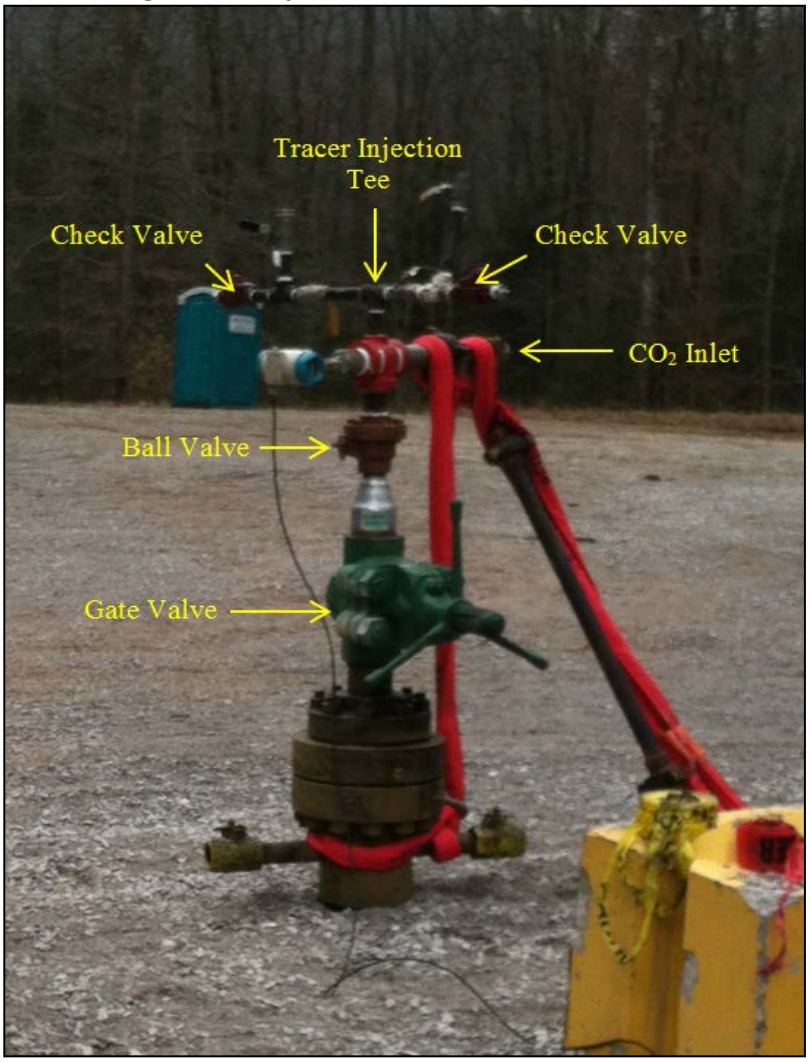
On the morning of March 17, 2014 FLO-CO2 personnel attended a Knox safety training meeting in the Knox office. FLO-CO2 began mobilizing equipment to the well site that afternoon. A 70-ton CO2 storage vessel, injection pump skid, line heater, and travel trailer were brought on site. P&C Well Services ("P&C") moved two light plants and a generator on site to power the travel trailer while Ferrellgas, a propane supplier, delivered a 500-gallon storage tank and propane (Figure 8-17). P&C installed absorbent matting under the pump truck, travel trailer, light plants and generators to catch any potential fluid leaks. FLO-CO2 transport trailers delivered the first product load late in the day of March

17, 2014. A 1.5" WECO 602 high-pressure injection flow line was connected directly to the master valve. This pipe was rated for 6,000 psi service. There was a tee in the injection line near the wellhead with 1" valves installed to provide two ports to inject tracers. All the equipment was completely positioned in place, connected and ready for operation on March 18, 2014. The injection flow line was pressure tested to 1800 psi, and Virginia Tech staff prepared an injection pump and supplies to inject tracers during the injection phase. A wellhead picture is shown in Figure 8-18.

Figure 8-17 Shale Site Layout



Figure 8-18 Injection Wellhead with Tracer Tee



8.5.2 Operations Permitting

Knox agreed to transfer the well operating permit to MM&A to oversee the execution of the injection of carbon dioxide in the well to enhance production. This operating permit allowed the new operator to conduct well work including any treatment programs for improving production. An Application to Change Operators, an Organization Report and Comprehensive Bond Identification form were submitted to the director of the Tennessee Oil and Gas Program. An application fee of $100 was required along with cash bonds of $3,000 and $1,500 for plug and abandonment and reclamation costs, respectively, if required.

At the conclusion of the project, MM&A prepared the application to transfer the well operating permit back to Knox and Knox submitted the application. MM&A also submitted the well treatment data to

the Tennessee Oil and Gas Program director as required. The director accepted the application and required data and transferred the permit to Knox.

8.5.3 CO2 Procurement

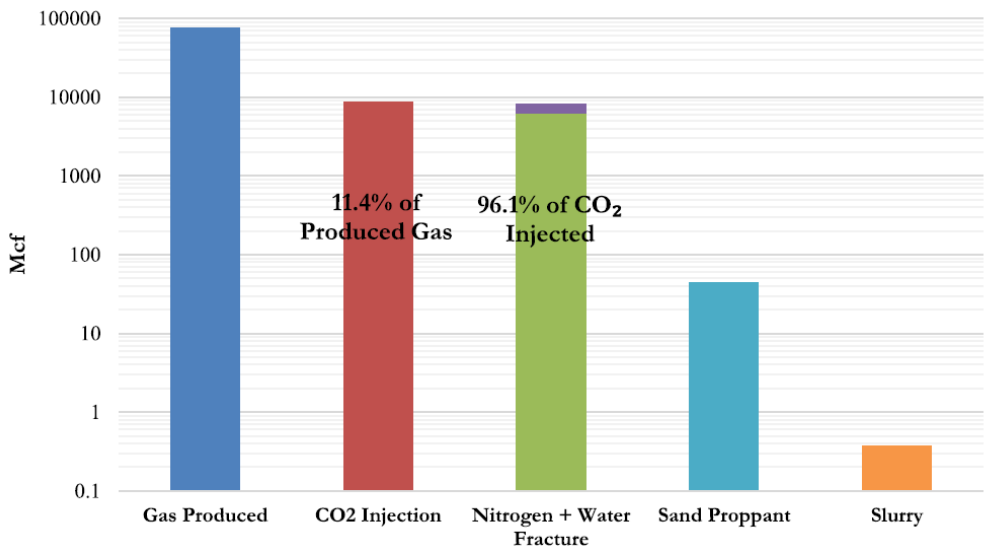
FLO-CO2 ("FLO-CO2") Limited of Midland, Texas received the award to provide the CO2 supply, delivery, storage and pumping operations after submitting a sealed proposal to Virginia Tech as part of a competitive Request for Proposal (RFP) process. One 70-ton CO2 storage vessel was positioned on-site to receive daily deliveries of product. FLO-CO2 procured the carbon dioxide from a commercial facility in Mississippi. An injection skid, line heater and crew living quarters were also provided by the company. A daily rental fee of $250 and $1,200 were assessed for the storage vessel and injection skid plus additional mobilization and demobilization charges of $45,150. Liquid carbon dioxide was delivered to the test site at $220/ton.

8.6 CO2 Injection Operations

8.6.1 Injection Results

The CO2 injection was carried out by the oilfield service company, Flo-CO2. Approximately 510 short tons of CO2 was injected to test the storage potential and enhanced gas recovery of gas-bearing shales. This injection was significant when compared to the amount of nitrogen and water used to initially hydraulically fracture the well (Figure 8-19). The injected CO2 would nearly equal the amount of nitrogen and water used to hydraulically fracture the well and is equivalent to 8595 Mcf which is approximately 11.4% of the total gas produced from the well.

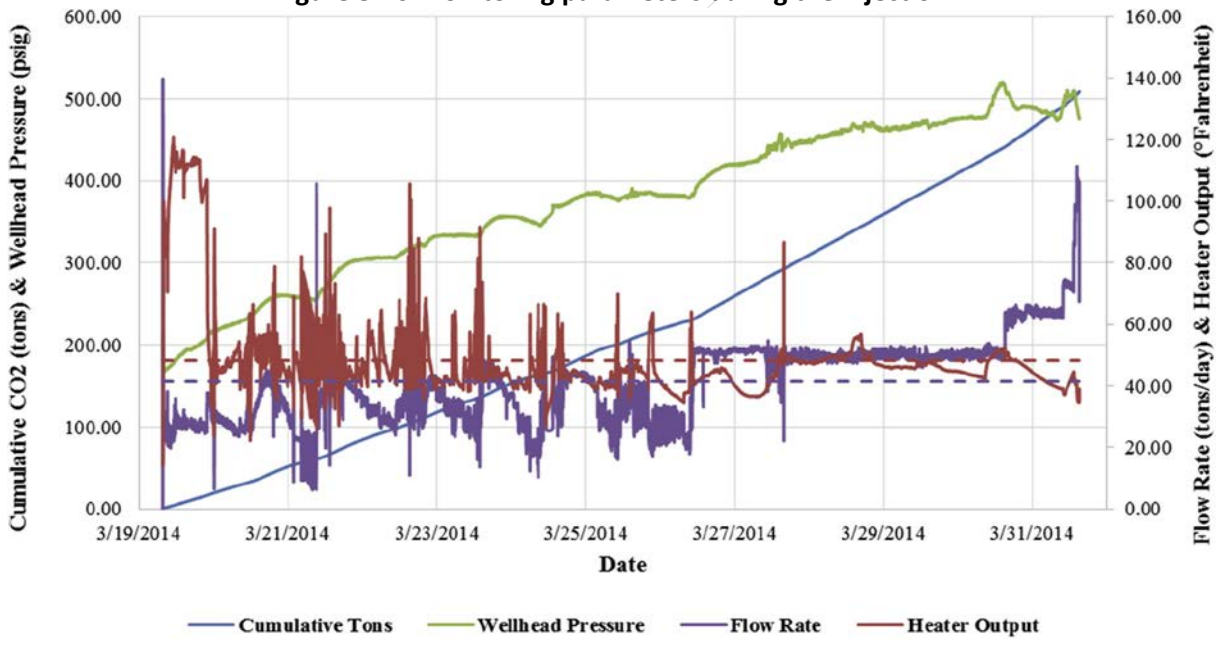
Figure 8-19 CO2 Injection Comparison



Injection commenced on March 19th, 2014 at 7:41 a.m. and concluded on March 31st, 2014 at 3:58 p.m. During injection, flow rate, temperature, wellhead pressure, and total cumulative tons were collected every 30 seconds by the operator (Figure 8-20). The average flow rate was 40.95 tons/day

and the average heater output was 48.59 ºF. Temperature output from the propane heater was the parameter that was held constant by the operator to keep CO2 above the freezing point throughout the injection period. Flow rate decreased at night due to ambient temperature drop, requiring a higher temperature output and more propane to heat the CO2. The lowest injection rate was during the initial start-up of operations at 3.5 gallons per minute (gpm). The highest injection temperature of 119°F occurred during the first twelve hours of injection while the flow rate was at its lowest point. The flow rate was gradually increased throughout the injection period. The highest rate achieved was near the end of injection at 17.4 gpm. The initial wellhead pressure was less than 50 psi when injection was initiated and gradually increased throughout the project to a maximum of 509 psi at the end of the injection. Twenty-eight tractor-trailer loads of product were delivered which consisted of 527.13 tons of CO2. This resulted in a loss of approximately 17 tons (3.2%) of product due to cool down and transfers. This was extremely efficient because of the cool temperatures and minimal transfers.

Figure 8-20 Monitoring parameters during the injection



Tracer Injection

As part of the CO2 injection, fluorinated tracers were added to help detect CO2 plume migration to offset production wells, and to account for the CO2 during the flowback of the well following the injection and soaking phase. For this test Sulfur Hexafluoride (SF6) and two perfluorocarbon tracers (PFTs), perfluoromethylcyclo- pentane (PMCP) and perfluoromethylcyclohexane (PMCH) were chosen as the tracers injected with the CO2. SF6 and PMCP were injected with the first 50 tons of CO2 to help model the initial plume movement through the reservoir by monitoring arrival times and concentrations at any of the offset production wells. PMCH was injected later in the test near the 350-ton mark of CO2 injected to help compare arrival times of similar PFTs at the offset production wells during different phases of the injection.

Sulfur Hexafluoride Injection

On March 20, 2014 at 12:00PM, 5,500 mL of SF6 were injected with CO2 at HW-1003. At this time, the cumulative amount of CO2 injected downhole totaled 20 tons, the wellhead pressure was 216 psig, the flow rate of the CO2 was 28 tons/day, and the heater output for the CO2 was 50 degrees Fahrenheit.

The SF6 gas cylinder was connected to a dual stage pressure regulator and then connected to an Alicat mass flow controller using 1/8th inch stainless steel tubing. From the flow controller, the gas went into a Sprague booster pump system. In order for the SF6 to overcome the pressure of the CO2, a higher pressure needed to be achieved. The booster pump was used to effectively utilize air from a standard air compressor to drive a compression piston in the pump allowing the input gas, SF6 in this case, to be compressed to a higher pressure. The maximum pressure the booster pump can achieve is 1,100 psig with a drive air pressure of 200 psig. A pressure gauge was connected to the outlet port to measure the boosted pressure before the SF6 was introduced to the CO2. Figure 8-21 shows a schematic of the SF6 injection system and Figure 8-22 shows the actual well head setup.

Figure 8-21 Sulfur Hexafluoride Injection Schematic

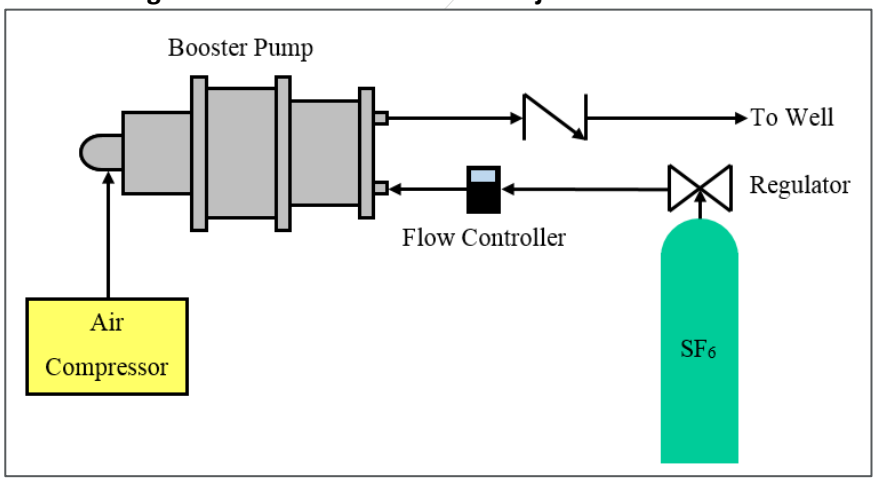
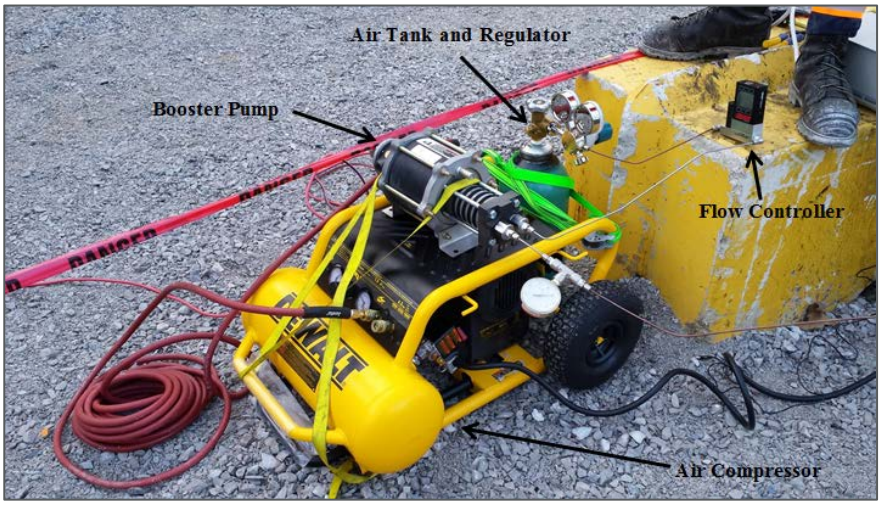


Figure 8-22 Sulfur Hexafluoride Injection Wellhead Setup



Perfluorocarbon Tracers

The perfluorocarbon tracers were injected using a Teledyne Isco 500D Syringe Pump. This pump has a 500 mL capacity and a maximum injection pressure of 3,750 psig. The pump can be programmed to inject at a constant flow rate or a constant pressure. For this test, constant flow rate was selected.

On March 20, 2014 at 12:07 PM, 500 mL (0.85 kg) of PMCP were injected at a constant flow rate of 62.5 mL/hr. At this time, the cumulative amount of CO2 injected downhole totaled 20 tons, the wellhead pressure was 216 psig, the flow rate of the CO2 was 28 tons/day, and the heater output for the CO2 was 50 degrees Fahrenheit. The total 500 mL of PMCP was completed at 8:07 PM the same day. At this time, cumulative tons of CO2 injected totaled 46 tons, the wellhead pressure was 260 psig, the flow rate of CO2 was 41 tons/day, and the heater output was 50 degrees Fahrenheit.

The flow rate was adjusted for the second PFT injection due to the higher injection rate of the CO2 at the time. This adjustment allowed for the concentration of tracer versus CO2 to remain the same for both PFT injections. On March 28th, 2014 at 1:30PM, 500 mL (0.89 kg) of PMCH were injected at a constant flow rate of 85.5 mL/hr. At this time, the cumulative amount of CO2 injected downhole totaled 337 tons, the wellhead pressure was 463 psig, the flow rate of the CO2 was 49 tons/day, and the heater output for the CO2 was 50 degrees Fahrenheit. The total 500 mL of PMCH was completed at 7:21 PM the same day. At this time, the cumulative amount of CO2 injected downhole totaled 350 tons, the wellhead pressure was 468 psig, the flow rate of the CO2 was 50 tons/day, and the heater output for the CO2 was 50 degrees Fahrenheit.

The pump cylinder is equipped with an inlet for filling and refilling, and an outlet for discharge. 1/8th inch tubing was placed on the inlet of the pump to fill the cylinder with the tracers. Once filled, the inlet was plugged and 1/8th inch stainless steel tubing was assembled to the pump outlet. Just past the outlet, a quarter turn plug valve was placed in-line so the pump could be shut off, disassembled, and cleaned. The tubing was connected to the check valves on the wellhead where the PFTs were introduced to the CO2 injection system. After each PFT injection, the pump was filled twice with 500 mL of ethanol (C2H6O) and allowed to pump in order to clean the pump cylinder, tubing, and wellhead assembly of any remaining tracer. Figure 8-23 and 8-24 show the PFT injection system.

Figure 8-23 Perfluorocarbon Tracer Injection Schematic

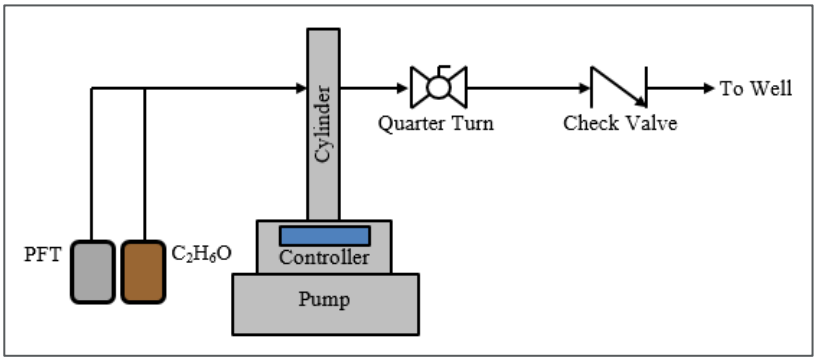
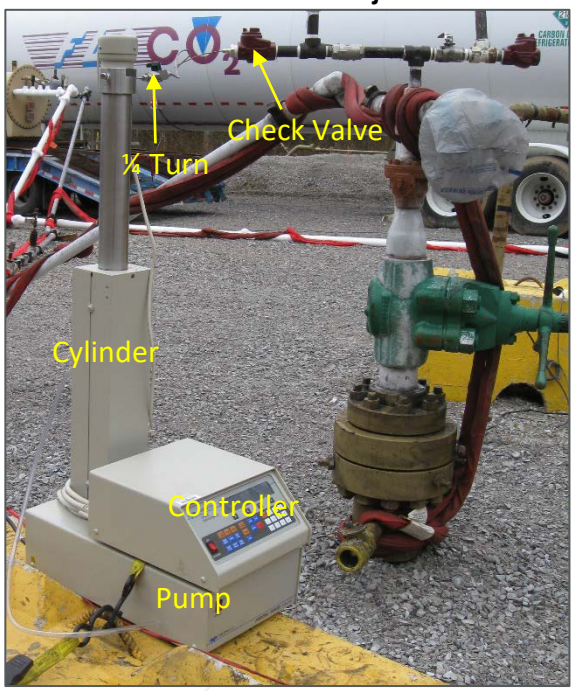


Figure 8-24 Perfluorocarbon Tracer Injection Wellhead Setup



8.7 Monitoring Results

8.7.1 Pre-injection baseline monitoring

As part of the pre-injection baseline monitoring, composition and pressure data from the injection and offset production wells were collected periodically five months prior to injection. Samples were collected by researchers at Virginia Tech and analyzed in the Subsurface Atmospheres Laboratory within the Mining and Minerals Engineering Department at Virginia Tech using analytical chemistry and gas chromatography techniques. Table 8-3 displays the average gas composition data of the injection well for the five-month baseline sampling period.

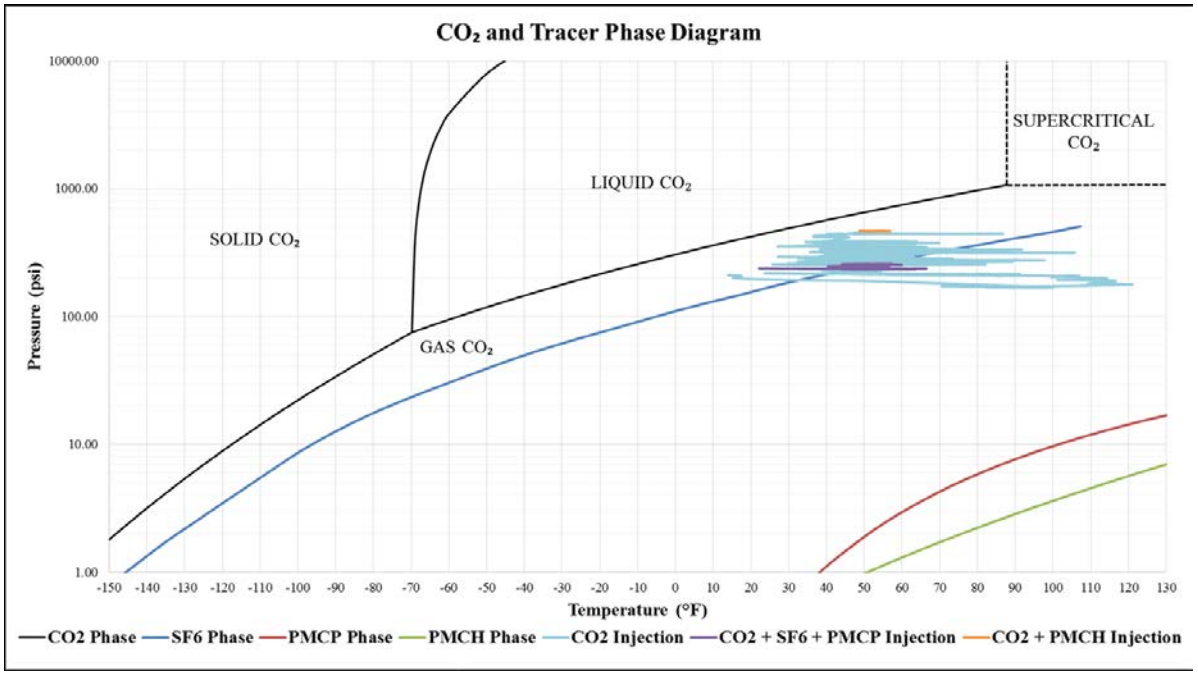
Table 8-3 Injection well baseline composition (% of total gas stream)

Component	Average (%)
Nitrogen (N2)	3.04624
Carbon Dioxide (CO2)	0.00834
Methane (CH4)	81.29997
Ethane (C2H6)	2.80925
Propane (C3H8)	12.04367
Butane (C4H10)	0.45482
IsoButane (iC4H10)	0.14477
Pentane (C5H12)	0.07422
NeoPentane (neoC5H12)	0.00100
IsoPentane (iC5H12)	0.04624
Hexane (C6H14)	0.06991

Phase of Injectates

Based on the injection pressure and temperature, the phase of the CO2 and tracers at the wellhead during injection can be graphically displayed on a phase-diagram (Figure 8-25). The CO2 injection is represented by the light blue line, SF6 by the dark blue line and the PFTs by the red and green lines respectively. From this plot it can be determined that the CO2 was injected as a gas for the entirety of the injection, while SF6 was injected as both a gas and liquid and both PFTs as a liquid.

Figure 8-25 CO2 and Tracer Injectate Phases



During the injection phase, pressure readings, tracer sampling, and composition analysis was conducted extensively at the offset production wells. It was determined there was no significant change in wellhead pressures at the offset production wells. After chromatographic analysis, it was determined that there was also no tracer detection at any of the offset production wells. Finally, composition analysis of the offset production wells during injection resulted in no significant increase in CO2 concentration at any of the offset production wells, including the closest horizontal well.

Approximately 1531 gallons of propane were consumed during 295 hours of heater operations. The propane usage was 5.2 gallons per hour. FLO-CO2 burned 238 gallons of diesel to operate the pumping unit for a consumption rate of 0.8 gallons per hour. Immediately upon concluding injection operations, FLO-CO2 disconnected and rigged down its equipment and began demobilizing. The well was shut-in and the CO2 allowed to soak in the reservoir for the next four months.

8.7.2 Soaking Phase

After the injection phase was complete, the injection well was shut in for a period of four months to allow for the CO2 to equilibrate within the reservoir. During this soaking phase, the wellhead pressure of the injection well was monitored daily once the well was shut in (Figure 8-26). The wellhead pressure after the injection phase was just above 500 psig. This pressure quickly decreased and then leveled out at 260 psig for a period of three months which is indicative of a closed system. Although a commercial CO2 'huff-and-puff' operation performed for the purpose of enhanced gas recovery would not support an extensive soaking period due to economic constraints, the primary focus of this test was to determine CO2 storage potential. As such, a soaking period of four months was chosen to provide sufficient time for reservoir equilibration, reflecting conditions pertaining to permanent storage of CO2.

During the soaking phase, gas samples were collected weekly from the offset production wells and analyzed for composition. Analysis of these samples concluded, again, no significant increase in CO2 concentration at the offset production wells. Gas samples were also collected from the injection well during the soaking phase. Analysis of these samples indicated that the gas stream averaged over 97% CO2.

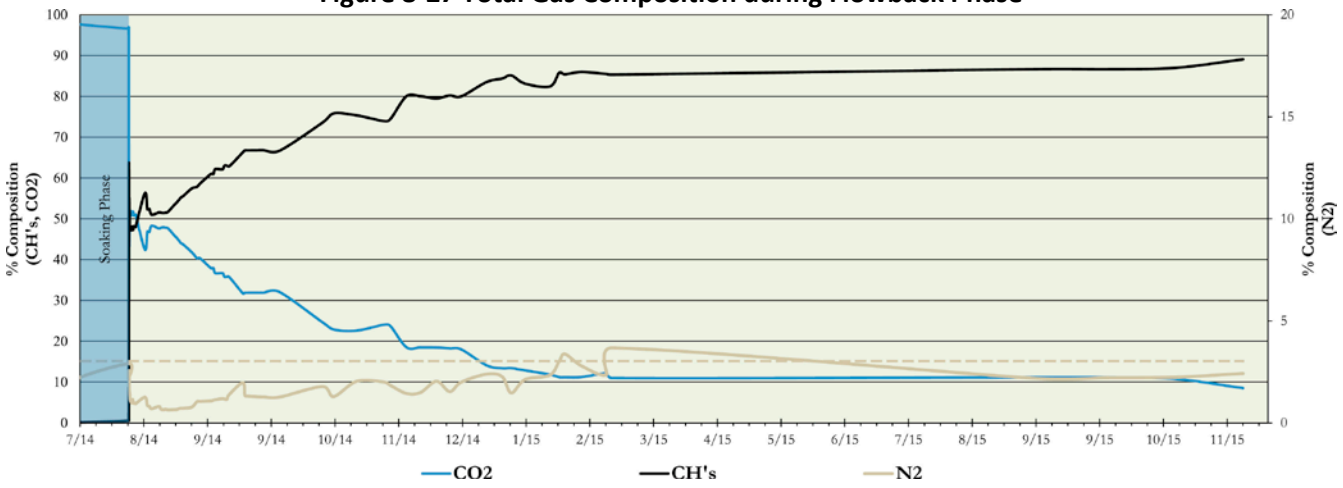
Figure 8-26 Wellhead Pressure during Soaking Phase



8.7.3 Flowback Results

During the flowback phase of the project, the well was opened back up and put back into normal pipeline operation. Flowback commenced on July 29th, 2014 at 8:40 a.m. Gas composition and tracer samples were collected every 30 min to 1 h during the first week of flowback, then once per day by the well tending service company, P&C Well Services. Figure 8-27 shows the gas compositions of HW-1003 during the flowback phase, including CO2 (blue), total hydrocarbons (black), and nitrogen (gold). The dashed gold line represents the average baseline composition of Nitrogen for comparison.

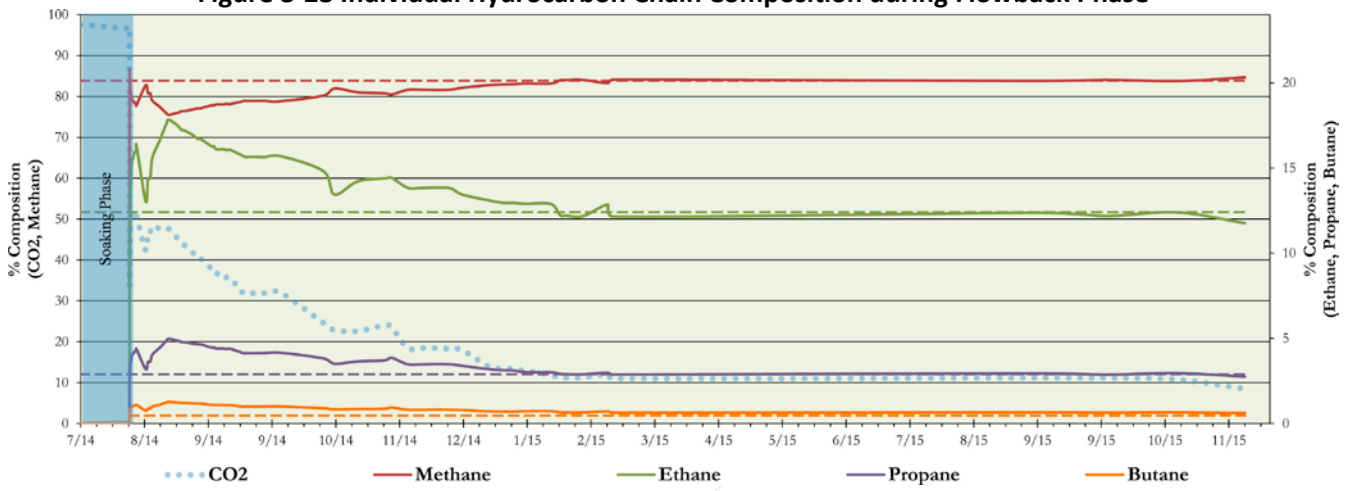
Figure 8-27 Total Gas Composition during Flowback Phase



In order to evaluate enhanced gas recovery, the quality of the total hydrocarbon composition during flowback was evaluated. Figure 8-28 displays the individual hydrocarbon chains and their relative percentage of the total hydrocarbon composition during the flowback phase, including methane (red), ethane (green), propane (purple), and butane (orange). The dashed lines corresponding to the matching colors represent the pre-injection baseline averages for each component for comparison. CO2 (dotted blue) composition is also displayed for comparison purposes. Figure 8-28 shows that during the flowback the more valuable natural gas liquids (NGLs) (ethane, propane, butane, etc.) composition was directly correlated to the CO2 composition while the methane composition was inversely proportional

to the CO2. CO2 mobilized the NGLs into the gas stream where the heavier the hydrocarbon the greater the effect.

Figure 8-28 Individual Hydrocarbon Chain Composition during Flowback Phase



Flow data from the ABB Totalflow XFC G4 meter located at the injection well was collected daily. This unit uses an orifice plate in the meter run to measure static pressure, differential pressure on both sides of the plate, temperature, and gas density to measure flow rate in Mcf/day. A standard density input is programmed in the flowback and the blue dotted line represents the total hydrocarbons produced during flowback. The flowrate data was adjusted to the actual density of the gas stream, which was calculated from the compositional analysis from each day collected. Figures 8-29 and 8-30 display the historical production (red shaded area), the injection and soaking period (green shaded area), and the flowback (blue shaded area). The red dotted line represents the projected decline curve based on the historical production data. The blue solid line represents the total gas produced during flowback and the blue dotted line represents the total hydrocarbons produced during flowback.

Figure 8-29 Flowback Production versus Historical Production

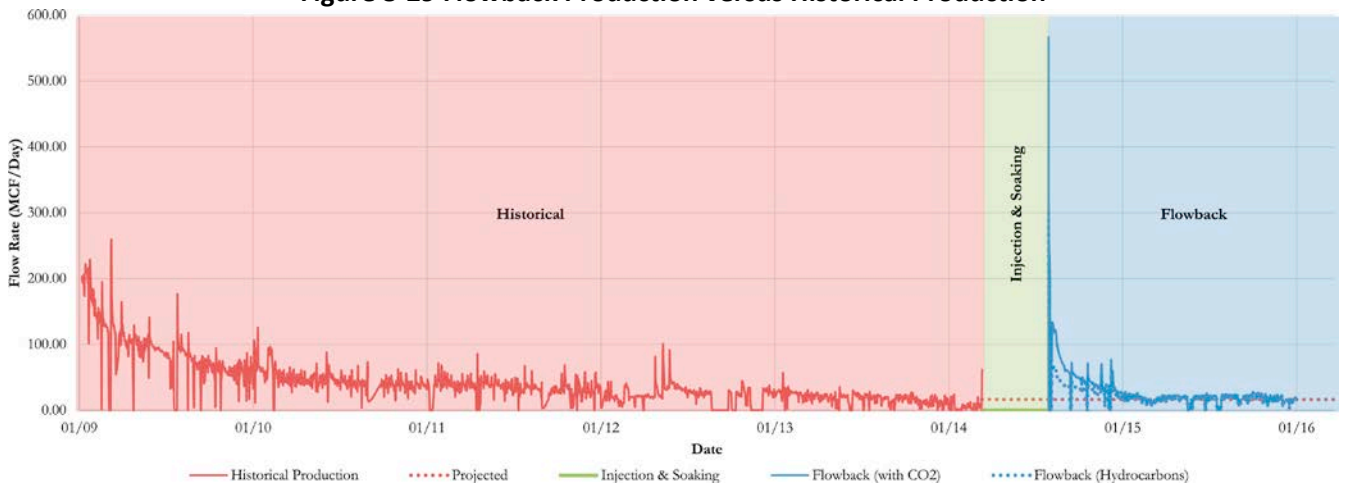
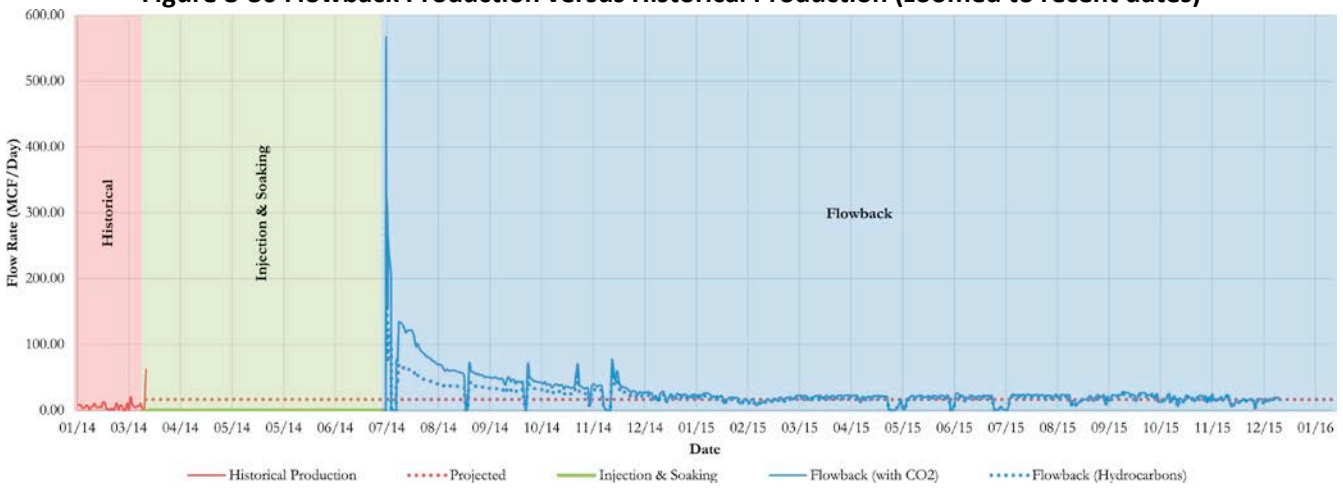
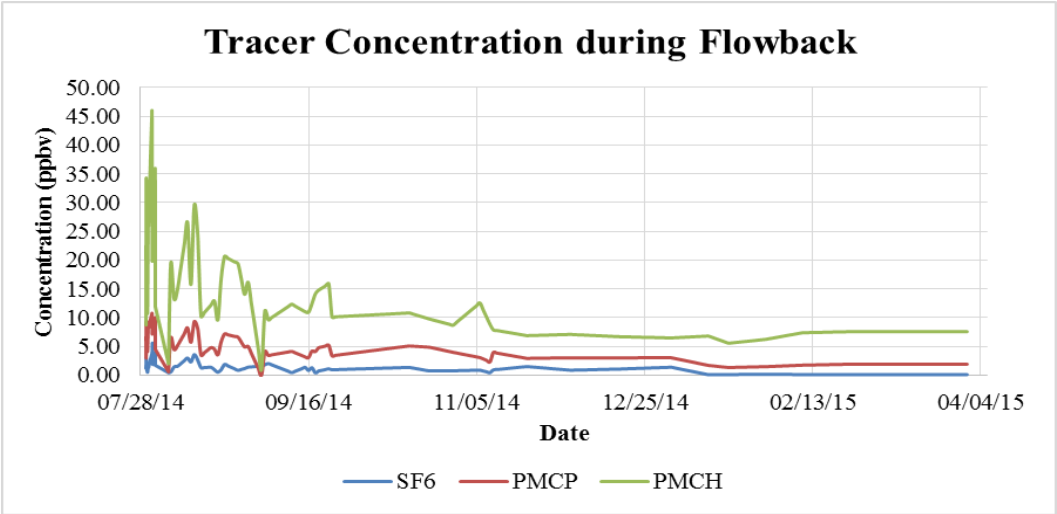


Figure 8-30 Flowback Production versus Historical Production (zoomed to recent dates)



During the flowback, tracer samples were collected and analyzed for flowback concentrations. Figure 8-31 displays the concentrations of all three tracers detected in the flowback. While the overall trend in concentration for all three tracers is consistent, the concentration of PMCH during flowback was higher than PMCP and SF6, respectively. During the first year of flowback, 35.1% of the PMCH, 12.0% of the PMCP, and 3.28% of the SF6 injected was recovered.

Figure 8-31 SF6 and PFT Concentrations during Flowback



A regression analysis was performed on flowrates pre and post-injection (Figure 8-32) as well as on CO2 content in the produced stream (Figure 8-33) and it is estimated that greater than 50% of the injected CO2 has been stored in the reservoir.

Figure 8-32 Regression Analysis of Pre and Post Injection Flowrates

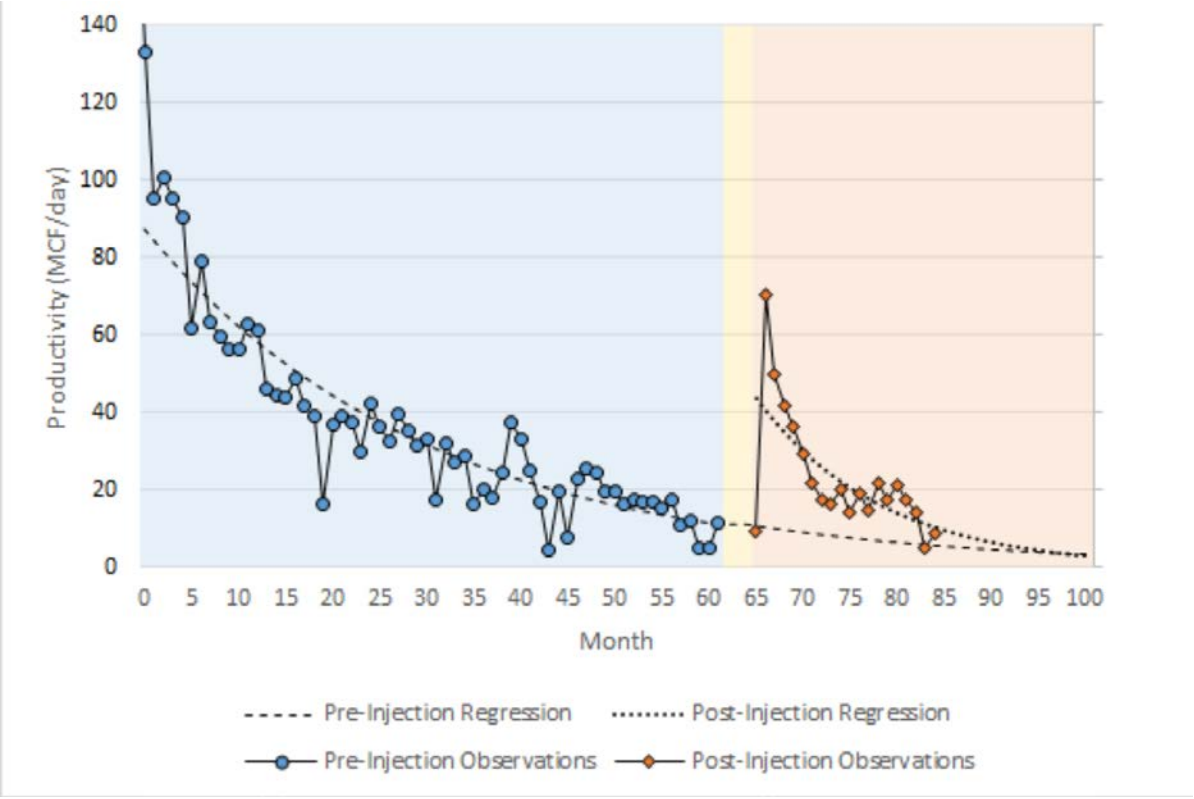
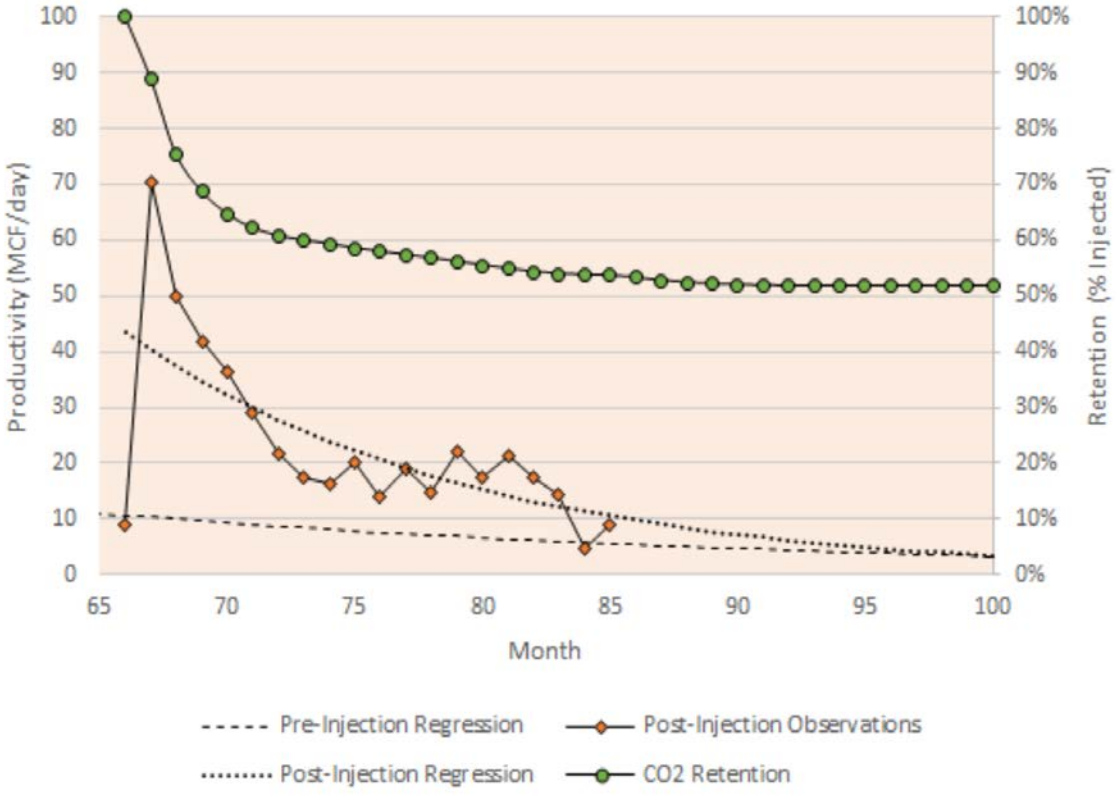


Figure 8-33 CO2 Retained through Regression Analysis



8.8 Post-Injection Reservoir Modeling

In post-injection reservoir modeling, Computer Modeling Group Ltd.'s GEM software, a compositional and unconventional reservoir simulator, was utilized. A dual porosity-dual permeability model which is generally used for shale gas production was assigned as in preliminary model. In dual porosity-dual permeability models, porosity and permeability are defined in both matrices and fractures. Shale has both Darcy flow and diffusion in matrix while it has Darcy flow and Non-Darcy flow in fractures.

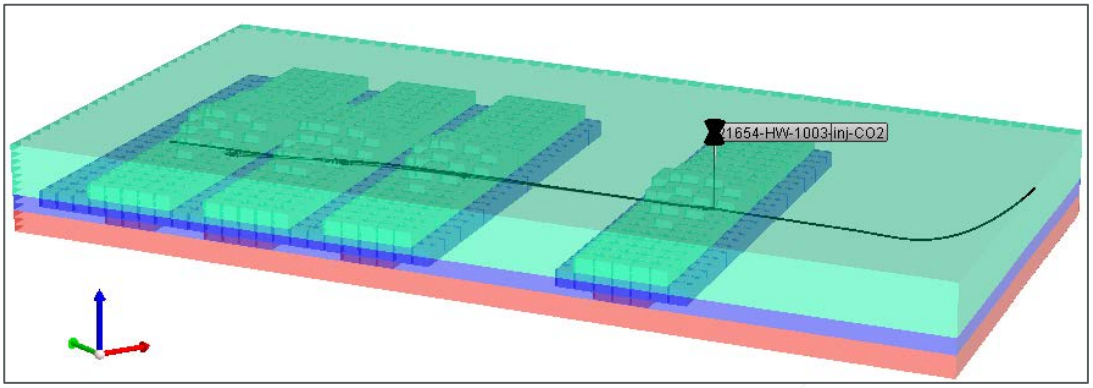
For post-injection simulation, a complex model was developed based on regional geologic data and produced gas compositional data allowing to research team to create more realistic model of the stimulated reservoir volume (SRV) around the horizontal well generated by hydraulic fracturing treatment. Sensitivity studies were done for this complex model to see their influence on gas production during pre-injection and flowback periods. The following section focuses on the complex reservoir model with associated regional geologic input. Moreover, the sensitivity analysis was completed using this complex reservoir model.

8.8.1 Methodology

Multiple modeling scenarios were simulated to investigate various reservoir parameters' influences on gas compositions, original gas in place, gas recovery and bottom-hole pressure (BHP). Different values were assigned to BHP, dimensions of the SRV (i.e., the half-length of the fracture network, the number of layer formations in the SRV and the width of each stimulated stage), Langmuir pressure and Langmuir volume for sensitivity analysis. Sensitivity studies also helped us to build the history matching model.

After sensitivity analysis on reservoir pressure, SRV dimensions, Langmuir volume and pressure, a model with the same number of grid blocks with previous models (i.e. 165,429) was generated for the history match study. Model geometry with the SRV used in the history matching study is demonstrated in Figure 8-34. In the figure, Fort Payne, Chattanooga and Sequatchie formations are in green, blue and red, respectively. Three stages in the SRV were connected to each other only in the Chattanooga formation. The volume of the fracture network decreased as you move farther away from the well perforations. The new SRV in the history matching model was equal to 179.2E+06 ft3 (5.074E+06 m3). 64.5 ft3 (36%) this volume was in Fort Payne formation, 80.9E+06 ft3 (45%) of it was in Chattanooga formation and the rest of it was in Sequatchie formation (i.e. 33.8E+06 m3 (19%)).

Figure 8-34 Model Geometry



As in preliminary model, matrix porosity was 0.061 and 0.066 for the Chattanooga shale and the Sequatchie shale formations, respectively. Matrix permeability was 4.61E-06mD for the Chattanooga Shale, 2.46E-6mD for the Sequatchie formation and 70mD for the SRV. Rock densities were 169.18 lb/scf for the limestone, 153.30 lb/scf for Chattanooga Shale and 166.83 lb/scf for Sequatchie Shale. Initial pressure and reference depth were 747 psi and 1200 ft respectively.

CH4 Langmuir volume and Langmuir pressure were equal to 139.48 scf/ton and 682 psi for the Chattanooga shale, and 16.1 scf/ton and 1330 psi for the Sequatchie shale, respectively. Langmuir volumes were taken constant for each component and they were taken as 682 psi for the Chattanooga shale and 1330 psi for the Sequatchie shale as in previous models. Gas component properties used in history matching study were the same as in Table 8-2 except Langmuir volume ratios. After sensitivity analysis and several history matching attempts, Langmuir volume ratios (CH4:C2H6:C3H8:CO2:N2) based on gas molar volume were assigned as 3:7:16:8:1, respectively.

For history matching of gas compositions, monthly production gas rate was defined as the primary constraint for pre-injection and flowback periods (until 12/1/2015) and daily injection rate was assigned for injection period primary constraint. After 12/1/2015, a constant bottom-hole pressure (i.e., 586psi, which is the last bottom hole pressure reading in the model for the date 12/1/2015) was assigned as a primary constraint for forecasting production for five years.

8.8.2 Model Parameters and Inputs

The complex model developed by technical team consists of a 12-layer with three formations including Fort Payne, Chattanooga shale and Sequatchie shale formations. The same input values used in preliminary model were assigned to the complex model unlike it stated otherwise. Structure and isopach maps of Chattanooga shale formations were used to create the model structure as in preliminary model. Reservoir properties for reservoir modeling inputs were determined using interpretations from log data from vertical wells near the injection well. The shape of the stimulated volume was estimated using another horizontal well's micro seismic data. This horizontal well has some similarities with the HW-1003 well in terms of gas production rate, cumulative gas production, and both wells cut the same geological formations.

Models used in the study had three different formations, which were Fort Payne Formation (140 ft), Chattanooga Shale Formation (approximately 45 ft), and Sequatchie Shale Formation (60 ft). In total, the average thickness of the model was around 245 ft. The total SRV varies with respect to the different models, but was typically equal to 157.86E+06 ft3.

Matrix porosity was 0.061 and 0.066 for the Chattanooga Shale and the Sequatchie Formation, respectively. Matrix permeability was 4.61E-06 mD in the Chattanooga Shale, 2.46E-6 mD in the Sequatchie Formation and 70 mD in the SRV. Fracture spacing was 12 ft, 1 ft and 30 ft for Fort Payne, Chattanooga and Sequatchie formations, respectively. Rock densities were 169.18 lb/scf for the limestone, 153.30 lb/scf for Chattanooga Shale and 166.83 lb/scf for Sequatchie Shale. Initial pressure and reference depth were 747 psi and 1200 ft respectively. Matrix porosity and permeability, fracture spacing, rock densities were from Corelab's analysis (2009) and the rest was assumed based on history matching studies.

Defining all the gas components into the model increases the computational time to run the model than defining one component, therefore, gas components only higher than 0.5% were included in the model (i.e., CH4, C2H6, C3H8, CO¬2 and N2). Initial gas compositions were predicted based on the recorded data. Langmuir volumes for the Ft. Payne were nearly zero for each component. CH4 Langmuir volume and pressures for the Chattanooga shale and the Sequatchie shale were measured from core from a nearby area. CH4 Langmuir volume and Langmuir pressure were equal to 139.48 scf/ton and 682 psi for the Chattanooga shale, and 16.1 scf/ton and 1330 psi for the Sequatchie shale, respectively. Langmuir volumes were taken constant for each component and they were taken as 682 psi for the Chattanooga shale and 1330 psi for the Sequatchie shale. Langmuir constants for each gas component were estimated based on the boiling point of each gas component. Langmuir volume ratios (CH4:C2H6:C3H8:CO2:N2) based on molar volume were 3:8:13:15:1. This ratio indicates that the CH4 volume is 3 times the N2 volume, C2H6 is 8 times N2 volume, C3H8 is 13 times N2 volume, etc. Details of the Langmuir volumes and other gas component properties used in the models are listed in Table 8-4. Those values were used in all complex models unlike it stated otherwise.

Table 8-4 Gas component properties used in reservoir modeling

Property	Gas Component				
	CH_4	C_2H_6	C_3H_8	CO_2	N_2
Glob. Comp. (%)	82.6	11.5	2.6	0.0	3.3
Langmuir Volume (gmole/kg) Ft Payne Limestone	1.838E-05	4.901E-05	7.964E-05	9.190E-05	6.127E-06
Langmuir Volume (gmole/kg) Chattanooga Shale	0.18380	0.49007	0.79638	0.918958	0.06127
Langmuir Volume (gmole/kg) Sequatchie Shale	0.04676	0.12472	0.20267	0.23389	0.01561
Langmuir Volume Ratio	3	8	13	15	1
Crit. Pres. (atm)	45.4	48.2	41.9	72.8	33.5

Crit. Temp. (°K)	190.6	305.4	369.8	304.2	126.2
Acentric factor	0.008	0.098	0.152	0.225	0.040
Mol. Weight (g/gmole)	16.043	30.070	44.097	44.010	28.013
Crit.Vol. (m^3/kgmole)	0.099	0.148	0.203	0.094	0.0895
Specific Gravity	0.300	0.356	0.507	0.818	0.809

The grid model was oriented so that the horizontal part of the well was parallel with the j-direction (i.e., N 35°E). The total number of grid blocks used in the study changes based on the model, but a typical model has 165,429 grid blocks including refined grid blocks for modelling SRV stages. Fundamental grid dimensions are 52x26x12 (in IxJxK directions). The optimal refined grid size was achieved as 7 in preliminary sensitivity studies and that value was used in post-injection model studies.

HW-1003 well commenced gas production in January 2009. Neither water nor oil was produced from the well. In sensitivity analysis, production, injection and post-injection data was used to compare more values for selected parameters. The gas production data was available from 8 January 2009 till 31 December 2015. After that day, BHP was taken as 586 psi (i.e., the BHP recorded in the model on 31 December 2015) as a primary constraint in the model to predict forecast production until January 2021.

8.8.3 Sensitivity Analysis

Sensitivity analysis showed that an increase in the initial reservoir pressure, increased the gas compositions of CH4 and N2 whereas it decreased the gas compositions of C2H6, C3H8 and CO2. Similar to the reservoir pressure study, an increase in SRV and bottom-hole pressure, increased CH4 and N2 compositions while C2H6, C3H8 and CO2 compositions decreased. Gas components having higher Langmuir pressures or lower Langmuir volumes were produced less during production.

Although including all the gas components is important for modelling to see their behaviors during production and injection time, sensitivity analysis showed that the variation in adsorbed gases was mostly due to compositional amounts instead of adsorption tendency.

8.8.4 History Matching Results

Results displayed that with the assigned values in history matching study, produced gas compositions (CH4, CO2, C2H6 and C3H8) overall matched well to the actual data. Figure 8-35 illustrates history matching results for CH4 and CO2 compositions. Figure 8-36 illustrates history matching results for N2, C2H6 and C3H8 compositions.

Figure 8-35 CH4 and CO2 Composition for History Match versus Measured Data

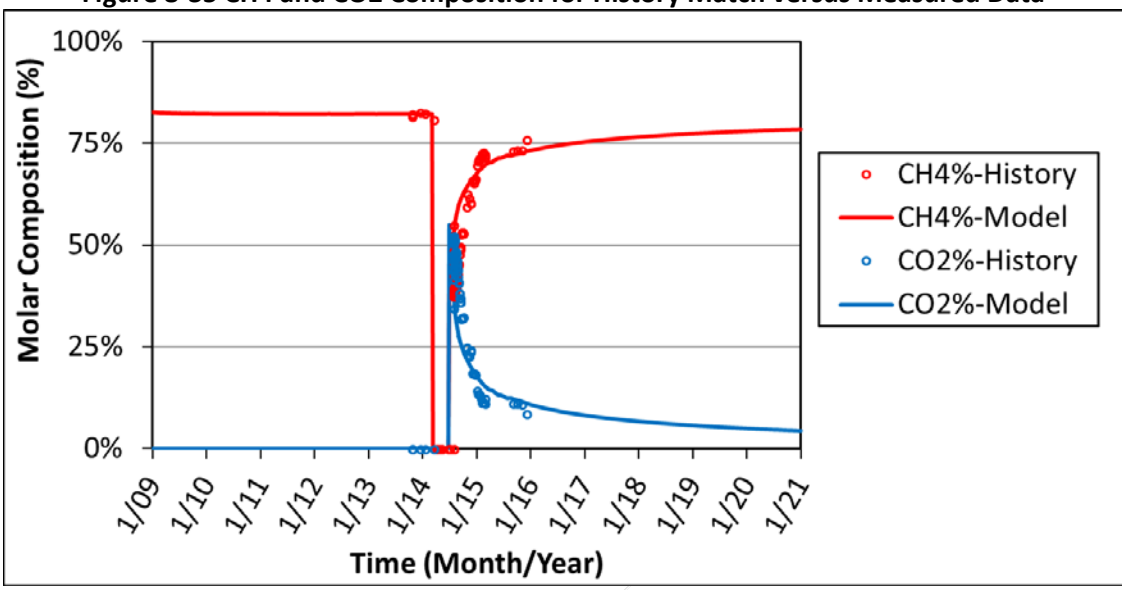
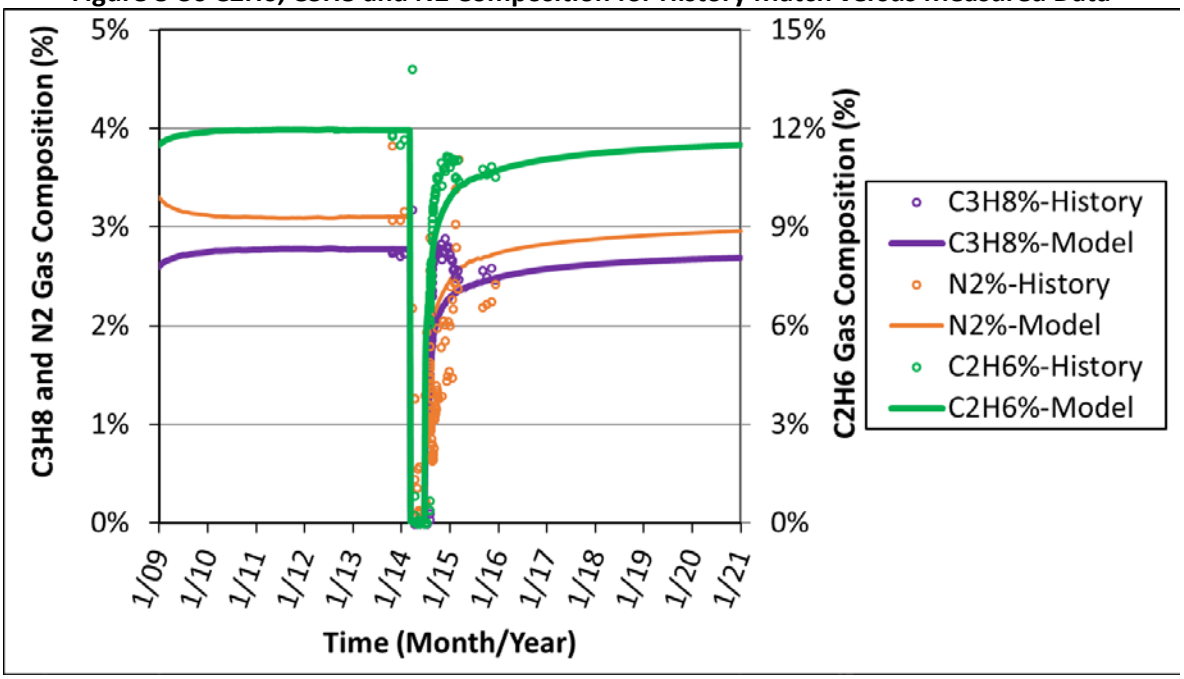
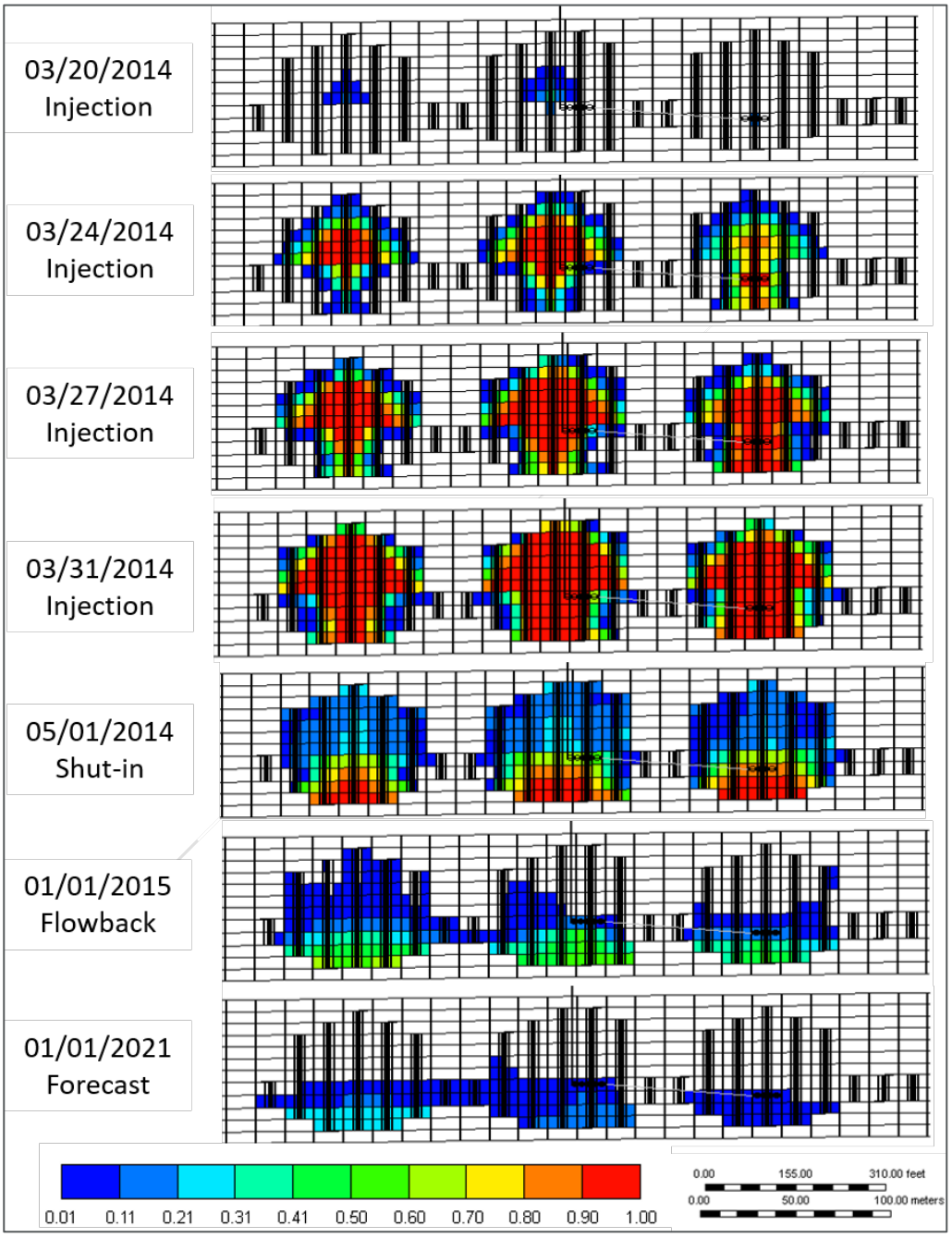


Figure 8-36 C2H6, C3H8 and N2 Composition for History Match versus Measured Data



At the end of the five-year forecast, 121.537MMCF (3.44E+06 m3) of gas was estimated to be produced with 78.41%CH4, 11.51%C2H6, 2.69%C3H8, 2.96%N2 and 4.43%CO2. 508.96 ton of CO2 was injected. The CO2% in the SRV fractures is illustrated for production, shut-in, flowback and forecast periods in Figure 8-37.

Figure 8-37 Cross-sectional view of SRV with CO2 global mole fraction during injection, shut-in, flowback and forecast

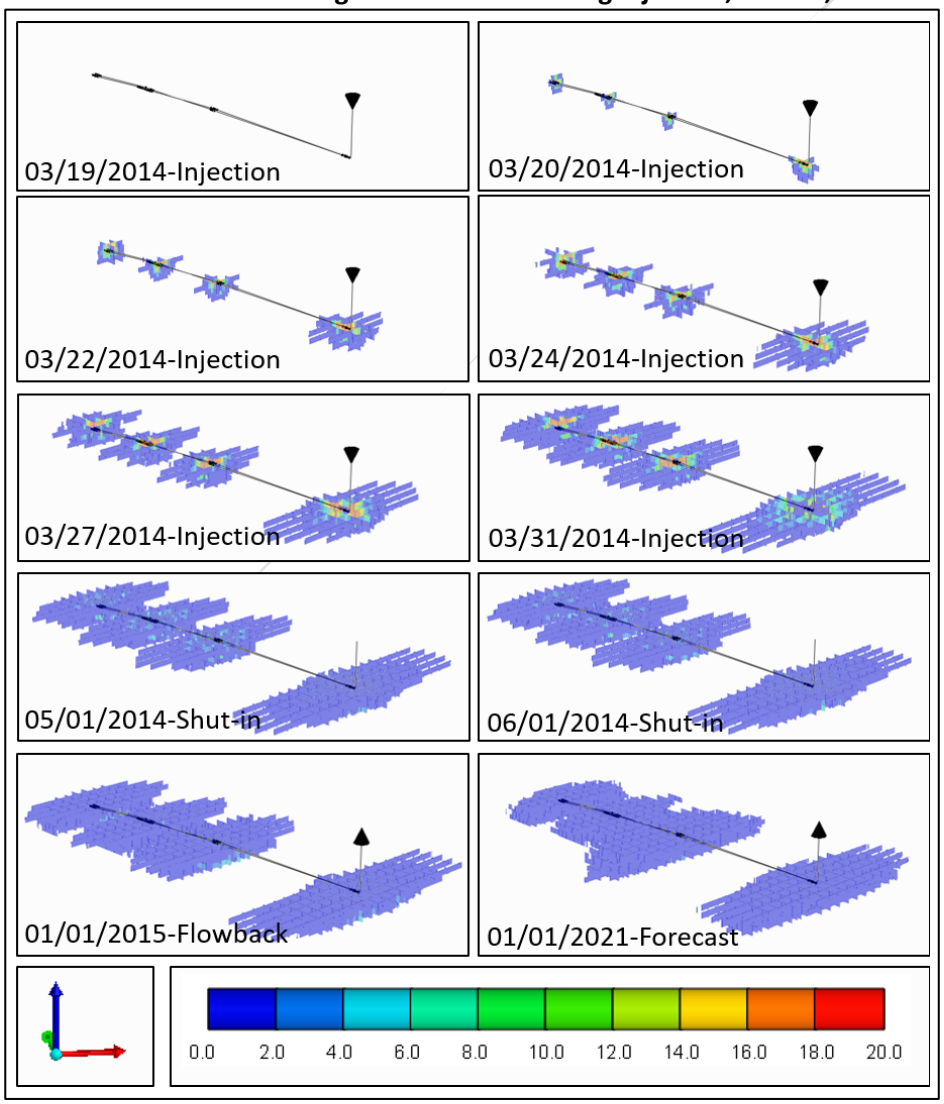


During the injection, figures show that most of the CO2 is moving to the upper formations and after shut-in, CO2 iss moving to the bottom formations. In flowback period, most of the CO2 removes from the Fort Payne formation and in forecast period, there is almost no CO2 left in Fort Payne formation.

At the end of 2020, 350.41 ton of the CO2 (68.8%) would be produced. It means at the end of five-year forecast, 158.55 tons of CO2 would be stored in the reservoir. From Figure 8-38, it seems that most of

the CO2 produced because the CO2 first moved into the Fort Payne fractures and since the limestone has lack of adsorption capacity, all CO2 accumulated in fractures of the Fort Payne and transferred back during flowback and forecast periods. Figure 5 illustrates adsorbed CO2 plume changes during injection, flowback production and forecast. Figure 5 demonstrates that there is no adsorbed CO2 in Fort Payne formation (not seen in the figures because adsorbed CO2 is less than 0.001 gmole/ft3), whereas the stored CO2 is mostly adsorbed in Chattanooga formation close to perforations.

Figure 8-38 3D model for the SRV showing adsorbed CO2 during injection, shut-in, flowback and forecast



Sensitivity and history matching studies confirmed that adsorption capacities of the gas components were C3H8>CO2>C2H6>CH4>N2. These results supported the relationship between adsorption capacity and boiling points of the gases. Langmuir volume ratios (CH4:C2H6:C3H8:CO2:N2) based on gas molar volume were determined as 3:7:16:8:1 for the Chattanooga shale. The same ratio was assigned for the Sequatchie shale as well, but the SRV in the Sequatchie shale was smaller and gas

content of the Sequatchie shale was lower than the Chattanooga shale, therefore, the model results were mostly affected from reservoir parameters assigned to Chattanooga shale formation.

For production forecasting, it was important to consider most of the gas components in the model to obtain more realistic results because each gas component behaved differently under particular reservoir conditions. CH4 behaved like N2 while CO2 behaved similar to the heavier hydrocarbons such as C2H6 and C3H8.

8.9 Financial Analysis

A brief financial analysis was conducted to determine the value of the CO_2 injected. For this analysis, the Henry Hub Natural Gas Spot Price ($/Mcf) was averaged over the past five years (EIA, 2015c). The 90th percentile and 10th percentile were also included in the analysis. Industry communication indicated that natural gas liquids (NGLs), including ethane, propane, butane, pentane, and hexane, are typically sold at 50% of the West Texas Intermediate (WTI) Spot Price ($/Bbl) (EIA, 2015d). Table 8-5 displays the average, 90th percentile, and 10th percentile spot prices for the last five years for natural gas and NGLs.

Table 8-5 Natural Gas and NGLs Spot Prices

Natural Gas $/Mcf			Petroleum & NGLs $/Bbl		
90%	Average	10%	90%	Average	10%
$4.59	$3.74	$2.71	$104.89	$90.48	$74.58

In order to associate a sales price to the NGLs, they first must be converted from Mcf to barrels (Bbl). Table 8-6 displays the conversion factors for NGLs.

Table 8-6 NGLs Conversion Factors (EIA, 2014b)

Component	Conversion Factor (Mcf/Bbl)
Methane*	2.468
Ethane	1.558
Propane	1.499
Isobutane	1.245
Normal Butane	1.288
Isopentane	1.095
Natural Gasoline	0.940
Plant Condensate	0.940
Other Products	0.940
*Not an NGL	

The individual flow rates for methane and NGLs were calculated using the flow and gas composition data collected during the flowback phase. Table 8-7 displays the value of the flowback for methane and total NGLs.

Table 8-7 Total Methane and NGLs in Flowback

Total Flowback					
Total Methane (Mcf)			Total NGL (Bbl)		
5072.69			832.61		
90%	Average	10%	90%	Average	10%
$23,283.63	$18,969.71	$13,746.98	$43,666.33	$37,666.91	$31,046.43

Once the value of the flowback was determined, two different scenarios were conducted; one that deducted the value of gas that would have been produced while the injection well was shut in during the four month soaking phase, and one that did not include the four month soaking phase. For both scenarios, the assumption that the well would have produced saleable gas at the projected decline curve flow rate, had the test not occurred, was made (red dotted line, Figures 5.6 and 5.7). In order to associate a value to this projected production rate, the flow rate was combined with the average pre-injection baseline gas composition of HW-1003 to find what the individual methane and NGL flow rates were for the well before it was taken offline for the CO_2 injection. Table 8-8 displays the first scenario where the soaking phase was not taken into account. Table 8-9 displays the second scenario where the soaking phase was taken into account.

Table 8-8 Flowback Value without the Soaking Phase

Not Including Soaking					
Total Methane Flowback (Mcf)			Total NGL Flowback (Bbl)		
2275.97			479.84		
90%	Average	10%	90%	Average	10%
$10,446.69	$8,511.16	$6,167.87	$25,165.01	$21,707.53	$17,892.13

Table 8-9 Flowback Value with the Soaking Phase

Including Soaking					
Total Methane Flowback (Mcf)			Total NGL Flowback (Bbl)		
715.01			282.94		
90%	Average	10%	90%	Average	10%
$3,281.88	$2,673.83	$1,937.67	$14,838.69	$12,799.97	$10,550.20

Tables 8-10 and 8-11 display the total summed value of the CO_2 injection test with and without the soaking phase, respectively, as well as a dollar per ton of CO_2 injected value.

Table 8-10 Total Flowback Value without the Soaking Phase

Not Including Soaking Phase		
90%	Average	10%
$35,611.70	$30,218.69	$24,060.00
$69.82/ton	$59.25/ton	$47.17/ton

Table 8-11 Total Flowback Value with the Soaking Phase

Including Soaking Phase		
90%	Average	10%
$18,120.58	$15,473.80	$12,487.87
$35.53/ton	$30.34/ton	$24.48/ton

Common to CO_2 – EOR projects is the recycling of the CO_2 that is reproduced with the oil in order to minimize the amount needed to be purchase in the future for the next project. On a commercial scale, the purchase cost is typically $2.00/Mcf of CO_2 and the recycle cost $0.70/Mcf of CO_2 (DOE, 2010b). Table 8-12 displays the net value associated to the CO_2 injection by including the purchase cost to the 510 tons of CO_2 injected for this project and the recycling cost to the 35.5% of CO_2 reproduced. This net value was only conducted for the scenario not including the soaking phase as a commercial 'huff-and-puff' injection can have a soaking phase as little as 10 days (Industry Communication).

Table 8-12 Total Net Flowback Value

Purchase of CO_2 ($2.00/Mcf)		
$17,533.80		
Cost of Recycling ($0.70/Mcf)		
$2,147.89		
Net Value		
90%	Average	10%
$15,930.01	$10,537.00	$4,378.31
$31.24/ton	$20.66/ton	$8.58/ton

8.10 Site Closure

On July 28, P&C mobilized flow back iron, separator, flare stack, and two light plants to the location. L&D Well Service moved a 300-barrel tank to the location to collect any liquids during flow back. The crew rigged up the high-pressure flow back line, rated at 15,000 psi, and connected it to the separator. A liquid line was connected from the separator to the storage tank and the gas flow line was connected to a flare stack. On July 29, the valve was opened to begin flow back operations on a 24/64 choke. The initial wellhead pressure at the start of flow back was 260 psi. The gas was sent to the flare stack and ignited approximately three hours after flow back began. The gas concentration at that time

was approximately 48% methane, 6% ethane and 41% CO2. Over the next few days, the CO2 concentration increased to approximately 51% and remained at that level, while the hydrocarbon concentration was roughly 48%. The flow back continued until August 1 when the well was shut-in because the data being obtained were not adding any additional information to the project team. P&C disconnected the flow back piping and connected the gas line to the sales meter for Knox to turn the well back on-line on August 4. The well site was returned to Knox in the same condition as when the project commenced.

On December 3, Griffith Well Service returned to the location to run the production tubing in the well because the wellhead pressure was safe to do so. Again, funds from the project were used to reimburse Knox for these expenses. This brought closure to the well site operations.

8.11 Conclusions and Recommendations

The injection of 510 tons of CO2 during this test demonstrates the first successful injection of CO2 in an organic shale formation to monitor for storage and enhanced gas recovery potential in Central Appalachia. This successful injection and monitoring of a CO2 in- jection in an organic shale reservoir is a great accomplishment and milestone for CO2 EGR as well as geologic CO2 storage in un-conventional reservoirs.

8.11.1 Injectivity

Based on the significant flow rates and relatively low injection pressures from the injection data, the injectivity of CO2 into fractured organic shale reservoirs is confirmed. Previous reservoir modeling results of history matching the production of the injection well also support that the fracture network permeability has limited influence on the bottom hole pressure (BHP) of the injection well (Keles, 2016). This may imply the possibility of liquid (or even supercritical) CO2 injection in shale gas wells. By increasing the injection pressure, a higher weight to volume ratio can be achieved, which can lead to a higher efficiency for enhanced gas recovery and CO2 storage.

8.11.2 CO2 storage

An initial reservoir model of the injection well based on microseismic data (Keles, 2016) developed a stimulated reservoir volume (SRV) predicted that there would not be communication in the fracture network between the injection well and the thirteen offset production wells, including the closest horizontal well because of the low permeability of the shale matrix. The results from the monitoring program confirmed that there was not communication between wells and that the system was closed. Factors that are indicative of a closed system at the injection well include: (a) no significant increase of CO2 concentration at the offset production wells; (b) no detection of any fluorinated tracers at the offset production wells; (c) no increased pressure and flow rate at the offset production wells; (d) 97% CO2 in HW-1003 during soaking phase, indicative of a full wellbore; (e) leveled pressure in HW-1003 during soaking phase. Based on these results, it can be assumed that if the injection well were shut in after the CO2 injection, complete and permanent geologic CO2 sequestration could have been

achieved. Considering the increasing number of depleted shale gas wells, this demonstration test provides a feasible application for CO2 storage. It is worth noting, however, that rigorous screening criteria are recommended in order to permanently store CO2 in depleted shale gas wells while avoiding any potential leakage and environmental impact.

8.11.3 Enhanced hydrocarbon recovery

Once the well was brought back online after the soaking period, a significant increase in gas production occurred. During the first month of flowback, the average daily production rate was 123.9 Mcf/day, which is over 8 times the average production for the last month before the well was taken offline for injection (Fig. 19). After two years of flowback, the well is still flowing at an increased production rate but is close to the projected historical production rate (Fig. 20). The similar behavior of the injection well has been reported for modeling CO2 'huff-and-puff' test in shale-oil reservoirs (Chen, 2014). Had additional CO2 been injected and a higher wellhead pressure been achieved during the CO2 injection phase, a more sustained period of increased gas flow rate might have been achieved.

The CO2 concentration in the production gas has steadily declined during the flowback of the injection well and 41% of the injected CO2 had been produced by the end of 2015 (17 months after flowback started). The average daily production of CO2 for the last month of 2015 is 0.11 tons/day and declining. If the rate held constant, it would take over eight years to produce all of the CO2 injected. One important trend that was discovered during the flowback was that the natural gas liquids (NGLs) (ethane, propane, butane, etc.) composition was correlated to the CO2 composition and the heavier the hydrocarbon the greater that effect (Fig. 18). Methane composition had the opposite effect where it was inversely proportional to the CO2 composition. As CO2 composition decreased, methane composition increased, and the heavier hydrocarbons decreased. CO2 is mobilizing the increased concentrations of NGLs in the gas stream. This is significant because the value of wet gas with NGLs is greater than that of a dry gas with high methane composition. Additionally, the increased production of NGLs may alleviate condensate blockage in wellbores in liquid rich shale plays like the Bakken, Eagle Ford, Woodford, and Utica.

8.11.4 Recommendations

It is recommended that additional field laboratory research into Enhanced Shale Gas Recovery (ESGR) is necessary to reduce the existing gaps in data and information related to how and why ESGR, with associated CO_2 storage, can work. The reduction or elimination of gaps should be conducted in a manner that will advance the state of research in ESGR beyond Technology Readiness Level 4. Some of the near-term opportunities include:

1. Shale Injection Project with larger CO_2 volumes
    a. Establish a field laboratory test plan for Appalachia that will advance CO_2 storage and utilization to level TRL4 for shale
    b. Conduct tests on 2-5 wells

c. Focus on oil, condensate and NGL rich formations
d. Assess multi-well tests to guide engineering development and commercialization by varying injection schemes and soaking time
e. Conduct multi-injection CO_2 tests on a single well to understand if ESGR and CO_2 storage is repeatable in the same well

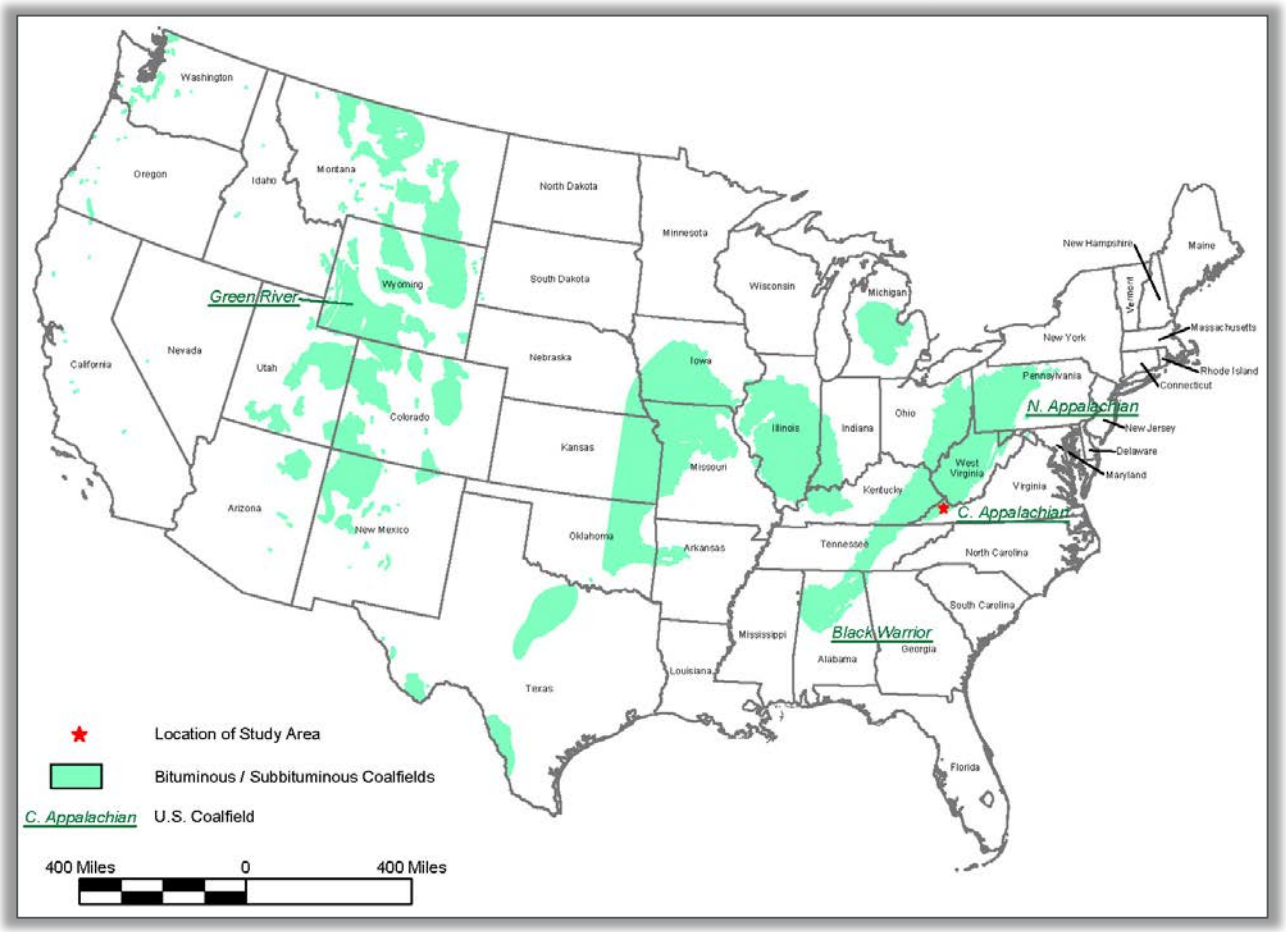
2. Hydraulic fracturing with CO_2 in Shale wells
    a. Establish a field laboratory test plan for Appalachia to assess hydraulic fracturing with CO_2
    b. Conduct tests on 2-5 wells
    c. Determine if production is enhanced with CO_2 fracturing
    d. Determine to what extent CO_2 is stored
    e. Determine if flowback CO_2 can be utilized for CO_2-EGR in the same or nearby wells

9 CBM Well CO_2 Injection Site: Buchanan County, VA

9.1 Overview

The CBM well injection site in Buchanan County, Virginia is the second location where CO_2 injection has recently been tested under this project (Figure 9-1). CO_2 was injected into three CBM wells from July 2015 through January 2017.

Figure 9-1 Index Map showing Location of CBM Study Area

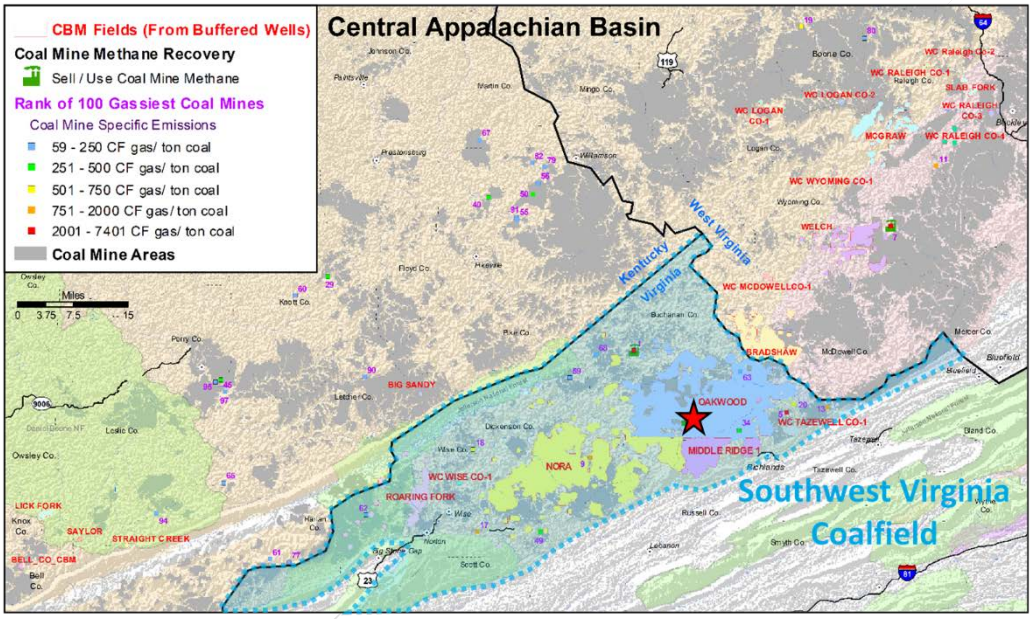


9.1.1 Oakwood Coalbed Methane Field

The Oakwood coalbed methane (CBM) field is located at the northeast margin of the Cumberland Overthrust Block, a large-scale geological feature in southwest Virginia that extends southwest into Kentucky and Tennessee (Figure 9-2). The Cumberland Overthrust Block contains significant fossil fuel resources, including the Southwest Virginia coalfield, which has an abundance of both mining and CBM operations (Nolde, 1995). Development of the overthrust block involved differential movement of up to seven miles along the Pine Mountain thrust fault, an extensive bedding plane-derived fault (Harris and Zietz, 1962). During transportation of the overlying block, rotation, warping, frictional dragging,

and crosscut structures contributed to complex internal deformation and resulted in localized folding, truncated beds, and duplicated beds (Harris and Zietz, 1962). Localized structural complexity has implications for the distribution and quality of coal bed methane resources.

Figure 9-2 Location of the Oakwood coalbed methane field within the Southwest Virginia Coalfield (modified after EIA, 2007; Nolde, 1995)



In the early 1990s, the Virginia Oil and Gas Board approved development of the Oakwood CBM field on 80-acre drilling units (Nolde, 1995). In the mid-2000s, operators began infill drilling programs, reducing units to approximately 40 acres per well. The primary operator in the south Oakwood field is CNX Gas. A typical well is cased and perforated at key intervals in the coal reservoir and then hydraulically fractured in vertical stages using nitrogen foam and sand proppant.

9.1.2 Geologic Background

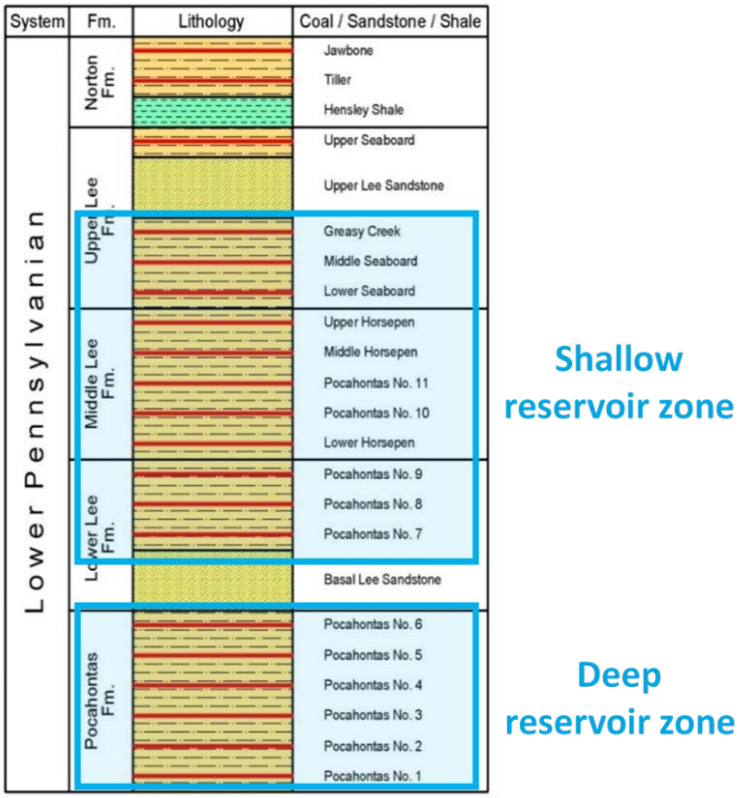
The Oakwood CBM field is one of the largest in the Southwest Virginia coalfield, covering portions of Buchanan, Tazewell, and Russell Counties. The southern margin of the Oakwood field is bounded by the Boissevain and Russell Fork faults. Here, the local geologic structure is characterized by gentle folds and small faults filled with calcite. Stratigraphic targets for coalbed methane drilling include 15-20 coal seams from the Early-Pennsylvanian Pocahontas and Lee formations (Figure 9-3). Individual seams vary in thickness but are typically less than two feet thick and are typically distributed over approximately 1000 feet in depth. A series of three tight shale units, including the 50-foot-thick Hensley shale, overlie the coal reservoir and are laterally continuous across the field, providing a stacked seal to vertical migration.

Eleven (11) principal coalbeds (belonging to the Norton, Lee, and Pocahontas Formations spanning an interval of approximately 1,035 feet) have been analyzed in this study (*Figure 9-3*). Associated coal splits

and carbonaceous shale strata have also been tested, including the following (in descending stratigraphic order):

- Greasy Creek seam
- Lower Seaboard seam
- Upper Horsepen seam
- Pocahontas No. 11 seam
- Pocahontas No. 10 seam
- Pocahontas No. 9 seam
- Pocahontas No. 7 seam
- Pocahontas No. 5 seam
- Pocahontas No. 4 seam
- Pocahontas No. 3 seam
- Pocahontas No. 2 seam

Figure 9-3 Generalized stratigraphic column for the Oakwood coalbed methane field. Shallow and deep reservoir zones are separated by the Basal Lee Sandstone (modified after Gilliland et al., 2013).

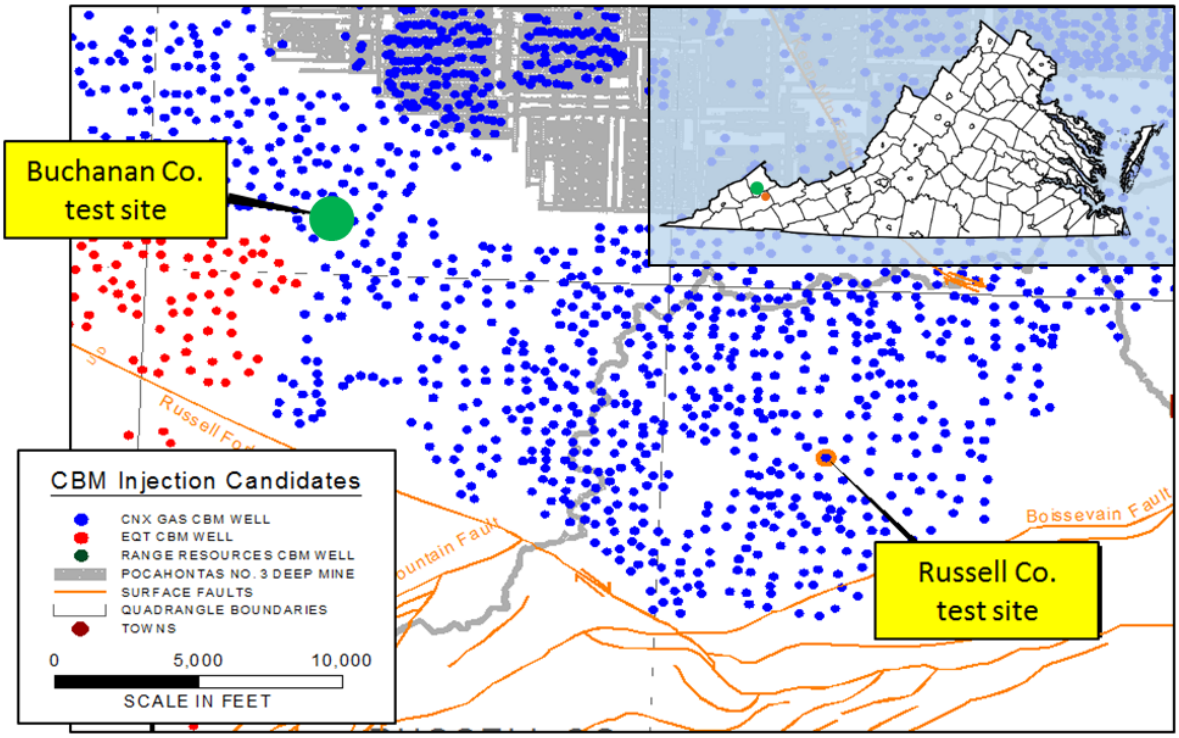


9.1.3 Russell County ECBM Test

A small-scale CO_2-ECBM validation test was conducted in the south Oakwood field at a site in Russell County in 2009 (Figure 9-4). A volume of 1000 tons of CO_2 was injected into a depleted CBM production

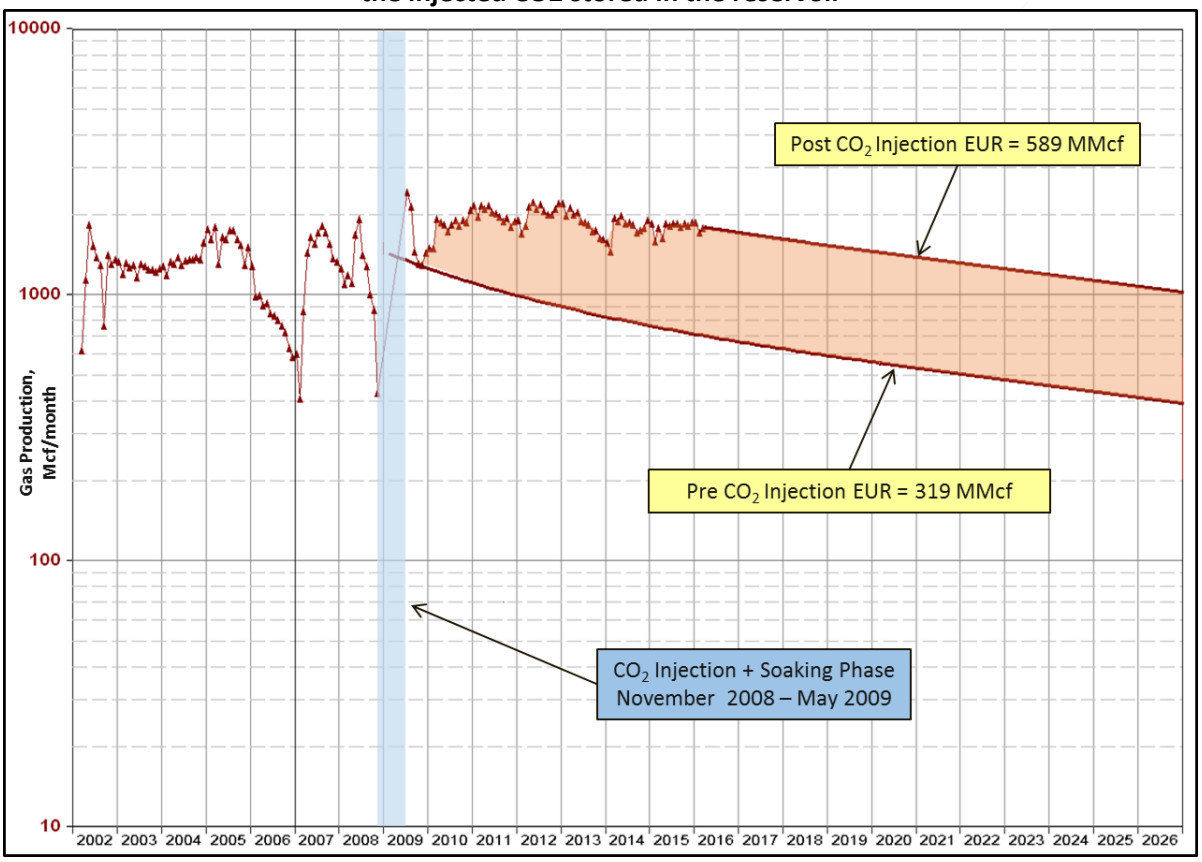
well over a one-month period. The well was then shut in for an additional one-month soaking phase, allowing the coal reservoir to adsorb CO_2 and desorb methane before flowback. The primary objective of this "huff-and-puff" injection technique is to enhance gas recovery from a depleted well, but a large fraction of injected CO_2 is stored in the process.

Figure 9-4 Locations of previous (orange) and active (green) CO2-ECBM field tests in the south Oakwood coalbed methane field of southwest Virginia



The injection test successfully enhanced recovery from the well, increasing the estimated ultimate recovery (EUR) for the well by 85 percent (Figure 9-5). To date, approximately 65 percent of the injected CO_2 volume remains stored in the reservoir. A comprehensive description of MVA results from the Russell County CO_2-ECBM test is provided in Ripepi (2009).

Figure 9-5 . Estimated ultimate recovery (EUR) for test well from 2009 CO2-ECBM test in Russell County, Virginia. The EUR for the well increased by 85 percent following the test with approximately 65 percent of the injected CO2 stored in the reservoir



9.1.4 Site Selection

The analyses of primary and alternative storage options for ECBM/sequestration sites were conducted previously in the regional Phase I and Phase II SECARB geologic characterization studies. Four CBM fields located in southwestern Virginia and two located in southern West Virginia were chosen for detailed characterization to determine the feasibility of supporting a large-volume test. The fields selected included the most promising structurally-controlled CBM fields (Frying Pan and Sourwood), non-structurally-controlled CBM fields (Bradshaw, Lick Creek and South Oakwood), and a horizontally-developed CBM field (Loup Creek) in the Central Appalachian region (Figures 9-6 and 9-7).

Figure 9-6 Detailed CBM Characterization Study Areas, Virginia

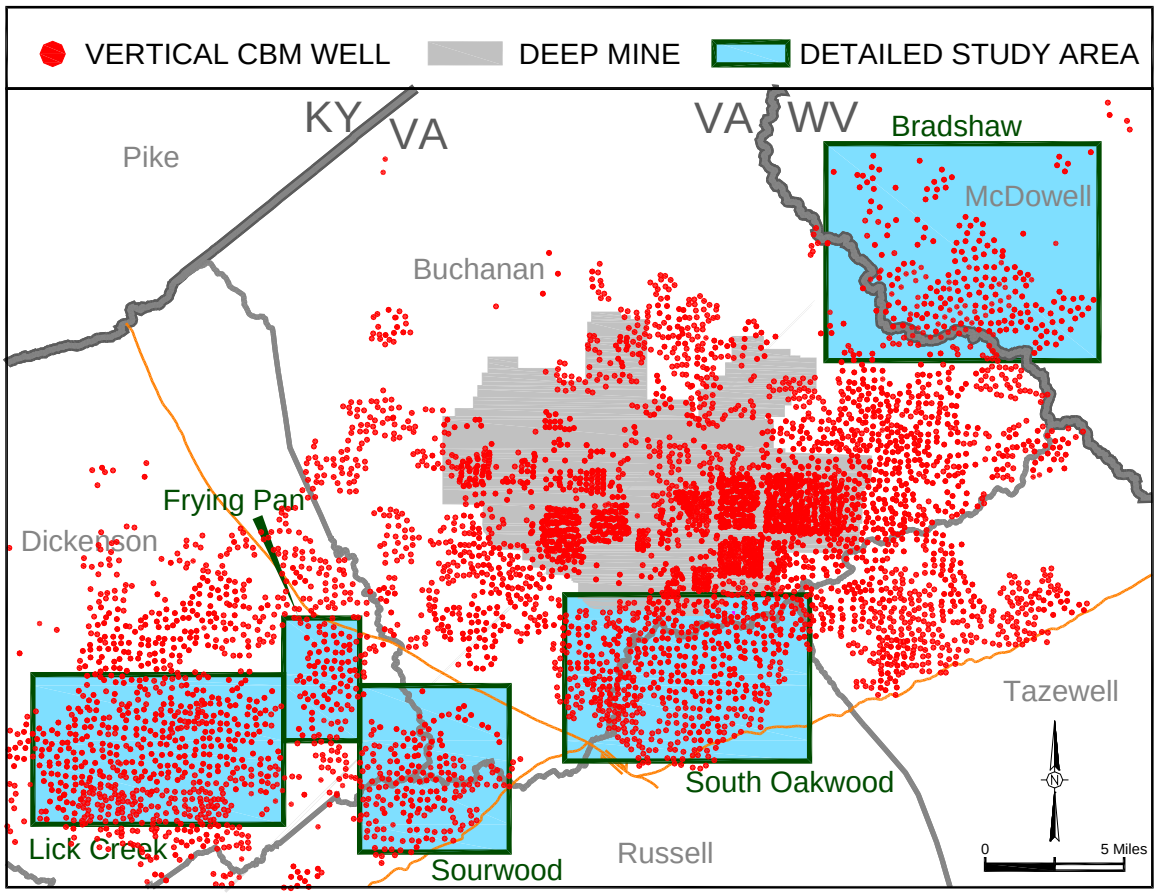
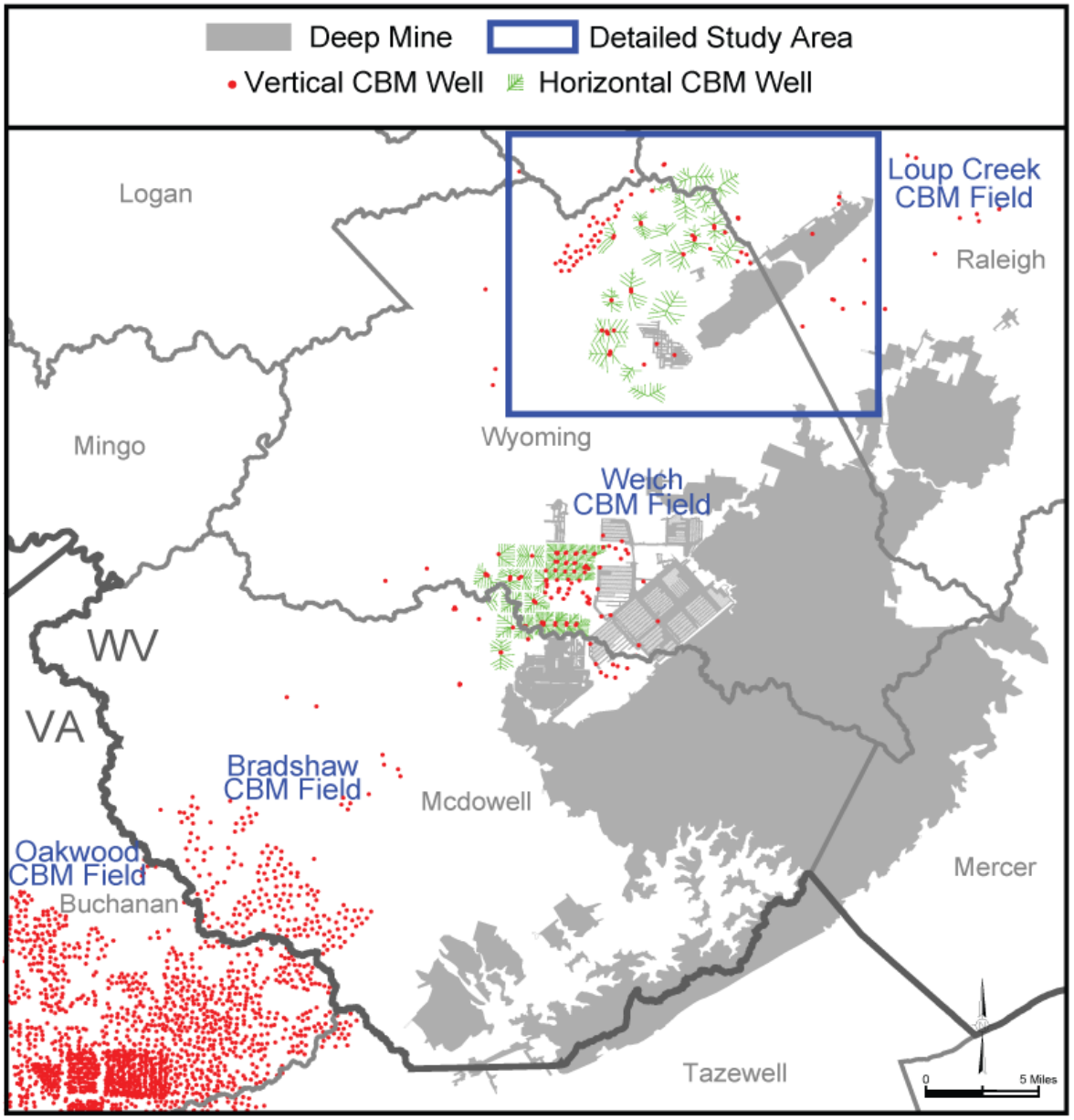


Figure 9-7 Loup Creek Field Study Area, West Virginia



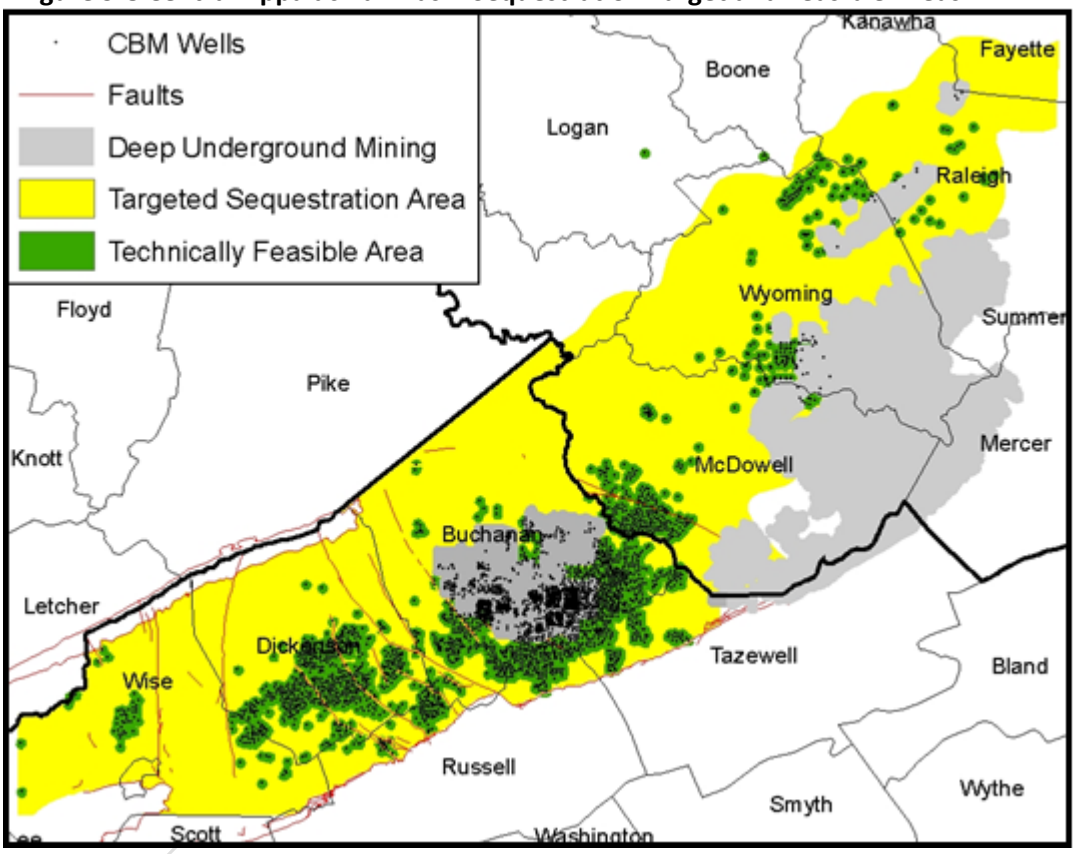
Ultimately, the South Oakwood field was selected for this ECBM/sequestration site as discussed in the following section.

Property

The primary objective was to define a general area that is prospective for CO_2 injection in Pennsylvanian-age coalbeds, primarily from a mature CBM producing area with a cooperative operator. The research team identified an initial CBM study area (Figure 9-8) with favorable geology, production characteristics, and likely storage capacities, and with a fairly-high state of CBM depletion. In addition,

this area has been very densely drilled by CNX Gas and EQT, thus providing adequate CBM subsurface data to characterize the target reservoirs.

Figure 9-8 Central Appalachian Basin Sequestration Target and Feasible Areas



The geologic and engineering data utilized in this initial assessment were derived from multiple sources, including published county reports, data and maps from industry and government agencies, and the published regional Phase I and Phase II SECARB geologic characterization studies. The evaluation also required the procurement of CBM databases, geophysical well logs, and CBM production data from the Virginia Division of Gas and Oil **(VDGO)**.

The research team conducted preliminary geologic analysis coupled with a review of the CBM reserve potential and state of depletion of the target coal seams to confirm the area has very favorable injection characteristics such as good storage capacity and coal permeability. Production data for approximately 70 CBM wells located in the selected CBM study area were processed and analyzed. MM&A conducted decline-curve analysis to determine the cumulative production, remaining reserves, estimated ultimate gas recovery, and state of depletion for each CBM well. After the initial analysis of these data, the research team met with CNX Gas senior management to locate properties with cooperative mineral owners within the defined prospective area.

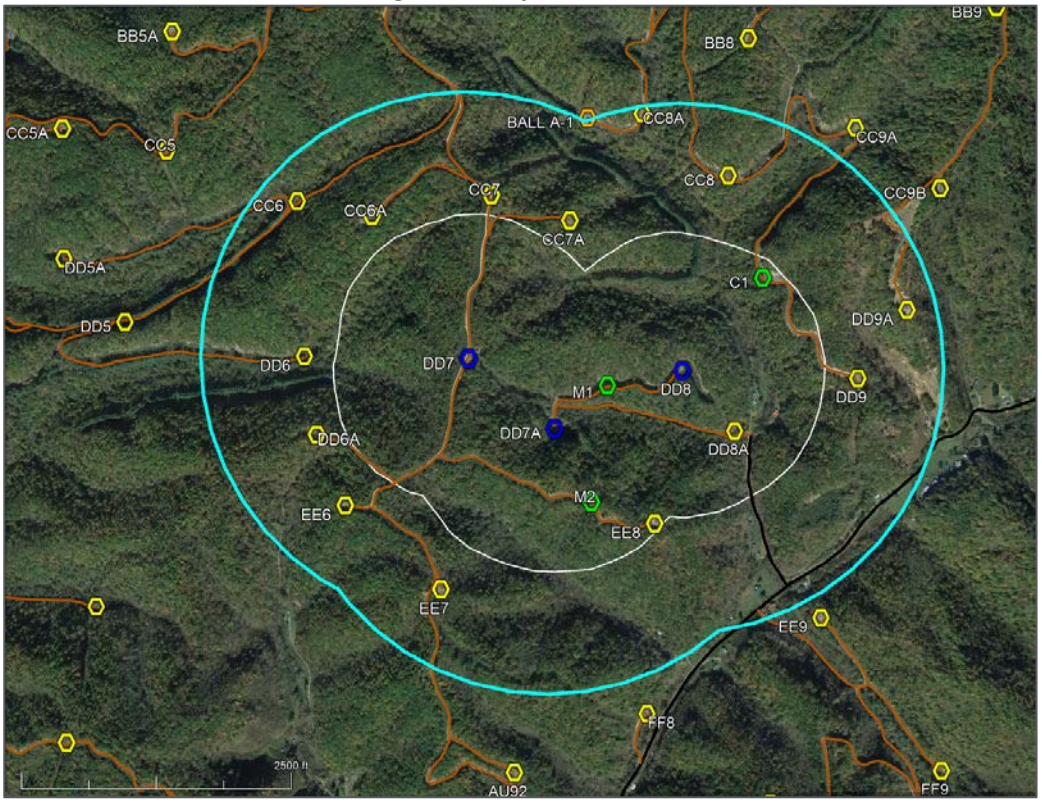
Site Suitability Analysis

The regional geologic characterization and CBM reserve analyses resulted in the screening and selection of several prospective areas for the CO_2 injection test. CNX Gas conducted an internal land review of the prospective areas and provided eight potential CO_2 injection well candidates from two primary test sites within the CBM study area. The technical review of the eight specific CBM wells provided by CNX Gas indicated favorable injection well candidates in terms of CBM production results, well integrity, existing infrastructure, surface logistics, and site access. The prospective wells are all located in areas with sparse population densities and away from deep mining activity in the Pocahontas No. 3 seam.

Mineral Control

During the test-site selection process, CNX Gas identified Harrison-Wyatt, LLC (**Harrison-Wyatt**), a company with large land and mineral holdings within the prospective test area. The research team reviewed Harrison-Wyatt's ownership position relative to the findings of the technical assessment. The team determined that there were numerous CBM well units located entirely on Harrison-Wyatt mineral tracts, that contain CBM wells with the geological and injectivity characteristics required for the proposed test. Preliminary reservoir modeling was conducted to confirm the prospective injectivity at CBM wells BB-8, CC-8, CC-9, DD-7, DD-7A, and DD-8 (Figure 9-9) and to predict the migration of the injected CO_2 plume from each of these prospective injection wells.

Figure 9-9 Injection area



The research team informed CNX Gas of the favorable characteristics of the Harrison-Wyatt tracts and a meeting was scheduled among CNX Gas, Harrison-Wyatt, Virginia Tech, and MM&A. The principal of Harrison-Wyatt and his associates were presented with the proposed injection test details at the ensuing meeting and expressed their solid support for the project. It was also explained that the converted CBM wells, to be used as CO_2 injection wells, would not generate revenue for the expected 12 to 18 months required for injection testing and subsequent shut-in monitoring. The research team agreed that any CBM wells converted for use as CO_2 injection wells would be returned to CNX Gas and could be converted back to CBM producing well status following the injection and shut-in periods.

Upon review of the modeled CO_2 plume expansion during the injection test and the requirements for drilling two to three monitor wells near the proposed CBM injection wells all four parties agreed to consider CBM wells DD-7, DD-7A, and DD-8, as the designated CO_2 injection wells. The selection of three wells for CO_2 injection was deemed necessary to ensure that the total volume of 20,000 tons of CO_2 could occur within the scheduled one-year time frame.

Surface Control

Most importantly, the three wells are also located on surface tracts owned by Harrison-Wyatt, thereby eliminating the need to obtain mineral and surface access agreements from different owners. MM&A and Virginia Tech personnel inspected the selected test site with CNX Gas personnel and determined that the DD-7 site would be sufficient for installation of necessary CO_2 tanks and injection, measurement, and monitoring facilities if the site were enlarged slightly. The project team enlarged the site by leveling the area of the original drilling pit which was part of the permit area. This area included over-grown brush and was eventually used to hold one CO_2 storage tank and the pump trailer. The test site area also had locations that required minimal development to drill monitoring wells. The M-1 and C-1 locations were sited alongside existing lease roads. The M-2 location was an existing, permitted drilling location that was developed by CNX Gas. Finally, there were existing pipeline right-of way between the injection site and the DD-7A and DD-8 wells which made for relatively easy installation of CO_2 pipelines.

Access

During a site visit, the project team along with the CO_2 supplier, Praxair Services, determined that the injection site had suitable road access for CO_2 deliveries. Throughout the project, Praxair mostly loaded product into transport trailers at Marmet, West Virginia. The main route included travel on Interstate 77 to US Route 460 in Princeton, West Virginia. The transport trailers traversed Route 460, a four-lane highway, to Vansant, Virginia. At this point, the deliveries continued on a two-lane state route for approximately six miles to the gas well lease road on top of the ridge. This state route included a mile-long, steep climb with several switch backs to reach the ridge. The two-mile long gravel lease road completed the product journey to the DD-7 injection site. Access to the M-2 monitoring well was along this same lease road and approximately a half mile beyond the injection site.

Access to the other two injection wells, DD-7A and DD-8, and the M-1 monitoring well was from another state route in the county. The gravel lease road was ¼ mile from Roy Ball Hollow Road off state route 600. The three wells were located along the mile-long lease road.

Finally, access to monitoring well C-1 was possible from two directions. The well could be reached by travelling approximately 3 miles along another lease road that branched off from the DD-7 lease road. Or access could be obtained off state route 620 at Ambrosia Road. Ambrosia Road is an approximately two-mile long single lane asphalt road that eventually widens to two-lanes and connects to a gas lease road. The lease road is approximately 3 miles long to the monitoring well.

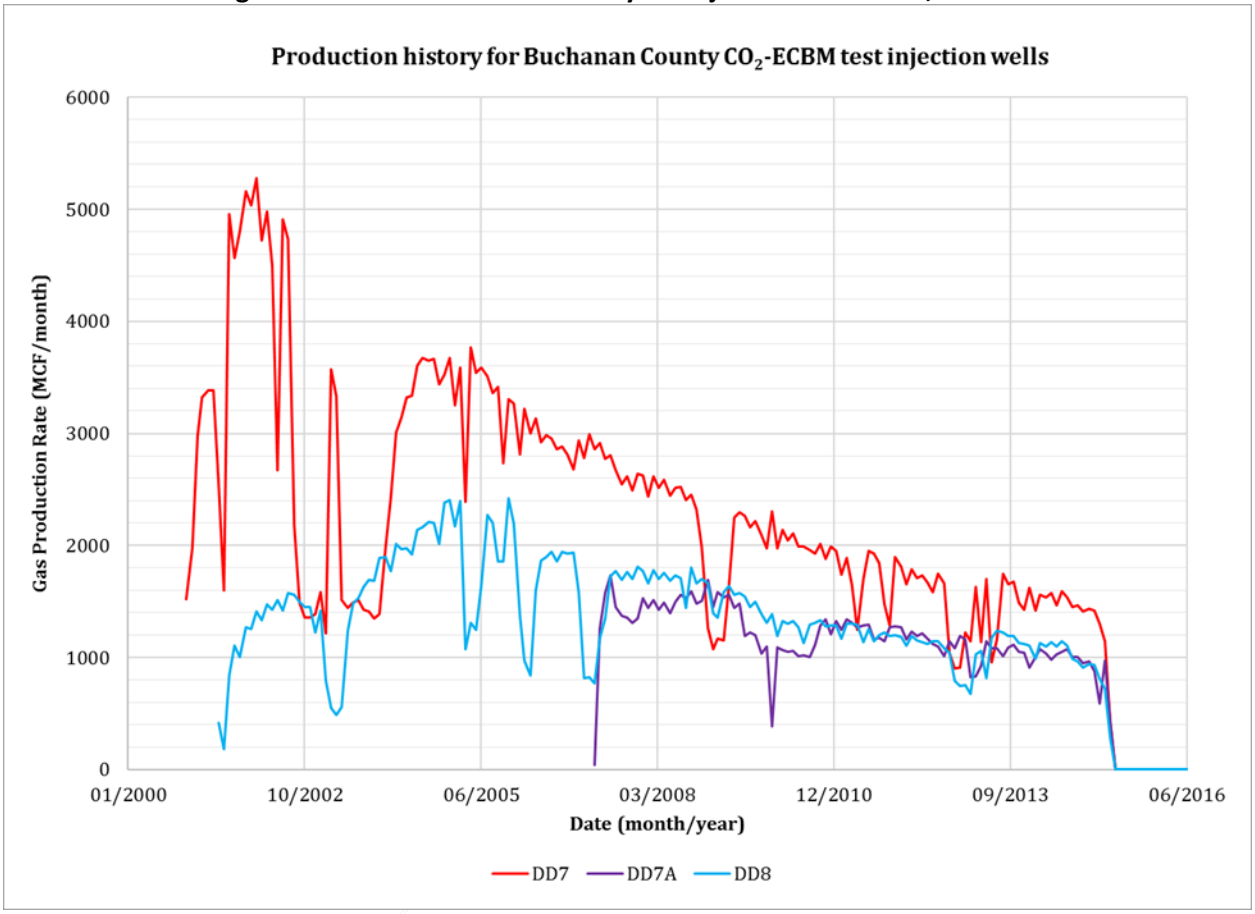
Each well site was sufficiently large enough to accommodate the various oilfield service company vehicles that assisted on the project. This included a drilling rig and associated equipment, tubing trailers, cement haulers and pump truck, well service rig, logging truck, and of course the CO_2 transport trailers.

Candidate Wells for Conversion

The final selection of the three injection well candidates, CNX Gas wells DD-7 (BU-1923), DD7A (BU-3337), and DD-8 (BU-1998), was based primarily on favorable mineral and surface ownership conditions. Furthermore, the potential test site is approximately 7.5 miles from the SECARB Phase II injection site (RU-84), which will facilitate data transfer and comparison to the CO_2 injection results of that test. Therefore, based on the mineral ownership, reservoir depletion, cultural setting, surface logistics, site access, lack of deep mining activity, and proximity to the Russell County test site, the selected CBM wells were deemed to be good injection-well candidates by our technical team.

The production history for DD7 shows superior production performance in comparison to DD7A and DD8 (Figure 9-10). The peak production rate of DD7 was 170 Mcfd, compared to only 56 Mcfd for DD7A and 78 Mcfd for DD8, and the average production rate has been consistently higher for DD7 over its lifespan. Despite being the oldest of the three wells, DD7 continues to produce at a significantly higher rate than DD7A or DD8. In the six months leading up to the test, DD7 produced at an average monthly rate of 1191 Mcf, compared to 798 Mcf and 768 Mcf for DD7A and DD8, respectively. The production history of DD7 suggests that it had a larger amount of original gas in place than DD7A or DD8. This could relate to conventional fluid migration on the Hurricane Creek Anticline or enhanced permeability due to local deformation.

Figure 9-10 Gas Production History for Injection Wells DD7, DD7A and DD8



9.1.5 Study Area

The property is located within the USGS 7.5-minute Vansant quadrangle of Buchanan County, Virginia, and consists of approximately 261.66 acres within the **Area of Review** (*AOR*) and an additional 511.32 acres, for a total of 771.98 acres within the **Monitoring Area** (*MA*). A list of the wells within the study area are summarized on *Tables 9-1* through *9-3* below. Within the MA, the following holes are present:

> 18 CBM wells

> 3 CO_2 monitoring wells

> 3 CO_2 injection wells (formerly CBM production wells)

> 1 brine injection well; and

> 3 desorption holes (2 of which were subsequently converted into CO_2 monitoring wells)

Table 9-1 8 Wells within Area of Review

Hole ID	State File #	Lithologic Data	Completion Date	Geophysical Log	Well Type
CB-DD7	BU-1923	Y	2000	MM&A / Weatherford	CBM Well / CO_2 Injection Well
CB-DD7A	BU-3337	Y	2007	MM&A	CBM Well / CO_2 Injection Well
CB-DD8	BU-1998	Y	2001	MM&A / Weatherford	CBM Well / CO_2 Injection Well
CB-DD8A	BU-3929	Y	2008	-	CBM Well
CB-EE8	BU-2072	Y	2001	MM&A	CBM Well
C-1	BU-5150	-	2015	Schlumberger FMI	CO_2 Monitoring Well
M-1	BU-5149	Y	2015	MM&A	CO_2 Mon. Well / Spot Core / Desorption
M-2 (CBM-EE7A)	BU-5056	Y	2015	MM&A	CO_2 Mon. Well / Spot Core / Desorption

Table 9-2 14 Wells within Monitoring Area

Hole ID	State File #	Lithologic Data	Completion Date	Geophysical Log	Well Type
BALL_A-1 (CB-CC7B)	BU-380	Y	1991	MM&A	Brine Injection Well
CB-CC6	BU-1480	Y	2000	MM&A	CBM Well
CB-CC6A	BU-3850	Y	2008	MM&A	CBM Well
CB-CC7	BU-1875	Y	2000	-	CBM Well
CB-CC7A	BU-3335	Y	2007	MM&A	CBM Well
CB-CC8	BU-0377	Y	2007	MM&A	CBM Well
CB-CC8A	BU-3599	Y	2008	MM&A	CBM Well
CB-DD6	BU-1743	Y	2000	MM&A	CBM Well
CB-DD6A	BU-3893	Y	2008	-	CBM Well
CB-DD9	BU-2092	Y	2001	MM&A	CBM Well
CB-DD9A	BU-4269	Y	2009	MM&A	CBM Well
CB-EE6	BU-1924	Y	2000	MM&A	CBM Well
CB-EE7	BU-1922	Y	2000	MM&A	CBM Well
CB-EE9A	BU-3942	Y	2008	MM&A	CBM Well

Lithologic data for all of the wells within the monitoring area (except C-1) is found within a database used to map seam thickness trends; and C-1 is located approximately 16 feet from CH-1-2014, which is in the lithologic database.

As shown below, *outside* of the MA are 39 additional CBM wells that are within the boundaries of the individual seam maps. Of this total, 22 wells are included within the lithologic database, while the remaining 17 wells have locations, but no lithologic information presently associated with them.

Table 9-3 39 Wells outside of Monitoring Area

Hole ID	State File #	Lithologic Data	Completion Date	Geophysical Log	Well Type
CB-AU92A	BU-4598	Y	2012	-	CBM Well
CB-BB5A	BU-3868	Y	2008	MM&A	CBM Well
CB-BB6	BU-1482	Y	2000	MM&A	CBM Well
CB-BB7	BU-0305	Y	1990 / 2007	-	CBM Well / Recompleted on latter date
CB-BB8	BU-0307	Y	1990 / 2007	-	CBM Well / Recompleted on latter date
CB-BB9	BU-0260	Y	1990	MM&A	CBM Well
CB-BB10	BU-0296	Y	1990 / 2007	MM&A	CBM Well / Recompleted on latter date
CB-CC5	BU-1973	Y	2001	MM&A	CBM Well
CB-CC9A	BU-2772	Y	2004	-	CBM Well
CB-CC9B	BU-3388	Y	2007	MM&A	CBM Well
CB-CC10	BU-0354	Y	1992	-	CBM Well
CB-DD5	BU-1950	Y	2000	MM&A	CBM Well
CB-DD5A	BU-3987	Y	2008	MM&A	CBM Well
CB-EE9	BU-3544	Y	2007	MM&A	CBM Well
CB-EE10	BU-3991	Y	2009	-	CBM Well
CB-EE10A	BU-2992	Y	2009	MM&A	CBM Well
CB-FF8	BU-2547	Y	2004	MM&A	CBM Well
CB-FF8A	BU-3629	Y	2007	-	CBM Well
CB-FF9	BU-2143	Y	2002	-	CBM Well
CB-FF10A	BU-3944	Y	2008	MM&A	CBM Well
VC-3956	BU-1473	Y	1999	-	CBM Well
VC-505181	BU-2359	Y	2002	-	CBM Well
CB-AU92	BU-4598	-	2011	MM&A	CBM Well / Not Evaluated
CB-BB5	BU-1456	-	2000	MM&A	CBM Well / Not Evaluated
CB-BB6A	BU-3939	-	2008	-	CBM Well / Not Evaluated
CB-BB7A	BU-3941	-	2008	-	CBM Well / Not Evaluated
CB-BB8A	BU-3696	-	2008	-	CBM Well / Not Evaluated
CB-BB9A	BU-3862	-	2008	-	CBM Well / Not Evaluated
CB-CC10A	BU-4102	-	2009	MM&A	CBM Well / Not Evaluated
CB-DD10	BU-3385	-	2007	-	CBM Well / Not Evaluated
CB-DD11	BU-3384	-	2007	-	CBM Well / Not Evaluated
CB-EE11	BU-2273	-	2003	MM&A	CBM Well / Not Evaluated / Shut-in
CB-EE12	BU-4807	-	2012	MM&A	CBM Well / Not Evaluated
CB-FF9A	BU-3628	-	2007	-	CBM Well / Not Evaluated
CB-FF10	BU-2240	-	2002	-	CBM Well / Not Evaluated
CB-FF11	BU-2232	-	2002	-	CBM Well / Not Evaluated
CB-FF12	BU-2142	-	2001	MM&A	CBM Well / Not Evaluated
CB-FF12A	BU-3764	-	2008	MM&A	CBM Well / Not Evaluated
VCP-3957	BU-1573	-	1999	-	CBM Well / Not Evaluated

As shown on *Map B8* in the *Appendix,* many of the gas wells on the property were drilled on an abandoned surface mine bench of the Kennedy seam; a few wells were actually drilled *through* abandoned underground mine workings in the same seam. All of the CBM wells located on the property are part of the Oakwood CBM Field which is laid out in an 80-acre grid pattern, within the Central Appalachian Basin. The monitoring area occurs primarily on portions of twelve 80-acre blocks:

> CC-6 through CC-9

> DD-6 through DD-9

> EE-6 through EE-9

Maps presented herein are shown in the NAD27 Virginia South State Plane Coordinate system.

9.2 Geologic Characterization

9.2.1 Regional Structure, Gas Content, and Stratigraphy of the Study Area

Regional Structural and Stratigraphic Framework

Structure

The study area is located at the northeastern edge of a well-known structural feature referred to as the Pine Mountain Thrust Sheet, or alternatively, the Cumberland Overthrust Block (depending upon author's preference), covering portions of Virginia, Kentucky, and Tennessee (See *A1* in the *Appendix* of this report). This structure has been widely studied and is recognized (as the name implies) by the presence of thrust faults, as well as strike-slip, and normal faults, and associated anticlinal and synclinal features, all of which warp and segment the strata in a moderately complex fashion within its boundaries.

For some investigators, the northeastern edge of the structure is defined along the Russell Fork Fault, while others extend the boundary further northeast to the Bishop-Bradshaw (aka Canebrake) Fault. The study area is located between these two faults (nearer to Russell Fork), north of the Boissevain Fault, and south of the Pine Mountain Fault.

Anticlinal and synclinal folds are prominent within the area of interest (some named, and many unnamed) including: Dry Fork Anticline (Byington, 2007), Hurricane Creek Anticline, Hurricane Creek Syncline, Pocahontas Syncline, and Sourwood Mountain Anticline. The CO2 injection site is located between the axis of the Hurricane Creek Anticline and Syncline. Many of the smaller-scale faults and folds are known or inferred largely through geologic observations from underground mines in the Pocahontas No. 3 seam.

Pine Mountain Thrust

Structural relationships associated with the Pine Mountain Thrust are illustrated in map view on the *Regional Overview Map* (*A1* in the *Appendix*) and in cross section view (after Henika, 1994 and Harris, 1981) within the *Appendix*, Figures *E5* and *E7*). The Harris section (*E1 – E2*) depicts the thrust fault ramping upward (from southeast to northwest) from the deeply-buried Cambrian Rome Formation, and extending through the entire stratigraphic section including the uppermost Pennsylvanian coal-bearing sequence to the surface, a vertical distance of more than 12,000 feet.

The Henika section (*C1 – C2*, perpendicular to Harris's section), depicts a portion of the Pine Mountain Fault as a decollement zone at the base of the Devonian (Chattanooga Shale), which likewise ramps upward through the Pennsylvanian section, with a detachment fault that occurs *within* and approximately *parallel* to bedding *within* the Pennsylvanian coal-bearing section, where it rises gradually eastward, and is exposed at the surface along the trace of the Bishop-Bradshaw (aka Canebrake) Fault.

While Henika does not specifically identify the location of the Pocahontas No. 3 seam on his section, it has been dashed herein and noted that the "true stratigraphic position of the seam in relation to the Pine Mountain Fault is uncertain; precise depths cannot be determined at this scale of presentation." As depicted on *C1-C2*, the Pine Mountain Thrust Fault underlies the Pocahontas No. 3 seam, and could be within a few tens or hundreds of feet below it.

Structural Features Observed in Coal Mines

In a study of geologic conditions related to coal mine roof falls within mines located in nearby Wise County, Virginia, Milici (1982) describes various structurally-related features associated with the Pine Mountain Thrust Sheet (mines located approximately 20 to 25 miles from the study area), including the following:

> Bedding parallel faults (decollements) within or at the top of coal beds; with thin zones of intensely crushed, abundantly slickensided rock; occasionally beds duplicated by faults; beds inclined either toward or away from the direction of tectonic transport; and faults associated with sub-horizontal sliding that are both extensional and contractional.

> Low- to moderate angle faults within coal beds or in the immediate roof

> Folded beds associated with faulting within coal beds or in the immediate roof; drag folds are commonly associated with contractional faults; small horsebacks to elongate features (tens of feet long) may extend upward into the roof a few tens of feet as well.

> Broad, gentle folding of individual coal beds.

Furthermore, Byington (2017) evaluated the influence of fracture systems affecting coal mine roof stability which were associated with the Pine Mountain Thrust Sheet across all of southwestern Virginia. At the Buchanan No. 1 Mine (within 10 miles of the study area), he specifically notes several small-scale structures:

> Intra-seam shear zones occurring above the coal seam near the contact with the immediate roof of the Pocahontas No. 3 seam.

> Extension fractures and roof fall occurrences that occur in swarms cutting diagonally across the entries.

Similar to published observations from underground mines in Buchanan, Dickenson, and Wise Counties, Virginia, Wickline has been tracking the locations and orientations of "slick-slip" features, otherwise known as "horsebacks", at Buchanan No. 1 Mine which are pyramidal-shaped roof fall areas believed to be a result of thrust faulting. Structural features, such as described by Milici and Byington, have most recently been observed (October 2017) as illustrated on *Figure 9-11 below* including:

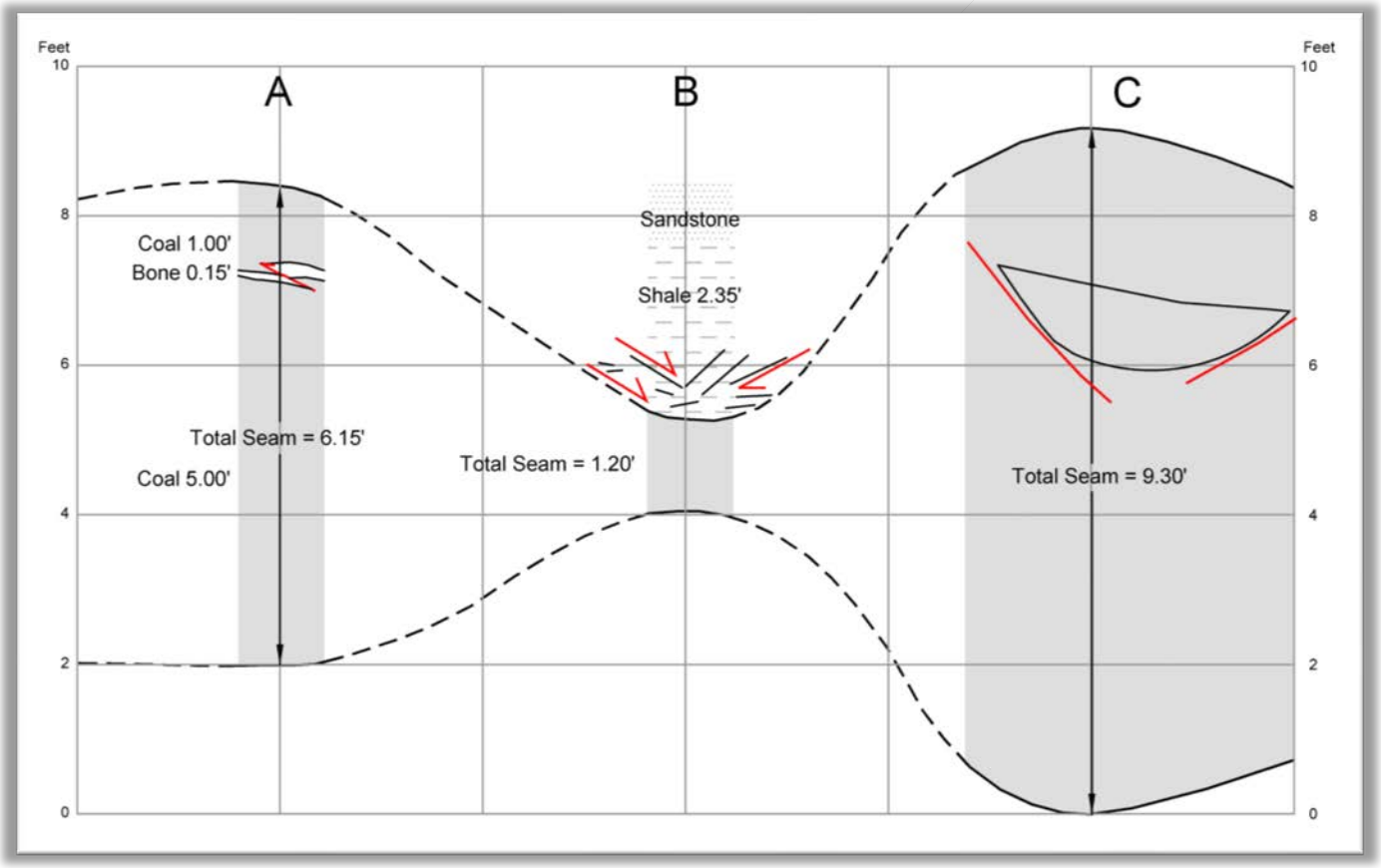
> Rapid, localized changes in seam thickness, some of which may be attributable to structural/tectonic influences; where average seam thickness may typically be on the order of 6.0

feet (*Location A* below), thickening to 9.3 feet (*Location C*), or thinning (but *not* scoured) to 1.2 feet thick (*Location B*), within a horizontal distance of approximately 1,600 feet.

> Intra-seam, low-angle shears (*Location A*).

> Horsebacks *(*see *Figure D9* in the *Appendix)* and other types of fractures (*Location B* below) within the immediate roof.

Figure 9-11 Schematic Diagram of Structural and Stratigraphic Relationships – Buchanan No. 1 Mine – (Observed in October 2017)



Smaller Scale Faults

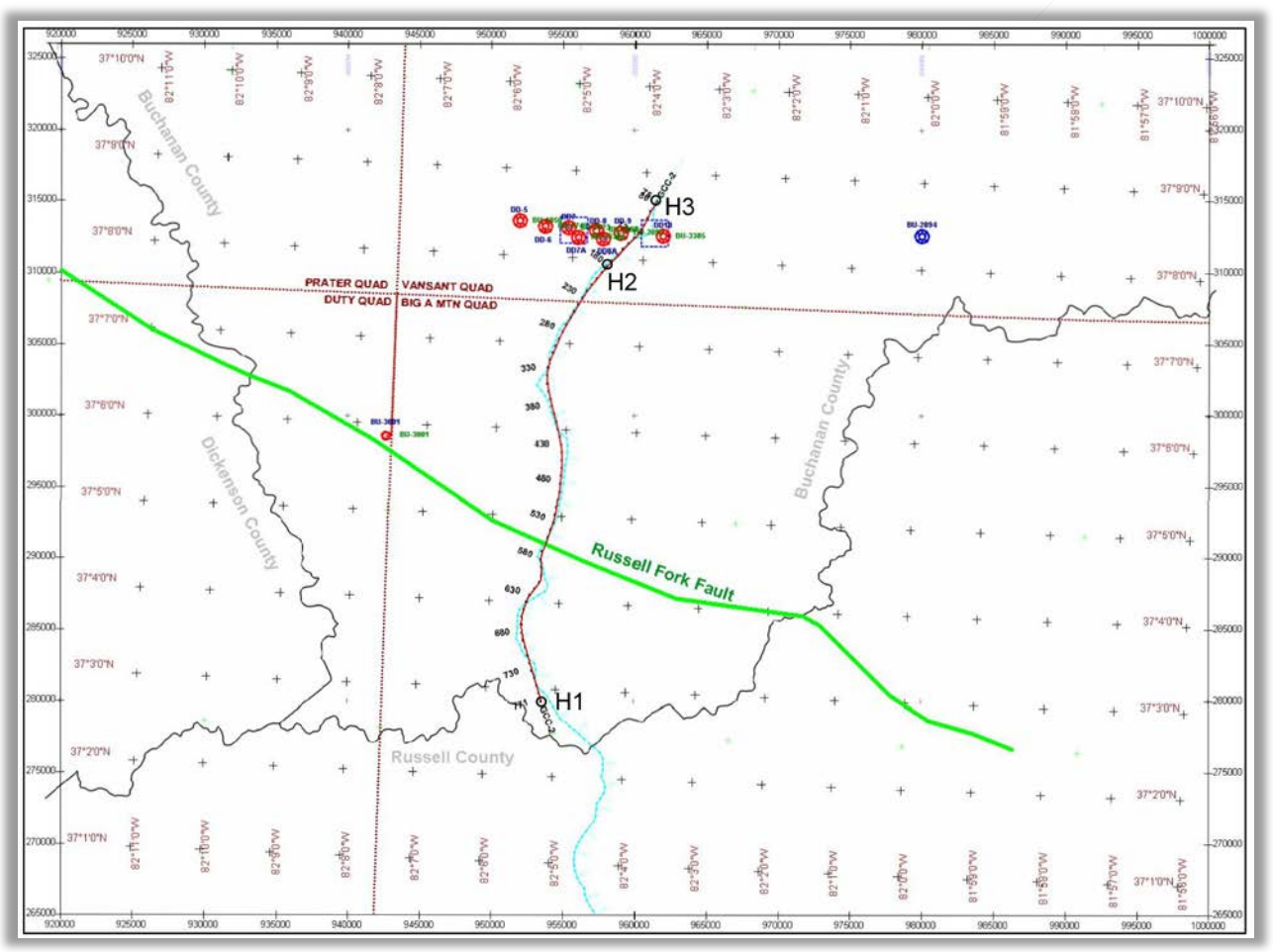
Numerous secondary northwest-trending faults (named and unnamed) are located within the region including (approximately parallel to the Russell Fork strike-slip fault): Keen Mountain, VP-3, VP-8, Pistol Gap, Little PawPaw, and Jess Fork fault. The Keen Mountain fault has been extensively reported in the literature and has been well documented from both surface and underground exposures, as well as through radar (**Side-Looking-Airborne-Radar** or ***SLAR***), and satellite (LANDSAT) imagery.

As shown on *Appendix Figure A4*, seven locations (identified as *A* through *G*) exhibit a moderately strong correlation / parallelism between mapped faults, floor gas outbursts, and lineament features, which have been identified by means of satellite and radar imagery.

Analysis of Seismic Data within Study Area

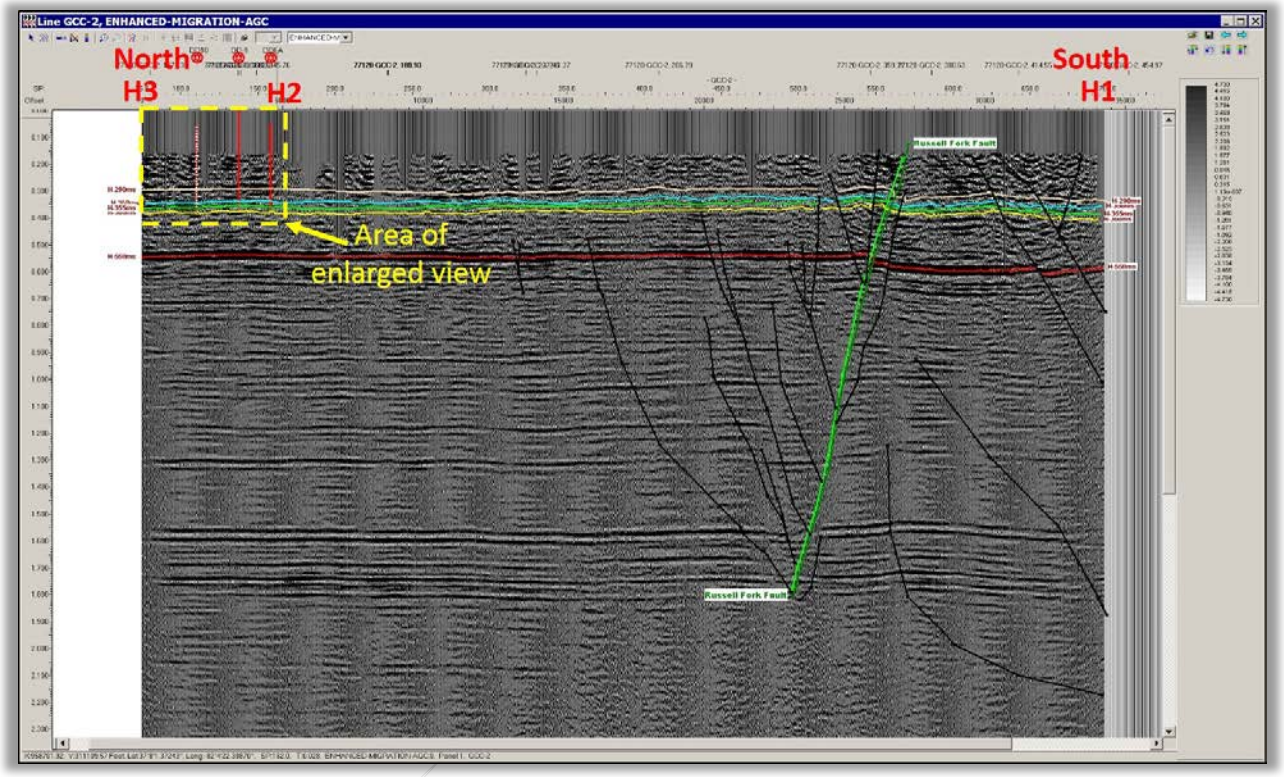
Sandia Technologies, LLC and Virginia Tech (2013) participated in a collaborative effort to reprocess and analyze 2-D seismic data acquired along a line (see *Figures 9-12* through *9-14* below) which passes through the injection test area.

Figure 9-12 Location of 2-D Seismic Line (after Sandia, 2013)



As shown on *Figure 9-13* below, the Russell Fork Fault (and associated smaller scale faults) has been interpreted from seismic data, the trace of which is approximately 3 miles south of the injection area.

Figure 9-13 2-D Seismic Line: Synthetic Model generated with Time-to-Depth Ties and Formation Picks with location of Russell Fork Fault (green) on right; location of Enlarged View (yellow) for *Figure 4-4* shown on left (after Sandia, with North on left).

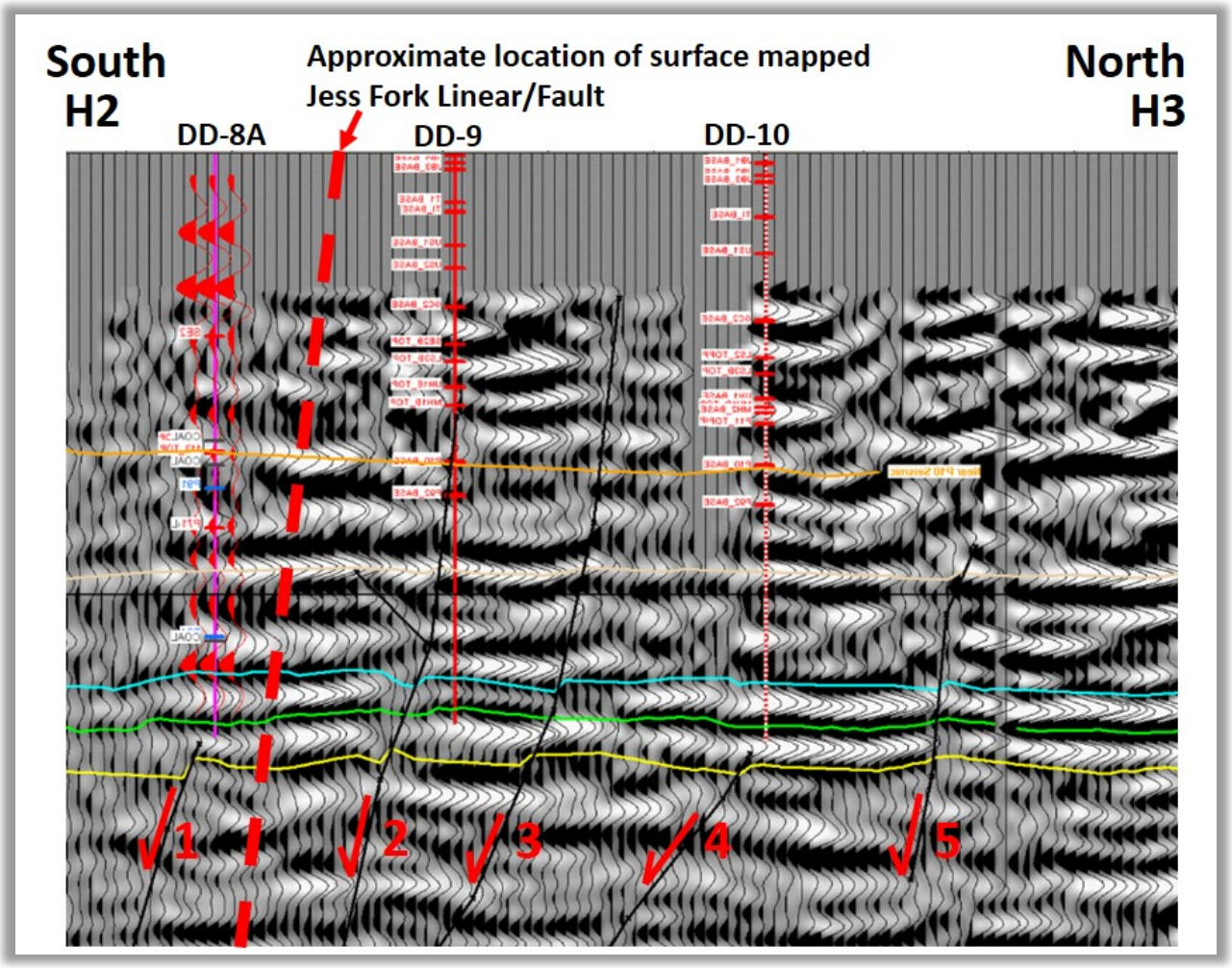


In a more detailed view (*Figure 9-14* below), imaging appears to define the existence of minor faulting at the northern end of the seismic line, which have been identified with numbers 1 thorough 5. Within the depth range tested from wells displayed within 1,800 feet of this seismic line, these 5 seismically-indicated fault discontinuities appear to have normal fault throws of less than 30 feet (numbers and red arrows have been added to the exhibit for clarity). The horizontal width of this zone is approximately 3,700 feet.

Alternatively, the appearance of these seismic reflections might also be explained as arising from shallow velocity statics, possibly due to the irregular crooked-line nature of the seismic acquisition geometry and may therefore represent shallow formation lithologic and alluvial variations not completely corrected for by processing.

However, in addition to the original information shown on the seismic section, the approximate location of two surface-mapped features, referred to herein as the Jess Fork Linear and the Jess Fork Fault (see *Map A6* in the *Appendix*), have also been superimposed on *Figure 4-4*. Heretofore, the existence of this fault zone (and the unknown amount of displacement associated with it) at that location had been questioned; the presence of the linear feature, however, is not in doubt.

Figure 9-14 Enlarged View of Northern End of Seismic Line with Interpreted Fault Locations (after Sandia, image has been modified with reversed viewing direction, with North on the right)

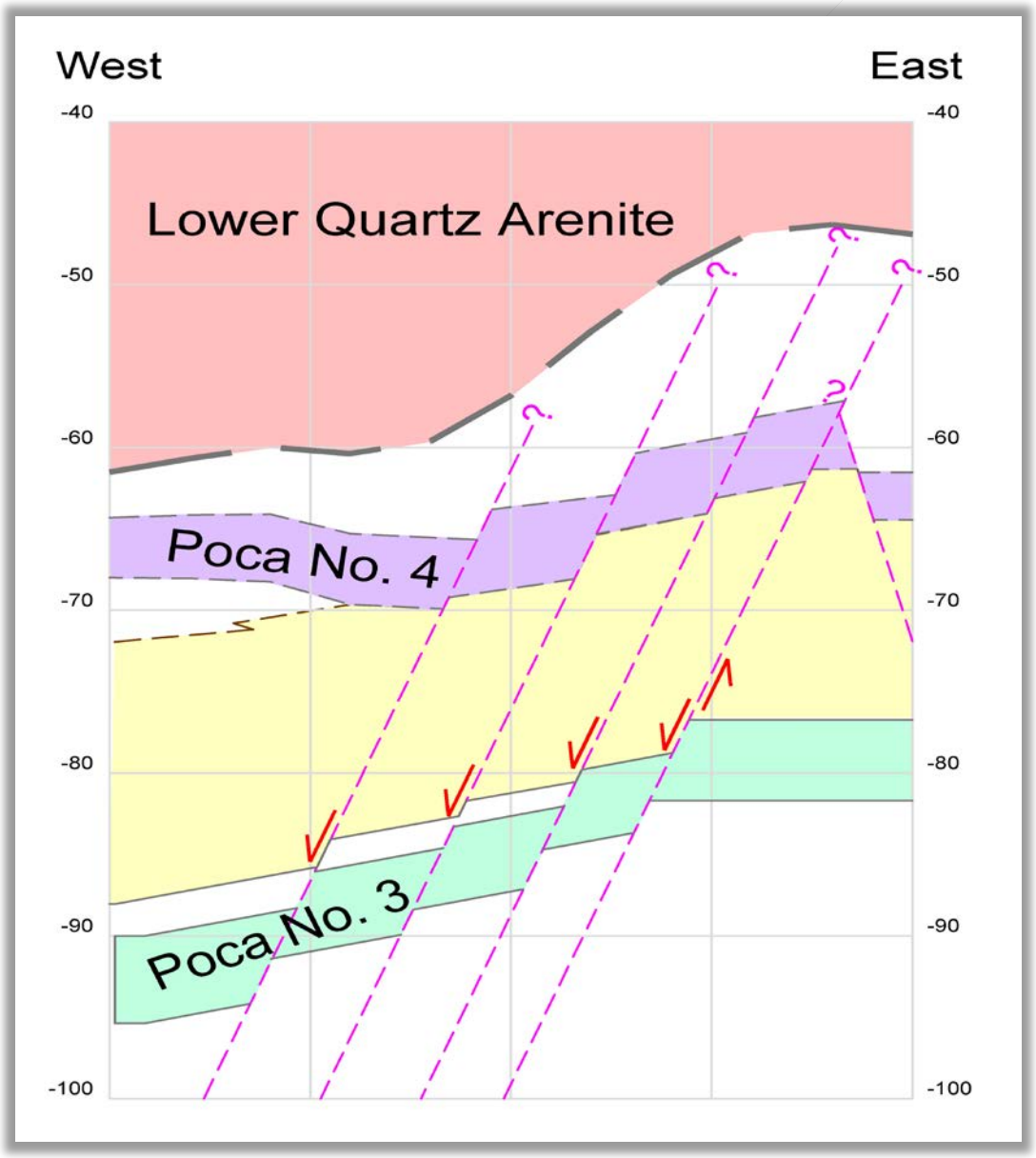


As part of this investigation, structural information from multiple sources has been compiled and analyzed from areas surrounding the injection site. One such feature, referred to herein as the VP-3 Fault, is located approximately 6.2 miles north of the study area (see *Figure 9-15* below, and *Figure E9* in the *Appendix*). With closely-spaced in-mine floor elevations, engineers at the mine described a slickensided displacement zone approximately 1,200 feet in width oriented at N 30° W, within the Pocahontas No. 3 seam.

If mining had continued advancing westward, the width of this zone may have been broader, but there is no structural data to extend the fault zone beyond the edge of the mine. Within that zone, mine floor elevations vary from approximately 82 to 95 feet below sea level, with indications of a small-scale horst and graben feature, and down-to-the southwest normal faults. The VP-3 Fault is suggested as an analog for the structure believed to be present within the study area.

Taken together, evidence from the above recited sources would suggest the probability that as many as 5 small-scale, *en echelon* normal faults (see *Figure A6* in the *Appendix*) are present within the subsurface of the study area, notwithstanding the lack of field mapping to confirm the presence and locations of these faults at the surface. Nevertheless, in conjunction with other information, the fault displacements suggested by the seismic data and nearby VP-3 Fault appears to be the more likely explanation of structural conditions within the study area.

Figure 9-15 Cross Sectional View of VP-3 Fault (see also Exhibit E9 in the Appendix)



Potential Basement Influence Upon Gas Content

Nearly seventy years ago, Wanless (1939) suggested that faults associated with the Pine Mountain Thrust may have been contemporaneous with Pennsylvanian sedimentation. Furthermore, directly *west* of the injection site, some investigators (McClure, 1990 unpublished master's thesis) have speculated that possible basement anomalies shown on the aeromagnetic map of Virginia (see *Appendix Figure A7*) may have been contemporaneous with and impacted sedimentary patterns within Pennsylvanian coal-bearing strata on the thrust sheet.

Moreover, in other studies of geophysical data in the Appalachian Foreland of Pennsylvania, Root (1977) has also shown that discontinuities in the basement are indicative of basement faulting that can be related to smaller-scale, shallower structures (faults and folds). While the level of precision of the magnetic data is relatively low, there is an interesting relationship between areas of greater magnetic intensity (*Map A7*) to elevated thermogenic gas contents in the Pocahontas No. 3 seam (*Map B4*) in the region.

If there is indeed some cause and effect relationship between elevated gas contents and aeromagnetic trends, this could be suggestive of a higher paleo-geothermal gradient arising from a poorly defined basement feature, with overlying coal beds having been subjected to greater metamorphism. Such an effect would result in higher-rank (Low-volatile Bituminous) coals with associated elevated levels of thermogenic methane. Further analysis of this possibility, or other alternative explanations, is recommended.

9.2.2 Lineaments

Lineament mapping and analysis have been widely used as an aid in a variety of natural resource exploration and exploitation programs. Despite the lack of consensus on lineament genesis, geologists have been using lineaments successfully as an exploration tool for a number of decades. Their application is well known in the search for oil and gas (especially in the Appalachians), prediction of potentially fractured strata in coal mines, and for a variety of mineral assessments worldwide. Moreover, it is only recently that lineament studies have been applied to exploration and production in coalbed methane.

The non-genetic term "lineament" or "linear" is used by photogeologists to describe a naturally occurring, reasonably linear or slightly curved alignment of topographic features such as drainage courses, escarpments and sags, saddles, tonal variations in vegetation and soils, or combinations of these, observed on imagery either directly in exposed rocks or indirectly as surface traces in overlying materials. Linear ridge crests, strike of bedding, and cultural features are excluded, as are joints. Lineament synonyms include topographic linears, photo linears, megajoints, micro and macro fractures and fracture traces. Although the causative mechanism is unclear, virtually all workers cite the following characteristics of lineaments:

1. Lineaments are naturally occurring and obvious features of the landscape, which are present on all continents and exhibit systematic patterns in two or more azimuth sets generally separated by approximate angles of 45 to 90 degrees.
2. Lineaments are quite similar to joint sets but on a far larger scale, because lineaments are not restricted to a particular lithologic unit or individual geologic structure. Moreover, lineament trends persist and often transect great stratigraphic columns and a variety of geologic structural features.
3. Lineaments at the surface exhibit traces that are linear, or slightly curvilinear, and vary in length from a few kilometers to tens or hundreds of kilometers.
4. Lineaments in cross-section are *assumed* to extend vertically, or nearly vertically, in the earth's crust for a few hundred meters to several kilometers, depending upon their length.
5. Lineaments rarely exhibit relative displacements between the two walls of the fracture; therefore, few of them can be classed as faults.

Based upon interpretative assessment of the ease of feature recognition, at differing levels of imagery enlargement and enhancement, MM&A has found it useful to categorize linears into one the following reliability classifications:

> **Primary lineament**: easily recognized feature requiring minimal, if any, mechanical enhancement of imagery; reflects maximum recognized strength, length, and consistency; suggests greatest potential impact on associated stratigraphy.

> **Secondary lineament**: expression not as easily pronounced as primary feature, recognition may require enhancement, but feature appears to display significant strength, length, and consistency; suggests moderately high stratigraphic impact potential.

> **Tertiary lineament**: very weak imagery expression, difficult recognition; requires maximum enhancement of imagery; reflects least strength, length, and consistency; suggests minimal potential impact on stratigraphy unless combined in intersection with other lineaments.

Compositing multiple imagery sources and published reports, lineaments are displayed across the area of interest (see *Appendix Figures A4, A5,* and *A6*). *Field work is necessary to verify the strength and validity of the lineaments; however, as part of this investigation, field work has not been conducted at the Site*. It should also be clearly noted that the variable width associated with these three classes of lineaments *as shown on the maps* is *not* intended to imply actual width in the field, as *width* cannot be estimated from the available imagery.

One of the linears, identified at A – C, also demonstrates a remarkable coincidence with a pronounced seam splitting / thinning trend in the Pocahontas No. 3 seam, as well as with the VP-8 Fault, suggesting the possibility of faulting contemporaneous with deposition of this seam. The Keen Mountain Fault, VP-8 Fault, and Pistol Gap Fault are all observable as linear features from satellite imagery.

As shown on *Map A6* in the *Appendix*, five linear features traverse the AOR, identified below ("*P"* for "primary", "*S"* for "secondary", and "*T"* for "tertiary" linear features).

> P1 – P2

> S1 – S2

> S3 – S4 (also referred to herein as the Jess Fork linear)

> T1 – T2

> T3 – T4

A lineament identified as the Jess Fork Linear (S3-S4) is nearly coincident with the Jess Fork Fault (discussed in *Section 4.1.1.3* above). Monitoring well C-1 is within approximately 100 feet of linear feature S1 – S2, and injection wells CB-DD7 and CB-DD8 are within approximately 150 feet of P1 – P2.

1991 MM&A Lineament Study

Although the original 1991 lineament study conducted by MM&A does not extend across the AOR, relevant information presented therein has been incorporated within this evaluation, specifically regarding the orientation of primary lineaments within the nearby Keen Mountain area. Results of this study are discussed in *Section 4.2.3* below.

9.2.3 Stress Fields

As noted previously, a significant number of geologic and mining-related studies have been conducted in Buchanan County of relevance to CBM production. *Table 9-4* below summarizes data from various studies in the region with respect to directional geologic features within the following general categories:

> Horizontal compressive stresses / hydraulic fracture orientation / borehole breakout

> Localized and regional structural trends / face and butt cleat

> Paleo-stress directions / lineament trends / underground slickenside trends

Studies by two investigators (McCulloch et al, 1974, and Campoli et al, 1990) were conducted at two Pocahontas No. 3 seam longwall mines (Beatrice and VP-3), formerly operated by Island Creek Coal Company. These studies were primarily focused upon identification of multiple geologic conditions that might have an adverse impact upon mine development and safety, including horizontal stresses.

Based upon surface and underground mapping, Byington (2007) examined the presence and orientations of coal cleat, fractures, joints, faults, folds, and horizontal stresses across a large portion of the southwest Virginia coal fields, including underground visits at two Pocahontas No. 3 seam longwall mines, Buchanan No. 1 and VP-8.

In addition to the above published data, two holes drilled within the study area, CH-1-2014 and C-1, were geophysically logged by MM&A and Schlumberger, respectively. Through borehole breakout analysis, horizontal stress directions are inferred, and in both holes, results demonstrate some consistency with published information.

Table 9-4 Compilation of Paleo-Stress and Current (Horizontal) Stress / Structural Features

Location	Miles from Injection Site	Parameter	Orientation	Data Source
Northeast Quadrant				
VA / KY / WV	59 / 48 / 71	Horizontal Compressive Stress	Maximum Principal: (N 55° - 66° E)	Zoback, 1989
VP-3 Mine	6.6	CBM Well Hydraulic Fractures	Range: (N 55° - 57° E)	Island Creek, 1997
Buchanan Mine	12 / 15	Observed UG Hydraulic Fractures	Range: (N 56° - 61° E)	Wickline/VT/MM&A, 2016-17
Beatrice Mine	5.5	Butt cleat	Range: (N 60° - 75° E)	McCulloch, 1974
Monitoring Well C-1	0.0	Horizontal Compressive Stress	Maximum Principal: (N 70° E)	Schlumberger, 2015
VP-3 Mine	5.3	Horizontal Compressive Stress	Maximum Principal: (N 76° E)	Campoli, 1990
Keen Mtn Area, VA	NA	Primary Lineament Trend	Secondary Direction: (N 60° - 65° E)	MM&A, 1991
SW Virginia	NA	Horizontal Compressive Stress	Maximum Principal: (N 74° E)	Byington, 2007
Dry Fork Anticline	NA	Fold Axial Trend	Average: (N 61° E)	Byington, 2007
D2b Anticlines	NA	Intermediate Paleo Stress	Mean: (N 76° E)	Byington, 2007
Buchanan Mine	12 / 14	Observed UG Slickenside Trend	Range: (N 46° -76° E)	Wickline/MM&A, 2016-17
Southeast Quadrant				
VP-3 Mine	5.0	Horizontal Compressive Stress	Minimum Principal: (S 16° E)	Campoli, 1990
D2b Anticlines	NA	Maximum Paleo Stress	Mean: (S 14° E)	Byington, 2007
Northwest Quadrant				
Beatrice Mine	5.5	Face cleat	Average: (N 18° W)	McCulloch, 1974
CH-1-2014	0.0	Borehole breakout	Range: (N 15° - 30° W)	MM&A, 2014
Keen Mtn Area, VA	NA	Primary Lineament Trend	Dominant Direction: (N 20° - 25°W)	MM&A, 1991
D2a Faults	NA	Maximum Paleo Stress	Mean: (N 25° W)	Byington, 2007
VP-3 Mine	6.2	Localized Fault & Structural Trend	Average: (N 30° W)	MM&A, 2015

Horizontal Compressive Stresses

As itemized in *Table 9-4* above, horizontal compressive stress directions have been reported from multiple sources across the region and occur within a range of 21°, varying from N 55° E to N 76° E, for the maximum principal stress direction.

Measurements of Hydraulic Fractures from an Underground Mine

Given the relatively broad range (21°) of stress field measurements in the region, personnel from Virginia Tech, Coronado Coal Company, and MM&A conducted several underground inspections of fractures from hydraulically-stimulated CBM wells. These were observed in the Buchanan No. 1 mine at 5 locations (see *Appendix Figures A1*, and *D1* through *D6*).

At 4 of the 5 locations, sand-filled fractures (or "*fracks*") were observed (typically vertical in nature), but at one site, both horizontal *and* vertical fracks were present (See *D6* in the *Appendix*). (In the interest of full disclosure, a sixth site was visited where no hydraulic fractures were observed, however, all other sites visited provided positive identification of fracks). Photographs of a sand-filled vertical fracture associated with CBM Well are found on *Figures D2* and *D3*. Average maximum length of a single *observable* frack wing is within approximately a 125-foot radius from the well bore. In comparison, previous investigators (Diamond, 1987) report vertical frack lengths at 16 US underground locations ranging from 5 to 416 feet, with only three greater than 200 feet in length, and 11 less than

100 feet in length. CM operators seem generally to assume a maximum frack radius of 500 feet from the well bore, which, based on the above observations, may be somewhat overly optimistic.

The orientation of these observed fractures occurs within a moderately narrow range of 5°, from N 56° E to N 61° E; all are located within 12 to 15 miles of the CO_2 injection site. Because hydraulic fractures theoretically propagate parallel to the horizontal compressive stress field, the best estimate of the average maximum principal horizontal compressive stress direction is ~N 60° E (+/- several degrees); the minimum principal horizontal compressive stress direction is assumed to be perpendicular to it, or ~N 30° W.

Coal Cleat Alignment with Stress Field Vectors

When present, naturally-occurring (nearly vertical) fracture patterns found within coal beds are referred to as "cleat", typically described as "face cleat" for the more dominant direction, and "butt cleat" for the less-pronounced direction which is often nearly orthogonal to the face cleat direction. McCulloch (1974) reported cleat directions at four sites within the Beatrice mine, adjacent to the Keen Mountain Fault (see *Figure A3*). Within the Beatrice Mine, face cleat directions varied from N 18° W to N 30° E, and butt cleat from N 60° E to N 75° E.

Interestingly, Beatrice Mine butt cleat directions (N 60° E to N 75° E) and Buchanan No. 1 Mine hydraulic fracture directions (N 56° E to N 61° E) are very similar, suggesting that the present-day horizontal stress field may have been operative at the same time coal cleat formation was occurring (i.e., paleo-stress field and present stress field are one and the same).

Lineament Alignment with Stress Field Vectors

Two primary lineament trends were observed from the MM&A linear study (1991), which exhibit a significant correlation to the present-day horizontal stress field.

Comparison 1:

> The *dominant* primary lineament trend in the Keen Mountain area: N 20° W to N 25° W

> The minimum principal horizontal compressive stress direction: ~N 30° W

Comparison 2:

> The *secondary* primary lineament trend in the Keen Mountain area: N 60° E to N 65° E

> The maximum principal horizontal compressive stress direction: ~N 60° E

Underground Slickenside Alignment with Stress Field Vectors

Wickline (2017) has conducted underground geologic mapping of the Buchanan No. 1 Mine over a period of years, in the Pocahontas No. 3 seam, with emphasis upon roof conditions (among other

factors). Particular attention has been given to mapping of structural features referred to as "slick-slips" or "horsebacks" (refer to *Section 4.1.1.1.1*) in the mine roof.

Notably (and similar to other geologic features discussed previously), the majority of slick-slips mapped across the mine are typically oriented within a range of N 46° E to N 76° E, as compared to the maximum principal horizontal compressive stress direction of ~N 60° E. (See also *Figures A1, A9,* and *D7 – D9* in the *Appendix*.)

Anticlinal Axes and Fault Alignment with Stress Field Vectors

Regional analysis of the orientations of anticlinal axes and faults has been referred to above and will be given brief discussion to provide a basis for explanation of the correlations that have been made to observations made by others. Byington (2007) postulated two distinct tectonic deformational events that occurred within the Pine Mountain Thrust Sheet:

1. The first of these, D1, was dominated by high-angle, sinistral strike-slip faulting. Furthermore, during this period, two "*sub-events*" were identified: D1a, followed by D1b.
2. The second event, D2, was dominated by low-angle thrust faulting, responsible for the most widespread and important fracturing associated with coal mine roof falls. Likewise, during this period, two sub-events were also identified: D2a, followed by D2b.

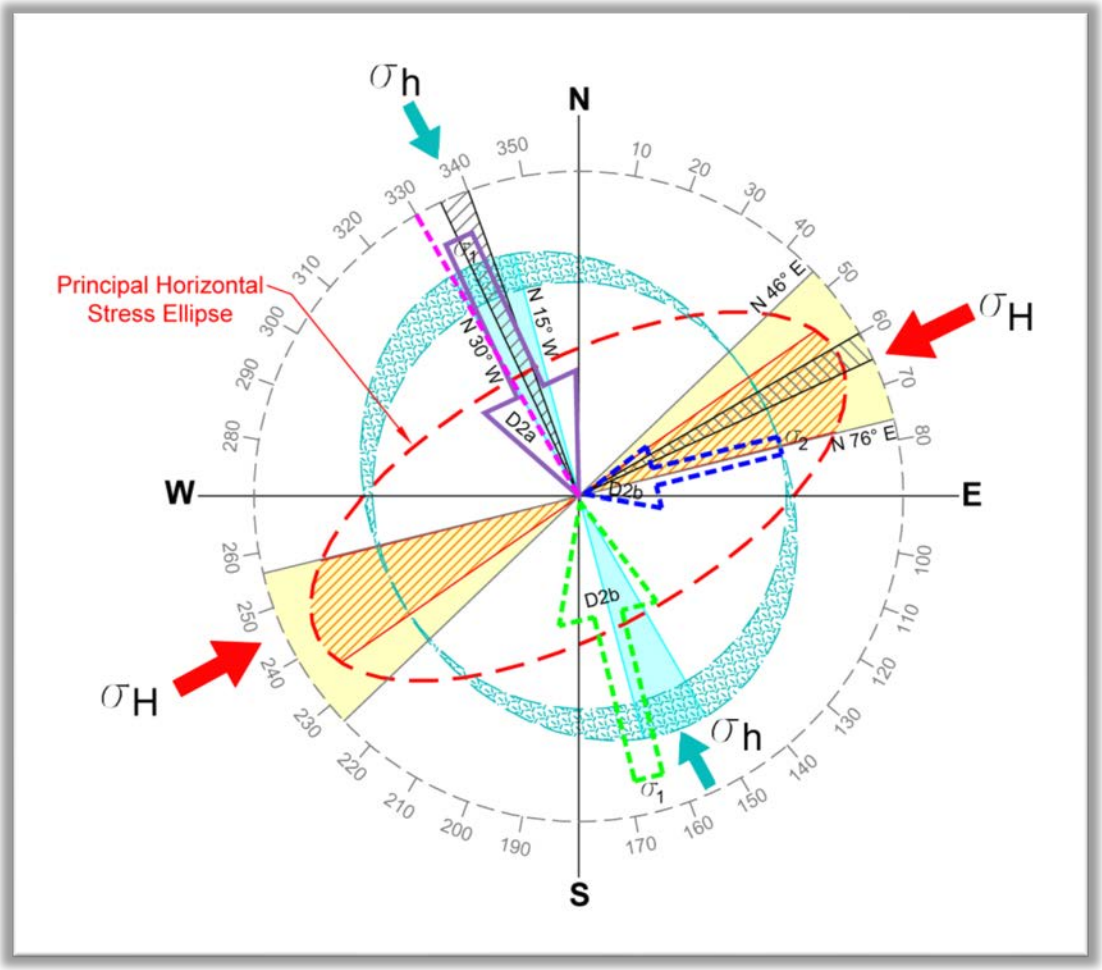
Each of Byington's deformational events also includes significant folding of the coal-bearing strata within the thrust sheet (including the study area), and each period exhibits a unique paleo-stress field orientation. Three of his calculated paleo stress directions align reasonably well with present-day horizontal stress vectors, and are shown on *Figure 4-5* below:

1. D2a faults with a mean maximum stress orientation of N 25° W; compared to the minimum principal horizontal compressive stress direction of: ~N 30° W.
2. D2b anticlines with a mean maximum stress orientation of S 14° E; compared to the minimum principal horizontal compressive stress direction of ~N 30° W (or S 30° E).
3. D2b anticlines with a mean intermediate stress orientation of N 76° E; compared to the maximum principal horizontal compressive stress direction of: ~N 60° E.

Stress Field Diagram

Shown below (Figure 9-16 and in greater detail in *Figure A9* of the *Appendix*) is a graphic compilation of the previously described geologic features relating: faults, folds, lineaments, coal face and butt cleat, hydraulic fractures, slick-slip trends, and present-day regional horizontal stresses. The nearly orthogonal alignment of these paleo and current stress field vectors is noteworthy.

Figure 9-16 Stress Diagram



9.2.4 Regional Gas Content Trends

From previous studies, pre-development gas content trends for the Lee and Pocahontas Formations have been mapped as shown on *Figures B3* through *B6* in the *Appendix* of this report, with values (in the Pocahontas No. 3 seam) as high as 689 scf/t. Possible reasons for one regional gas content trend, specifically the Pocahontas No. 3 seam, have been presented in *Section 4.1.2*.

Gas-in-Place Per Acre

Earlier estimates of gas-in-place per acre are provided on *Maps B5* and B6 in the *Appendix* of this report. The stratigraphic interval included within these estimates extends from the Upper Horsepen seam to the Pocahontas No. 1 seam, and varies from less than 10 *million cubic feet* (*MMCF*) to more than 22 MMCF per acre. Within the study area, gas contents are at the lower end of that range, from less than 10 to more than 16 MMCF per acre.

Local Gas Content

Shown on *Map B4* in the *Appendix* are significantly lower (*present day*) gas contents for the Pocahontas No. 3 seam ranging from 106.57 to 159.24 scf/t, compared to the *pre-development* trend, ranging from approximately 450 to 500 scf/t. The data suggests that as much as 65% to 80% of the original gas-in-place (or perhaps higher) has been produced from the Pocahontas No. 3 seam since the year 2000, when the first wells came on-line within the study area. Historical gas content data for the other produced seams is insufficient to determine the level of CBM depletion.

If these present-day gas contents are typical of the rest of the Oakwood CBM field, there is confirmation of the overall success of CBM extraction and production over the past 20+ years from this field.

Perforated Coal Thickness and Gas Production Trends

Mapping of the combined thickness of perforated (completed) coal beds within the study area is shown on *Map C20* in the *Appendix*. The seams included within this group of perforated coals extend from the Greasy Creek (20) seam to as deep as the Squire Jim 3 seam. The minimum completed coal thickness within a single well is 6.80 feet; and the maximum is 22.70 feet.

Two maps displaying gas production from the study area are found in the *Appendix*, *Maps C21* and *C22*. The first of these maps reports the volume of gas produced from 21 wells within the study area for the first 5 years of production; the second shows the best 5 years of gas production. As would be expected, the perforated coal thickness map and the 5-year production maps exhibit a moderately strong correlation.

9.2.5 Stratigraphy

Lithologically-complex Pennsylvanian-age coal-bearing formations are the source of CBM production within the coal beds of southwest Virginia and southern West Virginia. It should be noted that formation and coalbed names vary widely across the region from state to state, county to county, as well as from company to company, requiring considerable effort in drafting “correlation charts” of the Central Appalachian region.

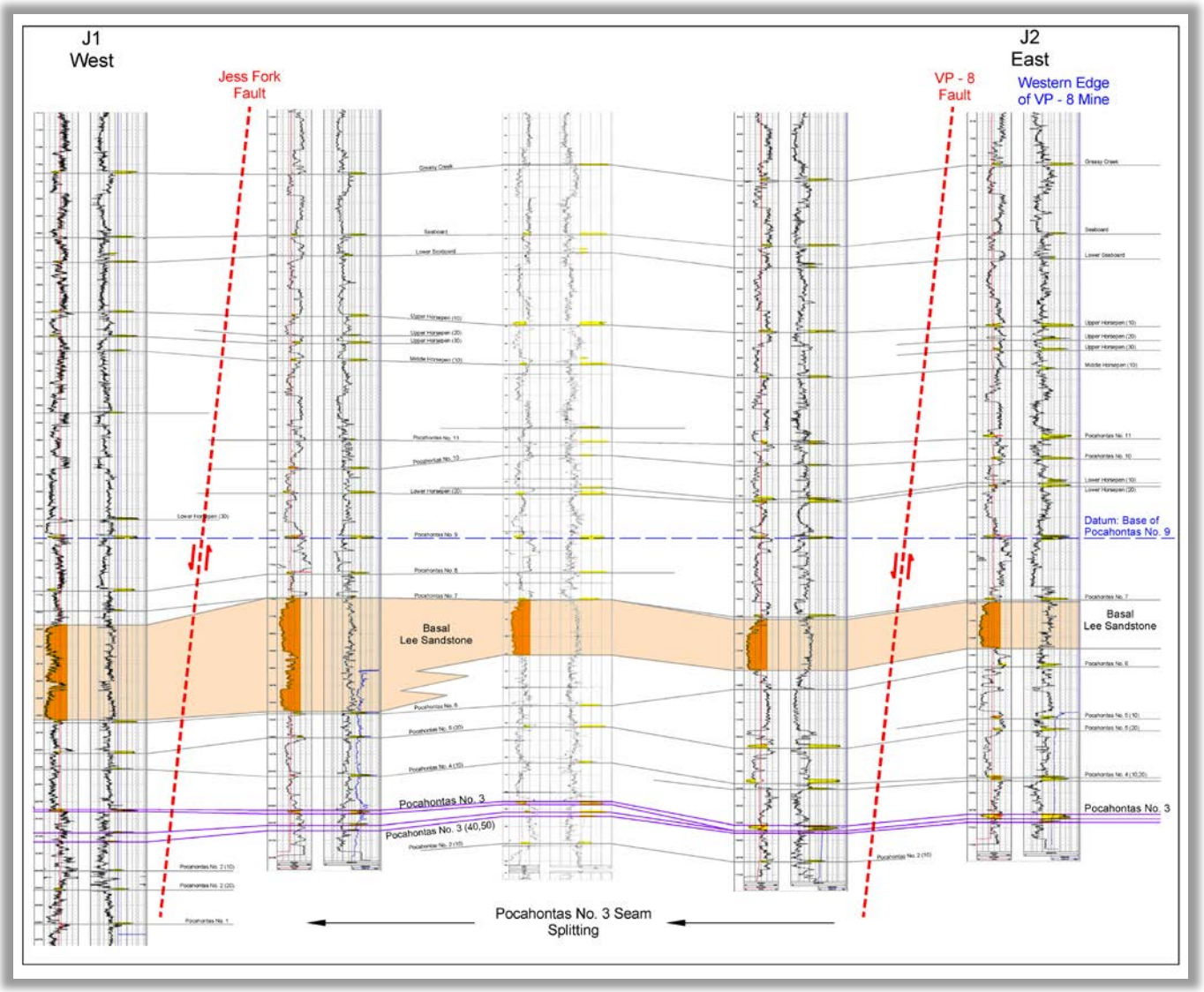
No discussion will be given herein to identifying the various names by which formations and coal seams are known. Local names for these formations and coal seams found within the study area have previously been reviewed (see *Section 1.1.1*). Fortunately, the Pocahontas No. 3 seam is for the most part widely recognized across Virginia and West Virginia; few if any other below-drainage coal seams are as consistently identified.

Stratigraphic Cross Sections

Stratigraphic relationships within the study area are illustrated in cross-sectional exhibits (contained herein and within the *Appendix*) at widely varying scales of presentation (see locations shown on *Map A1* in the *Appendix*). These are described below.

1. Site-specific cross sections *A1-A2, A2-A3*, and *B1-B2* (MM&A, 2017), illustrates strata from the Pennsylvanian Pocahontas – Lee Formations, including the Pocahontas No. 3 seam. These cross sections are described in greater detail in following sections of the report.
2. Regional sections *C1-C2* (after Henika, 1994) and *E1-E2* (after Harris, 1981), illustrates generalized stratigraphic and structural conditions from Precambrian through Pennsylvanian formations. Approximate location of the Pocahontas No. 3 seam has been added to *C1-C2*.
3. Cross section *D1-D2* (after Jacobeen, 1992), likewise illustrates generalized formational boundaries from the Devonian Shale through Pennsylvanian coal-bearing formations, with identification of the Pocahontas No. 3 seam.
4. Cross section *F1-F2* (after Englund, 1974), illustrates more detailed lithologic composition of the Mississippian Bluestone Formation through the Pennsylvanian Pocahontas – Lee – New River Formations, with identification of the Pocahontas No. 3 seam.
5. Cross section *G1-G2* (MM&A, 2017), illustrates structural and stratigraphic conditions within the western portion of the VP-3 Mine, which extracted coal from the Pocahontas No. 3 seam.
6. Seismic cross section *H1-H2-H3* (after Sandia, 2013), shown above.
7. As shown below on *Figure 9-17 (*see location on *Figure A1* in the *Appendix*), Cross section *J1-J2* (after MM&A, 2013), illustrates stratigraphic conditions at the western edge of VP-8 Mine (which extracted coal from the Pocahontas No. 3 seam), and west of the mine; approximate locations of the VP-8 and Jess Fork Faults have been superimposed on the section. Of note on this exhibit, the Pocahontas No. 3 seam (highlighted in purple) is a thick, mineable coal bed at the western edge of the mine, while seam splitting becomes evident immediately west of the VP-8 Fault and continues to split near the Jess Fork Fault. This suggests that precursors of these faults may have been present at the time of deposition of the Pocahontas No. 3 seam and would be referred to as “growth faults”. A very similar pattern of seam splitting associated with another group of faults was observed by McClure (1990) approximately 5.6 miles southwest of the study area, within the Raven – Jawbone – Tiller sequence of coal beds, located higher in the stratigraphic section.

Figure 9-17 Cross Section J1-J2, Illustrating splitting characteristics of the Pocahontas No.3 Seam



Site-Specific Cross Sections

The stratigraphic interval of interest, shown on the site-specific cross sections (*Exhibits E1 through E3 – Cross Sections A1 – A2, A2 – A3,* and *B1 – B2*) in the *Appendix* extends from the uppermost Tiller seam to the deepest Squire Jim seam.

The Pocahontas No. 9 seam is the datum for each cross section. Information included on each section includes the following:

> Identification of lithologic units within the CBM-producing interval, from the Greasy Creek 20 seam to the Pocahontas No. 2 seam.

- Identification of individual coal beds, the Hensley Shale confining beds, and the Basal Lee Sandstone unit.
- CBM well data including: year completed, completed coal seams, completion zones, and total depth of well.
- Identification of geophysical log curves run on each hole: gamma, density, and/or caliper.
- Gas content data from desorption holes.
- Information pertaining to the 3 CO_2 injection wells, DD7, DD7A, and DD8 including: dates of injection, injection zone, and status of well perforations (e.g. open, closed, not visible); furthermore, water levels are also indicated, as measured in 2015.

In addition to the information reported on the cross section exhibits, a small sample of representative video log images from CBM well DD7 (taken on March 31, 2015), is shown on *Exhibit E4* in the *Appendix*.

9.2.6 Regional Coal Thickness Trends

Composite seam thickness trends for a sequence of coal seams from the Upper Horsepen 10 Bench through the Pocahontas No.1 10 Bench are shown on *Appendix Figures B1* and *B2*, *Regional Net Coal Isopach Map*. Within the study area, coal thicknesses vary significantly from a minimum of 7.2 feet to a maximum of 26.9 feet, averaging approximately 16 feet.

The 3 desorption holes, CH-1-2014, M-1, and M-2, have a total coal thickness ranging from 14.40 feet to 16.96 feet. (By way of comparison to the 2010 SECARB project, hole BD-114-M2 had a somewhat greater total coal thickness of 23.04 feet.)

9.2.7 Individual Seam Thickness and Gas Content Trends

Thickness trends for 18 individual coal seams, from the Greasy Creek (20) seam to the Pocahontas No. 2 (10) seam, are shown on maps within the *Appendix, Maps C1* through *C18*. (A composite coal thickness map of the individual seams, *C19*, is also included.)

In addition to seam thickness (total seam / total coal) and base of seam elevation, each map also includes the following information, where available:

- Total coal thickness isolines (1.0-1.5’ with orange shading; greater than 1.5’ in green)
- Gas content by seam; borehole temperature at depth of seam
- Identification of wells (according to historical completion reports) that have been perforated / not perforated, with the assumed orientation of hydraulic fractures
- Locations of injection wells, including status of perforated intervals (based on downhole camera video logs)
- Locations of monitoring wells

Seam Map C1 – Greasy Creek (20)

> Total coal thickness range: 0.00 to 2.30 feet

> Seam distribution: two thick pods of coal (greater than 1.50 feet) separated by a zone of absent coal.

> As-received gas content: 204.30 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 61.9°F

> Number of wells completed within monitoring area: 6, apparently due to relative shallowness of this seam.

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: not reported
- CB-DD7A: not reported
- CB-DD8: not reported

Seam Map C2 – Seaboard (20)

> Total coal thickness range: 0.00 to 1.50 feet

> Seam distribution: three separate pods of coal greater than 1.00 feet thick; separated by a zone of thinner, to locally absent coal.

> As-received gas content: not measured

> Temperature: not measured

> Number of wells completed within monitoring area: 13; and 2 adjacent wells that may have fracked into the monitoring area.

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 7 of 8 perfs open
- CB-DD7A: 2 perfs, both open
- CB-DD8: 7 perfs, all open

Seam Map C3 – Lower Seaboard (10 & 20)

> Total coal thickness range: 0.10 to 2.10 feet

> Seam distribution: three separate pods of coal greater than 1.50 feet thick; separated by a zone of thinner.

> As-received gas content: 409.12 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 63.5°F

> Number of wells completed within monitoring area: 16; and 2 adjacent wells that may have fracked into the monitoring area.

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 8 perfs, all open
- CB-DD7A: 2 perfs, both open
- CB-DD8: 4 perfs, open

Seam Map C4 – Upper Horsepen (10)

> Total coal thickness range: 0.50 to 2.65 feet

> Seam distribution: four separate pods of coal greater than 1.50 feet thick.

> As-received gas content: 350.93 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 64.4°F

> Number of wells completed within monitoring area: 16; and 2 adjacent wells that may have fracked into the monitoring area.

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 8 perfs, all open
- CB-DD7A: 4 of 5 perfs open
- CB-DD8: 4 perfs, open

Seam Map C5 – Upper Horsepen (20 & 30)

> Total coal thickness range: 0.00 to 2.00 feet

> Seam distribution: two separate pods of coal greater than 1.50 feet thick; separated by a wide zone of thinner to absent coal.

> As-received gas content: not measured

> Temperature: not measured

> Number of wells completed within monitoring area: 9

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 2 of 3 perfs open
- CB-DD7A: no perfs, seam absent
- CB-DD8: 5 of 6 perfs open

Seam Map C6 – Pocahontas No. 11 / War Creek

> Total coal thickness range: 0.00 to 1.94 feet

> Seam distribution: single pod of coal greater than 1.50 feet thick along eastern side of monitoring area; seam is occasionally subject to splitting into multiple benches.

> As-received gas content: 323.41 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 66.1°F

> Number of wells completed within monitoring area: 11; and 3 uncertain.

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 4 of 6 perfs open
- CB-DD7A: no perfs, thin seam
- CB-DD8: 4 of 5 perfs open

Seam Map C7 – Pocahontas No. 10 (10)

> Total coal thickness range: 0.00 to 2.50 feet.

> Seam distribution: small, single pod of coal greater than 1.50 feet thick.

> As-received gas content: not measured

> Temperature: not measured

> Number of wells completed within monitoring area: 14

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 6 of 7 perfs open
- CB-DD7A: 1 of 2 perfs open
- CB-DD8: 4 perfs, all open?

Seam Map C8 – Pocahontas No. 10 (20)

> Total coal thickness range: 0.00 to 1.70 feet

> Seam distribution: multiple separate pods of coal generally less than 1.50 feet thick; separated by broad zone of less than 1.0-foot thick coal.

> As-received gas content: 464.73 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 66.4°F

> Number of wells completed within monitoring area: 12

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 2 perfs, 1 open; 1 partially open
- CB-DD7A: 1 perf closed

- CB-DD8: 4 perfs, all open?

Seam Map C9 – Pocahontas No. 9 (10)

> Total coal thickness range: 0.90 to 2.80 feet

> Seam distribution: more than 90% of the area contains coal thicknesses greater than 1.50 feet thick; one very limited area in the southeast less than 1.0-feet thick.

> As-received gas content: ranging from 170.03 to 241.10 scf/t (from all 3 desorption holes)

> Temperature measured from 3 holes: 67.4°F to 73.0°F

> Number of wells completed within monitoring area: 18

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: 11 perfs, 5 or 6 open
- CB-DD7A: 6 perfs, all open
- CB-DD8: 4 perfs, 2 open?

Seam Map C10 – Pocahontas No. 9 (20)

> Total coal thickness range: 0.00 to 1.30 feet

> Seam distribution: isolated, single pod greater than 1.00 foot thick.

> As-received gas content: 157.55 scf/t

> Temperature measured from core hole M-1: 72.9°F

> Number of wells completed within monitoring area: 5 to 8

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: no perfs, seam absent
- CB-DD7A: 6 perfs, all open
- CB-DD8: 4 perfs, 2 open

Seam Map C11 – Pocahontas No. 7 (10)

> Total coal thickness range: 0.10 to 1.80 feet

> Seam distribution: three separate pods of coal greater than 1.50 feet thick; separated by a zone of thinner.

> As-received gas content: 340.54 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 68.5°F

> Number of wells completed within monitoring area: 15

> Status of perforations within CO_2 injection wells observed in 2015:
  - CB-DD7: 6 perfs, 2 open
  - CB-DD7A: scale on walls, no perfs visible
  - CB-DD8: 4 perfs, 3 open

Seam Map C12 – Pocahontas No. 5 (10)

> Total coal thickness range: 0.00 to 1.35 feet

> Seam distribution: isolated, single pod greater than 1.00 foot thick.

> As-received gas content: 385.25 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 69.7°F

> Number of wells completed within monitoring area: 5

> Status of perforations within CO_2 injection wells observed in 2015:
  - CB-DD7: no perfs, seam absent
  - CB-DD7A: 3 perfs, all open
  - CB-DD8: 5 perfs, 4 open

Seam Map C13 – Pocahontas No. 5 (20)

> Total coal thickness range: 0.00 to 3.00 feet

> Seam distribution: two separate pods of coal greater than 1.50 feet thick; separated by a zone of thinner coal.

> As-received gas content: 379.22 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 70.0°F

> Number of wells completed within monitoring area: 13

> Status of perforations within CO_2 injection wells observed in 2015:
  - CB-DD7: 8 perfs, 4 open
  - CB-DD7A: 2 perfs, both open
  - CB-DD8: 8 perfs, 5 open

Seam Map C14 – Pocahontas No. 4 (10, 20 & 30)

> Total coal thickness range: 0.10 to 3.80 feet

> Seam distribution: Pocahontas No. 4 is the most erratic in terms of thickness, splitting, and lateral continuity. Indeed, the Pocahontas No. 4 seam has been mistaken for the Pocahontas No. 3 seam here and elsewhere. In one location at the nearby VP-5 mine, shaft excavation was almost

terminated within the Pocahontas No. 4 seam, instead of the intended Pocahontas No. 3 seam, due to its unusual thickness at that site.

> As-received gas content: 328.60 scf/t (from core hole CH-1-2014)

> Temperature measured from core hole CH-1-2014: 70.2°F

> Number of wells completed within monitoring area: 13

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: no perfs visible, water-filled
- CB-DD7A: 3 perfs, all open
- CB-DD8: 8 perfs, all open

Seam Map C15 – Pocahontas No. 3 (10, 20 & 30)

> Total coal thickness range: 1.20 to 3.00 feet

> Seam distribution: The Pocahontas No. 3 horizon exhibits significant splitting across the property, with the 30 Bench splitting away from the overlying 10 and 20 benches. North and east of the study area, the Pocahontas No. 3 seam has been longwall mined, where it is combined with the lower benches to form a single seam and fewer non-coal partings.

> As-received gas content: 106.57 to 159.24 scf/t (from 3 desorption holes)

> Temperature measured: ranging from 70.7 °F to 76.6 °F

> Number of wells completed within monitoring area: 18

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: no perfs visible, water-filled
- CB-DD7A: 3 perfs, all open
- CB-DD8: no perfs visible, water-filled

Seam Map C16 – Pocahontas No. 3 (40)

> Total coal thickness range: 0.10 to 1.10 feet

> Seam distribution: small, single pod greater than 1.00 feet thick.

> As-received gas content: not measured

> Temperature: not measured

> Number of wells completed within monitoring area: 13

> Status of perforations within CO_2 injection wells observed in 2015:

- CB-DD7: no perfs visible, water-filled

- CB-DD7A: no perfs visible, water-filled
- CB-DD8: no perfs visible, water-filled

Seam Map C17 – Pocahontas No. 3 (50)

> Total coal thickness range: 0.00 to 1.08 feet
> Seam distribution: very small, single pod greater than 1.00 feet thick.
> As-received gas content: not measured
> Temperature: not measured
> Number of wells completed within monitoring area: 7
> Status of perforations within CO_2 injection wells observed in 2015:
  - CB-DD7: no perfs visible, water-filled
  - CB-DD7A: no perfs visible, water-filled
  - CB-DD8: no perfs visible, water-filled

Seam Map C18 – Pocahontas No. 2 (10)

> Total coal thickness range: 0.00 to 1.00 feet
> Seam distribution: very small, single pod greater than 1.00 feet thick.
> As-received gas content: 217.76 scf/t (from core hole CH-1-2014)
> Temperature measured from core hole CH-1-2014: 72.1°F
> Number of wells completed within monitoring area: 6
> Status of perforations within CO_2 injection wells observed in 2015:
  - CB-DD7: no perfs visible, water-filled
  - CB-DD7A: no perfs visible, water-filled
  - CB-DD8: no perfs visible, water-filled

Composite Map C19 – Greasy Creek (20) through Pocahontas No. 2 (10)

Grid files for the 18 seams listed above, from the Greasy Creek 20 through the Pocahontas No. 2 (10 Bench), have been composited as shown in *Map C19*. Total coal thickness ranges from less than 10.0 to more than 22.0 feet.

Not surprisingly, it is evident that the composite seam thickness map should and does in fact demonstrate a strong correlation to the maps described below:

> Total Perforated Coal Thickness (*Map C20*)

> First 5-Years Gas Production (*Map C21*)

> Best 5-Years Gas Production (*Map C22*)

9.2.8 Factors Impacting CBM Production

Stratigraphic Conditions

Coal Thickness and CBM Production Relationships

Mapping of regional and local thickness trends (in conjunction with site-specific gas content) have identified the major coal seams contributing to CBM production within the area of interest. With some notable exceptions, gas wells which penetrated and perforated the thickest sequence of coal typically have higher gas production (refer to *Section* above).

Seams with Remaining Significant Gas Content

While some of the seams that have already produced a relatively high percentage of their original gas-in-place gas (comparing pre-development gas contents to those measured in 2014 / 2015), there are coal seams with yet significant volumes of remaining CBM (exceeding 300 scf/t on as-received basis) including the following coal beds:

> Lower Seaboard (20 Bench) – 409.12 scf/t

> Upper Horsepen (10 Bench) – 350.93 scf/t

> Pocahontas No. 11 – 323.41 scf/t

> Pocahontas No. 10 (20 Bench) – 464.73 scf/t

> Pocahontas No. 7 (10 Bench) – 350.54 scf/t

> Pocahontas No. 5 (10 Bench) – 385.25 scf/t

> Pocahontas No. 5 (20 Bench) – 379.22 scf/t

> Pocahontas No. 4 (20 Bench) – 328.60 scf/t

Reasons for the wide range of variability in the gas contents of these seams may in part be related to depositional factors such as:

1. Seam splitting into multiple, discontinuous benches (effectively isolating some pods of coal from hydraulic stimulation and CBM well development).
2. Seam thinning (difficult to precisely target and perforate coal beds).
3. Seam scouring by sandstone paleochannels (with impacts similar to those described above).

Results of video logging also indicated that some perforations were not always successfully completed, or later became plugged, suggesting an additional contributing factor to current (elevated) gas

contents. Even so, well operators have successfully developed CBM on the property during the past 17 years of production, with potential for continued development.

Structural Conditions

While the impact of structural features described herein (both shallow and deep subsurface) upon underground mining conditions are readily apparent, it can also be inferred that CBM development would similarly be impacted by these same features, including:

1) Reservoir thickness variability: where duplication or alternatively, thinning, may occur in close proximity; or where seam splitting may be associated with contemporaneous (or post-depositional) structures.
2) Reservoir compartmentalization along normal and/or strike-slip fault boundaries.
3) Reservoir permeability variability due to: thrust faulting *within* coal beds; face / butt cleat directions correlative with the horizontal stress field (wherever faulting has not sheared and/or otherwise altered the cleat); the presence of the Hurricane Creek anticline and syncline (affecting not only permeability, but also the direction of fluid migration); and, enhanced fracturing associated within lineament zones.
4) Propagation of hydraulic fractures parallel to the major principal horizontal stress direction.
5) Regional coal rank / gas content trends.

9.2.9 Over-Performing / Under-Performing Wells

As noted above, gas production during the first 5 years has been calculated for 21 CBM wells within the study area. Results of this study have identified three categories of CBM wells with respect to production history based on a linear relationship between completed coal thickness and gas production (see *Figure 5-1* below):

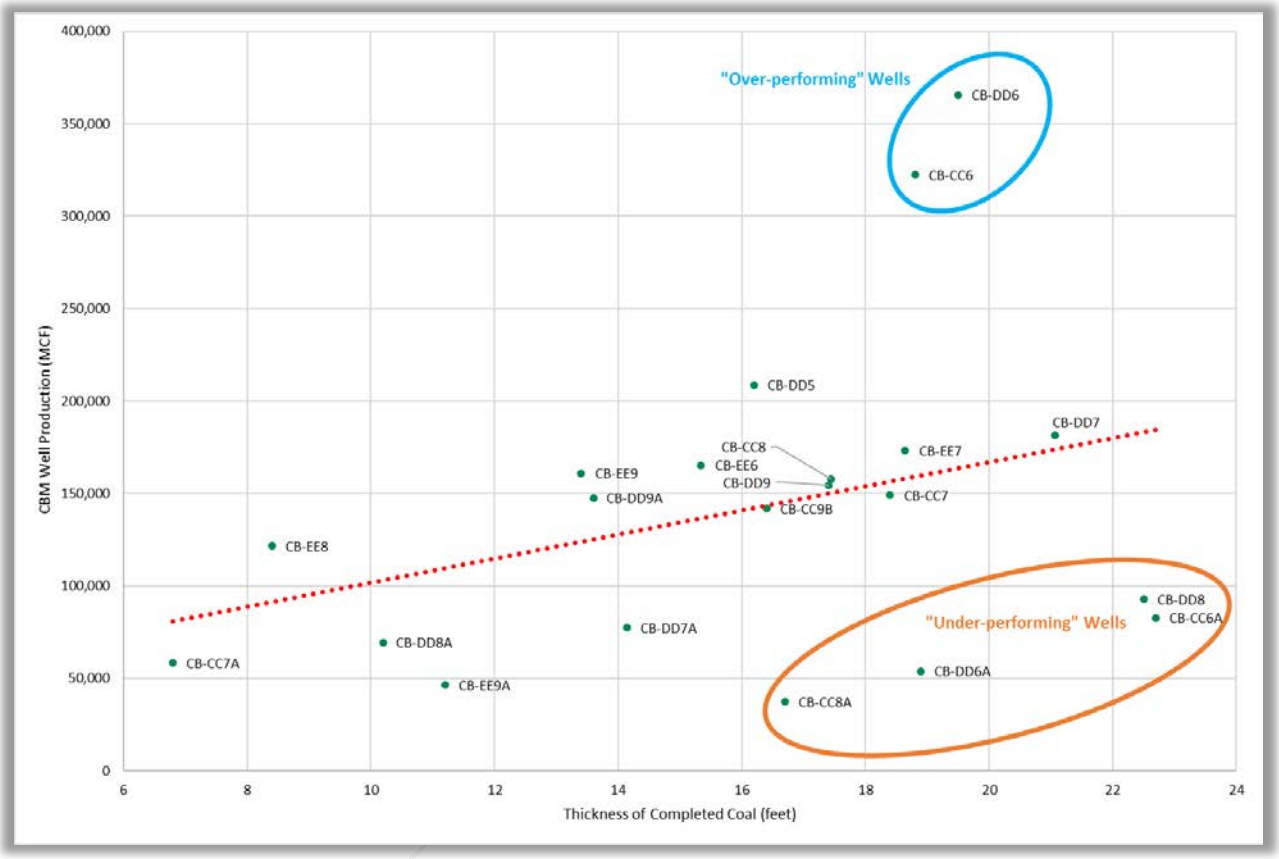
(1) Fifteen wells that performed within a fairly predictable (linear or "average") range during their 5-year CBM production history, compared to other wells of similar coal thickness.

(2) Two wells that "over -performed", compared to other wells of similar coal thickness.

(3) Four wells that "under – performed", compared to other wells of similar coal thickness.

As shown on *Figure 9-18* below, two wells produced significantly more gas ("over-performing") than those of similar coal thickness: CC6 and DD6 (high above the regression line). Whereas, four wells were less productive ("under-performing") than anticipated: CC6A, CC8A, DD6A, and DD8 (below the regression line). Factors potentially contributing to the variance of these 6 wells from the 15 "normal" wells are discussed below.

Figure 9-18 CBM Production in First 5 Years versus Completed Coal Thickness (21 Wells)



Proximity to Hurricane Creek Anticlinal Axis

One of the major factors believed to have contributed to the nonlinear (above average) variability between perforated coal thickness and gas production is proximity to anticlinal structures. Wells CC6 and DD6 are higher-than-average producers and are also located nearer to the axis of the Hurricane Creek anticline. These wells may have benefited from (1) enhanced permeability near the anticlinal axis, (2) as well as a more favorable hydrogeologic setting where formation water would migrate downdip away from the well bore, both of which would enhance productivity.

Proximity to Jess Fork Fault

Depending upon geometry, faults can serve either as (1) seals or partial seals to migration of methane, or conversely, (2) to enhance permeability and provide localized trapping of methane gas within the immediate vicinity.

Close proximity of the trace of the Jess Fork fault to DD-8 (within 250 feet) suggests one potential geologic factor that may have adversely impacted gas production during the first 5 years – with the fault(s) acting as barrier to hydraulic fracture propagation and gas migration into the well bore.

Drilling Sequence

The sequence of drilling is a significant factor in well production; secondary in-fill wells are more likely to be negatively impacted by lowered gas contents adjacent to the nearby wells which were drilled first within each block. As shown above, three of the four under-performing wells, CC6A, CC8A, and DD6A, are in-fill wells.

9.2.10 Consistency of Coal Description and Variable Coal Quality

Interpretation of Coal from Geophysical Logs

When observed in mines, outcrops, or core samples, the generic term "coal" often has numerous descriptive terms regarding its: overall appearance, luster, color, maceral composition, bedding characteristics, fracturing, presence of inorganic constituents, and relative purity. Furthermore, all other factors being equal, it is well known that relatively clean (low-ash) Low-volatile Bituminous coals (such as those typically present in the deep subsurface of Buchanan County, Virginia) are gassier than those with higher ash contents.

In contrast, when coal is interpreted from geophysical logs, thickness is typically the *only* parameter that can be readily described with low-resolution elogs, without any suggestion as to the purity of the coal. This is unfortunate as it is possible that some "coals" interpreted from geophysical logs may be relatively clean (low-ash) and gassier, while others may be more boney (high-ash), and consequently less gassy.

Moreover, determination of coal thickness can vary substantially depending upon the geophysical logging company, probes used (gamma, density, caliper, etc.), radioactive source and source-to-detector spacing, and scale of presentation (typically 1" = 20 feet). Thus, there is inherently greater uncertainty not only in the identification of coal / coal quality, but thickness as well, with the types of geophysical logs that were used by gas production companies in the study area.

It should be noted that much higher-resolution geophysical logging tools were utilized for the desorption holes, with presentation at 1" = 1 foot, and thus much higher confidence in the interpreted thickness of the coal beds, as well as having actual core samples to measure and analyze (see *Expanded Sections* in the *Appendix* of this report).

Coal Quality

Based on very limited data, coal quality within each seam, in terms of maceral composition, vitrinite reflectance / rank, ash, sulfur, and other parameters is variable both vertically and horizontally; and each of these parameters has a relationship to gas content. As noted above, inherently higher-ash seams possess less gas than lower-ash coals. Unfortunately, the available data within this study is limited to a single, continuous core hole, and thus evaluation of gas production potential in relation to coal quality is not possible.

Additional (Non-Geologic) Factors Impacting Well Productivity

Reasons for the lackluster performance of DD8 (in the first 5 years) are not immediately obvious. Other potentially non-geologic factors may come into play, include (but are not limited to) the following:

- Incompletely perforated well bore (as alluded to in *Section 5.1.2*)
- Perforations that missed the targeted coal horizons
- Difficulties encountered during well treatment / stimulation (unknown)
- Pump failure / delays in production start-up / power outages / well maintenance issues, etc.
- Build-up of scale over time on well casing, restricting / closing perforations (less likely)

The extent to which any of these factors (or none of them) may have been present at DD8 is unknown; additional field work (e.g. video camera logging with a gamma probe) and analysis would be recommended to clarify the presence or absence of any of these that may have contributed to lower-than-expected gas production during the first 5 years.

9.2.11 Summary of Geologic Characterization

Underground mining of the Pocahontas No. 3 seam since the 1960's has been a major factor that led to the eventual development of both CBM and CMM in Buchanan County, and will continue to contribute to gas production for the foreseeable future. (Deep mining, however, will *not* be feasible on the subject property due to thinning / splitting / faulting of the Pocahontas No. 3 seam.)

Various structural / tectonic and stratigraphic /depositional features have been reviewed that provide a conceptual framework within which reservoir geometry and, to a lesser extent, permeability as well as CBM well productivity, can more clearly be defined and quantified at small and large scales.

Within the Central Appalachian region of southwest Virginia, historical gas production from the Oakwood CBM field (and adjacent Nora CBM Field), by CNX, Equitable, Range, OXY, and others extends back to the early 1990's, at almost the same time that CMM was beginning to be captured by ICCCo and Consol from their coal mining operations in the Pocahontas No. 3 seam.

Results of this investigation demonstrate the impact of CBM development on the subject property during the past 17+ years, and the potential for continued CBM production. A reduction in gas content is apparent within the study area where the pre-development Pocahontas No. 3 seam gas content was initially between 450 and 500 scf/t prior to development, and is now within a range of 145 to 159 scf/t. The data suggests that as much as 65% to 80% of the original gas-in-place (or perhaps higher) has been produced from the Pocahontas No. 3 seam since the year 2000, when the first wells came on-line within the study area.

Prior to this analysis, no gas content data was available for carbonaceous shales adjacent to, or present as partings within, this sequence of coal beds. (Notably, some porous sandstone core samples were

also observed to desorb gas when removed from the core barrel, however, no samples were collected and desorbed in canisters.) The carbonaceous shale samples collected during the course of this project have gas contents ranging from 45.95 scf/t to 75.88 scf/t, and if perforated and stimulated, might contribute a limited volume of gas to producing wells.

More importantly, eight coal beds (listed below) within the study area have been identified as possessing gas contents exceeding 300 scf/t, thus indicating a reasonable prospect for continued gas production.

- Lower Seaboard (20 Bench)
- Upper Horsepen (10 Bench)
- Pocahontas No. 11
- Pocahontas No. 10 (20 Bench)
- Pocahontas No. 7 (10 Bench)
- Pocahontas No. 5 (10 and 20 Bench)
- Pocahontas No. 4 (20 Bench)

Well operators have successfully developed CBM on the property during the past 17 years, and potential for continued development, with or without enhanced recovery from a commercial-scale CO_2 injection program.

9.2.12 Gas Content

Documentation is provided regarding the methodology for determining gas content for a sequence of coalbeds penetrated by 3 core holes.

4. The first of these holes, **CH-1-2014,** was drilled by continuous coring methods from July through September 2014, (a portion of which was re-drilled, and referred to as **CH-1R-2014)**;
5. Two spot-core holes were drilled in March 2015, **M-1** and **M-2 (CBM-EE7A),** which were subsequently converted into monitoring wells.

According to available information, each of these coalbeds has been perforated and completed within nearby CBM wells between 2000 and 2008 (see Figures *B7* and *B8* in the *Appendix*). Core hole CH-1-2014 is a continuous core hole that captured all of the above-noted seams, wherever they were present.

Whereas two other spot-core holes, M-1 and M-2 (CBM-EE7A), captured only the Pocahontas No. 9 and Pocahontas No. 3 seams. (Furthermore, a monitoring well was also drilled approximately 16 feet away from the CH-1-2014, referred to as C-1, however no core samples were collected from this hole).

Analyses of a portion of the coal samples from these holes were conducted by Precision Testing Laboratory, located in Daniels, West Virginia including:

Proximate analysis (moisture, ash, sulfur, volatile matter, fixed carbon, and Btu/lb.)

Ultimate analysis (moisture, carbon, hydrogen, nitrogen, sulfur, ash, and oxygen)

Petrographic analysis (maceral composition, vitrinite reflectance, etc.)

Where available, coal quality was incorporated into this analysis to derive gas content in standard cubic feet per ton (*scf/t*) on both "as-received" and "dry, mineral-matter-free" (*DMMF*) bases. Furthermore, results of the coal quality analysis demonstrate that the rank of these coalbeds ranges from Medium Volatile to Low Volatile Bituminous; and mean-maximum vitrinite reflectance varies from 1.37 to 1.56 percent.

Based on regional information, pre-development / pre-mining gas contents for the Pocahontas No. 3 seam *within the study* area ranged from approximately 450 to 500 standard cubic feet per ton (*scf/t*), but significantly higher elsewhere. The objective of this analysis is to determine the gas content of coalbeds from which CBM has been extracted for more than 20 years.

From this analysis, as-received coalbed gas contents from this sequence of seams vary widely, from a minimum of 106.57 scf/t for Pocahontas No. 3 seam in CH-1R-2014, to a maximum of 464.73 scf/t for the Pocahontas No. 10 seam within CH-1-2014. With the exception of the Pocahontas No. 9 seam, the higher gas contents (greater than 300 scf/t) found within seams overlying the Pocahontas No. 3 demonstrates favorable potential for additional extraction of CBM from these seams.

Regional mapping of assumed pre-development coalbed gas contents is illustrated on *Figures B3* and *B4* in the *Appendix*. Pocahontas No. 3 seam gas contents vary significantly, from 300 to more than 650 scf/t. Indeed, the highest reported gas content for this seam (689 scf/t) is located less than two miles north of the study area. However, in 2014, gas contents from the combined benches of the Pocahontas No. 3 seam, #10 through #30 (analyzed in all three holes), range from 106.57 to 159.24 scf/t, providing a clear indication of the success of CBM extraction over the past 20+ years from the Oakwood CBM field.

In addition to gas content testing throughout the desorption and residual gas testing phases, gas samples were collected and provided to Virginia Tech for gas composition analysis; moreover, a set of 14 whole (uncrushed) coal core samples were also provided for CT-scan cleat examination. Results from these analyses are not included within this section of the report.

All desorption holes were geophysically logged by **Geophysical Logging Systems (*GLS*** a division of **Marshall Miller & Associates, Inc. [*MM&A*])**, including: gamma-density, resistivity, and temperature; an Acoustic Televiewer (*ATV*) log was run only on CH-1-2014. Furthermore, in 2015 information on the depth, number, and condition of wellbore perforations was interpreted from video logs of CO_2 injection wells, **CB-DD7**, **CB-DD7A**, and **CB-DD8 (**provided in the *Appendix* of this report).

Geophysical logging (High-definition Formation Micro Imager, or *FMI*) of C-1 was conducted by **Schlumberger** in 2015, which may be comparable to MM&A's nearby CH-1-2014 ATV log. Moreover, a CO_2 injection analysis of wells **CB-DD7** and **CB-DD8** was conducted in March 2016 by **Weatherford**, the results of which have been compared to MM&A's video logs of the same holes.

Finally, this report also includes data pertaining to the regional horizontal stress field, locations of known faults and folds, and mapped linear features, as well as coalbed face and butt cleat directions, all of which can have a significant impact upon gas production.

Background of Coal and Gas Production

This gas content analysis is part of an on-going investigation to test the feasibility of injecting CO_2 into existing CBM wells in order to:

1. Enhance CBM gas recovery (*ECBM*), and
2. Sequester CO_2 within a coal-bearing formation.

Northeast of and adjacent to the study area, underground mining (principally longwall) of the Pocahontas No. 3 seam has been on-going continuously since the late 1960's, with CBM / CMM production since the early 1990's. Prior to CBM development in Buchanan County, underground coal operations in the Pocahontas No. 3 seam were engaged in mining some of the gassiest coal seams in the United States (exceeding 650 cubic feet per ton), and thus found it necessary for purposes of mine safety to liberate large volumes of coal mine methane (*CMM*) prior to, during, and after coal extraction. For more than 25 years, CMM was continually vented into the atmosphere before methods were established to capture and produce pipeline-quality gas, while at the same time maintaining a safe working environment for continued coal extraction.

Within the study area, gas production from the Oakwood Coalbed Methane (*CBM*) field and adjacent Nora CBM Field, by **CNX**, **Equitable**, **Occidental** (***OXY***), and others extends back to the early 1990's, at almost the same time that CMM was beginning to be captured by **Island Creek Coal Company** (***ICCCo***) and **Consol**/CNX from their coal mining operations in the Pocahontas No. 3 seam. [Both Island Creek and Consol have since gone out of business and all longwall operations except Buchanan No. 1 have been shuttered.] MM&A's GLS has been e-logging gas wells within the AOR since 1991 (the Ball A-1 brine injection well) to the present.

Consol and ICCCo (and successors) have been the principal developers of coal from the Pocahontas No. 3 seam in Buchanan County from the following mines: Beatrice, Buchanan No. 1, VP-1, VP-2, VP-3, VP-4, and VP-8 (formerly VP-5 and VP-6).

Due to the high gas content of the deep seams in this region, the **US Bureau of Mines** (now part of *NIOSH*) conducted numerous studies in the 1970's and 1980's with the objective of improving underground mine safety, and secondarily to enhance mining productivity. Consequently, a variety

pre-mining through post-mining degasification techniques were developed to assist in this endeavor, which ultimately led to the creation of the Oakwood CBM Field.

Prior and More Recent Gas Content Testing

In 2009, MM&A conducted a gas content analysis of the same sequence of coal beds in hole **BD-114-M2**, approximately 7 miles from the present study area, the results of which have been previously presented.

This report presents the results of a coalbed gas (*CBM*) content analysis of samples collected by MM&A from three holes, the first of which was drilled to a depth of 1,847 feet by continuous coring methods in July – September 2014, **CH-1-2014** (a portion of which was re-drilled, and referred to as **CH-1R-2014**). Approximately 6 months after the first desorption hole (March 2015), two spot-cored holes were drilled: **M-1** and **M-2 (CBM-EE7A),** drilled to depths of 1,835 feet and 2,210 feet, respectively.

Information on the locations of wellbore perforations derived from video logs for three CO_2 injection wells, **CB-DD7**, **CB-DD7A**, and **CB-DD8**, is also provided in the *Appendix* of this report including: maps, cross sections, and site photographs. CO_2 injection into these 3 wells began in July 2015.

Target Seams

Eleven (11) principal coalbeds were canistered in this study (Table 9-5), spanning an interval of approximately 1,035 feet, which belong to the Pennsylvanian-age Norton, Lee, and Pocahontas Formations. These include the following seams (in descending stratigraphic order): Greasy Creek, Lower Seaboard, Upper Horsepen, Pocahontas No. 11, Pocahontas No. 10, Pocahontas No. 9, Pocahontas No. 7, Pocahontas No. 5, Pocahontas No. 4, Pocahontas No. 3, and Pocahontas No. 2 seams, as well as associated coal splits and carbonaceous shale strata.

The Pocahontas No. 3 seam occurs in as many as 5 separate benches, separated by non-coal partings of variable thickness. According to available information, each of these coalbeds has been perforated and completed within nearby CBM wells.

Table 9-5 Samples Collected from 4 Holes for Gas Content Analysis

Map #	Seam with Bench ID	Top Depth at CH-1-2014 (feet)	CH-1-2014	CH-1R-2014	M-1	M-2 (CBM-EE7A)
1	Greasy Creek - 20	765	Y	-	-	-
2	Seaboard - 20	863	-	-	-	-
3	Lower Seaboard – 10 & 20	905	Y	-	-	-
4	Upper Horsepen - 10	975	Y	-	-	-
5	Upper Horsepen – 20 & 30	1,014	-	-	-	-
6	Pocahontas No. 11	1,156	Y	-	-	-
7	Pocahontas No. 10 - 10	1,193	-	-	-	-
8	Pocahontas No. 10 - 20	1,200	Y	-	-	-
9	Pocahontas No. 9 - 10	1,297	Y	-	Y	Y
10	Pocahontas No. 9 - 20	1,300	-	-	-	-
11	Pocahontas No. 7 - 10	1,413	Y	-	-	-
12	Pocahontas No. 5 - 10	1,572	Y	-	-	-
13	Pocahontas No. 5 - 20	1,624	Y	-	-	-
14	Pocahontas No. 4 – 10/20/30	1,648	Y	Y	-	-
15	Pocahontas No. 3 - 10/20/30	1,727	Y	Y	Y	Y
16	Pocahontas No. 3 - 40	1,747	-	-	-	-
17	Pocahontas No. 3 - 50	1,758	-	-	-	-
18	Pocahontas No. 2 - 10	1,799	Y	-	-	-

Core hole CH-1-2014 was drilled as a continuous core capturing most of the above-noted seams; whereas the other two holes, M-1 and M-2 (CBM-EE7A), were spot cores that captured only the Pocahontas No. 9 and Pocahontas No. 3 seams. Spot-cored holes were subsequently converted into monitoring wells upon completion of drilling. (A monitoring well was also drilled approximately 16 feet away from the CH-1-2014, referred to as C-1).

Sample Processing

Core samples were collected and separated into lengths of approximately 2.0 feet and placed into 28 canisters (see *Appendix* for *General Datasheets*); desorption measurements were taken on-site before being transported to MM&A's Bluefield, Virginia laboratory, where measurements were completed. Laboratory staff from MM&A periodically reviewed the progress of the analysis with interested personnel during the course of the investigation.

Coal Analytical Testing

At the conclusion of the desorption phase, core samples were removed from the canisters, processed, and then transferred to **Virginia Tech** (***VT***) personnel. Some of the samples were subsequently shipped by VT to Precision Testing Laboratory, located in Daniels, West Virginia where coal quality testing was conducted, including the following analyses:

A. Proximate analysis (moisture, ash, sulfur, volatile matter, fixed carbon, and Btu/lb.)

B. Ultimate analysis (moisture, carbon, hydrogen, nitrogen, sulfur, ash, and oxygen)

C. Petrographic analysis (maceral composition, vitrinite reflectance, etc.).

Laboratory data for the above tests were provided for this study, and gas contents were subsequently calculated on a DMMF basis (as discussed in *Section 2.3* below).

Furthermore, a set of 14 whole (uncrushed) core samples were also provided for CT-scan cleat examination. Results from these analyses were not made available for this report.

Gas Composition Testing

Throughout the desorption and residual gas testing phases, more than 775 gas samples were collected from canisters and injected primarily into evacuated 10-cc glass vials (with four samples in 54.75-cc copper tubing) and provided to Virginia Tech for gas composition analysis. Results from these analyses were not made available for this report.

Methodology for Gas Content Analysis

U.S. Bureau of Mines Direct Method

The Direct Method Determination of Gas Content of Coal (Bureau of Mines RI-8515 and IC-9067) with minor modifications (described below) was utilized for this study. This method was subsequently incorporated into the **ASTM**'s standard **D7669-10**, *Standard Practice for Determination of Gas Content of Coal – Direct Desorption Method*.

Core samples were placed in canisters and temperatures regulated at a relatively uniform 70°F. Barometric pressure was also recorded at the same time that samples were sealed in canisters, and each time readings were taken thereafter. After a minimum of five readings was recorded at the drill site, samples were transported to the MM&A laboratory, where stable temperatures were maintained throughout the duration of the analysis.

"Barometric System" of Gas Desorption Testing

Subsequent to issuance of the 1981 USBM guidelines for determining gas content, researchers have investigated alternatives to the apparatus used to measure desorbed gas volumes, which is a simple inverted cylinder in a shallow, water-filled container. One such alternative method, while adhering to the basic concepts of the Direct Method, provides greater accuracy in the measurement of gas volume (refer to *Figure 9-19*).

Figure 9-19 Apparatus for Measuring Desorbed Gas Volumes



Utilizing procedures outlined by Close (1989) for the "Barometric System" of gas desorption testing (a.k.a., "manometric system"), the apparatus used to determine measured gas (after TRW design) includes two burettes (250- and 1,000-ml) attached to a frame to which a vented flask and "flask tubing" are also connected. Desorbed gas that collects in the canister is periodically bled into the burette and measured as a function of displaced water volume with respect to atmospheric pressure and temperature. The meniscus water level in the burette is matched with the water level in the flask by unclamping and slowly lowering the flask assembly in a vertical sense along the length of the burette until the meniscus levels are stabilized in both the burette and flask. Since the desorbed gas and water volumes are influenced by changes in temperature and atmospheric pressure at the drill site and during transport to the laboratory, these data are recorded for each desorption reading.

The barometric system is sensitive to atmospheric pressure changes, which strongly influence the volume of desorbed gas. For example, experience has shown that when atmospheric pressure increases approximately 0.5" (Hg) above the pressure that existed at the time of a previous desorption reading, the pressure within the desorption canister may be less than present atmospheric pressure even though gas continues to be liberated from the sample. Under these circumstances, when the canister is opened to release desorbed gas, the greater atmospheric pressure may cause a reversal of flow direction, that is, the canister will intake air rather than exhaust gas. Conversely, when

atmospheric pressure decreases between two consecutive measurements, the volume of gas liberated from the canister may appear artificially high due to the pressure drop.

Because the methodology utilized in this analysis is influenced by changes in atmospheric pressure, there are inherent sources of error upon the measurement of gas volume during the desorption phase of the evaluation. (Refer to additional discussion under the section, *Limitations Associated with USBM Gas Content Analysis*.) Nevertheless, the barometric system attempts to normalize these variables to *Standard Temperature* and *Pressure* (*STP*), thus facilitating the comparison of samples that were desorbed under differing temperature and pressure conditions. Following standard gas industry convention, gas volumes were adjusted to STP defined as 60° F and 14.70 pounds per square inch absolute (*psia*) (15.6°C and 760 mm Hg).

Gas Content Calculations

The calculation of CBM content is generally derived by the addition of three (3) separate gas component volumes referred to as "lost" gas, "desorbed" gas, and "residual" gas. Each of these is determined individually and subsequently composited to estimate the "total gas content" in units of cubic centimeters per gram (*cc/g*), or standard cubic feet per ton (*scf/t*). Two components, "lost" gas and "desorbed" gas, are combined to estimate the "gas content" for the sample. Unless the sample possesses no residual gas, the *gas content* estimate will always theoretically be less than the *total gas content* for the sample. The following equation illustrates the parameters for calculating both *gas content* and *total gas content*.

$$\text{Gas Content}\left[\text{from Lost} + \text{Desorbed Gas}\right] + \text{Residual Gas Content} = \text{Total Gas Content(scf/t}\ )$$

Furthermore, CBM content can be reported on: (1) as-received (*AR*), and (2) dry-mineral-matter-free (*DMMF*) bases. When coal analytical data is available (moisture, ash, and sulfur content), adjustment to a DMMF-basis is calculated according to the Parr formula (ASTM standard). This latter gas content value can help determine the degree to which non-coal material is influencing the total gas content of the coal bed. Methodology for calculating each of the components of CBM (lost, desorbed, and residual gas) is discussed in the following sections.

Lost Gas Calculations

As a drill bit penetrates a coal seam, coalbed gas begins to desorb almost immediately, and thus some gas unavoidably escapes from the sample during drilling. The actual volume of gas desorbed from the sample prior to containment is always unknown, but two equations were developed by the USBM to estimate the volume of "lost" gas. The two equations employed to estimate "lost" gas volume are distinguished by the type of media used during drilling operations, which is generally air or water.

Rotary drilling generally employs air or foam to remove cuttings, whereas core drilling uses water. The gas desorption rate when drilling with air is assumed to be greater than the rate when drilling with water, hence the necessity for two formulas. All four holes were drilled with water, which is the preferred method due to lower potential for loss of gas before the sample is sealed in a canister.

Whether drilling with air or water, the first five desorbed gas volumes are plotted cumulatively against the square root of time in order to estimate, by extrapolation, the volume of gas lost prior to containment. A "best fit" line (i.e., linear regression) is drawn through the data points; the negative of the Y-intercept is the estimated "lost gas" volume.

Desorbed Gas Calculations

After samples were sealed in canisters, desorption readings were taken more frequently during the first few hours to provide the data points necessary to calculate "lost" gas volume. As "desorbed" gas volumes declined, readings were taken less frequently.

Residual Gas Calculations

At the conclusion of the desorption phase of the analysis, coal samples were crushed in a sealed ball mill (a portion of which passed through a 10-mesh/2.0-mm sieve) allowing the remainder of CBM to be liberated and measured. Gas liberated by this means is referred to as "residual" gas. Finally, material from the ball mill was separated into two size fractions, "crushed" coal (-10-mesh material) and "uncrushed" coal (+10-mesh material). Each size fraction was weighed, and residual gas content was calculated using the weight of the crushed fraction only.

Limitations Associated with USBM Gas Content Analysis

The methodology utilized for this analysis was originally developed by the USBM in the early 1970s (Kissell, 1973) as an adaptation of the original direct method test by Bertard (1970), and has been highly successful in identifying seams with gas contents that could be potentially be dangerous during underground mining activities. USBM data has been utilized for many years and continues to be meaningful in studies to establish gas content trends for numerous U.S. coal-producing basins.

However, with the advent of U.S. CBM development during the mid-1980s, several investigators identified shortcomings with the original USBM methodology for determining gas content. In one study, it was demonstrated that variations in the in-situ reservoir temperature could have significant impact upon estimates of recoverable methane. Indeed, researchers (Nelson, Mavor and Pratt, 1997) have shown that gas content can be significantly over- or under-estimated when this and other reservoir characteristics are not carefully considered.

Interestingly, however, other studies (Knox, 2001) have reported that despite concerns expressed to the contrary, gas content analyses conducted at ambient temperatures can provide favorable results within an acceptable level of accuracy. The same author further qualifies this observation by noting

that, "*Areas with abnormally high heat flow or deep reservoirs at high temperatures should use the reservoir temperature method. Those areas with normal geothermal gradients and lower reservoir temperatures can be accurately assessed with the less costly ambient temperature method*" (Knox, 2001, p. 323).

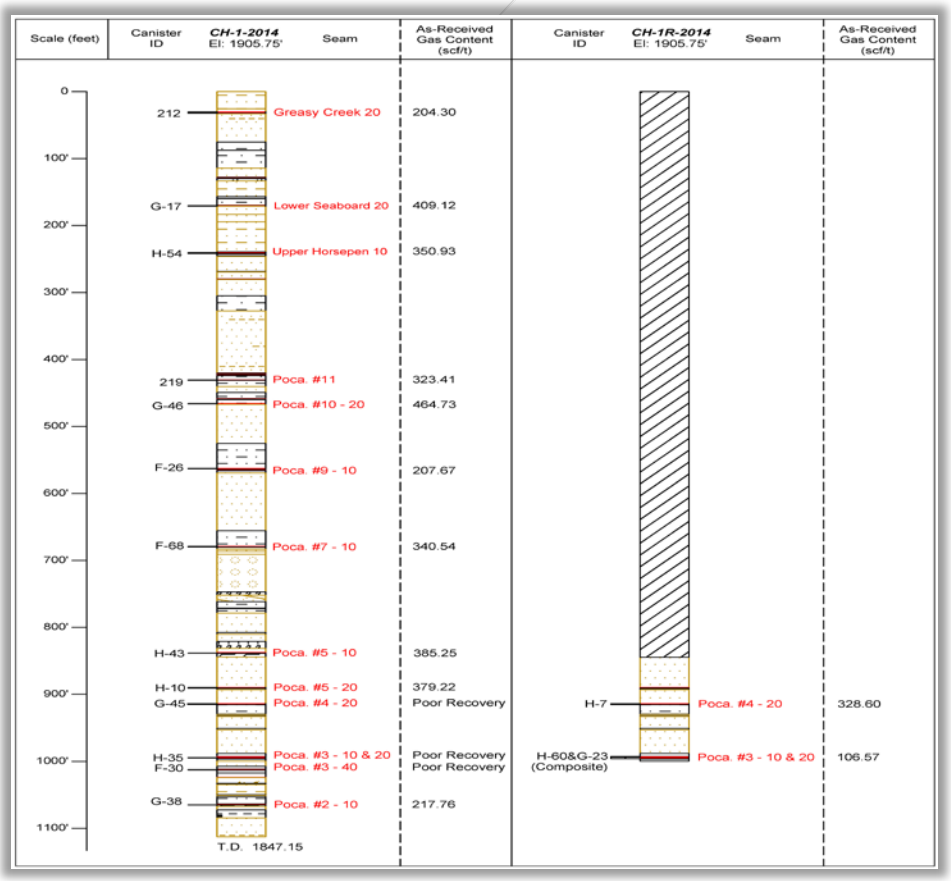
A temperature log was run on each of the holes (Figure 9-20), the results of which showed a range of 61.88°F to 76.60°F between the Greasy Creek and Pocahontas No. 2 seams. At the beginning of the project, it was determined to desorb samples at ambient temperature (70°F), which seems to be a reasonably close approximation of actual reservoir temperature.

Results of Gas Content Analysis

CH-1-2014 and CH-1R-2014

Graphic Logs

Figure 9-20 CH-1-2014 and CH-1R-2014 Stratigraphic Sections



Gas Content Summary

Gas content for the coalbeds in these holes are summarized on *Table 9-6* below. The desorption phase for samples from this hole was approximately 90 days; detailed tables are found in the *Appendix* of this report.

Table 9-6 CH-1-2014 and CH-1R-2014 Gas Content Summary

Canister ID#	Sample Top Depth (ft.)	Sample Thickness (ft.)	As-Received Basis			DMMF
			Gas Content (scf/t)	Residual Gas Content (scf/t)	Total Gas Content (scf/t)	Total Gas Content (scf/t)
Greasy Creek (20 Bench)						
212	765.05	1.87'	130.29	74.02	204.30	249.61
Lower Seaboard (20 Bench)						
G-17	905.00	0.73'	361.42	47.70	409.12	426.51
U. Horsepen (10 Bench)						
H-54	974.95	1.31'	310.72	40.21	350.93	440.71
Pocahontas 11						
219	1165.03	0.74'	253.91	69.50	323.41	352.89
Pocahontas 10 (20 Bench)						
G-46	1200.25	1.15'	391.45	73.28	464.73	514.77
Pocahontas 9 (10 Bench)						
F-26	1297.42	1.60'	176.78	30.89	207.67	228.19
Pocahontas 7 (10 Bench)						
F-68	1413.50	1.05'	292.39	48.15	340.54	396.29
Pocahontas 5 (10 Bench)						
H-43	1572.35	1.00'	344.21	41.05	385.25	418.50
Pocahontas 5 (20 Bench)						
H-10	1624.46	0.86'	331.27	47.95	379.22	413.93
Carbonaceous Shale						
F-52	1625.32	0.77'	19.14	56.74	75.88	0.00
Pocahontas 4 (20 Bench)						
*H-7**	*1648.50*	*1.37'*	*306.86*	*21.74*	*328.60*	*350.95*
G-45	1648.50	1.37'	296.06	0.00	0.00	0.00
Pocahontas 3 (10, 20 & 30 Benches)						
*H-60**	*1727.06*	*1.09'*	*59.40*	*44.68*	*104.08*	*198.78*
*G-23**	*1728.15*	*2.53'*	*74.43*	*33.69*	*108.12*	*119.56*
Composite		**3.62'**	**68.66**	**37.91**	**106.57**	**149.96**
Pocahontas 2 (10 Bench)						
G-38	1798.96	0.69'	164.88	52.88	217.76	285.37
Poor Recovery Samples						
Pocahontas 3 (10-20 Bench)						
H-35	1727.06	3.62'	N/A	N/A	N/A	N/A
Pocahontas 3 (40 Bench)						
F-30	1746.80	0.86'	N/A	N/A	N/A	N/A

*Re-drilled sample from CH-1R-2014

Coal Quality Summary

Listed below (Table 9-7) is a summary of the coal quality for samples from CH-1-2014 and CH-1R-2014.

Table 9-7 Summary of CH-1-2014 and CH-1R-2014 Quality

Sample ID	Seam	Raw Quality (DB)					Mean-Max. Reflectance in Oil, %	Coal Rank
		% Ash	% Sulfur	BTU/lb.	% Vol.	% FC		
212-A	Greasy Creek (20)	4.96	1.36	14,919	24.62	70.42	1.41	MV
212-B (1)	Greasy Creek (20)	26.70	0.37	11,129	17.18	56.12	1.40	LV
G-17	L. Seaboard (20)	2.52	0.68	15,364	22.43	75.05	1.39	MV
H-54	U. Horsepen	16.47	3.19	12,910	20.50	63.03	1.37	MV
219	Pocahontas 11	6.83	0.68	14,652	22.45	70.72	1.46	MV
G-46	Pocahontas 10 (20)	7.65	1.36	14,484	22.18	70.17	1.47	MV
F-26	Pocahontas 9-10	6.63	1.87	14,631	21.53	71.84	1.44	MV
F-68	Pocahontas 7	10.31	4.39	14,066	19.46	70.23	1.41	LV
H-43	Pocahontas 5 (20)	6.18	1.25	14,835	22.31	71.51	1.44	MV
H-10	Pocahontas 5 (20)	6.39	1.75	14,781	21.90	71.62	1.50	MV
H-7	Pocahontas 4 (20)	5.01	0.51	15,074	21.22	73.77	1.51	LV
H-60A (2)	Pocahontas 3 (10)	72.11	1.18	2,941	9.44	18.45	1.52	LV
H-60B	Pocahontas 3 (10)	12.33	4.15	13,681	18.78	68.89	1.54	LV
G-23	Pocahontas 3 (20/30)	7.21	1.50	14,606	19.82	72.97	1.56	LV
G-38	Pocahontas 2	19.94	2.94	12,277	18.20	61.86	1.48	LV

1) 212-B is a boney coal with low vitrinite and high semi-fusinite maceral composition.
2) H-60A is a carbonaceous shale with coal streaks.

Expanded Graphic Sections

Included in the *Appendix* of this report are expanded sections (at 1 inch = 1 foot) of each canistered interval, including gamma-density curves, canister identification, date of sampling, lithologic description, notes indicating lost core, as-received gas content, and identification of intervals that were: (1) preserved for cleat examination, and not crushed; (2) carbonaceous shale sections that were crushed to liberate residual gas, and; (3) shale sections that were preserved, but not crushed.

Core Photographs and Macroscopic Description of Samples

Annotated photographs of canistered samples are found in the *Appendix*. In addition to the photographs, a description of each sample is provided below (Table 9-8). The description includes the Stopes system of coal lithotypes (Vitrain, Clarain, Durain, and Fusain), the presence of minerals (pyrite and calcite) and other non-coal material, fracture patterns, and overall state of samples.

Table 9-8 CH-1-2014 Macroscopic Description

Canister	Thickness	CH-1-2014 Sample Description
Greasy Creek		
212	0.48	Vitrain
	0.08	Shale
	0.27	Vitrain with Clarain streaks
	0.14	Clarain with Durain streaks
	0.81	Boney coal with few Clarain laminations, hard
Lower Seaboard (20 Bench)		
G-17	0.20	Clarain with Vitrain and Fusain streaks
	0.05	Bone
	0.48	Vitrain with Clarain, few pyrite nodules and Fusain laminations

Canister	Thickness	CH-1-2014 Sample Description
Upper Horsepen (10 Bench)		
H-54	0.09	Vitrain with Clarain streaks
	0.08	Shale with coal streaks
	0.50	Vitrain with Clarain streaks
	0.29	Coal with bone streaks
	0.35	Vitrain with Clarain streaks
Pocahontas No. 11		
219	0.07	Clarain with Vitrain streaks, highly crushed
	0.67	Vitrain with Clarain laminations and occasional thin Fusain laminations
Pocahontas No. 10 (20 Bench)		
G-46	0.17	Vitrain with Clarain streaks
	0.31	Clarain with Vitrain streaks
	0.49	Vitrain
	0.18	Vitrain, highly crushed
Pocahontas No. 9 (10 Bench)		
F-26	1.54	Vitrain with occasional Fusain laminations
	0.06	Vitrain, highly crushed
Pocahontas No. 7 (10 Bench)		
F-68	0.56	Clarain with Vitrain plus few thin pyrite laminations
	0.07	Coal with bone
	0.42	Vitrain with Clarain, calcite on cleats and minor pyrite laminations
Pocahontas No. 5 (10 Bench)		
H-43	0.07	Vitrinite rubble
	0.02	Shale
	0.36	Vitrain with Clarain laminations, calcite-filled cleat
	0.54	Vitrain with Clarain laminations and Fusain laminations
Pocahontas No. 5 (20 Bench)		
H-10	0.68	Vitrain
	0.18	Clarain with Vitrain laminations
Pocahontas No. 4		
G-45	0.50	Vitrain with Clarain and Fusain laminations – Poor Recovery
	0.40	Vitrain with Clarain and Fusain laminations – Poor Recovery
	0.31	Clarain with Vitrain laminations, slightly hard – Poor Recovery
H-7	0.25	Clarain with Vitrain laminations – Re-drill
	0.17	Clarain with Vitrain and Fusain laminations – Re-drill
	0.95	Clarain with numerous Vitrain streaks and bands – Re-drill
Pocahontas No. 3 (10-20 Bench)		
H-35	0.80	Vitrain – Poor Recovery
	0.75	Carbonaceous shale – Poor Recovery
	0.47	Vitrain interbedded with Clarain – Poor Recovery
Pocahontas No. 3 (40 Bench)		
F-30	0.18	Shale with coal streaks – Poor Recovery (not re-drilled)
	0.36	Vitrain with Clarain laminations – Poor Recovery (not re-drilled)
	0.20	Interbedded Vitrain and Clarain – Poor Recovery (not re-drilled)
	0.07	Vitrain with Clarain laminations – Poor Recovery (not re-drilled)
Pocahontas No. 3 (10 Bench)		
H-60	0.50	Carbonaceous shale with thin coal streaks – Re-drill
	0.59	Interbedded Clarain and Vitrain with occasional thin Fusain laminations and single pyrite lamination – Re-drill

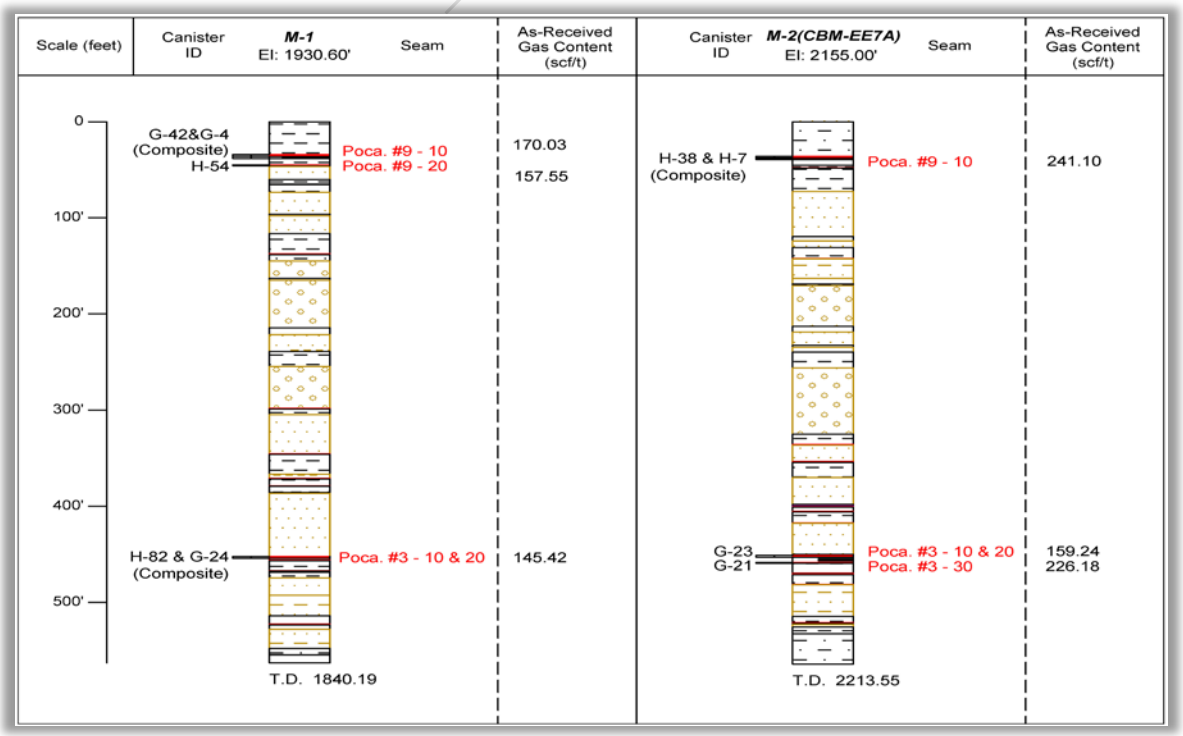
Canister	Thickness	CH-1-2014 Sample Description
Pocahontas No. 3 (10 - 20 Bench)		
G-23	0.37	Vitrain – Re-drill
	0.43	Vitrain with Bone bands – Re-drill
	0.05	Bone – Re-drill
	0.54	Vitrain with Clarain laminations and occasional Fusain – Re-drill
	0.15	Shale with carbonaceous shale – Re-drill
	0.59	Vitrain with Fusain laminations, high ash – Re-drill
Pocahontas No. 2 (10 Bench)		
G-38	0.07	Vitrain with Fusain streaks
	0.08	Vitrain with Clarain streaks
	0.07	Boney coal
	0.11	Vitrain with Clarain streaks
	0.16	Boney coal
	0.20	Vitrain with minor Fusain streaks

M-1

After core samples were collected for desorption, M-1 was converted into a monitoring well (Figure 9-21, Table 9-9, Table 9-10 and Table 9-11)

Graphic Logs

Figure 9-21 M-1 and M-2 (CBM-EE7A) Stratigraphic Sections



Gas Content Summary

Table 9-9 Summary of M-1 Coalbed Gas Content

Canister ID#	Depth (ft.)	Seam Thickness	As-Received Basis: Gas Content (scf/t)	As-Received Basis: Residual Gas Content (scf/t)	As-Received Basis: Total Gas Content (scf/t)	DMMF: Total Gas Content (scf/t)
Pocahontas No. 9 (10)						
G-42	1311.88	0.38'	143.73	39.18	182.91	211.51
G-4	1313.93	2.05'	129.47	37.95	167.42	185.07
Composite		**2.43'**	**131.88**	**38.16**	**170.03**	**228.10**
Pocahontas No. 9, (Carbonaceous Shale)						
G-38	1315.93	2.00'	28.08	17.87	45.95	
Pocahontas No. 9 (20)						
H-54	1323.37	0.87'	119.35	38.20	157.55	190.76
Pocahontas No. 3 (10,20)						
H-82	1731.49	1.89'	100.86	33.56	134.42	149.27
G-24	1731.65	0.16'	110.94	120.83	231.77	338.33
Composite		**2.05'**	**102.00**	**43.41**	**145.42**	**170.62**

Coal Quality Summary

Table 9-10 Summary of M-1 Quality

Sample ID	Seam	Raw Quality, Dry Basis: % Ash	% Sulfur	BTU/lb.	% Vol.	%FC	Mean-Max. Reflectance in Oil, %	Coal Rank
Desorption Sample								
G-42	Pocahontas 9 (10)	10.08	2.67	14,050	21.76	68.16	1.50	MV
G-4A	Pocahontas 9 (10)	3.83	0.68	15,169	22.53	73.64	1.46	MV
G-4B	Pocahontas 9 (10)	9.48	1.55	14,143	20.49	70.03	1.49	LV
	Composite	*6.92*	*1.16*	*14,609*	*21.42*	*71.67*	*1.48*	
H-54	Pocahontas 9 (20)	13.51	3.37	13,457	21.55	64.94	-	MV
H-82	Pocahontas 3 (10)	7.29	0.88	14,524	20.47	72.24	1.53	LV
G-24	Pocahontas 3 (20)	27.87	1.49	11,194	17.24	54.89	-	LV

Expanded Graphic Sections

Expanded graphic sections generated originally at 1 inch = 1 foot are found in the *Appendix*.

Core Photographs and Macroscopic Description of Samples

Annotated photographs of canistered samples are found in the *Appendix*.

Table 9-11 M-1 Macroscopic Descriptions

Canister	Thickness	M-1 Sample Description
Pocahontas No. 9 (10 Bench)		
G-42	0.38	Vitrain with occasional thin shale streaks and one thin pyrite lamination
G-4	0.07	Vitrain with Clarain streaks, rubble
	0.70	Vitrain, well cleated
	0.11	Clarain with Durain and thin pyrite laminations
	0.61	Vitrain with Fusain streaks
	0.08	Clarain with Durain and pyrite nodules
	0.48	Clarain with Durain and Vitrain laminations, slickensided
Pocahontas No. 9 (10 Bench) Parting		
G-38	2.00	Carbonaceous shale and clay shale with numerous thin Vitrain and Durain streaks, numerous plant fossils on bedding
Pocahontas No. 9 (20 Bench)		
H-54	0.09	Vitrain with Clarain and numerous pyrite laminations
	0.10	Vitrain
	0.04	Fusain
	0.54	Vitrain with Clarain laminations and occasional thin Fusain laminations
	0.10	Vitrain with pyrite laminations
Pocahontas No. 3 (10-20 Bench)		
H-82	1.12	Vitrain with Clarain and thin Fusain streaks
	0.10	Shaley coal
	0.40	Boney coal
	0.09	Vitrain with Clarain streaks
Pocahontas No. 3 (20 bench)		
G-24	0.16	Vitrain with obliquely interbedded Durain

M-2 (CBM-EE7A)

After core samples were collected for desorption, M-2 was converted into a monitoring well (see *Site Photographs* in the *Appendix and Tables 9-12*, 9-13 and 9-14)

Graphic Log

See section above.

Gas Content Summary

Table 9-12 Summary of M-2 Coalbed Gas Content

Canister ID#	Sample Top Depth (ft.)	Sample Thickness (ft.)	As-Received Basis			DMMF
			Gas Content (scf/t)	Residual Gas Content (scf/t)	Total Gas Content (scf/t)	Total Gas Content (scf/t)
Pocahontas No. 9 (10)						
H-38	1548.05	1.55'	207.21	24.22	231.43	-
H-7	1550.05	0.40'	228.03	49.35	277.38	306.07
Composite		1.95'	211.59	29.51	241.10	
Pocahontas No. 3 (10,20)						
G-23	1963.40	1.95'	129.85	29.40	159.24	185.84
Pocahontas No. 3 (30)						
G-21	1969.85	0.90'	190.55	35.63	226.18	353.79

Coal Quality Summary

Table 9-13 Summary of M-2 Quality

Canister ID	Seam	Raw Quality (DB)					Mean-Max. Reflectance in Oil, %	Coal Rank
		% Ash	% Sulfur	BTU/lb.	% Vol.	% FC		
H-38	Pocahontas 9 (10)	-	-	-	-	-	-	NA
H-7	Pocahontas 9 (10)	6.85	1.35	14,554	20.53	72.62	-	LV
G-23	Pocahontas 3 (10,20)	12.13	0.72	13,456	20.06	67.81	-	LV
G-21	Pocahontas 3 (30)	32.21	1.15	10,398	16.65	51.14	-	LV

Expanded Graphic Sections

Expanded graphic sections generated originally at 1 inch = 1 foot are found in the *Appendix*.

Core Photographs and Macroscopic Description of Samples

Annotated photographs of canistered samples are found in the *Appendix*.

Table 9-14 M-2 Macroscopic Descriptions

Canister	Thickness	M-2 Sample Description
Pocahontas No. 9 (10 Bench)		
H-38	0.54	Vitrain with Clarain bands, core intact
	1.01	Vitrain with occasional thick Clarain bands, highly crushed
212	1.07	Carbonaceous shale with coal streaks
H-7	0.06	Durain, slightly dull, gray
	0.34	Vitrain
Pocahontas No. 3 (10 Bench)		
G-23	0.40	Vitrain with Clarain bands and Fusain streaks
	0.18	Vitrain, highly crushed
	0.62	Vitrain with Clarain bands
	0.38	Vitrain with Clarain and few Fusain and coal streaks
	0.10	Shaley coal, broken
	0.12	Vitrain with Clarain streaks
Pocahontas No. 3 (30 Bench)		
G-21	0.10	Shale with coal streaks
	0.09	Clarain with Durain and shale streaks
	0.25	Vitrain with Clarain and Fusain streaks
	0.13	Shale
	0.09	Shale with coal streaks
	0.23	Vitrain with Clarain streaks, with few shale bands

9.3 Coal Testing

9.3.1 Targeted Coal Seams

Eleven principal coalbeds were canistered from the carbon dioxide injection site in Buchanan County, Virginia, spanning an interval of approximately 1,035 feet, which belong to the Pennsylvanian-age Norton, Lee, and Pocahontas Formations (see *Table 9-15*). These include the following seams (in descending stratigraphic order): Greasy Creek, Lower Seaboard, Upper Horsepen, Pocahontas No. 11, Pocahontas No. 10, Pocahontas No. 9, Pocahontas No. 7, Pocahontas No. 5, Pocahontas No. 4, Pocahontas No. 3, and Pocahontas No. 2 seams, as well as associated coal splits and carbonaceous shale strata.

The Pocahontas No. 3 seam occurs in as many as 5 separate benches, separated by non-coal partings of variable thickness. According to available information, each of these coalbeds has been perforated and completed within nearby CBM wells. Core hole CH-1-2014 was drilled as a continuous core capturing all of the above-noted seams.

Table 9-15 Coal Samples Collected from CH-1-2014 Hole

Coal samples	Depth at CH-1-2014 (feet)
Greasy Greek	765.05 - 765.97
L-Seaboard	905 - 905.73
Horsepen	974.95 - 976.26
Poca 11	1162.03 - 1165.77
Poca10	1200.25 - 1201.64
Poca 9	1297.42 - 1299.02
Poca 7	1413.15 - 1414.55
Poca 5	1572.35 - 1573.35
Poca 4	1648.5 - 1649.87
Poca 3	1728.15 - 1730.68
Poca 2	1798.96 - 1799.65

9.3.2 Sample Processing

Core samples were collected and separated into lengths of approximately 2.0 feet and placed into 28 canisters (see *Appendix* for *General Datasheets*); desorption measurements were taken on-site before being transported to MM&A's Bluefield, Virginia laboratory, where measurements were completed. Laboratory staff from MM&A periodically reviewed the progress of the analysis with interested personnel during the course of the investigation.

9.3.3 Gas Content Analysis

Documentation is provided regarding the methodology for determining gas content for a sequence of coalbeds penetrated by 3 core holes.

1. The first of these holes, **CH-1-2014,** was drilled by continuous coring methods from July through September 2014, (a portion of which was re-drilled, and referred to as **CH-1R-2014)**;
2. Two spot-core holes were drilled in March 2015, **M-1** and **M-2 (CBM-EE7A),** which were subsequently converted into monitoring wells.

According to available information, each of these coalbeds has been perforated and completed within nearby CBM wells between 2000 and 2008 (see Figures *B7* and *B8* in the *Appendix*). Core hole CH-1-2014 is a continuous core hole that captured all of the above-noted seams, wherever they were present.

Whereas two other spot-core holes, M-1 and M-2 (CBM-EE7A), captured only the Pocahontas No. 9 and Pocahontas No. 3 seams. (Furthermore, a monitoring well was also drilled approximately 16 feet away from the CH-1-2014, referred to as C-1, however no core samples were collected from this hole).

Analyses of a portion of the coal samples from these holes were conducted by Precision Testing Laboratory, located in Daniels, West Virginia including:

Proximate analysis (moisture, ash, sulfur, volatile matter, fixed carbon, and Btu/lb.)

Ultimate analysis (moisture, carbon, hydrogen, nitrogen, sulfur, ash, and oxygen)

Petrographic analysis (maceral composition, vitrinite reflectance, etc.)

Where available, coal quality was incorporated into this analysis to derive gas content in standard cubic feet per ton (*scf/t*) on both "as-received" and "dry, mineral-matter-free" (*DMMF*) bases. Furthermore, results of the coal quality analysis demonstrate that the rank of these coalbeds ranges from Medium Volatile to Low Volatile Bituminous; and mean-maximum vitrinite reflectance varies from 1.37 to 1.56 percent.

Based on regional information, pre-development / pre-mining gas contents for the Pocahontas No. 3 seam *within the study* area ranged from approximately 450 to 500 standard cubic feet per ton (*scf/t*), but significantly higher elsewhere. The objective of this analysis is to determine the gas content of coalbeds from which CBM has been extracted for more than 20 years.

From this analysis, as-received coalbed gas contents from this sequence of seams vary widely, from a minimum of 106.57 scf/t for Pocahontas No. 3 seam in CH-1R-2014, to a maximum of 464.73 scf/t for the Pocahontas No. 10 seam within CH-1-2014. With the exception of the Pocahontas No. 9 seam, the higher gas contents (greater than 300 scf/t) found within seams overlying the Pocahontas No. 3 demonstrates favorable potential for additional extraction of CBM from these seams.

Regional mapping of assumed pre-development coalbed gas contents is illustrated on *Figures B3* and *B4* in the *Appendix*. Pocahontas No. 3 seam gas contents vary significantly, from 300 to more than 650 scf/t. Indeed, the highest reported gas content for this seam (689 scf/t) is located less than two miles north of the study area. However, in 2014, gas contents from the combined benches of the Pocahontas No. 3 seam, #10 through #30 (analyzed in all three holes), range from 106.57 to 159.24 scf/t, providing a clear indication of the success of CBM extraction over the past 20+ years from the Oakwood CBM field.

In addition to gas content testing throughout the desorption and residual gas testing phases, gas samples were collected and provided to Virginia Tech for gas composition analysis; moreover, a set of 14 whole (uncrushed) coal core samples were also provided for CT-scan cleat examination. Results from these analyses are not included within this section of the report.

All desorption holes were geophysically logged by **Geophysical Logging Systems (*GLS*** a division of **Marshall Miller & Associates, Inc. [*MM&A*])**, including: gamma-density, resistivity, and temperature; an Acoustic Televiewer (*ATV*) log was run only on CH-1-2014. Furthermore, in 2015 information on the

depth, number, and condition of wellbore perforations was interpreted from video logs of CO_2 injection wells, **CB-DD7**, **CB-DD7A**, and **CB-DD8 (**provided in the *Appendix* of this report).

Geophysical logging (High-definition Formation Micro Imager, or *FMI*) of C-1 was conducted by **Schlumberger** in 2015, which may be comparable to MM&A's nearby CH-1-2014 ATV log. Moreover, a CO_2 injection analysis of wells **CB-DD7** and **CB-DD8** was conducted in March 2016 by **Weatherford**, the results of which have been compared to MM&A's video logs of the same holes.

Finally, this report also includes data pertaining to the regional horizontal stress field, locations of known faults and folds, and mapped linear features, as well as coalbed face and butt cleat directions, all of which can have a significant impact upon gas production.

Background of Coal and Gas Production

This gas content analysis is part of an on-going investigation to test the feasibility of injecting CO_2 into existing CBM wells in order to:

1. Enhance CBM gas recovery (*ECBM*), and
2. Sequester CO_2 within a coal-bearing formation.

Northeast of and adjacent to the study area, underground mining (principally longwall) of the Pocahontas No. 3 seam has been on-going continuously since the late 1960's, with CBM / CMM production since the early 1990's. Prior to CBM development in Buchanan County, underground coal operations in the Pocahontas No. 3 seam were engaged in mining some of the gassiest coal seams in the United States (exceeding 650 cubic feet per ton), and thus found it necessary for purposes of mine safety to liberate large volumes of coal mine methane (*CMM*) prior to, during, and after coal extraction. For more than 25 years, CMM was continually vented into the atmosphere before methods were established to capture and produce pipeline-quality gas, while at the same time maintaining a safe working environment for continued coal extraction.

Within the study area, gas production from the Oakwood Coalbed Methane (*CBM*) field and adjacent Nora CBM Field, by **CNX**, **Equitable**, **Occidental** (***OXY***), and others extends back to the early 1990's, at almost the same time that CMM was beginning to be captured by **Island Creek Coal Company** (***ICCCo***) and **Consol**/CNX from their coal mining operations in the Pocahontas No. 3 seam. [Both Island Creek and Consol have since gone out of business and all longwall operations except Buchanan No. 1 have been shuttered.] MM&A's GLS has been e-logging gas wells within the AOR since 1991 (the Ball A-1 brine injection well) to the present.

Consol and ICCCo (and successors) have been the principal developers of coal from the Pocahontas No. 3 seam in Buchanan County from the following mines: Beatrice, Buchanan No. 1, VP-1, VP-2, VP-3, VP-4, and VP-8 (formerly VP-5 and VP-6).

Due to the high gas content of the deep seams in this region, the **US Bureau of Mines** (now part of *NIOSH*) conducted numerous studies in the 1970's and 1980's with the objective of improving underground mine safety, and secondarily to enhance mining productivity. Consequently, a variety pre-mining through post-mining degasification techniques were developed to assist in this endeavor, which ultimately led to the creation of the Oakwood CBM Field.

Prior and More Recent Gas Content Testing

In 2009, MM&A conducted a gas content analysis of the same sequence of coal beds in hole **BD-114-M2**, approximately 7 miles from the present study area, the results of which have been previously presented.

This report presents the results of a coalbed gas (*CBM*) content analysis of samples collected by MM&A from three holes, the first of which was drilled to a depth of 1,847 feet by continuous coring methods in July – September 2014, **CH-1-2014** (a portion of which was re-drilled and referred to as **CH-1R-2014**). Approximately 6 months after the first desorption hole (March 2015), two spot-cored holes were drilled: **M-1** and **M-2 (CBM-EE7A),** drilled to depths of 1,835 feet and 2,210 feet, respectively.

Information on the locations of wellbore perforations derived from video logs for three CO_2 injection wells, **CB-DD7**, **CB-DD7A**, and **CB-DD8**, is also provided in the *Appendix* of this report including: maps, cross sections, and site photographs. CO_2 injection into these 3 wells began in July 2015.

Target Seams

Eleven (11) principal coalbeds were canistered (Table 9-16) in this study, spanning an interval of approximately 1,035 feet, which belong to the Pennsylvanian-age Norton, Lee, and Pocahontas Formations. These include the following seams (in descending stratigraphic order): Greasy Creek, Lower Seaboard, Upper Horsepen, Pocahontas No. 11, Pocahontas No. 10, Pocahontas No. 9, Pocahontas No. 7, Pocahontas No. 5, Pocahontas No. 4, Pocahontas No. 3, and Pocahontas No. 2 seams, as well as associated coal splits and carbonaceous shale strata.

The Pocahontas No. 3 seam occurs in as many as 5 separate benches, separated by non-coal partings of variable thickness. According to available information, each of these coalbeds has been perforated and completed within nearby CBM wells.

Table 9-16 Samples Collected from 4 Holes for Gas Content Analysis

Map #	Seam with Bench ID	Top Depth at CH-1-2014 (feet)	CH-1-2014	CH-1R-2014	M-1	M-2 (CBM-EE7A)
1	Greasy Creek - 20	765	Y	-	-	-
2	Seaboard - 20	863	-	-	-	-
3	Lower Seaboard – 10 & 20	905	Y	-	-	-
4	Upper Horsepen - 10	975	Y	-	-	-
5	Upper Horsepen – 20 & 30	1,014	-	-	-	-
6	Pocahontas No. 11	1,156	Y	-	-	-
7	Pocahontas No. 10 - 10	1,193	-	-	-	-
8	Pocahontas No. 10 - 20	1,200	Y	-	-	-
9	Pocahontas No. 9 - 10	1,297	Y	-	Y	Y
10	Pocahontas No. 9 - 20	1,300	-	-	-	-
11	Pocahontas No. 7 - 10	1,413	Y	-	-	-
12	Pocahontas No. 5 - 10	1,572	Y	-	-	-
13	Pocahontas No. 5 - 20	1,624	Y	-	-	-
14	Pocahontas No. 4 – 10/20/30	1,648	Y	Y	-	-
15	Pocahontas No. 3 - 10/20/30	1,727	Y	Y	Y	Y
16	Pocahontas No. 3 - 40	1,747	-	-	-	-
17	Pocahontas No. 3 - 50	1,758	-	-	-	-
18	Pocahontas No. 2 - 10	1,799	Y	-	-	-

Core hole CH-1-2014 was drilled as a continuous core capturing most of the above-noted seams; whereas the other two holes, M-1 and M-2 (CBM-EE7A), were spot cores that captured only the Pocahontas No. 9 and Pocahontas No. 3 seams. Spot-cored holes were subsequently converted into monitoring wells upon completion of drilling. (A monitoring well was also drilled approximately 16 feet away from the CH-1-2014, referred to as C-1).

Coal Analytical Testing

At the conclusion of the desorption phase, core samples were removed from the canisters, processed, and then transferred to **Virginia Tech** (***VT***) personnel. Some of the samples were subsequently shipped by VT to Precision Testing Laboratory, located in Daniels, West Virginia where coal quality testing was conducted, including the following analyses:

A. Proximate analysis (moisture, ash, sulfur, volatile matter, fixed carbon, and Btu/lb.)

B. Ultimate analysis (moisture, carbon, hydrogen, nitrogen, sulfur, ash, and oxygen)

C. Petrographic analysis (maceral composition, vitrinite reflectance, etc.).

Laboratory data for the above tests were provided for this study, and gas contents were subsequently calculated on a DMMF basis (as discussed in *Section 2.3* below).

Furthermore, a set of 14 whole (uncrushed) core samples were also provided for CT-scan cleat examination. Results from these analyses were not made available for this report.

Gas Composition Testing

Throughout the desorption and residual gas testing phases, more than 775 gas samples were collected from canisters and injected primarily into evacuated 10-cc glass vials (with four samples in 54.75-cc copper tubing) and provided to Virginia Tech for gas composition analysis. Results from these analyses were not made available for this report.

Methodology for Gas Content Analysis

U.S. Bureau of Mines Direct Method

The Direct Method Determination of Gas Content of Coal (Bureau of Mines RI-8515 and IC-9067) with minor modifications (described below) was utilized for this study. This method was subsequently incorporated into the **ASTM**'s standard **D7669-10**, *Standard Practice for Determination of Gas Content of Coal – Direct Desorption Method*.

Core samples were placed in canisters and temperatures regulated at a relatively uniform 70°F. Barometric pressure was also recorded at the same time that samples were sealed in canisters, and each time readings were taken thereafter. After a minimum of five readings was recorded at the drill site, samples were transported to the MM&A laboratory, where stable temperatures were maintained throughout the duration of the analysis.

"Barometric System" of Gas Desorption Testing

Subsequent to issuance of the 1981 USBM guidelines for determining gas content, researchers have investigated alternatives to the apparatus used to measure desorbed gas volumes, which is a simple inverted cylinder in a shallow, water-filled container. One such alternative method, while adhering to the basic concepts of the Direct Method, provides greater accuracy in the measurement of gas volume (refer to *Figure 9-22*).

Figure 9-22 Apparatus for Measuring Desorbed Gas Volumes



Utilizing procedures outlined by Close (1989) for the “Barometric System” of gas desorption testing (a.k.a., “manometric system”), the apparatus used to determine measured gas (after TRW design) includes two burettes (250- and 1,000-ml) attached to a frame to which a vented flask and “flask tubing” are also connected. Desorbed gas that collects in the canister is periodically bled into the burette and measured as a function of displaced water volume with respect to atmospheric pressure and temperature. The meniscus water level in the burette is matched with the water level in the flask by unclamping and slowly lowering the flask assembly in a vertical sense along the length of the burette until the meniscus levels are stabilized in both the burette and flask. Since the desorbed gas and water volumes are influenced by changes in temperature and atmospheric pressure at the drill site and during transport to the laboratory, these data are recorded for each desorption reading.

The barometric system is sensitive to atmospheric pressure changes, which strongly influence the volume of desorbed gas. For example, experience has shown that when atmospheric pressure increases approximately 0.5" (Hg) above the pressure that existed at the time of a previous desorption reading, the pressure within the desorption canister may be less than present atmospheric pressure even though gas continues to be liberated from the sample. Under these circumstances, when the canister is opened to release desorbed gas, the greater atmospheric pressure may cause a reversal of flow direction, that is, the canister will intake air rather than exhaust gas. Conversely, when

atmospheric pressure decreases between two consecutive measurements, the volume of gas liberated from the canister may appear artificially high due to the pressure drop.

Because the methodology utilized in this analysis is influenced by changes in atmospheric pressure, there are inherent sources of error upon the measurement of gas volume during the desorption phase of the evaluation. (Refer to additional discussion under the section, *Limitations Associated with USBM Gas Content Analysis*.) Nevertheless, the barometric system attempts to normalize these variables to *Standard Temperature* and *Pressure* (*STP*), thus facilitating the comparison of samples that were desorbed under differing temperature and pressure conditions. Following standard gas industry convention, gas volumes were adjusted to STP defined as 60° F and 14.70 pounds per square inch absolute (*psia*) (15.6°C and 760 mm Hg).

Gas Content Calculations

The calculation of CBM content is generally derived by the addition of three (3) separate gas component volumes referred to as "lost" gas, "desorbed" gas, and "residual" gas. Each of these is determined individually and subsequently composited to estimate the "total gas content" in units of cubic centimeters per gram (*cc/g*), or standard cubic feet per ton (*scf/t*). Two components, "lost" gas and "desorbed" gas, are combined to estimate the "gas content" for the sample. Unless the sample possesses no residual gas, the *gas content* estimate will always theoretically be less than the *total gas content* for the sample. The following equation illustrates the parameters for calculating both *gas content* and *total gas content*.

$$\text{Gas Content}\left[\text{from Lost} + \text{Desorbed Gas}\right] + \text{Residual Gas Content} = \text{Total Gas Content(scf/t}\ )$$

Furthermore, CBM content can be reported on: (1) as-received (*AR*), and (2) dry-mineral-matter-free (*DMMF*) bases. When coal analytical data is available (moisture, ash, and sulfur content), adjustment to a DMMF-basis is calculated according to the Parr formula (ASTM standard). This latter gas content value can help determine the degree to which non-coal material is influencing the total gas content of the coal bed. Methodology for calculating each of the components of CBM (lost, desorbed, and residual gas) is discussed in the following sections.

Lost Gas Calculations

As a drill bit penetrates a coal seam, coalbed gas begins to desorb almost immediately, and thus some gas unavoidably escapes from the sample during drilling. The actual volume of gas desorbed from the sample prior to containment is always unknown, but two equations were developed by the USBM to estimate the volume of "lost" gas. The two equations employed to estimate "lost" gas volume are distinguished by the type of media used during drilling operations, which is generally air or water.

Rotary drilling generally employs air or foam to remove cuttings, whereas core drilling uses water. The gas desorption rate when drilling with air is assumed to be greater than the rate when drilling with water, hence the necessity for two formulas. All four holes were drilled with water, which is the preferred method due to lower potential for loss of gas before the sample is sealed in a canister.

Whether drilling with air or water, the first five desorbed gas volumes are plotted cumulatively against the square root of time in order to estimate, by extrapolation, the volume of gas lost prior to containment. A "best fit" line (i.e., linear regression) is drawn through the data points; the negative of the Y-intercept is the estimated "lost gas" volume.

Desorbed Gas Calculations

After samples were sealed in canisters, desorption readings were taken more frequently during the first few hours to provide the data points necessary to calculate "lost" gas volume. As "desorbed" gas volumes declined, readings were taken less frequently.

Residual Gas Calculations

At the conclusion of the desorption phase of the analysis, coal samples were crushed in a sealed ball mill (a portion of which passed through a 10-mesh/2.0-mm sieve) allowing the remainder of CBM to be liberated and measured. Gas liberated by this means is referred to as "residual" gas. Finally, material from the ball mill was separated into two size fractions, "crushed" coal (-10-mesh material) and "uncrushed" coal (+10-mesh material). Each size fraction was weighed, and residual gas content was calculated using the weight of the crushed fraction only.

Limitations Associated with USBM Gas Content Analysis

The methodology utilized for this analysis was originally developed by the USBM in the early 1970s (Kissell, 1973) as an adaptation of the original direct method test by Bertard (1970), and has been highly successful in identifying seams with gas contents that could be potentially be dangerous during underground mining activities. USBM data has been utilized for many years and continues to be meaningful in studies to establish gas content trends for numerous U.S. coal-producing basins.

However, with the advent of U.S. CBM development during the mid-1980s, several investigators identified shortcomings with the original USBM methodology for determining gas content. In one study, it was demonstrated that variations in the in-situ reservoir temperature could have significant impact upon estimates of recoverable methane. Indeed, researchers (Nelson, Mavor and Pratt, 1997) have shown that gas content can be significantly over- or under-estimated when this and other reservoir characteristics are not carefully considered.

Interestingly, however, other studies (Knox, 2001) have reported that despite concerns expressed to the contrary, gas content analyses conducted at ambient temperatures can provide favorable results within an acceptable level of accuracy. The same author further qualifies this observation by noting

that, "*Areas with abnormally high heat flow or deep reservoirs at high temperatures should use the reservoir temperature method. Those areas with normal geothermal gradients and lower reservoir temperatures can be accurately assessed with the less costly ambient temperature method*" (Knox, 2001, p. 323).

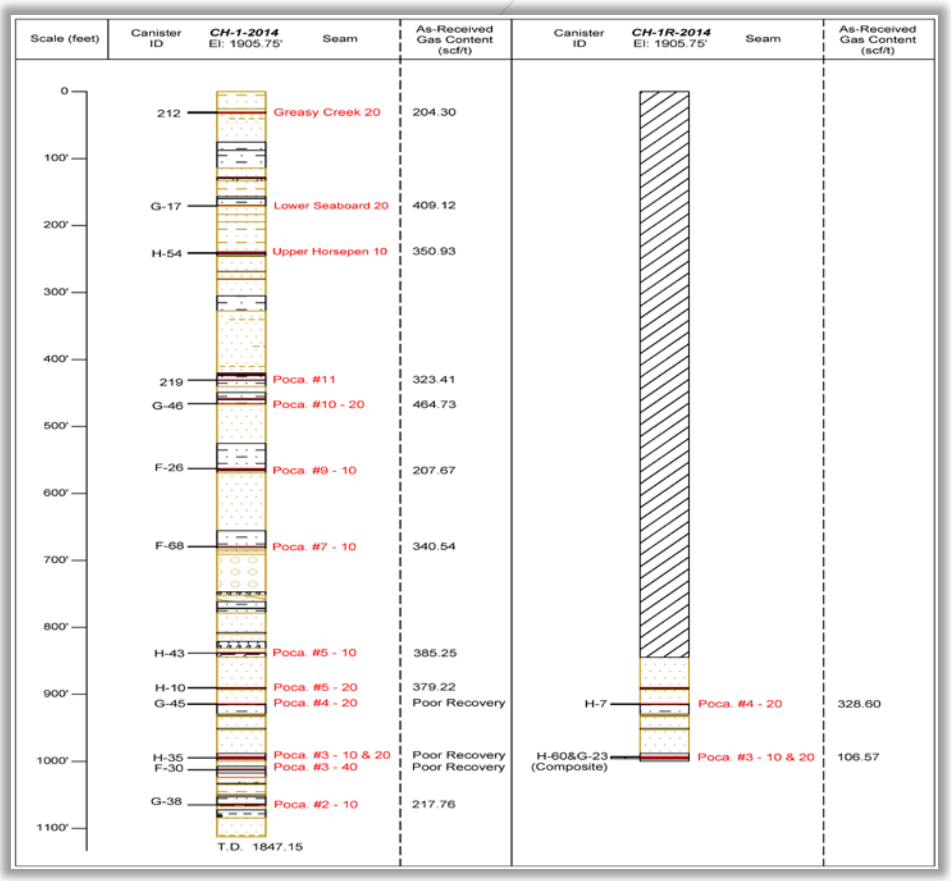
A temperature log was run on each of the holes, the results of which showed a range of 61.88°F to 76.60°F between the Greasy Creek and Pocahontas No. 2 seams. At the beginning of the project, it was determined to desorb samples at ambient temperature (70°F), which seems to be a reasonably close approximation of actual reservoir temperature.

Results of Gas Content Analysis

CH-1-2014 and CH-1R-2014 (Figure 9-23)

Graphic Logs

Figure 9-23 CH-1-2014 and CH-1R-2014 Stratigraphic Sections



Gas Content Summary

Gas content for the coalbeds in these holes are summarized on *Table 9-17* below. The desorption phase for samples from this hole was approximately 90 days; detailed tables are found in the *Appendix* of this report.

Table 9-17 CH-1-2014 and CH-1R-2014 Gas Content Summary

Canister ID#	Sample Top Depth (ft.)	Sample Thickness (ft.)	As-Received Basis			DMMF
			Gas Content (scf/t)	Residual Gas Content (scf/t)	Total Gas Content (scf/t)	Total Gas Content (scf/t)
Greasy Creek (20 Bench)						
212	765.05	1.87'	130.29	74.02	204.30	249.61
Lower Seaboard (20 Bench)						
G-17	905.00	0.73'	361.42	47.70	409.12	426.51
U. Horsepen (10 Bench)						
H-54	974.95	1.31'	310.72	40.21	350.93	440.71
Pocahontas 11						
219	1165.03	0.74'	253.91	69.50	323.41	352.89
Pocahontas 10 (20 Bench)						
G-46	1200.25	1.15'	391.45	73.28	464.73	514.77
Pocahontas 9 (10 Bench)						
F-26	1297.42	1.60'	176.78	30.89	207.67	228.19
Pocahontas 7 (10 Bench)						
F-68	1413.50	1.05'	292.39	48.15	340.54	396.29
Pocahontas 5 (10 Bench)						
H-43	1572.35	1.00'	344.21	41.05	385.25	418.50
Pocahontas 5 (20 Bench)						
H-10	1624.46	0.86'	331.27	47.95	379.22	413.93
Carbonaceous Shale						
F-52	1625.32	0.77'	19.14	56.74	75.88	0.00
Pocahontas 4 (20 Bench)						
*H-7**	*1648.50*	*1.37'*	*306.86*	*21.74*	*328.60*	*350.95*
G-45	1648.50	1.37'	296.06	0.00	0.00	0.00
Pocahontas 3 (10, 20 & 30 Benches)						
*H-60**	*1727.06*	*1.09'*	*59.40*	*44.68*	*104.08*	*198.78*
*G-23**	*1728.15*	*2.53'*	*74.43*	*33.69*	*108.12*	*119.56*
Composite		**3.62'**	**68.66**	**37.91**	**106.57**	**149.96**
Pocahontas 2 (10 Bench)						
G-38	1798.96	0.69'	164.88	52.88	217.76	285.37
Poor Recovery Samples						
Pocahontas 3 (10-20 Bench)						
H-35	1727.06	3.62'	N/A	N/A	N/A	N/A
Pocahontas 3 (40 Bench)						
F-30	1746.80	0.86'	N/A	N/A	N/A	N/A

*Re-drilled sample from CH-1R-2014

Coal Quality Summary

Listed below (Table 9-18) is a summary of the coal quality for samples from CH-1-2014 and CH-1R-2014.

Table 9-18 Summary of CH-1-2014 and CH-1R-2014 Quality

Sample ID	Seam	Raw Quality (DB)					Mean-Max. Reflectance in Oil, %	Coal Rank
		% Ash	% Sulfur	BTU/lb.	% Vol.	% FC		
212-A	Greasy Creek (20)	4.96	1.36	14,919	24.62	70.42	1.41	MV
212-B (1)	Greasy Creek (20)	26.70	0.37	11,129	17.18	56.12	1.40	LV
G-17	L. Seaboard (20)	2.52	0.68	15,364	22.43	75.05	1.39	MV
H-54	U. Horsepen	16.47	3.19	12,910	20.50	63.03	1.37	MV
219	Pocahontas 11	6.83	0.68	14,652	22.45	70.72	1.46	MV
G-46	Pocahontas 10 (20)	7.65	1.36	14,484	22.18	70.17	1.47	MV
F-26	Pocahontas 9-10	6.63	1.87	14,631	21.53	71.84	1.44	MV
F-68	Pocahontas 7	10.31	4.39	14,066	19.46	70.23	1.41	LV
H-43	Pocahontas 5 (20)	6.18	1.25	14,835	22.31	71.51	1.44	MV
H-10	Pocahontas 5 (20)	6.39	1.75	14,781	21.90	71.62	1.50	MV
H-7	Pocahontas 4 (20)	5.01	0.51	15,074	21.22	73.77	1.51	LV
H-60A (2)	Pocahontas 3 (10)	72.11	1.18	2,941	9.44	18.45	1.52	LV
H-60B	Pocahontas 3 (10)	12.33	4.15	13,681	18.78	68.89	1.54	LV
G-23	Pocahontas 3 (20/30)	7.21	1.50	14,606	19.82	72.97	1.56	LV
G-38	Pocahontas 2	19.94	2.94	12,277	18.20	61.86	1.48	LV

1) 212-B is a boney coal with low vitrinite and high semi-fusinite maceral composition.
2) H-60A is a carbonaceous shale with coal streaks.

Expanded Graphic Sections

Included in the *Appendix* of this report are expanded sections (at 1 inch = 1 foot) of each canistered interval, including gamma-density curves, canister identification, date of sampling, lithologic description, notes indicating lost core, as-received gas content, and identification of intervals that were: (1) preserved for cleat examination, and not crushed; (2) carbonaceous shale sections that were crushed to liberate residual gas, and; (3) shale sections that were preserved, but not crushed.

Core Photographs and Macroscopic Description of Samples

Annotated photographs of canistered samples are found in the *Appendix*. In addition to the photographs, a description of each sample is provided below (Table 9-19). The description includes the Stopes system of coal lithotypes (Vitrain, Clarain, Durain, and Fusain), the presence of minerals (pyrite and calcite) and other non-coal material, fracture patterns, and overall state of samples.

Table 9-19 CH-1-2014 Macroscopic Description

Canister	Thickness	CH-1-2014 Sample Description
Greasy Creek		
212	0.48	Vitrain
	0.08	Shale
	0.27	Vitrain with Clarain streaks
	0.14	Clarain with Durain streaks
	0.81	Boney coal with few Clarain laminations, hard
Lower Seaboard (20 Bench)		
G-17	0.20	Clarain with Vitrain and Fusain streaks
	0.05	Bone
	0.48	Vitrain with Clarain, few pyrite nodules and Fusain laminations

Canister	Thickness	CH-1-2014 Sample Description
Upper Horsepen (10 Bench)		
H-54	0.09	Vitrain with Clarain streaks
	0.08	Shale with coal streaks
	0.50	Vitrain with Clarain streaks
	0.29	Coal with bone streaks
	0.35	Vitrain with Clarain streaks
Pocahontas No. 11		
219	0.07	Clarain with Vitrain streaks, highly crushed
	0.67	Vitrain with Clarain laminations and occasional thin Fusain laminations
Pocahontas No. 10 (20 Bench)		
G-46	0.17	Vitrain with Clarain streaks
	0.31	Clarain with Vitrain streaks
	0.49	Vitrain
	0.18	Vitrain, highly crushed
Pocahontas No. 9 (10 Bench)		
F-26	1.54	Vitrain with occasional Fusain laminations
	0.06	Vitrain, highly crushed
Pocahontas No. 7 (10 Bench)		
F-68	0.56	Clarain with Vitrain plus few thin pyrite laminations
	0.07	Coal with bone
	0.42	Vitrain with Clarain, calcite on cleats and minor pyrite laminations
Pocahontas No. 5 (10 Bench)		
H-43	0.07	Vitrinite rubble
	0.02	Shale
	0.36	Vitrain with Clarain laminations, calcite-filled cleat
	0.54	Vitrain with Clarain laminations and Fusain laminations
Pocahontas No. 5 (20 Bench)		
H-10	0.68	Vitrain
	0.18	Clarain with Vitrain laminations
Pocahontas No. 4		
G-45	0.50	Vitrain with Clarain and Fusain laminations – Poor Recovery
	0.40	Vitrain with Clarain and Fusain laminations – Poor Recovery
	0.31	Clarain with Vitrain laminations, slightly hard – Poor Recovery
H-7	0.25	Clarain with Vitrain laminations – Re-drill
	0.17	Clarain with Vitrain and Fusain laminations – Re-drill
	0.95	Clarain with numerous Vitrain streaks and bands – Re-drill
Pocahontas No. 3 (10-20 Bench)		
H-35	0.80	Vitrain – Poor Recovery
	0.75	Carbonaceous shale – Poor Recovery
	0.47	Vitrain interbedded with Clarain – Poor Recovery
Pocahontas No. 3 (40 Bench)		
F-30	0.18	Shale with coal streaks – Poor Recovery (not re-drilled)
	0.36	Vitrain with Clarain laminations – Poor Recovery (not re-drilled)
	0.20	Interbedded Vitrain and Clarain – Poor Recovery (not re-drilled)
	0.07	Vitrain with Clarain laminations – Poor Recovery (not re-drilled)
Pocahontas No. 3 (10 Bench)		
H-60	0.50	Carbonaceous shale with thin coal streaks – Re-drill
	0.59	Interbedded Clarain and Vitrain with occasional thin Fusain laminations and single pyrite lamination – Re-drill

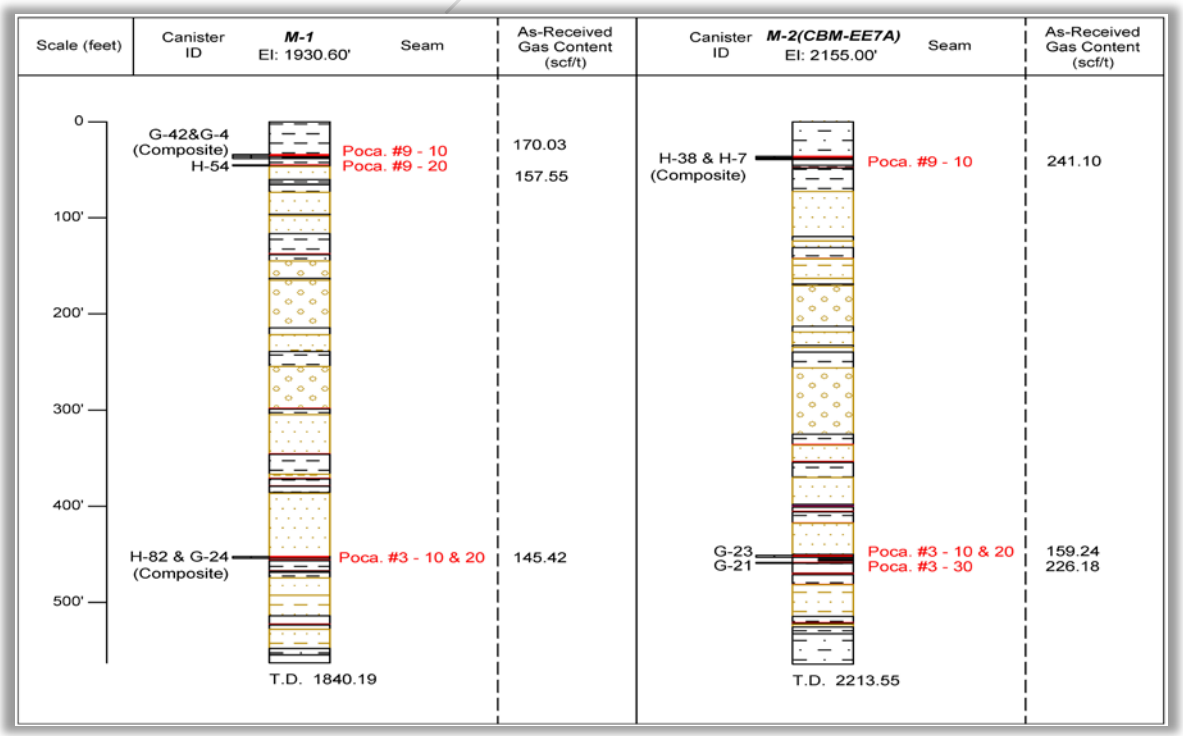
Canister	Thickness	CH-1-2014 Sample Description
Pocahontas No. 3 (10 - 20 Bench)		
G-23	0.37	Vitrain – Re-drill
	0.43	Vitrain with Bone bands – Re-drill
	0.05	Bone – Re-drill
	0.54	Vitrain with Clarain laminations and occasional Fusain – Re-drill
	0.15	Shale with carbonaceous shale – Re-drill
	0.59	Vitrain with Fusain laminations, high ash – Re-drill
Pocahontas No. 2 (10 Bench)		
G-38	0.07	Vitrain with Fusain streaks
	0.08	Vitrain with Clarain streaks
	0.07	Boney coal
	0.11	Vitrain with Clarain streaks
	0.16	Boney coal
	0.20	Vitrain with minor Fusain streaks

M-1

After core samples were collected for desorption, M-1 was converted into a monitoring well (see *Site Photographs* in the *Appendix*.)

Graphic Logs (Figure 9-24)

Figure 9-24 M-1 and M-2 (CBM-EE7A) Stratigraphic Sections



Gas Content Summary (Table 9-20)

Table 9-20 Summary of M-1 Coalbed Gas Content

Canister ID#	Depth (ft.)	Seam Thickness	As-Received Basis: Gas Content (scf/t)	As-Received Basis: Residual Gas Content (scf/t)	As-Received Basis: Total Gas Content (scf/t)	DMMF: Total Gas Content (scf/t)
Pocahontas No. 9 (10)						
G-42	1311.88	0.38'	143.73	39.18	182.91	211.51
G-4	1313.93	2.05'	129.47	37.95	167.42	185.07
Composite		**2.43'**	**131.88**	**38.16**	**170.03**	**228.10**
Pocahontas No. 9, (Carbonaceous Shale)						
G-38	1315.93	2.00'	28.08	17.87	45.95	
Pocahontas No. 9 (20)						
H-54	1323.37	0.87'	119.35	38.20	157.55	190.76
Pocahontas No. 3 (10,20)						
H-82	1731.49	1.89'	100.86	33.56	134.42	149.27
G-24	1731.65	0.16'	110.94	120.83	231.77	338.33
Composite		**2.05'**	**102.00**	**43.41**	**145.42**	**170.62**

Coal Quality Summary (Table 9-21)

Table 9-21 Summary of M-1 Quality

Sample ID	Seam	Raw Quality, Dry Basis: % Ash	% Sulfur	BTU/lb.	% Vol.	%FC	Mean-Max. Reflectance in Oil, %	Coal Rank
Desorption Sample								
G-42	Pocahontas 9 (10)	10.08	2.67	14,050	21.76	68.16	1.50	MV
G-4A	Pocahontas 9 (10)	3.83	0.68	15,169	22.53	73.64	1.46	MV
G-4B	Pocahontas 9 (10)	9.48	1.55	14,143	20.49	70.03	1.49	LV
	Composite	*6.92*	*1.16*	*14,609*	*21.42*	*71.67*	*1.48*	
H-54	Pocahontas 9 (20)	13.51	3.37	13,457	21.55	64.94	-	MV
H-82	Pocahontas 3 (10)	7.29	0.88	14,524	20.47	72.24	1.53	LV
G-24	Pocahontas 3 (20)	27.87	1.49	11,194	17.24	54.89	-	LV

Expanded Graphic Sections

Expanded graphic sections generated originally at 1 inch = 1 foot are found in the *Appendix*.

Core Photographs and Macroscopic Description (Table 9-22) of Samples

Annotated photographs of canistered samples are found in the *Appendix*.

Table 9-22 M-1 Macroscopic Descriptions

Canister	Thickness	M-1 Sample Description
Pocahontas No. 9 (10 Bench)		
G-42	0.38	Vitrain with occasional thin shale streaks and one thin pyrite lamination
G-4	0.07	Vitrain with Clarain streaks, rubble
	0.70	Vitrain, well cleated
	0.11	Clarain with Durain and thin pyrite laminations
	0.61	Vitrain with Fusain streaks
	0.08	Clarain with Durain and pyrite nodules
	0.48	Clarain with Durain and Vitrain laminations, slickensided
Pocahontas No. 9 (10 Bench) Parting		
G-38	2.00	Carbonaceous shale and clay shale with numerous thin Vitrain and Durain streaks, numerous plant fossils on bedding
Pocahontas No. 9 (20 Bench)		
H-54	0.09	Vitrain with Clarain and numerous pyrite laminations
	0.10	Vitrain
	0.04	Fusain
	0.54	Vitrain with Clarain laminations and occasional thin Fusain laminations
	0.10	Vitrain with pyrite laminations
Pocahontas No. 3 (10-20 Bench)		
H-82	1.12	Vitrain with Clarain and thin Fusain streaks
	0.10	Shaley coal
	0.40	Boney coal
	0.09	Vitrain with Clarain streaks
Pocahontas No. 3 (20 bench)		
G-24	0.16	Vitrain with obliquely interbedded Durain

M-2 (CBM-EE7A)

After core samples were collected for desorption, M-2 was converted into a monitoring well (see *Site Photographs* in the *Appendix*.)

Graphic Log

See section above.

Gas Content Summary (Table 9-23)

Table 9-23 Summary of M-2 Coalbed Gas Content

Canister ID#	Sample Top Depth (ft.)	Sample Thickness (ft.)	As-Received Basis			DMMF
			Gas Content (scf/t)	Residual Gas Content (scf/t)	Total Gas Content (scf/t)	Total Gas Content (scf/t)
Pocahontas No. 9 (10)						
H-38	1548.05	1.55'	207.21	24.22	231.43	-
H-7	1550.05	0.40'	228.03	49.35	277.38	306.07
Composite		1.95'	211.59	29.51	241.10	
Pocahontas No. 3 (10,20)						
G-23	1963.40	1.95'	129.85	29.40	159.24	185.84
Pocahontas No. 3 (30)						
G-21	1969.85	0.90'	190.55	35.63	226.18	353.79

Coal Quality Summary (Table 9-24)

Table 9-24 Summary of M-2 Quality

Canister ID	Seam	Raw Quality (DB)					Mean-Max. Reflectance in Oil, %	Coal Rank
		% Ash	% Sulfur	BTU/lb.	% Vol.	% FC		
H-38	Pocahontas 9 (10)	-	-	-	-	-	-	NA
H-7	Pocahontas 9 (10)	6.85	1.35	14,554	20.53	72.62	-	LV
G-23	Pocahontas 3 (10,20)	12.13	0.72	13,456	20.06	67.81	-	LV
G-21	Pocahontas 3 (30)	32.21	1.15	10,398	16.65	51.14	-	LV

Expanded Graphic Sections

Expanded graphic sections generated originally at 1 inch = 1 foot are found in the *Appendix*.

Core Photographs and Macroscopic Description (Table 9-25) of Samples

Annotated photographs of canistered samples are found in the *Appendix*.

Table 9-25 M-2 Macroscopic Descriptions

Canister	Thickness	M-2 Sample Description
Pocahontas No. 9 (10 Bench)		
H-38	0.54	Vitrain with Clarain bands, core intact
	1.01	Vitrain with occasional thick Clarain bands, highly crushed
212	1.07	Carbonaceous shale with coal streaks
H-7	0.06	Durain, slightly dull, gray
	0.34	Vitrain
Pocahontas No. 3 (10 Bench)		
G-23	0.40	Vitrain with Clarain bands and Fusain streaks
	0.18	Vitrain, highly crushed
	0.62	Vitrain with Clarain bands
	0.38	Vitrain with Clarain and few Fusain and coal streaks
	0.10	Shaley coal, broken
	0.12	Vitrain with Clarain streaks
Pocahontas No. 3 (30 Bench)		
G-21	0.10	Shale with coal streaks
	0.09	Clarain with Durain and shale streaks
	0.25	Vitrain with Clarain and Fusain streaks
	0.13	Shale
	0.09	Shale with coal streaks
	0.23	Vitrain with Clarain streaks, with few shale bands

9.3.4 Coal Analytical Testing

At the conclusion of the desorption phase, core samples were removed from the canisters, processed, and then transferred to Virginia Tech (VT) personnel. Some of the samples were subsequently shipped by VT to Precision Testing Laboratory, located in Daniels, West Virginia where coal quality testing was conducted, including the following analyses:

6) Proximate analysis (moisture, ash, sulfur, volatile matter, fixed carbon, and Btu/lb.)

   Ultimate analysis (moisture, carbon, hydrogen, nitrogen, sulfur, ash, and oxygen)

   Petrographic analysis (maceral composition, vitrinite reflectance, etc.).

The proximate analysis, ultimate analysis, and petrographic analysis of 15 coals are shown in *Table 9-26*. The proximate analysis includes the moisture, ash, volatile matter, and fixed carbon contents of coals. Ultimate analysis tests produce more comprehensive results than the proximate analyses, which is used to determine the elemental composition of the coal including moisture, ash, carbon, hydrogen, nitrogen, sulfur, and oxygen (by difference). The petrographic analysis shows the macroscopic characteristics of coal samples which is used to determine a coal's rank (degree of coalification) and type (amount and category of macerals).

Table 9-26 Coal analytical testing results for 15 coal samples

212-A, Greasy Creek (765.05-765.97 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.41
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.77	//	% Moisture	0.77	0.77		V-type	13	40.3	Semifusinite	1.8		Composition balance index	0.94
% ash	4.92	4.96	% Carbon	85.66	85.66	86.32		14	41.2	Micrinite	3.9		Rank (Strength) index	6.48
% Sul	1.35	1.36	% Hydrogen	4.87	4.78	4.82		15	2.5	Fusinite	5.5		Calculated stability	+65
% Volatile	24.43	24.62	% Nitrogen	1.46	1.46	1.47		//		Mineral matter	3		//	
Fixed Carbon	69.88	70.42	% Sulfur	1.35	1.35	1.36	Vitrinite	84					Ash, % (dry)	4.96
BTU/lb	14.804	14919	% Ash	4.92	4.92	4.96	Exinite	1.3		//			Sulfure, % (dry)	1.36
MAF BTU		15698	%Oxygen (diff)	1.75	1.06	1.07	Resinite	0					Volatile matter, % (dry)	24.62
//			Total (%)	100.01	100	100	Semifusinite	0.5					Volatile matter, daf	25.9
//							Total Reactive	85.8		Total	14.2		//	

212-B, Greasy Creek (765.97-765.92 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.4
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.65		% Moisture	0.65	0.65		V-type	12	0.9	Semifusinite	30.1		Composition balance index	13.33
% ash	26.53	26.7	% Carbon	64.25	64.25	64.67		13	9.3	Micrinite	17.5		Rank (Strength) index	5.91
% Sul	0.37	0.37	% Hydrogen	3.45	3.38	3.4		14	11.4	Fusinite	3.2		Calculated stability	NA
% Volatile	17.07	17.18	% Nitrogen	0.86	0.86	0.87		//		Mineral matter	16.5			
Fixed Carbon	55.76	56.12	% Sulfur	0.37	0.37	0.37	Vitrinite	21.6					Ash, % (dry)	26.7
BTU/lb	11057	11129	% Ash	26.53	26.53	26.7	Exinite	1.1		//			Sulfure, % (dry)	0.37
MAF BTU		15138	%Oxygen (diff)	4.54	3.96	3.99	Resinite	0					Volatile matter, % (dry)	17.18
//			Total (%)	100	100	100	Semifusinite	10					Volatile matter, daf	23.44
//							Total Reactive	32.7		Total	67.3		//	

G-17, L Seaboard (905-905.73 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.39
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	1.02		% Moisture	1.02	1.02		V-type	12	0.8	Semifusinite	5.6		Composition balance index	1.07
% ash	2.49	2.52	% Carbon	88.27	88.27	89.18		13	45.7	Micrinite	5.3		Rank (Strength) index	6.37
% Sul	0.67	0.68	% Hydrogen	4.87	4.75	4.8		14	33.7	Fusinite	4.3		Calculated stability	+65
% Volatile	22.2	22.43	% Nitrogen	1.48	1.48	1.5		//		Mineral matter	1.5		//	
Fixed Carbon	74.28	75.05	% Sulfur	0.67	0.67	0.68	Vitrinite	80.2					Ash, % (dry)	2.52
BTU/lb	15207	15364	% Ash	2.49	2.49	2.52	Exinite	1.2		//			Sulfure, % (dry)	0.68
MAF BTU		15761	%Oxygen (diff)	2.21	1.31	1.32	Resinite	0					Volatile matter, % (dry)	22.43
//			Total (%)	99.99	99.99	100	Semifusinite	1.9					Volatile matter, daf	23.01
//							Total Reactive	83.3		Total	16.7		//	

H-54, Horsepen (974.95 - 976.26)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.37
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	1.03		% Moisture	1.03	1.02		V-type	12	4.3	Semifusinite	6.5		Composition balance index	1.78
% ash	16.3	16.47	% Carbon	72.35	72.35	73.1		13	51.2	Micrinite	6.6		Rank (Strength) index	6.03
% Sul	3.16	3.19	% Hydrogen	4.14	4.03	4.07		14	15.6	Fusinite	2.8		Calculated stability	61
% Volatile	20.29	20.5	% Nitrogen	1.29	1.29	1.3		//		Mineral matter	10.5		//	
Fixed Carbon	62.38	63.03	% Sulfur	3.16	3.16	3.19	Vitrinite	71.1					Ash, % (dry)	16.47
BTU/lb	12777	12910	% Ash	16.3	16.3	16.47	Exinite	0.3		//			Sulfure, % (dry)	3.19
MAF BTU		15456	%Oxygen (diff)	2.77	1.85	1.87	Resinite	0					Volatile matter, % (dry)	20.5
//			Total (%)	100.01	100	100	Semifusinite	2.2					Volatile matter, daf	24.54
//							Total Reactive	73.6		Total	26.4		//	

Table 9-26: Coal analytical testing results for 15 coal samples (Continued)

219, Poca 11 (1162.03 - 1165.77)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.46
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.66		% Moisture	0.66	0.66		V-type	13	2.6	Semifusinite	4.2		Composition balance index	1
% ash	6.78	6.83	% Carbon	84.14	84.14	84.7		14	73.9	Micrinite	2.7		Rank (Strength) index	7.02
% Sul	0.68	0.68	% Hydrogen	4.76	4.69	4.72		15	9.4	Fusinite	1.8		Calculated stability	+65
% Volatile	22.3	22.45	% Nitrogen	1.49	1.49	1.5		//		Mineral matter	3.9		//	
Fixed Carbon	70.25	70.72	% Sulfur	0.68	0.68	0.68	Vitrinite	85.9					Ash, % (dry)	6.83
BTU/lb	14555	14652	% Ash	6.78	6.78	6.83	Exinite	0.5		//			Sulfure, % (dry)	0.68
MAF BTU		15726	%Oxygen (diff)	2.15	1.56	1.57	Resinite	0					Volatile matter, % (dry)	22.45
//			Total (%)	100	100	100	Semifusinite	1					Volatile matter, daf	24.1
//							Total Reactive	87.4		Total	12.6		//	

G-46, Poca 10 (1200.25 - 1201.64 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.47
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.78		% Moisture	0.78	0.78		V-type	13	4.2	Semifusinite	2.9		Composition balance index	1.31
% ash	7.59	7.65	% Carbon	83.44	83.44	84.1		14	63.2	Micrinite	4		Rank (Strength) index	6.99
% Sul	1.35	1.36	% Hydrogen	4.69	4.6	4.64		15	15	Fusinite	4.5		Calculated stability	+65
% Volatile	22.01	22.18	% Nitrogen	1.44	1.44	1.45		16	0.8	Mineral matter	4.6		//	
Fixed Carbon	69.62	70.17	% Sulfur	1.35	1.35	1.36	Vitrinite	83.2					Ash, % (dry)	7.65
BTU/lb	14371	14484	% Ash	7.59	7.59	7.65	Exinite	0		//			Sulfure, % (dry)	1.36
MAF BTU		15684	%Oxygen (diff)	1.49	0.79	0.8	Resinite	0					Volatile matter, % (dry)	22.18
//			Total (%)	100	99.99	100	Semifusinite	0.8					Volatile matter, daf	24.02
//			//				Total Reactive	84		Total	16		//	

F-26, Poca 9 (1297.42 - 1299.02)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.44
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.88		% Moisture	0.88	0.88		V-type	12	1.6	Semifusinite	6.1		Composition balance index	1.27
% ash	6.57	6.63	% Carbon	84.16	84.16	84.91		13	11.4	Micrinite	2.8		Rank (Strength) index	6.81
% Sul	1.85	1.87	% Hydrogen	4.58	4.48	4.52		14	61.8	Fusinite	3		Calculated stability	65
% Volatile	21.34	21.35	% Nitrogen	1.28	1.28	1.29		15	6.5	Mineral matter	4.1		//	
Fixed Carbon	71.21	71.84	% Sulfur	1.85	1.85	1.87	Vitrinite	81.3					Ash, % (dry)	6.63
BTU/lb	14502	14631	% Ash	6.57	6.57	6.63	Exinite	1.2		//			Sulfure, % (dry)	1.87
MAF BTU		15670	%Oxygen (diff)	1.55	0.77	0.78	Resinite	0					Volatile matter, % (dry)	21.53
//			Total (%)	99.99	99.99	100	Semifusinite	1.5					Volatile matter, daf	23.06
//			//				Total Reactive	84		Total	16		//	

H-60A, Poca 3 (1727.06 - 1727.56)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.52
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	1.5		% Moisture	1.5	1.5		V-type	13	0.4	Semifusinite	7		Composition balance index	26.47
% ash	71.03	72.11	% Carbon	20.49	20.49	20.8		14	8.4	Micrinite	2.6		Rank (Strength) index	6.35
% Sul	1.16	1.18	% Hydrogen	1.26	1.09	1.11		15	10.4	Fusinite	2.8		Calculated stability	NA
% Volatile	9.3	9.44	% Nitrogen	0.3	0.3	0.3		16	2.9	Mineral matter	63.8		//	
Fixed Carbon	18.17	18.45	% Sulfur	1.16	1.16	1.18	Vitrinite	22.1					Ash, % (dry)	72.11
BTU/lb	2897	2941	% Ash	71.03	71.03	72.11	Exinite	0		//			Sulfure, % (dry)	1.18
MAF BTU		10545	%Oxygen (diff)	5.76	4.43	4.5	Resinite	0					Volatile matter, % (dry)	9.44
//			Total (%)	100	100	100	Semifusinite	1.7					Volatile matter, daf	33.85
//			//				Total Reactive	23.8		Total	76.2		//	

H-60B, Poca 3 (1727.56 - 1728.15)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.54
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.66		% Moisture	0.66	0.66		V-type	13	1.4	Semifusinite	10.5		Composition balance index	3.58
% ash	12.25	12.33	% Carbon	77.59	77.59	78.11		14	9.7	Micrinite	4.8		Rank (Strength) index	6.9
% Sul	4.12	4.15	% Hydrogen	4.15	4.07	4.1		15	53.4	Fusinite	4.5		Calculated stability	52
% Volatile	18.66	18.78	% Nitrogen	0.96	0.96	0.97		16	4.9	Mineral matter	8.2		//	
Fixed Carbon	68.44	68.89	% Sulfur	4.12	4.12	4.15	Vitrinite	69.4					Ash, % (dry)	12.33
BTU/lb	13591	13681	% Ash	12.25	12.25	12.33	Exinite	0		//			Sulfure, % (dry)	4.15
MAF BTU		15605	%Oxygen (diff)	0.92	0.34	0.34	Resinite	0					Volatile matter, % (dry)	18.78
//			Total (%)	99.99	99.99	100	Semifusinite	2.6					Volatile matter, daf	21.42
//			//				Total Reactive	72		Total	28		//	

F-68, Poca 7 (1413.15 - 1414.55)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.41
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.6		% Moisture	0.6	0.6		V-type	12	2.4	Semifusinite	3.8		Composition balance index	1.35
% ash	10.25	10.31	% Carbon	79.11	79.11	79.59		13	28.9	Micrinite	1.7		Rank (Strength) index	6.52
% Sul	4.36	4.39	% Hydrogen	4.33	4.26	4.29		14	45.7	Fusinite	6.4		Calculated stability	+65
% Volatile	19.34	19.46	% Nitrogen	0.99	0.99	1		15	3.2	Mineral matter	7		//	
Fixed Carbon	69.81	70.23	% Sulfur	4.36	4.36	4.39	Vitrinite	80.2					Ash, % (dry)	10.31
BTU/lb	13982	14066	% Ash	10.25	10.25	10.31	Exinite	0		//			Sulfure, % (dry)	4.39
MAF BTU		15683	%Oxygen (diff)	0.95	0.42	0.42	Resinite	0					Volatile matter, % (dry)	19.46
//			Total (%)	99.99	99.99	100	Semifusinite	0.9					Volatile matter, daf	21.7
//			//				Total Reactive	81.1		Total	18.9		//	

Table 9-26: Coal analytical testing results for 15 coal samples (Continued)

H-43, Poca 5 (1572.35 - 1573.35)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.44
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.63		% Moisture	0.63	0.63		V-type	13	15.3	Semifusinite	4.7		Composition balance index	1.39
% ash	6.14	6.18	% Carbon	85.43	85.43	85.97		14	61.3	Micrinite	4.4		Rank (Strength) index	6.78
% Sul	1.24	1.25	% Hydrogen	4.79	4.72	4.75		15	4	Fusinite	5.1		Calculated stability	+65
% Volatile	22.17	22.31	% Nitrogen	1.1	1.1	1.11		//		Mineral matter	3.7		//	
Fixed Carbon	71.06	71.51	% Sulfur	1.24	1.24	1.25	Vitrinite	80.6					Ash, % (dry)	6.18
BTU/lb	14742	14835	% Ash	6.14	6.14	6.18	Exinite	0.4		//			Sulfure, % (dry)	1.25
MAF BTU		15812	%Oxygen (diff)	1.29	0.74	0.74	Resinite	0					Volatile matter, % (dry)	22.31
//			Total (%)	99.99	100	100	Semifusinite	1.1					Volatile matter, daf	23.78
//			//				Total Reactive	82.1		Total	17.9		//	

H-10, Poca 5 (1624.46 - 1625.32 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.5
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.57		% Moisture	0.57	0.57		V-type	13	0.7	Semifusinite	7.6		Composition balance index	2.41
% ash	6.35	6.39	% Carbon	84.82	84.82	85.31		14	35.7	Micrinite	8.6		Rank (Strength) index	6.94
% Sul	1.74	1.75	% Hydrogen	4.67	4.6	4.63		15	37.9	Fusinite	3.1		Calculated stability	60
% Volatile	21.86	21.99	% Nitrogen	1.07	1.07	1.08	//			Mineral matter	4		//	
Fixed Carbon	71.21	71.62	% Sulfur	1.74	1.74	1.75	Vitrinite	74.3		//			Ash, % (dry)	6.39
BTU/lb	14697	14781	% Ash	6.35	6.35	6.39	Exinite	0.5					Sulfure, % (dry)	1.75
MAF BTU		15790	%Oxygen (diff)	1.34	0.84	0.84	Resinite	0					Volatile matter, % (dry)	21.99
//			Total (%)	99.99	99.99	100	Semifusinite	1.9					Volatile matter, daf	23.49
//							Total Reactive	76.7		Total	23.3		//	

H-7, Poca 4 (1648.5 - 1649.87)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.48
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.72		% Moisture	0.72	0.72		V-type	13	2.8	Semifusinite	8.9		Composition balance index	3.17
% ash	4.97	5.01	% Carbon	87.65	87.65	88.29		14	24.9	Micrinite	7.7		Rank (Strength) index	6.84
% Sul	0.51	0.51	% Hydrogen	4.73	4.65	4.68		15	38.1	Fusinite	8.4		Calculated stability	55
% Volatile	21.07	21.22	% Nitrogen	1.1	1.1	1.11		16	3.5	Mineral matter	2.8		//	
Fixed Carbon	73.24	73.77	% Sulfur	0.51	0.51	0.51	Vitrinite	69.3		//			Ash, % (dry)	5.01
BTU/lb	14965	15074	% Ash	4.97	4.97	5.01	Exinite	0.7					Sulfure, % (dry)	0.51
MAF BTU		15869	%Oxygen (diff)	1.04	0.4	0.4	Resinite	0					Volatile matter, % (dry)	21.22
//			Total (%)	100	100	100	Semifusinite	2.2					Volatile matter, daf	22.34
//							Total Reactive	72.2		Total	27.8		//	

G-23, Poca 3 (1728.15 - 1730.68 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.56
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	1.04		% Moisture	1.04	1.04		V-type	13	0.8	Semifusinite	3.3		Composition balance index	1.59
% ash	7.14	7.21	% Carbon	84.37	84.37	85.26		14	5.9	Micrinite	2.1		Rank (Strength) index	7.2
% Sul	1.48	1.5	% Hydrogen	4.45	4.33	4.38		15	62.5	Fusinite	5.1		Calculated stability	+64
% Volatile	19.61	19.82	% Nitrogen	1.09	1.09	1.1		16	15.2	Mineral matter	4.3		//	
Fixed Carbon	72.21	72.97	% Sulfur	1.48	1.48	1.5	Vitrinite	84.4		//			Ash, % (dry)	7.21
BTU/lb	14454	14606	% Ash	7.14	7.14	7.21	Exinite	0					Sulfure, % (dry)	1.5
MAF BTU		15741	%Oxygen (diff)	1.47	0.54	0.55	Resinite	0					Volatile matter, % (dry)	19.82
//			Total (%)	100	99.99	100	Semifusinite	0.8					Volatile matter, daf	21.36
//							Total Reactive	85.2		Total	14.8		//	

G-38, Poca 2 (1798.96 - 1799.65 feet)														
Parameters	Coal analysis		Parameters	Ultimate analysis			Petrographic analysis							
							Maceral composition, volume %						Mean maximum vitrinite reflectance, %	1.48
	As received	Dry basis		As received-1	As received-2	Dry basis	Reactives			Inerts				
% Moisture	0.7		% Moisture	0.7	0.7		V-type	13	2.2	Semifusinite	5.6		Composition balance index	2.52
% ash	19.8	19.94	% Carbon	69.5	69.5	69.99		14	46.6	Micrinite	4.2		Rank (Strength) index	6.85
% Sul	2.92	2.94	% Hydrogen	3.8	3.72	3.75		15	24	Fusinite	3.3		Calculated stability	60
% Volatile	18.07	18.2	% Nitrogen	0.89	0.89	0.9	//			Mineral matter	12.7		//	
Fixed Carbon	61.43	61.86	% Sulfur	2.92	2.92	2.94	Vitrinite	72.8		//			Ash, % (dry)	19.94
BTU/lb	12191	12277	% Ash	19.8	19.8	19.94	Exinite	0					Sulfure, % (dry)	2.94
MAF BTU		15335	%Oxygen (diff)	3.08	2.46	2.48	Resinite	0					Volatile matter, % (dry)	18.2
//			Total (%)	99.99	99.99	100	Semifusinite	1.4					Volatile matter, daf	22.73
//							Total Reactive	74.2		Total	25.8		//	

9.3.5 Coal Pore Structure Testing

Low pressure gas adsorption study

Low pressure gas adsorption test (utilizing N_2 & CO_2) was applied to analyze the pore structure and surface area of coals: the N_2 adsorption test is used to characterize meso-pore (2-100 nm) structure of shales and specific surface area, and CO_2 adsorption test is used to characterize micropore (0-2nm) structure of coals. Gas sorption was conducted using a Micromeritics 3Flex volumetric analyzer (Norcross GA, USA) using ultrapure N_2 and CO_2 adsorbates (BOC gases, Nottingham, UK) at the University of Nottingham in UK.

All samples were degassed for 15 hours at 110 ℃ using a VacPrep Degasser (Micrometritics, Norcross GA, USA). Approximately 1.0 to 2.3 grams coal samples were used for each sorption isotherms. For N_2 adsorption tests, sample tube bulbs were immersed in liquid N_2 at approximately -196 °C. For CO_2 adsorption tests, the bulbs were immersed in 50% ethylene glycol solution inside an isothermal controller (in place of the liquid nitrogen dewar) during the tests which was set to 0 ℃. The equilibrium

state for each test was set based on the pressure measurement approach, i.e. when the partial pressure fluctuation inside the test tube is within 0.3%.

Measured nitrogen sorption isotherms in coals under -196 °C are shown in *Figure 1*. The pore size distribution (PSD) was obtained using the density functional theory (DFT) model applied to the adsorption branch. The calculation approach of the pore size distribution using DFT method is based on the integral adsorption equation (equation 1).

$$N(p/p_0) = \int_{D\min}^{D\max} N(p/p_0, D) f(D) dD \quad (1)$$

where D is the pore size (diameter or width), $N(p/p_0,D)$ is the kernel of the theoretical isotherms of different pore widths, and f(D) is the PSD. Once the isothermal adsorption data is obtained, the PSD can be derived numerically by solving the integral adsorption equation. The DFT model is available for describing the PSD to the whole range of micro- and meso-pore sizes.

Since several DFT kernels have been applied for both mesoporous activated carbons and other organic materials, this approach is believed to be applicable for coal analysis. The carbon black with partial graphitization and slit/cylinder pore model described by quench solid DFT (QSDFT) kernel was applied for meso- and macro-pore region using N2 adsorption data with fitting error 0.45-0.83 %. The PSD for pores from 2 to 100 nm in coal samples are shown in Figure 9-25.

Figure 9-25 Nitrogen adsorption isotherms on central Appalachian coals at -196 °C: solid lines represent adsorption branch and dotted lines represent desorption branch

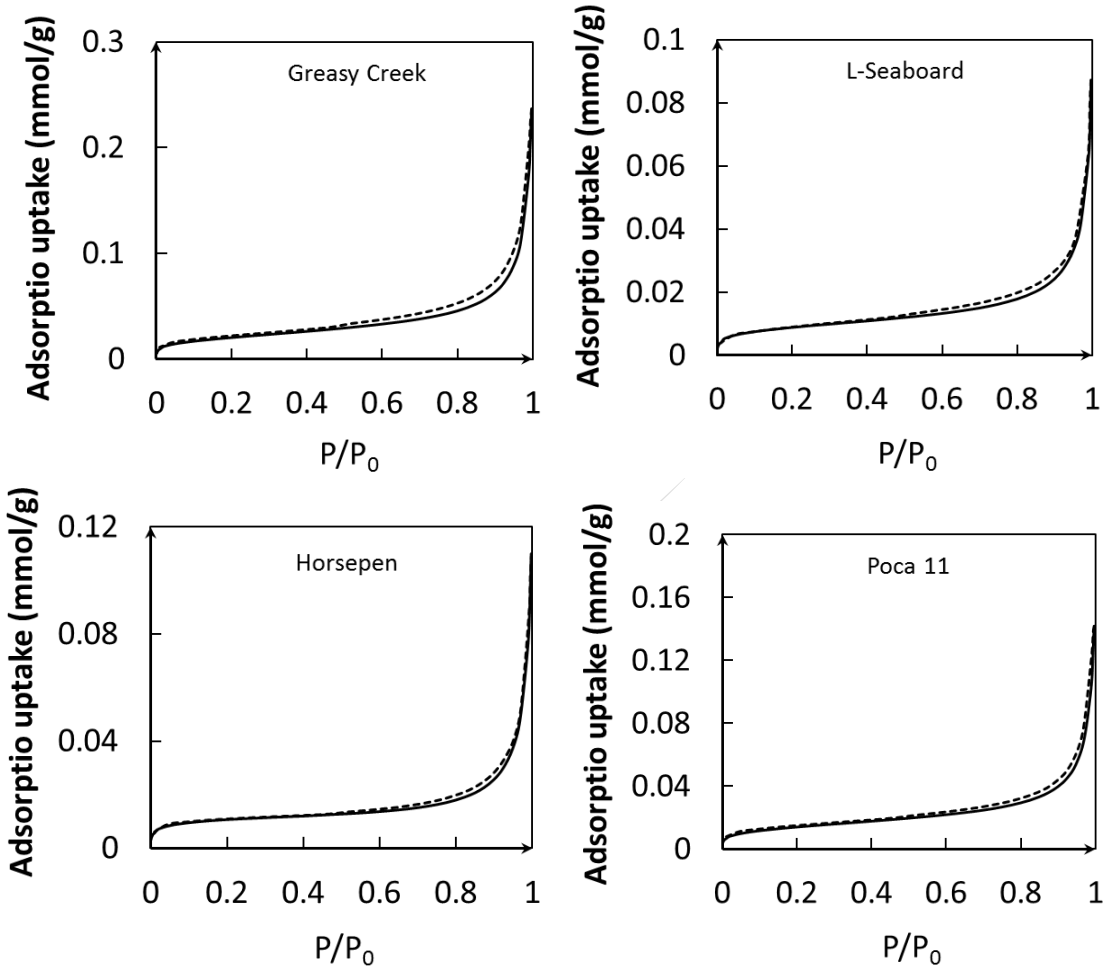


Figure 9-25 Nitrogen adsorption isotherms on central Appalachian coals at -196 °C: solid lines represent adsorption branch and dotted lines represent desorption branch (Continued)

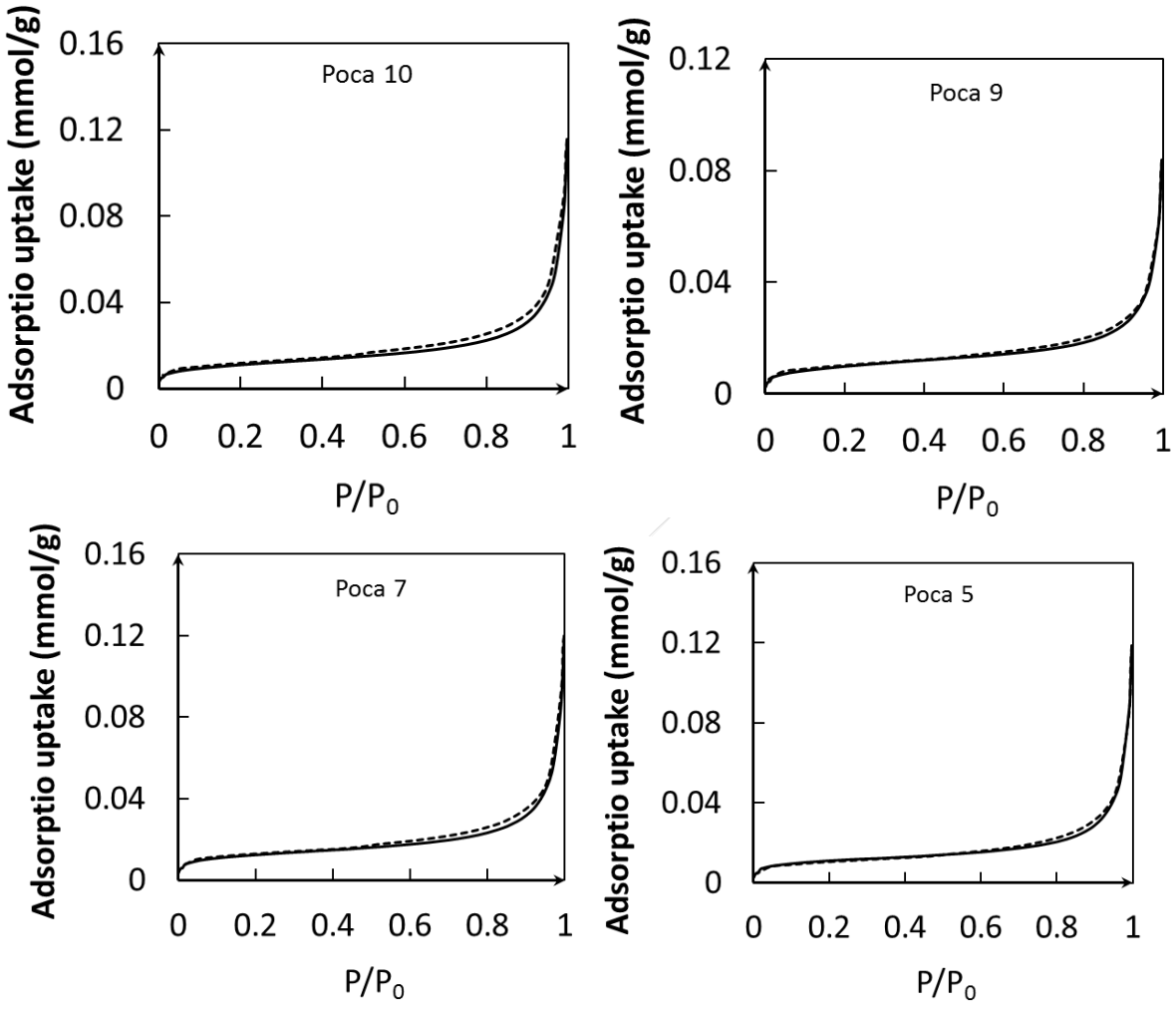


Figure 9-25: Nitrogen adsorption isotherms on central Appalachian coals at -196 °C: solid lines represent adsorption branch and dotted lines represent desorption branch (Continued)

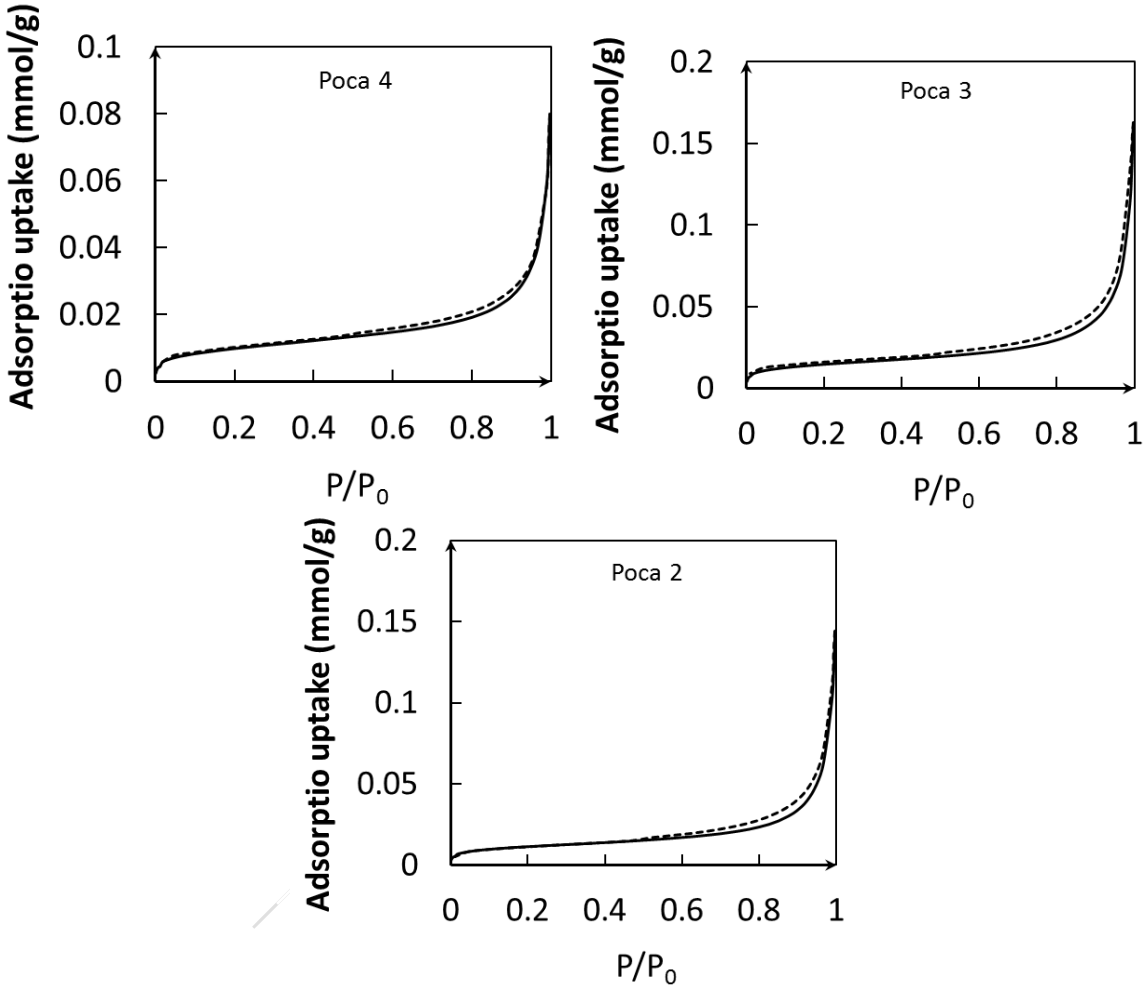


Figure 9-26 Meso-pore size distribution of coals

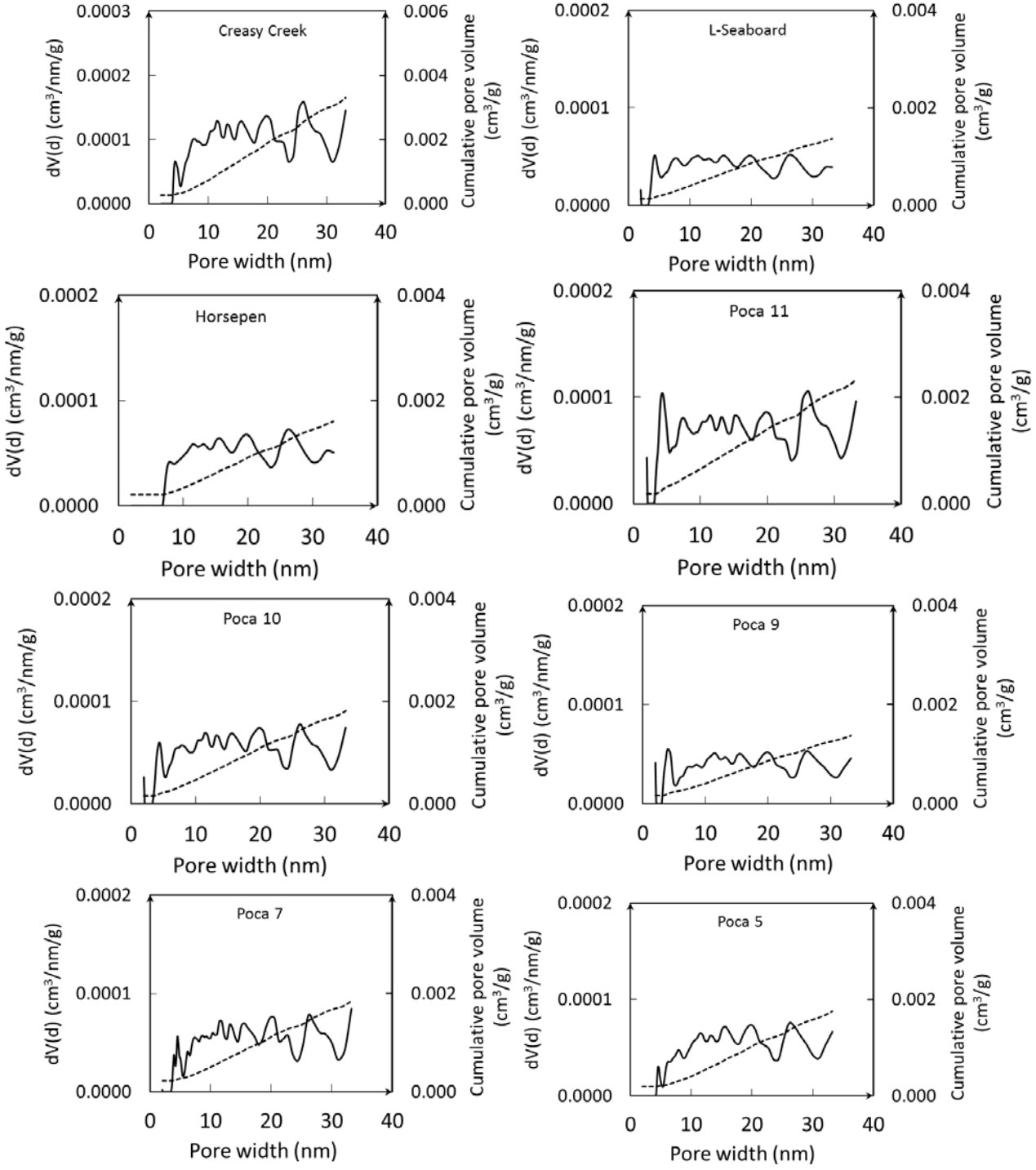
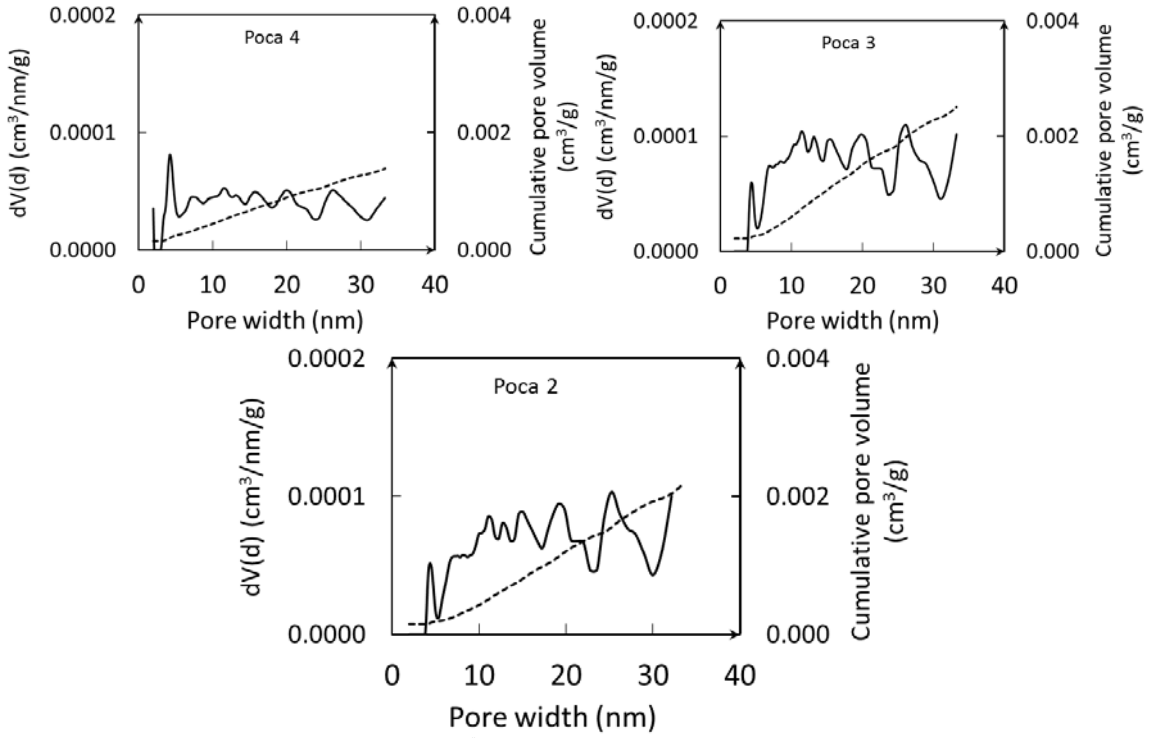


Figure 9-26 Meso-pore size distribution of coals (Continued)



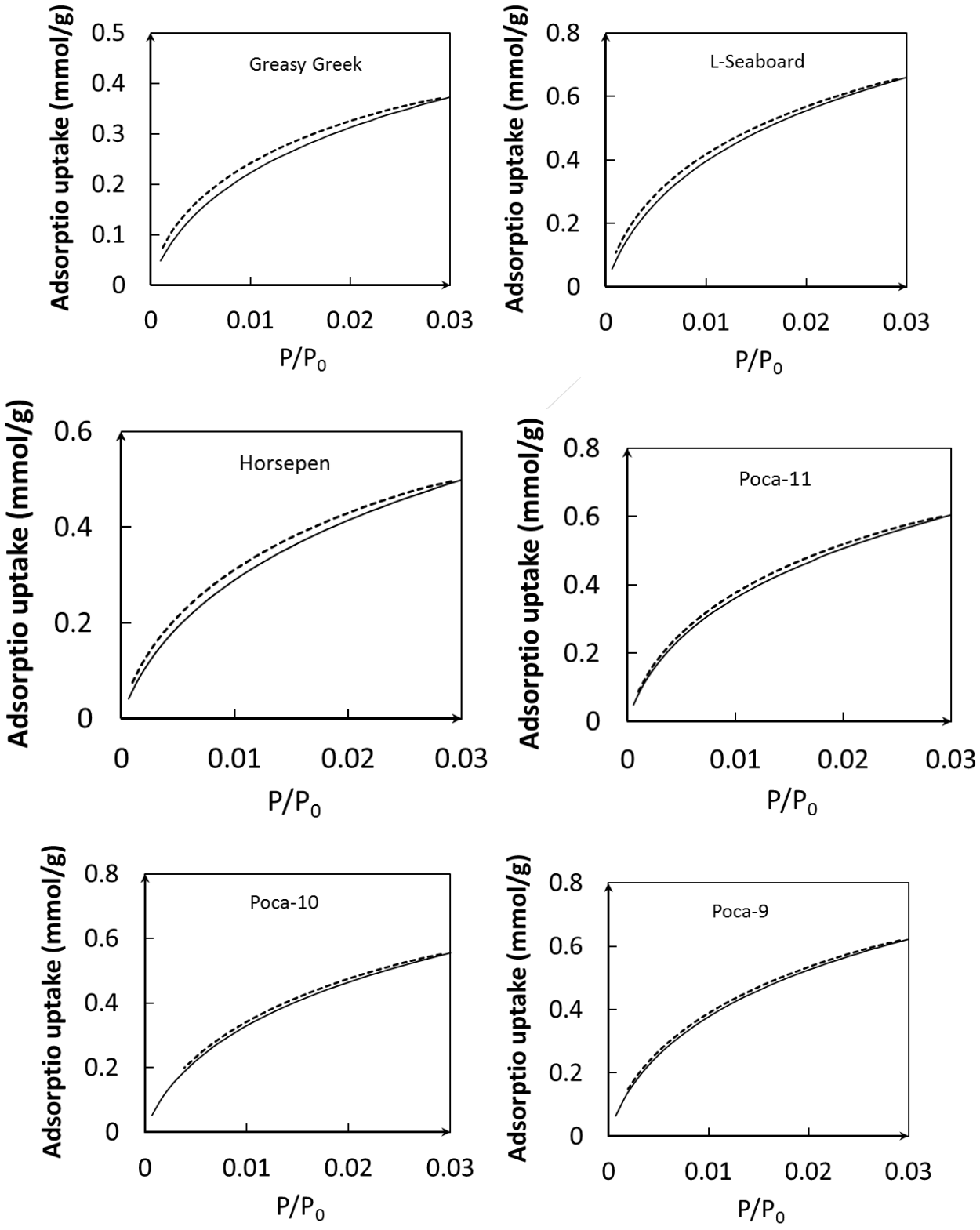
The BET specific surface area using N_2 was calculated by the linear BET relationship under the relative pressure ranges from Rouquerol's approach, which necessitates (1) both the resulting parameter C_{BET} and the intercept on the ordinate of the BET-plot being positive, and (2) the term $V_{ad}(p_o\text{-}p)$ continuously increasing with p/p_o (Rouquerol et al., 2007; ISO 9277: 2010). The BET specific surface area of coal samples is shown in *Table 9-27*.

Table 9-27 BET specific surface of coal samples

Coal samples	BET specific surface area (m^2/g)
Greasy Greek	1.4974
L-Seaboard	0.723
Horsepen	0.882
Poca 11	1.164
Poca10	0.9045
Poca 9	0.8076
Poca 7	1.0042
Poca 5	0.9086
Poca 4	0.8063
Poca 3	1.2025
Poca 2	0.9332

Measured carbon dioxide sorption isotherms in coals under -0°C are shown in Figure 9-27. The pore size distribution (PSD) was obtained using the same density functional theory (DFT) method, and the carbon model described by nonlocal DFT (NLDFT) kernel was applied for micropore regions using CO2 adsorption data with fitting error 0.064-0.09 %. The PSD for pores from 0 to 2 nm in coal samples are shown in Figure 9-28.

Figure 9-27 Carbon dioxide adsorption isotherms at 0 °C on central Appalachian coals: solid lines represent adsorption branch and dotted lines represent desorption branch



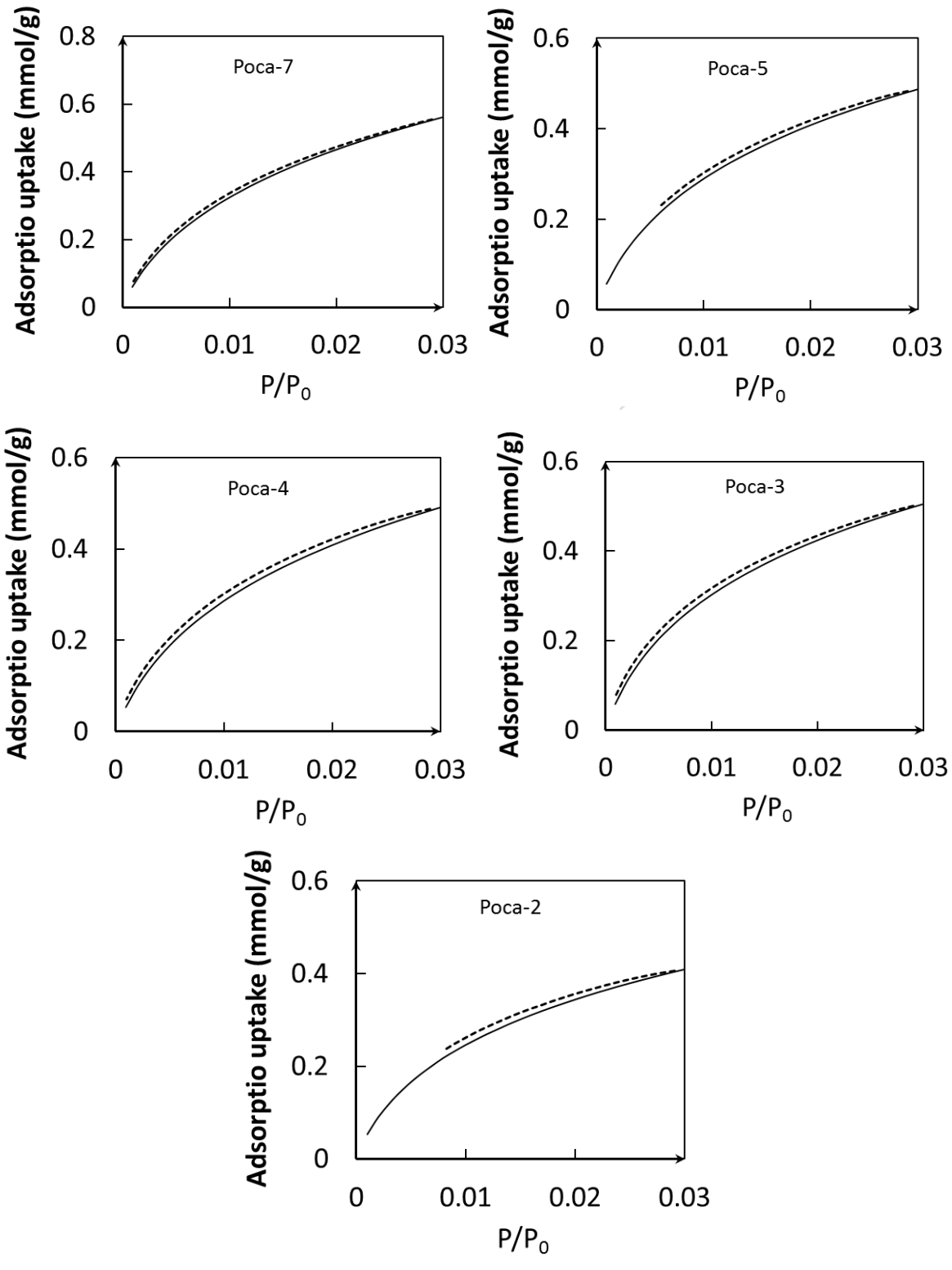

Poca-7
Adsorptio uptake (mmol/g)
0.8
0.6
0.4
0.2
0
0
0.01
0.02
0.03
P/P0
Poca-5
Adsorptio uptake (mmol/g)
0.6
0.4
0.2
0
0
0.01
0.02
0.03
P/P0
Poca-4
Adsorptio uptake (mmol/g)
0.6
0.4
0.2
0
0
0.01
0.02
0.03
P/P0
Poca-3
Adsorptio uptake (mmol/g)
0.6
0.4
0.2
0
0
0.01
0.02
0.03
P/P0
Poca-2
Adsorptio uptake (mmol/g)
0.6
0.4
0.2
0
0
0.01
0.02
0.03
P/P0

Figure 9-28 Micropore size distribution of coals

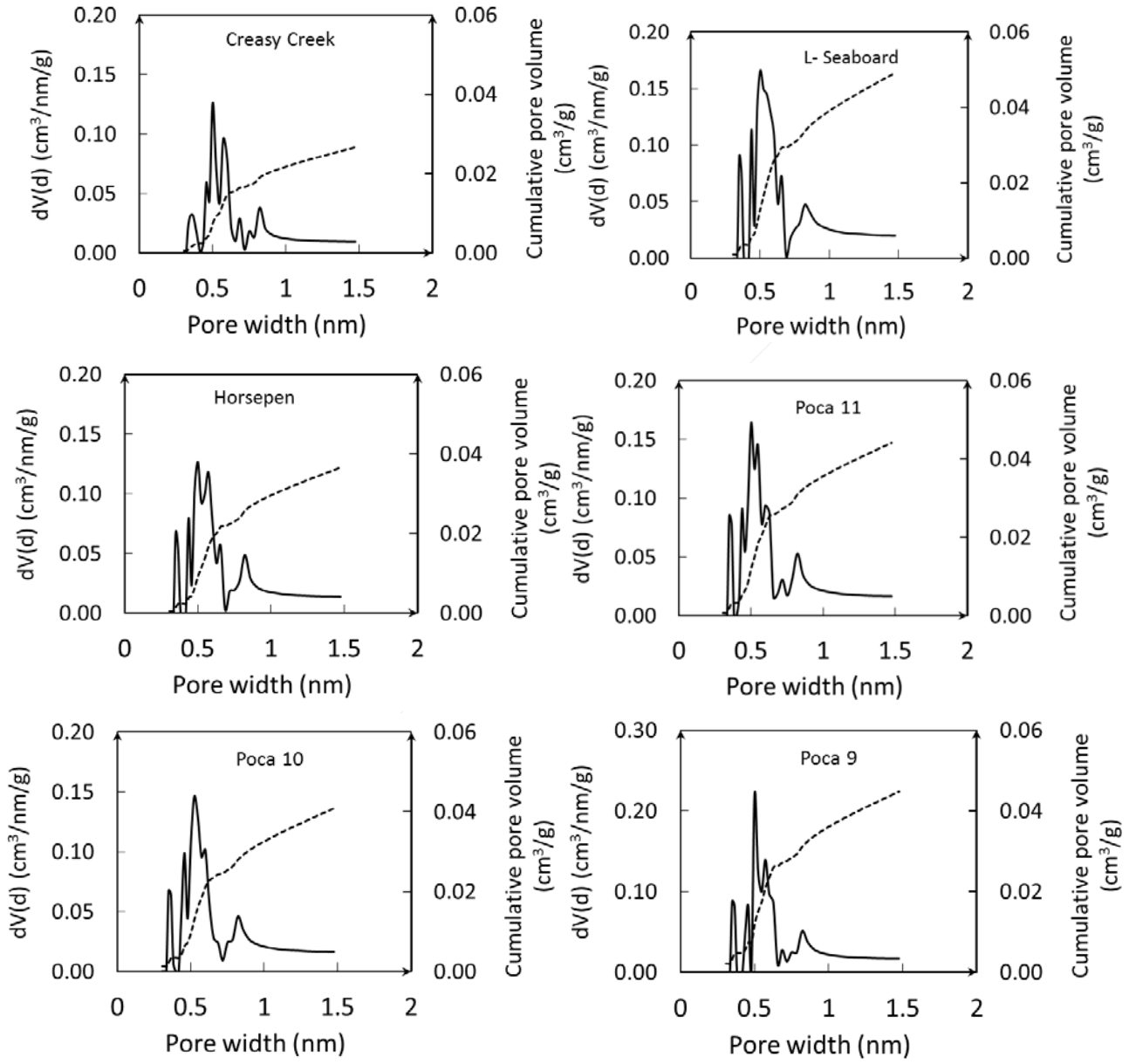
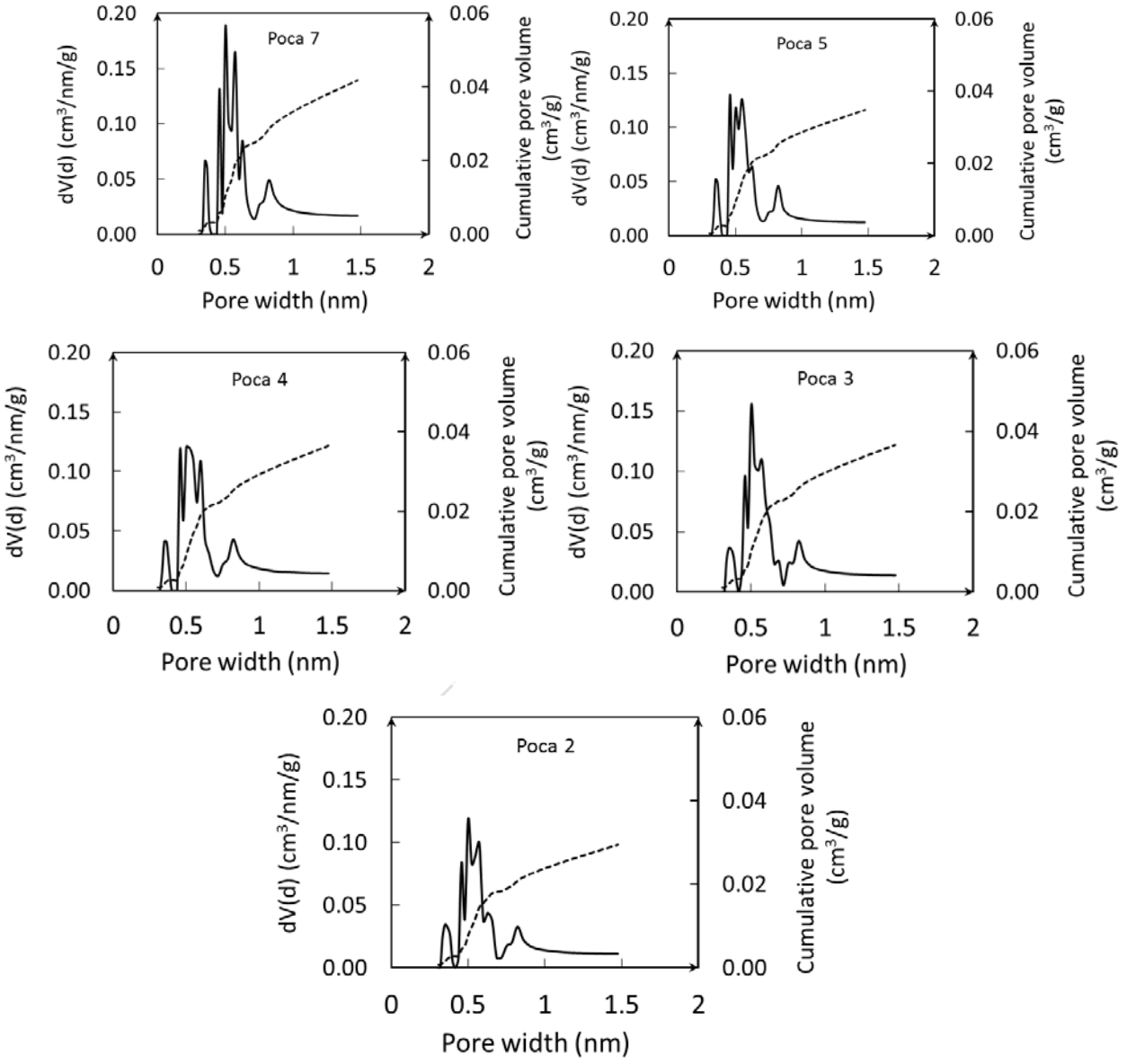


Figure 9-28 Micropore size distribution of coals (Continued)



Micro computed tomography (Micro-CT) and scanning electron microscope (SEM) Imaging

A set of 14 whole (uncrushed) core samples were also provided for CT-scan cleat examination and SEM imaging to characterize fractures (cleats), pore morphology and minerals in these coals.

Micro-CT Scan

Micro-CT is a nondestructive approach for analyzing complex cleat structures, cleat filling, and mineralization bands within coal samples. In X-ray computed tomography, materials are exposed to a concentrated beam of X-rays, and radiation is partly reflected, scattered, absorbed, re-emitted as

electromagnetic radiation, or is transmitted through the material. The rays that penetrate the sample are received on a back plate located on the opposite side of the emission source.

In the case of a micro-CT, the sample is rotated, as compared to a traditional CT scan, the specimen is fixed in place, and the emission / detection source is moved around the orbit of the specimen. A micro-CT scan is a density map of a material or specimen. Since X-ray attenuation is related to density, the micro-CT image gives the density distribution within every point scanned.

Samples are scanned using SkyScan's micro-CT 1172 scanner of the Advanced Multiscale CT Facility (AMCT) in the School of Biomedical Engineering and Sciences (SBES) at Virginia Tech. The initial data is processed and basic determinations of cleat structure, cleat filling, cleat orientation, and other mineralization are recorded. Target areas are then selected for more detailed scanning and quantification. These areas include: complex cleat structures, cleat filling, mineralization bands, and/or attempts to reduce ring artifacts in the scan. The nonhomogeneous nature of the coal requires multiple scans to successfully map the coal sample with minimum background noise, ring artifacts, and beam hardening.

Initial settings for scanning parameters include a resolution of 17.4 microns with a 100kV and 100 amps for a scanning area of less than five centimeters on the longitudinal axis of the core. Scanning time increases with smaller resolution and rotational steps. Typical scanning times exceed 24 hours per coal sample. Once the area of interest is defined further verification of the area is needed.

SEM Imaging

An SEM imaging method was also used to verify the mineral composition of the coal determined by using micro-CT, however this is a destructive method and the sample is no longer useable for μCT scanning. The SEM method is used to visualize the pore morphology/structure of coal samples. The environmental SEM (FEI Quanta 600 FEG) in ICTAS Nanoscale Characterization and Fabrication Laboratory at Virginia Tech is used here. SEM is an automated image analysis system which uses back scattered electron and energy dispersive X-ray signals from a scanning electron microscope to create digital images across the sample surface.

Each pixel in these images contains information, derived from BSE and energy dispersive spectrometry (EDS) data, on the chemistry of the mineral, matrix, or organic component that make up an individual small region under the electron beam [33]. The unit is coupled to a computer, which controls the movement of the sample stage and the electron beam and also collects and analyses the data from the various measurement devices. In particular, data on the chemistry of each pixel site are converted by the computer to qualitative data on mineralogy due to the association of chemical elements present.

Micro-CT and SEM Imaging Results

One coal sample (collected at the depth of 1682 feet) with a diameter of 47.6mm and 80 mm length was selected to perform micro-CT imagining. After the micro-CT imaging, three 10× (6-8) mm size

specimens were cut from the middle of sample as identified on *Figure 9-29* below: ① to do the FSEM-EDS scanning analysis, which are samples ②, ③ and ④. Sample ③ and ④ share the same cutting face. Dry samples ② and ③ were directly scanned to verify the calcite in the coal. Sample ④ was saturated in a solution of 5.7 pH carbonic acid under vacuum of 66.66 kPa for seven days at room temperature of 22.2 ˚C.

Each day the system was allowed to return to atmospheric pressure before the vacuum was reset to 66.66 kPa in order to liberate any air bubbles from the sample, and encourage the weak acidic solution to fill the pore space. A water sample was taken before the sample was rinsed with deionized water and the coal core sample was set in a drying oven on the lowest setting (32.2 ˚C) for a period of 72 hours. Selection of this sample was due to the calcite-filled cleats shown in the initial µCT scanning, a sample with structural integrity and volume.

Figure 9-29 Specimen preparation for micro-CT and FSEM-EDS scanning

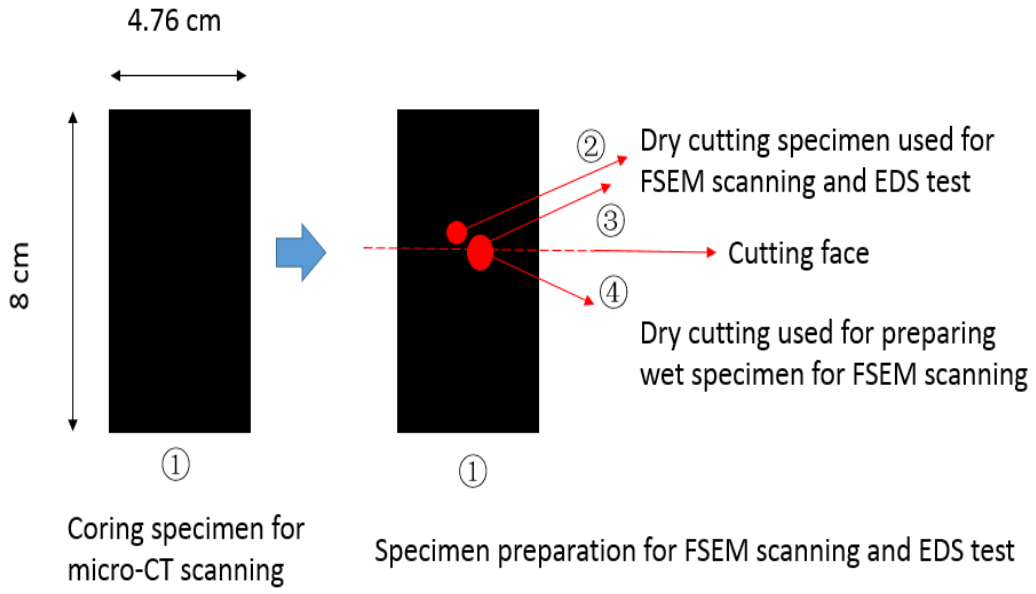


Figure 9-30 shows eight representative CT images of the cored samples, where the fracture structure of the coal sample is clearly shown. All CT images are from the same scanning cycle and therefore have the same density mapping. Comparison of these images reveals the heterogeneous properties of the samples in the fracture system, local density, and mineral distribution. Images (*a-c*) show the macro fracture system in coal, and that the center of the coal is compact. Images (*d-h*) shows the contrast of local density. Image (h) also shows the presence of minerals in coal.

Cleat structure is one of the features of these coal samples. However, it is difficult to identify the precise cleat structure due to the micro-CT image resolution and the large sample size. The µCT image in *Figure 9-30* shows the progression of calcite in the cleats with the green color scale; the darker the color on the scan, the greater the density of the material. The progression from *Figure 9-30* slice A to slice H shows the empty cleat structures in white to more calcite and pyrite in the structures as blues and reds.

While this figure shows artifacts, the resolution is sufficient near the center of the sample to confirm that there is a denser material present. This is confirmed to be calcite in the SEM scans in the following section.

Figure 9-30 Micro-CT image for sample ①

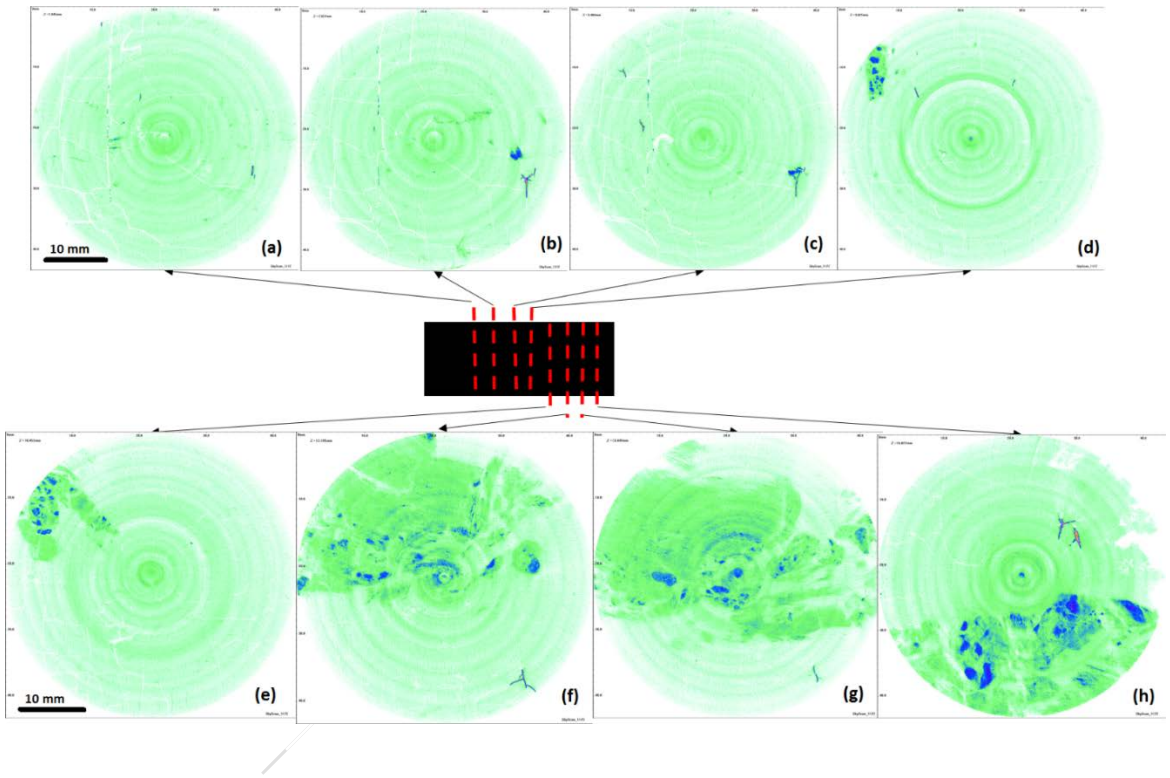


Figure 9-31 FSEM image for subsample ②

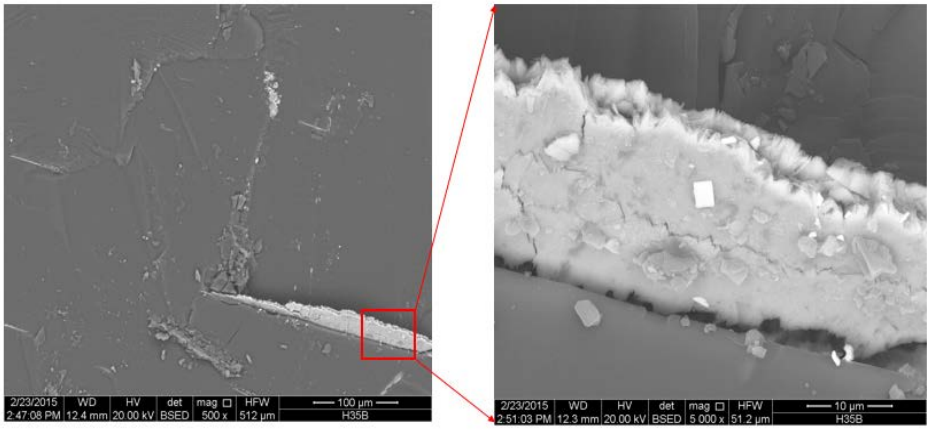


Figure 9-31 (above) is an ESEM scan of subsample ②. The 500-magnification image on the left shows sporadically distributed calcite in the subsample; one main calcite-filled band in the fracture (cleat) is

very clear while others are scattered on the surface. The 5,000-magnification on the right shows the double layer of the banded calcite and irregular fracture surface of bright white color. Within the banded calcite is distributed fracture, one main fracture and several side extended small fractures. On the surface of the coal, there are also scattered calcite. At the interface between calcite and coal, the irregular interface is clear.

Figure 9-32 below is an ESEM scan of the subsample ③. From the 80-magnification image on the left, the orthogonal banded calcite is clear. Since the orthogonal feature is the labeled feature of the cleat system, it may be conjected that the banded calcite is filled through the cleat. The thickness of each banded calcite is also different. For the thicker banded, the calcite is discontinuous. At 350-magnification on the right, the images show the calcite contained within the cleat system, with no gap observed in the interface. *Figure 9-32* also shows a heterogeneous fracture along the calcite, but no calcite can be observed in these fractures.

Figure 9-32 FSEM image for subsample ③

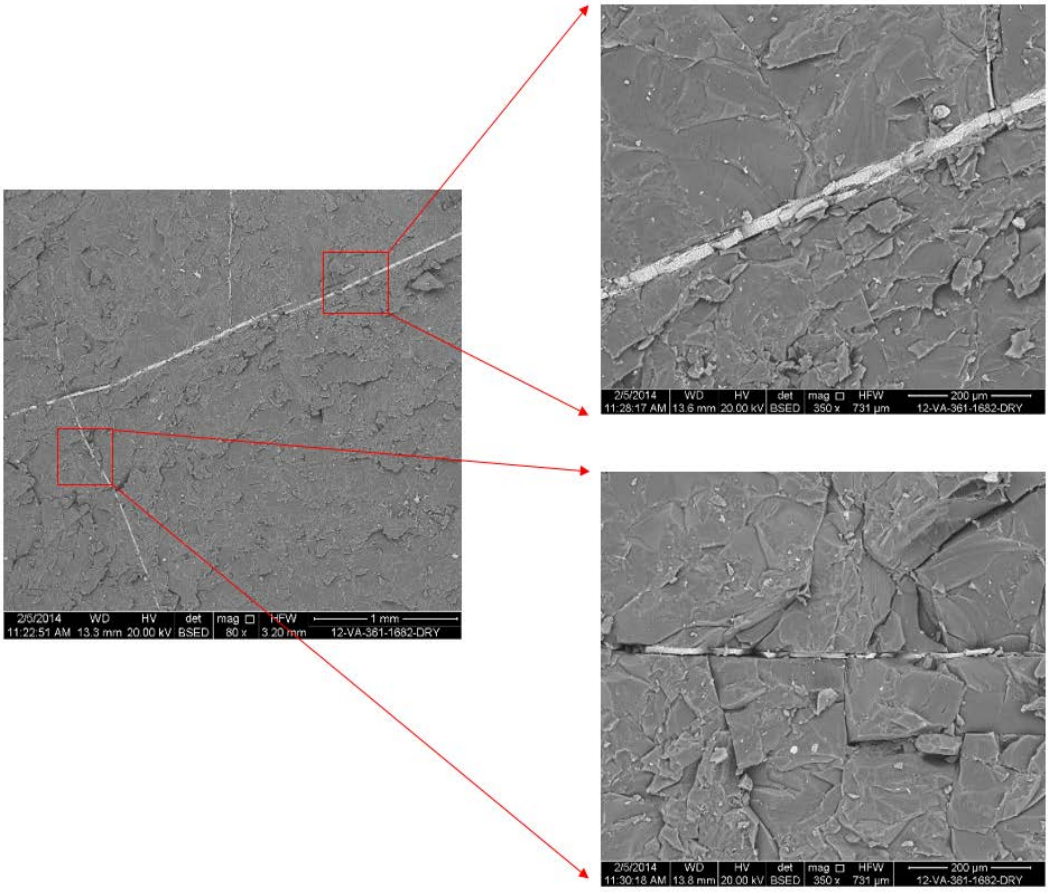
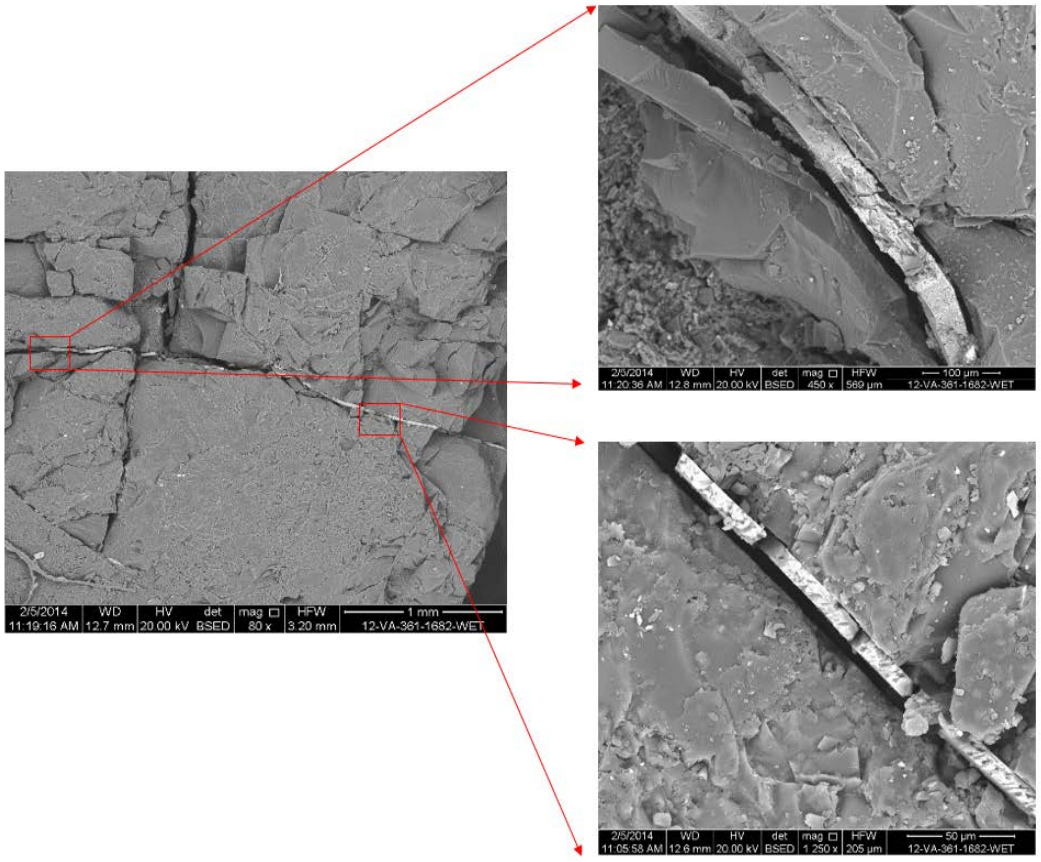


Figure 9-33 below shows the SEM image after acid water treatment. At 80-magnification, orthogonal banded calcite can be observed within the cleat structure which is similar to subsample ③. At 450-

(on the left) and 1250-magnification (on the right), the images show the open cleat system due to calcite dissolution; with gaps in the interface between calcite and cleat surface.

It is interesting that only one face of the calcite is separated between the contact of the calcite and the coal in both images. At 450-magnification, the image shows the contact face between calcite and coal. Therefore, it can be concluded that the acidic solution has a significant effect on the alteration of the calcite in coal.

Figure 9-33 ESEM image for subsample ④



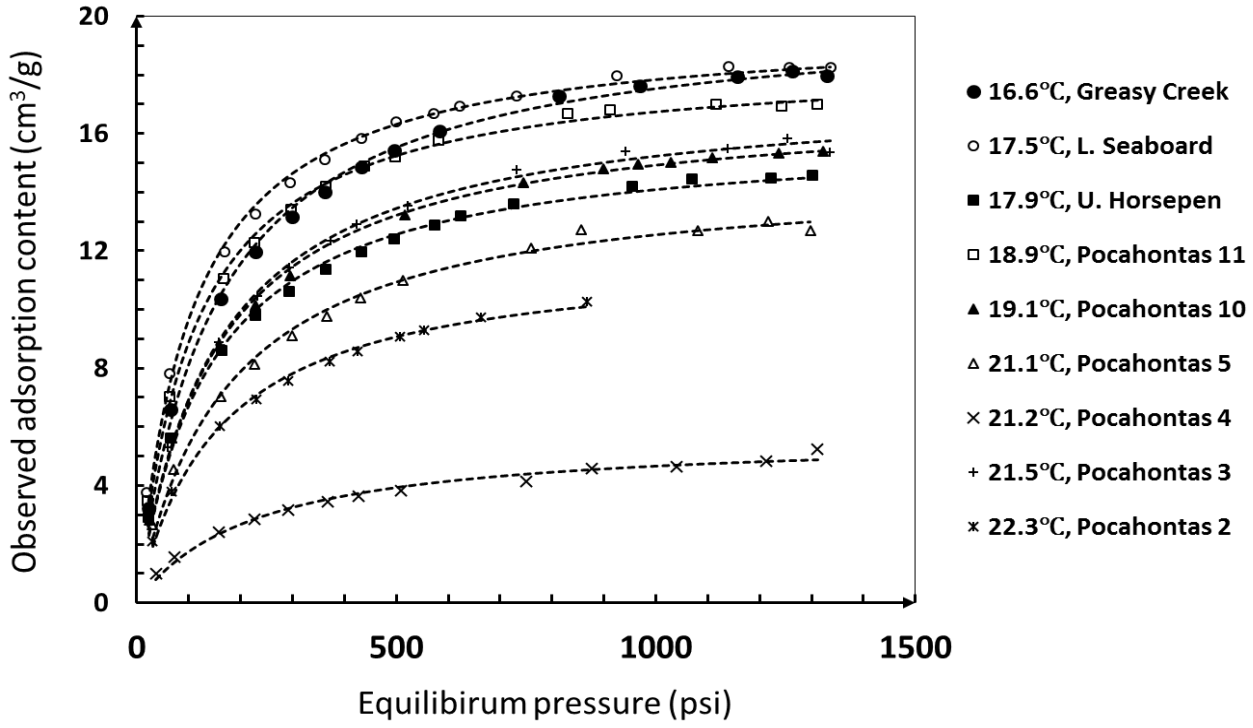
9.3.6 Methane adsorption isotherm testing

High pressure methane adsorption tests are conducted to know the adsorption capacity of methane in coals under elevated pressure conditions and reservoir temperatures. All methane adsorption isotherm measurements were conducted using high-temperature and pressure (HTHP) isothermal test equipment made by GoldenAPP of China, and the facility is at the Natural Gas Laboratory in the Department of Mining & Minerals Engineering at Virginia Tech. The measurement is based on the manometric method using the Sieverts apparatus. In this approach, the defined amount of gas is

transferred from the calibrated reference cell to sample testing cell with sample. The amount of adsorbed gas at the equilibrium pressure is the difference between the total amount of dosing gas and the amount of free gas remaining in the test cell.

Measured methane adsorption isotherms are shown in *Figure 9-34* below, where the maximum equilibrium pressure is approximately 1,300 psi. The test was conducted under varying reservoir temperatures; however, a seam by seam comparison of results may not be strictly comparable. Nevertheless, these results provide an indication of the methane adsorption capacity under reservoir conditions; the shallow Greasy Creek and Lower Seaboard samples show highest adsorption capacity, while the Pocahontas 4 shows the lowest adsorption capacity.

Figure 9-34 Methane adsorption isotherms in different coals under reservoir temperatures: dotted lines represent Langmuir fitting curves, and solid symbols represents measured data



9.3.7 Carbon dioxide adsorption in coal: kinetics and equilibrium

Measurement and modeling of carbon dioxide adsorption kinetics

Carbon dioxide adsorption kinetics testing were conducted using the same HTHP isothermal test equipment at the Natural Gas Laboratory in the Department of Mining & Minerals Engineering. The relationship between time and adsorption uptake is obtained during the adsorption isotherm measurement from one equilibrium pressure to another equilibrium pressure. Then, the pseudo-

second order (PSO) model is introduced to approximate the carbon dioxide sorption kinetics in coal, and the kinetics properties are also investigated via the PSO model.

This section was previously published as "*Tang, X., Ripepi, N., & Gilliland, E. (2016). Isothermal adsorption kinetics properties of carbon dioxide in crushed coal. Greenhouse Gases: Science and Technology, 6(2), 260-274.; Tang, X., & Ripepi, N. (2017). High pressure supercritical carbon dioxide adsorption in coal: Adsorption model and thermodynamic characteristics. Journal of CO2 Utilization, 18, 189-197.*", and is also included within the *Appendix 1-2.*

Measurement and modeling of carbon dioxide adsorption kinetics

As shown in *Figure 9-35* below, changes in the isothermal sorption content with time are recorded during the sorption process at eight different pressure ranges (MPa) under 50℃. To compare the sorption processes over different pressures, each sorption process is extracted (refer also to the right side of *Figure. 3).*

Figure 9-35 Relation between isothermal sorption content and time at 50℃ for bituminous and subbituminous coal

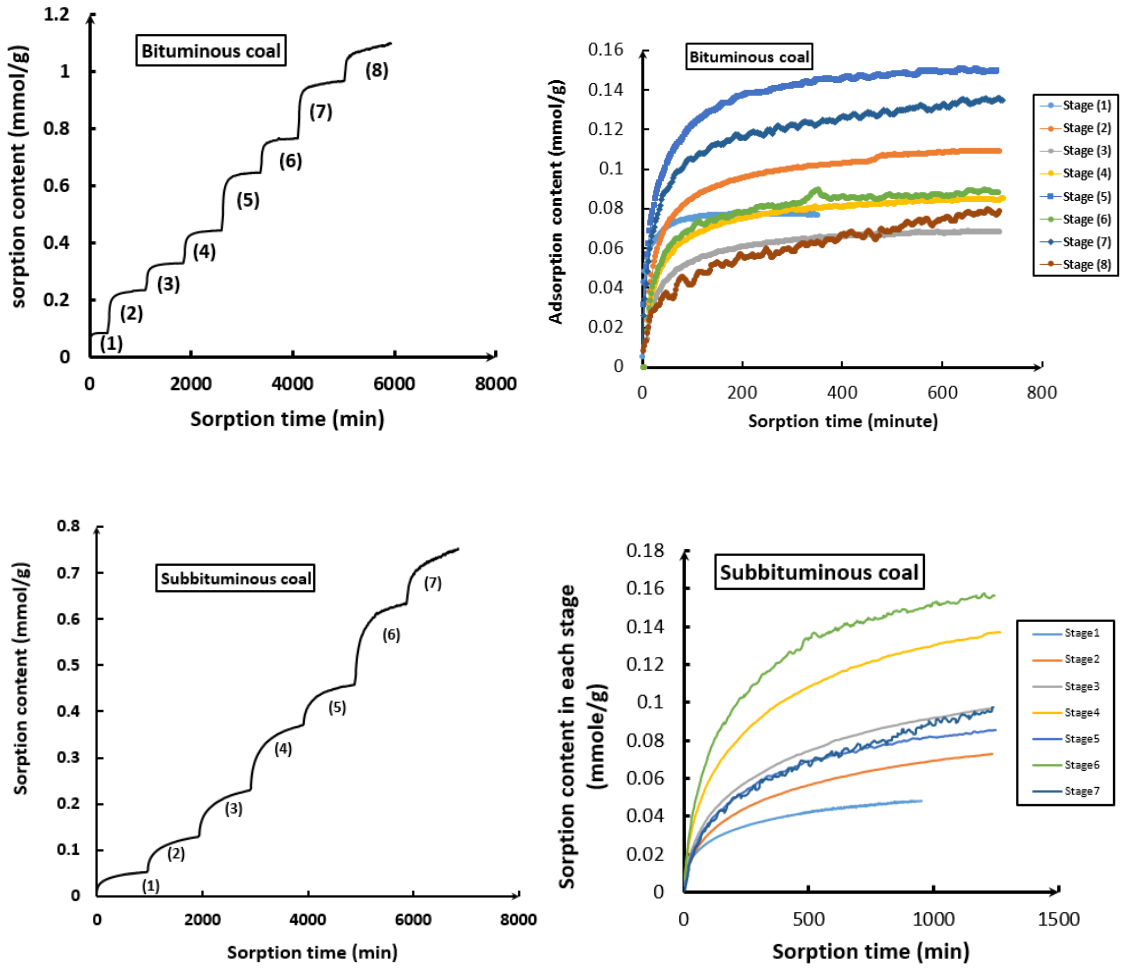
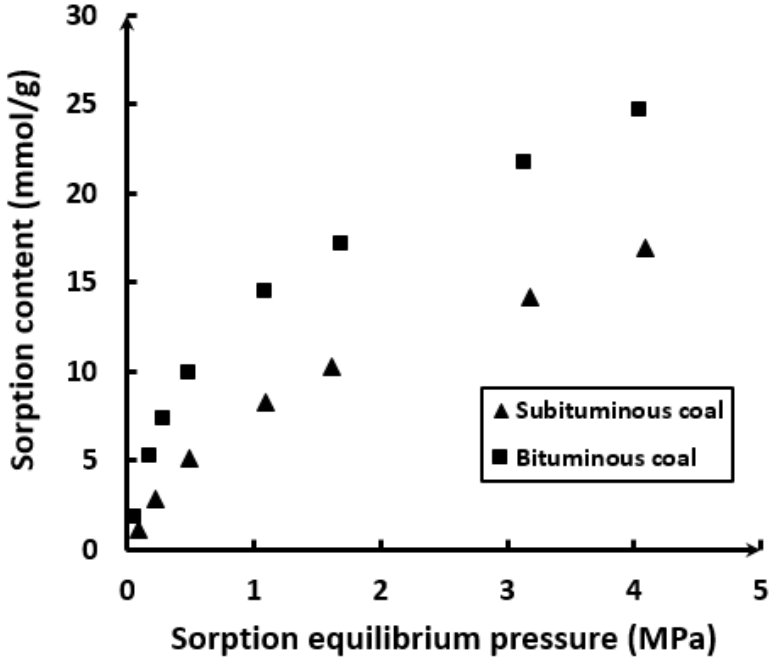


Figure 9-36 shows that there are sorption content fluctuations when the sorption pressure increases during stages (5-8) for the bituminous coal and during stages (6-7) for the subbituminous coal. These fluctuations are inevitable and are caused by pressure measurement error and temperature influence. The pressure transducer is of very high precision (0.05% of full scale) and is able to monitor and record slight changes occurring in the test cell. When the test cell pressure increases, the corresponding measurement error also increases, ultimately causing the fluctuation in sorption content.

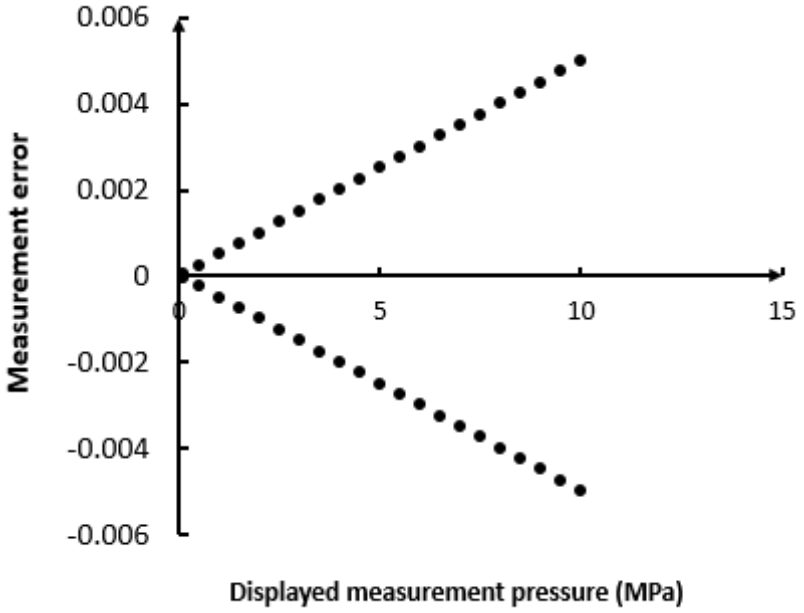
Figure 9-37 shows the isothermal adsorption curves of both bituminous coal and subbituminous coal. The adsorption capacity of bituminous coal is higher than the subbituminous coal.

Figure 9-36 Isothermal adsorption curves for bituminous and subbituminous coal at 50℃



Another factor contributing to the sorption fluctuations is related to the calculation of the sorption content, which is based on the density of gas under different pressures and temperatures. The fluctuation of the sorption value is the integrated effect of both temperature and pressure variation. In the later sorption stages, as the absolute sorption pressure increases, the absolute sorption content becomes smaller. The measurement error resulting from both the pressure measurement error and the temperature error will be magnified compared to the previous stages (refer to *Figure 9-37* below).

Figure 9-37 Measurement error of the pressure transducer



In order to model the adsorption kinetics behavior of carbon dioxide in coal, the pseudo-second-order model (PSO) is used here. The PSO model was first empirically proposed by Blanchard et al (1984) and was later theoretically proven by Azizian (2004). The PSO model has the following form,

$$\frac{dQ_t}{dt} = k_2 (Q_e - Q_t)^2 \quad (1)$$

\where Q_t is the amount gas adsorbed on the surface of adsorbent, Q_e is the equilibrium value of Q_t, t is time, and k_2 is the PSO rate coefficient, a complex function of the density of adsorbed gases. Integral equation (1) produces the PSO model.

$$Q_t = \frac{k_2 Q_e^2 t}{1 + k_2 Q_e t} \quad (2)$$

Equation (2) can be rearranged in the following form, which is most favorable,

$$\frac{1}{Q_t} = \left(\frac{1}{k_2 Q_e^2}\right) \cdot \frac{1}{t} - \frac{1}{Q_e} \quad (3)$$

Plotting $1/Q_t$ and $1/t$ gives a linear relationship, where $1/Q_e$ is the intercept of the obtained line and $1/(k_2 Qe^2)$ is the slope. The physical meaning of the kinetics parameter in equation (3) of the gas-solid system needs to be explained. Here, Q_e represents the equilibrium sorption content in each sorption stage under different pressure ranges, and the k_2 represents the other kinetics parameter used to evaluate the sorption process. The linear relationship between t/Q_t and t is used to fit the data, which

correspond very well to the test data (Figures 9-38 and 9-39, Table 9-28). The equilibrium sorption content (Q_e) and kinetics parameter (k_2) in each sorption stage are also obtained (Table 9-28).

Figure 9-38 Linear relationship between t/Qt and t: stage (1) and stage (8) for bituminous

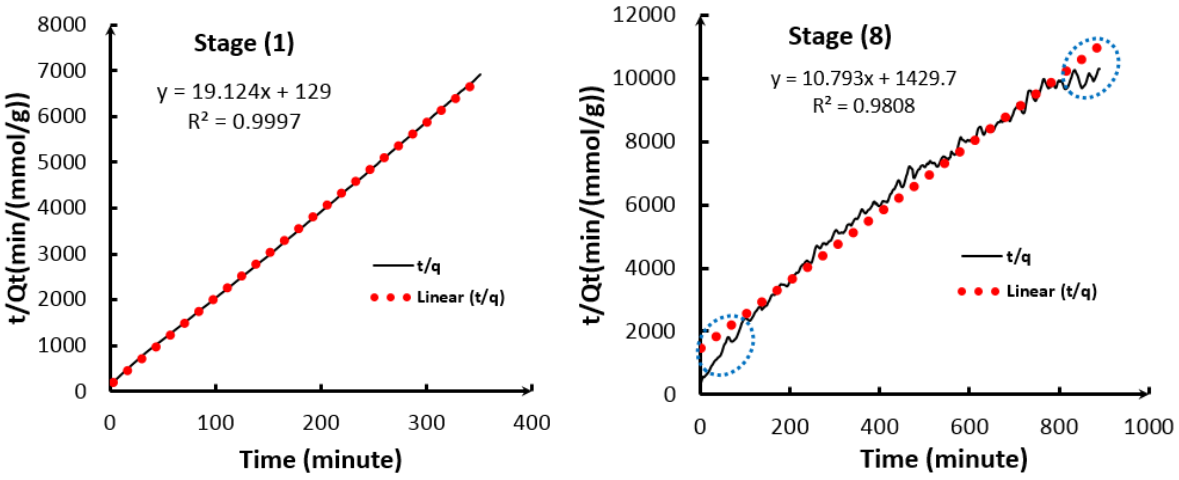
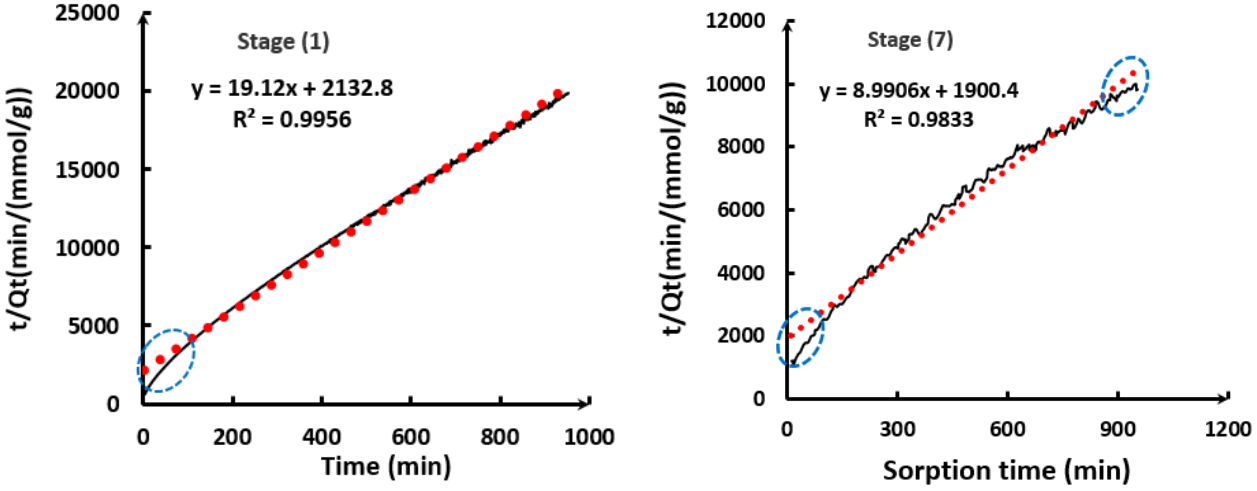


Figure 9-39 Linear relationship between t/Qt and t: stage (1) and stage (8) for sub-bituminous coal



Figures 9-38 and *9-39* demonstrate that, even though the curves show a very highly fitting trend (R^2>0.98), there are deviations in the initial test stage and the final test stage (blue circles). In the initial test stage, the diffusion-controlled process dominates the process; carbon dioxide molecules are adsorbed on the surface of coal and/or fill pore spaces as a result of the increase of pressure in each stage. At this time, the increasing pressure increases the density of the gas molecules inside the pores of the coal and is the controlling factor in the sorption system compared to interactions among gas molecules. This is supported by the unipore model, which is applicable when Q_t/Q_∞<0.5 and which has bulk diffusion as the controlling factor in the initial adsorption stage.

In the following stages, the interaction among the gas molecules becomes dominant (linear relationship between sorption content and time), which means the dynamic process of gas adsorption/desorption controls the system. This is the point where the PSO model can be applied. As shown in *Figures 9-38* and *9-39*, the diffusion-controlled process is only a small part of the total sorption process and does not significantly influence the overall sorption process.

Table 9-28 PSO model fitting data

	Sorption process	PSO model linear fitting	R^2	Q_e(mmol/g)	k_2
Bituminous coal	Stage (1)	y = 19.1240x + 1290	0.9997	0.0523	2.8351
	Stage (2)	y = 8.7926x + 296.16	0.9992	0.1137	0.2610
	Stage (3)	y = 14.027x + 430.78	0.9997	0.0713	0.4567
	Stage (4)	y = 0.4195x + 13.077	0.9997	0.0883	0.3634
	Stage (5)	y = 6.4357x + 168.09	0.9999	0.1554	0.2464
	Stage (6)	y = 10.935x + 307.90	0.9992	0.0914	0.3884
	Stage (7)	y = 7.0164x + 300.72	0.9986	0.1425	0.1637
	Stage (8)	y = 10.793x + 1429.7	0.9808	0.0927	0.0815
Subbituminous coal	Stage (1)	y = 19.137x + 2122.1	0.9955	0.0562	0.1726
	Stage (2)	y = 12.236x + 1838.1	0.9925	0.0855	0.0815
	Stage (3)	y = 9.0867x + 1442.7	0.9927	0.1139	0.0574
	Stage (4)	y = 6.5057x + 924.43	0.9952	0.1577	0.0458
	Stage (5)	y = 10.431x + 1451.2	0.9963	0.0984	0.0750
	Stage (6)	y = 5.7648x + 655.78	0.9982	0.1926	0.0507
	Stage (7)	y = 9.0223x + 1880.2	0.9833	0.1332	0.0433

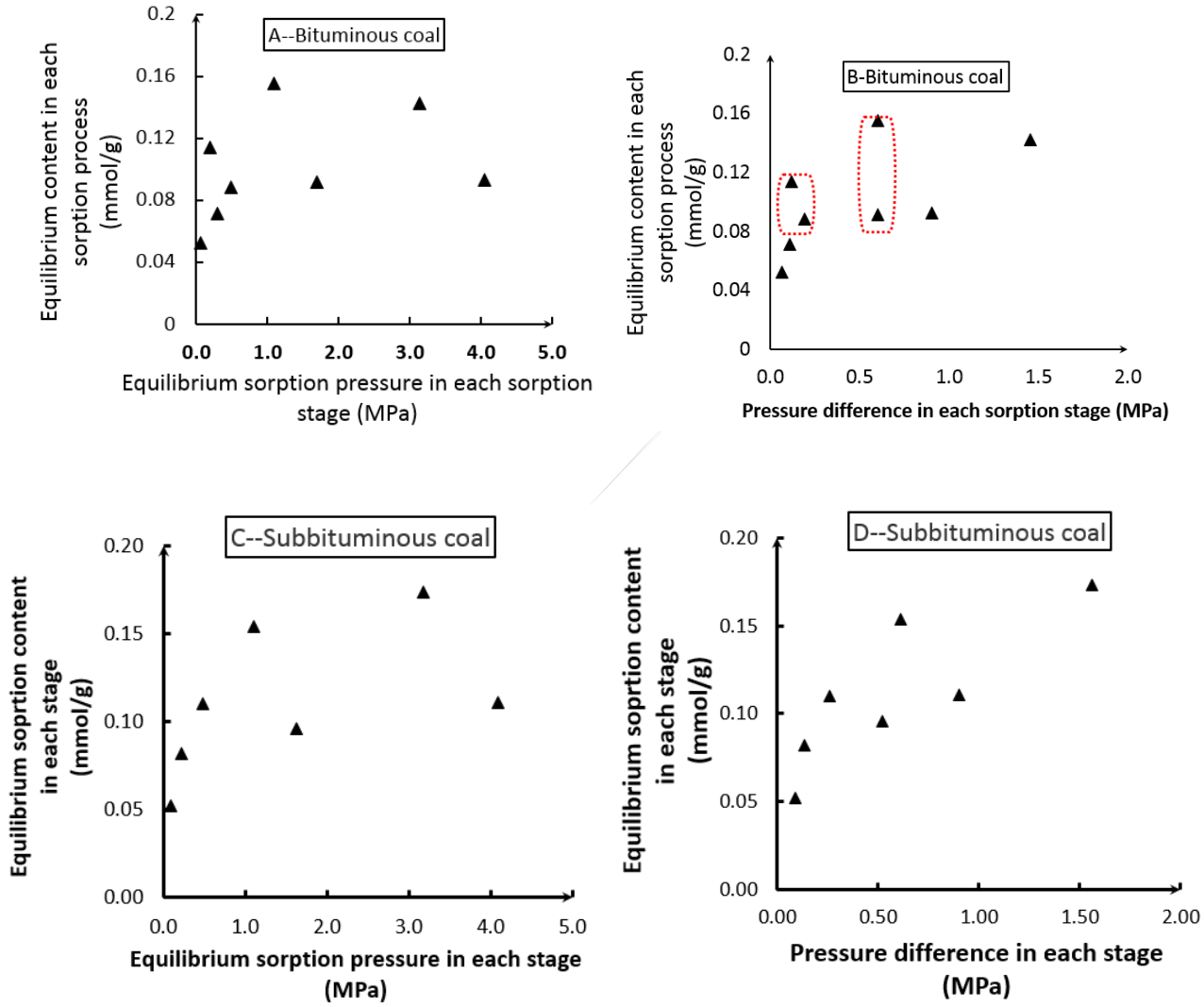
Reviewing the sorption content curves in *Figure 9-35*, it can be observed that the sorption content in stages (7-8) of bituminous coal and stages (6-7) of subbituminous coal shows an increase compared to previous stages. This could be due to capillary condensation the meso-pore system of the coal or the pore-filling phenomena which occurs in nanopores. In addition, since the coal sample is dried naturally, the presence of residual water vapor inside the coal may also contribute to the carbon dioxide condensation. Therefore, the conventional sorption equilibrium determination approach cannot be applied in these stages.

As shown in *Figure 9-40* (A & C), as the equilibrium sorption pressure increases, the equilibrium sorption content in each stage appears to initially increase and then begins to fluctuate. No consistent quantitative relationship can be obtained from current data. *Figure 9-40* (B &D) shows that an increase in pressure difference causes a general but unstable increase in the equilibrium sorption content. When the pressure differences are approximately the same, the stage of low sorption equilibrium pressure results in a higher sorption content than the stage of high sorption equilibrium pressure (red ellipse in Figure 9-40 (B)). Figure 9-40 (A-D) also show the sorption content in each sorption process (1-8) is controlled by both the final equilibrium pressure and the pressure difference.

For bituminous coal, the maximum sorption content occurs at a sorption equilibrium pressure of 1.0884 MPa with a pressure difference of 0.6018 MPa, and the minimum sorption content occurs at the first sorption pressure point of 0 MPa with a pressure difference of 0.064 MPa. For subbituminous coal, the maximum sorption content occurs at a sorption equilibrium pressure of 3.1822 MPa with a pressure

difference of 1.5608 MPa, and the minimum sorption content occurs at the first pressure point of 0 MPa with a pressure difference of 0.0889 MPa.

Figure 9-40 Relationship between pressure and kinetics parameter Qe

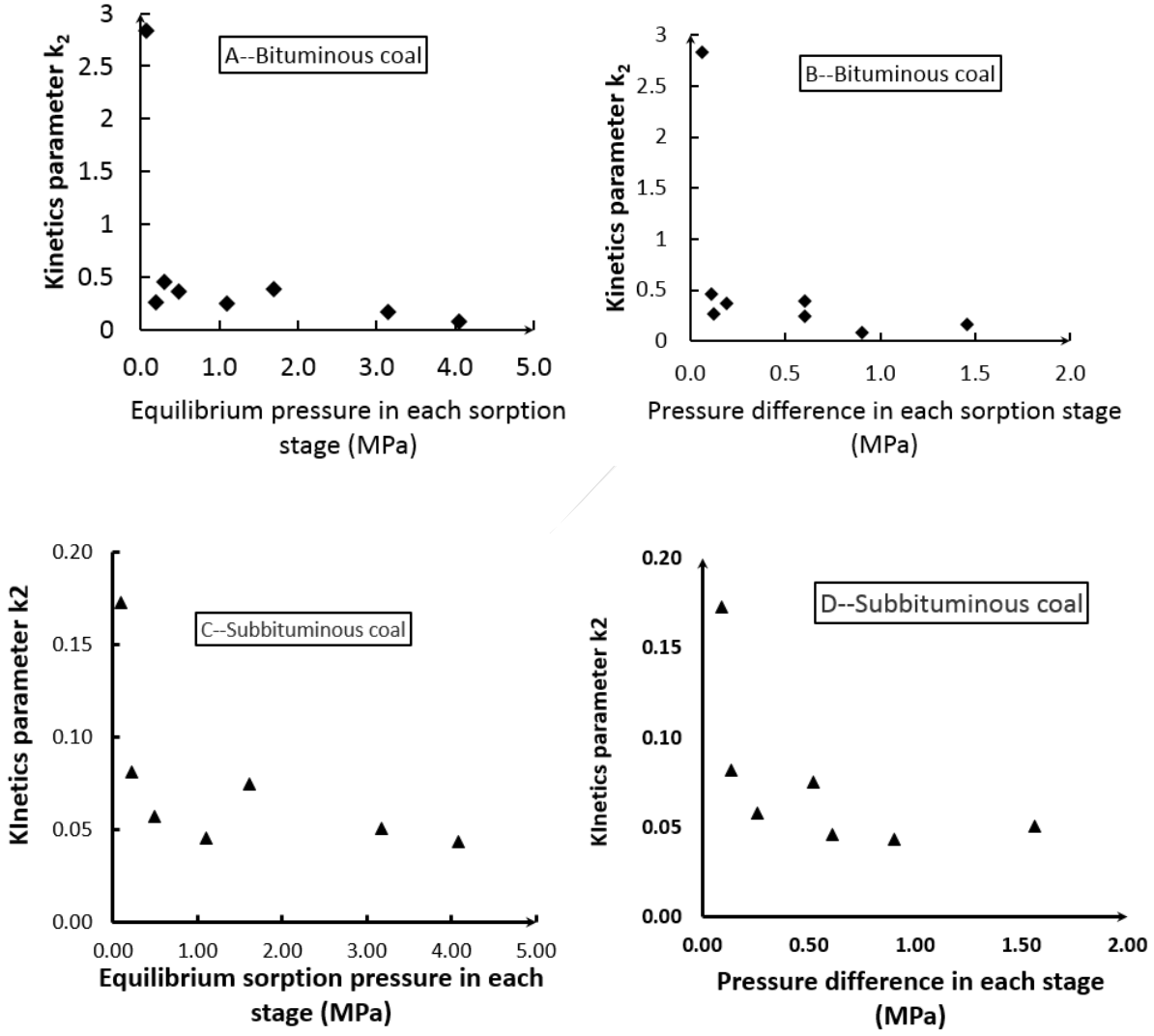


The kinetics parameter (k_2) decreases as the equilibrium sorption pressure and the pressure difference increase for both bituminous and subbituminous coal (Figure 9-41). The highest k_2 value occurs at a pressure of 0.064 MPa for bituminous coal and at a pressure of 0.0368 MPa for subbituminous coal. The lowest k_2 is 0.0815 for bituminous coal at the sorption equilibrium pressure of 4.0451MPa with a pressure difference of 0.9018 MPa, and is 0.0458 for subbituminous coal at a sorption equilibrium pressure of 3.1822 MPa with a pressure difference of 1.5608 MPa.

Figure 9-41 also shows that the k_2 of bituminous coal is generally higher than the k_2 of subbituminous coal, which implies that the value of k_2 may be influenced by the coal rank or the affinity of different types of coal. Since the highest k_2 value is obtained in the first sorption stage where the sorption pressure is low (0.064 MPa for bituminous coal and 0.0368 MPa for subbituminous coal), it may indicate

the affinity of different types of coal or the retention properties of carbon dioxide on different types of coal.

Figure 9-41 Relationship between pressure and kinetics parameter k2



Since sorption equilibrium content (Q_e) is easily obtained from the time and (t/q) linear relationship, it may be possible to determine the (Q_e) using different time ranges under each pressure step. To validate this hypothesis, the initial portion of the sorption-time relationship is used to predict the final sorption equilibrium status. The different sorption time ranges are analyzed using the PSO model for bituminous and subbituminous coal. Figure 18 shows predicted curves for adsorption equilibrium content based on the PSO model for different time intervals (120, 180, 240, 360, 480, 600 min) compared to the measured test data.

The fitting coefficient of the PSO model for each sorption stage is extremely high (> 95%). *Figure 9-42*shows the error analysis for fitting the measured data curves to the PSO model, where the error is the ratio of the difference of the calculated value and test value to test value. For bituminous coal, the

lowest error is achieved using the 360-minute predicted sorption-time curve to match the measured test data. The best match for subbituminous coal is the 600-min predicted sorption-time curve.

The best-fit curve for each coal type is plotted with the associated measured test data in *Figure 9-43* and confirms the relatively low error of each match, measured within 0.2 percent. The test results support that the sorption-time relationship can be used to predict the final equilibrium sorption content in each sorption stage.

Figure 9-42 Isothermal adsorption curves and error analysis; Qtc is the predicted value using PSO value, Qtm is the measured test value.

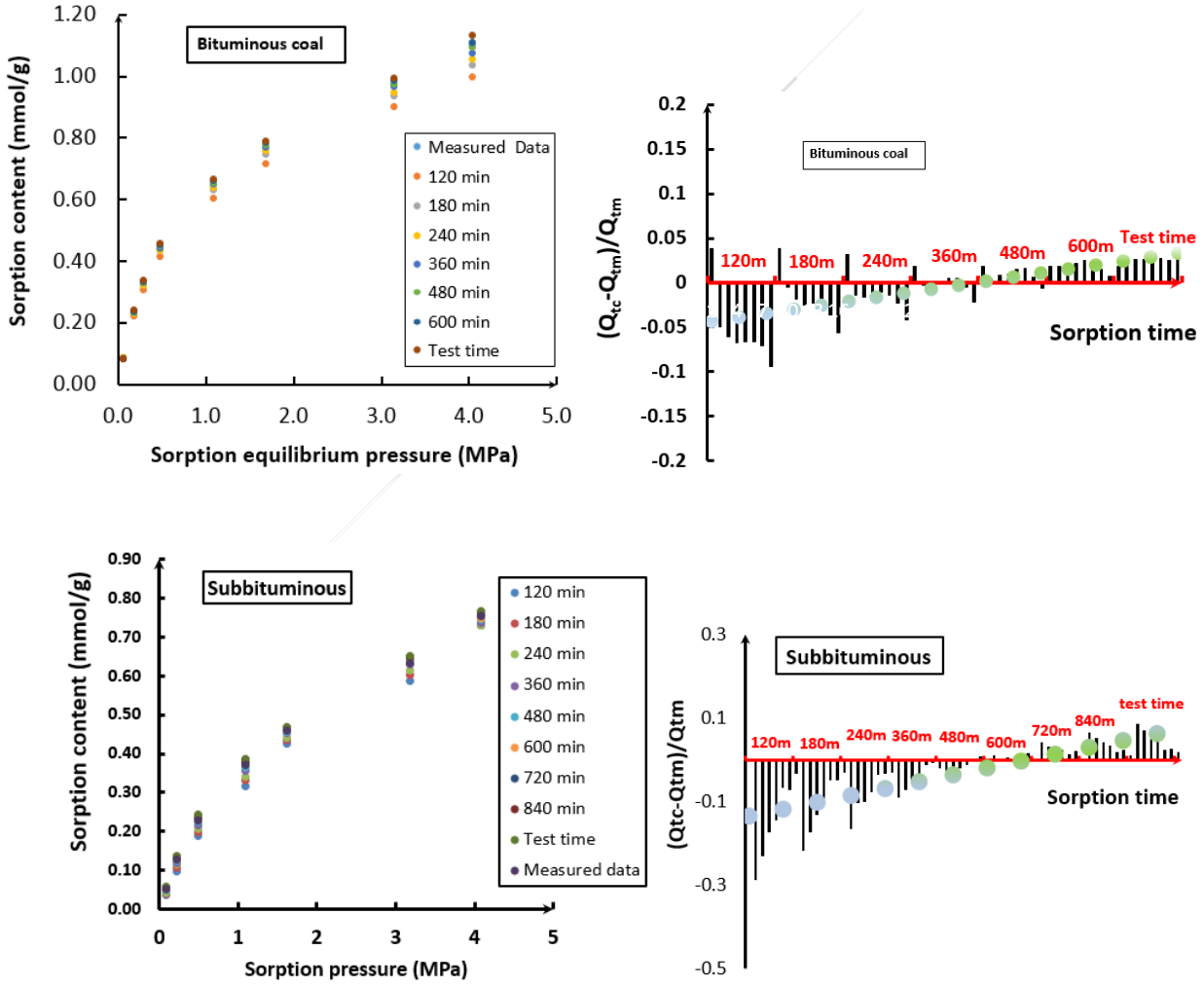
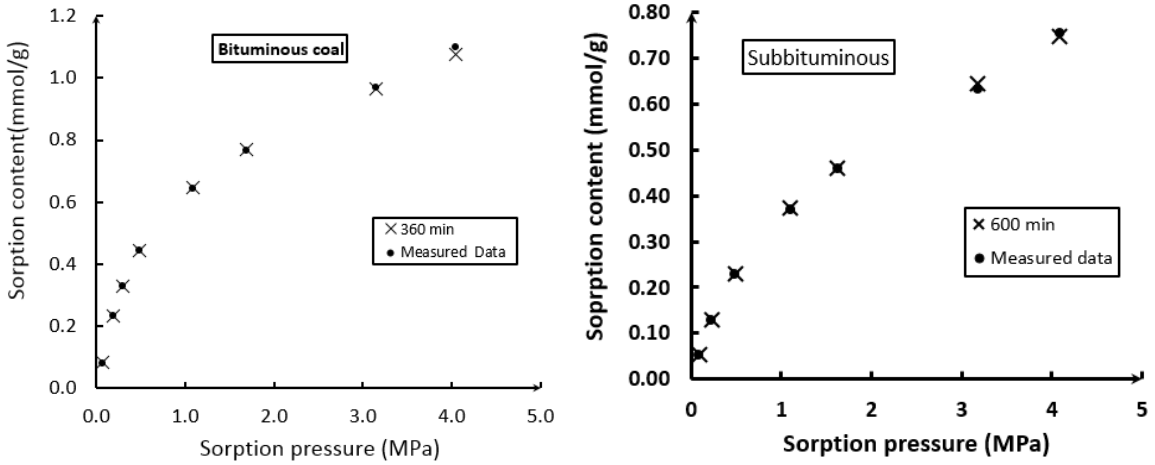
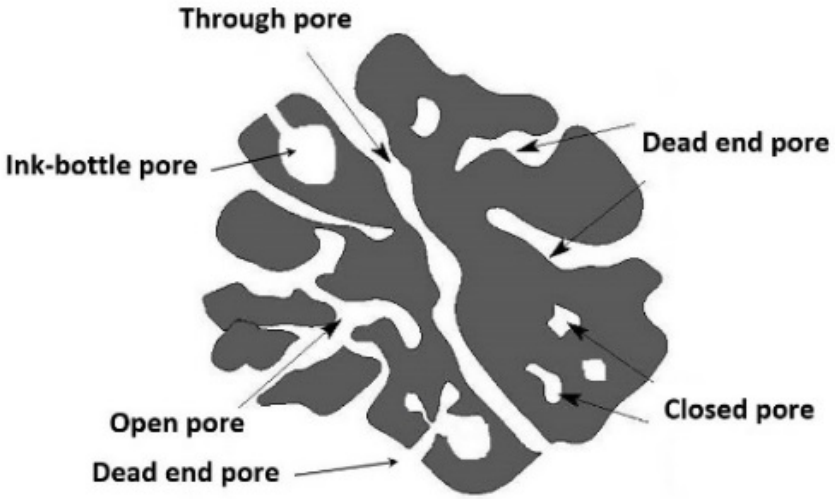


Figure 9-43 Comparison between predicted values and measured test data



Generally, the pore system of coal is complicated and consists of macropores (50nm < pore width), meso-pores (2nm <pore width< 50nm), micropores (< 2 nm) (IUPAC, 2001), and submicropores (< 0.4 nm). The micropore dominates and determines the specific surface area in coal. The different types and shapes of pores in coal also complicate gas transport in coal (*Figure 9-44*). The two-ended open pore is easy to access while the one-ended open pore (dead end pore and ink-bottle pore) and closed pore are hard to reach. For the ink-bottle pore, a high external force is needed to push the gas molecule into the pore. This may also be true for narrow channels within the pore system induced by pore wall effects.

Figure 9-44 Generalized pore system in coal



The pressure influenced kinetics parameters (Q_e and k_2) can reveal and describe important physical properties of coal, including the complex pore system, heterogeneous properties of the coal surface, and the approximation of monolayer adsorption or pore-filling effects under low pressures. As shown in *Figures 9-42 and 9-43*, there is no consistent relationship between the maximum equilibrium sorption

content Q_e and kinetic parameter k_2. This may be attributed to the different size and number of pores within the coal sample. It could also indicate that the gas easily accesses the coal but does not remain securely stored; the higher kinetic parameter does not imply the highest sorption content. The different sorption contents associated with different pressures does suggest the heterogeneous nature of the coal surface.

When carbon dioxide is first exposed to the coal, it can be easily adsorbed in the high potential energy sites induced by pore wall effects. When the pressure is increased, the low sorption potential energy sites are occupied, and the interaction of carbon dioxide molecules increases. Once the low sorption potential energy sites are filled, the higher external force is needed to force the carbon dioxide molecule to access the available sorption site and stay stable. The highest kinetics parameter (k_2) in the initial pressure stage implies that monolayer adsorption or pore-filling dominates the adsorption process, which is different from the following sorption stages. Multilayer adsorption or capillary condensation may occur because of the increasing external force and the interaction among gas molecules as the sorption pressure increases.

The successful application of the PSO model provides a new viewpoint to understand the carbon dioxide-coal sorption system. The PSO model is based on a surface interaction assumption, which has only two kinetics parameters (Q_e and k_2). The high correlation coefficient (>99%) of the fitted data supports that this model can be used to analyze the sorption kinetics data. This model can also be used to accurately predict equilibrium sorption content under different pressures.

However, does the successful use of the PSO model mean that this model can explain how the carbon dioxide interacts with coal during the adsorption process? Is the simple fitting procedure using the PSO model sufficient for describing carbon dioxide adsorption kinetics in coal? The answer is still unclear. The experimental results suggest the adsorption process for coal and carbon dioxide to be a combination of both bulk diffusion-controlled and surface interaction-controlled processes. For the non-isobaric process associated with the carbon dioxide-coal sorption system, the initial stage is controlled by the bulk diffusion process. This is supported by the deviation of the PSO model fitting process in the initial part of each stage.

It should be noted that this bulk diffusion-controlled process is only a small part of the total process considering the long equilibrium time. Following the bulk diffusion stage is the surface interaction - controlled sorption process, which requires a lengthy time for the sorption system to reach equilibrium. The surface interaction process dominates the sorption process when the bulk diffusion process decreases in importance. As mentioned earlier, the PSO model is based on the surface interaction-controlled sorption; the surface interaction dominates the sorption process, which is supported by strong curve fitting derived from the PSO model.

It should be noted that, even though the PSO model has been widely used and can reasonably explain most of the liquid-solid sorption processes, there exist some situations where the PSO model is

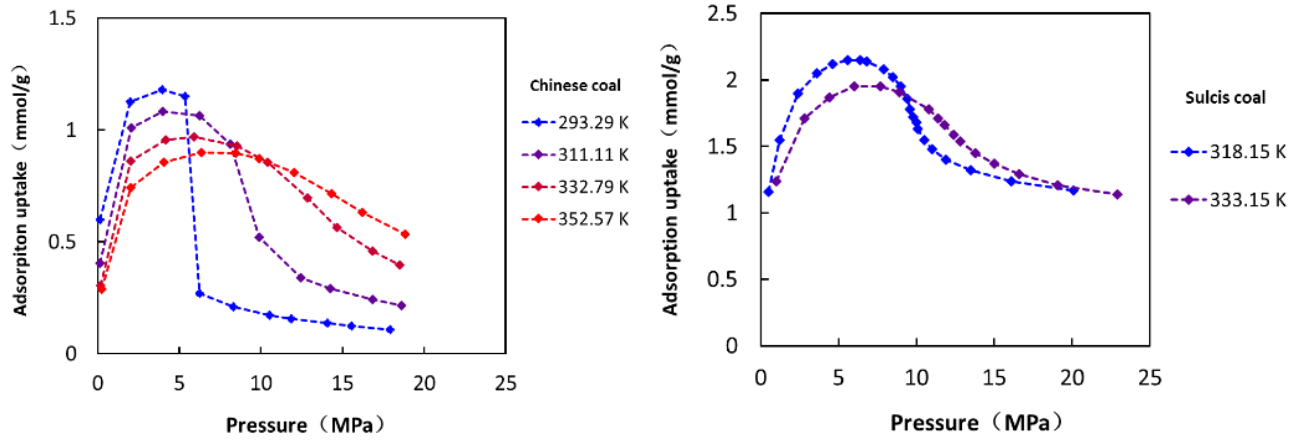
applicable, but surface interaction does not dominate the process. Therefore, even though the PSO model may not reveal the mechanism behind the carbon dioxide-coal sorption system, it provides an accurate description of the main part of the adsorption process, which is the surface diffusion-controlled process. The relationship between the kinetics parameter (k_2) and pressure shows both the heterogeneous properties of the coal surface and the approximation of monolayer adsorption for low pressures. The linear relationship between sorption content and time can be used to predict the equilibrium sorption content (Q_e) during the sorption process.

Modeling of supercritical carbon dioxide adsorption isotherms

Two sets of data for supercritical carbon dioxide ($scCO_2$) adsorption isotherms in coals are directly retrieved from the literature for investigating $scCO_2$ adsorption behavior and the associated thermodynamics. These data were measured using the gravimetric approach to obtain the $scCO_2$ sorption isotherms in dry coal under different temperatures and pressures (>=15MPa). Detailed information about these tests can be found in the original publications (Song et al., 2015; Ottiger et al., 2006).

The $scCO_2$ adsorption isotherms in coals are limited in the literature. Two sets of data are directly retrieved from the literature (Song et al., 2015; Ottiger et al., 2006). These data were measured using the gravimetric approach to obtain the $scCO_2$ sorption isotherms in dry coal under different temperatures and pressures (>=15MPa). Detailed information about these tests can be found in the original publications (Song et al., 2015; Ottiger et al., 2006). The pertinent data from these papers are shown in Figure 9-45.

Figure 9-45 Experimental data retrieved from Song et al. (2015), Ottiger et al. (2006); the dotted line is to connect data points for visualization.



Coal swelling is a well-known phenomenon associated with CO_2 injection into coal seams, which can result in injectivity issues during field tests. Researchers have used different approaches such as dilatometric method, optical or strain gages, and X-ray and small-angle scattering techniques to study the coal-swelling effects at a laboratory scale, but have not reached an agreement on whether the coal swelling is universal or not. Some researchers have found that coal microstructures were unaffected by

exposure to CO_2 over a period of days based on the SANS and USANS tests. Most other researchers agree that the uptake of CO_2 in coal results in the swelling monotonically with pressure which can be modeled by Langmuir-type curves based on laboratory evidence,

$$\varepsilon_s = \varepsilon_0 \cdot \frac{k_s P}{1 + k_s P} \quad (4)$$

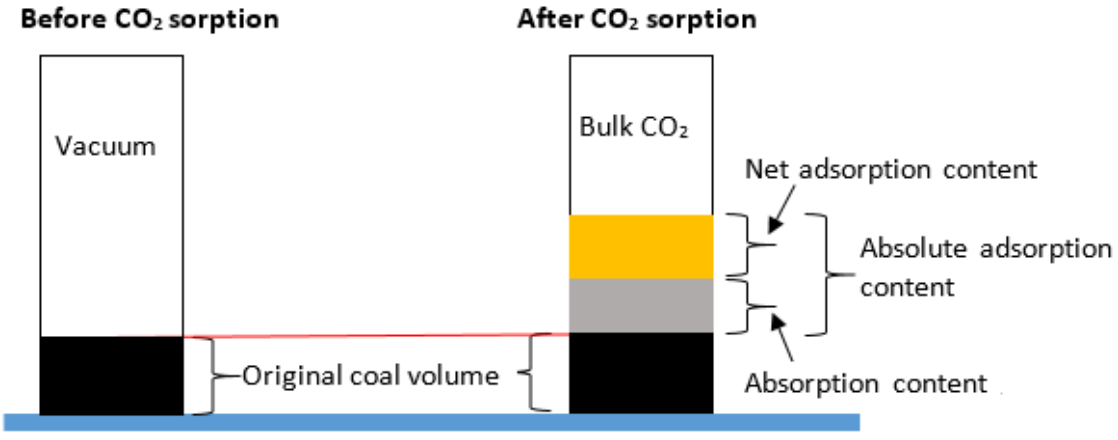
where ε_s is the swelling strain under specific pressure, ε_0 and k_s are fitting coefficients.

Based on the assumption that coal swelling is induced by the CO_2 penetration (absorption) in the macrostructure of coal, the dual-site model is used for describing both the CO_2 adsorption and the CO_2 absorption in coal as shown in equation (5). *Figure 9-46* shows how the CO_2 phase changes before and after CO_2 sorption; absolute adsorption is the sum of net adsorption and absorption uptake. The dual-site model therefore combines both the adsorption and absorption content of CO_2 in coal, represented by a Langmuir-type term. In addition, the absorption term essentially has similar properties with the coal swelling behavior.

$$n_a = n_{ad} \frac{K_1 P}{1 + K_1 P} + n_{ab} \frac{K_2 P}{1 + K_2 P} \quad (5)$$

where n_a is the absolute adsorption content under specific pressure, n_{ad} is the net adsorption content, n_{ab} is the absorption content, K_1 and K_2 are corresponding Langmuir contents (($K_1(T) = A_1 \cdot \exp(-\frac{E_1}{RT})$ and $K_2(T) = A_2 \cdot \exp(-\frac{E_2}{RT})$)), P is pressure.

Figure 9-46 The difference of CO2-coal sorption system before and after CO2 adsorption.



Assuming that the fraction ratio between the absorbed and adsorbed phase is α the equation can be rewritten (5), as follows:

$$n_a = n_{\max} \cdot \left[(1-\alpha) \frac{K_1(T)P}{1+K_1(T)P} + \alpha \frac{K_2(T)P}{1+K_2(T)P}) \right] \quad (6)$$

Notably, the physical meaning of $n_{\max}$ in equation (6) is different form the conventional Langmuir equation which is composed of both the net adsorption content and the absorption content. The term "adsorbed" will be used in the following sections as a simplification which actually refers to both adsorbed and absorbed (penetrated) phases for CO_2 in coal.

For a pure gas and solid sorption system, the excess adsorbed amount (n_e) can be shown by the Gibbs equation (7),

$$n_e = n_a - V_a \cdot \rho_g \quad (7)$$

where n_e is the excess adsorption content, n_a is the absolute adsorption content, V_a is the total volume of both adsorbed layer, ρ_a is the density of adsorbed phase and ρ_g is the density of bulk phase under specific temperature and pressure. When the V_a is very small, the contribution of the adsorbed phase can be neglected and n_e is the approximation of the n_a. However, for a high-pressure sorption system, the contribution of the adsorbed phase must be taken into consideration to physically interpret the abnormal gas adsorption behavior. For example, the observed adsorption uptake increases, reached maximum and then decreases with increasing gas pressure. Therefore, it is imperative to find a reasonable approach for obtaining the absolute isotherms from Gibbs excess isotherms for the gas-solid sorption system under high pressure and temperature.

Considering the accepted assumption that the density of the adsorbed phase can be treated as an unknown constant, the volume of the adsorbed gas phase can be obtained by equation (8),

$$V_a = \frac{n_a}{\rho_a} \quad (8)$$

Combining with equation (6), equation (8) can be rewritten as,

$$V_a = V_{\max} \cdot \left[(1-\alpha) \frac{K_1(T)P}{1+K_1(T)P} + \alpha \frac{K_2(T)P}{1+K_2(T)P}) \right] \quad (9)$$

where V_a is the total volume of the adsorbed phase under specific temperature and pressure, V_{max} is the maximum volume at maximum adsorption content, $V_{\max} = n_{\max} / \rho_a$. Combining equations (6), (7) and (9), both excess adsorption (n_e) and surface coverage (θ) equations can be obtained as shown in equation (9) and (10)

$$n_e(P,T) = (n_{\max} - V_{\max} \cdot \rho_g) \cdot \left[(1-\alpha)(\frac{K_1(T)P}{1+K_1(T)P}) + \alpha(\frac{K_2(T)P}{1+K_2(T)P}) \right] \quad (9)$$

$$\theta = (1-\alpha)\frac{K_1(T)P}{1+K_1(T)P} + \alpha\frac{K_2(T)P}{1+K_2(T)P} \quad (10)$$

If the observed adsorption isotherms (Gibbs excess adsorption isotherms) are obtained through isothermal adsorption tests, equation (8) is able to describe the adsorption behavior where the parameters ($V_{\max}$, $n_{\max}$, $K(T)$) can be obtained via curve fitting. The absolute adsorption content can then be solved for via equation (6).

Based on the Clapeyron relationship, it is known that:

$$\Delta H_{ad} = (\frac{dP}{dT})_{n_a} \cdot T \cdot \Delta v = (\frac{dP}{dT})_{n_a} \cdot T \cdot (v_a - v_g) \quad (11)$$

where ΔH_{ad} is the isosteric heat of adsorption, $\Delta v (= (v_a - v_g))$ is the volume change of the phase change, v_g is the molar volume of the bulk gas phase, v_a is the molar volume of the adsorbed phase, and T is temperature.

In order to obtain ΔH_{ad}, the $(\frac{dP}{dT})_{n_a}$ must be obtained first. Based on the surface coverage concept (equation (10)), the following relationship can be obtained using the chain rule,

$$(\frac{dP}{dT})_{n_a} = (\frac{\partial P}{\partial \theta})_{n_a} \cdot (\frac{\partial \theta}{\partial K})_{n_a} \cdot (\frac{\partial K}{\partial T})_{n_a} \quad (12)$$

Combining with equation (9) and (10) and applying the ideal gas law ($Pv_g = RT$), we can obtain one form of isosteric heats of adsorption mathematically (equation 13),

$$-\Delta H_{ads(n_a),IGL} = (\frac{\partial P}{\partial \theta})_{n_a} \cdot (\frac{\partial \theta}{\partial K})_{n_a} \cdot (\frac{\partial K}{\partial T})_{n_a} \cdot T \cdot (\frac{RT}{P} - \rho_a^{-1}) \quad (13)$$

If we combine equation (11) and (12) and apply the real gas law, another analytical form of the isosteric heat of adsorption can be obtained (equation (14),

$$-\Delta H_{ads(n_a),RGL} = (\frac{\partial P}{\partial \theta})_{n_a} \cdot (\frac{\partial \theta}{\partial K})_{n_a} \cdot (\frac{\partial K}{\partial T})_{n_a} \cdot T \cdot (\rho_g^{-1} - \rho_a^{-1}) \quad (14)$$

Equation (13) and (14) are much easier to solve using the analytical approach. Equation (13) shows the analytical solution of $(\frac{dP}{dT})_{n_a}$,

$$(\frac{\partial P}{\partial \theta})_{n_a} \cdot (\frac{\partial \theta}{\partial K})_{n_a} \cdot (\frac{\partial K}{\partial T})_{n_a} = \frac{\frac{(1-\alpha)P}{(1+K_1(T)P)^2} \cdot \frac{-E_1K_1(T)}{RT^2} + \frac{\alpha P}{(1+K_2(T)P)^2} \cdot \frac{-E_2K_2(T)}{RT^2}}{\frac{(1-\alpha)K_1(T)}{(1+K_1(T)P)^2} + \frac{\alpha K_2(T)}{(1+K_2(T)P)^2}} \quad (15)$$

Using the dual-site Langmuir adsorption model, absolute adsorption isotherms can be obtained without any subjective assumptions from the excess adsorption isotherms. The isosteric heat of adsorption can be calculated considering the real gas behavior and the contribution of the adsorbed phase, neither are considered in the classic Clausius-Clapeyron approximation.

The observed adsorption isotherms under different temperatures are fitted simultaneously using equation (9) within the limits of the fitting parameters ($0<n_{max}<100$ mmol/g, $0<V_{max}<100$ cm^3/g, $0<\alpha<1$, 10 kJ/mol $<E_1, E_2<100$ kJ/mol, $0<A_1, A_2$). The test data is processed using the Universal Global Optimization (UGO) method of the Auto2Fit software (*7D*-soft High Technology Inc., China), and the UGO can find the global maximum/minimal value of any functions without using the initial start values. The obtained fitting parameters are shown in Table 1.

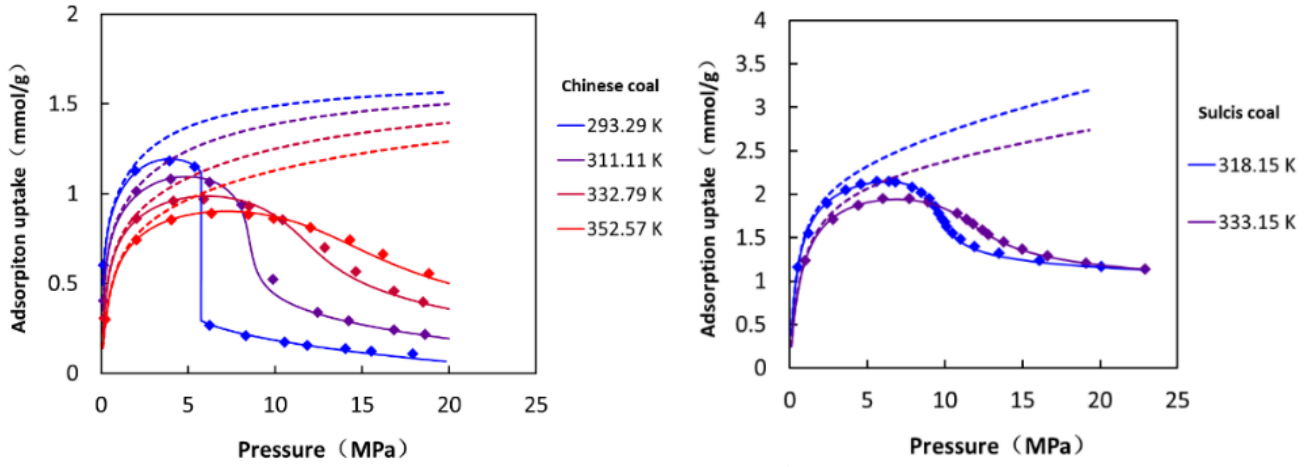
Table 9-29 Fitting parameters (equation (9)) for coal samples

Samples	Temperatures (K)	n_{max}(mmol/g)	V_{max}(cm^3/g)	α	E_1(kJ/mol)	E_2(kJ/mol)	A_1(MPa^{-1})	A_2(MPa^{-1})
Chinese coal	293.29, 311.11, 332.79, 352.55	1.6675	0.0752	0.4941	26.702	25.497	2.15E-04	1.10E-05
Sulcis coal	318.15, 333.15	6.3932	0.2220	0.6612	28.019	36.940	5.16E-05	1.54E-08

Once all the fitting parameters are obtained from fitting the observed adsorption isotherms using equation (9), the absolute adsorption isotherm can be calculated using equation (6). Then, the isosteric heat of adsorption can also be obtained using equations (13) & (14).

Figure 9-47 shows the dual-site Langmuir model fits observed adsorption isotherms very well. It is clear that the predicted absolute adsorption content of $scCO_2$ increases continuously with increasing pressures. The absolute adsorption content is much higher than Gibbs excess adsorption isotherms. The distinguishable difference between observed and absolute adsorption isotherm implies the significant contribution of the adsorbed layer of $scCO_2$ in coal for absolute adsorption content.

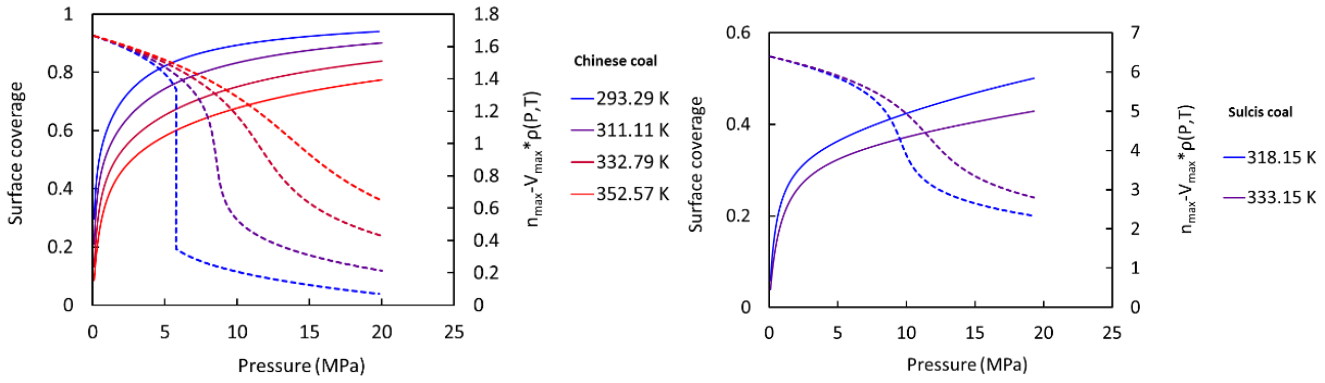
Figure 9-47 Fitting adsorption isotherms using dual-site Langmuir model for five coals; solid line: Gibbs excess fitting (equation (9)) and dotted line: absolute adsorption uptake (equation (6))



For both coals, there are consistent crossovers of the observed adsorption isotherms under different temperatures after the observed adsorption content reached the maximum value. After the crossover, the observed adsorption content at higher temperatures is greater than at low temperatures under the same pressure. However, the temperature-dependent property of adsorption uptake under different temperatures can be shown via the absolute adsorption uptake, where the higher the temperature the lower the adsorption uptake.

The abnormal crossover phenomenon of the observed adsorption isotherms can be attributed to the increasing volume of the adsorbed phase under different temperatures during the adsorption process, which results in an increasing surface coverage but an opposite trend of the term, (n_{max}-V_{max}*ρ (P,T)) (*Figure 9-48*). The competition between the surface coverage and the term (n_{max}-V_{max}*ρ (P,T) results in the crossover of the observed adsorption isotherms under different temperatures.

Figure 9-48 Surface coverage (solid line, left axial) and the term (nmax-Vmax*ρ (P,T)) (dotted lines, right axial) with increasing pressure for both Chinese and Sulcis coals

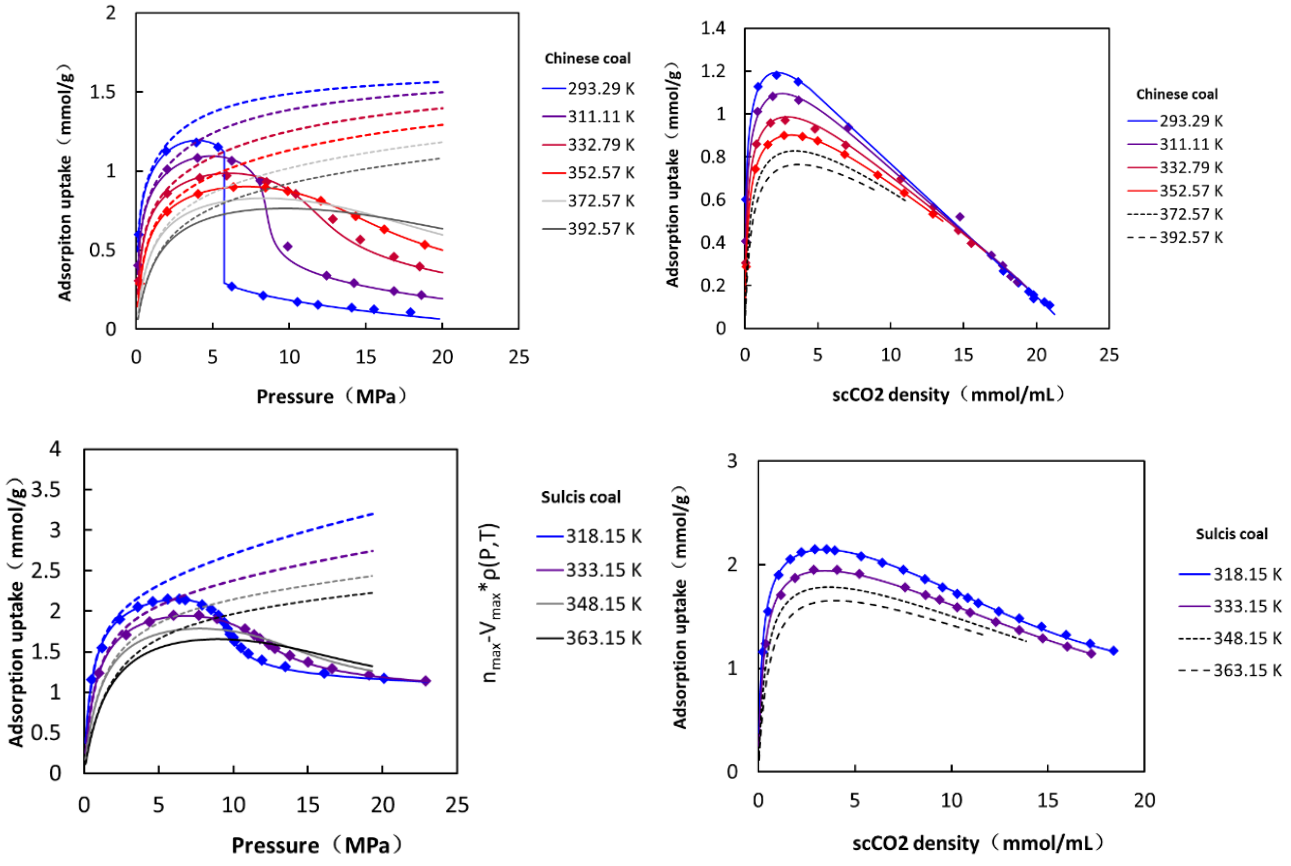


For geological storage of carbon dioxide in the subsurface such as unminable coal seams and shale formations, one of the crucial issues is to estimate the storage capacity of carbon dioxide under real geological conditions. With increasing depth, both in-situ reservoir pressure and geothermal effect

become pronounced, and there will be a phase change of carbon dioxide from subcritical status to supercritical status. Thus, carbon dioxide storage capacity must take high pressure and high temperature conditions into consideration. However, it is impractical to measure all isotherms under different temperatures. Therefore, finding an adsorption model capable to predict higher temperature adsorption isotherms using lower temperature data pique researchers' interests.

Predicting isotherms under different temperatures are possible using the proposed model because the temperature dependency of adsorption isotherms are only exhibited through the Langmuir constant ($K_1(T)$ and $K_2(T)$). *Figure 25* (left side) shows that the predicted adsorption isotherms have the same feature of the observed adsorption isotherms, where both the crossovers and the abnormal phenomenon (the higher the temperature the high the observed adsorption uptake) occur. When the adsorption isotherms are plotted as a function of bulk density, the crossovers disappear, which means the higher the temperature the lower the observed adsorption uptake. This behavior can also be shown in the predicted adsorption isotherms (*Figure 9-49*, right part).

Figure 9-49 Prediction of adsorption isotherms (black lines) beyond test data; left part: adsorption uptake as a function of pressure; right part: adsorption uptake as a function of bulk density.



In order to validate the prediction ability of the proposed model, the Chinese coal sample is taken as an example to show the confidence of the predicted adsorption isotherms. First, only three adsorption

isotherms from the four isotherms are fitted using the proposed method. Then, the predicted adsorption isotherms are compared with the test data to see the difference. Table 9-30 shows that the fitting parameters use only three adsorption isotherms. Figure 9-50 shows that all predicted absolute isotherms are consistent with test data. The predicted adsorption isotherms beyond test data are approximately the same. This also means the best-fit parameter can only be achieved using a large set of measured data.

Table 9-30 Fitting parameters for Gibbs adsorption isotherms using three adsorption isotherms

Samples	Fitting isotherms (K)	Predicted isotherms (K)	n_{max}(mmol/g)	V_{max}(cm^3/g)	α	E1(kJ/mol)	E2(kJ/mol)	A1(MPa^{-1})	A2(MPa^{-1})
Chinese coal	293.29, 311.11, 332.79	352.55, 392.57	1.6837	0.0760	0.5345	26.593	27.244	6.08E-06	1.54E-04
	293.29, 332.79, 352.55	311.11, 392.57	1.6521	0.0745	0.5033	27.632	24.941	1.66E-04	1.44E-05
	293.29, 311.11, 352.55	332.79, 392.57	1.6471	0.0742	0.5050	26.962	25.192	2.05E-04	1.41E-05

Figure 9-50 Adsorption isotherms comparison between fitting data using three adsorption isotherms (dotted lines). Solid symbol represents test data.

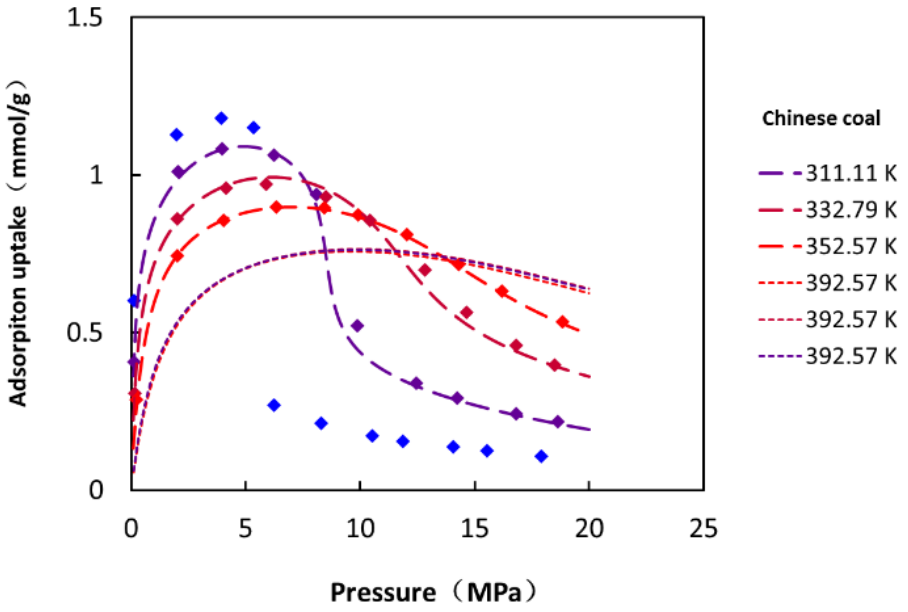
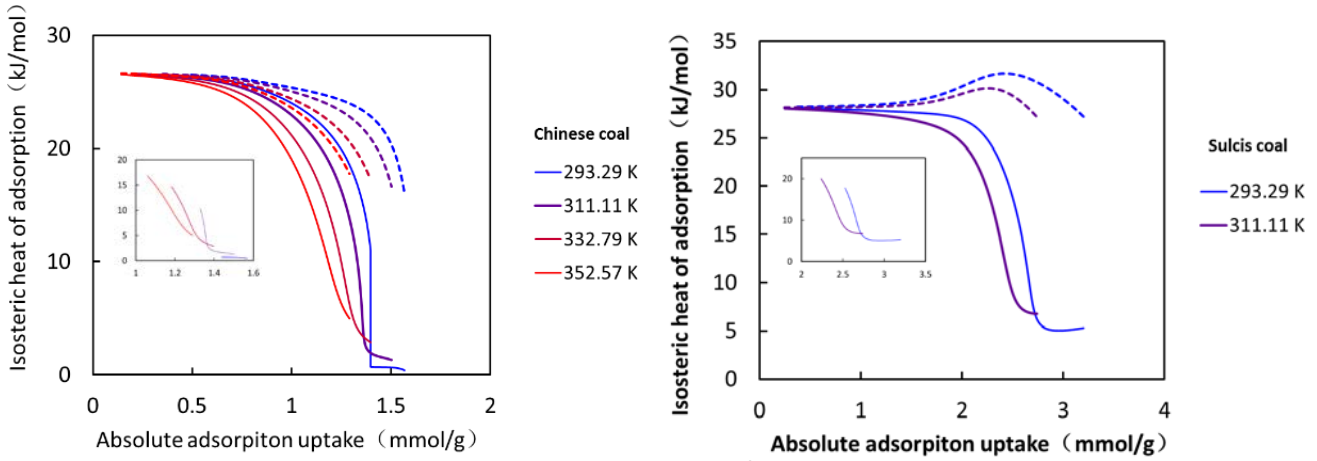


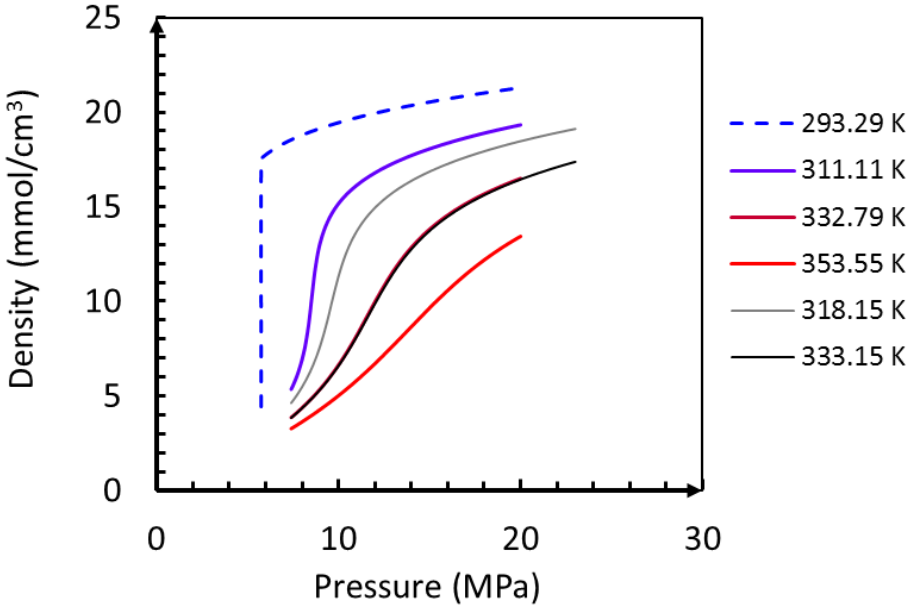
Figure 9-51 shows isosteric heats of adsorpiton calcualted using equations (13) and (14) and it can be seen that (i) the isosteric heat of adsorption decreases with increasing absolute adsorption uptake and (ii) temperature dependence of the isosteric heat of adsorption. It is also clear that the isosteric heats of adsorption using the ideal gas law are always higher than that using the real gas law at the same temperature. This means the isosteric heats of adsorption using the ideal gas law always overestimates the isosteric heat of adsorption. Both the temperature dependency and adsorption uptake dependency of the isosteric heat can also be readily shown using the proposed approach.

Figure 9-51 Comparison of different isosteric heats of adsorption for scCO2 in coal: isosteric heat of adsorptions using ideal gas law (dotted lines) and real gas law (solid lines), and the gas phases are supercritical and liquid in the magnified area.



After carbon dioxide becomes $scCO_2$ (or liquid CO_2), the heat of adsorption shows different behaviors as shown in the magnified area in Figure 9-52. When the CO_2 is in liquid phase, the isosteric heat of adsorption is the lowest compared with $scCO_2$. When the CO_2 becomes $scCO_2$, the isosteric heat of adsorption decreases with increasing absolute adsorption uptake but there are crossovers of isosteric heat of adsorption under different temperatures, which has not been reported in literature. This can be attributed to the enhanced interaction among the adsorbed phase over the coal surface at a higher density. Figure 9-52 shows the density at low temperatures is much higher than that at high temperatures for $scCO_2$, which may strengthen the enhanced interaction effect.

Figure 9-52 Density of liquid and scCO2; dotted line represents liquid carbon dioxide and solid line represents scCO2



Carbon dioxide storage in deep unminable coal seams and deep shale formations are two promising geological sites for onshore carbon sequestration. Since the adsorption phase of carbon dioxide in coal is one of the main components of the total carbon dioxide gas-in-place in the subsurface, the accurate prediction of adsorption carbon dioxide in coal is crucial. With the increasing reservoir depth, high pressure and high-temperature geological situations have to be considered. Such geological conditions result in the change of carbon dioxide from subcritical phase to supercritical phase, and an optimized model is needed to analyze such behavior.

The proposed dual-site Langmuir model can describe both the observed adsorption and the absolute adsorption of sub- and super-critical carbon dioxide in coal. In order to accurately assess the storage capacity of $scCO_2$ in coal, equation (16) should be used which is derived from mass conservation,

$$GIP = n_e + V_{tot}\rho_g \quad (16)$$

Where n_e is the observed adsorption uptake (Gibbs excess adsorption uptake), V_{tot} is the total pore space of coal, and ρ_g is the density of bulk gas. Equation (16) supports the fact that if the observed adsorption isotherms are obtained from laboratory tests, the carbon dioxide storage capacity can be accurately assessed and there is no need to differentiate absolute adsorption content from observed adsorption isotherms. However, this is only valid for estimating the total storage capacity of coal seams. In order to better understand the existing status of injected carbon dioxide in coal and carbon dioxide transport behavior under reservoir conditions, the ratio between bulk carbon dioxide and the adsorbed phase must be understood.

Using the observed adsorption isotherms (Gibbs excess adsorption isotherms) will always underestimate the true content of the adsorbed phase as shown in *Figure 23*. The dual-site Langmuir model can solve this problem by extrapolating the true content of the adsorbed phase (equation (6)) from observed adsorption isotherms. Furthermore, for large scale carbon dioxide injection tests in deep coal seams, one of the fundamental issues is to understand how the injected carbon dioxide transports within the coal matrix.

Since carbon dioxide exists in coal seams mainly in two states (free gas and adsorbed phase), the adsorbed phase influences the transport behavior of carbon dioxide because it not only occupies space in nanopores, but also interacts with pore walls. It has been found that the adsorbed gas phase significantly affects adsorptive gas (methane) transport in coal seams and shale formations. This situation will also occur with respect to carbon dioxide transport in coal. Therefore, in order to build a reasonable gas transport model for carbon dioxide transport in coal seams, the first step is to calculate the ratio of the free phase to the adsorbed phase. The proposed dual-site Langmuir adsorption model makes this possible.

9.3.8 Gas composition testing

Throughout the desorption and residual gas testing phases, more than 775 gas samples were collected from canisters and injected primarily into evacuated 10-cc glass vials (with four samples in 54.75-cc copper tubing) and provided to Virginia Tech for gas composition analysis. These gas samples were analyzed at the Natural Gas Laboratory in the Department of Mining & Minerals Engineering using a Shimadzu GC2010 gas chromatograph (GC) equipped with an electron capture detector (ECD) and coupled with a QP2010S mass spectrometer (MS).

An Agilent HP-PLOT/Q column was installed in the GC. This column is a 30 m long, 0.320 mm internal diameter (ID), 20.0 µm film thickness, porous layer open tubular (PLOT) column. The stationary phase inside the column is polystyrene-divinylbenzene which is commonly used in columns that separate C1 to C7 hydrocarbons, CO2, air/CO, water, and sulfur compounds. A particle trap, which helps protect the equipment from any particles that may become dislodged from the column, is also used in this GC/MS system.

Gas composition analysis of the sampled gas (775 in total) from coring canisters are performed using gas chromatography-mass spectrometer, and the gas composition change as a function of time is obtained as shown in *Figures 9-53 through 59*. CH_4, C_2H_6, C_3H_8, C_4H_{10}, C_5H_{12}, CO_2 and H_2S can be identified from these gas samples, where only the concentration of CH_4 and CO_2 can be quantified due to instrument limitations. Test results show that both methane and carbon dioxide content decreases with time in the desorption canister (*Figures 9-53 and 9-54*).

Figure 9-53 CH4 concentration as a function of time

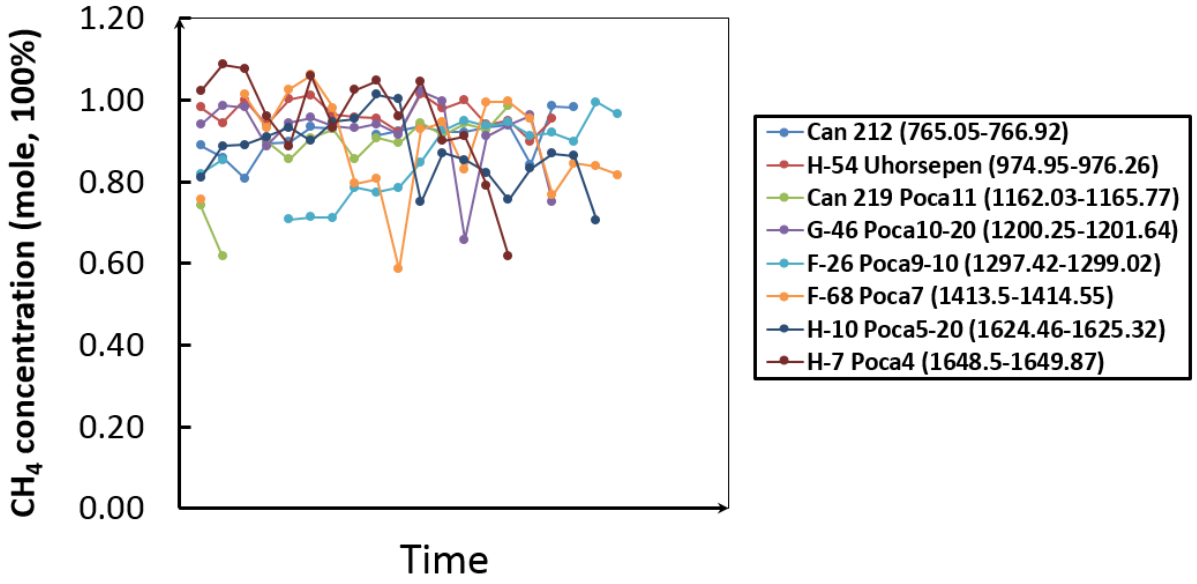


Figure 9-54 CO2 concentration as a function of time

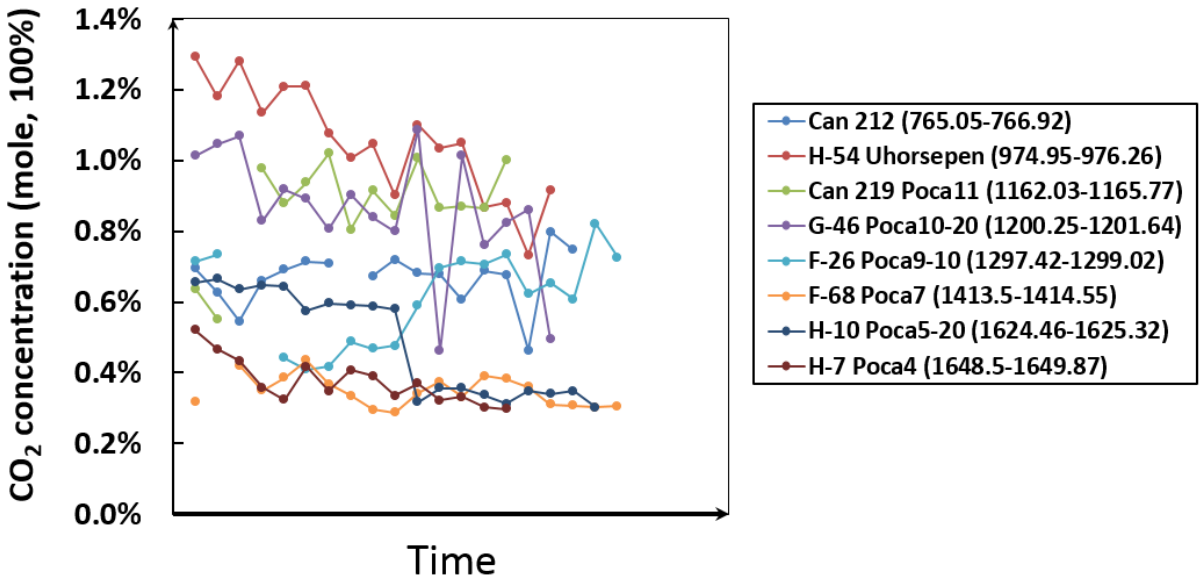


Figure 9-55 C2H6 concentration as a function of time

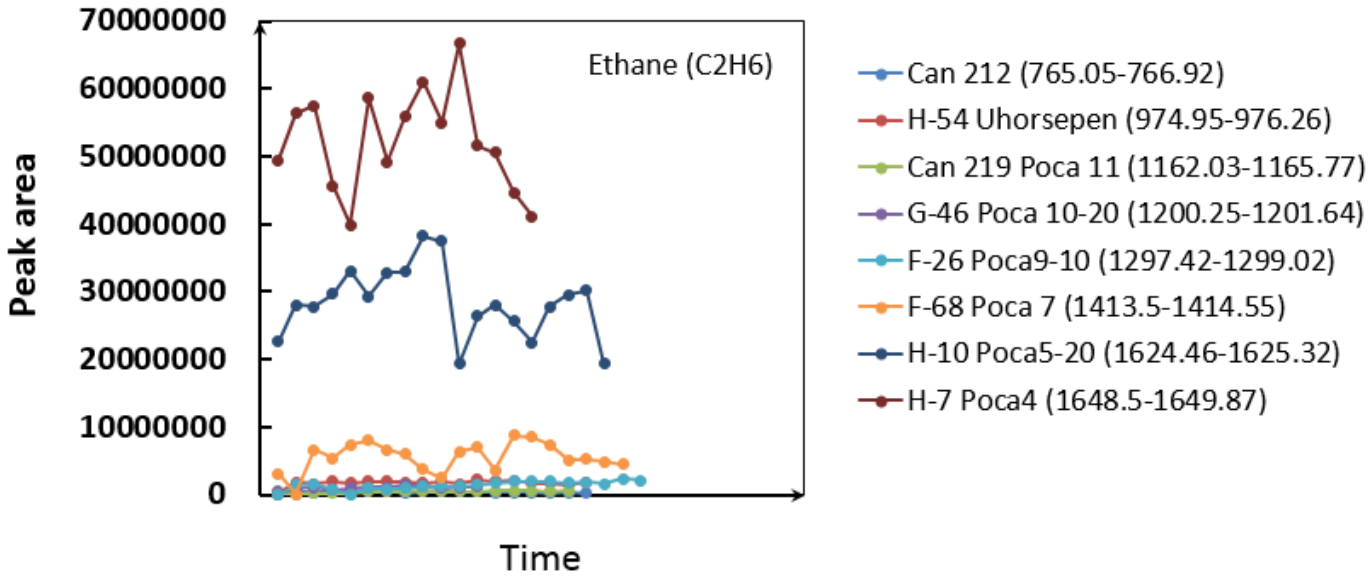


Figure 9-56 H2S concentration as a function of time

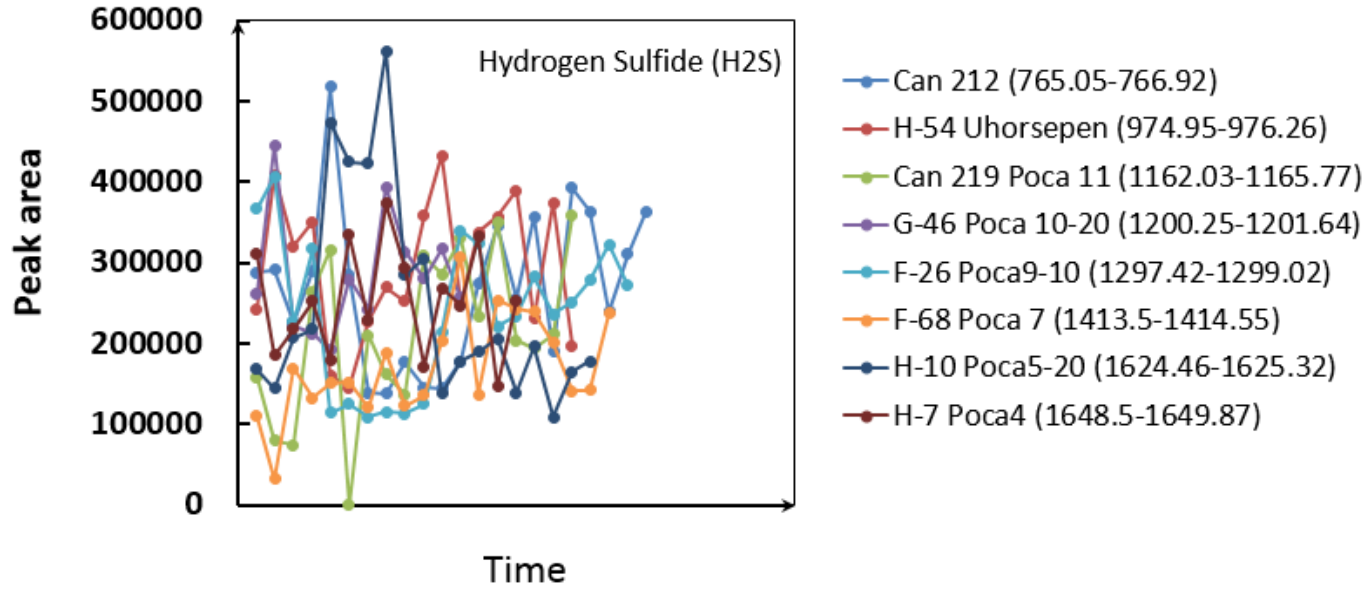


Figure 9-57 C3H6 concentration as a function of time

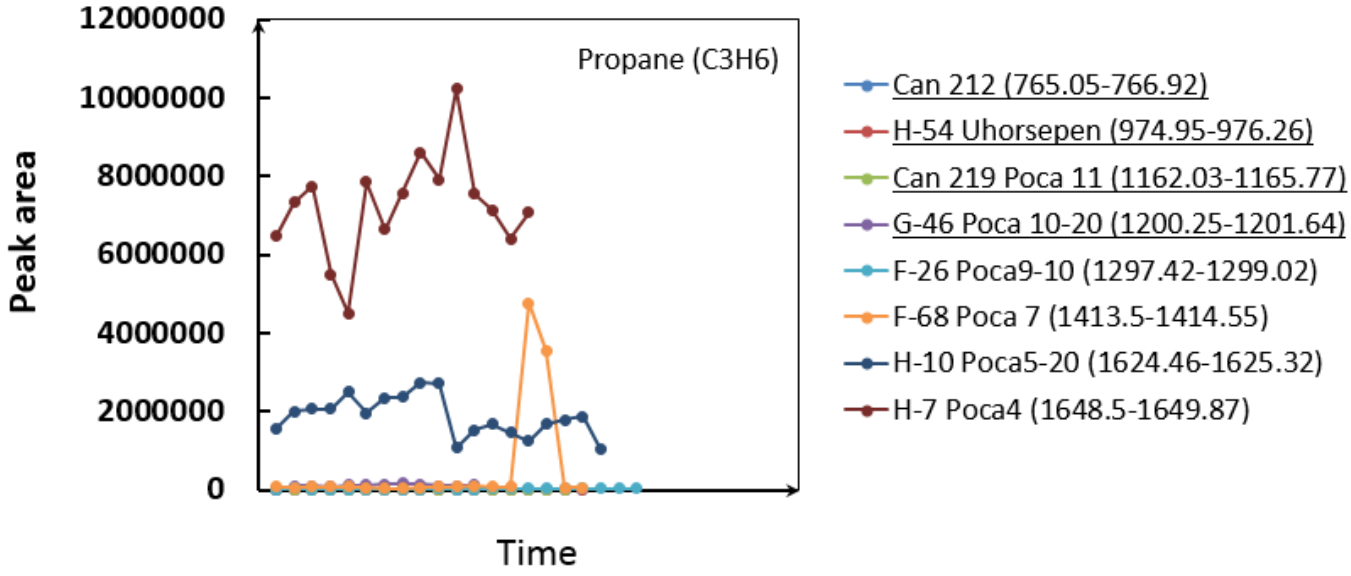


Figure 9-58 C4H10 concentration as a function of time

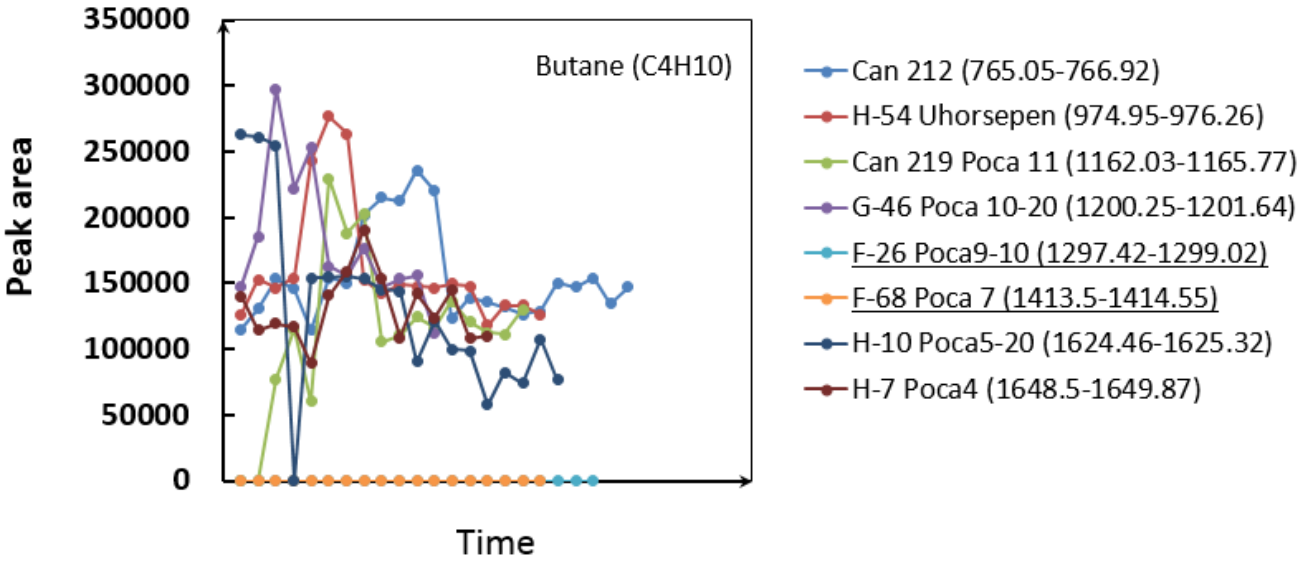
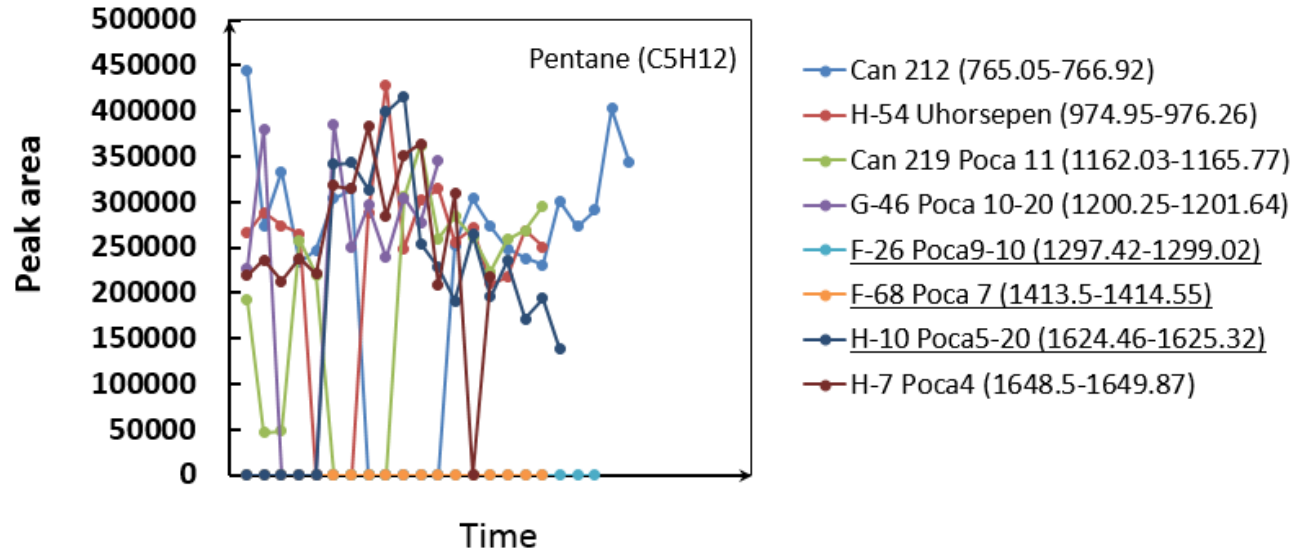


Figure 9-59 C5H12 concentration as a function of time



9.4 Preliminary Reservoir Modeling

Preliminary reservoir modeling was completed using two different reservoir simulation tools, which are Resources' COMET3™ reservoir simulator and CMG's GEM software. COMET3™ simulator was used to create a very basic model. The COMET3™ program was not very powerful to solve complex models. For that reason, reservoir modeling team was trained to use CMG's GEM program to be able to model more complex models (i.e., adding to a model several coal seams, hydraulic fractures, multiple gas components, etc.) The first preliminary model (with three different scenarios) using GEM software was decided to be built using the data of Phase II injection test in Russell County, Virginia for team to gain experience on using GEM. After reservoir modeling team gained experience using GEM, CO_2 injection

test achieved in Buchanan County was simulated in two preliminary models. Altogether, three preliminary model sets were simulated using GEM software.

9.4.1 Preliminary Model Using COMET Software

A preliminary model was developed based on regional geologic data, allowing the research team to obtain initial estimates of expected injection rates and plume migration in an expeditious manner. The following section focuses on the preliminary reservoir model created using COMET software and associated regional geologic inputs.

Modeling Methodology

Multiple modeling scenarios were simulated to study CO2 injection rates, injection volumes, ECBM, and CO2 plume extent. The model can be conceptually divided into three-time periods, including pre-injection, injection, and post-injection stages. Injection was initially simulated in two wells: DD-7A and DD-8. Assuming poor initial injection rates could occur a second scenario was simulated by assuming injection in three wells: DD-7, DD-7A, and DD-8. This three-well model was generated to ensure the sequestration of 20,000 tons of CO2 over a one-year injection period.

All modeling scenarios require that the reservoir be adjusted to its injection start-up state by simulating gas production for each well from its initial production date through an assumed injection startup of October 2013. Historical gas production data from 1993 through October 2011 for the 20 simulated wells were incorporated into the reservoir model. The technical team's decline-curve analyses were used to predict production from October 2011 through October 2013. A baseline model was simulated assuming continued CBM production (without injection) as a comparative basis for ECBM analysis. Decline-curve analyses were also used to predict future gas production rates in the baseline model.

Injection modeling was completed using an assumed 600-psi injection pressure, equivalent to injection pressures from the Phase II injection test in Russell County, VA that corresponded to the highest injection rates. Although injection could take place at pressures considerably higher, the technical team opted to use the conservative 600-psi value. This lower value is expected to minimize the impacts of coal swelling and eliminate any potential damage to the reservoir due to over pressurization. Production for nearby wells was estimated using pressure conditions extracted from the baseline model. Utilizing production rates determined from the decline-curve analyses for control of the nearby wells during and after injection would inaccurately depict no ECBM effects due to CO2 injection.

Reservoir Modeling Inputs

The preliminary model developed by the technical team consisted of a homogeneous, single-layer, horizontal coal bed with reservoir input parameters that were averages based on the available data in the area. Utilizing that method had obvious limitations and was intended to provide an approximation of injection rates and plume path. The technical team reviewed production data corresponding to the three candidate injection wells and 17 additional CBM wells located proximal to the injection sites for

incorporation into the reservoir model. Wells included in the reservoir model are shown below in Table 9-31.

Table 9-31 Wells Included in Reservoir Model

CC6 (BU-1480)	CC9A (BU-2772)	DD7 (BU-1923)	DD9A (BU-4269)
CC6A (BU-3850)	CC9B (BU-3388)	DD7A (BU-3337)	EE6 (BU-1924)
CC7 (BU-1875)	DD5 (BU-1950)	DD8 (BU-1998)	EE7 (BU-1922)
CC7A (BU-3335)	DD6 (BU-1743)	DD8A (BU-3929)	EE8 (BU-2072)
CC8 (BU-0377)	DD6A (BU-3893)	DD9 (BU-2092)	EE9A (BU-3942)

Regional geologic parameters for use in the preliminary reservoir modeling were obtained from multiple sources. Reservoir parameters, including Langmuir coefficients, matrix shrinkage-swelling data, porosity, and relative permeability curves were sourced from modeling completed for the Phase II injection test in Russell County, Virginia. Other inputs, including coal thickness, initial reservoir gas content, pressure gradient, and average coal depth were approximated by the research team based on the initial geologic characterization work conducted in the study area. Cleat orientations were obtained from published information and confirmed by field measurements. Hydraulically stimulated fracture orientations and fracture lengths were provided by coal operators in the area. Physical measurements in underground coal mines offered the only accurate means to determine hydraulic fracture geometry. Pertinent reservoir modeling inputs are summarized below in Table 9-32.

Table 9-32 Preliminary Reservoir Modeling Parameters

Parameter	Value
Total Coal Thickness (ft)	15
Coal Depth (ft)	1,800
Initial Gas Content (scf/ton)	400
Pressure Gradient (psi/ft)	0.3
Permeability (mD; face:butt cleat)	8:4
Coal Porosity (%)	1
Langmuir Volume (scf/ton)	720
Langmuir Pressure (psi)	333
Face Cleat Orientation	N 18° W
Butt Cleat Orientation	N 67° E
Hydraulic Fracture Orientation	N 57° E
Fracture Half Length (ft)	650

The grid model was oriented so that the face-cleat strike of N 18°W was rotated to the Y-axis. The reservoir modeling software (COMET3) assumes an orthogonal relationship between the face and butt

cleat directions. The measured butt cleat orientation of N 67°E falls 85 degrees from the face cleat direction. Since the butt cleat is not the dominant flow path for water and gas within the coal matrix, the research team deemed it appropriate to use the face cleat as the Y-direction with the true butt cleat orientation 5 degrees different than the model's assumed orthogonal butt cleat orientation. A new coordinate system was generated to account for the 18-degree rotation to place the face cleat orientation in the Y-direction.

Grid cells were modeled as squares with X and Y dimensions of 100 feet. The technical team opted for large grid sizes to economize the computational requirements. Smaller grids would generate a more accurate depiction of injection rates and plume path on a smaller scale. The modeled 100-ft by 100-ft grid cells were assumed to be appropriate for the macro-level model of 20 simulated wells over a 25-year period.

Boundary conditions were modeled with the northernmost, southernmost, easternmost, and westernmost wells 500 feet from a no-flow boundary. Reservoir depressurization rates during water and CBM production at the model's no-flow boundaries could be interpreted as high, yet additional CBM wells located beyond the boundary also facilitate reservoir depressurization. Additionally, these boundaries are not proximal to the proposed candidate injection wells or immediate offset wells and could be assumed to be outside the area of interest. Ultimately, the modeled grid consists of 98 grid cells in the X-direction and 69 grid cells in the Y-direction.

Modeling Results: Injection Volumes

Injection wells DD-7 and DD-8 demonstrate a higher degree of depletion than infill well DD-7A and likely have a higher CO2 sequestration capacity. Initial modeling suggested that a 20,000-ton injection volume is feasible by injecting CO2 in wells DD-7 and DD-8 over a three-month period. Published research indicates that injection volumes and rates are highly sensitive to dynamic permeability values which tend to decrease as reservoir pressure increases. High pressure injection will increase reservoir pressure proximal to the wellbore, causing coal matrices to swell and consequently decrease in permeability. Therefore, a second scenario of injecting into a three-well system (DD-7, DD-7A, and DD-8) was considered. The injection times predicted by modeling for the two- and three-well injection system were three and two months, respectively.

Modeling Results: CO_2 Plume and Breakthrough

Preliminary modeling of the two-well injection system showed CO2 breakthrough from injection well DD-7A to producing well DD-7 following the completion of the injection period. The modeled three-well scenario did not indicate significant CO2 breakthrough to nearby wells. Modeling suggested that well DD-8A was the only well which would produce CO2 due to breakthrough. Over a 4-year post injection study period, well DD-8A produced a negligible CO2 volume of 18 mcf, approximately 0.05% of the total increased gas production volume.

Figures 9-60 and 9-61 depict the CO2 plume extents for the two- and three-well injection scenarios, respectively at the end of the injection period. The plume extents four years after injection are shown for the two scenarios in Figures 9-62 and 9-63, respectively. Reservoir modeling suggested that the plume did not grow significantly over time.

Figure 9-60 CO_2 Plume (2 Injection Wells), End of Injection

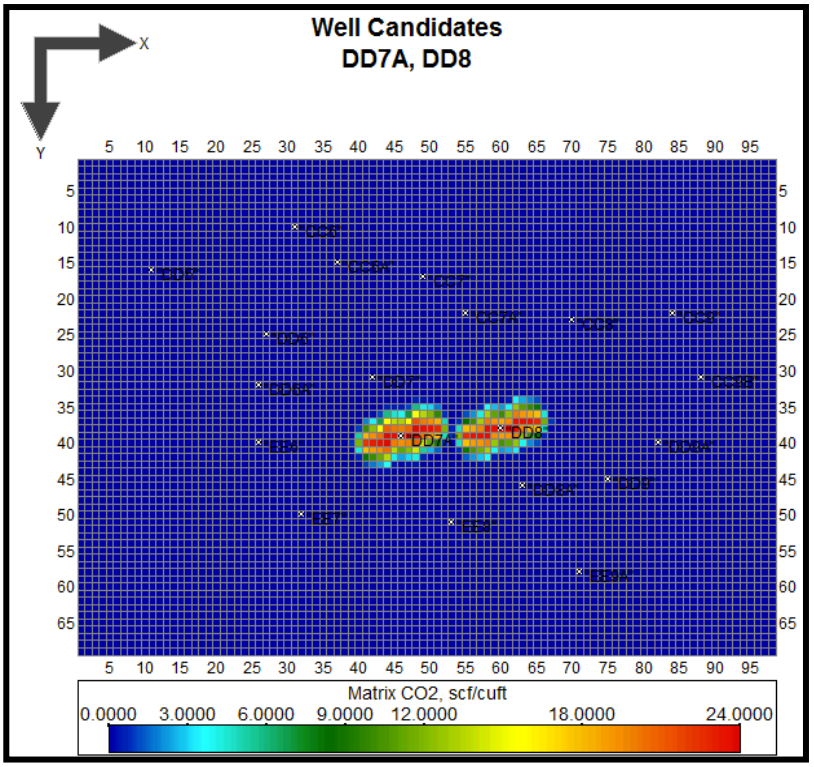


Figure 9-61 CO_2 Plume (3 Injection Wells), End of Injection

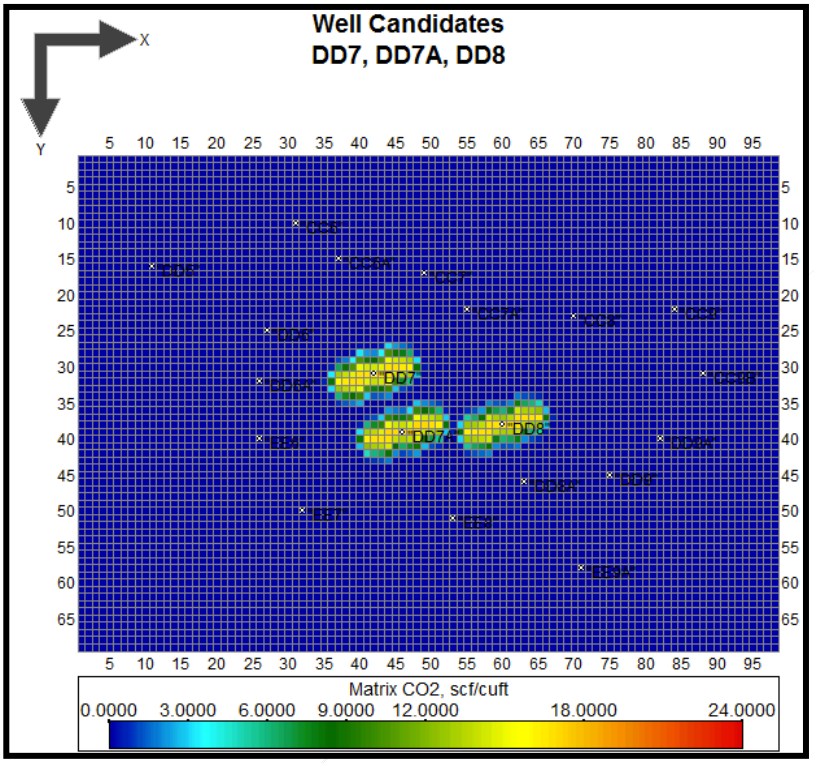


Figure 9-62 CO_2 Plume (2 Injection Wells), 4 Years Post-Injection

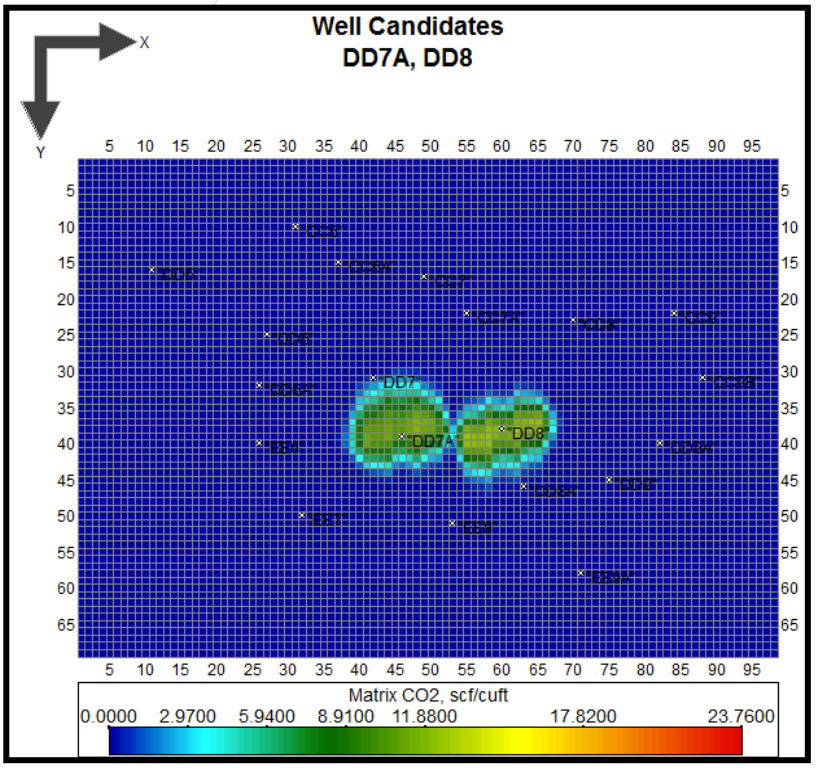
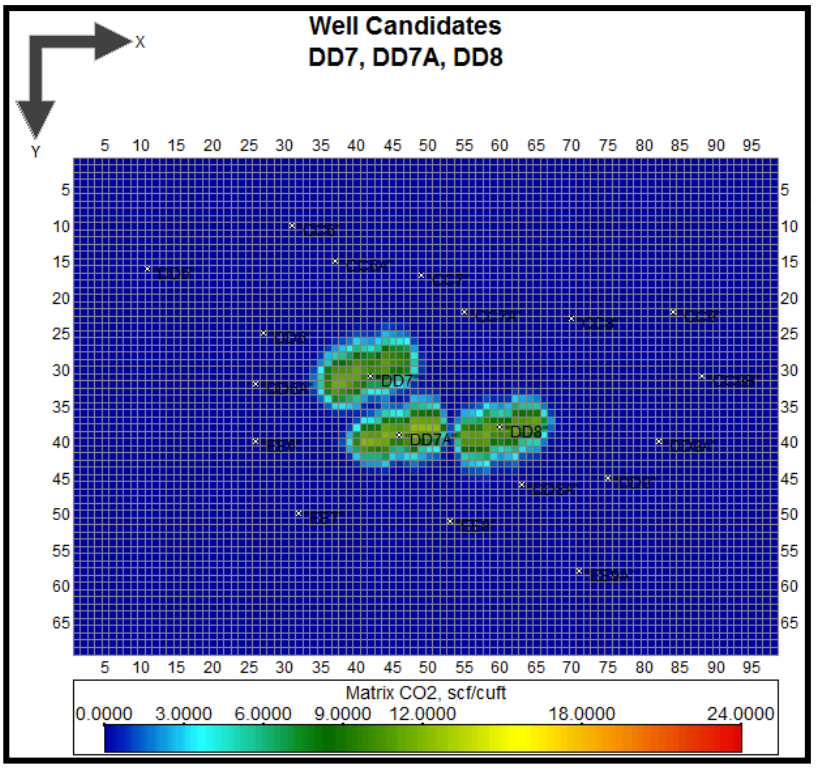


Figure 9-63 CO_2 Plume (3 Injection Wells), 4 Years Post-Injection



Modeling Results: ECBM

Preliminary modeling suggested significant ECBM recovery would occur as a result of CO2 injection. Predicted ECBM recovery varied at the nearby CBM wells and was highly dependent on proximity to injection wells. Figures 9-64 through 9-69 show examples of projected gas production with, and without CO2 injection, for several offset wells. These offset wells are delineated on the map in Figure 9-70. Well DD-8A served as the best example of ECBM recovery, attributed to its close proximity to injection well DD-8. Over a four-year post-injection study period, modeling indicated that well DD-8A produced an additional 32 MMcf of CBM and only 18 Mcf of CO2 as a result of injection. On a field-scale, the 17 nearby CBM wells were anticipated to produce an additional 106 MMcf of CBM as a result of CO2 injection. These results suggested that a 20,000-ton CO2 injection volume would displace significant volumes of methane to the nearby producing CBM wells by creating a high-pressure zone within the reservoir.

Figure 9-64 ECBM Example, Well CC6A

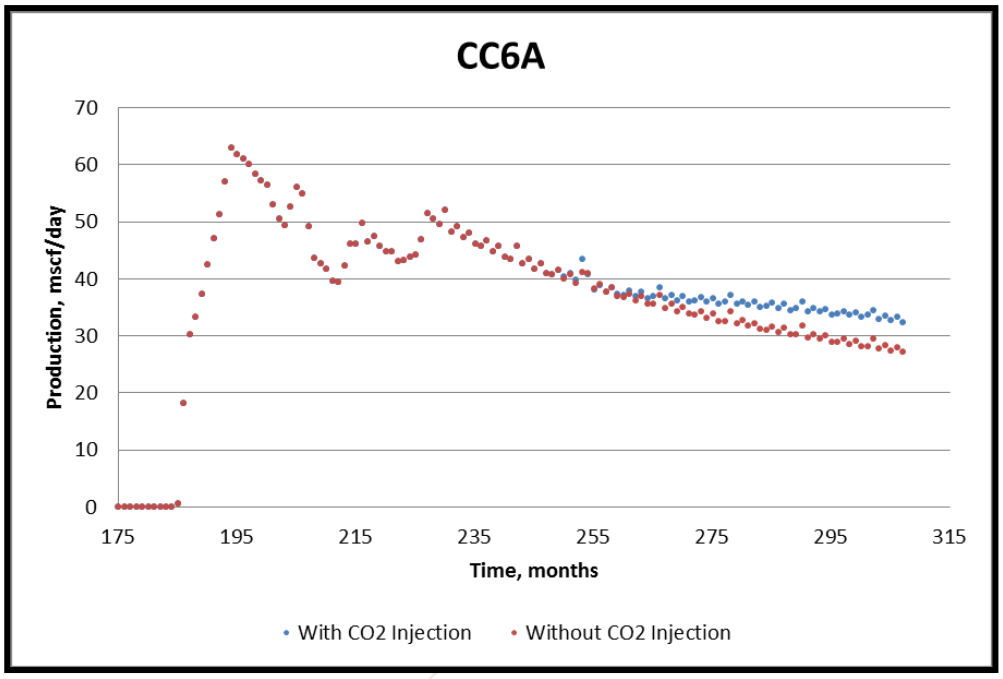


Figure 9-65 ECBM Example, Well CC7

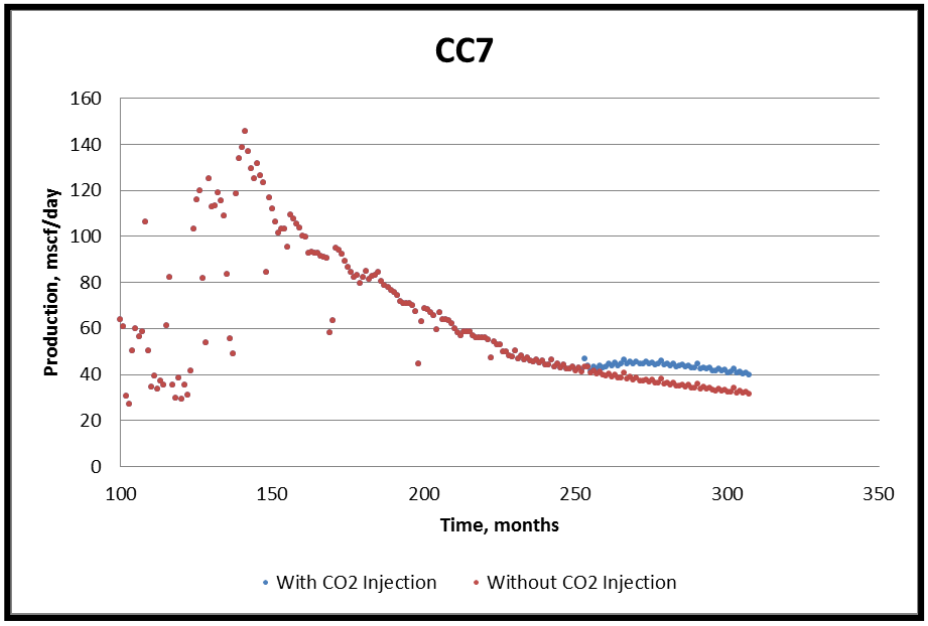


Figure 9-66 ECBM Example, Well CC7A

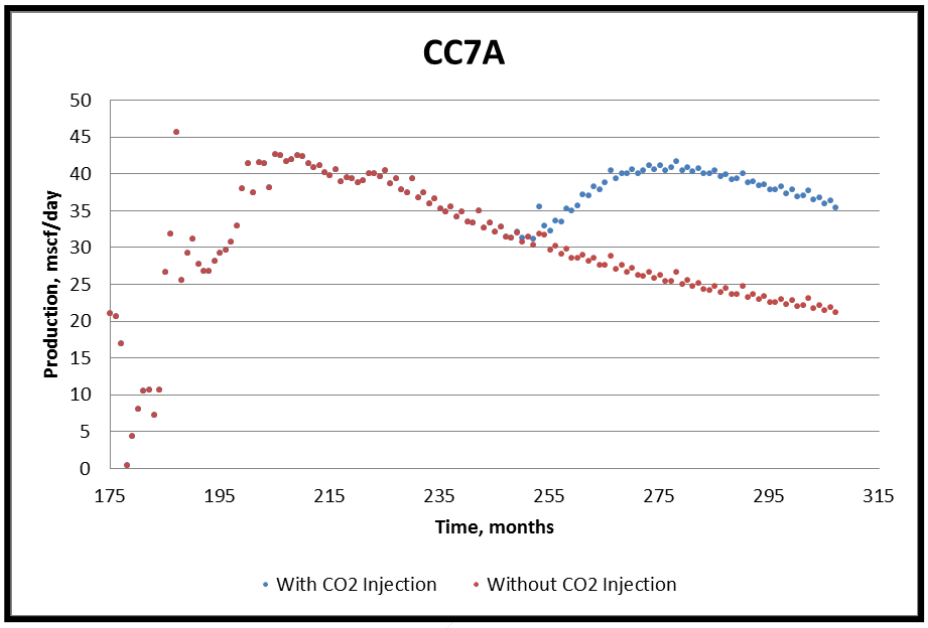


Figure 9-67 ECBM Example, Well CC8

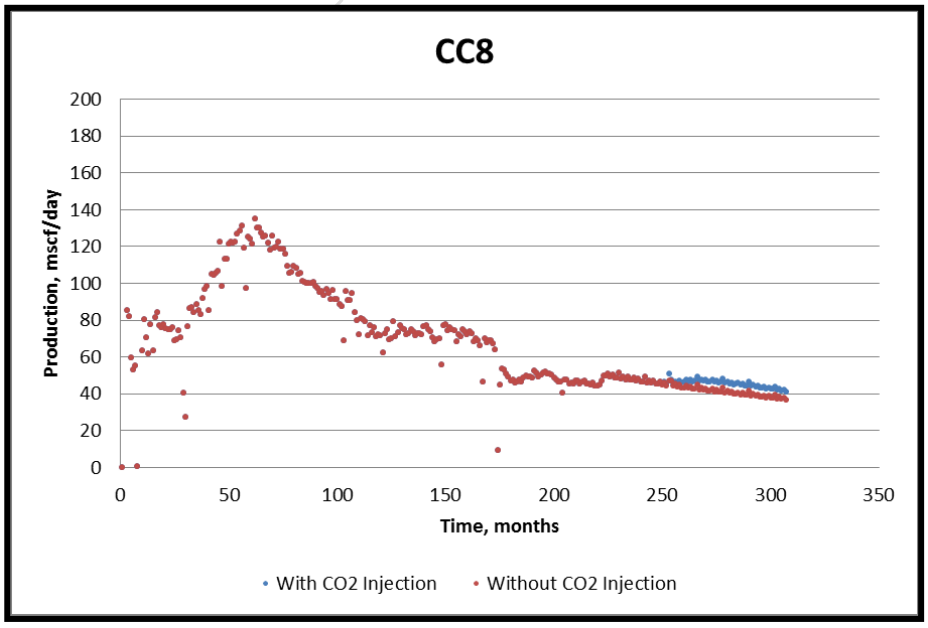


Figure 9-68 ECBM Example, Well DD8A

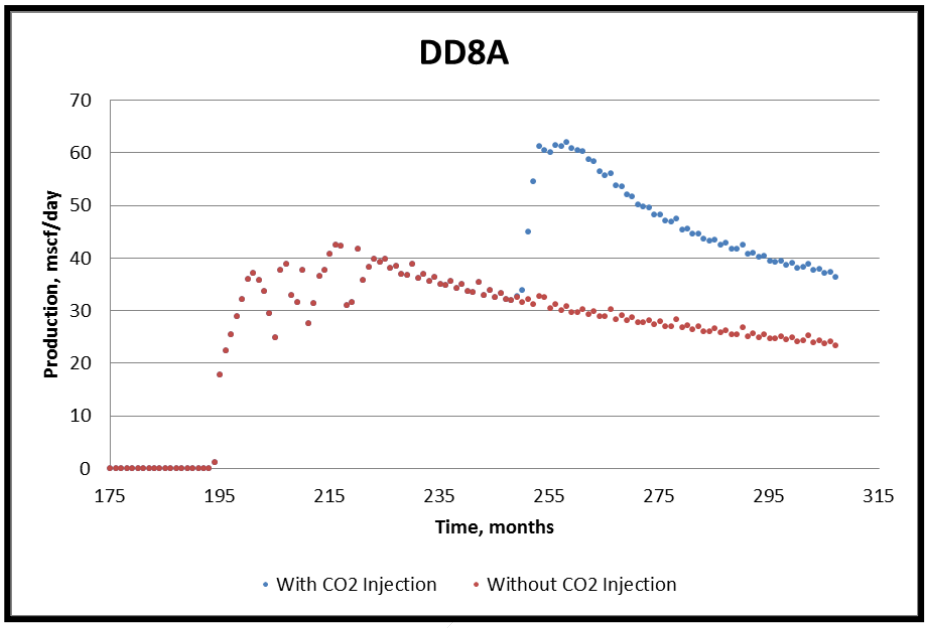


Figure 9-69 ECBM Example, Well EE8

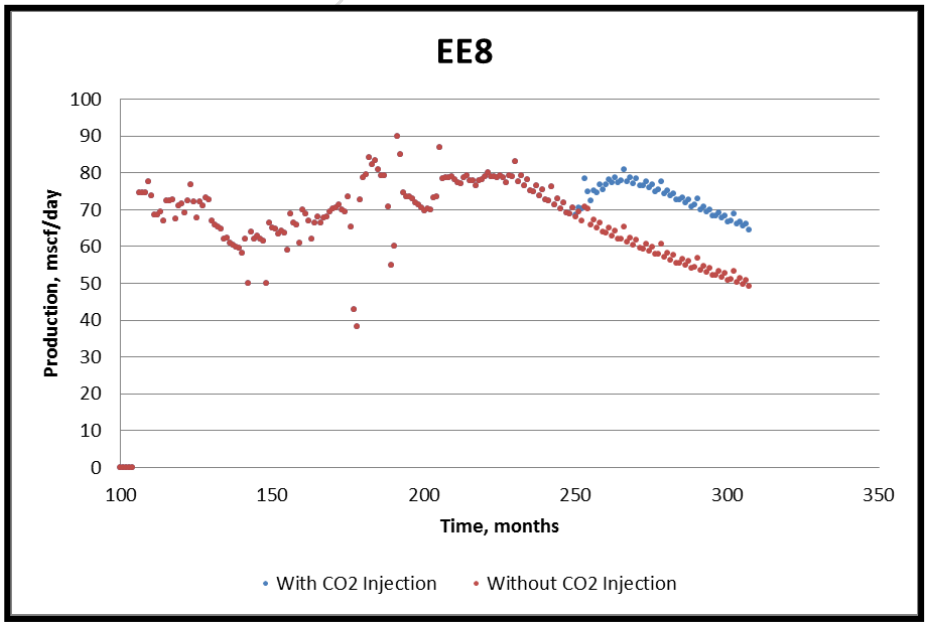
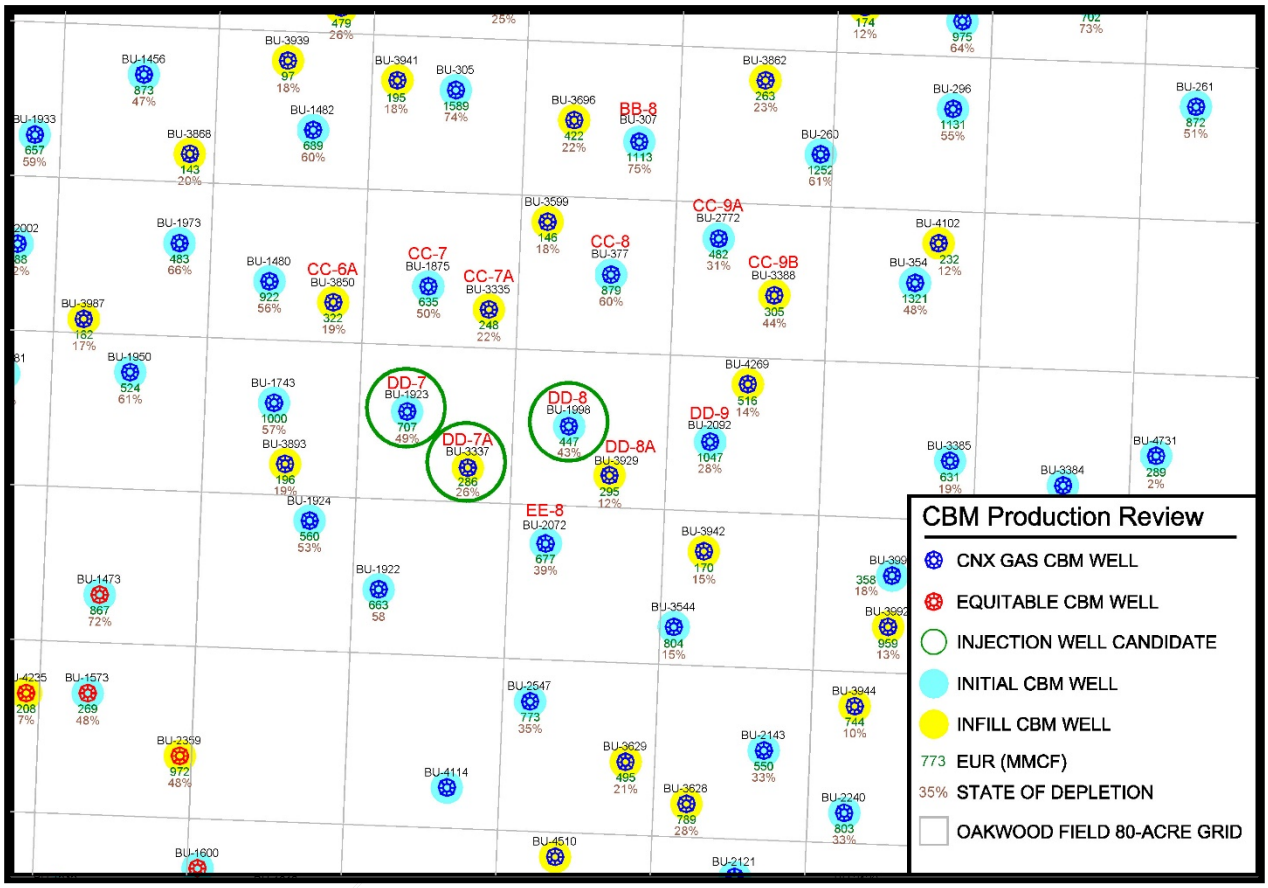


Figure 9-70 CBM Reserves and State of Depletion, Injection Test Site



9.4.2 Preliminary Model Using GEM Software for Russell County Injection Test

The Russell County SECARB Phase II Injection test was a small injection test with eight production wells and one was converted into an injection well after seven years of production. Another reason to use this injection test data is wells in this area and in Buchanan County area cut the same coal seams and they are all vertical wells with similar features. The preliminary model had three scenarios: The first case was the base model, the second scenario had the same features with the first one and additionally skin factor was defined for each well to simulate hydraulic fracture effect, in the third scenario instead of using skin factor, hydraulic fracture effect was defined by assigning hydraulic fractures into the model.

Methodology

In the base scenario, the optimal values for fracture porosity, face cleat permeability, butt cleat permeability, bottom hole pressure and water saturation were investigated using the optimization algorithm (CMOST) built into the CMG/GEM package. In total, 835 runs were completed using CMOST.

The actual data ranges entered into the optimizer are shown in Table 9-33. The optimization algorithm was instructed to find optimum parameter combinations in these ranges. The objective function was

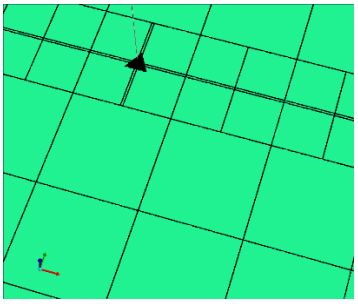
set to minimize the error on cumulative water while the operating constraint was to match the gas produced. The face to butt cleat permeability ratio was kept at 3:1 for all runs because preliminary runs showed that approximate ratio to be valid for all wells.

Table 9-33 Parameter range used as input in the CMOST model runs

Fracture Porosity	Butt Cleat Permeability (mD)	Bottom Hole Pressure (kPa/psi)	Water Saturation in the Cleats
0.0010	1	200 /29	0.900
0.0015	2	500/73	0.925
0.0020	3	800/116	0.950
0.0025	4	1100/160	0.975
0.0030	5	1400/203	1.000
	6	1700/247	
		2000/290	

The second and third cases complemented the first (base) model. In these two scenarios, two new features, which are skin factor and hydraulic fractures were added to the first model separately and the result of those two new cases were compared. Figure 9-71 illustrates a typical hydraulic fracture discretization for all wells. Details of these two cases can be found in Vasilikou et al. (2013b).

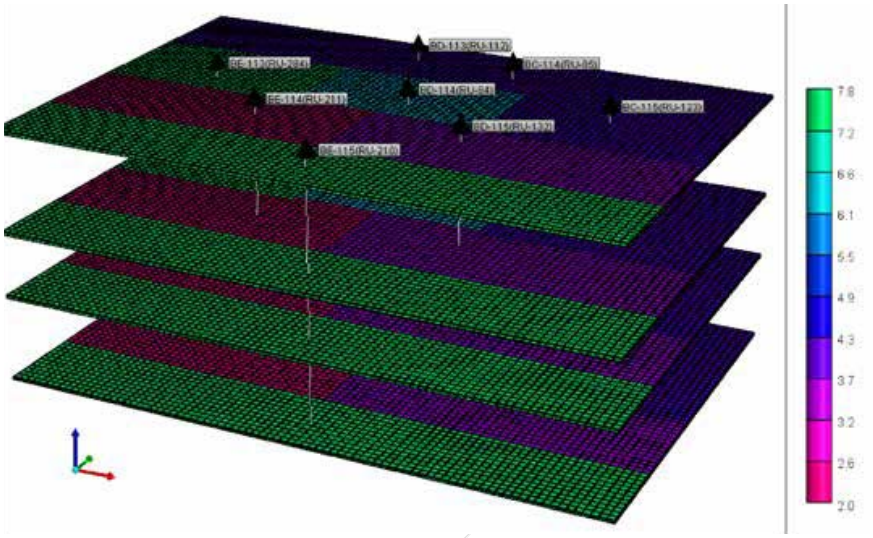
Figure 9-71 Typical hydraulic fracture discretization



Model Parameters and Inputs

In Russell County test, twenty-four separate coal seams were perforated through the casing for well stimulation. The coal seams perforated for the four-stage well stimulation average 1.5 feet thick. Instead of modeling each coal seam separately, the coal seams were modeled in zones by adding the coal thicknesses in each zone together to simplify the model (Figure 9-72).

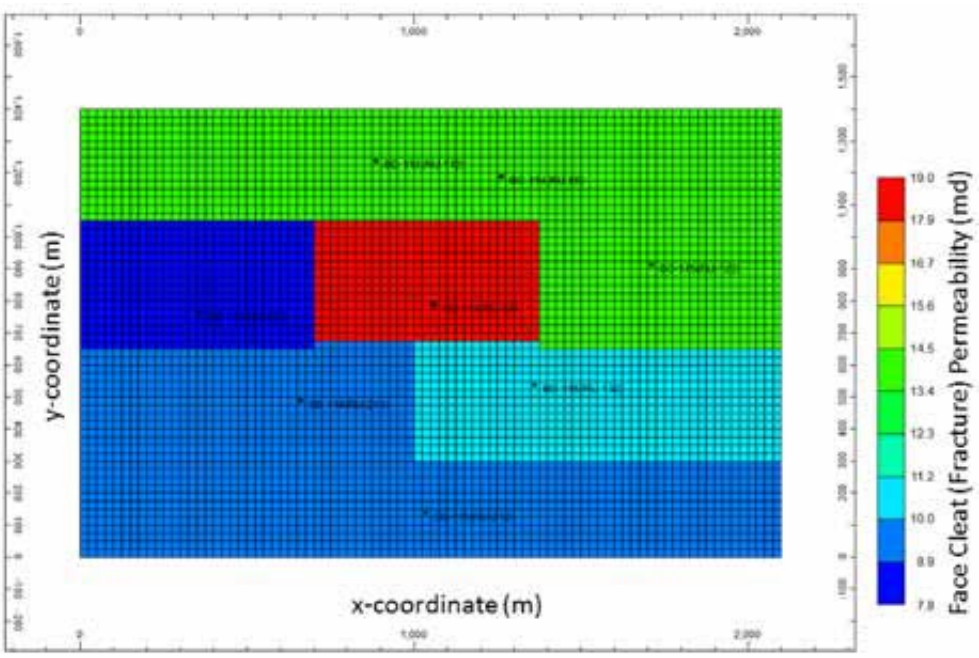
Figure 9-72 3-D view of model grid and wells. Legend shows the permeability in I direction



The orientation of the hydraulic fractures was critical in determining grid generation. As the model can only allow for hydraulic fractures along either the I (x) or J (y) direction, and hydraulic fractures were developed along the maximum horizontal stress in the area, the grid was rotated by 35 degrees clockwise (–35°) to orient the maximum horizontal stress in the I direction. The generated grid encompasses all production wells allowing for a distance of 492-656 ft (150-200 m) between each well and the grid boundary. The grid size was set to 82ftx82ft (25mx25m), with the grid extending to 84 blocks in the I (x) direction and 56 blocks in the J (y) direction.

Since coal matrix permeability is considered extremely low in coalbed methane reservoirs, a dual porosity, single permeability model was setup for each GEM model. Previous work (VCCER, 2011) had shown that cleat permeability may be different around each producing well. Under this assumption, eight single-well models were setup which comprised 25 to 50 cells in the X direction, approximately 20 cells in the Y direction and 1 cell in the Z direction for each of the four modeled seams. the cleat permeability regions for each well were assigned to the base model as in Figure 9-73. Details of the base model can be found in Vasilikou et al (2013a).

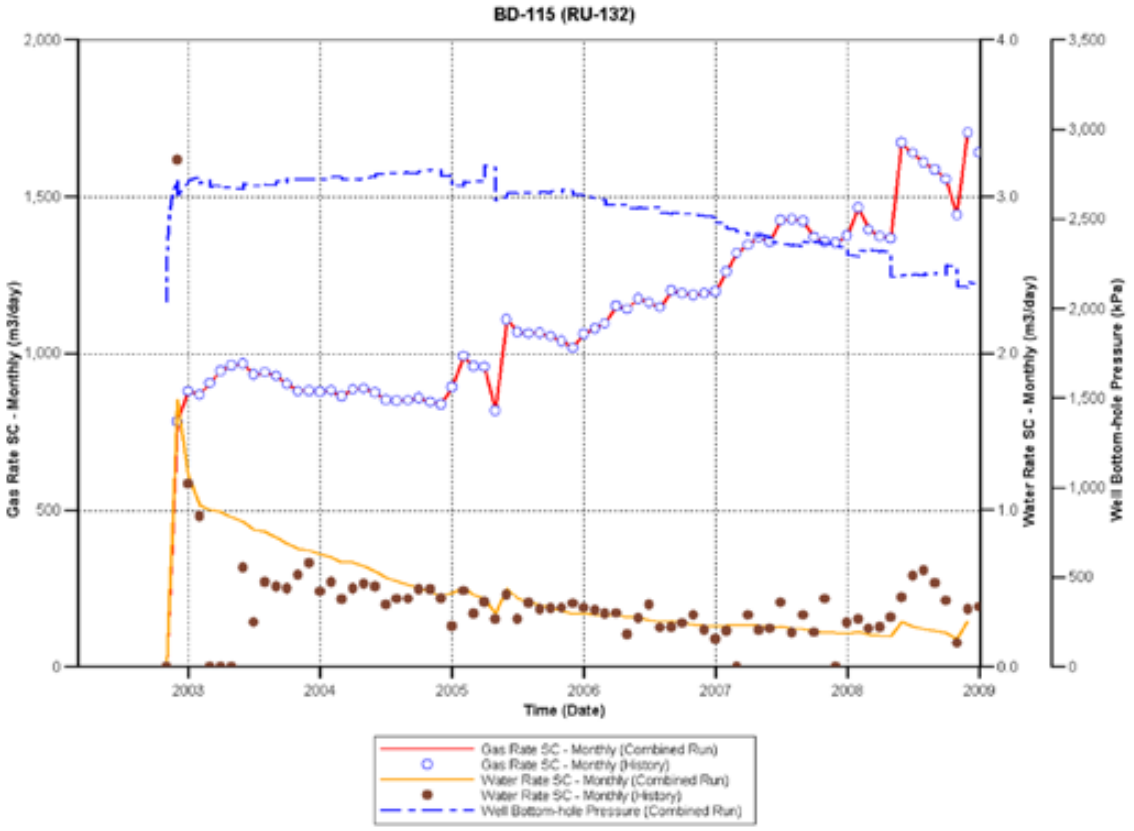
Figure 9-73 Face cleat permeability regions for single-well models and combined model



History Matching Results

Figure 9-74 shows history matching results for one of the wells in production. Details of this study can be found in Vasilikou (2013a).

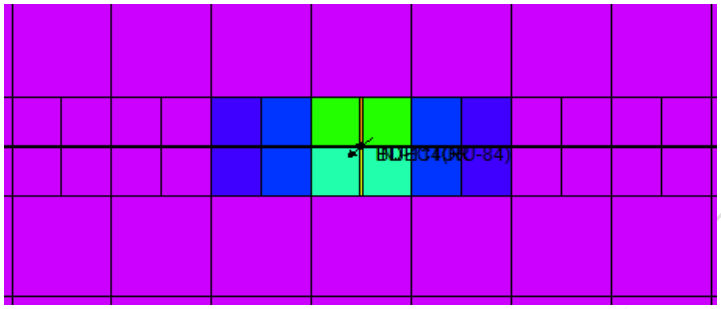
Figure 9-74 History match on gas and water rates for well BD-115 (RU-132) for the combined run.



The advantage of the skin factor model is that it can run in much less time than the hydraulic fracture model. The skin factor approach however induces a symmetric effective permeability change around each well since the skin factor is not directional. This is also evident in the plume representations for the skin factor models. In contrast the hydraulic fracture models correctly account for preferential effective permeability changes around the fractured area but take significantly more computer resources to complete. Although all models converged and met the specified gas rate and cumulative gas production values, none of the models provided a unique match to water production data for all wells.

Figure 9-75 shows the spatial distribution of the CO2 plume around the injector well immediately after injection completed for the hydraulic fracture model. As expected, the plume traveled along the high effective permeability zones on either side of the well. In addition, the CO2 plume decreased in magnitude as depth increased. Results indicate that the topmost injection zone received more CO2 than the injection zone at the bottom. In addition, the simulated CO2 plume reached the location of monitoring well M1 which was drilled in the path of the hydraulic fractures, skin factor and base models showed a uniformly distributed CO2 around the well bore.

Figure 9-75 CO_2 plume around injection well immediately after injection has been completed in the hydraulic fracture (3rd) model.



These preliminary results verified that the injection process characterized by sorption and the process of flowback followed by CH4 and/or CO2 desorption was mainly driven by the effective permeability of the formation around each well. The skin factor approach might be applicable for large scale simulations where well interference is not an issue, while the hydraulic fracture simulation should be used when more accuracy in the formation and migration of injected and/or produced gases is needed.

9.4.3 Single Well Model Using GEM for Buchanan County Injection Test (Model Set 1)

After reservoir modeling team gained experience using GEM, CO2 Injection Test achieved in Buchanan County was simulated in a single-well model. The preliminary single-well reservoir parametric simulations were conducted to identify how the variation of selected reservoir parameters and properties affect model results. More specifically, this sensitivity analysis focused on three areas: a) the effect of selected initial conditions (pressure gradient, adsorption isotherm, and porosity), b) the influence of the production mechanism (permeability, relative permeability, and compressibility), and c) the contribution of the well characteristics (hydraulically stimulated well and skin factor). This modeling work formed the base for calibration of reservoir models for simulating CO2 injection and subsequent prediction of post-injection behavior for the injection test in Buchanan County, VA. In the following sections, the preliminary single-well model scenarios are mentioned.

Modeling Methodology

The key parameters investigated in this analysis were: (i) pore pressure gradient, (ii) coal and cleat porosity, (iii) Langmuir constants, (iv) water saturation in cleats, (v) cleat permeability, (vi) relative permeability curves to water and gas, (vii) methane desorption time from the coal matrix, (viii) skin factor and (ix) hydraulic fractures for well stimulation. The primary objective in each model was to match the historic gas and water production up to year 2013 for the selected well, DD7.

The first set of input parameters that were varied in the simulations is as follows: pore pressure gradient (∇P), coal (matrix, M) and cleat (fracture, F) porosity, Langmuir volume (VL) and Langmuir pressure (VP)

constants, and the initial water saturation (SW) in the cleats, shown in Table 9-34. The remaining parameters used in the first set of models (C) were kept constant as shown in Table 9-33.

Table 9-34 Set of Parameters Varied in Simulations for Cases C1 to C11

Parameters	∇P psi/ft	Porosity (M), %	Porosity (F), %	VL scf/ton	PL 1/psi	SW %
C1	0.315	1	0.1	500	0.01	100
C2	0.315	1	0.1	650	0.01	100
C3	0.315	1	0.1	800	0.01	100
C4	0.315	1	0.1	500	0.01	90
C5	0.315	1	0.1	800	0.003	100
C6	0.36	1	0.1	500	0.01	100
C7	0.36	1	0.1	650	0.01	100
C8	0.36	1	0.1	800	0.01	100
C9	0.315	0.15	0.015	500	0.01	100
C10	0.315	0.15	0.015	650	0.01	100
C11	0.315	0.15	0.015	800	0.01	100
∇P: Pressure gradient, M: Matrix, F: Fracture, VL: Langmuir volume, PL: Langmuir pressure, SW: Water saturation						

The wells were hydraulically stimulated to account for enhanced flow properties around DD7 three scenarios were studied (S1, S2 and S3). In the first scenario (S1) a skin equal to zero was assigned; in the second (S2) a negative skin of -2 and in the third (S3) a negative skin of -4 was used. The minimum value of skin factor that could be assigned in order to maintain a positive production index for the well was -4.

Another way to account for hydraulically stimulated wells in reservoir simulations is to explicitly model hydraulic fractures. This approach is more computationally intensive compared to assigning a negative skin factor. For the purposes of this investigation four scenarios with hydraulic fractures were studied. In all four scenarios (H1, H2, H3, H4) only 40 percent of the seams per stage, as suggested by the operator of the wells, were assumed to be successfully fractured. For scenarios H1, H2 and H3 the thickest seams per stage were selected to be fractured (Pashin, 2014). In scenario H4 the seams per stage selected to be hydraulically fractured were the ones that initially had a higher amount of gas in place. The properties of the hydraulic fractures assumed in the modeling work and the layer numbers selected to be fractured per scenario are shown in Table 9-35. Other details of the sensitivity studies can be found in Vasilikou (2014).

Table 9-35 Input Parameters for Modeling Hydraulic Fractures in Scenarios H1, H2, H3, H4

Parameters, unit	H1	H2	H3	H4
Layer Number with HF	4, 6, 8, 12, 14, 16, 18			4, 5, 9, 13, 15, 16, 18
Fracture Width, ft	0.00833 (GEM, 2003)	0.01042 (EPA, 2004)	0.12500 (EPA, 2004)	0.00833 (GEM, 2003)
Fracture Permeability, mD	6,000 (GEM, 2003)			
Fracture Half Length, ft	300			
Grid Refinement	I: 9, J: 9, K: 1			
Effective Fracture Permeability, mD	55	61	405	55

Model Parameters and Inputs

The geologic structure employed for the single well simulations in this study was an 18-layer model (Figure 9-76A) proposed by the MM&A team. The drainage area for the single well simulations was approximately 42 acres. In addition, based on a slightly different interpretation of the previously mentioned geologic structure proposed by MM&A, a second structure where 5 zones of coal seams assumed was also investigated in order to examine sensitivity of model response to variation of number of layers in the model (Figure 9-76B). For both models, the grid size was set to 50ftx50ft, with the grid extending to 27 blocks in the I (x) direction and 27 blocks in the J (y) direction. Reservoir parameter inputs were the same for both models. Table 4 tabulates the reservoir parameters and their values used in both models. Details of other parameters used in the single-well models can be found in Vasilikou (2014).

Figure 9-76 3D view of (A) 18-layer model and (B) 5-zone model with grid elevations

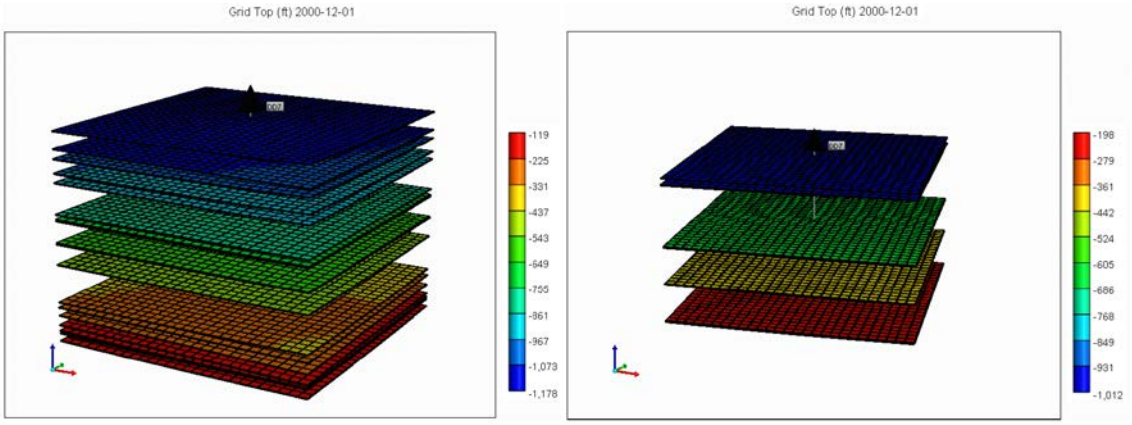
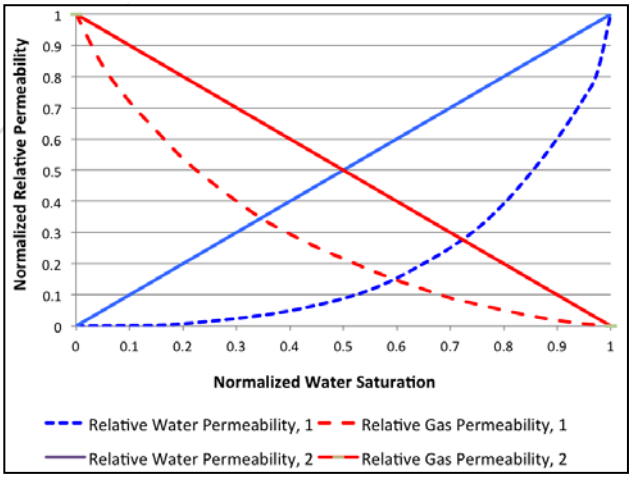


Table 9-36 Reservoir parameters and their values used in both models

Parameter, unit	Value
Pore Pressure Gradient, psi/ft	0.315
Coal (Matrix) Porosity, %	1
Cleat (Fracture) Porosity, %	0.1
Cleat (Fracture) Permeability, mD	I: 30, J: 30, K: 3
Relative Water and Gas Permeability Curve	Figure 18
Langmuir Volume (VL), scf/ton	800
Langmuir Pressure (PL), psi	333
Fracture Spacing, ft	I: 0.01667, J: 0.01667, K: 0.01667
Well Radius, ft	0.13124
Formation Compressibility (Matrix&Fracture), 1/psi	2E-08 (at reference pressure 416.15 psi)
Reservoir Temperature, °F	69.8
Water Density, lb/ft^3	62.4779 (at reference pressure 416.15 psi)
Coal Density, lb/ft^3	82.65
Desorption Time, days	20
Cleat (Fracture) Water Saturation	1

Figure 9-77 Different scenarios for the relative permeability curves to water and gas



Sensitivity Analysis Results

The results of the parametric analysis for the (C) models are shown in Figure 9-77 and Figure 9-78. For cases C1, C2 and C3, where the Langmuir volume constant was varied as shown in Table 9-36, the original gas in place in case C1 increased by 29.92 and 42.87 percent compared to cases C2 and C3, respectively. The original water in the system, shown in Figure 20, for cases C1, C2 and C3 was not affected by the variation of the Langmuir constant volume and it was the same for all cases.

In case C4 the initial water saturation in the cleat system was reduced from 100% to 90%. A negligible increase in the original gas in place was noted of approximately 0.42% in case C4 compared to case C1. The small increase was due to the increase of free gas in the cleat system. The original water in place was affected the most by the reduction in the initial water cleat saturation. In case C4 the original water in place reduced by 10% compared to case C1 (Figure 9-79).

In cases C5 and C3 all input parameters were the same with the exception of the Langmuir pressure constant, which in case C5 is reduced from 0.01 1/psi to 0.003 1/psi. The change in the Langmuir pressure constant was resulted in a reduction of the original gas in place in the system of approximately 28.22 percent (Figure 9-78). As expected, the original water in place of the system was not affected by the reduction in the Langmuir pressure constant.

In cases C6, C7, C8 a higher pore pressure gradient of 0.36 psi/ft compared to 0.315 psi/ft of cases C1, C2, C3 is assigned in the models and all other input parameters are assumed to be the same. The increased pore pressure gradient used in cases C6, C7 and C8 resulted in an increase by 2.22% of the original gas in place compared to cases C1, C2 and C3. There was no change in the original water in place because of the increase in pore pressure.

In cases C9, C10 and C11, both the coal and cleat porosity of the models were reduced to 0.15% and to 0.015% respectively, compared to cases C1, C2, C3. Reduction of the coal porosity results in a negligible increase of the original gas in place (Figure 9-78). Reduction in the cleat porosity has a significant effect to the original water in place (Figure 9-79). It results in a decrease of 85% of the overall water in the system from cases C1, C2, and C3 to C9, C10 and C11.

In all cases aforementioned more than 99% of the original gas in place is stored in an adsorbed state on the coal matrix. Only in case C4, where an initial cleat water saturation less than 100% was assigned, there was more than 1 percent free gas in the cleat system. In the models it is assumed that no methane is dissolved in the water.

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In all cases aforementioned more than 99% of the original gas in place is stored in an adsorbed state on the coal matrix. Only in case C4, where an initial cleat water saturation less than 100% was assigned, there was more than 1% free gas in the cleat system. In the models it is assumed that no methane is dissolved in the water.

Figure 9-78 Original Gas in Place in the Model and Initially Adsorbed Gas on the Coal Matrix for All Cases (C)

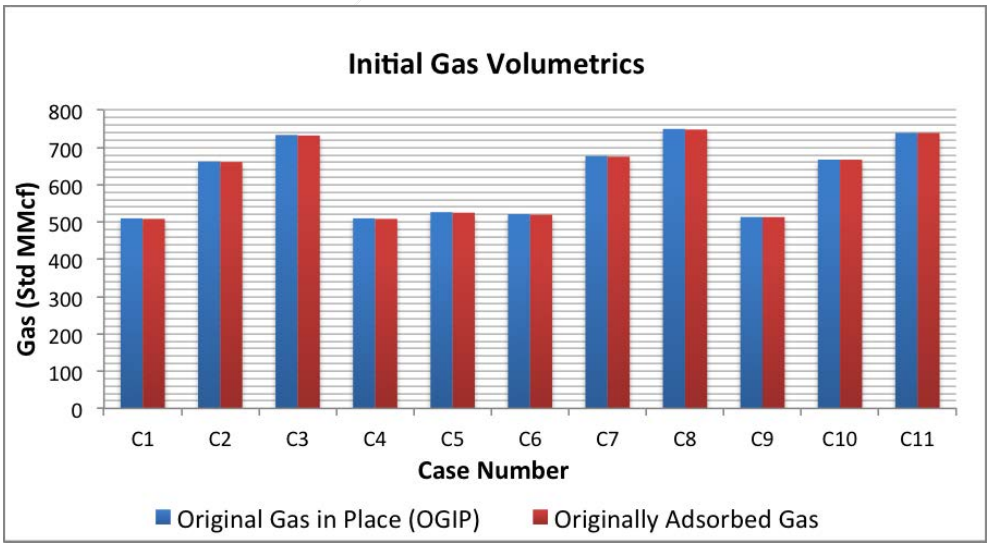
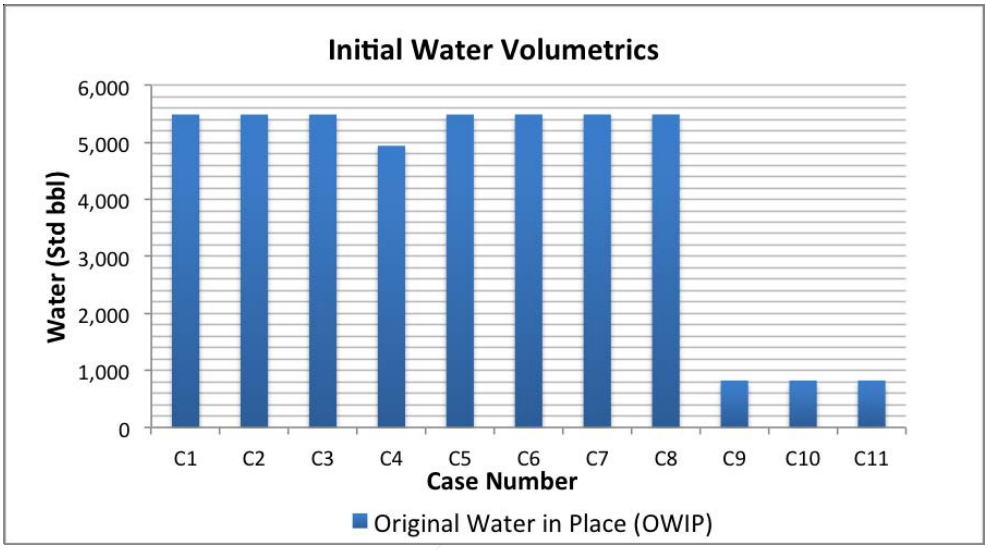


Figure 9-79 Original Water in Place for All Cases (C)



Reduction in both the coal and cleat porosity in case C11 compared to case C3 results only in 0.08 percent increase of the coal (matrix) volume per seam in case C11. For the coal seams in the study area in Buchanan County, VA, the pore pressure gradient was assumed to range between 0.315 and 0.36 psi/ft (VCCER, 2013). By employing the 18-layer geologic structure proposed, the pressure profile per depth per coal seam for the two different pore pressure gradients of 0.315 psi/ft and 0.36 psi/ft was developed. For the 0.315 psi/ft pressure gradient assumed, pore pressures in the model range between 239- 692 psi. For the 0.36 psi/ft gradient, pore pressures in the 18-layer model vary between 274-791 psi. For more details on results per layer can be found in Vasilikou (2014).

Parameters such as cleat permeability, relative permeability curves to water and gas, and desorption time have an effect on the production mechanism of coalbed wells. Three different scenarios for cleat permeability were examined. In scenarios P1, P2 and P3, cleat permeability of 20, 30 and 45 mD was respectively assigned, with a primary operational constraint to meet the historic water rate and with a secondary constraint of minimum bottom hole pressure. The results showed that the percentage of gas produced over the initial gas in place for scenarios P1, P2 and P3 was 35.40, 35.40 and 39.84 percent, respectively. There is essentially no change in the recovery factor between scenarios P1 and P2, whereas an increase of 12.32 percent in gas production is noted for scenario P3. The layers in order of highest to lowest production were as follows: layer 9, 15, 5, 4, 13, 2, 11, 16, 3, 8, 17, 14, 7, 6, 18, 1, 12, and 10. As expected, the layers with the highest initial gas content are also the ones producing the most gas.

Two different curves for relative permeability to water and two curves for relative permeability to gas were studied (Figure 9-77). In coalbed reservoirs primary dewatering of the seams is important for gas

production. Hence, the magnitude of the relative permeability to water for high water saturations is important for gas production. When water and gas start to co-exist in the cleats, the shape of the relative permeability curves has a significant effect on the production profile. In this analysis, when relative permeability to water 1 was changed to relative permeability to water 2 (Figure 9-77), more water was initially produced but gas production did not start until lower water saturations and ultimately gas deliverability of the system were reduced. When relative permeability curve to gas was changed from (1) to (2), as shown in Figure 9-77, initial water deliverability was unaffected and gas production increased.

Regarding variations in desorption time of 5, 20 and 50 days, the results show that the percentage of gas recovery over the initial gas in place are 39.94, 39.84 and 39.64 percent, respectively. It was expected that the lower and hence faster desorption time used in the modeling work would yield higher gas production, but it is not significant.

From the investigation of the (S) models where a skin factor was used to account for enhanced flow around the well, it was shown that recovery factors of the original gas in place for scenarios S1 (zero skin), S2 (negative 2) and S3 (negative 4) were 38.82, 41.59 and 45.77, respectively. The recovery factors in the (S) models were higher compared to the ones of the (H) models where hydraulic fractures were explicitly simulated. For the H models, recovery factors for scenarios H1, H2, H3 and H4 were 38.00, 38.68, 40.50 and 38.38 percent, respectively. It must be noted that even scenario S1, where a zero skin factor is used, has a higher recovery factor than most of the H models. This is most likely due to the different flow properties assumed for the H models versus the S models. For the H models, it must be noted that increase in the primary fracture width (Table 9-36) yields an increased effective permeability and ultimately a higher recovery factor. Also, in scenario H4 where hydraulic fractures per stage were selected based on higher initial gas content, the recovery factor was slightly higher compared to the recovery of scenario H1 where stimulated seams were selected based on the thickest seams per stage criterion.

The results regarding the two different geologic structures considered, the 5-zone model and the 16-layer model, showed that the original gas in place was 6.95e5 and 6.38e5 Mcf, respectively. The gas recovery factor for the 5-zone model was higher compared to the 16-layer model, which was expected since the original gas in place was also higher.

9.4.4 Twenty and Four-Well Models Using GEM for Buchanan County Injection Test (Model Set 2)

After single well studies were completed, another preliminary reservoir simulation with two models were generated. One of those models which was called larger model (L) in the study covered a drainage area of approximately 1552 acres and incorporated the three selected injection wells and seventeen offset CBM wells, which were the same wells used in the model created using COMET3TM simulator (Table 9-32). The wells in the simulated area were brought on-line at different times within a time span of sixteen years; the first well started production in 1993 and the latest producer started in 2009. In the

last model set, two different types of models were investigated. Moreover, a smaller 4-well model focusing on the area around the three selected injection wells and the closest offset well, DD8A. Those models were conducted to predict the amount of CO2 that can be stored in multiple thin coal seams following injection, the extent of CO2 plumes by seam, the potential for CO2 breakthrough at offset wells, and the amount of CO2 stored if the injection wells were flowed back. In the following sections, the larger and smaller 4-well models are mentioned.

Methodology

The main objective of the last preliminary reservoir simulation efforts was to model all phases throughout the estimated life of the wells within the study area and assess the storage capacity of coalbeds and the extent of CO2 plumes. More specifically, the first step was to model the initial period up to year 2013, utilizing available historical gas and water production data for all wells in order to calibrate the models. The next step was to model the one-year injection period. 20,000 tons of carbon dioxide was planned to be injected into the three selected wells. Additionally, the model was used to forecast the behavior of all wells in the study area post injection until the end of their estimated life, year 2052. Details of this study can be found in Vasilikou (2014).

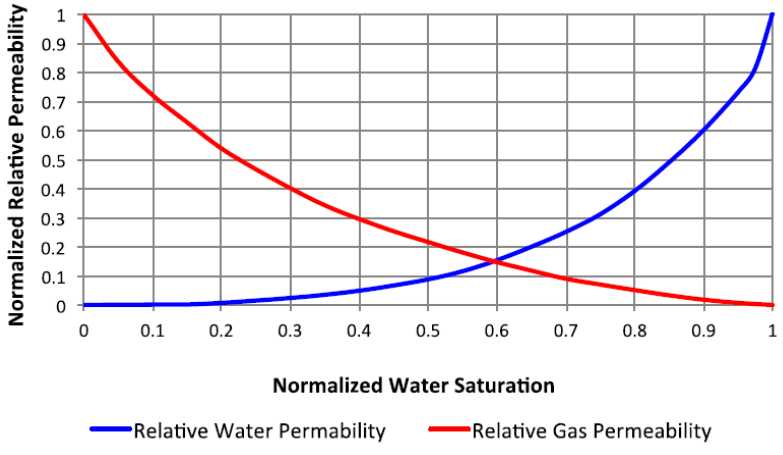
Model Parameters and Inputs

In the reservoir models, a geologic structure for the coal seams was assumed, based on integrated data for coalbeds within the study area (VCCER, 2013). Surface elevations in the study area range from 1685-2364 ft. The models include 16 layers at elevations ranging from 29 feet to 1201 ft with varying thicknesses between 0.01 to 4.2 ft. Due to the large size of the full field scale models (element-wise) and the added complexity of the multiple seams structure, in order to reduce overall simulation time two different groups of models were set up for the purposes of this investigation. A larger model (L) that includes all 20 wells within the study area and assumes a 16-layer geologic structure where seams 9, 10 and seams 16, 17 were aggregated into single zones; a smaller model (S) incorporates the three selected injectors and the offset well, DD8A, and assumes an 18-layer structure. Modeling input parameters and their values are listed in Table 9-37 and shown in Figure 9-80. Details of other parameters used in the models can be found in Vasilikou (2014).

Table 9-37 Input parameters for the combined and four-well models

Parameter, unit	Combine Model (L)	4-Well Model (S)
Coal Matrix Porosity, %	Layers: 1 to 6, 2 Layers: 7 to 16, 1	Layers: 1 to 6, 2 Layers: 7 to 18, 1
Cleat Fracture Porosity, %	Layers: 1 to 6, 0.2 Layers: 7 to 16, 0.1	Layers: 1 to 6, 0.2 Layers: 7 to 18, 0.1
Cleat Permeability, mD	Layers: 1 to 10, 30 Layers: 11 to 16, 10	Layers: 1 to 10, 30, Layers: 11 to 18, 10
Fracture Spacing per Direction, ft	I: 0.01667 J: 0.01667, K: 0.01667	
Well Radius, ft	0.13124	
Formation Compressibility, 1/psi	2E-08 (at reference pressure 416.15 psi)	
Reservoir Temperature, °F	69.8	
Water Density, lb/ft^3	62.4779 (at reference pressure 416.15 psi)	
Relative Permeability Curves	Figure 9-80	
CH_4 Langmuir Volume (VL), scf/ton	720.003	
CH_4 Langmuir Pressure (PL), psi	250	
CO_2 Langmuir Volume (VL), scf/ton	830	
CO_2 Langmuir Pressure (PL), psi	300	
Coal Density, lb/ft^3	82.65	
Methane Desorption Time, days	20	
Pore Pressure Gradient, psi/ft	0.315	

Figure 9-80 Relative permeability curves to water and gas as determined through history matching gas production for all the wells in the study area



Sensitivity Analysis Results

The small models (S) incorporated the three selected injectors: DD7, DD7A and DD8 and the offset well DD8A. The drainage area of the 18-seam geologic structure for the (S) models was 167.9 acres and,

based on the input parameters, the original gas in place (OGIP) was estimated to be 1.84e6 standard Mcf and the original water in place 2.64e4 standard bbl.

Three different scenarios with regard to well characteristics were examined (S1, S2, S3). In scenario S1, all 18 coal seams were perforated but not hydraulically stimulated; in scenario S2 a negative skin was assigned to all four-wells to account for enhanced flow around the wellbore; and in scenario S3, the hydraulic fractures were explicitly modeled.

It is common practice in reservoir modeling to assign a negative skin factor to a well in order to account for its hydraulic fracture stimulation and, at the same time, avoid explicit modeling of the fractures, which is very computationally intensive. For the specific reservoir properties assumed in the modeling, the maximum skin factor that can be assigned to sustain a positive productivity index is -4.

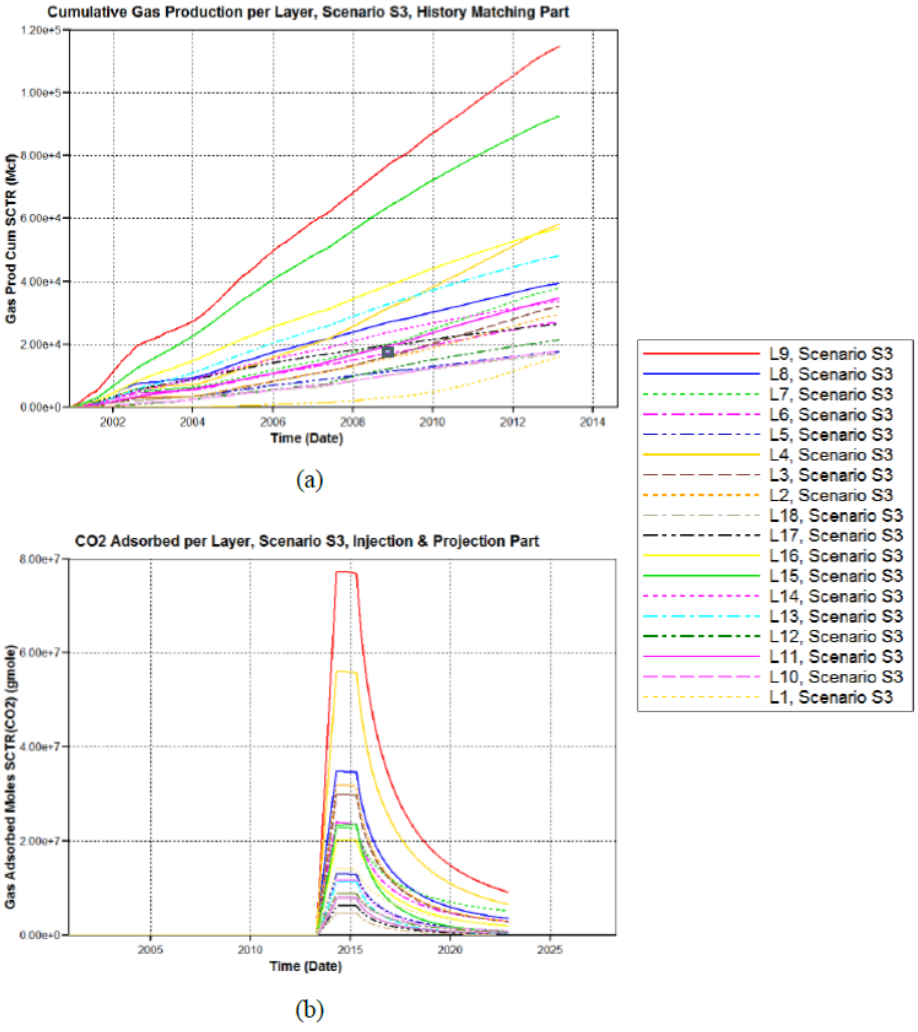
Regarding hydraulic fractures, it was suggested by the operator of the wells that only 40 percent of the coal seams per completion stage have been successfully hydraulically fractured (CNX, 2013) and that the thickest seams are expected to have received most of the fractures (Pashin, 2013). For this reason, model S3, where hydraulic fractures are explicitly simulated, only includes layers 4, 6, 8, 12, 14, 16 and 18, which represent the thickest seams and account for 38 percent of the stimulated seams. A primary fracture width of 0.01042 feet (EPA, 2004) with a primary fracture permeability of 10,000 mD and 350 feet of half-length is assigned in the models. These input parameters for the hydraulic fractures translate into pseudo-fractures with proper grid refinement that account for non-Darcy flow with an effective permeability of 82.1 mD. Hydraulic fractures were developed along the maximum horizontal stress direction in the area and thus the modeling grid was rotated to orient the maximum horizontal stress in the I direction. In addition, it was assumed that the permeability in the I direction is equal to butt cleat permeability and that in the J direction equal to face cleat permeability (Vasilikou et al., 2013).

Initially, for all three investigated scenarios S1, S2, S3 (base, skin, hydraulic fractures), history matching of the gas rate was achieved up to year 2013. Cumulative gas production of the field was similar for all scenarios at approximately 719.65 standard MMcf, accounting for almost 40 percent primary recovery of the original gas in place. The main coal seams contributing to gas commingle production in all three scenarios are listed below in order (from the largest contribution to the least): seams number 9, 15, 4, 16, 13, 8, 11, 7, and 14.

The second phase of the modeling was the injection period. The injection start date was set for the 1st of May 2013 with injection on-going until the 1st of May 2014. Wells DD7, DD7A and DD8 were shut in for one-month prior to commence of the injection and then turned into injectors. The same amount of carbon dioxide was injected into DD7, DD7A and DD8, approximately 6,667 tons per well, at a constant daily rate of 18.26 tons/day over a 1-year period. After injection of 20,000 tons of CO2 was completed the three injectors remained shut in for one year until the 1st of May of 2015. Gas production for all four wells in the study area was projected to year 2023.

From the simulation results it is shown that for the three different scenarios where CO2 is primarily injected into the coal seams there is a higher differential between the injection pressure at the wellhead and the flowing pressure yielded at the end of the history matching period at the specific coal seam depth. As shown in Figure 9-81 for scenario S3, more CO2 is injected in coal layer 9 and that was also the seam most depleted during the history matching exercise. The second most depleted seam during history matching was layer 15. However, during injection layer 4, which is at a shallower depth and thus has a lower pore pressure, the seam takes up more of the injected CO2 (Figure 9-81).

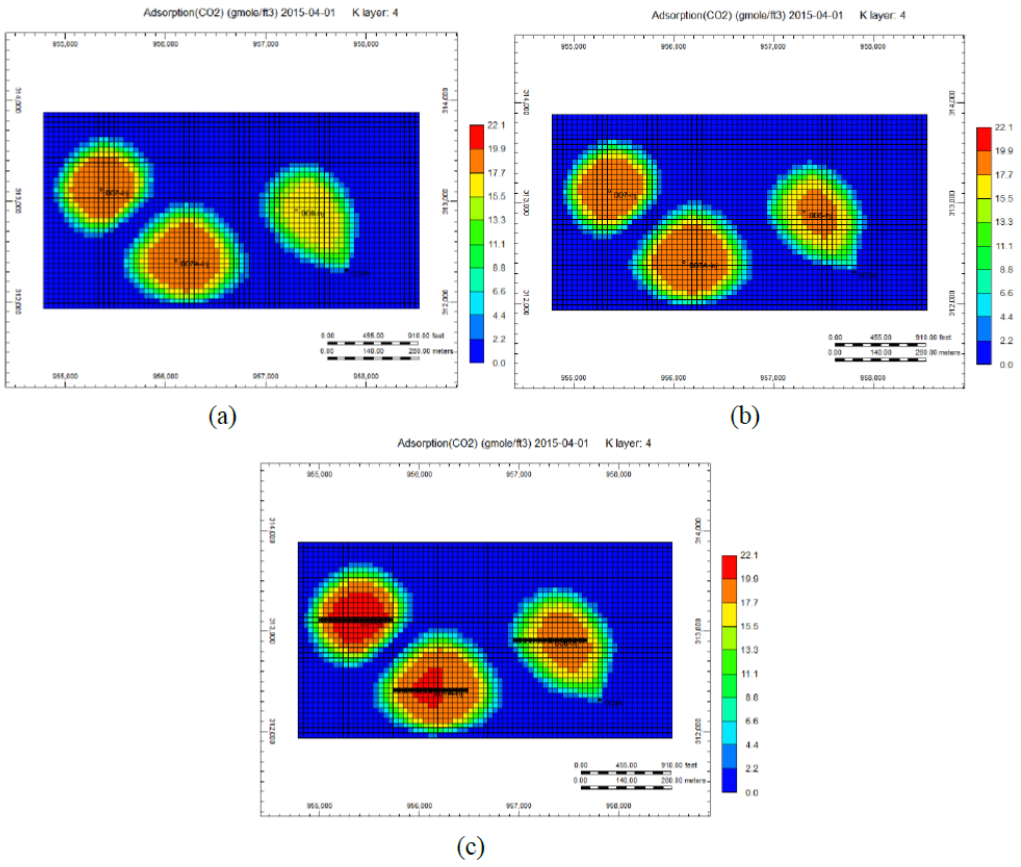
Figure 9-81 Cumulative Gas Production per Layer Up to Year 2013 and (B) CO2 Adsorption per Layer during Injection and Post Injection Up to Year 2023 for Scenario S3



Scenario S3 (where hydraulic fractures were explicitly simulated) shows that the CO2 plumes are more extensively developed compared to scenarios S1 and S2 (skin and base models), as shown in Figure 23, for the stimulated layers. However, since only 40 percent of the coal seams are hydraulically stimulated the highest levels of CO2 breakthrough at the offset well, DD8A, are exhibited in scenario S2 (skin factor

scenario), where an enhanced flow zone is assigned along the wellbore for all the coal seams in the model.

Figure 9-82 CO_2 Adsorption Profile in gmole/ft^3 at Layer 4 for Scenarios (A) S1 Base, (B) S2 Skin and (C) S3 Hydraulic Fractures Scenario



The results of the S model simulations show that the injection wells DD7 and DD7A produce more CO2 during flowback when brought back on-line a year after injection is completed in scenario S2 compared to scenarios S1 (base model) and S3 (hydraulic fractures model) and the third injector, DD8, has a higher CO2 flowback in scenario S3 (hydraulic fractures model) (Table 9-38). In all three scenarios, injector DD7 has a higher CO2 flowback amount compared to DD7A and DD8; DD8 produces the least amount of CO2.

According to the modeling results of the (S) models, only 11, 6, and 10 percent of the total 20,000 tons of CO2 injected in the study area is successfully (permanently) stored up to year 2023 for scenarios S1, S2 and S3, respectively. The skin factor model, scenario S2, which has been assigned the highest flow

enhancement around the wellbore, is the one allowing for the least CO2 storage and maximum flowback.

Cumulative gas production per well for each HF scenario is listed in Table 9-39. As far as ultimate field methane recovery is concerned for the (S) models, 89, 94 and 90 percent (for scenarios S1, S2 and S3, respectively) of the initial gas in place is achieved. These results are higher but still comparable to the assumption that up to more than 75 percent recovery of methane in place can be achieved with CO2 injection in coalbeds (VCCER, 2011).

Table 9-38 CO_2 Flowback at the Injectors and CO_2 Breakthrough at the Offset Well for the (S) Models for Projection Time to Year 2023

CO_2 Flowback at Injection Wells (Tons)			
Well	Base Model (S1)	Skin Model (S2)	Hydraulically Fractured Model (S3)
DD7	6,349	6,565	6,384
DD7A	5,381	5,791	5,526
DD8	5,093	4,929	5,175
CO_2 Breakthrough at Offset Well (Tons)			
DD8A	963	1,462	905
CO2 Total Field Production (Tons)	17,786	18,747	17,990

Table 9-39 Cumulative CH_4 Production for the (S) Models for the Base (S1), Skin (S2) and Hydraulic Fractures (S3) Scenarios for Projection Time to Year 2023

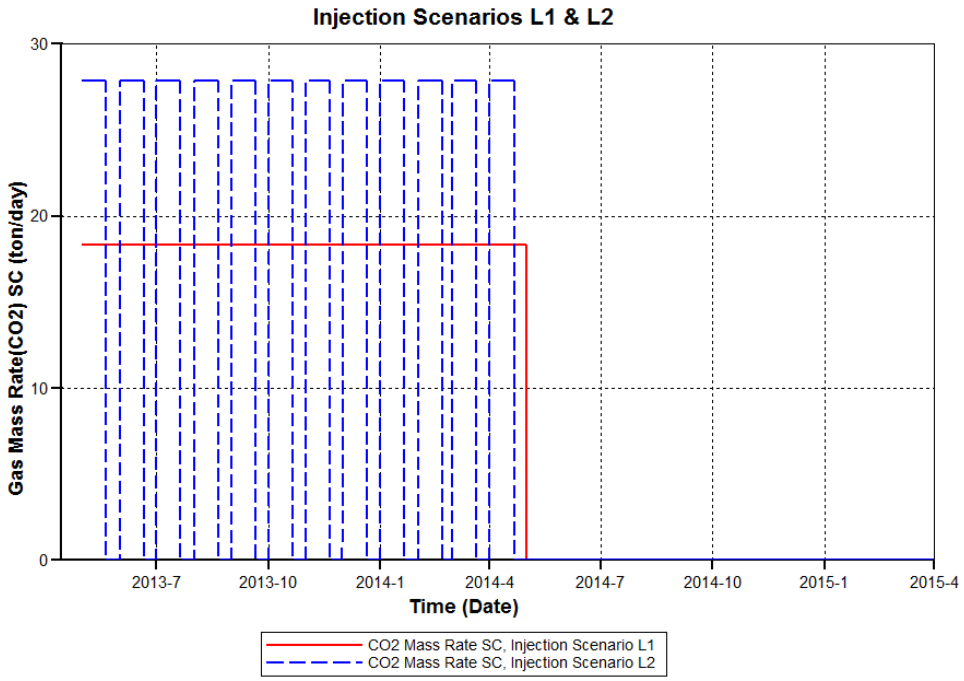
Cumulative CH_4 Production (Std Mcf)			
Well	Base Model (S1)	Skin Model (S2)	Hydraulically Fractured Model (S3)
DD7	578,811	639,177	584,588
DD7A	231,607	262,101	237,485
DD8	395,162	422,485	401,668
DD8A	206,529	257,726	204,616

The larger models (L) incorporated all wells within the study area. The drainage area of the 16-seam geologic structure for the (L) models was 1552 acres. Based on the input parameters, the original gas in place (OGIP) was estimated to be 1.77e7 standard Mcf and the original water in place to be 2.50e5 standard bbl.

The L models were first calibrated to match gas and water production data up to 2013. Then two different injection scenarios were applied in the simulations in order to achieve injection of 20,000 tons of CO2 in wells DD7, DD7A and DD8. More specifically, in the first injection scenario (L1), 20,000 tons of CO2 were equally distributed among the three injectors (approximately 6,667 tons per well) and CO2 was injected at a constant daily rate of 18.26 tons/day for 365 days, in the same manner as in the (S) models. In the second injection scenario (L2), the same amount of CO2 was injected per well as in scenario L1, but at a higher daily rate of 27.78 tons/day for the first 20 days of each month for a year; the injection wells were shut in during the final days of each month during injection. Figure 9-83 shows the CO2 mass injection rate at surface conditions for injection scenarios L1 and L2 over time.

After the one-year injection period was completed, different cases were examined where the shut in period of the three injectors varied in time. The performance of all the wells within the study area was projected to year 2052.

Figure 9-83 Gas Mass Rate of Injected CO2 at Surface Conditions Versus Time for the Injection Scenarios L1 and L2



Four cases with varying injection scenarios (L1, L2) and shut in periods post injection for wells DD7, DD7A and DD8 were examined. In all cases, the well characteristics were kept constant and no skin factor or explicit simulation of hydraulic fractures was employed in the (L) models. In case L1a, injection scenario L1 was applied and the three injectors were shut in for 1 year post injection; in case L1b, injection scenario L1 was used and the injectors were shut in for 4 years; in case L2a, injection scenario L2 was employed and the selected injection wells were shut in for 1 year post injection; and in case L1c

injection scenario L1 was applied and the injectors were shut in for 36 years post injection, which means they were shut in throughout the projected time of the simulation.

During injection, for both injection scenarios L1 and L2, the bottom hole pressures in the wells did not exceed the maximum allowable pressure as indicated by a U.S. EPA class II UIC permit (VCCER, 2013). For injection scenario L1, the maximum bottom hole pressures for the three injectors DD7, DD7A and DD8 were approximately 423, 484 and 416 psi respectively; for injection scenario L2, the maximum bottom hole pressures were 482, 564 and 483 psi respectively. Also, under the specific pressure and temperature conditions, carbon dioxide was injected as a gas and remained in the gaseous state throughout the injection.

Cumulative gas production and CO2 flow back and breakthrough for cases L1a, L1b, L2a, and L1c are tabulated in Table 9-40 and Table 9-41, respectively. More details on the results can be found in Vasilikou (2014).

Table 9-40 Cumulative Gas Production (CGP) for All Wells for Cases: L1a, L1b, L2a, L1c

Cumulative Gas Production (Std Mcf)					
Wells	L1a	L1b	L2a	L1c	Baseline EUR
CC6	987,936	994,560	987,979	954,294	971,235
CC6A	413,518	421,162	413,518	338,075	340,920
CC7	732,541	744,980	732,609	722,581	481,097
CC7A	276,046	283,501	276,089	277,727	339,373
CC8	1,422,654	1,439,308	1,422,845	1,366,867	607,132
CC9	36,651	36,651	36,651	36,651	N/A
CC9A	709,577	715,687	709,671	659,101	N/A
CC9B	629,022	633,463	629,079	580,365	320,446
DD5	720,020	723,772	720,039	682,670	588,601
DD6	1,135,585	1,146,610	1,135,673	1,102,503	972,886
DD6A	341,131	348,545	341,132	327,608	252,699
DD7	534,744	491,058	534,361	371,580	638,375
DD7A	242,935	201,746	242,843	90,420	277,865
DD8	419,415	362,923	418,783	207,072	370,263
DD8A	327,622	329,922	328,006	306,586	285,564
DD9	904,661	914,451	904,687	877,530	1,105,313
DD9A	447,732	452,743	447,714	421,883	512,732
EE6	737,057	748,151	737,105	718,395	530,887
EE7	914,234	925,790	914,227	884,206	828,465
EE8	666,874	683,045	666,752	670,343	713,174
EE9	360,081	365,278	360,108	335,567	161,065

Table 9-41 CO_2 Flowback and Breakthrough for Cases: L1a, L1b, L2a, L1c

Produced CO_2 (tons)				
Wells	L1a	L1b	L2a	L1c
CC6	4.95E-04	2.50E-02	9.19E-04	1.89E-01
CC6A	4.90E+00	2.23E+01	4.92E+00	6.58E+01
CC7	4.22E+00	1.72E+01	4.50E+00	5.79E+01
CC7A	5.52E-02	2.14E-01	5.88E-02	6.24E-01
CC8	1.08E-02	1.55E-01	1.61E-02	7.56E-01
CC9	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CC9A	2.30E-05	2.08E-05	2.59E-05	1.87E-05
CC9B	2.70E-05	2.70E-05	2.78E-05	2.69E-05
DD5	4.16E-06	2.21E-06	3.25E-06	1.47E-06
DD6	3.10E+01	1.13E+02	3.16E+01	2.50E+02
DD6A	8.79E+00	2.54E+01	8.89E+00	5.44E+01
DD7	5.92E+03	4.70E+03	5.91E+03	0.00E+00
DD7A	5.78E+03	4.93E+03	5.77E+03	0.00E+00
DD8	5.54E+03	4.64E+03	5.56E+03	0.00E+00
DD8A	1.03E+03	1.74E+03	1.01E+03	2.85E+03
DD9	1.12E-01	7.13E-01	1.20E-01	2.21E+00
DD9A	7.60E-05	3.62E-04	7.68E-05	1.44E-03
EE6	2.25E-02	1.54E-01	2.32E-02	9.32E-01
EE7	2.86E-03	9.71E-03	2.84E-03	2.16E-03
EE8	6.44E+01	1.61E+02	6.41E+01	3.86E+02
EE9	9.99E-06	1.30E-05	1.20E-05	1.00E-05

9.5 Monitoring, Verification and Accounting Plan

9.5.1 Approach

The goals for an effective monitoring, verification, and accounting (MVA) program for CCUS projects are outlined in the best practices manual Best practices for: monitoring verification, and accounting of CO2 stored in deep geologic formations, developed by the U.S. Department of Energy and the National Energy Technology Laboratory in 2009. An update to the manual was released in 2012. According to these documents, the major goals of an MVA program include improved understanding of injection and storage processes, evaluation of interactions among CO2, reservoir fluids, and formation solids, assessment and minimization of environmental impacts, and ensuring that CO2 storage is “safe, effective, and permanent in all types of geologic formations” (DOE and NETL, 2012). Additionally, a complete MVA program should incorporate technologies that monitor the near-surface and subsurface atmosphere of the test site. The program should also utilize a subset of the monitoring and geophysical

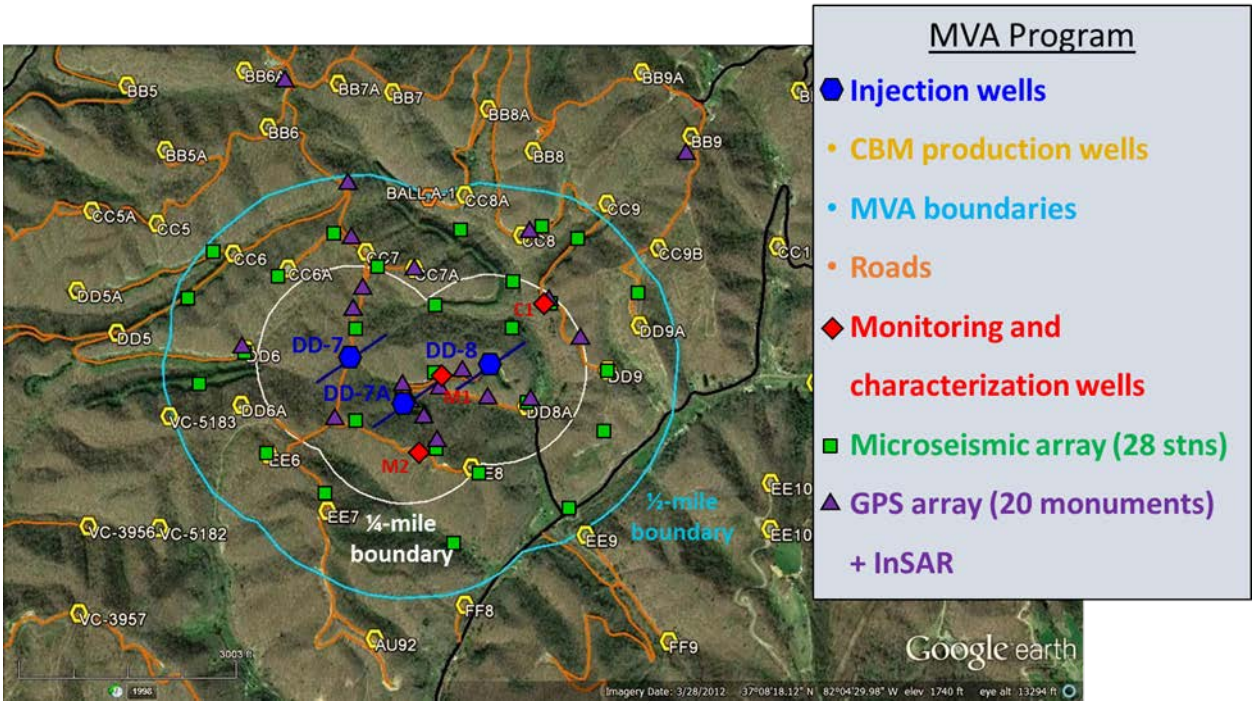
technologies available that is well suited for the unique characteristics of the site, target reservoir, and test objectives.

The selection of technologies for the MVA program was limited by the steep and heavily forested terrain at the study area, which restricts physical access almost entirely to roads and well pads. The unique geometry of the coal reservoir, comprising several thin, dispersed seams, also presented challenges for monitoring and geophysical imaging, preventing the use of some technologies. The MVA program includes technologies deployed over different, overlapping spatial scales and data acquired at varying temporal sampling rates. Correlating datasets acquired at a borehole scale with data acquired over large areal extents allows interpolation of results across the study area. Combining overlapping datasets in this way can better define CO2 plume migration or other reservoir-scale processes. The ability to cross-validate interpretations with overlapping datasets is especially important in the setting of an active production field because simultaneous operations can further complicate the ability to attribute signals to sources.

9.5.2 Design overview

An overview of the monitoring program is shown in Figure 9-84. Injection wells DD7, DD7A, and DD8 are indicated with blue symbols with blue lines to represent estimated hydraulic fracture lengths and orientations. The MVA focus area is indicated by a white boundary, which represents a ¼-mile radius surrounding the injection wells. The focus area was derived from a preliminary simulation of the injected CO2 plume extents for the target injection volume. The larger MVA study area is indicated the blue ½-mile boundary. The study area was expanded beyond estimated plume extents in order to better define plume edges. Note that locations for monitoring stations are limited primarily to existing roadways and well pads due to hazardous terrain.

Figure 9-84 Overview of the MVA program for the CO2-ECBM test in Buchanan County, Virginia



Blue symbols represent injection wells with blue lines indicating the estimated orientation and extents of hydraulic fractures. The white ¼-mile boundary indicates the MVA focus area and the estimated final CO_2 plume extents. The blue ½-mile boundary indicates the larger MVA study area.

Three dedicated monitoring wells, M1, M2, and C1, are indicated in Figure 9-84 with red symbols. The wells were drilled prior to injection at varying distances and orientations from the injection wells. The monitoring wells are key features of the MVA program because they represent points of overlap for several types of data acquisition, including reservoir pressure and temperature monitoring, produced gas composition, and well logging. M1 was drilled between injection wells DD7A and DD8 in order to study the inter-well region during injection operations. Fracture communication between DD7A and DD8 is likely due to the orientation and proximity of the wells to each other. M1 is approximately aligned with the hydraulic fractures to observe reservoir responses in the induced high-permeability orientation. The location of M2 was selected to observe reservoir responses at an orientation offset to hydraulic fractures, where natural permeability would govern fluid migration. C1 was drilled farthest from the injection wells and is also relatively isolated from other production wells in the study area. Because of its proximity from CBM operations and mechanical alteration from hydraulic fracturing, C1 was also designated as a reservoir characterization well and used for formation logging and continuous coring.

9.5.3 Selected Technologies and Deployment

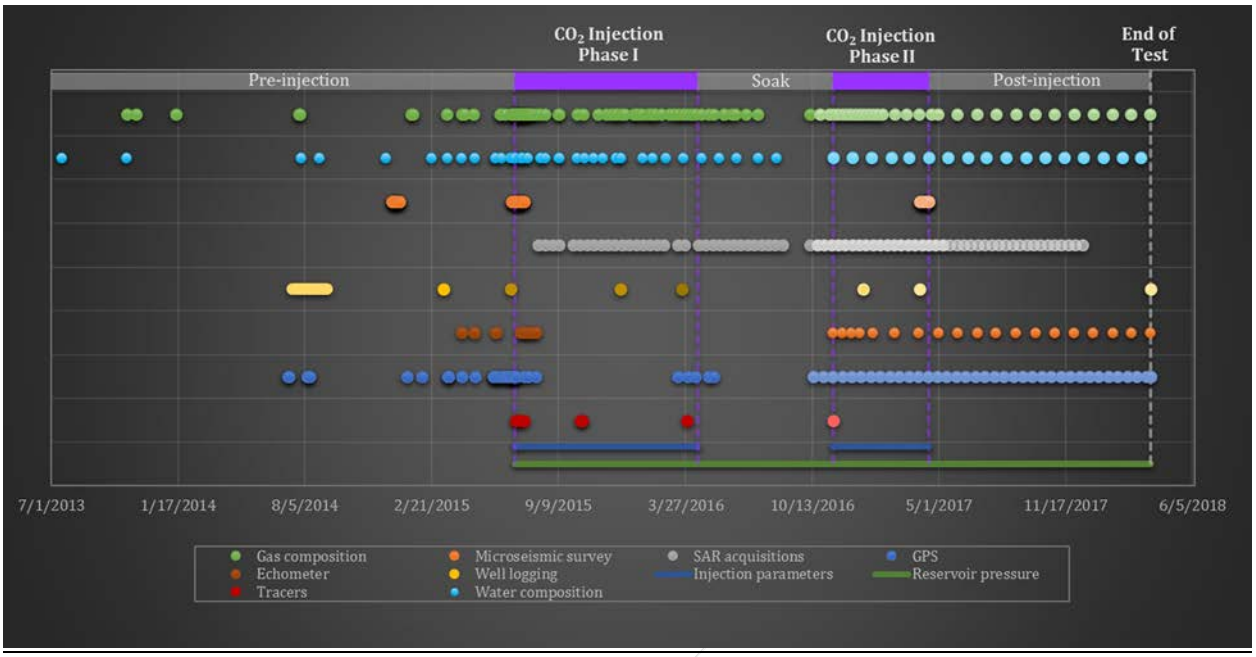
The monitoring technologies selected for the MVA program are summarized in Table 9-42 and described in detail below. The data acquisition schedule for the MVA program is shown in Figure 9-85.

The schedule reflects a focus on time-lapse acquisition to observe changes due to CO2 injection and adaptive sampling frequency based on operational activities.

Table 9-42 Summary of monitoring technologies selected for the MVA program for the CO2-ECBM field test in Buchanan County, Virginia

Technique	Deployment/Acquistion	Sampling Frequency
CO_2 injection operations monitoring		
Injection rate	Controlled at CO_2 injection skid; recorded by coriolis flowmeters	Continuous, real-time recording
Injection pressure	Recorded at injection wellheads	Continuous, real-time recording
Injection temperature	Controlled at CO_2 injection skid; recorded at injection wellheads	Continuous, real-time recording
Reservoir pressure	Recorded at monitoring observation wells on sensors installed on tubing and annulus, downhole and on wellheads	Continuous, real-time recording
Reservoir temperature	Recorded at monitoring observation wells on sensors installed on tubing and annulus, downhole and on wellheads	Continuous, real-time recording
Gas composition	Samples collected from 19 offset production wells, all monitoring observation wells, and nearby gas compressor station	Daily-weekly for first two months of Phase I injection, then monthly
Formation water composition	Produced water samples collected from 19 offset wells	Weekly-monthly
Tracers (gas and liquid)	Gas and liquid tracers added to CO_2 injection stream at wellhead; liquid tracers added to water pre-injection	Deployment is on-demand; gas composition monitoring includes tracer detection
Borehole liquid level measurement	Echometer wellhead attachment	Daily-weekly at start of injection, then monthly
Microseismic monitoring array	Surface array of 28 stations; shallow borehole installation at depth of approximately 75 feet	On-demand surveys, continuously recorded over 15-20 days
Surface deformation		
Global Positioning System (GPS)	Four receiver units, rotated acquisition at 20 monuments	Weekly-monthly rotation
Synthetic Aperture Radar (SAR)	TerraSAR-X satellite	11-day satellite orbit
Well logging and tests		
Reservoir characterization logging	Down-hole logging of monitoring observation wells	On-demand
Spinner test (production rate)	Down-hole flow rate, pressure, and temperature logging of injection wells, DD7 and DD8	On-demand
Water flood test (kill test)	Down-hole flooding and flow rate logging of CC7A and DD8A	On-demand

Figure 9-85 Data acquisition schedule for the MVA program



CO_2 injection operations monitoring

Monitoring of CO2 injection operations is conducted continuously (every 60 seconds) for DD7, DD7A, and DD8. At the injection skid, each injection pipeline is equipped with a Coriolis flowmeter to measure the injection rate. Injection wellheads are equipped with sensors to record injection pressure and temperature. The CO2 injection rate and temperature are controlled from the injection skid. All real-time injection operations data are accessible remotely using a SCADA system, which can also be used to adjust CO2 injection rate and temperature settings. The SCADA system also ensures that injection operations are conducted in compliance with permit specifications by triggering alarms when injection parameters approach defined operational limits or by force-stopping injection if limits are reached.

Reservoir pressure and temperature

Monitoring observation wells M1, M2, and C1 are equipped with reservoir pressure and temperature sensors installed on the tubing and the annulus, downhole and at the wellhead. Pressure and temperature data are recorded continuously (every 60 seconds) and accessible remotely in real-time using a SCADA system.

Gas composition

Gas samples are collected regularly from 19 offset production wells in the study area and from the annulus and tubing of monitoring observation wells M1, M2, and C1. Gas from a nearby compressor station has also been sampled. Samples are analyzed using a gas chromatograph for percent composition of methane, CO2, N2, and several additional heavy hydrocarbon constituents, which are present in very small amounts. A published database of gas composition for the project will be updated

over the remaining course of the project (Louk et al., 2016). Samples are also analyzed for the presence of tracers that were added to the CO2 injection stream and water in the injection wells.

Formation water composition

Samples of formation water are collected regularly from 19 offset wells in the study area for lab- and field-based testing. Samples are analyzed in the lab for isotopes of 20 trace element constituents using inductively coupled plasma mass spectrometry (ICP-MS). Salinity is measured in the lab using a refractometer. Additional measured parameters include alkalinity, pH, temperature, oxidation/reduction potential, dissolved oxygen, total dissolved solids, total organic carbon, sodium adsorption ratio, and electrical conductivity.

Tracers (gas and liquid)

Tracers were deployed at three distinct times during Phase I operations to track the migration of reservoir fluids under different pressure conditions. The three rounds of tracers were deployed at the start of injection operations, when the injected volume reached 15 percent of the total injection target, and when the injected volume reached 40 percent of the total injection target.

Prior to the start of injection operations, the three injection wells were shut-in from production to be converted to injection wells, and formation water collected in the wellbores. Unique perfluorocarbon tracers were added to the water in each of the wells in order to track migration of the water plume in the reservoir. A volume of 150 mL of perfluoromethylcyclopentane (PMCP) was added to water in DD7, 150 mL of perfluoromethylcyclohexane (PMCH) was added to water in DD7A, and 250 mL of perfluoromethylcyclohexane (PECH) was added to water in DD8. Additionally, On July 17, 2015, during the first days of CO2 injection, a volume of 2000 mL of sulfur hexafluoride (SF6) was added to the CO2 injection stream of DD8 to track migration of the CO2 plume during early injection operations.

A second round of tracers was injected from October 14-17, 2015, when the injected volume reached approximately 15 percent of the total injection target (30 percent of the total Phase I volume). Unique refrigerant tracers were added to the CO2 stream of each injection well to track CO2 migration under steady-state and relatively low-pressure injection operations (CO2 injected in gas phase). A volume of 2500 cm3 of trifluoromethane (CHF3) was added to the injection stream of DD7, a volume of 2000 cm3 carbon tetrafluoride (CF4) was added to the injection stream of DD7A, and a volume of 4000 cm3 of octofluoropropane (C3F8) was added to the injection stream of DD8.

A third round of tracers was injected on March 29, 2016, when the injected volume reached approximately 40 percent of the total injection target (75 percent of the total Phase I volume). Unique perfluorocarbon tracers, distinct from those previously injected, were added to the CO2 injection stream of each injection well to track CO2 migration during higher-pressure injection operations (CO2 injected in gas and liquid phases). A volume of 500 mL of perfluoromethylpentane (PMP) was added to the injection stream of DD7, a volume of 500 mL of perfluoroethylpentane (PEP) was added to the

injection stream of DD7A, and a volume of 500 mL of perfluorodimethylcyclohexane (PDMCH) was added to the injection stream of DD8.

Borehole liquid level measurement

The liquid level in the three injection wellbores was measured regularly during Phase I operations in order to track the evacuation of formation water from the wells into the reservoir. An Echometer wellhead attachment was used for the measurements. The unit sends an acoustic signal down the wellbore that reflects off the water and received again by the unit. The travel time is used to calculate the distance to the water surface. The Echometer unit was also used to measure wellbore liquid levels for water flood tests conducted on offset production wells CC7A and DD8A, described under "Well logging and tests."

Microseismic monitoring array

A buried surface array of 28 three-component 10-Hz geophones was installed for passive microseismic monitoring (Figure 5-7). The technology was selected for its high sensitivity, which is well-suited to the low-pressure CO2 injection operations. A lateral array configuration was selected to optimize lateral resolution over the study area. Geophones were installed in shallow boreholes at a depth of approximately 75 feet to avoid attenuation near the surface and improve received signal quality. The distribution of geophone stations was designed to optimize aperture for imaging the estimated maximum lateral extents and depth of the injected CO2 plume. Passive, continuously-recorded microseismic monitoring is conducted for surveys lasting several days. A pre-injection survey was conducted on December 20, 2014-January 1, 2015, while injection wells were still producing gas under typical operational conditions. An early injection survey was conducted on June 27-July 16, 2015 and included five pre-injection days before the start of staggered injection operations. Installation of the array and data acquisition were conducted by Global Geophysical Services of Houston, TX.

Surface deformation

Potential surface deformation due to CO2 injection is monitored using interferometric synthetic aperture radar (InSAR) and global positioning system (GPS) measurements. InSAR uses time-lapse images acquired by satellite to identify changes in the land surface. The TerraSAR-X satellite, operated by the German Aerospace Center, DLR, acquires synthetic aperture radar (SAR) images over the CO2-ECBM study area. The full extents of the acquisition scene are 30 km x 50 km. A detailed description of the satellite and its operational parameters is available in DRL's "TerraSAR-X Ground Segment Basic Product Specification Document" (2010). The satellite orbits from a height of 514 km on a repeat cycle of 11 days. The X-band radar has a high carrier frequency of 9.65 GHz, associated with a short wavelength of 31 mm and high imaging resolution. For acquisitions over the study area, which the radar operates in single-polarization, stripmap mode, the ground range resolution is 3 m.

Ground-based surface deformation monitoring is conducted using four GPS receivers which are mounted onto survey monuments. Twenty monuments were installed across the study area (Figure 5-

7). Monuments are concentrated within the MVA focus area, but several are located outside of the study area and expected region of influence for the test. Monument installation involved driving steel rods into the earth within shallow boreholes and securing the rods in position with poured cement and rebar. Four survey-grade CHC X90-OPUS GPS receivers are rotated around the monuments to take elevation readings. The receivers can measure elevation to an estimated accuracy ± 5mm.

Well logging and tests

The location of the C1 well, selected for its relative isolation from CBM operations, was used for multiple characterization tests. In July 2014, a location on the C1 well pad was continuously cored to collect samples of the reservoir coal seams and seals for characterization including gas content analysis. The core hole was filled, and the C1 well was drilled and instrumented approximately 10 feet away. In March 2015, formation logging was conducted on C1, including caliper, density, gamma ray, neutron porosity, resistivity, sonic, and temperature logs. Schlumberger Ltd conducted imaging logs using their Formation Microimager (FMI) tool, an optical televiewer, and their Ultrasonic Borehole Imager (UBI) an acoustic televiewer.

Days prior to injection, in June 2015, a water flood test (kill test) was performed on offset production well CC7A. A water flood test involves incrementally filling the wellbore with water to cover an increasing number of seams of the stacked reservoir while measuring gas flow rate. The test can determine which seams contribute most to production. Echometer readings are conducted throughout the test to measure the increasing level of water in the wellbore. In December 2015, additional water flood tests were performed on CC7A and DD8A.

In March of 2016, near the end of Phase I injection operations, spinner tests were conducted on injection wells DD7 and DD8 to determine the production rate from different depth zones of the reservoir. The spinner tests were conducted by Weatherford International as part of an injection logging service. A single toolstring deploys the spinner instrument and runs logs for gamma ray, CCL, temperature, pressure, and radioactive density.

9.6 Site Development and Operations

9.6.1 Site Development

The project team designed a pipeline and injection skid, which would be used to measure and control CO_2 flow rates and pressures, to begin site development. Three monitoring wells were drilled for this project, and three CBM production wells had to be converted to injection wells. Praxair's storage tanks and pumping unit were connected to the inlet of the injection skid.

CO_2 Pipeline Design

Initial Design

The project team planned to construct a single pipeline from the outlet of the measurement and control skid on the DD-7 injection site with separate lines going to each well. The original layout can be seen in Appendix F. The branch line to each well is identified at the departure point from the main line by a junction number J1 or J2. A flow meter, control valve and a back-pressure regulator were planned at the end of the pipeline to be placed in line immediately before the connection to the wellhead. Appendix F shows the planned configuration for DD-7 which was the same for the other wells. A CO_2 pipeline flow model was constructed to determine the minimum diameter line required to flow and inject 60 tons/day. Each segment of pipeline was evaluated assuming various scenarios of fluid flow and diameters. The segments evaluated were from the CO_2 tank/pump outlet (Tank – J1), the line to the DD-7 well (J1 – DD7), the main line towards the other two injection wells (J1 – J2), the line to the DD-7A well (J2 – DD7A), and the line to the DD-8 well (J2 – DD8). There is a significant elevation change of 380 feet from the injection site down the hill to J2. Flow of either gas or liquid phases was evaluated through various pipeline sizes of 2", 2.5", 3" and 3.5". It was determined that a 2" pipeline was required for the planned daily injection flow rate. The model data can be seen in Appendix F.

Final Design

The project team engaged Trimeric Corporation to assist with the design of the CO_2 pipeline, flow, measurement and pressure controls, and safety devices. Trimeric has a great deal of experience in CO2 design projects and was very instrumental in the operational success and safety achieved on this project.

Trimeric recommended a separate pipeline run from the CO_2 pump discharge to each well. This would allow the injection operations for each well to be independent. In the event one or two wells were shut-in, we would not have to be concerned about manifold pressure when restarting a well. This would also eliminate some other operating concerns. For example, it would eliminate CO_2 condensing at the bottom of the 1000-foot run of pipeline down the 41% grade and then flashing to a very low temperature across the pressure control valve when it enters an injection well. Separate pipelines would also allow all the flowmeters and pressure control valves to be placed on a skid in one place near the CO_2 pumping unit. This would enable the operator to check all equipment on a regular basis without having to leave the site. Each pipeline was designed identically. The final pipeline is shown on the map in Appendix F. Trimeric developed a process simulation of the piping manifold and individual pipelines downstream of the leased pumping and heating units using the WinSim process modeling tool, and they evaluated the process over a wide range of operating flow rates, temperatures, and pressures based upon data in Table 9-43.

Table 9-43 Potential Values for Flow, Pressure, and Temperature Downstream of the Leased Pumping and Heating Unit

Parameter	Minimum Potential Value	Expected Operating Value	Maximum Potential Value
Flow - Total	10 tonne/day (923 lb/hr or 1.8 gpm)	55 tonne/day (5,078 lb/hr or 10.1 gpm)	100 tonne/day (9,234 lb/hr or 18.4 gpm)
Flow – Per Well	3 tonne/day (277 lb/hr or 0.55 gpm)	18 tonne/day (1,662 lb/hr or 3.3 gpm)	50 tonne/day (4,617 lb/hr or 9.2 gpm)
Pressure at Wellhead – Well DD7	0.24 MPa gauge (35 psig)	4.4 MPa gauge (639 psig)	5.9 MPa gauge (852 psig)
Pressure at Wellhead – Well DD7A	0.24 MPa gauge (35 psig)	4.9 MPa gauge (707 psig)	6.5 MPa gauge (943 psig)
Pressure at Wellhead – Well DD8	0.24 MPa gauge (35 psig)	6.0 MPa gauge (865 psig)	7.9 MPa gauge (1,153 psig)
Temperature at Wellhead	-1^{o}C (30^{o}F)	4^{o}C (40 ^{o}F)	38^{o}C (100 ^{o}F)
Phase	Vapor, Liquid, or Two-Phase		

The expected rate considered a total of 55 tonne/day with a split of 18 tonne/day/well. A maximum case of 50 tonne/day to one well was also evaluated. The modeling determined that a 2” pipeline to each well would be required. Each pipeline was built from the outlet of the measurement and control skid to the injection wellhead. A main block valve and check valve were installed at the end of the pipeline where it connected to the wellhead. Each pipeline also had a pressure relief valve with block and bleed valves installed. This device was located upstream and adjacent to the main block valve on pipeline. The pressure relief valves were set to release at 1480 psig. Trimeric indicated that they typically recommend Schedule 80 pipe only from the standpoint of withstanding external damage. The only pipe at risk to possible external damage was that going down a steep, wooded hill. Since it was very unlikely to be damaged the project team used Schedule 40 pipe. This provided cost savings and the pipe was easier to handle during the construction phase. Based upon the results of the modeling program, Trimeric recommended that all above ground piping be insulated with a foam wrap. Six-foot long, pre-formed 2” armaflex foam pipe insulation was used to cover all bare piping on the skid and above-ground pipelines. After the pipelines reached the bottom of the steep grade, they were buried from that point to very near the wellhead and therefore did not require insulation.

After the pipeline was constructed, a pipeline cleaning pig was sent through each pipeline twice using an air compressor to push it. The lines were then filled with fresh water to conduct a hydrostatic

pressure test at 1500 psig. The pressure test duration was four hours. The first test on the DD-7A pipeline failed as there was a leak on a 45° welded elbow twenty feet from the wellhead connection. The elbow was ground down and re-welded. The line then held the pressure during the test. A pig was then sent through the lines again to push out the water. Trimeric recommended that the pipelines be well-purged with dry nitrogen before introducing CO_2 into the system. A block and bleed method was used as Trimeric suggested this is typically more effective than a continuous flow of nitrogen through the system. C&J Services, an oilfield pumping company, delivered and pumped the nitrogen to purge the lines. Each line was pressured to 200 psig with a block valve closed at the end of the line. The block valve was then opened to purge the line. This process was repeated three times on each line. The valve remained open and 1000 cfm of nitrogen was pumped through each line for four minutes to complete the purge. Lastly, the pipelines were then connected to the wellheads using pipeline flanges. The lines were pressured to 1400 psig and held for ten minutes to ensure the flanges and gaskets were sealed properly. The nitrogen was then bled off the line at the pump truck and the system was ready for CO_2 operations.

Injection Skid Design

Trimeric prepared a process and instrumentation diagram (P&ID) for the entire system between the outlet of the CO_2 heating/pump skid to each injection well. There is a flow line on the skid for each injection well. See the P&ID in Appendix F. The project team decided to place most the items shown on the P&ID onto a prefabricated skid. This allowed for the construction of the skid to be completed inside a controlled environment at a fabrication shop. A pipeline firm, EMATS, built and painted the base skid which was 8.5’ wide by 18’ long. All items shown on the P&ID beginning at the check valve numbered V-101 through the control valves numbered PCV 200, 300 and 400 were built and installed on the skid. Prior to installing the flow meters, process control valves and pressure relief valves, the piping, valves, and welds were hydrostatically pressure tested at 1500 psig for 4 hours in the shop. The pressure relief valves were installed after the pressure test. The skid was then transported to wellsite DD-7 and set in place. The flow meters and process control valves were installed in the field. The skid is shown in Figure 9-86.

Figure 9-86 Injection Skid



Flow Meters

Trimeric has had experience using Coriolis flow meters from its work on other CO_2 injection projects. Based on the flow, pressure and temperature parameters in previously presented Table 9-43, Trimeric evaluated Coriolis meters for our project. Coriolis meters measure the mass flow rate of the CO_2 through the meter independent as to whether the flowing CO_2 is a gas, liquid or a two-phase, dense slurry. In the early stages of the project the CO_2 was injected as a gas due to the low pressures in the wellbores. Over time as pressure increased in the reservoir, the CO_2 was in a slurry phase as dense gas/liquid. Eventually the CO_2 was pumped as a liquid as pressures continued to climb. This meter was ideal for these scenarios. Attached in Appendix F are flow calculation and data configuration sheets prepared by the vendor of the meters. Thus, the project team purchased and used the Coriolis flow meters recommended by Trimeric. The three Coriolis meters are in the foreground on the skid shown in Figure 9-86 above.

Control Valves

Three separate pressure control valves were necessary for the pipeline run going to each injection well. Trimeric evaluated the process parameters that were previously reviewed and recommended Badger

process control valves with electronic actuators. The Badger control valve sizing sheets can be seen in Appendix F. The valves were 1" globe cast stainless body and flanges with an electric actuator. These control valves were designed to control the downstream pressure of the CO_2 going to each injection well. If the pressures at the wellheads were less than the injection pressure set point, the valves opened to allow CO_2 flow from the piping manifold to the injection wells. If the pressures at the wellheads would have approached the project limit set points, which did not happen, the valves would have closed as much as necessary to keep the downstream pressures below the desired injection pressures.

During startup, these pressure control valves regulated the pressures in the pipelines going to each wellhead and served to prevent the upstream pressure in the supply manifold from dropping too low. The initial CO_2 supply pressure at startup was discharged to the skid at approximately 300 psig. Therefore, this pressure was maintained by the valves until the wellhead and pipeline pressures increased. The set point for each well's pressure control valve was set near the initial surface shut-in pressure of each well, and then raised gradually as the pressure at the surface increased.

The pressure control valves were linked to a communication system that received data on wellhead pressures which would allow the valves to open or close. Opening or closing the valves could also be controlled from an office location if it was desired to increase or decrease flow to a specific well. The control valves are red and can be seen on the right side of the skid in Figure 9-87.

Figure 9-87 Control Valves



Electrical Supply

The original electrical supply available on the DD-7 wellsite was 110 V, single-phase, 60 Hz power. This power was sufficient for the instruments and controls that were installed on the skid. Primary Energy installed and connected the wires from a junction box it installed on the power pole to the skid to provide power for the process control valves, flow meters, and communication devices. Additionally, Primary Energy connected all the control wires on the skid for these units.

Communication

Each flow line on the skid has its own remote terminal unit which is a XARTU/1 ***(XARTU)*** made by Eagle Research Corporation ***(Eagle)***. It is a real time monitor and recorder in a pole-mounted Hoffman fiberglass enclosure. The unit (gray box) can be seen in Figure 9-87 above. The unit is software programmable and handles measurement, control, data gathering, and alarm functions. Eagle has a software program named Talon that handles all the data processing. These units on the skid were connected to its respective Coriolis flow meter and process control valve. The Coriolis meter sent flow rate and volume data to the unit. The unit recorded real-time daily flow rate, current and previous day volumes, current and previous month volumes, and cumulative volume from inception. The process

control valves were configured in the system to open or close as needed based on wellhead pressures that were gathered by the units. The units also gathered data from remote terminal units located at the injection and monitor wellheads. Additionally, the XARTU on the DD-8 flow line received CO_2 pump discharge temperature, pressure, and flow rate data from the Praxair system. Alarm functions were also input for each unit. The alarms were set to provide real-time warnings for high or low flow rate, high injection pressure, high wellhead casing pressure, low injection temperature, and low voltage. The high and low flow rate alarm was based on the Coriolis flow meter on the skid. The low rate alarm was set at 2 tons/day while the high rate alarm was set at 36 tons/day. If these values were realized, the on-site operator investigated and adjusted as needed. The other alarms will be discussed in the injection well section.

The various data received by the processor can be viewed on-site through an external LCD display with a magnetic scroll switch. A magnet the size of a pencil eraser is used to press against a dimple in the box to scroll through the real-time data values. Power is supplied to each unit by 110-volt AC from electric power lines on site. A back-up battery is included to continue operations if power to the site goes down.

The data from the DD-7 and DD-7A units on the skid was transferred to the DD-8 unit for transmission to the office. This unit is connected to a communication box with a LS300 cellular modem. The communication box is powered through a 110-volt electric supply and is connected to a Yaggi antenna via a 6’ coaxial cable. The wireless modem is on the Verizon network and transmits data hourly to an Eagle host website where the data is stored. Project team members then access the website to view and download data as necessary or remotely modify operations.

The software program on the website gave project team managers the ability in real-time to affect operations if desired. Through the program, the process control valves could be operated remotely from a computer or smart phone. A valve could be opened or closely incrementally or completely to re-direct the flow of CO_2 to different wells.

Monitor Wells

Drilling

There were three monitoring wells planned for the project. One of the wells was identified as a geological characterization well that was to be cored over its entire depth. The sites were named M-1 and M-2 for monitoring well number 1 and 2, and C-1 for characterization well number 1. The initial plan was to drill a core hole first and then attempt to ream it out to a full-size hole. After discussions with the DGO, the project was permitted to drill a separate core hole and full-size well if the surface location of the bores were within 10 feet of the permitted coordinates. The core hole was spotted 7’ north and the monitoring well was 8’ south of the permit coordinates. The core hole was identified as CH-1. These monitoring well locations are shown on Figure 9-84.

Site construction for the first monitoring well began at the C-1 location on June 23, 2014 and was completed in one week. The M-1 and M-2 locations were constructed following completion of C-1. LJ Hughes Company moved on-site at C-1 on July 14 and began coring operations two days later. NQ wireline tools were used to recover 2" diameter continuous cores. Cores were not retained for the first 767' of drilling. The Greasy Creek coal seam at 767' was the first coal that was put in a desorption canister on-site by the geologist. Table 9-44 identifies the coal seams that were cored, the depth to the seam, and the thickness of the seam placed in a desorption canister.

Table 9-44 Core Hole Data from CH-1

Coal Seam	Depth to Seam (ft)	Thickness of Seam (ft)
Greasy Creek	767	1.78
Upper Horsepen	978	1.31
P11	1168	.87
P10	1203	1.15
P9	1301	1.60
P7	1417	1.09
P5	1575	1.03
P5 Split	1628	.89 and .77 (shale in separate canister)
P4	1652	1.17
P3	1731	2.02
P3 Leader	1750	.75
P2	1801	.70
Total Depth	1845	

Geophysical logs were then run in the core hole by MM&A Geophysical Logging Services (GLS). Gamma ray, density, temperature, resistivity, and acoustic televiewer logs were obtained. The logs indicated that a portion of the P3 seam, approximately one foot, was not properly recovered. By contract, LJ Hughes Company guaranteed 100% recovery of the coal. Therefore, additional coring was conducted to fully recover this seam. The lower portion of the hole was grouted to prepare to set a wedge at 1625' to kick off. The operator drilled into the wedge but failed to kick off. A second wedge was set at 1391'. The kick off was successful and full cores were recovered from the P4 and P3 seams and placed in canisters. An additional 1.18' of coal was recovered in the P3 seam as compared to the initial core.

The core hole was grouted to surface with 73 bags of cement and plugged and abandoned on September 10.

Drilling of the three monitoring wells began in the spring of 2015. Noah Horn Well Drilling spud the C-1 well on March 9, 2015. The conductor hole was drilled to 20' with a 12-3/8" tri-cone bit. 9-5/8" casing was set in the hole and backfilled. The surface hole was drilled to 575' with an 8-7/8" hammer bit. Prior to running the 7" surface casing which is the fresh water protection string, the hole was filled with fresh water for logging operations. Schlumberger Carbon Services (SCS) ran the Platform Express (PEX) and sonic scanner logs. The PEX suite consists of the gamma ray, caliper, laterolog resistivity, density and compensated neutron logs. 575' of 7" surface casing was installed in the well and cemented with 100 sacks of class A cement with 3% CaCl and ¼ lb. flake per sack by Nabors Completion and Production Services (Nabors). The water protection string was cemented to the surface with good cement returns to the pit.

The monitoring hole was then drilled with a 6-3/8" hammer bit to the total depth of 1855'. The hole was loaded with fresh water again to conduct geologic characterization logging with SCS. The open hole was logged from total depth to the bottom of the surface casing. The PEX logs were obtained in the first logging run. The second run included the formation microimaging (FMI) and sonic scanner logs, and the ultrasonic borehole imager log was done on the last run. At the completion of logging, the drill pipe was tripped back into the open hole, and the rig's air compressors were used to evacuate the water and clean and dry the hole. After tripping the drill pipe out of the well, a 3' joint of tubing with a valve on top was set in the wellhead to shut-in the well until completion operations were scheduled.

The drilling rig then moved to the M-1 location. The well was spud on March 16, 2015 with a 12-3/8" tri-cone bit and drilled to 16' where solid rock was encountered. The 9-5/8" conductor casing was set in the hole and backfilled. The surface hole was drilled to 775' with an 8-7/8" hammer bit. GLS ran gamma ray, caliper, deviation and temperature logs in the surface hole. The rig crew ran 760' of 7" casing into the well which was cemented to surface with 140 sacks of class A cement with 3% CaCl and ¼ lb. flake per sack by Nabors. Again, there were good cement returns to the pit. The monitoring hole was then drilled with a 6-1/2" hammer bit to 1307'. The bit was tripped out of the hole to prepare to run a core barrel.

The project team wanted to collect full cores of the P9 and P3 seams in this well. A 20' long core barrel was run in the hole to core the P9 seam. During the trip out of the hole to recover the core, an O-ring in a hydraulic line on the rig failed causing the rig to shut down for repair. This delay allowed the core to de-gas an extra hour prior to recovering and placing the core in a canister. Three pictures of the P9 core are shown below (Figure 9-88 through 9-90).

Figure 9-88 M-1 P9 Photo 1



Figure 9-89 M-1 P9 Photo 2



Figure 9-90 M-1 P9 Photo 3



Drilling resumed to 1725’ which was the core point starting depth for the P3 seam. The core barrel was then run in hole and cored from 1725’ to 1745’. The P3 coal seam core was recovered in the final 2’ of the core barrel. The on-site geologist ordered an additional core run to ensure the P3 was fully recovered. After a review of the driller’s depth records, it was discovered that the length of the coal interval cored in the P9 seam was incorrectly added to the depth tally. So, coring to recover the P3 seam began sooner than it should have which is why the coal was at the very end of the barrel. After pulling the core barrel back to surface, it was confirmed that the P3 coal was recovered in the first run. The P3 core is shown below in Figure 9-91 through 9-93.

Figure 9-91 M-1 P3 Photo 1



Figure 9-92 M-1 P3 Photo 2



Figure 9-93 M-1 P3 Photo 3



Drilling resumed with a 6-1/4" tri-cone bit and continued to the total depth of 1835'. The hole was cleaned and dried to prepare for GLS. GLS ran gamma ray, density, caliper, deviation and temperature logs in the open hole from total depth to the bottom of the surface casing. After logging, a 3' joint of tubing with a valve on top was set in the wellhead to shut-in the well until completion operations were scheduled.

The final monitoring well to be drilled was on the M-2 location. CNX Gas had plans to drill a new CBM well on this location sometime in the near future. Therefore, the project team worked with CNX Gas personnel on using this location as a cost-share opportunity. CNX Gas built and paid for the drilling pad because it was in its plans. The project team agreed to drill a monitoring well on the pad and then transfer the well to CNX Gas after the project, so it can be completed as a CBM production well.

The conductor hole was spud on March 23, 2015 with a 12-3/8" tri-cone bit. The hole was drilled to 28' and 9-5/8" conductor pipe was set in hole. An 8-7/8" hammer bit was used to drill the surface hole to 847'. GLS ran gamma ray, caliper, deviation and temperature logs in the surface hole. The rig crew ran 827' of 7" casing into the well which was cemented to surface with 150 sacks of class A cement with 3% CaCl and ¼ lb. flake per sack by Nabors. Like the other wells, there were good cement returns to the pit.

The monitoring hole was then drilled with a 6-3/8" hammer bit to 1538'. As was done in the M-1 well, core samples of the P9 and P3 coal seams were to be collected from this well. As a reference check, the P10 seam was encountered within 2' of its projected depth. This provided confidence in the

projected depth of the P9 seam. The bit was tripped out of the hole to prepare to run the core barrel. The core was drilled from 1538’ to 1558’ and tripped out of the hole. On the trip out of the hole, a hydraulic hose failed which suspended the trip with the core barrel still in the hole. The hydraulic line repair lasted 4-3/4 hours during which time the core continued to de-gas prior to sealing it in a canister. The coal seam core was collected within 2’ of its projected depth (Figure 9-94).

Figure 9-94 M-2 P9 photo 1



Drilling resumed and continued to the projected core point starting depth at 1955’ for the P3 coal. The core barrel was used to drill from 1955’ to 1975’. The P3 coal seam was encountered at its projected depth and the core was recovered and sealed in a canister.

A 6-1/4” tri-cone bit was tripped into the hole and used to drill to the final depth of 2210’. The hole was cleaned and dried in preparation for logging. Again, GLS ran gamma ray, density, caliper, deviation and temperature logs in the open hole from total depth to the bottom of the surface casing. After logging, a 3’ joint of tubing with a valve on top was set in the wellhead to shut-in the well until completion operations were scheduled.

Geophysical Logging

Schlumberger Carbon Services conducted the geophysical logging on the C-1 characterization well. GLS provided logging services for the CH-1 core hole and the M-1 and M-2 monitor wells. The open hole logs obtained are shown in Table 9-45.

Table 9-45 OPEN LOGS in CHARACTERIZATION, MONITOR WELLS & CORE HOLE

Logged Interval	C-1 Characterization Well	M-1 Monitor Well	M-2 Monitor Well	CH-1 Core Hole
Bottom of Conductor Pipe to Surface Casing Depth	Caliper Comp Neutron Density Gamma Ray Resistivity Sonic Scanner	Caliper Deviation Gamma Ray Temperature	Caliper Deviation Gamma Ray Temperature	
Surface Casing Shoe to TD of Well	Caliper Comp Neutron Density FMI Gamma Ray Resistivity Sonic Scanner UBI	Caliper Density Deviation Gamma Ray Temperature	Caliper Density Deviation Gamma Ray Temperature	
Surface to TD of Well				Acoustic Televiewer Density Gamma Ray Resistivity Temperature

FMI: Formation Micro Imager; UBI: Ultrasonic Borehole Imager

Wellbore and Wellhead Configurations and Downhole Equipment

The hardware in all three monitoring wells was identically configured with the only exception being differences in setting depths of various components. The wells have 9-5/8" conductor pipe, 7" surface casing, and 2-3/8" tubing set with an open hole packer. The grade and weight of the 9-5/8" conductor pipe is J55 40 lb/ft. The grade and weight of the 7" surface casing is AT50 ERW 17 lb/ft with standard thread and coupling. The C-1 and M-2 wells required 5' and 10' casing pup joints for setting depth spacing. These pup joints are MC50 ERW 20 lb/ft with standard thread and coupling. These pup joints have a slightly thicker wall thickness than the full joints in the string. This weight of casing for the pup joints was the only size available in the vendor's inventory. It was not deemed to be an issue because 4-1/2" casing can still be installed to make either well a CBM production well in the future. 2-3/8" J55 ERW 4.7 lb/ft tubing with 8 round external upset end (EUE) thread and coupling was installed inside the 7" casing. This tubing string was set on a Baker Hughes 4-1/4" open hole packer with a pump out plug in a wireline entry guide on the end of the tubing. The packer is shown in the photo below (Figure 9-95).

Figure 9-95 Packer for injection test



After the packer was at the correct setting depth, the tubing was filled with fresh water, and Nabors then hydraulically inflated the packer elements by increasing pump pressure incrementally. During this period, 4,000 to 6,000 pounds of tubing weight was allowed to set down on packer. The pump out sub pins sheared once the packer was set and the pressure in the bottom of the tubing reached 2100 to 2200 psig. The packer was set in a massive sandstone interval and used to isolate the lower coal seams, P2 through P5, from the upper coal seams, P7 through the Seaboard. The tubing was used to be able to install downhole pressure and temperature gauges and obtain gas samples at the surface from the lower seams. Pressure, temperature and gas samples from the upper seams were obtained from the tubing-casing annulus.

Three downhole pressure and temperature gauges each were attached to the tubing to record data. Two sets of gauges were memory recording gauges placed above and below the packer and the other set was above the packer connected to a cable running to the surface to enable real-time data capture. The memory gauges were installed in a 1” diameter tube carrier that was welded to a 2-3/8” by 3’ long tubing pup joint. Two hose clamps were also used as backup to secure the carrier to the tubing. The carrier was open-ended on the top and bottom with a screw and locknut through the carrier to hold the gauges in place. The carrier is shown in the picture below (Figure 9-96) along with the wireline entry guide on the bottom of the tubing.

Figure 9-96 Downhole gauge carrier



The gauge connected to the cable was secured to the pup joint above the memory gauge with a hose clamp. This is shown in the photo below (Figure 9-97). As the tubing was run in the well, the cable was fed off a spool through a side-entry port on the wellhead and secured to the tubing with duct tape.

Figure 9-97 Downhole gauge carrier



A fourth set of gauges connected to a cable to the surface was installed through the 2-3/8" tubing string and out the bottom of the wireline entry guide. The gauges were lowered and set close to the bottom of the open hole.

The three monitoring wellbore schematics can be seen in Appendix H. The schematics show the setting depths of the casings, tubing, packer and gauges.

The pressure and temperature gauges used downhole are made by In-Situ and known as a Level TROLL 700. The completely sealed Level TROLL contains pressure and temperature sensors, real-time clock, microprocessor, sealed lithium battery, data logger, and memory. The operating limit for this device is 176° F and 1,000 psia, well above the operating conditions for the monitoring wells. A RuggedCable® non-vented system is used to connect two of the measuring device to the surface. The cable includes conductors for power and communication signals, a strength member, and a Kellems® grip to anchor the Level TROLL securely. Communication cable for programming the device and downloading the logged data is part of the package. The up hole and downhole ends are identical female bayonet-type twist-lock connectors that mate with the Level TROLL body and TROLL Com communication cable. The up-hole end coming out of the wellhead is connected to a 3' cable with a male twist-lock connector. The other end of the 3' cable is directly hard wired to a remote telemetry unit to transmit the downhole data. The twist-lock connection at the wellhead allows for a quick connection to a laptop for downloading data if the remote telemetry unit is not functioning.

The wellhead begins with the 7" x 2" Larkin 1500 psig male tubing head with two 2" side ports for access to the annulus. The 2-3/8" tubing is set in slips and landed in the tubing head. The cable from the Level TROLL 700 in the tubing – casing annulus is threaded through one of the 2" ports. A 2" full-port 1500 psig Balon ball valve is installed on the other port. Using a series of threaded pipe fittings, this port is used to connect an echometer to obtain fluid levels in the annulus, obtain the annular surface pressure and temperature, and collect gas samples from the upper coal seams. The echometer connected directly to a 2" cross after removing a bull plug. An integrated static pressure transducer with a range of 0 – 2,000 psig and a temperature probe are installed in a 1" tee. These items are connected to the remote telemetry unit. A ¼" needle valve installed off the 2" cross is used to collect gas samples.

Above the 2-3/8" tubing collar is a tubing nipple to transition from 8 round to national pipe threads. A 2" Balon valve is added along with two 2" cross pieces above that. The first cross is used in the same manner as the casing port discussed in prior paragraph for echometer, pressure, temperature and sampling. Identical items are attached here to monitor the lower coal seams through the tubing. The upper cross is used to hold a steel rod upon which the Kellems® grip is attached to anchor the cable and Level TROLL. This cable exits the top of the wellhead and connects to the remote telemetry unit. A pressure and temperature and three monitor wellhead schematics can be seen in Appendix H. The M-2 wellhead is shown in Figure 9-98 below.

Figure 9-98 M-2 wellhead



Communication

The downhole data captured by the Level TROLL 700 units and the surface pressure and temperature readings at all three monitoring wells are input to its own remote terminal unit located next to the wellhead. The unit is a XARTU by Eagle like the units on the skid. It is a real time monitor and recorder in a Hoffman fiberglass enclosure. The unit has two integrated static pressure transducers, 0 – 2,000 psig, that are connected to the wellhead by ¼" stainless steel tubing. These transducers measure and record the tubing and annulus surface pressures of the CBM and/or CO_2 gases. The unit also measures and records the surface temperature of the gases in the tubing and annulus through a cable connection to the temperature probe. The circuit board has analog and Modbus inputs to receive data from the downhole pressure and temperature sensors. For this application, the unit was set up to use the Modbus signal. The various data received by the processor can be viewed on-site through an external LCD display with a magnetic scroll switch just like the XARTUs on the skid. Power is supplied to the unit by a 12-volt DC rechargeable battery that is connected to a 70-watt solar charging panel. The battery is stored in an aluminum battery enclosure that is pole-mounted along with the XARTU and solar panel. Figure 9-99 shows the communication equipment installed on the C-1 well.

Figure 9-99 Communication Equipment on C-1 Well



The remote terminal units use free wave radio transmission through a 30' coaxial cable to an antenna on top of a 10' pole upon which all the equipment discussed above is attached. The three monitor well units transmit its data to a dedicated XARTU located on the measurement and control skid on the DD-7 injection site. The M-1, M-2 and C-1 remote terminal units are set up to communicate with the DD-7, DD-7A, and DD-8 XARTUs respectively.

Conversion of Production Wells to Injection Wells

Removal of Production Equipment

The DD-7 well was drilled on November 1, 2000 and completed three days later with a four-stage foam fracture stimulation. Well conversion work began on March 31, 2015. Total gas production from the well at the time of conversion was 406.8 MMcf and the daily rate was approximately 45 Mcfd. The DD-7A well was drilled on January 24, 2007 and completed on February 20, 2007 with a three-stage foam fracture stimulation. Work to convert this well began on April 10, 2015. Total gas production from the well at the time of conversion was 90.4 MMcf and the daily rate was approximately 29 Mcfd. The DD-8 well was drilled on February 15, 2001 and completed with a three-stage foam fracture stimulation on March 15, 2001. Conversion work on this well also began on April 10, 2015. Total gas production from the well at the time of conversion was 232.3 MMcf and the daily rate was approximately 30 Mcfd.

A service rig from L & D Well Services was used to convert the production wells to injection wells. All three wells had 2-3/8" tubing with sucker rods and a down hole pump installed. The service rig pulled the rods and pump from each well and swabbed the tubing. The swabbing was done to remove as much water as possible to prepare to run a down hole video camera to inspect the perforations.

Four swab pulls were conducted in the DD-7 tubing. Approximately eighty gallons were swabbed from the total depth of the tubing at 2182' upon which the last pull was dry. The rig pulled the tubing from the well and GLS moved in and rigged up to run the down hole video camera. Eventually the camera encountered the water level four hours after the final swab pull at 2035'. Ninety-nine gallons of water entered the well bore during this time. The well was shut-in, after pulling the camera out of the hole, until the completion operations began.

The service rig made twelve swab pulls in the DD-7A well. Fluid was encountered at 1730'. The tubing was swabbed dry to 1840' recovering eighteen gallons of water. The tubing was then pulled to allow for a video camera run. The video camera was immediately run to the bottom of the well to look at perforations before fluid accumulates in the casing. The water level was encountered at 1762' two and one-half hours after the last swab pull. Fifty gallons of water entered the well bore in this period. Like DD-7, the well awaited completion operations after video logging.

Ten swab pulls were carried out on the DD-8 well to 1852'. The swabbing operation could not get ahead of the fluid entry as approximately thirteen gallons were swabbed each run. After pulling the tubing, the video camera was again immediately run to the bottom of the casing but hit fluid at 1690' in ninety

minutes after swabbing. There was 132' of fluid inside the casing. After video inspection, the well was shut-in awaiting completion.

Video Camera Logging

As previously mentioned, a downhole video camera was utilized to inspect the perforations in the casing after the tubing was removed from the well. The inspections were conducted to determine if the perforations in each coal seam were open or closed. This was important to determine so the project team would know whether each seam had the opportunity to accept CO_2. It is understood that sometimes not all the perforations are opened during the hydraulic fracture treatment. This exercise was a qualitative assessment as to whether a perforation was open or closed. The results of the inspection for each well are summarized in Tables 9-46 through 9-48. The data indicate that the majority of the perforations inspected were open, and thus it could be reasonably assumed that injection of CO_2 would occur in all the coal seams.

Table 9-46 DD-7 Perforation Assessment from Video Camera Logging

Coal Seam - Depth	# of Perforations	# of Perforations Open	% of Perforations Open
Seaboard - 1216'	8	7	87.5
L. Seaboard -1260'	8	8	100
U. Horsepen (10) – 1336'	8	8	100
U. Horsepen (20) – 1385'	8	8	100
Pocahontas No. 11 – 1532'	6	4	66.6
Pocahontas No. 10 – 1564'	7	6	85.7

Pocahontas No. 10 – 1570’	2	1.5	75
Pocahontas No. 9 (10) – 1674’	11	6	54.5
Pocahontas No. 9 (30) – 1700’	1	0	0
Pocahontas No. 7 (10) – 1784’	6	2	33.3
Pocahontas No. 7 (20) – 1866’	8	8	100
Pocahontas No. 5 – 1997’	8	4	50
Pocahontas No. 4 (10) – 2024’	8	7	87.5
Pocahontas No. 4 (20) – 2046’	Unable to view		
Pocahontas No. 3 (10, 20) – 2100’	Unable to view		
Pocahontas No. 3 (30) – 2107’	Unable to view		
Pocahontas No. 3 (40) – 2126’	Unable to view		

Pocahontas No. 3 (50) – 2130’	Unable to view		
Total Visible	89	69.5	78.1

Table 9-47 DD-7A Perforation Assessment from Video Camera Logging

Coal Seam - Depth	# of Perforations	# of Perforations Open	% of Perforations Open
Seaboard - 856’	2	2	100
L. Seaboard -902’	2	2	100
U. Horsepen (10) – 975’	5	4	80
Pocahontas No. 11 – 1203’	2	1	50
Pocahontas No. 10 – 1207’	1	0	0
Pocahontas No. 9 (10) – 1316’	6	6	100
Pocahontas No. 7 (10) – 1419’	Scale on casing – no perfs visible		
Pocahontas No. 5 (10) – 1599’	3	3	100

Pocahontas No. 5 (20) – 1637’	2	2	100
Pocahontas No. 4 (20) – 1691’	3	3	100
Pocahontas No. 4 (30) – 1702’	3	3	100
Pocahontas No. 3 (10, 20) – 1735’	3	3	100
Pocahontas No. 3 (40) – 1757’	Unable to view		
Pocahontas No. 2 – 1802’	Unable to view		
Total Visible	32	29	90.6

Table 9-48 DD-8 Perforation Assessment from Video Camera Logging

Coal Seam - Depth	# of Perforations	# of Perforations Open	% of Perforations Open
Seaboard - 871’	7	7	100
L. Seaboard -910’	4	4	100
U. Horsepen (10) – 984’	4	4	100

U. Horsepen (20) – 1031’	6	5	83.3
M. Horsepen – 1068’	6	6	100
Pocahontas No. 11 – 1165’	5	4	80
Pocahontas No. 10 – 1198’	4	4	100
Pocahontas No. 9 (10) – 1311’	4	2	50
Unnamed Coal – 1397’	5	5	100
Pocahontas No. 7 (10) – 1422’	4	3	75
Pocahontas No. 7 (20) – 1467’	8	7	87.5
Pocahontas No. 5 (10) – 1591’	5	4	80
Pocahontas No. 4 (10) – 1637’	8	8	100
Pocahontas No. 4 (20) – 1677’	8	8	100

Pocahontas No. 3 (10,20) – 1711’	Unable to view		
Pocahontas No. 3 (30) – 1721’	Unable to view		
Pocahontas No. 3 (40,50) – 1731’	Unable to view		
Pocahontas No. 2 – 1746’	Unable to view		
Pocahontas No. 1 – 1802’	Unable to view		
Total Visible	78	71	91.0

Wellbore and Wellhead Configurations and Downhole Equipment

All three injection wells were set-up and configured with the same equipment with only the setting depths being different. Baker Hughes Wireline Services was used to set bridge plugs and packers. Baker Hughes Oil Tools division provided the hardware and service man to supervise installation of equipment. Because the former production wells have an open hole section below the 4-1/2” casing, it was necessary to install a bridge plug in the casing below the bottom-most perforations. A drillable cast iron plug was set in each well. Baker Hughes then ran a wireline-set hornet packer in the well that was placed approximately one hundred feet above the shallowest perforations in each well. A rupture disk and wireline entry guide (WLEG) was installed on the bottom of the packer. The rupture disk was necessary to be able to circulate and fill the well bore with a packer fluid. The WLEG guides the re-entry of logging tools to the tubing during future logging operations. After installing an on/off tool on the packer, L & D ran tubing in the well, latched on to the packer, and pulled 5,000 lbs over string weight to ensure packer was set. Tubing was then backed off packer and Nabors circulated corrosion-inhibited packer fluid down the tubing and up the annulus to fill well bore. Tubing was then latched onto the packer and it was set in place with 2,000 lbs of tension on it.

Mechanical Integrity Test

The EPA required mechanical integrity tests on the tubing/casing annulus to test the packer at a pressure 10% greater than the maximum allowable surface pressure in the permit. The pressure had to be sustained for thirty minutes with a 5% or less drop in pressure. Each well was tested with a Nabors pump truck. The tubing and wellhead were also pressure tested to ensure the integrity of the connections.

Nabors connected a line from the pump truck to the wellhead and increased the pump pressure to the test threshold. The pressure was held for thirty minutes. After testing the well head connections and tubing string, the pressure relief valve for the well head was installed and its operation was tested. The pressure relief valves were set to release at 1480 psig which is below the pressure rating of the wellhead components. The MIT was conducted next. The test line was disconnected from the wellhead and connected to the valve on the annulus. The pump pressure was applied to a value greater than the EPA requirement and held for thirty minutes. All the tests were passed and approved by the EPA. Table 9-49 shows the pressure test values. The MIT test documents can be seen in Appendix G.

Table 9-49 Mechanical Integrity Test

Well Number	Maximum Allowable Surface Injection Pressure (MASIP) (psig)	MIT Pressure 10% Above MASIP (psig)	Actual MIT Pressure Start/Finish (psig)	Actual Well Head & Tubing Pressure Test Start/Finish (psig)
DD-7	852	937	1120/1120	1505/1500
DD-7A	943	1037	1080/1080	1520/1513
DD-8	1153	1268	1320/1305	1710/1678

After the pressure testing was completed, L & D ran a sand line with a steel rod on it into the tubing to knock out the rupture disk below the packer. The check valves and remaining well head components were installed, and the well was ready for injection operations. The wellbore and wellhead

configurations and down hole equipment schematics are shown in Appendix H. The DD-7 wellhead is shown in Figure 9-100.

Figure 9-100 DD-7 Wellhead



Communication

The wellhead pressure and temperature readings at all three injection wells are input to its own remote terminal unit located next to the wellhead. The unit is a XARTU like those on the monitor wells. The two integrated static pressure transducers, 0 – 2,000 psig, measure and record the wellhead injection pressure of the CO_2 in the tubing and the annulus pressure to ensure the tubing and packer are not leaking. The unit also measures and records the injection temperature of the CO_2 through a cable connected to the temperature probe in the flow line on the wellhead. The pressure and temperature data received by the processor can be viewed on-site through an external LCD display like on the monitor well units. Power is supplied to each unit by 120-volt AC from electric power lines on site.

Alarms are also configured on the wellhead units to warn the project team about high casing pressure in the annulus, high CO_2 injection pressure in the tubing, or low CO_2 injection temperature. The high casing pressure alarm was set at 10 psig. The process control valve was programmed to shut-in the

well if this pressure reached 100 psig. The high injection pressure alarms were set at 800 psig, 886 psig, and 1084 psig for the DD-7, DD-7A, and DD-8 wells respectively. If the injection pressures approach these limits, the process control valves would gradually start to close to limit flow to the well. The respective shut-down pressures were set at 850 psig, 940 psig, and 1150 psig to automatically close the valve. A low injection temperature of 30° was set as an alarm point. This was not a critical factor so no automatic events were tied to this value. Any alarms are sent by text message to certain members of the project team staff.

The XARTU uses free wave radio transmission through a 30' coaxial cable to an antenna, approximately 15' high, on top of the idle pumping units on the DD-7A and DD-8 locations. These two units transmit data to its respective XARTU located on the measurement and control skid on the DD-7 injection site. Since the DD-7 well is located very near the measurement and control skid, the XARTU on the skid for the DD-7 flow line is also used to retrieve the pressure and temperature data from the wellhead. As previously mentioned, the data from the on-skid XARTU for the DD-7 and DD-7A wells is transferred to the on-skid DD-8 XARTU for transmission of all data through the cellular modem.

Praxair CO_2 Huff-n-Puff Unit

Praxair used its mobile, trailer-mounted CO_2 pump and propane-fueled heater unit for this project. The unit is commonly referred to as a huff-n-puff unit. The unit is shown in Figure 9-101.

Figure 9-101 CO2 huff-n-puff unit



The unit is self-contained and uses either a diesel generator or electricity to supply power for everything. The pump on the mobile unit was capable of injecting CO_2 (liquid or gaseous) at rates from 3 gpm (16 Metric tons/day) to 31 gpm (172 Metric tons/day). The injection temperature range was -10° F (no heating) to 180° F. If the injection temperature was greater than 50°, the maximum rate of the pump was reduced to 22 gpm (122 Metric tons/day) due to the BTU limit of the heater. The CO_2 pump can provide injection pressures in a range from 10 psig to 5000 psig. The wellhead pressures usually determine the flow rate. In this case, the pressures were not expected to limit the planned rate until possibly the later stages of the project. The on-site operator can increase or decrease the flow rate by changing the speed of the triplex pump. Praxair planned to set an alarm and automatic shut-down pressure at set points below the maximum allowable surface injection pressures for the wells.

The heater on the Praxair trailer required propane for fuel. The project team signed a contract with Ferrellgas to provide two 1,000-gallon propane tanks, a 1" fuel line from a manifold at the tanks to Praxair's inlet fuel connection valve, and routine deliveries. Propane usage and a delivery schedule were to be determined after injection started due to the possible wide range of consumption depending on the injection parameters. The usage rate of propane was dependent on the injection rate, surface pressure and desired temperature required during the pumping operation. The planned injection rate was 50 – 60 tons per day. The initial surface pressure was approximately 75 psig that was expected to reach more than 800 psig over the duration of the project. The initial injection temperatures were planned to be 60° - 80° F and gradually reduced over the first several months but remaining above 30° F. Thus, Praxair did not expect to use more than 300 gallons per day. Praxair burned 58,095 gallons of propane over 315 days of injection operations. This resulted in a usage rate of 184.4 gallons per day. The total cost of the propane for the project was $69,746.

The project team decided it would be more economical to power the CO_2 pumping unit with electricity instead of diesel. This also eliminated the need for additional truck traffic to deliver diesel on a routine basis. The CO_2 pumping unit required 460 V, 3-phase power which was not initially present on the site. The host company for this project, CNX Gas, agreed to install new power lines to the site through a cost-share donation. Its contractor, Hi-line Electrical Company, installed new wires and power poles to deliver this voltage to a junction box near the pump trailer. Primary Energy made the final connection between the junction box and the pumping unit electrical panel.

Praxair instruments recorded pump discharge pressure, CO_2 temperature at pump discharge and flow rate data on a continuous basis. Praxair's computer system captured this data and the recording devices were also tied into the project's data capture system. Praxair was capable of generating a daily report for the project team if necessary.

Reliability of the CO_2 pump was not expected to be an issue based on Praxair's experience. This is a very robust unit that rarely fails. Praxair indicated it may need to shut down every ten days for a couple of hours for routine maintenance. This maintenance could also be accomplished during periods when

injection may be suspended due to testing by the project team or maintenance on equipment on the skid.

Praxair personnel were on location 24/7 during injection operations. This ensured security of equipment, daily supervision to ensure there were no leaks or equipment failures, product transfers were completed safely, and personnel regularly available to check on the operation of the project team's equipment and data communications.

Pressure, Temperature, and Rate Constraints

The United States Environmental Protection Agency's (EPA) Region III office in Philadelphia has authority over injection operations in Virginia and required a Class II Underground Injection Control (UIC) permit for enhanced recovery type wells. As part of the permitting process, the applicant must request allowable injection pressure and flow rate limits for each well. Because the proposed injection wells were active production wells that were previously hydraulically fracture stimulated, a review and study of the fracture treatment pressure for each stage of completion was required by the EPA. The EPA will not approve permits that request an injection pressure that will exceed the bottom-hole fracture treatment pressure. There were no constraints related to temperature in this permit, so this section will only discuss pressure and rate constraints.

The project team acquired completion stimulation data from CNX Gas for the three wells slated to become injection wells and many wells surrounding these. The initial evaluation consisted of a review of breakdown pressures and the various depths of the fracture treatment stages. The breakdown pressure is the surface-recorded pressure necessary to crack or break the rock and initiate a fracture. Fracture treatments are conducted in stages that occur at different depths. A single stage typically covers three to four coal seams that are near each other. The first stage occurs at the lowermost coals, the second stage at the next set of coals moving up the wellbore, and so on until the last stage is pumped. In this project, the DD-7 well was stimulated in four stages while the DD-7A and DD-8 wells were done in three stages each. Using the breakdown pressure, average depth of the coals in each stage, and the density for the type of fluid in the hole used for breakdown, a bottom hole fracture pressure was determined. This was assumed to be the maximum allowable bottom hole pressure. From that pressure, a maximum surface injection pressure was back calculated assuming the wellbore was full of liquid CO_2. This procedure was reviewed and discussed with personnel from the Region III office. The personnel indicated that the EPA-preferred method of determining the maximum bottom hole pressure is to start with the instantaneous shut-in pressure (ISIP) instead of the breakdown pressure. They believed this to be a better indicator for calculating bottom hole pressures.

The ISIP is determined immediately upon shut down of the pressure pumps used to hydraulically breakdown the formation. As soon as the pumps are turned off, the frac engineer records the instantaneous pressure at the wellhead. Beginning with the ISIP and using the average depth of the coals in each stage along with the density of the type of fluid used for breakdown, the maximum

allowable bottom hole pressure is calculated. A maximum allowable surface injection pressure is then back calculated assuming the wellbore is full of liquid CO_2.

The table that can be found in Appendix G shows the data and calculated values that was submitted to the EPA as part of the permit application to obtain the maximum allowable injection pressures for each well. An analysis and calculation were made for each stage in each well. All the wells were fracture stimulated with a 75-quality foam mixture. This means that 75% of the fluid was nitrogen and 25% was fresh water which formed the foam mixture. Thus, the hydrostatic pressure from 25% of the density of fresh water filling the wellbore from the surface to the depth of the coal seam was calculated and then added to the ISIP value. The result is the maximum bottom hole injection pressure for that stage. The EPA requires the operator to limit injection pressures at that value so that new fractures are not created. From that value, a surface injection pressure is then calculated.

To calculate the maximum allowable wellhead surface injection pressure, the EPA assumes the wellbore is filled with liquid CO_2. This would create the worst-case scenario as higher density liquid CO_2 creates greater hydrostatic pressure than gaseous CO_2. As the reservoir pressure increases from inception of gaseous CO_2 injection, the CO_2 phase will become denser and gradually change to a liquid phase. The density of CO_2 is pressure and temperature dependent. The density values used in the table were determined from the modeling conducted to determine adequate pipeline sizing.

A proxy was required for two ISIP values in the calculations. The well completion data did not include an ISIP value for the first stage in DD-7 and the third stage in DD-8. For each case, data was obtained from nearby offset wells that had the same coals treated in a stage. The EPA initially requested that we use the lowest ISIP value to calculate pressure. The project team agreed to this for the DD-7 well but not the DD-8 well. All the nearby wells used in the DD-8 analysis were direct offsets and three of the four were infill wells. The project team believed the ISIP values were negatively affected in the infill wells because a large volume of gas had been produced from these areas. Thus, the reservoir pressure was much lower when these wells were completed than the initial reservoir pressure. The project team explained this to the EPA and requested that the average value be used. The use of the average value was approved.

The calculated pressures for each stage in each well were then compared and the stage with the lowest bottom hole and wellhead pressures was determined to be the limiting factor for that well. Therefore, based on this analysis, the EPA approved the injection pressures shown in Table 9-50.

Table 9-50 EPA Maximum Allowable Injection Pressures

	DD-7	DD-7A	DD-8
Maximum Wellhead Pressure (psig)	852	943	1153
Maximum Bottom Hole Pressure (psig)	1583	1262	1535

The rate constraint in the UIC permit is 50 metric tons per day per injection well. This was the rate requested by the project team in the permit application.

Practical Constraints

The wellhead pressures in these partially depleted CBM wells were approximately 75 psig when the injection operations began. Since the CO_2 storage tank pressure was 275 psig, it was necessary to choke the flow of CO_2 at the pressure control valve until the reservoir pressure increased to this value. The Praxair pumping unit, as previously mentioned, can pump up the CO_2 delivery pressure to 5000 psig. So, from a practical point of view, we were not really constrained. Therefore, the constraint was from the UIC permit.

The project team along with the host company, CNX Gas, decided to keep injection temperatures above 32° F throughout the project. This required the CO_2 to be heated after it came out of the storage vessel at -10° F. Praxair's heating unit could raise the CO_2 temperature to 180° F if desired. However, the project team wanted to constrain the temperature to 60° - 80° F during the first month of operations. After that, the temperature was to be decreased to approximately 40° F.

The rate constraint was based on logistics and the project goal to inject 20,000 metric tons of CO_2 in one year. On a daily basis, this total volume equaled a rate of 54 metric tons per day. A CO_2 transport trailer can haul approximately 20 U.S. tons (18 metric tons) which would require three deliveries per day. Praxair's plan was to deliver three to four transports per day to meet this rate. As previously stated, there were three 60-ton storage vessels on location and off-site nearby. The extra transport each day allowed the storage to remain full so that no deliveries were required on the weekends.

Trucking of CO_2

Praxair moved the CO_2 pump trailer on the DD-7 site on June 22, 2015. Three 60-ton CO_2 storage vessels were delivered and spotted in place over the next two days. Praxair asked the project team to locate and secure a satellite location for its use to transfer product deliveries. Praxair also parked three 60-ton storage vessels at the satellite site to facilitate transfers. The plan called for Praxair or its contract carrier, Genox, over-the-road drivers to deliver and drop off full, 20-ton transport trailers at the satellite site and return to the CO_2 plant with an empty transport. Since the injection test objective was to pump 20,000 metric tons, approximately 1,100 transport trailer deliveries would have been required to accomplish this goal. Ultimately there were 703 transport deliveries to the project storage vessels. While the state routes and lease roads remained free of ice and snow, local Praxair or Genox drivers would then shuttle the transport trailer to and from the injection site. In the event of inclement weather when it was unsafe for a tractor trailer to travel to the injection site, product was transferred into a 60-ton storage vessel. A 12-ton short-base bobtail delivery truck would then load product from the storage vessel for delivery to the site.

The project team secured two satellite sites for Praxair's transfers over the duration of the injection operations. The first was located along route 460 and 9.5 miles from Vansant. Noah Horn Well Drilling Company allowed use of its rig yard for the storage and transfers to occur. This site was utilized from inception through January 2016. To reduce distance and travel time to shuttle product to the injection site, the project team searched for and discovered a large, open lot approximately 2 miles from Vansant. An agreement was reached with Torque Enterprises to use this lot from February 2016 through February 2017. This helped to reduce transportation costs for product delivery.

Health & Safety

CNX Safety—PPE/Training

This project was made possible through CNX Gas Company by contributing three CBM production wells, sites to drill monitor wells, and access to adjacent CBM production wells for testing, sampling and monitoring. As a result, the project team would be traveling on CNX Gas lease roads and working on its well sites. Therefore, under CNX Gas company policy, it is mandatory that anyone working on this project undergo CNX Gas safety training each calendar year and adhere to the safety rules.

The training program consists of a safety class to review CNX Gas safety documents which include Hazard Training for Gas Operations, Gas Operations Conduct Rules, and Environmental Training. The Hazard Training document provides fifty-five safety rules for review and discussion. The Conduct Rules outlines eleven rules of unacceptable behavior while working on a CNX Gas site. The Environmental Training document identifies eight ways to handle fluids and potential spills on-site. Two safety training videos are also required to be viewed in class. One video provides Hazard Training and the other teaches Environmental Compliance Training. After the videos and documents are reviewed, Hazard Training and Environmental Compliance Training quizzes are given to all participants in class. Each participant who passes is given a CNX Gas safety training sticker that indicates hazard and environmental training has been completed. The sticker is to be placed on a hard hat. The recipient of training also receives a Certificate of Training that should be carried with them when on a CNX Gas site.

Personal Protective Equipment (PPE) consisting of hard hat, safety glasses, flame-retardant clothing, metatarsal, steel-toe safety boots and metacarpal gloves are required at all times when on CNX Gas property. The project property is accessed by narrow lease roads. A CB radio is required for all vehicles traversing the property. The driver is expected to call for the road before entering by using the call letters that are identified on road signs. A hazard light should be placed on the vehicle and the lease road speed limit of 15 mph should be followed.

<u>Gas Sensors</u>

CNX Gas safety personnel requested that the project team install a gas sensor on the DD-7 injection site near the Praxair propane-fired heater. This sensor would be used to detect any CBM gas from a potential pipeline leak or propane gas from a potential tank leak. Both potential sources were approximately 150' away from the heating unit. A Millennium II Multi-Channel Transmitter by Emerson

Process Management was installed on the heating skid near the propane heater. The gas sensor output was hard-wired to the heater and configured to automatically shut down the heater if any gas were detected.

Overland CO_2 Tankers—Escorts

After leaving the main four-lane highway, Route 460 at Vansant, Virginia, the tractor-trailer loads of CO_2 traveled over two-lane state routes and a single lane lease road to the storage tanks on the DD-7 well location. The trucks had to travel approximately 3.5 miles on state route 620 and then 2.2 miles on state route 657 to the lease road. These routes were narrow with several blind curves and switchbacks. Therefore, to ensure highway safety, a pilot car was used to lead the product delivery over these roads. The pilot car continued to escort the trailers on the lease road to the storage tanks to avoid any issues with water trucks or well tenders working on the property. The pilot car escorted the trailers back to the main highway after completing the delivery.

9.6.2 Permitting

CNX Gas donated three CBM production wells, DD-7, DD-7A and DD-8 to the project to be converted to CO_2 injection wells. The wells are in the Hurricane District in the Vansant quad of Buchanan County and are part of the Oakwood CBM field.

There were several permits required to convert the production wells and to operate them as injection wells. Initially, an UIC permit was sought from the EPA for the three wells. EPA form 7520-6, UIC Permit Application, and section XIII attachments were submitted to the EPA on February 22, 2013. A Class II-R area-wide permit was requested for the project. A Class II permit is for oil and gas production and storage related injection wells, and type R is an enhanced recovery well. This permit application is attached in Appendix G. The attachments in section XIII of the application provide all the details of the injection wells and the proposed injection operations plan.

The EPA sent a Notice of Deficiency (NOD) letter on April 3, 2013 requesting additional data and clarification of certain statements in the permit application. This NOD was addressed by MM&A on May 7. The EPA sent a Statement of Basis (SOB) which approved a draft permit on August 21. After discussions with EPA personnel regarding the maximum allowable bottom hole injection pressure approved in the SOB for the DD-8 well, MM&A sent a letter with additional data on September 13 requesting a revised pressure. The public comment period was extended an additional thirty days due to this request. The EPA approved and granted an operating permit with the revised pressure on December 19, 2013. This permit is attached in Appendix G.

Lastly, the EPA required the submission of completion reports, form 7520-10, and the results of the mechanical integrity tests (MIT) for the wells before issuing a final approval to commence operations. The MIT were successfully completed over three days in mid-April 2015 and the completion reports

were submitted on April 27, 2015. The EPA issued a formal letter authorizing commencement of injection operations on May 1, 2015. All of these documents are attached in Appendix G.

A final condition of permitting, once the injection operations commenced, was the requirement to submit annual injection reports under form 7520-11. These completed forms for 2015 – 2017 are attached in Appendix G – Annulus Report.

Transfer permits were required by the DGO to change the operating company name from CNX Gas to MM&A. MM&A processed the paperwork for these permits in July and August of 2014. The DGO approved the transfers in late August. The transfer permits are attached in Appendix G – DGO Transfer Permits.

The DGO required a permit supplement to build new 2" CO_2 pipelines from the DD-7 location to the DD-7A and DD-8 wells since the pipelines were being installed in the same, originally permitted right-of-way. These supplemental permit applications were filed on August 21 and September 2 in 2014 for the DD-8 and DD-7A wells, respectively. The DGO approved the permits on September 17, 2014.

Finally, a permit modification was required by the DGO to change the operating status of each well from a production to injection well. The modified well bore configuration and permit application was submitted to the DGO on August 22, 2014. These permits were approved and issued on January 21, 2015 for the DD-7A and DD-8 wells, and on February 4, 2015 for the DD-7 well. The modified permits are in Appendix G – DGO Modification Permits.

At the conclusion of the project, the three injection wells were converted back to production wells and returned to CNX Gas. The M-2 well was also returned to CNX Gas for them to complete as a production well. CNX Gas submitted applications to the DGO for each of these wells to transfer the operating permits to them. Upon transfer, MM&A notified the EPA that the wells reverted to production wells and this terminated the UIC permit.

9.6.3 CO2 Procurement

Praxair Services, Inc. ("Praxair") of The Woodlands, Texas received the award to provide the CO2 supply, delivery, storage and pumping operations after submitting a proposal to Virginia Tech. Three 60-ton CO2 storage vessels were positioned on-site to receive daily deliveries of product. Three other 60-ton CO2 storage vessels were set at a satellite location within 10 miles of the project site to facilitate additional deliveries of product. Praxair procured the carbon dioxide from its commercial facility in Marmet, West Virginia. An injection skid, propane-fired heater and crew living quarters were also provided by the company. The monthly equipment rental and operations charge for the equipment on the injection site was $47,000 with mobilization and demobilization charges of $24,693 each time. The monthly rental for the vessels at the satellite storage location was $4,500 with mobilization and demobilization charges of $9,287 each time. Liquid carbon dioxide was delivered to the test site for

$89.90/ton. There was also a delivery charge of $160 per hour when transferring product from the satellite location to the site. The delivery time was approximately three hours.

9.6.4 CO2 Injection Operations

Injection operations commenced in the DD-7A well on July 6, 2015 and on July 8 in the DD-7 and DD-8 wells. Injection continued a regular basis until September 19, 2015. At that time, Praxair's Marmet plant had a maintenance outage and could not supply product to the project. The wells were shut-in, and operations were temporarily suspended until injection resumed on October 2, 2015. Injection operations ran relatively smoothly until April 16, 2016 when the wells were shut-in again. There were multiple issues which caused the operations to be suspended until December 13, 2016 including product availability and project funding. During this period, the project team was unable to purchase product from Praxair. Once funding and product availabilitu was restored, injection started up again and continued until January 29, 2017. The field injection operations were completed on that day and post-injection monitoring began. In total, the actual number of days injected into the DD-7, DD-7A, and DD-8 wells were 285, 303, and 315, respectively.

Phase I of the injection test was conducted from July 2, 2015 to April 15, 2016 where a total of 10,601 tons of CO2 was injected. Phase II of the injection was conducted from December 14, 2016 to January 30, 2017 where an additional 2,662 tons of CO2 was injected, for a total of 13,263 total tons of CO2 injected.

All three injection wells behaved very similarly with respect to pressure, injection rate, and cumulative volume of CO_2 injected. The three data series plots for these parameters in each well basically had the same shape throughout the project. The plots can be seen in (Figure 9-102 and Appendix I). The CO_2 was discharged from the CO_2 pump into a header pipe and the CO_2 allowed to flow freely to any well. The pressure in each well dictated how much flow the well could handle.

Data for injection rates and pressures are plotted beyond the end of injection operations in order to observe the pressure fall-off response observed at the injection wellheads. A reservoir injectivity parameter is calculated as the injection rate divided by the injection pressure (Pashin et al., 2015). By this measure, the slopes of the decline curves may be interpreted as indicators of relative permeability. Pressure fall-off following the end of injection operations suggests injectivity for the reservoir is restored during the soaking phase. Injection temperatures decrease steadily at the start of Phase I for most of the injection test, but level out and rise slightly over the last few months. This rise correlates with a steady increase to high injection pressures and marks a transition from gas- to liquid-phase CO2, as shown in Figures 9-106 and 9-107.

Figure 9-102 CO2 Injection Rates by Well

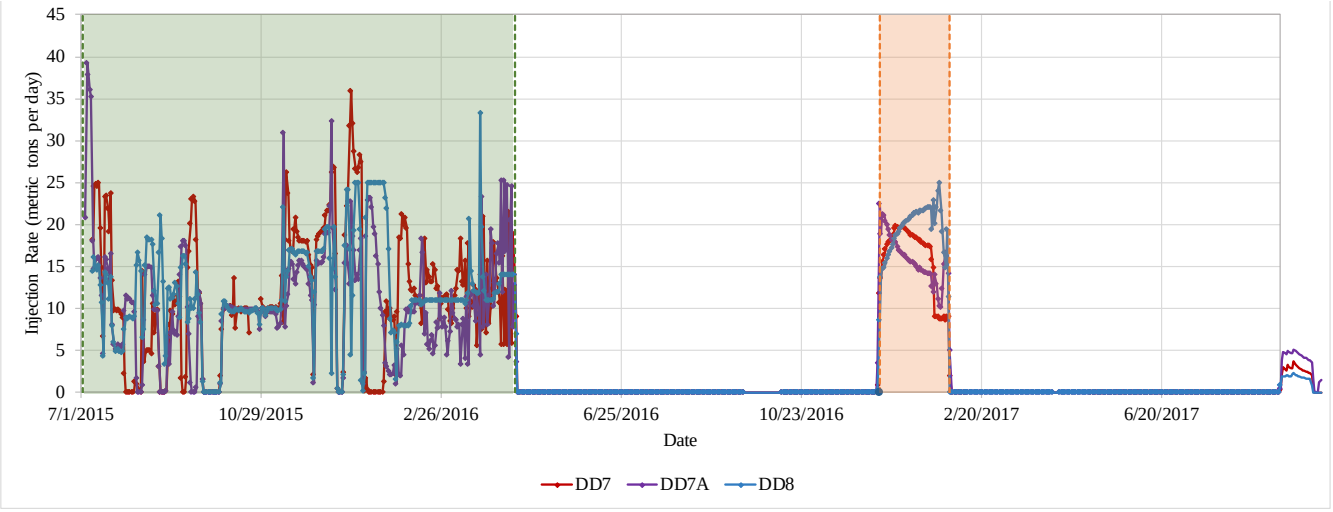


Figure 9-103 CO2 Injection Pressure by Well

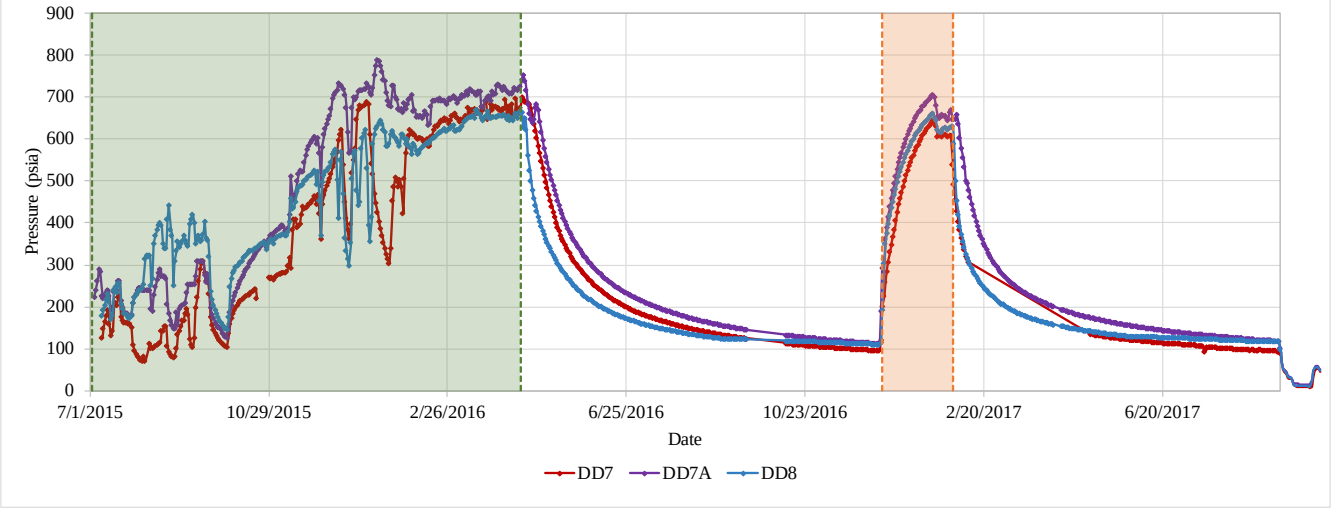


Figure 9-104 CO2 Injection Temperature by Well

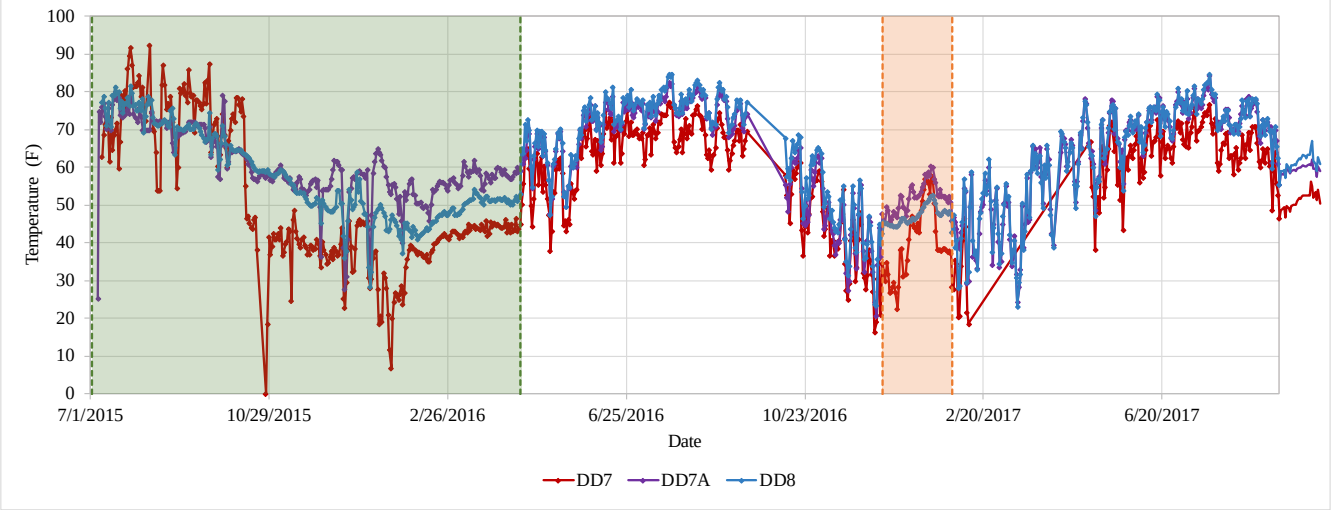


Figure 9-105 CO2 Injectivity by Well

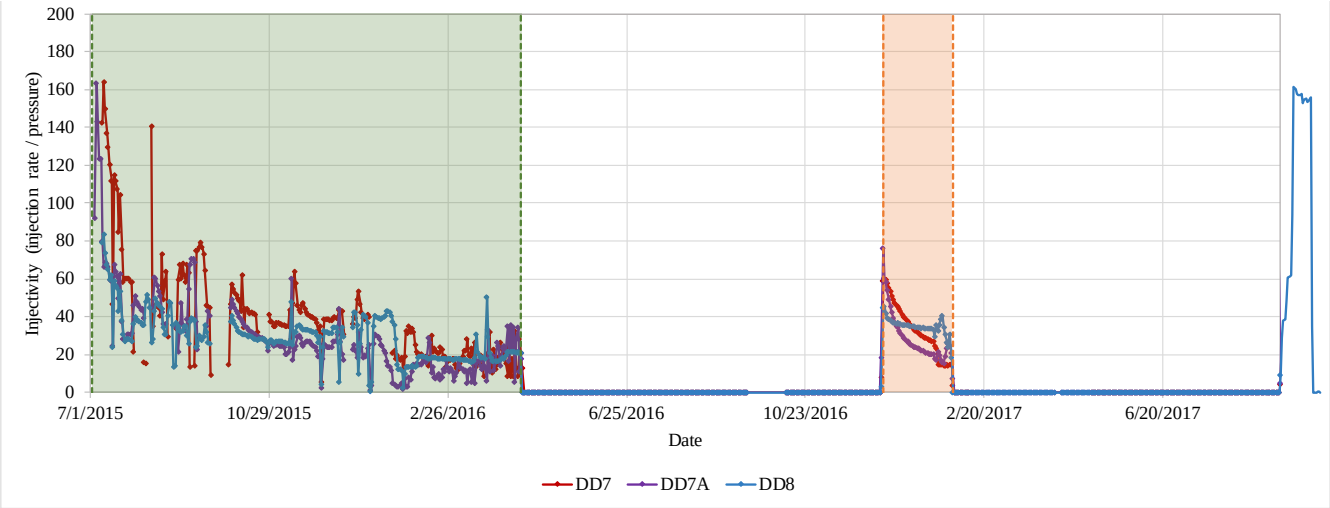


Figure 9-106 CO2 Injection Phase Diagram: Phase I

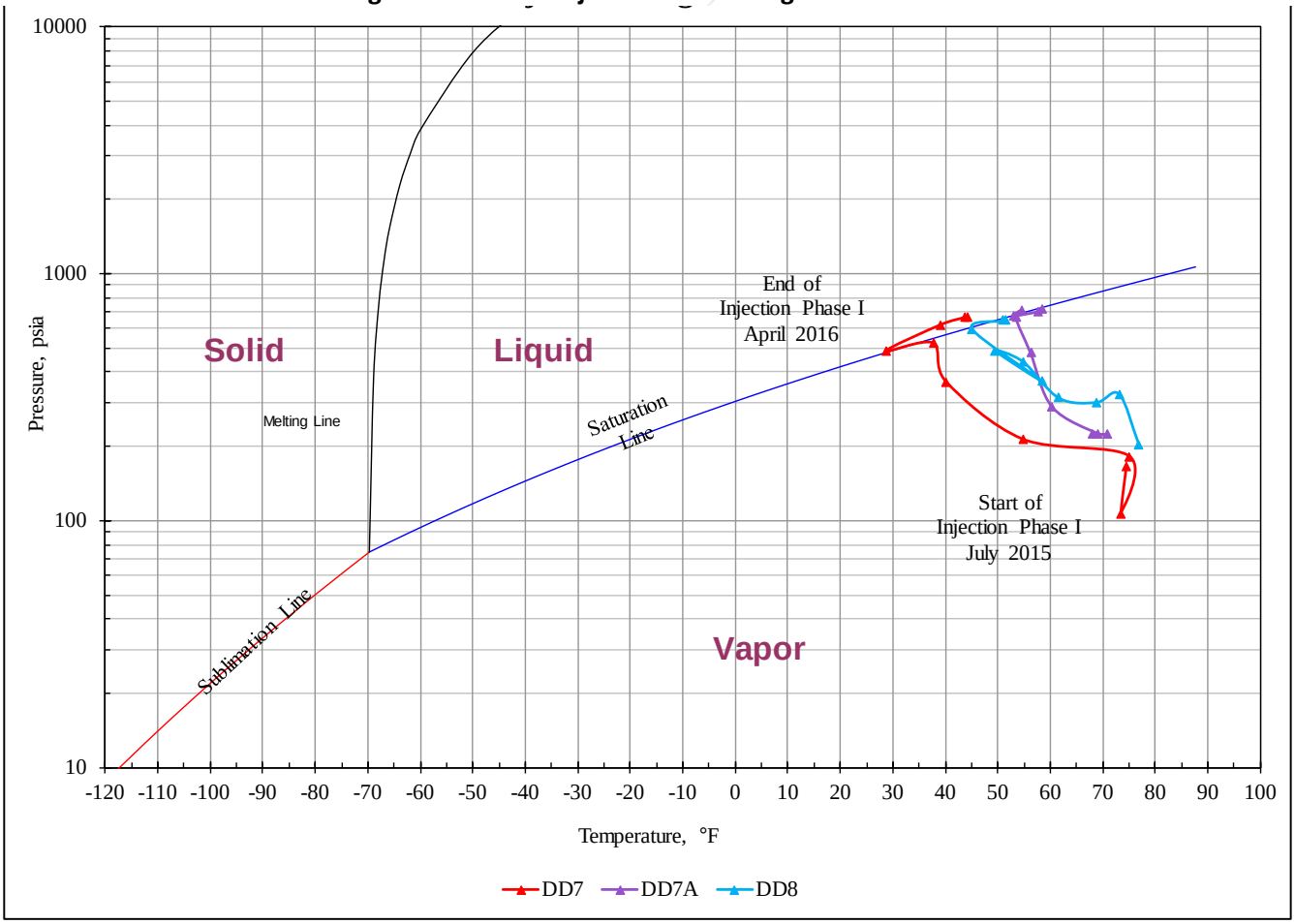
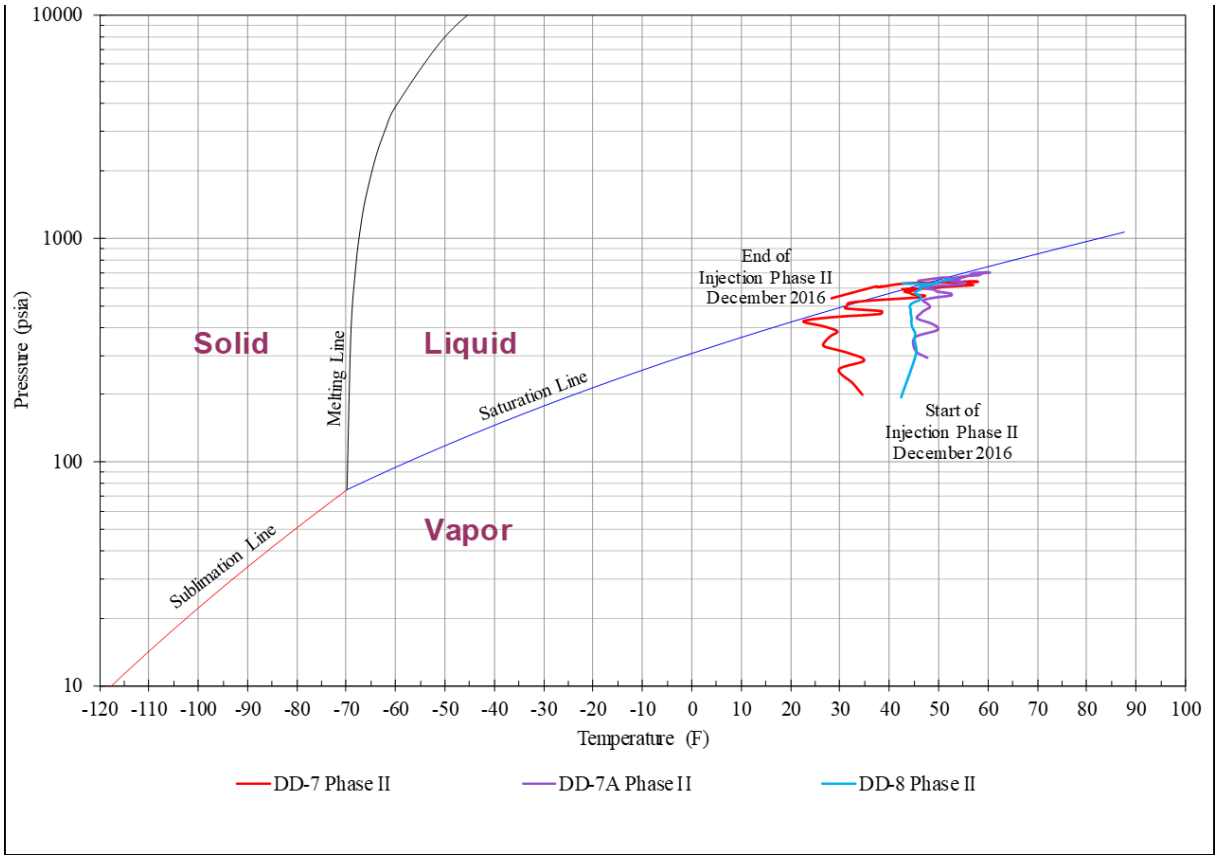


Figure 9-107 CO2 Injection Phase Diagram: Phase II



The DD-7 well has the largest amount of depletion among the three wells at 407 MMcf gas produced, followed by the DD-8 and DD-7A wells at 232 MMcf and 90 MMcf of gas produced, respectfully. When comparing the performance of the injection in these wells, more CO_2 was injected in the DD-7 well and at consistently lower pressures than in the DD-7A well. This is to be expected based on depletion. The same holds true when comparing the DD-8 well to the DD-7A well. However, during three of the initial four months, the DD-8 injection pressure was higher than that in DD-7A because of higher injection rates in the well. After that, the pressure in DD-8 was consistently lower. The DD-7 and DD-8 wells compared to each other were very closely aligned. The injection pressure in DD-8 was generally, slightly higher, but the pressures and volumes tracked closely for most of the project. Ultimately, more CO_2 was injected in the DD-8 well, but that is because it realized 25 more actual days of injection. From a volume standpoint, it appears that more CO_2 would have been injected in the DD-7 well as compared to DD-8 if average injection rates were assumed for those 25 days. The tables 9-51 through 9-53 below show the data for injection pressures, rates, and volumes.

Table 9-51 DD-7

2015	Average Injection Pressure (PSIG)	Monthly CO_2 Metric Tons (Mt)	Average Injection Rate (Mt/D)	Cumulative CO_2 Metric Tons (Mt)
July	169	354	14.75	354
August	121	116	3.74	470
September	229	237	7.90	707
October	216	296	9.55	1,003
November	365	455	15.17	1,458
December	542	564	18.19	2,022
2016				
January	540	250	8.06	2,272
February	620	383	13.21	2,655
March	658	367	11.84	3,022
April	673	194	12.13	3,216
May	0	0	0.00	3,216
June	0	0	0.00	3,216
July	0	0	0.00	3,216
August	0	0	0.00	3,216
September	0	0	0.00	3,216
October	0	0	0.00	3,216
November	0	0	0.00	3,216
December	373	324	17.05	3,540
2017				
January	604	432	14.40	3,972

Table 9-52 DD-7A

2015	Average Injection Pressure (PSIG)	Monthly CO_2 Metric Tons (Mt)	Average Injection Rate (Mt/D)	Cumulative CO_2 Metric Tons (Mt)
July	217	427	14.23	427
August	234	221	7.13	648
September	253	167	5.57	815
October	295	286	9.23	1,101
November	480	377	12.57	1,478
December	668	422	13.61	1,900
2016				
January	716	320	10.32	2,220
February	677	262	9.03	2,482
March	705	304	9.81	2,786
April	720	251	15.69	3,037
May	0	0	0.00	3,037
June	0	0	0.00	3,037
July	0	0	0.00	3,037
August	0	0	0.00	3,037
September	0	0	0.00	3,037
October	0	0	0.00	3,037
November	0	0	0.00	3,037
December	470	339	17.84	3,376
2017				
January	666	417	13.90	3,793

Table 9-53 DD-8

2015	Average Injection Pressure (PSIG)	Monthly CO_2 Metric Tons (Mt)	Average Injection Rate (Mt/D)	Cumulative CO_2 Metric Tons (Mt)
July	204	237	9.87	237
August	327	394	12.71	631
September	371	224	7.47	855
October	320	285	9.19	1,140
November	442	414	13.80	1,554
December	511	413	13.32	1,967
2016				
January	585	518	16.71	2,485
February	599	303	10.45	2,788
March	648	394	12.71	3,182
April	655	207	12.94	3,389
May	0	0	0.00	3,389
June	0	0	0.00	3,389
July	0	0	0.00	3,389
August	0	0	0.00	3,389
September	0	0	0.00	3,389
October	0	0	0.00	3,389
November	0	0	0.00	3,389
December	437	297	15.63	3,686
2017				
January	627	612	20.40	4,298

The average injection pressure in a well is more a function of cumulative volume injected rather than the injection rate. Of course, as the injection rate is increased the well head pressure increases too. Throughout the project, the average injection rate for each well was generally around 13 metric tons/day. The rates varied at times to as high as 40 to 50 metric tons per day. However, because these rates were not sustained, pressure peaks were created and reduced immediately once the rate was lowered. By looking at the plots, as the cumulative volume rose steadily in each well the injection pressures increased significantly. During a few periods when injection was suspended the pressure dropped off rapidly. Upon resumption of injection, the pressures returned quickly to the previous level.

It should be noted that after the first ten months of injection in each well the slope of the pressure increase became flatter. As pressures approached 650 – 700 psig, the density of the CO_2 starts changing

from gas to a slurry-type mixture of gas-liquid. As pressures continue to rise the CO_2 becomes a liquid phase. This increase in density creates hydrostatic head in the wellbore column which adds pressure to the bottom hole and slows the increase of the surface wellhead pressure. At the end of the project, all the surface wellhead pressures were considerably below the permitted limits of 852 psig, 943 psig, and 1153 psig for the DD-7, DD-7A, and DD-8 wells, respectively.

Throughout the project, Praxair's equipment was extremely reliable. The Praxair technicians typically performed major maintenance on its equipment during project shut downs when no product was being delivered. There was one equipment failure on the injection skid as a processor board that operated the DD-7 control valve malfunctioned. This made the valve inoperable. The vendor sent a new processor board and the valve was returned to service after a five-day outage.

During the winter months, extra road maintenance was required on the lease road to the storage tanks on the DD-7 site to enable routine deliveries of product. Snow removal was occasionally required along with grading the wet, muddy roads caused by precipitation. After grading the roads gravel was spread on certain sections, mainly the hills, to provide traction for the trucks. There were only a limited number of days when a truck could not make a delivery. However, because of the amount of storage capacity on the site, injections operations were not negatively impacted.

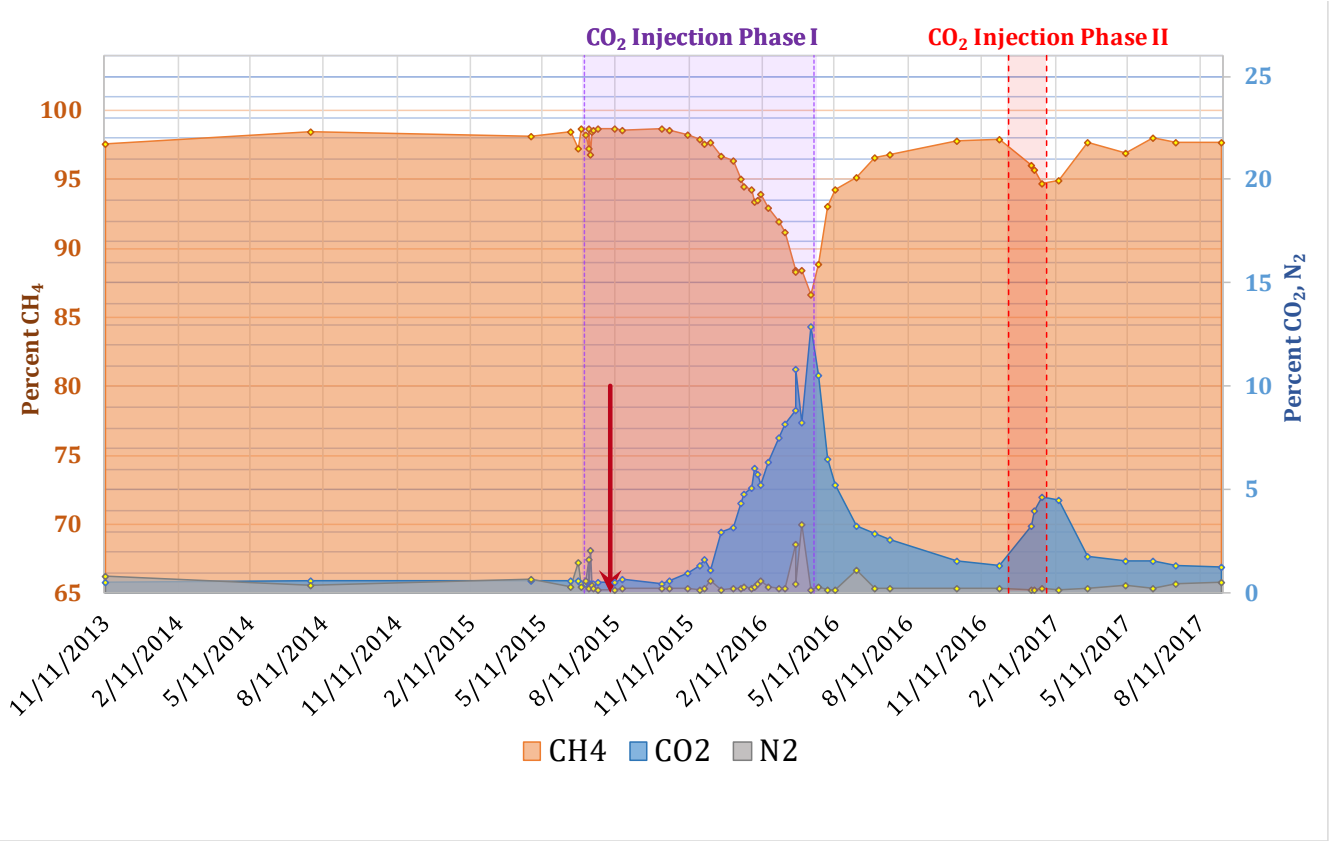
Winter also impacted the pressure readings on the casing annulus on the DD-7A and DD-8 wells. The pressure was recorded by connecting ¼" stainless steel tubing from a valve on the casing to a pressure transducer in the remote terminal unit. When temperatures were below freezing, the water in the lines began to freeze and expand. This caused damage to one of the transducers. The water in the lines was replaced with an oil which eliminated the freezing issue.

9.7 Monitoring Results

9.7.1 Gas composition

Gas composition analysis for samples collected at offset production and monitoring wells shows CO_2 breakthrough at one offset well, DD8A, as shown in Figure 9-108. Computational simulations of CO_2 injection predicted breakthrough at this location. Enhanced coalbed methane recovery (ECBM) was not detected for any wells in the study area.

Figure 9-108 Gas Composition showing CO2 Breakthrough at DD8A



During Phase I injection operations, CO2 composition for DD8A increased from a baseline of less than one percent to 12.9 percent and during Phase II to nearly 5 percent. Breakthrough of CO2 at DD8A was confirmed in fall 2015 and assumed to originate from injection well DD8 due to proximity and reservoir simulations. The increase of CO2 at DD8A was monitored with no adjustments to production of the well or CO2 injection operations because the CO2 composition did not reach impact thresholds for either activity. Gas produced from the DD8A well is comingled with gas from a large number of wells across the study area at a compressor station. The CO2 composition of the comingled gas did not increase significantly because of breakthrough at DD8A and did not affect mechanical equipment at the station, the primary concern of the operator. The peak CO2 composition measured at DD8A, 12.9 percent, equates to approximately three percent of the daily volume of CO2 injected at the time of measurement. By this calculation, CO2 injected for the test was reproduced from DD8A at a maximum rate of 0.30 ton/ day. The amount of CO2 reproduced as a result of breakthrough at DD8A was determined to have a negligible impact on project objectives.

Nitrogen composition increased moderately during CO2 injection operations. Like methane, nitrogen also desorbs from coal in the presence of preferred CO2. The observation of elevated nitrogen composition may be an indication of gas exchange in the reservoir due to preferential adsorption.

9.7.2 Formation water composition

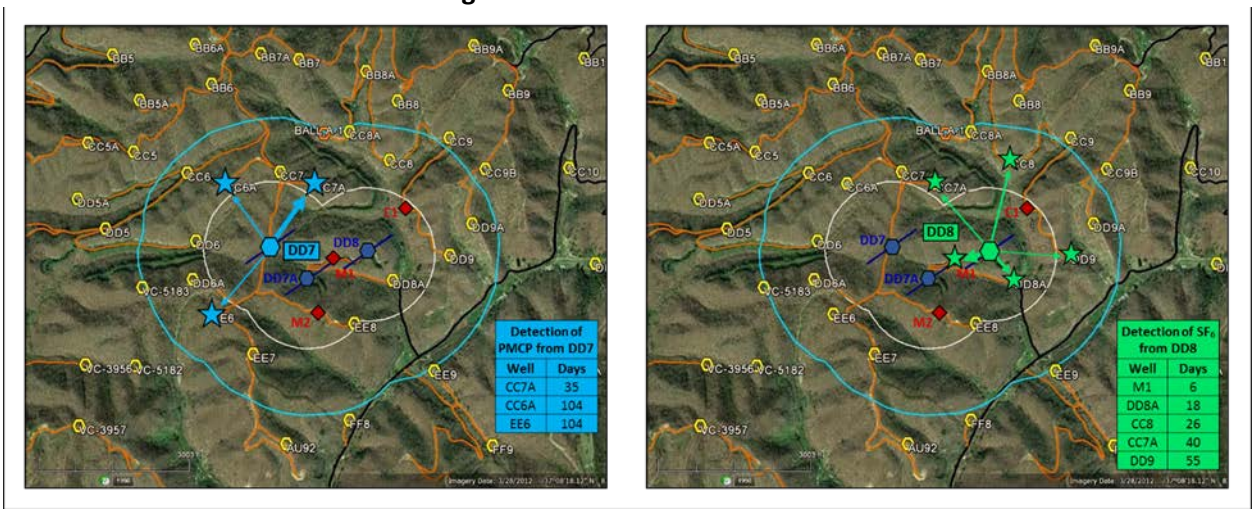
Formation water testing established important baselines for production wells across the study area. Baseline pH values measured in the lab were generally acidic, ranging from 4.07 to 6.87 and averaging 5.51 across the study area. Baseline salinity values were extremely high, ranging from 61‰ to 142‰ and averaging 93‰ across the study area.

Analysis of samples collected during both Phase I and Phase II operations do not indicate an impact to the pH of formation water in the study area. DD8A was selected for a closer preliminary analysis, as the only well with confirmed CO2 breakthrough and impact from CO2-ECBM operations. No impact to pH was detected, but formation water temperature shows a potential correlation with the CO2 injection temperature curve for DD8.

9.7.3 Tracers (gas and liquid)

Gas samples collected at offset production wells and monitoring wells for composition analysis were also analyzed for the presence of tracers. Tracers were deployed at three distinct times during Phase I injection operations, but only two tracers from the first round, deployed at the start of injection, were detected at other wells. A summary of the detection results is shown in Figure 9-109. A perfluorocarbon tracer, PMCP, added to the water in the DD7 wellbore shortly before the start of injection, was detected in gas samples from three offset production wells. Additionally, SF6 added to the CO2 stream of DD8 was detected at 5 wells. Arrow thickness in Figure 9-109 corresponds to the approximate travel time to the well, estimated by the number of days between tracer deployment and detection. It is possible that these or other tracers did reach offset wells without detection due to sampling outside the specific time window for detection.

Figure 9-109 Tracer Detection Results



It is possible that the PMCP added to the water of DD7 evaporated out of phase while still sitting in the DD7 wellbore prior to injection and/or in the offset wellbores where the tracer was detected in gas samples. The tracer was detected at azimuths from DD7 that could be related to one or multiple factors.

DD7 is located on the flank of a NE-SW trending anticline, and the three azimuths are all structurally updip from DD7. Detection at these azimuths could relate to enhanced permeability and conventional, updip fluid migration on the anticline. Additionally, CC7A and EE6 are approximately aligned with the hydraulic fracture direction. Another factor may be pressure interference from injection at the other wells that affects CO2 migration in regions of overlap. The detection of SF6 from DD8 at M1 contradicts this suggestion. However, detection at M1 occurred very early during CO2 injection operations, only 6 days after the start of injection in DD8, when pressures had not increased significantly. Pressure interference could become a factor for higher injection pressures or for increased distances within regions of overlap.

The five offset wells where SF6 from DD8 was detected represent varying azimuths. The number of days between tracer deployment and detection is low for very close offset locations at M1 and DD8A, but the correlation between distance and detection time is not consistent for farther offset locations.

9.7.4 Borehole liquid level measurement

Liquid levels in the injection wellbores, calculated using an Echometer, measured the gradual evacuation of water from the wellbore into the formation due to CO2 injection. Prior to the start of injection operations, the standing water columns in the wellbores were approximately 500 feet for DD7, 300 feet for DD7A, and 250 feet for DD8. At the start of CO2 injection, the water level in DD7 dropped rapidly and was completely displaced from the wellbore within one week. For DD7A and DD8, the water level increased slightly before slowly declining and evacuated the wellbores completely within four months.

The difference in the response of the formation water to CO2 injection is likely due to geologic structure. DD7 is located on the flank of the Hurricane Creek anticline, and DD7A and DD8 are located down-dip, approaching the Hurricane Creek syncline. Production history for wells on these structures shows a trend of relatively high water production for wells on the syncline and low production for wells on the anticline (Gilliland et al., 2013). The trend demonstrates localized conventional behavior for formation water on the structures. Water from DD7 was likely pushed down-dip, consistent with observed conventional behavior, and may have contributed to the brief rise in water levels at DD7A and DD8 before their decline. However, enhanced permeability may have assisted rapid water migration in a wide range of azimuths.

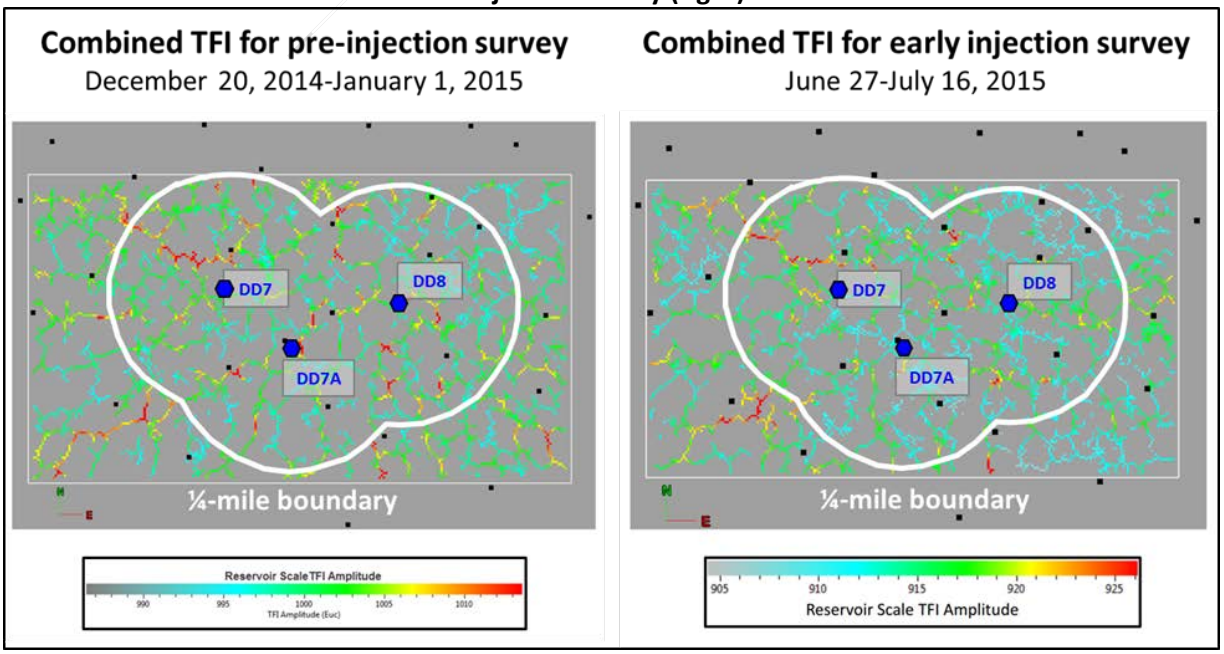
9.7.5 Microseismic monitoring array

Continuously-recorded passive microseismic data were processed in two ways: 1) to identify traditional micro-earthquakes (MEQs) and locate their hypocenters, and 2) to generate coherence volumes and interpret fracture networks using Tomographic Fracture Imaging SM (TFI). No MEQs were detected during the pre-injection survey (December 20, 2014-January 1, 2015) or during the early injection period (June 27-July 16, 2015). Coherence volumes are generated using Streaming Depth Imaging (SDI), a variation of seismic emission tomography. SDI sums total trace energy from all stations for all voxels

in a discretized model over defined time steps. Stacking the incremental time steps over a day of recording produces a coherence volume which provides a relative measure acoustic energy levels distributed throughout the reservoir model. Coherence volumes can be further processed using TFI to interpret fracture networks.

TFI volumes were generated for each day of each survey. Daily TFI volumes were synthesized into combined TFI volumes for the pre-injection survey and the early injection survey, as shown in Figure 9-110. Note that the early injection recording period began five days prior to the start of injection. Results from these pre-injection days and days of staggered initial injection operations are included in the combined TFI volume. The white 1/4-mile boundary indicating the MVA focus area also represents the area of optimized array aperture for imaging. Note that the range of time-normalized amplitude values is generated uniquely for each processed volume, and the scales are not comparable between volumes. The color scale is an accurate relative measure of acoustic energy within the volume for the processed time period. Combined TFI volumes for pre-injection and early injection surveys show similarities in the distribution and density of fractures throughout the reservoir. The volumes also show similar distributions of acoustic energy, indicated by amplitude, including hotspots of high activity on the western margin of study area, approaching the Hurricane Creek anticline. The similarities in TFI results for the two surveys suggest that the same fracture networks are activated during ambient pre-injection conditions (including production from the injection wells) and during early CO2 injection operations. SDI and TFI processing were conducted by Global Geophysical Services.

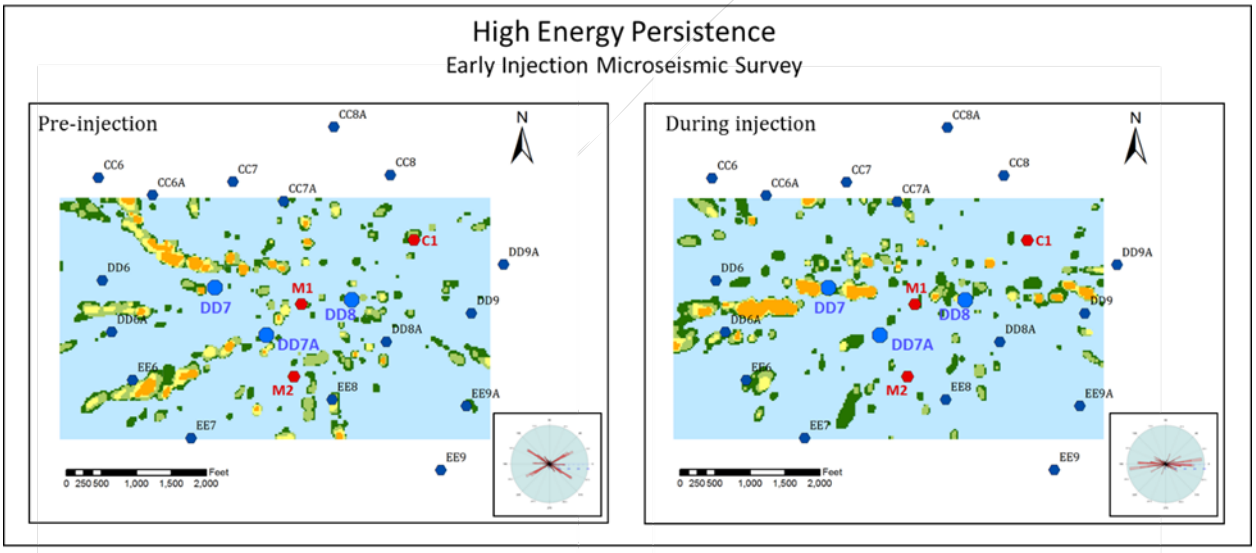
Figure 9-110 Reservoir-depth slices through combined TFI volumes for pre-injection survey (left) and early injection survey (right).



Daily coherence volumes generated for the early injection survey were used for a close examination of geostatistical trends in acoustic energy distribution. Characterizing the regions of highest energy was

a priority because induced activity from CO2 injection operations is likely to generate large signals relative to ambient activity. A subset of four volumes corresponding to pre-injection days in June 2015 was compared to a subset of four volumes corresponding to the last four days of early injection recording in mid-July. For each subset, the lateral distribution of the highest one percent of acoustic energy, representing the distribution of the highest activity, was determined for all volumes. The distribution of high energy was then evaluated within each subset for persistence over time. A comparison of the persistence of the highest energy over time (maximum of four days) for the pre-injection and during-injection coherence volumes is shown in Figure9-111. The comparison shows that the distribution of energy for the pre-injection subset is consistent for all days, the distribution of energy for the during-injection subset is consistent for all days, and the two distributions are different from each other.

Figure 9-111 Persistence of the lateral distribution of high acoustic energy recorded pre-injection (left) and during injection (right) for the early injection microseismic survey.



For both subsets, acoustic energy is generally higher on the western margin of the study area, which is consistent with the TFI results. The pre-injection result shows high energy "streaks" at two dominant orientations of approximately N055E-N060E, which aligns with the hydraulic fracture direction, and approximately N120E. The during-injection result shows a consistent reorganization of energy to an orientation of approximately N085E-N090E. Additionally, the during-injection result shows persistent, deep-focusing hotspots of high energy near DD7 that are present pre-injection and are likely due to water evacuating the DD7 wellbore in the early days of CO2 injection operations.

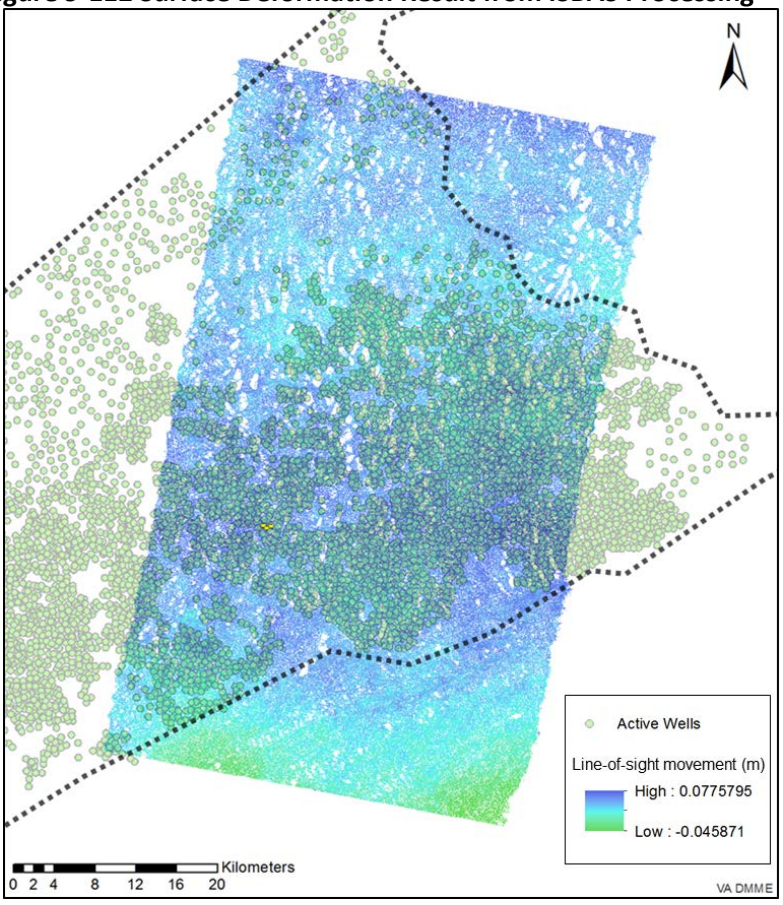
9.7.6 Surface deformation

Coal swelling due to CO2 adsorption could produce measurable uplift of the ground surface at the CO2-ECBM test site in Buchanan County, Virginia. However, the steep, variable terrain and forestation across the study area present challenges for surface deformation measurement technologies, which rely on physical access to surface locations or satellite line-of-sight.

A recently developed technique for processing SAR imagery acquired by satellite has demonstrated improvements in measuring surface deformation over large areal extents in variable terrain. The intermittent small baseline subset (ISBAS) method can calculate elevation changes at more locations within an imaged scene than traditional techniques by incorporating data from intermittently coherent reflectors (Bateson et al., 2015). ISBAS provides a more complete deformation solution across the scene extents compared to traditional processing but, like all interferometric methods, requires a large data stack for accurate results.

The result of ISBAS processing of satellite radar imagery over the CO2-ECBM study area is shown in Figure 9-112 and compared to the footprint of CBM operations in the Southwest Virginia coalfield. The locations of the three injection wells are indicated in yellow. The ISBAS result represents line-of-sight movement toward or away from the satellite, indicated respectively as “high” or “low,” over the acquisition period of approximately one year. This measure is a proxy for surface deformation. The preliminary ISBAS result was generated with a small data stack of 30 images. ISBAS processing was conducted by Geomatic Ventures Ltd.

Figure 9-112 Surface Deformation Result from ISBAS Processing



The preliminary result over the CO2-ECBM study area does not show a significant change relative to the surrounding region. The larger scene extents show a potential correlation between surface

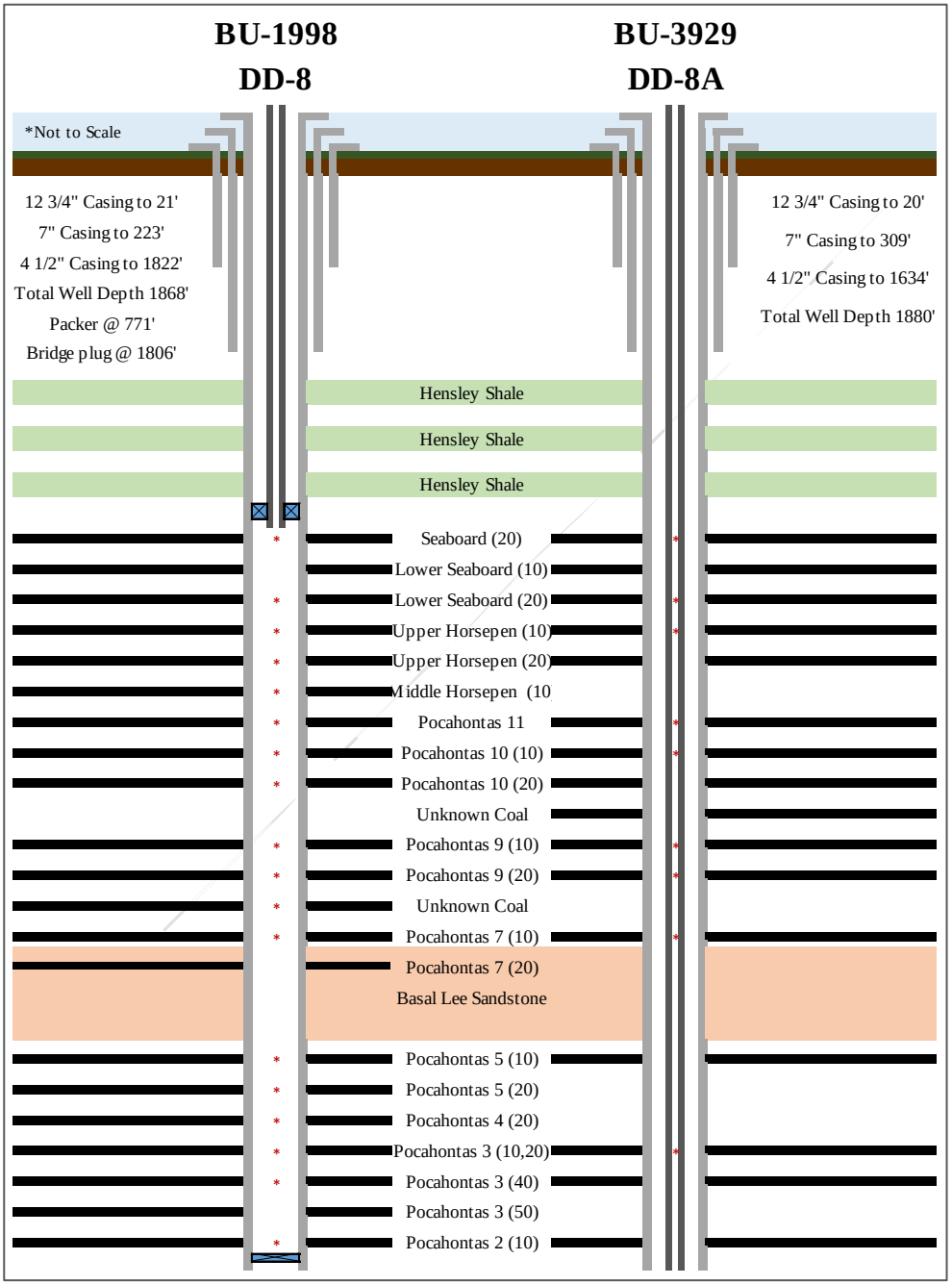
deformation and CBM production. Deformation could also correlate to underground mining or natural, geologic processes. However, the result demonstrates that the CO2-ECBM test has not produced a deformation signal that is detectable above surrounding signals. Accuracy of the ISBAS solution can increase with additional acquisitions.

Ground-based GPS data collected at 20 locations across the CO2-ECBM study area can provide cross validation of ISBAS results. Challenging terrain and tree cover have contributed to long occupation times and poor results at some locations. Higher quality measurements have peak-to-peak errors of approximately 7 mm, consistent with optimal operational accuracy and did not show uplift.

9.7.7 Water Injection Test

In order to delineate the CO2 plume migration by coal seam or zone, it is important to understand the connectivity between the DD-8 and DD-8A wells (Figure 9-113). There are 21 coal seams present in the DD-8 injection well, while they are only 16 coal seams present in DD-8A offset production well. Of the 16 coals present in DD-8A, 15 are present in DD-8. Of the 16 coals present in DD-8A, nine of them were perforated and completed. All of these completed coals in DD-8A were also completed in DD-8.

Figure 9-113 DD-8 and DD-8A Interwell Connectivity



Motivation

Most coalbeds are naturally saturated with water. The presence of water significantly hinders gas transport through coal seams and contributes to pressure in coal seams that keeps methane adsorbed on coal surfaces. Water exists in coal seams in different states including bulk water in coal cleats and fractures, chemical-bonded water in clay minerals, and adsorbed water on coal surface within the coal matrix. For water-saturated coal seams, the removal of bulk water in coal cleats and fractures will create

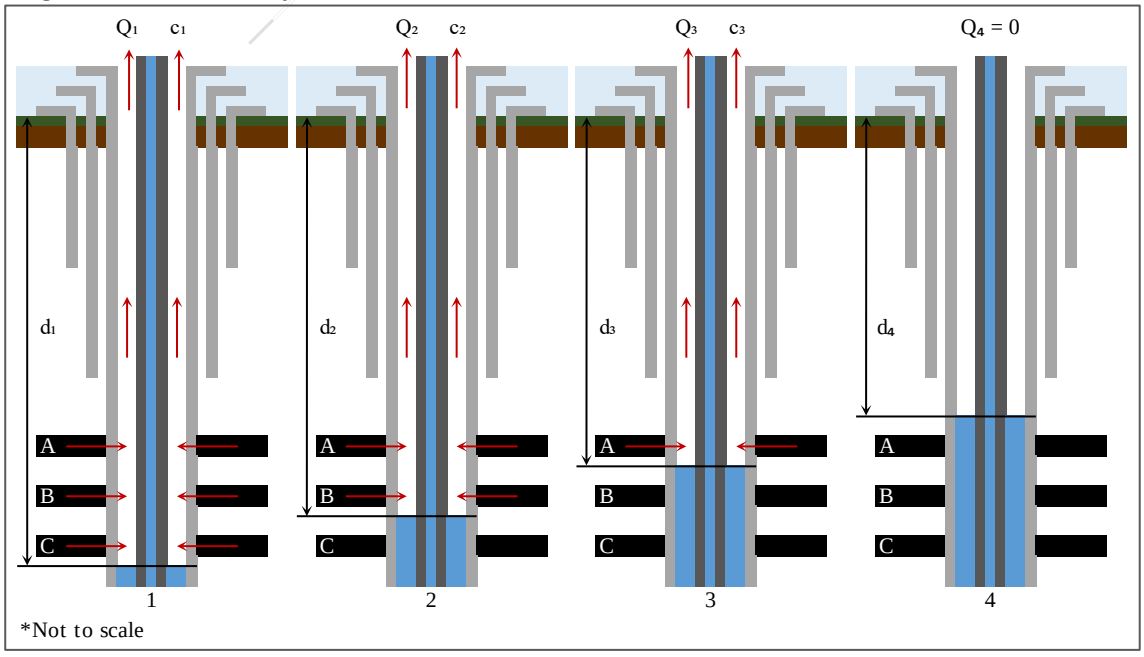
more flow pathways and improve gas flow by increasing relative permeability. Therefore, coalbed methane production relies heavily on the dewatering of the coal seams in order to lower reservoir pressure, which increases permeability and initiates gas desorption. Over time, the production of CBM increases, as more water in the coal seams are dewatered.

The goal of this specific test is to inject a volume of water on the annulus of the DD-8A well, covering individual coal seams or known perforation zones at different intervals. By injecting water at multiple intervals in the wellbore, gas production from coal seams that are below the water level will be terminated due to the increased hydraulic pressure created by the water column, which will be higher than the low pressure typically found in coal seams.

Methodology

At each water injection level, gas composition and flow rate were collected to determine the quantity and quality of gas from each individual coal seam or interval. This general process is illustrated in Figure 9-114 below. In step 1, the depth of the water, d1, is measured and the gas flowrate, Q1, and gas composition, c1, for this interval is contributed from coal seams A, B, and C. In step 2, a volume of water is injected and the depth of the water, d2, is measured. The gas flowrate, Q2, and gas composition, c2, for this interval and contributed from coal seams A and B. In step 3, more water is injected and the depth of the water, d3, is measured. The gas flowrate, Q3, and gas composition, c3, for this interval is contributed from only coal seam A. Finally, in step 4, water is injected to cover up all of the coal seams. At this step, the gas flowrate, Q4, will equal zero.

Figure 9-114 Water Injection Test to Determine Gas Production from Individual Coal Seams



In order to determine the downhole liquid level in the wellbore, an Echometer Remote Fire Gas Gun coupled with the Total Well Management (TWM) software was used. The Echometer gun generates a pressure pulse that travels down the annulus of the wellbore. This pulse reflects off each individual collar and the liquid level. The reflected pulse is picked up by a microphone located in the gun and transmitted via electric signal to the TWM software. The software then counts the number of collar reflections detected, and with the input of known collar lengths, can calculate the depth of the liquid level.

Fresh water was injected into the well using an 80-barrel capacity water truck. The well's water pump was turned off and the wellhead was fitted with a tee on the annulus to connect the water truck's hose, as well as the Echometer gun. After each water injection, the flow rate was allowed to stabilize. Flow rate was measured and gas composition samples were collected using DOT compliant stainless steel gas cylinders using the GPA Standard 2166 for obtaining natural gas samples for analysis by gas chromatography. Tracer samples were collected using vacuumed glass vials with a rubber septum. A rubber septum was fitted on the sample port of the well and a double-sided needle was used to transfer the gas sample from the port to the vial without outside air contamination.

Gas composition samples were analyzed using an ABB NGC 8206 portable natural gas chromatograph. The tracer gas samples were analyzed using a Shimadzu GC2010 gas chromatograph equipped with a mass spectrometer (MS).

Results

A total of eight water injections were performed for this test. Based on the Echometer liquid level results, water levels were determined to be at 1559 ft., 1341 ft., 1267 ft., 1133 ft., 1012 ft., 963 ft., 744 ft., and 658 ft. Figure 9-115 below shows a generalized schematic of the DD-8A well, including each coal seam in the well and geologic features of interest. The determined water levels are denoted by a blue line. While each individual, perforated coal seam could not be isolated and covered, individual zones, Z1-Z6, were created, some of which contain multiple perforated coal seams. It is important to note that the water levels at 1341 ft. and 963 ft. did not cover any additional perforated coals from the level below. For these water levels, the gas flow rate did not change, as there was no change in perforated coal seams contributing to those zones. Therefore, data from these water levels were not considered in the analysis of this test.

Figure 9-115 Echometer Results from the DD-8A Water Injection Test

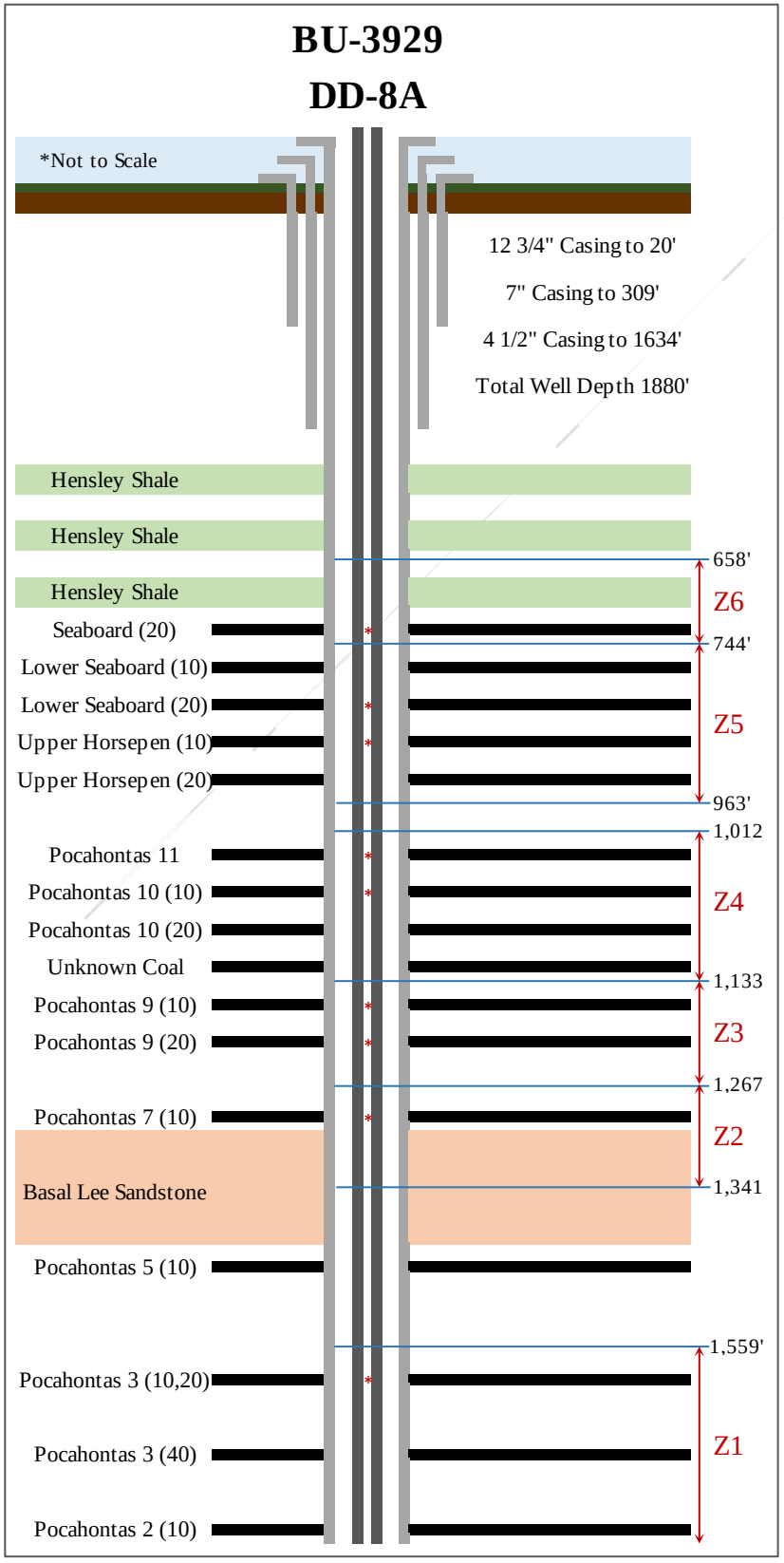
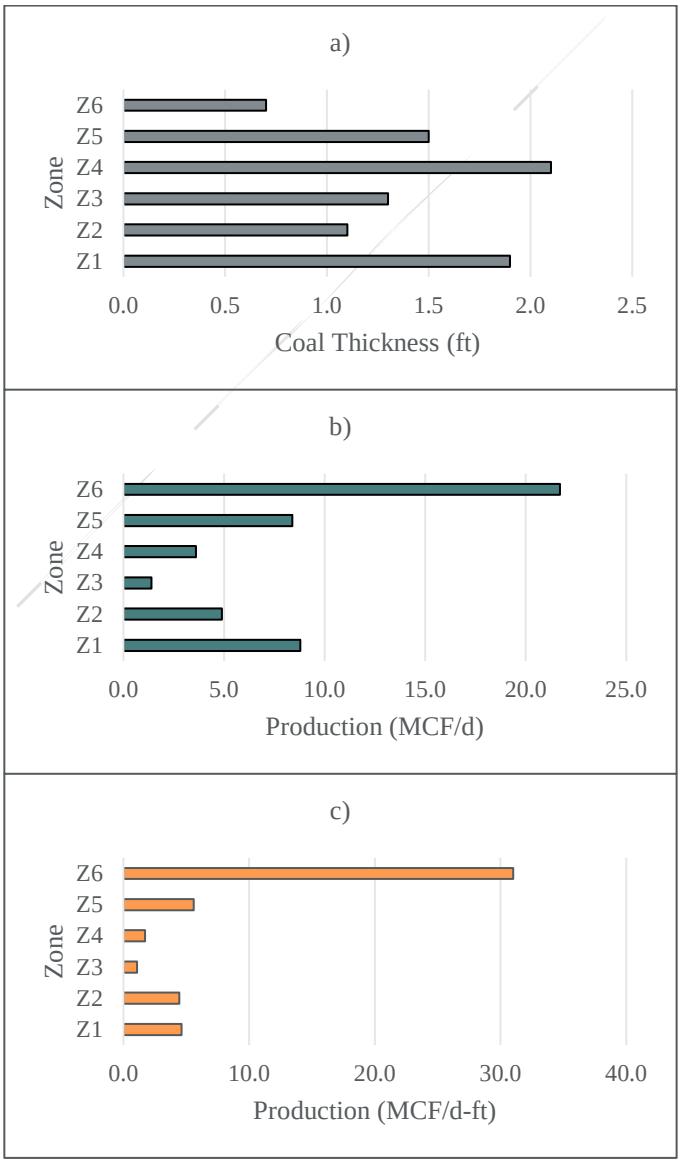


Figure 9-116a shows the total coal thickness per Zone. Zone1 and Zone 4 contain the highest amount of coal thickness. Gas production from each zone (Figure 9-116b) shows that the majority of the gas is produced from Zone 1 and Zone 6. Zone 1 contains gas produced solely from the Pocahontas 3 (10.20) coal seam and Zone 6 contains gas solely produced from the Seaboard coal seam. Gas production per unit of coal thickness (Figure 9-116c) shows that Zone 1 has the highest gas production per foot of coal thickness.

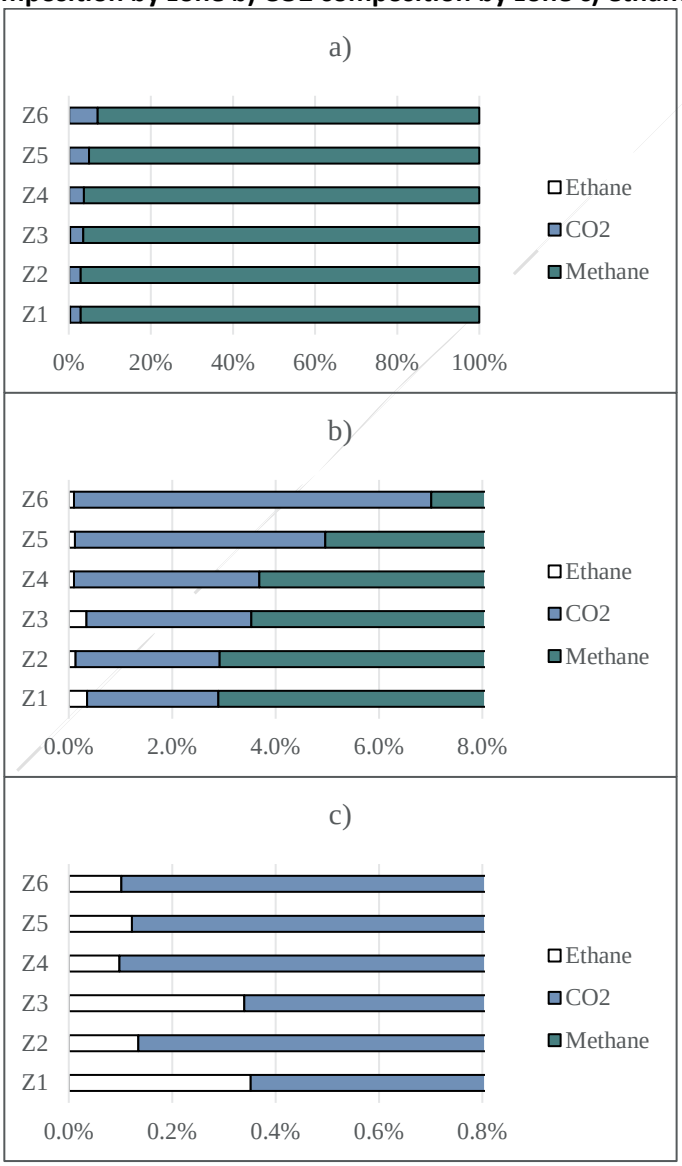
Figure 9-116 a) coal thickness by zone. b) gas production by zone. c) gas production per foot of coal thickness by zone



For each water level, composition samples were taken and attributed to each zone. For each zone, methane dominates the content of the gas (Figure 9-117a). Looking at the smaller components of the

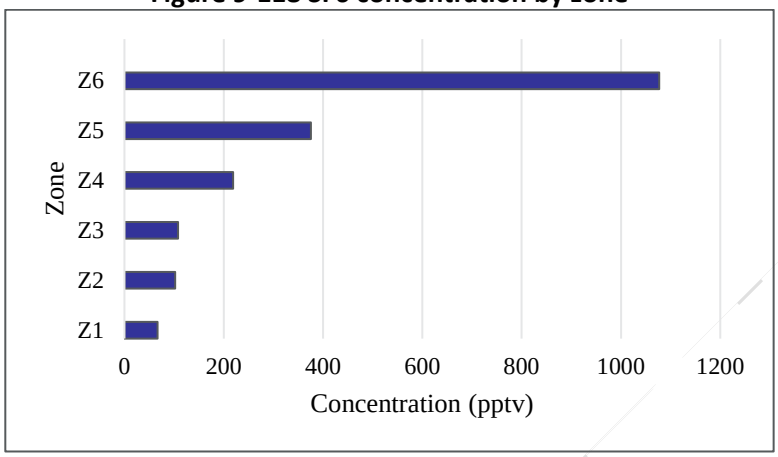
gas stream (Figure 9-117b), it was determined that CO2 composition was highest in Zone 6. This trend suggests that the majority of the CO2 is migrating through Zone 6, the Seaboard coal seam. It was also determined that ethane composition was highest in Zone 3 and Zone 1 which are dominated by the Pocahontas 9 and Pocahontas 3 coal seams (Figure 9-117c).

Figure 9-117 a) CH4 composition by zone b) CO2 composition by zone c) ethane composition by zone



For each water level, tracer samples were also taken to determine which coal seams or zones SF6 was migrating through (Figure 9-118). The highest concentration of SF6 was found in Zone 6 at a concentration of 1,076 parts per trillion volume (pptv). Zone 1 had the lowest concentration at 67 pptv. This trend suggests that the majority of the SF6 is migrating through Zone 6, the Seaboard coal seam.

Figure 9-118 SF6 concentration by zone



In order to determine CO2 and SF6 production from each zone, the CO2 composition and SF6 concentrations were multiplied by the flowrate for each zone (Figures 9-119 and 9-112, respectively). The highest production of CO2 and SF6 were both determined to come from Zone 6.

Figure 9-119 CO2 Production by Zone

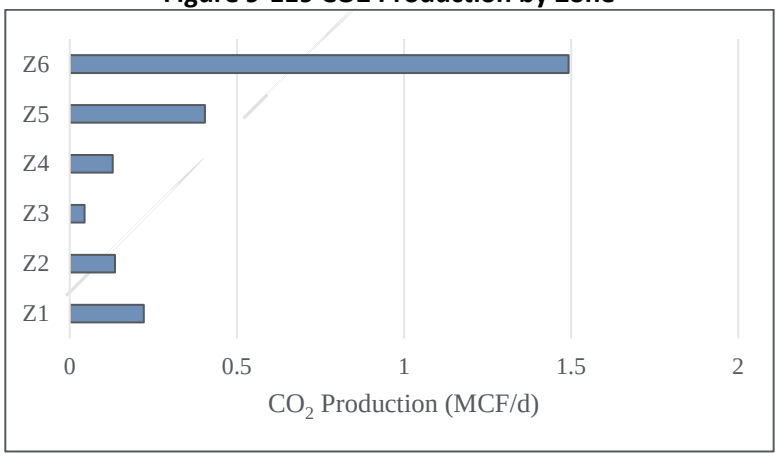
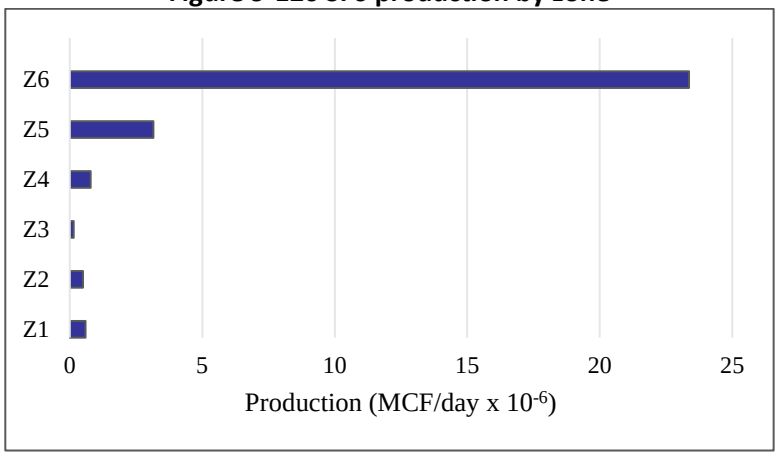


Figure 9-120 SF6 production by zone



9.7.8 Production Logging Tool

Approximately eight months after injection operations began, an injection log survey with a production logging tool (PLT) was run in the injection wells to try to determine the coal seam injection zones. Weatherford Wireline Services conducted the spinner surveys on the DD-7 and DD-8 wells on March 22-23, 2015. The tools were run while injecting into the wellbore. Weatherford was unable to log the DD-7A well because the logging tools sat down on an obstruction at the very bottom of the tubing string. The PLT string consisted of gamma ray, casing collar locator, temperature, pressure, radioactive density, and a 1.69" full-bore or jewel spinner. At the time of logging, approximately 2,915 and 3,068 metric tons of CO_2 had been injected in the DD-7 and DD-8 wells, respectively.

The DD-7 well was logged first with a full-bore spinner. Two round trip logging passes from 1150' to 2150' were conducted at different logging speeds, 100 and 150 feet per minute (fpm). A calibration pass from 1385' to 1531' and back was conducted at 50 fpm. All passes were run while CO_2 was being injected. The initial injection rate was 45 tons/day; however, the spinner was not turning enough so Weatherford requested a rate increase. The rate was increased to 80 tons/day and held there while the main passes were logged.

A Weatherford engineer prepared the data by filtering it, analyzed the flow meter data to compute the injection profile, determined the injection zones and computed the flow per injection zone based on the surface flow rate. The up pass at 150 fpm was used for the injection profile due to its average consistency in the overall data. The injection zones were determined by the change in direction of the spinner curve. The percent flow to each zone was calculated by the change in revolutions per second on the spinner as it passed each coal seam.

At the point in time logging was conducted, it was determined that three of the four stages originally fracture stimulated, 1216'-1385', 1531'-1570' and 1674'-1866', had active perforations. Unfortunately, a closer look at the injection profile shows that injection was limited to only three coal seams. The Pocahontas No. 9, Pocahontas No. 10, and Lower Seaboard received 20%, 31% and 49% of the total flow, respectively. There are distinct changes in the temperature log which corresponds to changes in the spinner speed for all logging passes which helps to confirm this. Finally, the CO_2 density has a very distinct phase change at 1265' from a gas to a gas/liquid mixture. This occurs in the immediate vicinity of the Lower Seaboard seam. The pressure and temperature at that depth place the phase of the CO_2 on the saturated liquid line of a CO_2 phase diagram. The density of the CO_2 changes from 4.0 to 6.0 pounds per gallon (ppg) at this point. From here, as depth increases so does the pressure and this quickly turns the phase to liquid CO_2.

The DD-8 well was logged with a jewel full-bore spinner. Two round trip logging passes from 820' to 1806' were conducted at different logging speeds, 100 and 150 fpm. A calibration pass from 1205' to 1311' and back was conducted at 50 fpm. All passes were run while CO_2 was being injected. The initial

injection rate was 60 tons/day, however, Weatherford requested a rate increase to 80 tons/day to try to increase the revolutions on the spinner. This rate could not be sustained due to high pump discharge pressure. The 2" flow line to this well is about 2300 feet longer than the line to the DD-7 well and this caused excessive friction losses. So, the average rate during logging was 61 tons/day.

Weatherford processed the data the same as they did on the DD-7 well. The injection profile was calculated using the down pass at 150 fpm.

The logging interpretation determined that the active perforations are in the last stage which was originally fracture stimulated at 871'-1205'. It appears that nearly 100% of the injection was in the Seaboard seam with a very minimal amount going into the Lower Seaboard and Upper Horsepen seams. Immediately below the tubing, the CO_2 density is 5.83 ppg and 300' deeper the density is 6.25 ppg. The pressure and temperature recorded at all depths below the tubing indicate the wellbore is filled with liquid CO_2 according to the phase diagram.

It should be noted that Weatherford indicated there was a bit of a yo-yo effect, based on the tension readings of the logging line, that affected the spinner data with the lower than desired injection rate at the time of logging. Therefore, it cannot be determined with certainty that the Seaboard seam was the only one receiving CO_2. The PLT Interpretation well report prepared by Weatherford for these two wells can be found in Appendix J.

9.7.9 In-situ Spatial Distribution Determination Test

Introduction

After around 14000 tons of carbon dioxide was injected in the stacked coal seams through three injection wells, how the large volume injected carbon dioxide distributed in these vertically stacked coal seams are still unknown. This question has not been addressed in literature including previous field carbon dioxide injection tests. In order to determine how the injected carbon dioxide sequestered in these stacked coal seams, a novel Downhole Reservoir Raman System (DRRS) was deployed in these wells to characterize actively-flowing carbon dioxide and methane in situ down the length of the well during the post-injection phase from November 6th to 11th, 2017.

Downhole reservoir Raman system (DRRS)

Raman spectroscopy is a well-established laboratory chemical analysis technique. It was invented after the discovery of the Raman Effect in 1928, for which Sir Chandasekhra Venkata won the Nobel Prize for Physics in 1930.

Raman spectroscopy is a scattering technique based on Raman effect, i.e., frequency of a small fraction of scattered radiation is different from frequency of monochromatic incident radiation. In Raman spectroscopy, monochromatic illumination of a material by a laser induces Rayleigh scattering (elastic scattering) and Raman scattering (inelastic scattering). For Raman scattering, the laser light interacts

with molecular vibrations, phonons or other excitations in the system, resulting in the energy of the laser photons being shifted up or down. The shift in energy gives information about the vibrational modes in the system and these vibrational modes can be interpreted to reveal the molecular bonding and structure of molecules in the material. The Raman spectroscopy is now a well-established technique and is commonly used to provide a structure fingerprint by which molecules can be identified. It has been used to characterize chemical properties of organic-rich rocks and investigate nanoconfinement effect on gas phase behavior (Bryndzia et al., 2016; Arakcheev et al., 2011 & 2013). Furthermore, it also has the capacity to identify and precisely quantify the components in a chemical mixture such as mixtures containing solubilized gases and other liquid hydrocarbons.

The DRRS logging instrument was developed by Welldog Inc. to characterize unconventional reservoirs by measuring the concentration of different gases, including natural gas liquids, as well as higher hydrocarbons solubilized or diluted in fluids extracted from carbonaceous strata including coal seams and shale (Pope et al, 2004; Lamarre et al., 2007). The DRRS incorporates a full spectrum Raman spectrometer and an analogue sensor package to measure fluid conductivity, temperature and pressure, with the instrument package integrated into a single housing deployed on multi-core wireline to acquire real-time component concentration profiles. The direct laser-based interrogation technique generates a spectrum with embedded Raman signatures unique to each detected component that allows distributions of individual specie, such as hydrocarbon and non-hydrocarbon, to be precisely logged as a function of depth and time. The DRRS has been historically used for determining gas saturation and gas content of coal seams and was recently used for the rapid appraisal of shale gas resource (Pope et al, 2004; Lamarre et al., 2007; Lamarre et al., 2007; Myers et al., 2017). Briefly, the Raman platform interrogates composition and concentration of the solubilized gases in wellbore or produced water in real-time. Appropriate solubility constants are obtained from proprietary lookup tables, based on gas type and measurements of reservoir pressure and temperature and fluid electrical conductivity. The measured concentrations of the different solubilized gases are then equated to the effective partial pressures of the gases in the reservoir. The obtained partial pressure can then be used for estimating adsorbed gas content according to the calibrated adsorption isotherms. The gas saturation and gas content of the coal seams can then be obtained which is the summation of gas phase, dissolved phase and adsorbed phase. The deployment of the DRRS and aspects of the instrument for field tests are shown in Figure 9-121.

Figure 9-121 Deployment of the DRRS



The Raman spectroscopy of water dissolved methane and gaseous methane are different; the water dissolved methane peak centered at 2912 wavenumbers is broadened and reduced in energy slightly

when compared to the free gas methane peak at 2917 wavenumbers. This is due to interactions between methane and the solvating water molecules and makes it possible to distinguish chemical phases of methane. Two example Raman spectra characteristic of gaseous methane gas and methane dissolved in water are shown in Figure 9-122. Furthermore, the Raman spectroscopy allows direct quantification of chemical concentrations in mixtures. When the water dissolved methane contents are different, the size of these peaks can be used to build a quantitative calibration between instrument response and methane partial pressure. As the partial pressure is increased, the instrument response is observed to increase linearly as shown in Figure 9-123. Through careful instrument design and maintenance, this instrument response can be calibrated to concentration or partial pressure of the methane. Similar calibrations can be built for the various forms of gases dissolved in water or in gaseous phase, such as carbon dioxide.

Figure 9-122 Raman peaks typical of (left) solution gas and (right) production gas. The x-axis is wavenumber, or energy, and the y-axis is photons collected at each energy. Solvation of the methane molecule by water molecules causes a decrease in wavenumber and slight broadening of the peak.

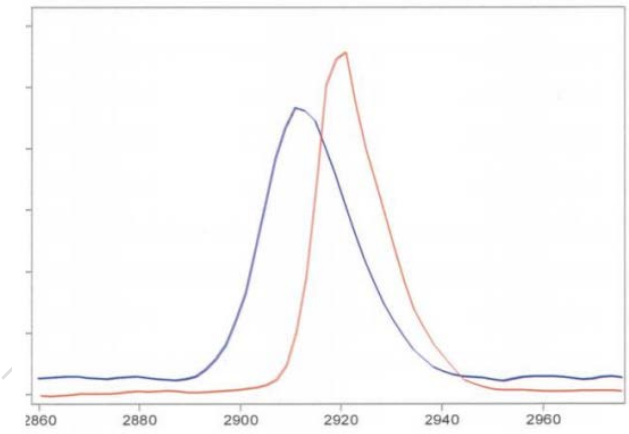
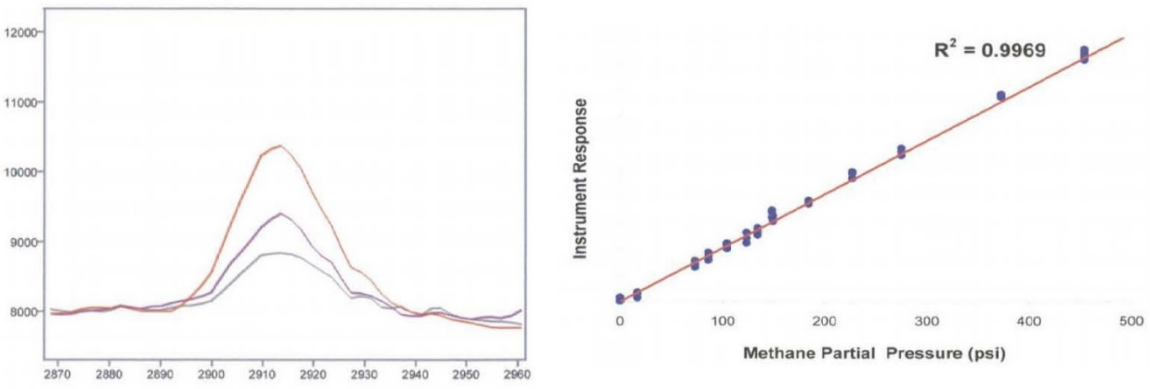
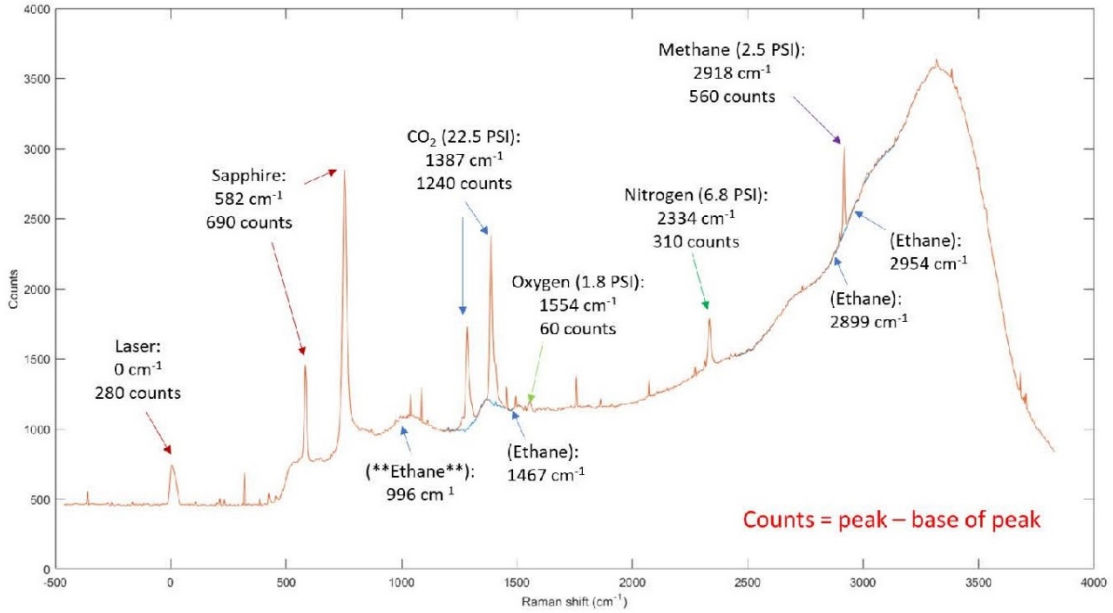


Figure 9-123 Methane spectra and response curve



A Raman spectrum interpretation guide is shown in Figure 9-124 below, where significant Raman features have been annotated. The spectrum shown here is for a gas mixture composed of 22.5 psi carbon dioxide, 6.8 psi nitrogen, 2.5 psi methane, and 1.8 psi oxygen. The Raman-shift location of ethane peaks is indicated below, with the main diagnostic peak being at 996 cm-1 for the purposes of identifying possible natural gas liquids production downhole. The sapphire peaks indicated in the spectrum near 600 cm^{-1} arise from the passage of the interrogation laser through a 0.125”-thick sapphire window before coming to a focus in the borehole in front of the DRRS. When the laser path outside the window is unobstructed, the sapphire peaks are useful as an internal standard that account for fluctuations of laser power that can affect absolute concentration measurements, which are related to the area under peaks after baseline subtraction.

Figure 9-124 Raman spectrum guide for analysis of gas species



Field test design

The general logging program for each well included an initial run of the DRRS to log the length of the well from surface to the bridge plug above the rathole, stationary scans above zones (three or four zones consisting of 2-7 perforated coal seams), and finally, pull out of hole. Perforation intervals were divided into three or four zones designated A, B, C and D, but these zones did not necessary encompass equivalent coal seams from well to well. The seams included various Seaboard, Horsepen and Pocahontas intervals. In well DD7, which was situated topographically above the other two, perforated seams spanned from 1216 ft.-below-surface (FBS) to 2130 FBS. DD7A and DD8 were situated downhill from DD7 and had perforated seams spanning the interval from 856 FBS to 1802 FBS. In DD7, water and foam obscured quantitative Raman spectral measurement of gas composition from seams below 1560 FBS, including all but one of the seams designated as Pocahontas. Nevertheless, bubbles of gas having high amounts of methane and moderate amounts of carbon dioxide were observed in the unsettled water at the base of the wellbore at 2140 FBS. In DD8, water and foam also obscured analysis of coal

seams, here below 1585 FBS, including seams designated Pocahontas 1 through 5. In contrast to DD7, the liquid water in DD8 did not exhibit actively bubbling gases. Table 9-54 is a summary of these seams along with observation of gas, foam or liquid during DRRS logs and designated locations of temporary plugs.

Table 9-54 Designated test zones for DRRS in three wells

Coal Seam	Well DD7 Zone / Depth FT / Thickness FT	Well DD7A Zone / Depth FT / Thickness FT	Well DD8 Zone / Depth FT / Thickness FT
Seaboard-20	A / 1216 / 1.5	A / 856 / 0.7	A / 871 / 1.3
Lower Seaboard	A / 1260 / 1.6 (LS-10,20)	A / 902 / 0.5 (LS-20)	A / 902 / 0.2 (LS-10) A / 912 / 1.6 (LS-20
Upper Horsepen	A / 1336 / 1.5 (UH-10) A / 1383 / 0.9 (UH-20)	A / 975 / 1.3	A / 984 / 1.4 (UH-10) A / 1031 / 0.6 (UH-20)
Unknown	-	-	A / 1054 / 0.4
Middle Horsepen-10	-	-	A / 1068 / 0.7
	Plug 1504	**Plug 1170**	**Plug 1132**
Pocahontas 11	B / 1531 / 0.8	B / 1203 / 0.9 (P11-3)	A / 1165 / 0.8
Pocahontas 10	B / 1564 / 1.8	B / 1207 / 0.7	A / 1198 / 0.4 (P10-10) A / 1204 / 0.8 (P10-20)
	Plug 1640	**Plug 1290**	**Plug 1288**
Pocahontas 9	C / 1674 / 2.5 (P9-10) - C / 1700 / 1.4 (P9-30)	B / 1316 / 2.3 (P9-10) B / 1322 / 0.2 (P9-20) -	B / 1311 / 1.9 (P9-10) B / 1314 / 0.5 (P9-20)
Unknown	-	-	B / 1397 / 0.9
Pocahontas 7	C / 1784 / 1.0 (P7-10) C / 1866 / 0.6 (P7-20)	B / 1419 / 0.6 (P7-10)	B / 1422 / 0.6 (P7-10) B / 1467 / 0.7 (P7-20)
		Plug 1560	**Plug 1490**
Unknown	-	C / 1599 / 0.9	-
Pocahontas 5	D / 1997 / 1.0 (P5-20)	C / 1637 / 0.7 (P7-20)	B / 1591 / 0.6 (P5-10)
Pocahontas 4	D / 2024 / 1.0 (P4-10) D / 2046 / 0.6 (P4-20)	C / 1691 / 0.7 (P4-20)	B / 1637 / 1.6 (P4-10) B / 1677 / 0.6 (P4-20)
Unknown	-	C / 1702 / 0.6	-
Pocahontas 3	D / 2100 / 2.2 (P3-10,20) D / 2107 / 0.7 (P3-30) D / 2126 / 0.9 (P3-40) D / 2130 / 1.1 (P3-50)	C / 1735 / 1.8 (P3-10) C / 1740 / 0.1 (P3-30) C / 1750 / 1.0 (P3-40)	C / 1711 / 2.4 (P3-10,20) C / 1721 / 0.6 (P3-30) C / 1731 / 2.0 (P3-40,50)
Pocahontas 2		C / 1802 / 0.5	C / 1746 / 0.8
Pocahontas 1			C / 1802 / 0.8
KEY:	Gas	Foam	Water	Temporary Plug

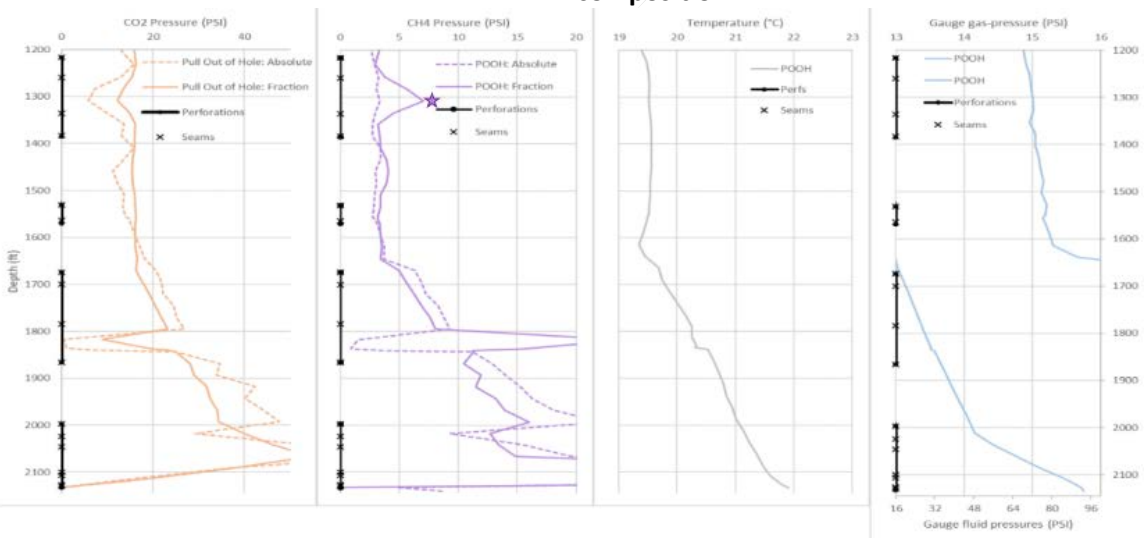
Next, a temporary bridge plug was set to block production from underlying zones and then the DRRS was redeployed to log from surface to the plug, to perform stationary scans above zones and then pulled out of hole. Two more temporary plugs were placed sequentially above zones and similar DRRS logs were performed. In each well, a total of four runs of the DRRS in hole were performed. In wells DD7 and DD8, the first temporary bridge plug was placed just above the level of the foam layer in the borehole. In DD7, only two plugs were placed and for the final run, these plugs were retrieved and a DRRS log to the rathole and back was performed, which confirmed the persistence of the 400-ft. foam layer and actively-bubbling gases in water at the base.

The DRRS is a self-contained Raman spectrometer with onboard pressure, temperature and salinity sensors that collects and transmits multiple data streams to the surface in real time. In the present study, data were collected at a nominal continuous sampling rate of 2.5 samples·min^{-1} for the duration of time in hole. The tool was generally run into the borehole at a rate of 60 ft.·min^{-1} from surface to zones or on pullout, then 30 ft.·min^{-1} between zones, and in some cases at 10 ft.·min^{-1} for a high-resolution log of zones. Additionally, the tool could be stationed at a given depth and run continuously for a period 5-20 minutes to characterize the dynamics of the gas mixture over time.

Results and discussions

Figure 9-125 is an example log of well DD7 from the ascent to surface including CO2 and CH4 composition measurements, as well as temperature and pressure logs. The pressure log shows clear inflections when moving from water, to foam, and to gas phases. The transient increase in methane near 1300 FBS is clearly shown and indicated with a star.

Figure 9-125 DRRS logs of measured CO2, CH4, and onboard temperature and pressure: the solid line in the gas pressure logs indicates the measured Fraction composition while the dashed line indicates the absolute composition.



During characterization of the three wells DD7, DD7A and DD8, the composition of gases at the surface generally measured between 82% and 88% CO2, with the remainder CH4. This surface composition was observed to exhibit slight changes after placement of temporary plugs in wells, accompanied by changes in production flow rate (when the gauge was functioning properly). These observations indicate production from seams below plugs. Logs of wellbores show a mixed gas column a top layers of foam and water in DD7 and DD8, and exclusively gas in DD7A. Logs of gas composition indicate salient differences in CO2/CH4 fraction that often can be correlated with coal seams down the length of the wellbore. A summary table is provided in the Appendix with observations of activity associated with seams in all three wells including measured gas compositions, magnitude of changes in composition and color coding to indicate increased methane or carbon-dioxide production relative to seams below.

In DD7, beginning at the base of the gas column, foam was observed below 1640 FBS, obscuring seams below. It can be concluded that gases bubbling up from the rat hole are actively produced through the foam and water layers, because when the temporary plug was set at 1640 FBS, the measured flow rate dropped by 44%. The only seams that showed compositional changes and thus activity before the temporary plug was set were the Upper Horsepen (10) and Lower Seaboard (10,20). After the plug was set, gas composition was not dramatically different in the stagnant zone between the plug and above the Pocahontas 10 and 11 seams, and the Upper Horsepen (20), indicating that these seams are either inactive or are producing gas that matches the composition in the stagnant zone. Again, the Upper Horsepen (10) and Lower Seaboard (10,20) showed changes in gas composition and are thus actively producing gases. When the next plug was placed at 1504 FBS to stop flow from the Pocahontas 10 and 11, flow rate dropped 40%, suggesting that one or both of the seams were actively producing gas. A transient temperature dip in one log-pass corresponding with Pocahontas 10 could indicate that it is the more active of the two seams. Composition of the gas above that seam was 81% CO2, balance CH4. Flow rate from those two seams was measured to be 0.4 mT/day, the difference between surface flow rates before and after the plug was placed at 1504 FBS. Stagnant gas between that plug and the Upper Horsepen (20) had a composition of 78% CO2. Interestingly, after the 1504-plug was set, the composition above UH-20, the first perforated seam above the plug, increased in methane to 40%. This suggests that seam is producing that gas composition. Composition above UH-10 was 26% methane, which suggests that it is producing gas with significantly more than 60% CO2, i.e. more than the seam below. Above the next seam, Lower Seaboard (10,20) CH4 was 19%, another significant drop, suggesting that this seam is producing more CO2 than the combination of the two seams below. Composition above the Seaboard (20) was more or less equivalent to the combination of gases from seams below.

In DD7A, which had the most complete log of perforated seams, beginning at the base of the well, stagnant blow-down gas mixed with methane and carbon dioxide was observed below the Pocahontas 3 (40) seam at 1757 FBS. This suggests that the seams below, including the Pocahontas 3 (50) and the Pocahontas 2, are inactive. Pocahontas 1 was not perforated in this well and was obscured by water in the other wells. Above Pocahontas 3 (40), measured gas composition changed, suggesting active production of gases from the seam. The next significant change in gas composition was observed above the Pocahontas 4 (20) seam at 1691 FBS. This could suggest that the intervening coal seams (including Pocahontas 3 (30), Pocahontas 3 (10), and an Unknown Coal-1702) are inactive, or alternatively, that these seams are producing a gas composition that matches what was emitted by Pocahontas 3 (40). The next significant change can be associated with the Unknown Coal seam at 1599 FBS (the Pocahontas 5 (20) seam at 1637 FBS was either inactive or producing equivalent). After placing a plug at 1560 FBS, stagnant gases between the plug and the Pocahontas 7 (10) seam at 1419 FBS measured differently from the gases above the seam, suggesting it too is actively producing gases, though this was not evident from logs recorded prior to placement of the plug. Logs of gas composition above the next two seams, Pocahontas 9 (20) and Pocahontas 9 (10), show no significant difference in gas composition, which again could mean they

produce an equivalent gas composition or are inactive. After placing a plug at 1290 FBS, stagnant gases between the plug and the Pocahontas 10 seam at 1207 FBS measured differently than the gases above the seam suggesting active production of gas with a composition of 86% CO2. Differences in gas composition were also observed in logs above the Upper Horsepen (10), the Lower Seaboard (20) and the Seaboard (20), suggesting all three of those seams are actively producing gases with compositions different than the aggregate of seams below. The Upper Horsepen (10) seam is likely producing a significant amount of methane, as the intervening gas composition measured up to 25% CH4.

In DD8, beginning at the base of the gas column, foam was observed below 1585 FBS obscuring the Pocahontas 5 (10) and seams below. Stagnant gas observed between a plug placed at 1490 and the next seam above, the Pocahontas 7 (20) seam at 1467 FBS, measured an average of 85% CO2, and between the Pocahontas 7 (20) and the Pocahontas 7 (10) seam at 1422 FBS, the average was 86%, not significantly different, indicating that the lower seam is inactive or producing gas that matches the stagnant gas above the plug. Between PH7-10 and Unknown Coal- 1397, there's a slight dip in CH4 to 12%, indicating that the Pocahontas 7 (10) is producing more than 15% CH4. Above the Unknown-1397 seam, the average was back to 86% CO2 up through the Upper Horsepen-10 at 984 FBS indicating that the Unknown-1397 is actively producing more CO2 than the aggregate of seams below. After the next plug was placed at 1288 FBS, stagnant gas between that plug and the Pocahontas 10 (20) seam at 1204 FBS measured 87% CO2. Composition was not significantly different between the plug and the Middle Horsepen (10) seam at 1068 FBS, which averaged 87%, indicating that the Pocahontas 10 (20) seam is inactive or is producing gas equivalent to the stagnant gas above the plug (which roughly matches the gas composition observed in that zone prior to placement of the plug). The last plug was placed at 1132 FBS and stagnant gas between that plug and Middle Horsepen (10) was 79% CO2. This composition matches the composition up to the Upper Horsepen (20) seam at 1031 FBS, which also averaged 79% CO2. This indicates that the Middle Horsepen (10) and Unknown-1054 seam are either inactive, or are producing gas that matches the stagnant gas above the plug. The latter is the likely case for the Middle Horsepen (10), because prior to placing the plug, gas in that same zone had a lower CH4 fraction. Above the Upper Horsepen (20), CH4 spiked to 55% up through the Upper Horsepen (10) seam at 984 FBS, indicating that the Upper Horsepen (20) is producing gas with a composition greater than 21% CH4, the aggregate of seams below. Between the Upper Horsepen (10) and Lower Seaboard (20) at 912 FBS, CH4 was an average of 29%, indicating that the Upper Horsepen (10) is producing more CO2 than the aggregate of seams below. Between the Lower Seaboard (20) and the Seaboard (20) at 871 FBS, CH4 was down to 22%, indicating that the Lower Seaboard (20) is producing gas with more CO2 than the aggregate of seams below and that the Lower Seaboard (10) at 902 FBS is either inactive or producing an equivalent composition. Above the Seaboard (20), CH4 fraction dropped further to 12%, indicating that it too is producing more CO2 than the aggregate of seams below.

Conclusions

A novel DRRS was deployed in the three injection wells to characterize actively-flowing carbon dioxide and methane in situ down the length of the well during the post-injection phase in order to determine

how the injected carbon dioxide sequestered in these stacked coal seams. The results establish that sequestration occurred into the majority of the coal seams intersected by the injection wells. All of the active coal seams were producing primarily carbon dioxide.

The seams were producing varying levels of methane, up to 40% CH4 for the Upper Horsepen (20), as indicated clearly by the DD7 well log and confirmed in logs of the other two wells. The Upper Horsepen seam was producing significantly more methane than lower seams in all three wells. Close examination of the composition logs of this seam in the three wells shows that in DD7 and DD8, the Upper Horsepen (10) and (20) seams are delineated, and separated by 50 ft. of depth, whereas in DD7A the methaniferous seam is designated as Upper Horsepen (10) and the (20) was not perforated. Notably, the Upper Horsepen (20) in DD7 and DD8 is shown to be producing gas with a CO2 fraction of 60% and the (10) is actively producing more CO2 than the seams below. This would, at first, appear to contradict the observation of 75% CO2 being emitted from the Upper Horsepen (10) seam in DD7A. One possible explanation could be that the two Upper Horsepen seams are in active communication and that the methane being emitted from unperforated (20)-seam in DD7A manifests in combination with the increased CO2 from the (10)- seam. Another notable methane-producing seam observed in DD7 and DD7A is the Pocahontas 10, which in these two well logs showed a methane fraction between 15% and 20%. In DD7, the flow rate from this seam plus the overlying Pocahontas 11 is an estimated 0.4 mT/day or nearly 30% of the aggregate production at surface after placement of a plug just below.

Additional information regarding local reservoir characteristics, in particular individual coal seam properties, as well as production history, injection schedule, etc., would make it possible to draw more specific conclusions about the composition of gases moving out of seams and up the wellbore to comprise the gas exiting the wells.

9.8 Post-Injection Reservoir Modeling

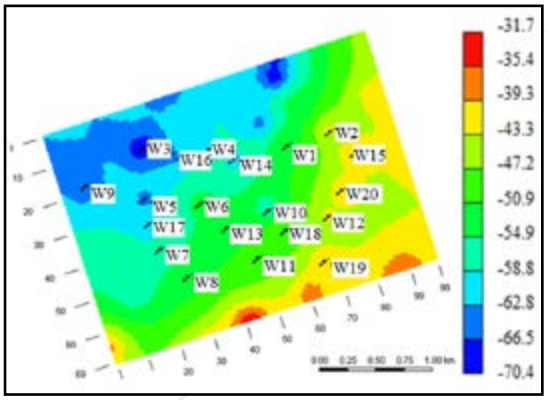
In post-injection reservoir modeling, Computer Modeling Group Ltd.'s GEM software, a compositional and unconventional reservoir simulator, was utilized. A dual porosity-single permeability model which is generally used for coalbed methane simulations was assigned as in the preliminary models.

For post-injection simulation, two complex models were developed based on regional geologic data and historic production and injection data allowing to research team to create more realistic models. The first model included all the wells in approximately ½ mile circle around the injection wells (Keles et al, 2016). and the second model included the wells in ¼ mile circle around injection wells (Keles, Louk, and Ripepi, 2017). Sensitivity studies were done for both post injection models to see the CO2 plume behavior in different conditions. The following section focuses on the post-injection reservoir models with associated regional geologic input and the sensitivity analysis completed using the post-injection reservoir models.

9.8.1 Reservoir Model with 20 Wells (1st Model)

The first post-injection reservoir model included 20 wells (Figure 9-126). Three of those wells were converted into CO2 injection wells. The post-injection model developed by technical team consists of a 16-layer model.

Figure 9-126 Structure map of Pocahontas 3 coal seam with well names and locations (legend in meters).



Reservoir Modeling Inputs

Face and butt cleat directions, which were observed in one of the mines in Buchanan County, VA, are N 18° W and N67°E, respectively. Moreover, hydraulic fracture direction is parallel to butt cleat direction. Since hydraulic fracture direction is the dominant fracture system to transfer water and gas from the reservoir, the model grid was generated based on hydraulic fracture direction and I direction was set as hydraulic fracture direction. Figure 9-126 illustrates structure map of Pocahontas 3 coal seam in the simulated area with well names and locations, and number of grids in I and J directions (i.e., hydraulic fracture direction and face cleat direction, respectively.). Well numbers were assigned based on production dates. Total number of block in the model was equal to 108,192; 98 grids in I direction, 69 grids in J direction, and grid size was identical in both directions and equal to 30.48 m (100 ft). Modeled area was approximately 6.28E6 m2 (1,552 acres). The total of sixteen coal seam layers were modeled by using coal seam elevation and thickness maps created with completion report and well data. Southeast part of the area is deeper than the northwest part.

Input parameters used in modeling work are listed in Table 9-55. Coal compressibility was measured on the coal samples from the same formation in another field close to working area (S. Harpalani, personal communication). Rest of the input values in modeling work were mostly based on the data reported in VCCER (2011, 2013, 2014, 2015) and Vasilikou (2014).

Table 9-55 Model Inputs (Adapted from VCCER 2011, Vasilikou 2014)

Parameter, Unit	Value
Coal density, kg/m^3	1323.93
Coal compressibility, 1/kPa	2.90E-09
Reference pressure for compressibility, kPa	2869.25
Reservoir temperature, °C	21
Langmuir volume (CH_4), m^3/tonne	22.47
Langmuir pressure (CH_4), kPa	2295.95
Langmuir volume (CO_2), m^3/tonne	25.91
Langmuir pressure (CO_2), kPa	1723.69
Coal desorption time, day	20
Reference pressure, kPa	3861.06
Reference depth, m	-46.63
Water-gas contact, m	-47.24

The permeability in the matrix is very low compared to permeability in the cleats (=0.001 mD) therefore a dual porosity system was used to model the coalbed methane reservoir. The permeability in the cleats was varied by seam and well area. The cleat permeability in the shallower seams, layers 1 to10, was three times higher than the permeability in the deeper layers. The permeability was assigned as 45 millidarcy (mD) for shallower seams while it was equal to 15 mD for deeper seems due to the increase in vertical stress in the deeper seams. Moreover, permeability around W1, W3 and W5 wells were equal to 60 mD, higher from the rest of the model area (Figure 9-127), because those wells had the highest cumulative gas production among the modeled wells (Figure 9-128). I:J permeability ratio was assumed to be 3:1 in all models in order to model the hydraulic fracture effect on the wells.

Figure 9-127 Cleat permeability distribution

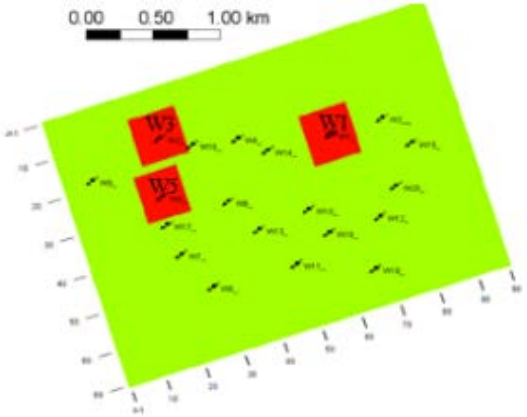
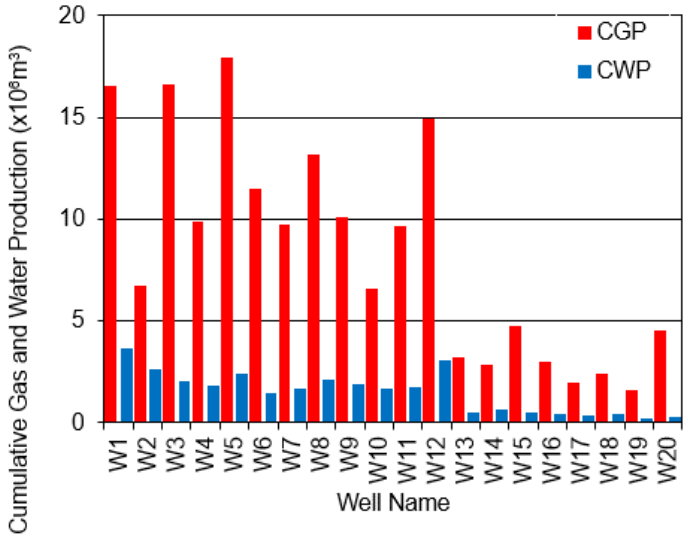
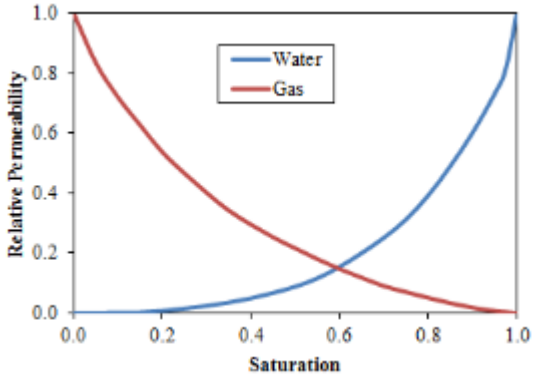


Figure 9-128 Cumulative gas and water production per well



Similar to fracture permeability, fracture and matrix porosities in the model were decreased with depth (i.e., fracture and matrix porosities were assigned as 0.2% and 2% for layers 1 to 6 while they were defined as 0.1% and 1% for the rest of the layers, respectively). Fracture spacing was set as 0.2 in (0.0051 m). Relative permeability relation used in the model is shown in Figure 9-129. It is the same plot used in Vasilikou (2014).

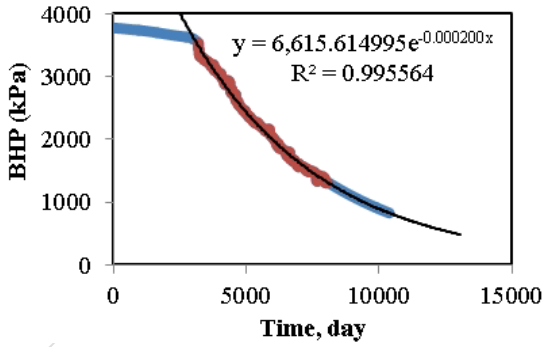
Figure 9-129 Relative permeability curves used in the model (Adapted from Vasilikou, 2014)



Reservoir pressure changes from 3771 kPa to 4220 kPa based on the grid top contours and reference depth and corresponding pressure at that depth. Besides reservoir parameters, well parameters like primary and secondary constraints, and well diameter are also important in simulation work. From

production start date (February 1, 1993) to the day before the shut-in production wells (March 1, 2015), primary operational constraint was set as gas rate to match the historic gas rates in monthly basis. Secondary constraint was set as minimum bottom-hole pressure (BHP) of 193 kPa, which is a default value in GEM. It means that BHP can change with gas rate and when it reaches its minimum value, it becomes constant through the rest of the model. In models, while gas rates were matched with history, BHP corresponding to production period was estimated by GEM. BHP projection for each well was calculated by drawing exponential curve to fit the BHP, and those fitting equations were used to calculate BHP for the period from after shut-in the production wells to the end of the simulation (Figure 9-130). Model simulations were run till July 1, 2021. Well diameter used in modeling work was the same for all vertical wells in all model cases, which was equal to 0.1143 m.

Figure 9-130 Bottom-hole pressure (BHP) versus time for well W12



Modeling Methodology

Sensitivity studies were focused on injection parameters such as injection well locations, number of injection wells, and time and rate of the injection. Results were interpreted based on production in flow back period. Model scenarios were classified in three categories, which are base model, models with and without base model injection wells.

Base Model: The base model consists of twenty methane production vertical wells and three of the wells, which are W6, W10, and W13, were shut-in in April 1, 2015. After three months, those wells were converted into injection wells. In injection period, primary constraint was set as maximum injection gas rate. Injection rate for W6-inj was 13.91E3 m3/day while it was equal to 8.34E3 m3/day for W10-inj and W13-inj. After one year of injection, injected cumulative mass CO2 reached to around 20,000 tonnes, and then the injection wells were shut-in. After one year of soaking period, injection wells were turned into production wells again, and all of the wells were produced till July 1, 2021.

Models with Base Model Injection Wells: Models with base model injection wells were studied in nine different cases. Case 2 and Case 3 were very similar to base case due to gas injection rate and injection

period. The difference was only the higher injection rate (i.e., 13.91E m3/day) belonged to W13-inj in Case 2 and W10-inj in Case 3.

In Cases 4, 5, and 6, all of the CO2 was injected from just one well with 29.24E3 m3/day injection rate. In each case the injection well was different: W6-inj, W10-inj, and W13-inj were used for Case 4, 5, and 6 respectively.

In Cases 7, 8 and 9, two injection wells were used at a time. In Case 7, the chosen wells were W6-inj and W10-inj, in Case 8, the chosen ones were W6-inj and W13-inj while in Case 9, the wells used for injection were W10-inj and W13-inj. In all three cases, CO2 injection rate was 14.62E6 m3/day per well. In Case 10, all three wells had the same injection rate, which was 9.75E3 m3/day. Soaking periods and flow back periods were the same for those ten cases.

The last two cases, which were Case 11 and Case 12, had different injection periods than the previous models. Injection rates applied in Case 11 were as twice as the base case model while injection period was the same as in the base case model, but the time passed for injection was half of the time passed in the base case model. In injection period, CO2 was injected for one month. After one month, well was shut-in for one month, and after that, injection was continued one month and then well was shut-in for another one month. That injection pattern (i.e., injection one month and shut-in one month) continued till the injection period reached one year with six-month of injection. In case 12, injection rate was the same with Case 11, but the injection period was equal to half of the base case (that is, 6 months). Model scenarios used in "base model" and "models with base model injection wells" are tabulated in Table 9-56 with their average CO2 injection rates.

Table 9-56 injection rates for base model" and "models with base model injection wells"

Injection Well	W6-inj	W10-inj	W13-inj
Model	CO_2 Injection Rate, $\times 10^3 m^3$/day		
Case 1*	13.29	7.97	7.97
Case 2	7.97	7.97	13.29
Case 3	7.97	13.29	7.97
Case 4	29.24	-	-
Case 5	-	29.24	-
Case 6	-	-	29.24
Case 7	14.62	14.62	
Case 8	14.62		14.62
Case 9		14.62	14.62
Case 10	9.75	9.75	9.75
Case 11	26.58	15.95	15.95
Case 12	26.58	15.95	15.95

*Case 1 is the base case model.

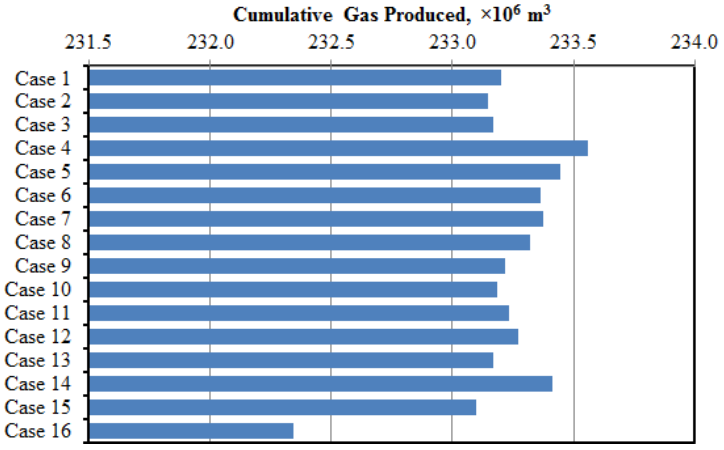
Models without Base Model Injection Wells: Models without base model injection wells were analyzed in four different model cases. Three of the models (i.e., Case 13, 14, and 15) had one injection well with 29.24E3 m3/day injection rate. In Case 13, a well having the minimum cumulative production (i.e., 1.56E6 m3) with minimum average gas production rate (i.e., 0.70E3 m3/day), which is W19, turned into an injection well. In Case 14, a well having the maximum cumulative gas production (that is, 17.91E6 m3) with maximum average gas production rate (i.e., 3.42E3 m3/day), which is W5, was chosen as an injection well. In Case 15, a well having minimum pressure before shut-in the production wells, which is W12, was selected as an injection well.

In Case 16, three production wells, which are W12, W19, and W20 were converted into the injection wells due to their location. Coal seams were dipping from northwest to southeast and those wells were located in the deepest part of the seams in the working area (Figure 9-126).

Modeling Results: Sensitivity Analysis

Sixteen different injection scenarios were examined in this model. In order to investigate effect of injection parameters on produced cumulative gas volumes, stored CO2 and extent of CO2 plume. The base model scenario, which is planning to be achieved by injection of 20,000 tonnes of CO2, had produced 233.201E6 m3 of gas in the simulation (Figure 9-131). Maximum gas production was achieved in Case 4. CO2 was injected from one well (W6-inj) with 29.24E3 m3/day injection rate. During injection, maximum BHP reached in injection well (W6-inj) to 3986 kPa, which is lower than minimum breakdown pressure (11307 kPa) achieved in completion of one of the vertical wells in Russell County area (Ripepi 2009). Russel County area is close to Buchanan County study area. Since BHP was lower than the breakdown pressure, injecting CO2 with 29.24E3 m3/day rate did not cause any crack propagations in the reservoir. Similar to Case 4, in Case 5 and in Case 14, cumulative gas production was higher than other cases. W10-inj (in Case 5) and W5-inj (in Case 14) were used for injection. The same injection rate was used for those wells. Location of those two wells is very close to well W6-inj (Figure 9-126). However, minimum cumulative gas production was attained in Case 16, which had three injection wells (W12-inj, W19-inj, and W20-inj).

Figure 9-131 Cumulative gas production for each case



After CO2 injection, CO2 in the gas composition increased. Some of the CO2 was adsorbed by coal matrix while some of it was produced with CH4. Produced gas mass percentages of CO2 and CH4 are illustrated in Figure 9-132 for each case. Case 4 had the lowest CO2 production (less than 2%) among the cases. Case 6 and Case 14 had low CO2 percentages as well. Wells used for injection in those cases were W13-inj and W5-inj respectively. On the other hand, in Case 15 and in Case 16, CO2 production was higher than the rest of the wells.

Injected CO2 was equal to 20,000 tonnes for each model. Figure 9-133 illustrates CO2 mass values produced from reservoir (with blue rows) and stored in the reservoir (with red rows) till July 1, 2021. Results showed that in Case 4, 13% of CO2 was produced while 87% of it kept in the reservoir. On the other hand, in Case 16, half of the CO2 was produced and half of it was stored in the reservoir.

Figure 9-132 Cumulative gas mass (CO2 and CH4)

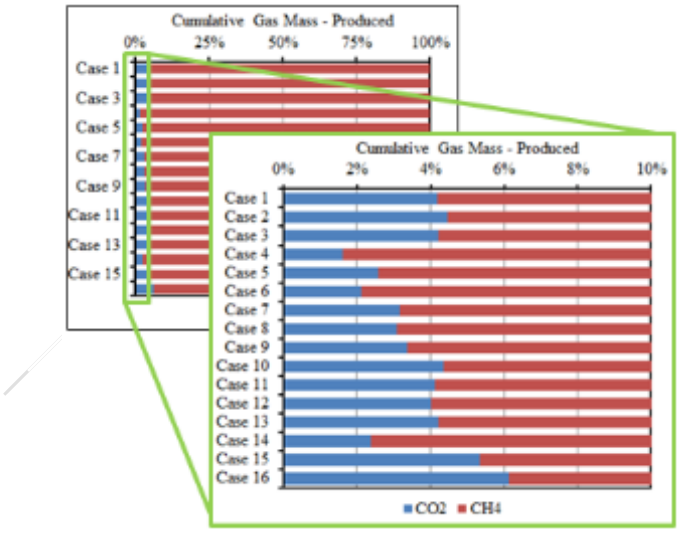


Figure 9-133 Produced and stored CO_2 mass

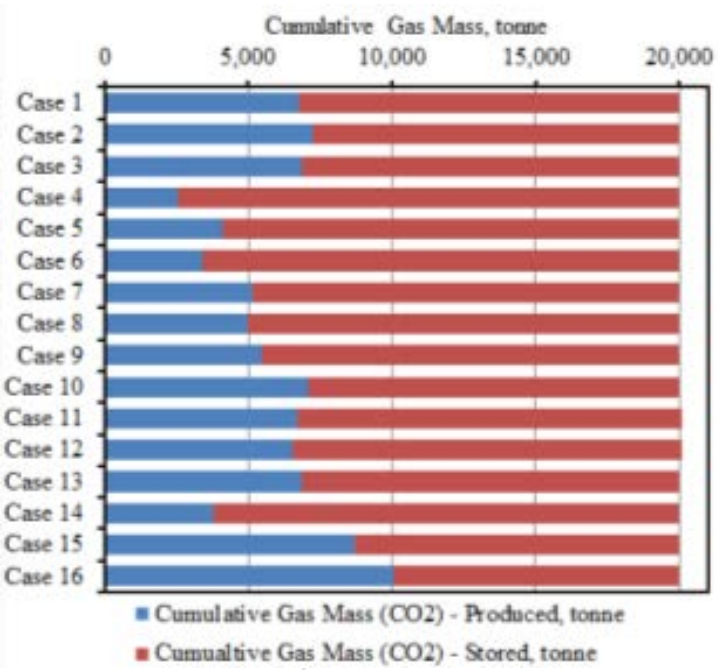
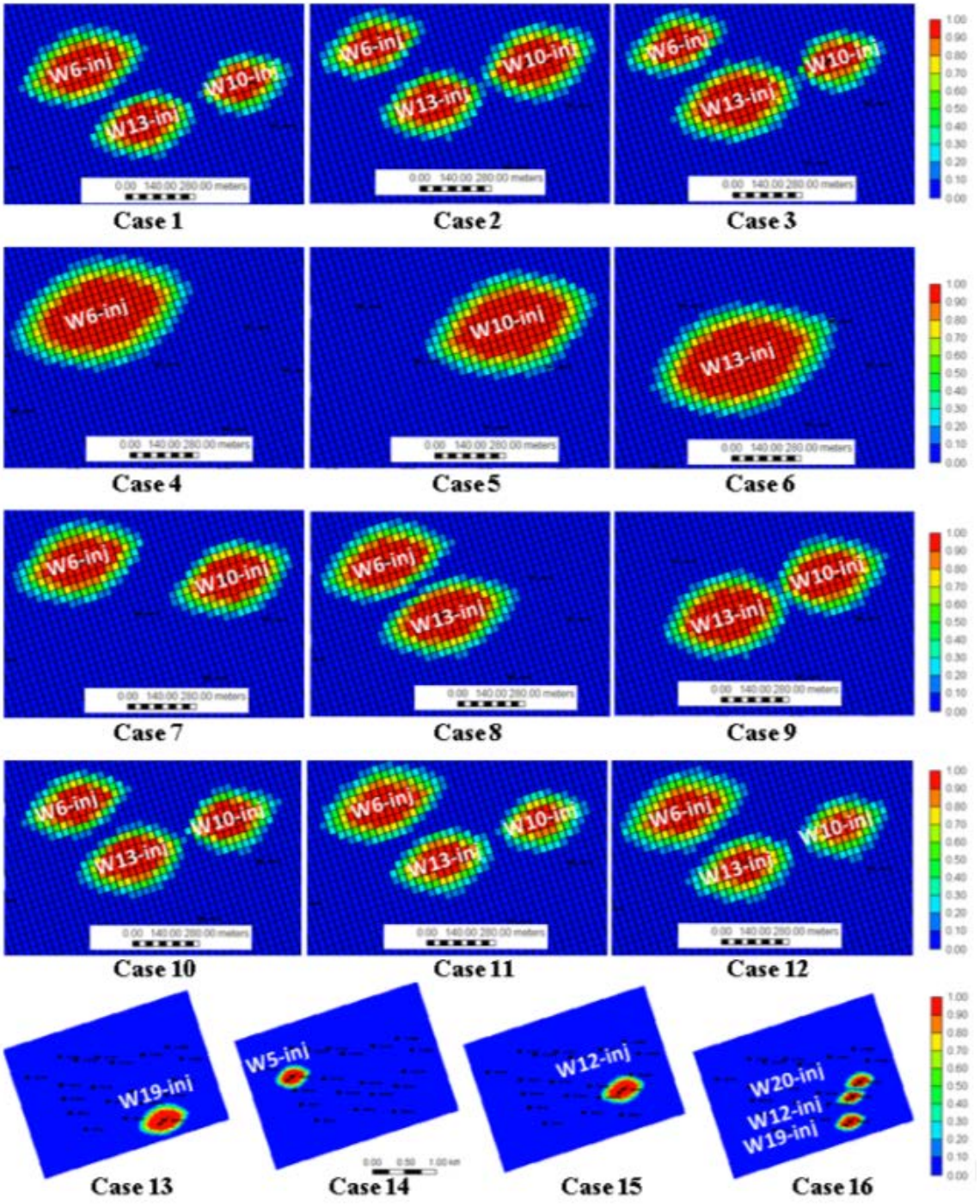


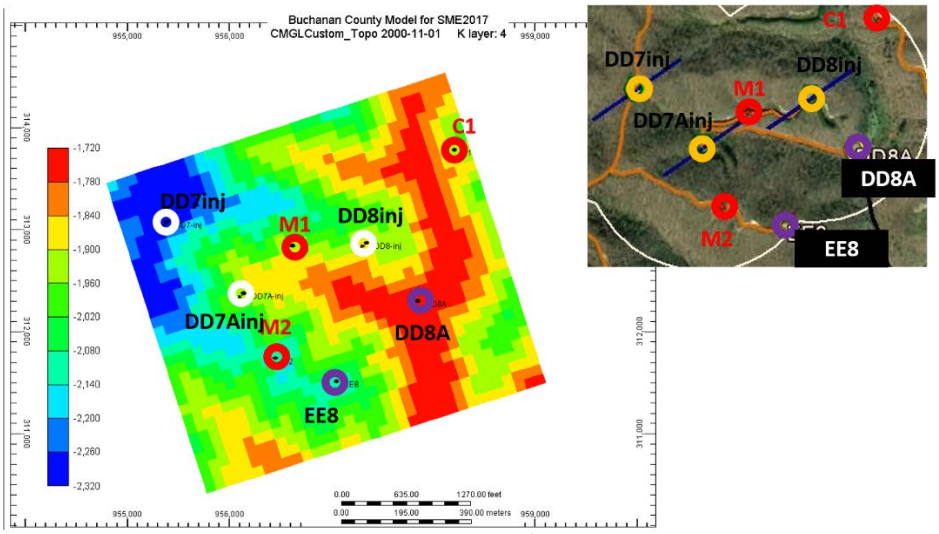
Figure 9-134 shows global mole fraction for CO2. CO2 plumes are extensively developed in hydraulic fracture direction. Anisotropic permeability ratio (I:J) of 3 was used to provide a hydraulic fracture effect. For cases 2, 3, 8, 9 and 10, where the injection rate for W10-inj and/or W13-inj were higher than 7.97 m3/day, CO2 breakthrough was occurred between injection wells.

Figure 9-134 Global mole fractions (CO2) at layer 10 for each case study



The second post-injection reservoir model included 5 wells (Figure 9-135). Three of those wells were converted into CO2 injection wells. The complex model developed by technical team consists of a 16-layer model.

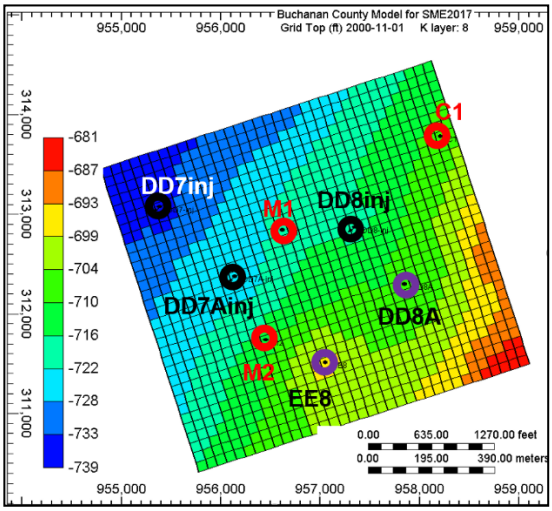
Figure 9-135 Topographic map of the CO_2 injection area



Reservoir Modeling Inputs

The grid size was set to 100ftx100ft, with the grid extending to 35 blocks in the I (x) direction and 32 blocks in the J (y) direction and 16 blocks in the K (z) direction. Modeled area was around 11.2E6ft2. Face and butt cleat directions, which were observed in a nearby mine in Buchanan County, VA, are N 18° W and N67°E, respectively. Moreover, the dominant hydraulic fracture direction is nearly parallel to the butt cleat direction. Since the hydraulic fracture direction is the dominant fracture system to transfer water and gas from the reservoir, the model grid was generated based on hydraulic fracture direction where the I direction was set. Figure 9-136 and Figure 9-137 illustrate the topographic and structure contours around the injection wells plotted in modeling software.

Figure 9-136 Structure map of Pocahontas 10 coal seam with well names and locations (legend in ft).



The target coal seams were Pennsylvanian-age and part of the Lee and Pocahontas formations. The major seams in those formations include the Greasy Creek, Seaboard, Lower Seaboard, Upper

Horsepen, and Pocahontas No. 11, through No. 2 Seams. Well perforations were included into the model using well completion reports. Table 9-57 shows the perforated seams and wells used in the model. Perforated seams were marked with starts "*" in the table.

Table 9-57 Wells and seams used in the model

Seams	Wells in the Model				
	DD7	DD7A	DD8	DD8A	EE8
GC20					
SE20	*	*	*	*	*
LS20	*	*	*	*	*
UH10	*	*	*	*	*
UH20	*		*		*
P11	*		*	*	*
P1010	*	*	*		*
P1020	*	*	*		*
P910-P920	*	*	*	*	*
P710		*	*	*	*
P510			*		*
P520	*	*			*
P420	*	*	*		*
P310	*	*	*		*
P340-P350	*	*	*	*	*
P210					

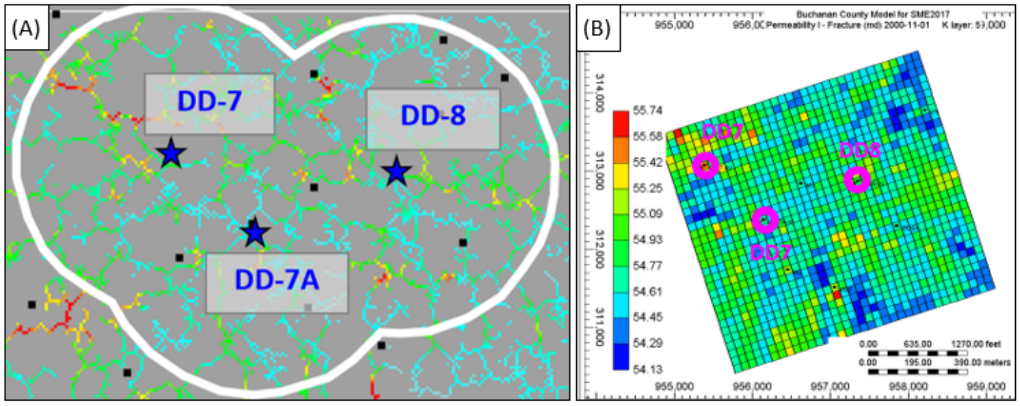
Gas compositions in shallow coal seams were measured in production wells and monitoring wells. Compositions in deeper seams were measured only in monitoring wells. Based on the gas composition measurements, CH_4, N_2 C_2H_6 and CO_2 gases are the dominant gases in the coal seams so to simplify the model, only those gases were included into the model. Since gas compositions were different for shallow and deep coal seams two different values for each component assigned as in Table 9-58. Shallow coal seams were seams between Greasy Creek and Pocahontas 9 coal seams while deep seams are seams between Pocahontas 7 and Pocahontas 2. Langmuir constants and desorption time were measured for several coal seams and they were assigned in to the model. If there is no data for the seam, then the closest seam's data was used. The ratio between CO_2: CH_4, N_2:CH_4 were calculated for P3 coal sample and the same ratio was applied to other coal seams.

Table 9-58 Gas components and compositions used in the model

Seams		N_2 %	CH_4 %	CO_2 %	C_2H_6 %
Shallow	GC20-P9	0.56	98.53	0.41	0.50
Deep	P7-P2	1.05	97.48	0.08	1.39

The permeability in the matrix is very low compared to the permeability in the cleats (=0.001 mD) therefore a dual porosity system was used to model the coalbed methane reservoir. Active fracture network of the coal seams was measured using tomographic fracture imaging. The values inferred from tomographic imaging was used for cleat permeability. Cleat permeability values assigned in HF direction and it was changing between 54-56 mD and the face/butt cleat permeability ratio was set as 2. The permeability in the cleats was varied by seam and well area. Figure 9-137A and Figure 9-137B demonstrate the active fracture network using tomographic fracture imaging and cleat permeability values assigned to the model based on the active fracture network data, respectively. Cleat spacing was assumed 0.2 inches for each direction.

Figure 9-137 Active fracture network around the injection wells (B) Cleat permeability values for one layer



Modeling Methodology

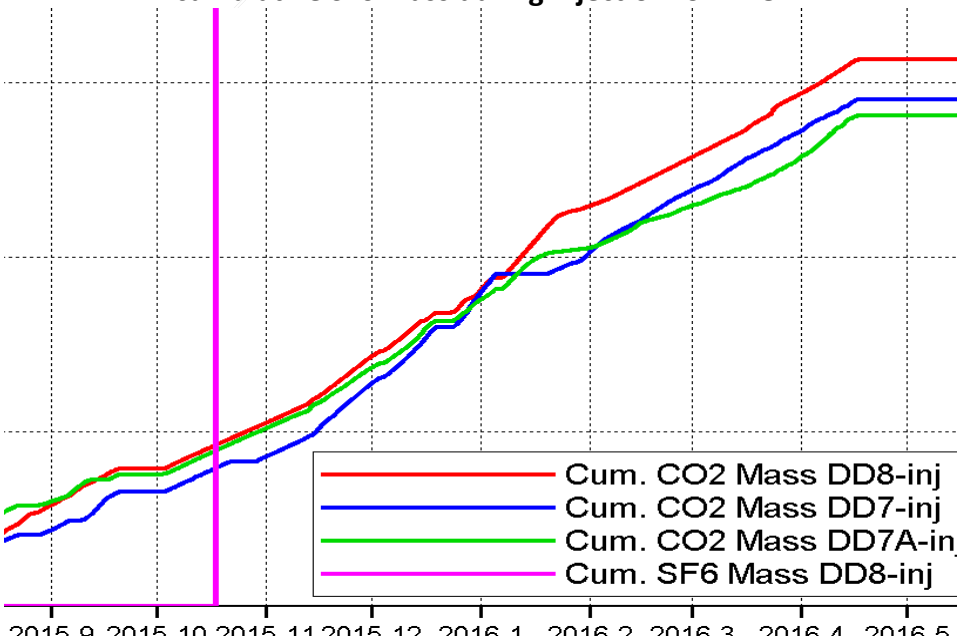
CO2 and SF6 tracer injections were modeled together in GEM simulator to estimate CO2 plume and tracer movements. CO2 and SF6 behavior were investigated for several layers to observe how CO2 and SF6 migrated when the injection or production wells were perforated or not perforated.

CO2 injection was modeled using daily data and SF6 was modeled using hourly data. Injection dates and cumulative CO2 masses injected for each well is tabulated in Table 9-59. Figure 9-138 illustrates the cumulative injection masses for each well.

Table 9-59 CO_2 and SF6 injection data used in the model

	DD7A	DD7	DD8	DD8
	CO2 injection			SF6 Injection
Injection Commencement Date	7/3/2015	7/8/2015	7/7/2015	10/17/2015-1pm
Shut-in Date	4/16/2016	4/17/2016	4/16/2016	10/17/2015-2pm
Number of days (hrs) in injection	290	278	285	(1)
Cumulative Injected Mass, tonne (g)	2,810	2,905	3,132	119.4

Figure 9-138 Cumulative CO2 mass during injection for each injection well and cumulative SF6 mass during injection for DD8.



Modeling Results: Sensitivity Analysis

CO2 plume was investigated in four seams for five different days (Figure 9-139). Figure 9-139 illustrates Seaboard 20 (Layer 2), Pocahontas 11 (Layer 6), Pocahontas 9 (Layer 9) and Pocahontas 5 (Layer 11)

seams. All wells in the model were perforated in Layer 2 and Layer 9. All wells except DD7A were perforated in Layer 6. DD7, DD7A and DD8A were not perforated in Layer 11.

Since permeability I to J ratio defined as 2:1, the CO2 plumes having an elliptical shape rather than a circular shape. CO2 plumes elongated in I direction (in HF direction) and the plume extent reached to 275 m after 9.5 month of CO2 injection. The results showed that this model worked to investigate the plume for short period of times (i.e., days). To see the bigger picture, all the wells close to the model needs to be included into the model. Moreover, permeability ratio is important to estimate the shape of the plume. In this area HF is almost in the same direction with butt-cleat, so high permeability was assigned to butt cleat to create a HF effect in the model. To see the gas and water production and CO2 injection behavior in a shorter period of time which means to see the effect around injection wells, this approach worked well, but to see the bigger picture, HF needs to be assigned to the model and face to butt cleat ratio must be defined as J:I =2:1 or larger.

Based on the field and lab measurements, SF6 reached M1 after 6 days and DD8A after 18 days. Figure 15 shows the same seams Seaboard, Pocahontas 11, Pocahontas 9, and Pocahontas 5 seams for SF6 injection after 1 hour of injection, after 6 days, after 10 days and after 18 days. After 6 days, SF6 composition was higher on M1 than on DD8A for each coal seam simulated here. In the seams where DD7A was perforated as in Seaboard and P9 seams, the SF6 emission in DD7A direction was less than SF6 emission in other seams, because CO2 injection in DD7A pushed the CO2 toward DD8-inj well. Injected CO2 behaved like a barrier for SF6 in Seaboard and P9 seams. On the other hand, in seam P11 and P5, DD7A was not perforated so SF6 moved more in DD7A direction. Moreover, DD8A was not perforated in P5 seams, so since it did not produce gas, SF6 did not reach to DD8 unlike in other seams. After 18 days, SF6 was seen in both wells. The composition of SF6 was higher in between M1 and DD8 because the wells in the other side (i.e., right) were not included into the model.

As a conclusion, considering the perforations are significant in reservoir modeling, depending on the perforations, pressure changes around the well due to production and injection, this affects the plume area and emission direction. Advantages of creating a model with smaller area helped to change parameters easily and run models and see the changes in each parameter in short period of time as well as save computer’s memory.

Figure 9-139 CO_2 plume in four coal seams for six different days

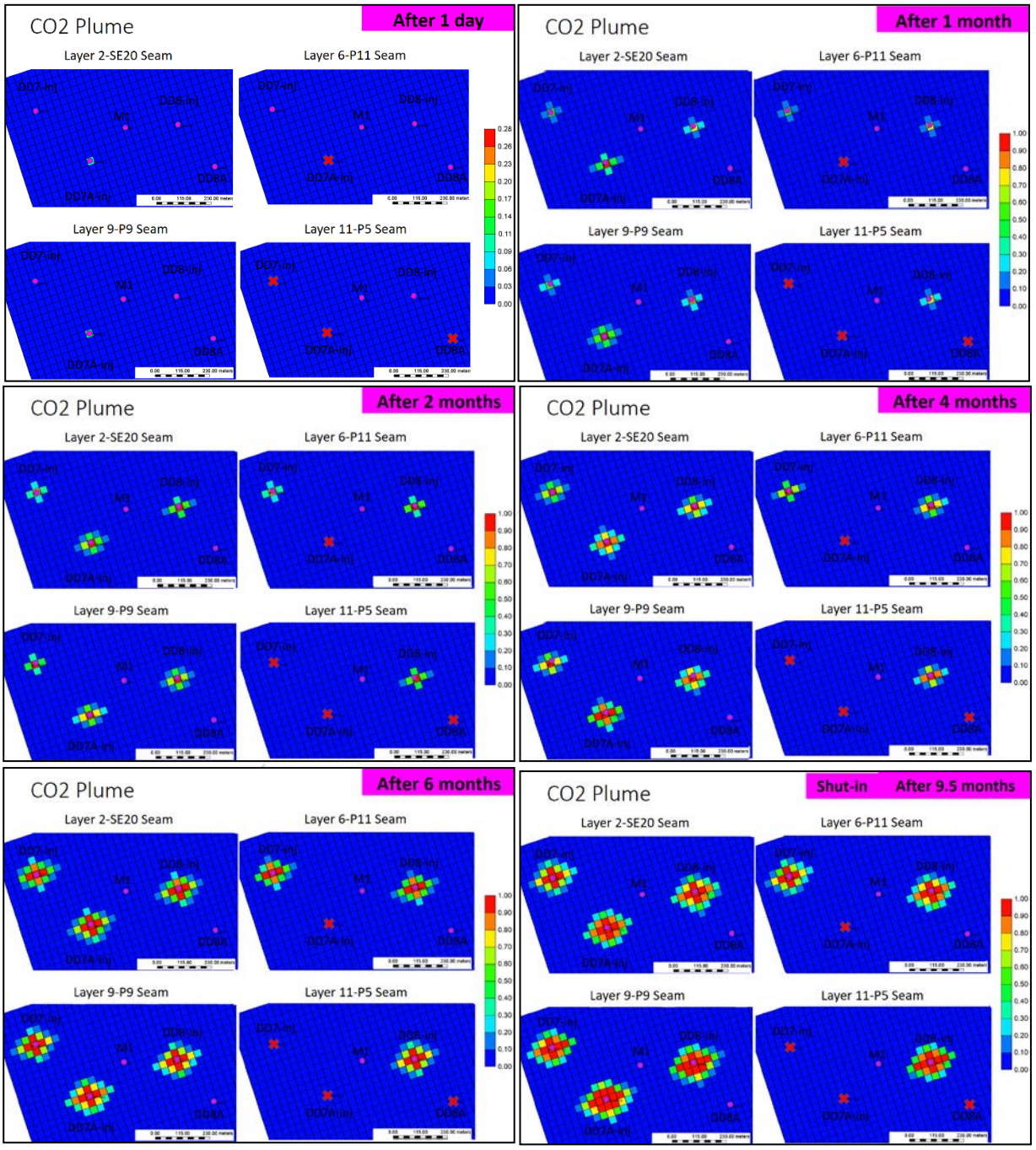
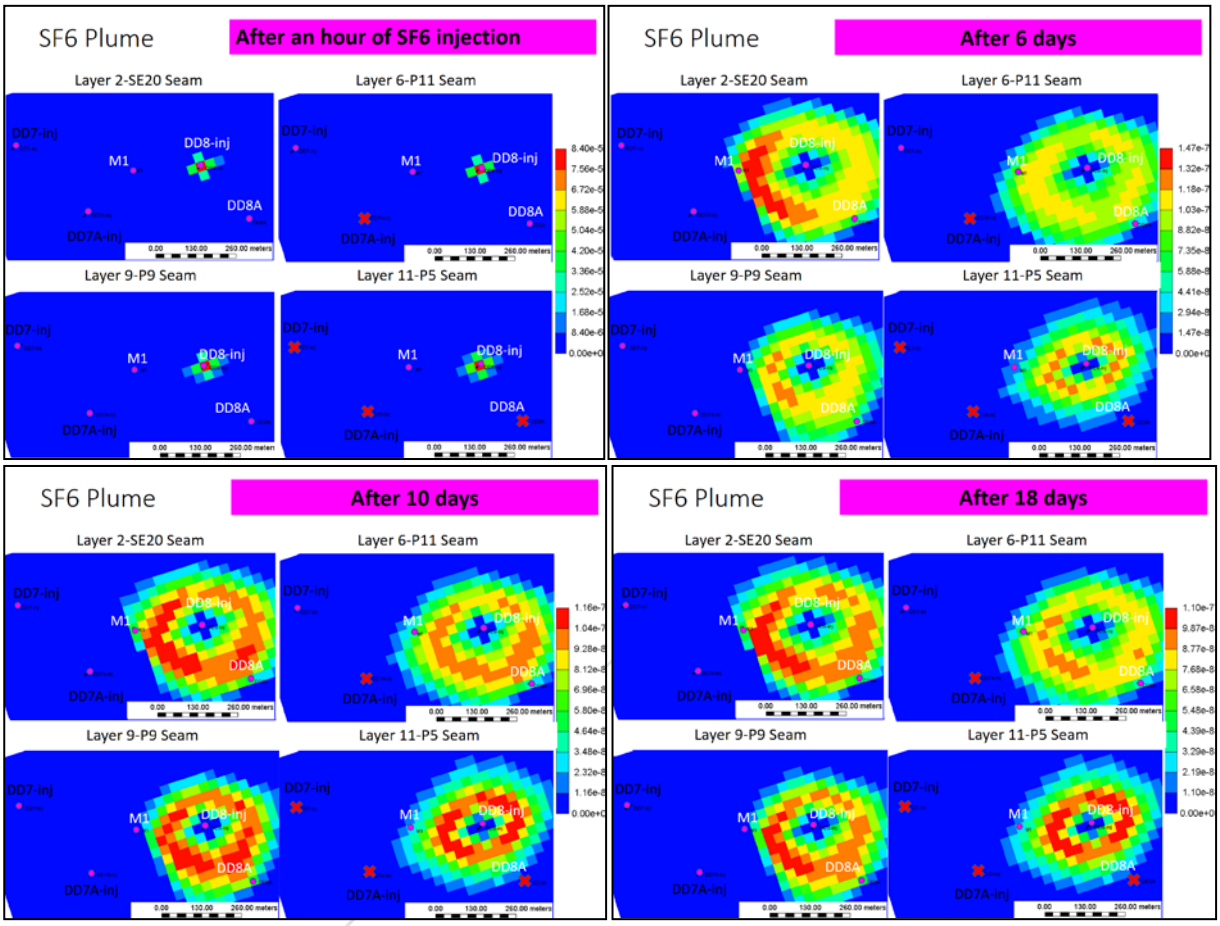


Figure 9-140 SF6 Plume in four coal seams for four different days



9.9 Site Closure

9.9.1 Flow Back

The injection wells were shut-in from January 29, 2017 until flow back operations were initiated on September 7, 2017. Prior to flow back, a few modifications were made to the injection skid and pipelines. The project team wanted to measure the volume of gas being flowed back from the wells. It was determined that the flow could be reversed from the injection flow direction and measured through the Coriolis meters on the skid. Furthermore, after discussions with CNX Gas, they preferred the flow back go into its pipeline rather than vent any CO_2 and methane to the atmosphere.

Check valves that were installed upstream of the wellheads to prevent CO_2 from back flowing during injection were removed so flow could come out of the wellheads. The control valves on the skid were removed and replaced with spool pieces to remove any obstruction to flow. The Coriolis meters were turned around to properly accept gas flow in the correct direction and the cumulative total counter on each meter was reset to zero to measure the cumulative flow back. Another check valve on the original

inlet piping on the skid was turned around to enable flow to the CNX pipeline. CNX then connected a flow line from the skid to tie into its gathering line that flows to the inlet of its 1006 compressor station.

On September 7, CNX brought its mobile gas chromatograph unit to the 1006 station to monitor the CO_2 concentration in the gas after the flow back gas is mixed with the CBM production in the inlet gathering line. The injection wells were opened one at a time to gradually increase flow in the system while the CNX valve to the gathering line was approximately 50% open. Although the flow back gas was nearly 100% CO_2, CNX indicated that the gas was diluted by the CBM volumes and the concentration was acceptable. The initial flow back rate was set at approximately 9.3 mTons/day. Over the next three weeks as the wellhead pressures continued to fall, as well as the flow rates, the valve to the CNX pipeline was gradually opened. This increased the flow back out of the wells. Once the valve was 100% open, the flow back during this period reached a peak of 13 mTons/day and declined to 7 mTons/day when CNX changed its gas flow operations. Due to the change in flow operations, CNX had to shut-in the flow back gas on September 28 until its revised operations were stable. CNX had too much oxygen in the gas flow stream from GOB well producers. The valves on the skid were reopened to flow into the CNX gathering line on October 3. The peak flow rate over the next month reached 9.92 mTons/day and declined gradually to 5.65 mTons/day until well work commenced on November 2 to prepare the wells for Welldog's logging operations.

9.9.2 Conversion of Injection Wells to Production Wells

Upon completion of the Welldog logging operations, L&D Well Service moved its service rig back on the DD-7, DD-7A, and DD-8 wells to complete the conversion of the injection wells back to production wells. The rig ran production tubing, pump and rods and connected the rods to the CNX pumping unit. This completed the set up as a production well and the wells were then turned over to CNX operations.

9.9.3 Disposition of Monitoring Wells

L&D also pulled the tubing, packer, cables and downhole pressure gauges out of the wellbores in the C-1, M-1 and M-2 monitoring wells. The tubing from these wells was transferred to the former injection wells and used to convert them to production wells.

The M-2 well was shut-in and transferred to CNX for them to complete as a CBM production well. The C-1 and M-1 wells were then plugged and abandoned by placing cement from total depth to the surface as instructed by the DGO. The well sites were reclaimed as required under the DGO regulations.

9.9.4 Disposition of Pipeline

All the above ground pipelines were cut into approximately 40' lengths and moved to the CNX pipe storage yard. The two sections of pipeline that were buried will remain in place. A solid cap was welded on to the end of these pipelines. The injection skid that was connected to the pipelines was removed from the site and transferred to Marshall Miller & Associates' storage yard. All sites were cleaned of debris and returned to CNX in its original condition.

9.10 Conclusions and Recommendations

A small-scale CO2 injection test was conducted in southwest Virginia to assess the storage and ECBM potential of CO2 in a stacked coalbed methane reservoir. This goal of the test was to inject up to 20,000 tons of CO2 into a coal reservoir of approximately 15-20 stacked coal seams. Phase I of the injection test was conducted from July 2, 2015 to April 15, 2016 where a total of 10,601 tons of CO2 was injected. Phase II of the injection was conducted from December 14, 2016 to January 30, 2017 where an additional 2,662 tons of CO2 was injected, for a total of 13,263 total tons of CO2 injected. Post-injection monitoring occurred through December 31, 2017 when the wells were returned to CNX Gas and returned to production. A customized plan was created to monitor CO2 injection activities, including surface, near-surface, and subsurface technologies.

The monitoring program for the CO2-ECBM test in Buchanan County, Virginia, has demonstrated success in characterizing the behavior of the coal reservoir in response to CO2 injection. The monitoring results and findings validate the design efforts and rationales for technology selection described previously.

The use of multi-scale monitoring technologies constrained interpretations of reservoir behavior in a complex monitoring environment. Perhaps the best illustration of this relates to a synthesis of monitoring observations from injection well DD7. Gas and water production history for the well indicate that it is a consistently strong gas producer with little water production. Its strong performance, coupled with its location on the flank of a local anticline, led to early suspicions that the reservoir near DD7 has enhanced permeability due to structural deformation.

Borehole liquid level measurements at the start of Phase I injection operations recorded the rapid evacuation of a 500-ft water column from the DD7 wellbore. In contrast, water levels in DD7A and DD8 rose slightly during the same time interval. Analysis of microseismic data recorded over the same period shows a strong, deep-focusing signal near DD7 that is persistent during early injection. This signal is interpreted as evacuation and transportation of formation water from the DD7 wellbore, possibly assisted by enhanced permeability. The rise in water levels at DD7A and DD8 are interpreted as pressure responses from the DD7 water plume.

A tracer deployed in the accumulated water of DD7 shortly before the start of CO2 injection was detected at several offset CBM production wells, all up-dip from DD7. This seems inconsistent with the indication of water from DD7 impacting DD7A and DD8, which are located down-dip. Additionally, microseismic results indicate water transportation in both directions. However, production rate tests performed on several wells across the study area and under different operational conditions all suggest that most gas flow occurs in the shallow reservoir interval. Formation logging supports this case with observations of geomechanical character for shallow and deep reservoir intervals. These observations

point to a possibility that the tracer deployed in DD7 evaporated out of the formation water prior to CO2 injection or was not successfully deployed in the water initially.

An integrated interpretation of all DD7 monitoring observations points to the governing role of geologic structure and suggests that injected CO2 migrates up-dip in the shallow coal seams carrying the tracer. This is a conventional gas migration pattern. Coal is typically an unconventional reservoir, but CBM production history and rapid water transportation rates indicate enhanced permeability that could contribute to conventional behavior on the anticline. Water migrated down-dip under conventional behavior, but high injection pressures coupled with well-developed hydraulically conductive fractures on the anticline could have forced water in multiple directions during early injection.

In addition to demonstrating the benefits of multi-scale monitoring for data integration, monitoring results produced several recommendations. Geostatistical analysis of microseismic results proved to be successful for identifying and quantifying spatial trends and changes in the distribution of acoustic energy due to CO2 injection. The management and reduction of large datasets can be obstacles to meaningful analysis, but methods applied to large microseismic data volumes were successful and preserved original data resolution in the dimensions of investigation. Finally, continuous monitoring of injection parameters throughout the operations led to the development of a recommended injection strategy for CO2-ECBM operations.

Monitoring observations during Phase I and Phase II of CO2 injection and the soaking phase suggest the following injection strategy for CO2-ECBM operations:

1. Inject CO2 at a low, sustained rate until either injectivity is lost (high injection pressures put reservoir integrity at risk) or CO2 breakthrough compromises project objectives or CBM operations.

2. Shut-in injection operations for a soaking period. The duration of the soaking period should match the duration of the injection operations (1:1), or may end sooner if measured pressures demonstrate reservoir equilibrium.

3. Repeat CO2 injection-soak cycles or flowback the well for production, depending on project objectives and achieved measured pressures.

4. Maximize CO2 injection prior to final well shut-in.

10 Outreach

The Virginia Center for Coal and Energy Research (VCCER) managed and administered the Public Outreach Plan and the Communication Plan initiated under this project. The Public Outreach Plan (POP) and the Communications Plan (CP) followed the guidelines set forth in the NETL manual, *Best Practices for: Public Outreach and Education for Carbon Storage Projects.*

The VCCER established a Public Outreach Team, drawing on experienced staff available from within the organizations that make up the project's research team ("Project Team"). The Public Outreach Team was led by Margaret Radcliffe, Assistant Director for Operations of the VCCER, and was staffed by both outreach and technical personnel, including engineers and scientists from the organizations that compose the Project Team and those experienced in carbon management outreach and education from the VCCER, CONSOL/CNX, and SSEB. Team members included:

- Margaret Radcliffe, VCCER
- Patti Berry, SSEB
- Kimberly Gray, SSEB
- Cathy St. Clair, Consol Energy
- Brad Kelley, VCCER
- Nino Ripepi, VCCER

10.1 Public Outreach Implementation

The team identified stakeholders for the two test locations in Morgan County, TN, and Buchanan County, VA, drawn from the following targeted groups (Table 10-1).

Table 10-1 Stakeholders for public outreach

Stakeholder Categories	Local	State	Federal
Landowners and Neighbors	Residents, Business Leaders, Chambers of Commerce, Electric Power Companies, Local Environmental Groups		
Elected Officials	Mayor, Boards of Supervisors, County Commissioners, etc.	Governors, Senators, Delegates (VA), Representatives (TN)	U.S. Congressmen, U.S. Senators
Community Leaders	Educators, Religious Leaders, Civic Groups		
Regulatory and Permitting Authorities		Virginia Department of Mines, Minerals and Energy, Division of Gas and Oil; Tennessee Department of Environment and Conservation	EPA Regions 3 (VA) and 4 (TN)
Media Outlets	Newspaper, Television, Radio		DOE/NETL, Professional Associations

The outreach strategy employed was broad, including public meetings and open houses, media contacts through press releases, the development of public information materials, and a project-specific web site.

The following public meetings were held, to which members of the local Board of Supervisors, other elected officials, economic development representatives, federal and state administration, landowners and neighbors, and the public were invited. At each meeting (Table 10-2), project team members made presentations and answered questions.

Table 10-2 Public meetings

Public Meetings			
Date	**Location**	**Event**	**Format**
2/4/2013	Grundy, VA	Buchanan County Board of Supervisors Meeting	Presentation and Q&A
11/14/2013	Wartburg, TN	Morgan County, TN, Chamber of Commerce Luncheon	Presentation and Q&A
9/3/2014	Grundy, VA	Buchanan Public Open House - Pre-Injection	Presentation, Posters, Q&A
10/13/2017	Breaks, VA	Buchanan Public Open House - Post-Injection	Presentation, Posters, Q&A

In local media, advertisements and press releases were employed in conjunction with these events to increase public awareness of the project.

The outreach team developed public information materials that can be printed as page-sized documents to be handed out at events or mailed to stakeholders, as posters to be displayed at events, and supplied through the World Wide Web or via email as pdfs. The content was developed by the team to include a range of information from very basic to project specifics, and all materials were vetted by the research partners and approved by NETL prior to release. The materials (Appendix L) have been updated over the life of the project to insure accuracy and will be maintained as archival records.

- What is Carbon Dioxide?
- Frequently Asked Questions
- CO_2 Monitoring, Verification, and Accounting (MVA)
- Buchanan County Field Site Fact Sheet
- Project Timeline
- Geological Characteristics
- Carbon Dioxide Transport to the Site
- Monitoring, Verification and Accounting Details

A Carbon Management section of the VCCER website was developed. It initially went live, with the materials listed above, on September 3, 2014, in conjunction with the pre-injection open house in Buchanan County. This webpage has evolved over the life of the project to include an overview of the VCCER's activities and research related to carbon management, the outreach materials listed above, and links to the VCCER's presentations at the NETL annual review meeting, providing the ongoing results of the project. During the project period, the VCCER migrated to a new web platform and the Carbon Management page can currently be found at www.energy.vt.edu/carbon-management.html.

10.2 Communications Plan

The Public Outreach Team and Project Team recognized that unforeseen events could alter the project in important ways and the implementation of a formal Communications Plan by the Project Team was necessary. Effective ongoing communications within the Public Outreach Team and with the broader Project Team were established early in the project. All members of the outreach and research teams recognized the need to be proactive in anticipating situations that might occur and to respond quickly and efficiently to any situations that might arise. Over the life of the project, there were no events that caused the communications plan to be invoked.

11 Conclusions

11.1 Major Findings

The Virginia Center for Coal and Energy Research (VCCER) successfully completed two unique CO2 injections into unconventional stacked geologic formations in two locations: (1) ***the Chattanooga Shale in Morgan County, Tennessee*** and (2) ***the Oakwood coalbed methane (CBM) field, in southwestern Virginia***.

These projects helped accomplish the programmatic research goal of understanding the behavior, migration, and stability of carbon dioxide (CO2) in different depositional environments/classes of reservoirs throughout injection and post-injection periods by implementing a rigorous monitoring, verification and accounting plan for both sites. Major findings include:

The Chattanooga Shale Test in Morgan County, Tennessee

i) Injectivity in a horizontal shale well was maintained through continuous injection of 510 tons of CO2

ii) CO2 was contained in the near the wellbore based on pressure monitoring

iii) CO2 storage was verified by post-injection flowback monitoring where greater than 50% of the injected CO2 was retained in the reservoir

iv) Enhanced hydrocarbon recovery was documented during flowback monitoring and included significant increase in natural gas liquids (NGLs)

v) Reservoir models matched flowback of CO2 and NGLs and predicts that the findings can be replicated

The Coalbed Methane Test in Buchanan County, Virginia

i) A comprehensive geologic characterization and monitoring program was deployed that included drilling three monitoring wells

ii) Injectivity into three coalbed methane wells was maintained throughout the life of the project

iii) Slow, but steady and cyclical injection operations both maintained injectivity in the reservoir

iv) CO2 broke through to one off-set well and monitoring activities identified the plume through the use of multiple technologies

v) Microseimic monitoring was utilized to track CO2 movement

vi) A unique reservoir monitoring tool was designed and implemented to track CO2 and injected tracers through individual coal seams

vii) A unique downhole Raman Spectrometry tool was utilized to track CO2 through flowback operations

11.2 Lessons Learned

11.2.1 Technical Challenges

There were several technical challenges that occurred throughout the project. Each item is discussed in detail:

7) Drilling of monitor wells – Technical Challenge: Retrieving core barrel in a timely manner to minimize lost gas through desorption. There were two events where there was a delay in retrieving the core barrel. Both were due to mechanical equipment failures. While pulling the core barrel with the P9 seam in the M-1 well, an O-ring in the rig hydraulic system failed. It took approximately 1 hour to repair the line until the rig could resume pulling the core barrel. A similar episode took place when pulling the P9 seam core barrel in the M-2 well. A hydraulic hose failed on the winch pump. A new line had to be prepared in the shop and the repair lasted 4.75 hours. Unfortunately, neither of these events could have been anticipated or prepared for.
8) Measuring the CO2 temperature injected into wellhead – Technical Challenge: Placement of temperature probe in proper location. The original design location for the temperature probe was in the wellhead on a side-arm fitting beyond where the CO2 turns 90° and flows downward in the tubing. As a result, the temperature probe was essentially measuring the temperature of the wellhead where the CO2 was static. It was necessary to relocate the probe and place it in the flow line immediately before entering the wellhead, thereby giving a valid flowing injection temperature.
9) Wellhead casing pressure annulus monitoring – Technical Challenge: Preventing the ¼" stainless steel tubing line, used to measure pressure, from freezing during winter operations. The annulus, casing-side of wellhead, and the stainless-steel tubing at the injection wells are filled with corrosion inhibited water. During periods of very cold weather, the water in the stainless-steel tubing froze, expanded and placed erroneous pressure on the transducers. Eventually one of the pressure transducers failed and had to be replaced. To alleviate this issue, the stainless-steel tubing was filled with Marvel oil which eliminated freezing.
10) Wellhead casing pressure annulus monitoring – Technical Challenge: Installing pressure transducer with appropriately sized pressure range for the application. The pressure transducer used for the application had a range of 0 – 2,000 psig. This is much too high for this

measurement. The transducer's range should be 0 – 100 psig which would provide greater accuracy.

11) Logging operations in injection wells – Technical Challenge: Operate video camera log to inspect perforations in each coal seam before water encroaches and covers perforations. A video camera log was run in each injection well to examine the perforations to determine whether they are open or closed. The log cannot be run until the well is swabbed through tubing to lower the water level below the perforations and the tubing is pulled from the well. From the time of the last swab until the log was lowered in well bore varied from 1.25 hours to 2.5 hours depending on the depth of the well. In each case, water encroached and covered the P3, P2 and P1 perforations before the camera could view them. The water is too murky for the camera to view through. Unfortunately, this phenomenon is reservoir-induced and cannot be controlled.

12) Logging operations in injection wells – Technical Challenge: Operating the Production Logging Tool in the DD-7A injection well. Unfortunately, the PLT would not pass through the end of the tubing string. The operator moved the PLT up and down several times to try and work through but could not. The PLT was pulled from the well, the spinner taken off and replaced with two weight bars. Several more attempts were made to get through the obstruction by increasing line speed while running in hole. This too was unsuccessful. It is possible that a shard from a ceramic rupture disk did not break away cleanly after conducting the MIT a year earlier. At that time when the service rig was still on the well, a gauge ring should have been run to ensure the tubing inside diameter was completely clear.

13) Logging operations in injection wells – Technical Challenge: Operating the Production Logging Tool in the DD-8 injection well. Weatherford used a jeweled spinner, different from what was used a day earlier in the DD-7 well, because they were concerned about the injection rate not being high enough. Although the jeweled spinner provided data, Weatherford wasn't completely satisfied with the results. Unfortunately, due to the long length of the flow line to this well, Praxair could not achieve the rate Weatherford requested. Weatherford was informed of the injection rates being applied months before the job. They indicated that the rates were acceptable. It appears that this issue was a result of miscommunication.

14) Process control valves – Technical Challenge: Operating the valve 100% of the time. A processor board in one of the three process control valves made by Badger failed. A new board was required, and the valve was out of service for approximately five days until the new board arrived. This is a random event and one that could not have been planned.

15) Uni-directional manual ball valves used on wellhead and CO2 injection lines – Technical Challenge: Use of a uni-directional ball valve not adequately holding pressure. Uni-directional ball valves have an upstream weep hole in the ball that allows for pressure relief due to freezing fluids when the valve is closed. The valve used on the wellhead for the injection tubing is a uni-directional valve and was used to avoid potential freezing of CO2 if the well were shut-in during injection operations. This type of valve has a floating ball and works well when there is a higher pressure

on the upstream side of the valve. However, after injection operations were complete there was no longer any pressure on the upstream side. When the valve is closed, the high pressure is now on the down-stream side coming out of the reservoir and up the tubing string. This pressure pushes the floating ball against the valve seats on the upstream side of the valve creating a seal but allows pressure to enter the ball cavity and ultimately escape through the weep hole. So, this type of valve does not adequately seal when the highest pressure is on the down-stream side. The solution is to avoid the use of a uni-directional valve on the wellhead. If injection operations are suspended and the wellhead must be shut-in a normal ball valve is sufficient. The CO2 in the wellhead above the valve could easily be blown down to eliminate potential freezing and damage to the valve.

16) Power on site to run Praxair CO2 heater/pump skid – Technical Challenge: Praxair needed 460-volt 3-phase power. Praxair had two options to power its equipment. The costlier option was to run a generator with diesel fuel. The preferred option was electric power. The problem was solved when CNX Gas agreed to have its electrical contractor install this power to the DD-7 location. This service was provided under a cost share arrangement that benefited the project finances.

17) Delivery of CO2 to the DD-7 storage tanks – Technical Challenge: Maintain daily deliveries of product over state and lease roads in a safe manner during inclement weather. Praxair scheduled three to four deliveries each day to the site. During periods of ice or snow on the state roads, Praxair suspended deliveries until the roads were clear and safe for the tractor-trailers to traverse the mountain road. After a snow accumulation on the lease roads, it was difficult for the trailers or bobtails to travel to the site. The project team had a contractor who quickly responded by providing a road grader to clear the snow after each event. An additional solution to this challenge was having extra on-site storage tanks to continue to operate when deliveries were suspended. There were two extra 60-ton storage tanks in addition to a 60-ton tank that could maintain injection for at least a day.

18) Daily metered volume of CO2 injected – Technical Challenge: Praxair's metered volume at its pump discharge did not match the metered volume through the Coriolis meters on the measurement skid. The Coriolis meter's mass/volume flow accuracy is +/- 0.10% and +/- 0.25% for liquids and slurries, and gases respectively. The density accuracy for liquids and slurries is +/- 0.0005 g/cm3. These are highly accurate and dependable meters. Praxair's measurement was dependent on a calculation that used a conversion factor to determine the daily rate. This factor was not varied throughout the project but is dependent on the temperature and pressure. As these parameters change so too should the conversion factor. Therefore, the Coriolis metered volumes were accepted as accurate.

11.2.2 Data Communication Challenges

As previously mentioned, the XARTU units on the monitoring wells used free wave radio transmission to transmit data. There were a few issues throughout the project with sending data.

1) Initially, the C-1 XARTU was configured to transmit data directly to the DD-8 on-skid XARTU. However, the dense tree cover and higher elevation topography between the two sites prevented this from happening. Therefore, the C-1 XARTU was reconfigured to transmit data to the DD-8 injection well site XARTU as this was the nearest well and next best option for transmitting data. Unfortunately, communication between the units could never be established so C-1 data was never delivered via radio transmission.
2) The data from the DD-7A well site XARTU was originally but inadvertently programmed to be sent to the M-2 XARTU, upon which data would then be sent to the DD-7A on-skid XARTU. Occasionally, the M-2 XARTU unit went down due to battery discharge or a fuse breaker due to lightning from a storm. When this happened, the DD-7A data could not be retrieved. Since the DD-7A data was more critical than the M-2 data, the system was reconfigured. The M-2 data was programmed to be sent to the DD-7A well site XARTU and then transferred to the on-skid unit.
3) Unfortunately, the communication between the Level TROLL 700 units and the XARTU processor unit at C-1 did not work as planned. The team believes the down hole cable was damaged during installation that prevented data transfer from one of the units. The other unit would not send data through the Modbus connection and the team was unable to convert to retrieval using a 4-20 mA signal. There were, however, two down hole memory gauges used in the well as back-ups that recorded this data.
4) The communication between the Level TROLL 700 units and the XARTU units in the M-1 and M-2 wells worked well at times throughout the project. The negative is that down hole data was only recorded for about five months over the duration of the project. This is because the M-1 and M-2 XARTU units were out of power frequently and unable to record or data was skewed. During the winter months at these wells, it was difficult to keep the batteries charged with solar power due to the shorter daylight period. It is possible that the frequency of data transfer was draining the batteries and the solar panel did not have enough time to recharge the batteries. The frequency of data transfer was changed to try to alleviate the issue. At other times, data was recorded, however, it did not appear to be reliable as the data was much different than the previous trends. The team has been unable to determine what caused the data error. Again, each well has two down hole memory gauges used as back-ups to record and store the data.

11.3 Commercialization Opportunities

As an element of the project closeout, the project team prepared a Commercialization Plan, which is included in its entirety in Appendix M. The Commercialization Plan addresses three objectives: 1) to summarize the work completed with emphasis on unconventional storage reservoirs vs conventional enhanced oil recovery (EOR) storage; 2) to recommend research initiatives that will advance the field work to Technology Readiness Level six (TRL6) for systems verification in a relevant environment; and 3) to provide a commercialization roadmap for CO_2 utilization and storage in unconventional reservoirs in Appalachia.

This chapter summarizes the field test results that demonstrate the commercial potential of enhanced recovery in coalbed methane and shale fields as well as recommended research initiatives to improve understanding of these mechanisms and promote wide-spread commercial adoption of these strategies.

11.3.1 Enhanced Production from CBM and Shale wells

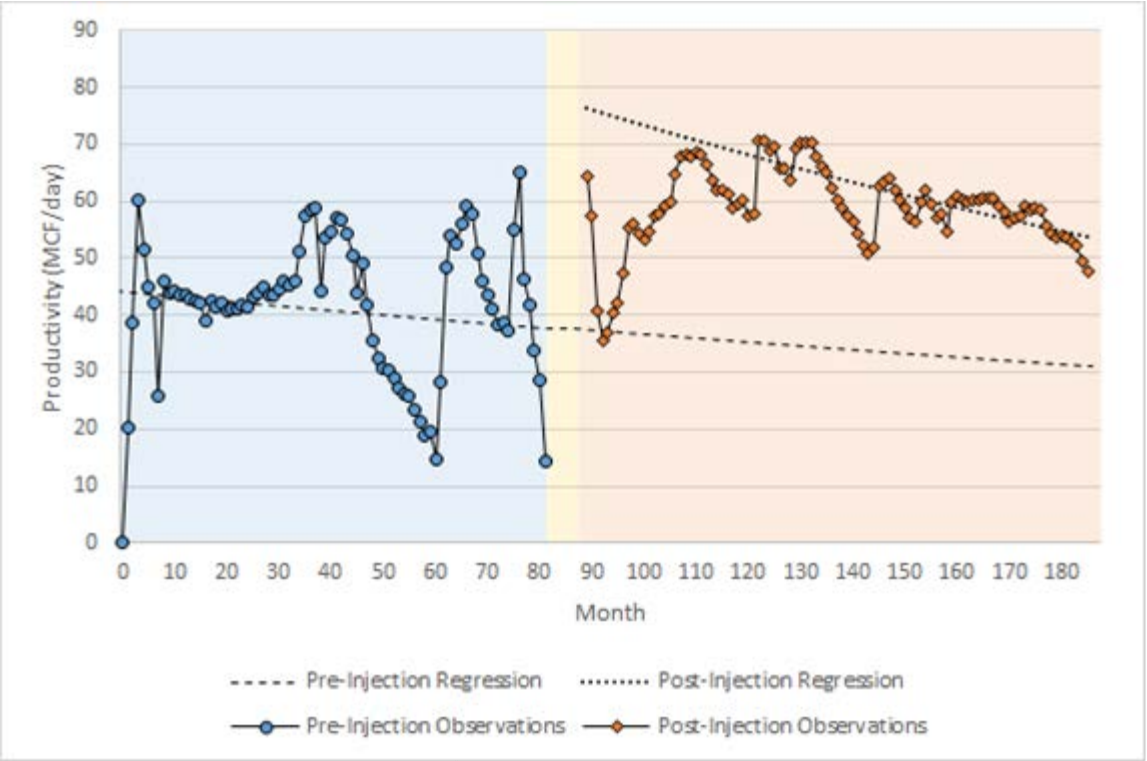
While CO2 is used in many industrial processes, CO2 enhanced oil recovery (EOR) accounts for the majority of global non-captive CO2 consumption and associated storage. Likewise, enhanced coalbed methane (ECBM) and enhanced shale gas (EGS) technologies which use CO2 to increase hydrocarbon recovery from unconventional fields holds great promise as a market-driven use of captured anthropogenic CO2.

In this project, injections of CO_2 were conducted in an organic shale bed in Morgan County, Tennessee and a coalbed methane (CBM) formation in Buchanan County, Virginia. Based upon current and previous small quantity CO_2 injections, mechanisms for CO_2 trapping and enhanced hydrocarbon recovery in organic shales and coal bed methane formations are unlike the trapping/recovery mechanisms noted in CO_2 enhanced oil recovery. Oil recovery relies on CO_2 to sweep hydrocarbons from injection wells to production wells. The CO_2 huff-and-puff treatment that is conducted on organic shale and coal bed formations acts to “stimulate” hydrocarbon production, while retaining the bulk of the injected CO_2 for long-term storage.

Results from two previous Southeast Regional Carbon Sequestration Partnership (SECARB) Phase II projects in Central Appalachia (2009) and the Black Warrior Basin (2010) report that CO_2 stimulation of coal bed methane wells can result in post-injection increases in gas production of 50% above pre-injection levels. The increase in methane production seen in the results from the 2009 and 2010 projects were also seen in the Tennessee shale well project and are expected to be present in Virginia CBM project.

Detailed post-injection production data (2009 – 2017) has been maintained on the SECARB Phase II CBM well in Russell County, Virginia. The project team has modeled the pre-injection decline curve for the well and modeled the expected decline curve resulting from enhance methane production after CO_2 stimulation (Figure 11-1). The projected increase in methane production is approximately 40% per year. In addition, the assumed shut in date of the well could be extended by decades, due to higher annual gas production levels.

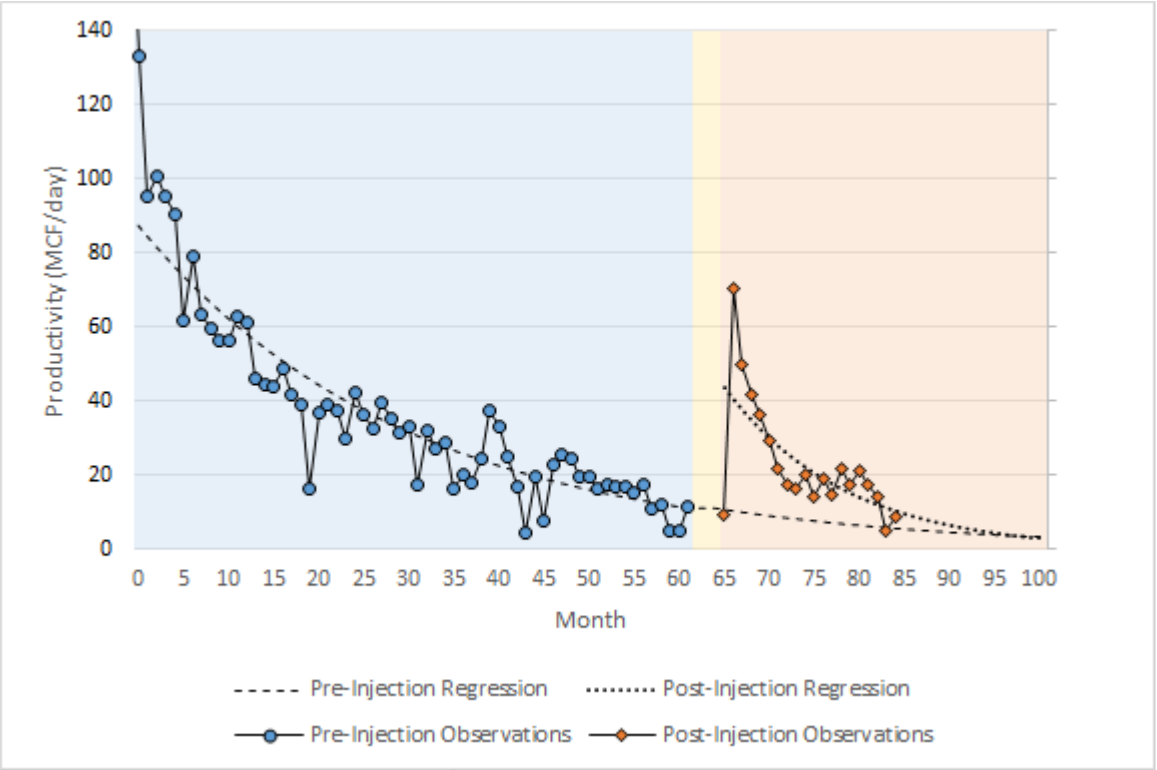
Figure 11-1 Russel County, VA CBM well production data



The 2010 Black Warrior Basin test was conducted in a mature CBM production well in the Blue Creek Degasification field in Alabama and included the injection of 3,250 barrels of water and 252 tons of CO_2 in a battery of slugs over two months. The results of injections showed that the "post-test production performance of the test well has improved substantially relative to that in the four years prior to CO_2 injection. Gas production for the first year after the injection tests was limited as the bulk of the injected water flowed back to the wellbore. As the water rate decreased, the gas rate improved by >50% relative to the pre-injection rate. Long-term improvement of well performance is apparently related to a number of factors, including the removal of wellborn scale, dissolution of cleat-filling calcite and displacement of CH_4 as CO_2 is adsorbed into the reservoir matrix." (Pashin 2015)

In the Tennessee project, a single-well (510 ton) CO_2 injection into an organic shale bed in 2014 showed an increase in methane production and an increase in gas liquids production during initial flow back (Figure 11-2). The ability to stimulate additional gas and gas liquids production from wet shales could provide additional revenues to justify CO_2 purchases. However, additional research, with larger CO_2 injections, must be conducted before any reliable conclusions can be drawn on enhanced gas liquids production.

Figure 11-2 Morgan County, TN shale well production data



A three-well (13,000 metric ton) CO_2 stimulation injection of coal bed methane seams in Buchanan County, Virginia was completed in 2017. Flow back began in December 2017. The project team will receive production data from the field operator in early 2018 and begin to chart post-stimulation gas production and decline curves.

11.3.2 Recommended Research Initiatives

Additional field laboratory research into ECBM and ESG will continue to reduce the existing gaps in data and information related to how and why ECBM and ESG, with associated CO_2 storage, can work. The reduction or elimination of these gaps will help move commercial scale ECBM and ESGR operators to develop business plans and invest in the Appalachian region to unlock additional methane resources in CBM and Shale formations, while storing CO_2. Some of the near-term opportunities include:

1. Buchanan County, VA – CBM Wells
    a. Monitoring of flowback, including CO_2 content and hydrocarbon composition, from the 3 injection wells placed back into production in December 2017
    b. History match the flowback results for predictive reservoir modeling and the assessment of associated CO_2 storage
    c. Update commercialization opportunities from predictive modeling and flowback results
2. New CBM Injection Project with larger CO_2 volumes

a. Establish a field laboratory test plan for Appalachia that will further confirm CO_2 storage and utilization to level TRL4 for CBM
b. Conduct research on 10-15 CBM wells to approximate a relevant field laboratory environment to establish that the basic technological components are integrated and will work together
c. Study interactions between CBM wells in a 10 – 15 well test to guide commercialization efforts
d. Conduct multi-seam monitoring to better understand preferred flow paths to guide commercialization
e. Vary injection schemes by well to guide engineering development (TRL 5 – 6) and commercialization, including injection rates and soaking times

3. Shale Injection Project with larger CO_2 volumes
    a. Establish a field laboratory test plan for Appalachia that will advance CO_2 storage and utilization to level TRL4 for shale
    b. Conduct tests on 2-5 wells
    c. Focus on oil, condensate and NGL rich formations
    d. Assess multi-well tests to guide engineering development and commercialization by varying injection schemes and soaking time
    e. Conduct multi-injection CO_2 tests on a single well to understand if ESGR and CO_2 storage is repeatable in the same well
4. Hydraulic fracturing with CO_2 in CBM and Shale wells
    a. Establish a field laboratory test plan for Appalachia to assess hydraulic fracturing with CO_2
    b. Conduct tests on 2-5 wells
    c. Determine if production is enhanced with CO_2 fracturing
    d. Determine to what extent CO_2 is stored
    e. Determine if flowback CO_2 can be utilized for CO_2-EGR in the same or nearby wells

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13 Appendix A – CBM Structure Maps

Appendix A – CBM Structure Maps

A1 ..... Regional Overview (Full View) Map
A2 ..... Structure - Pocahontas No. 3 Seam Map
A3 ..... Structure – Beatrice Mine Cleat Adjacent to Keen Mountain Fault Map
A4 ..... Lineaments (Full View) Map
A5 ..... Lineaments (Intermediate View) Map
A6 ..... Lineaments (Close-up View) and Seismic Features Map
A7 ..... Aeromagnetic Map
A8 ..... Overburden Thickness - Pocahontas No. 3 Seam Map
A9 ..... Stress Field Composite Diagram
A10 ..... Regional Geologic Map in Relation to CO2 Injection Wells

Virginia Tech
A1 Small Scale CO_2 Injection Test

Regional Overview Map

SECARB/DOE Desorption Hole Location
Tested by MM&A (2009 / 2014)

Pocahontas No. 3 Seam Deep Mining
(as of August 2017)

Pocahontas No. 3 Seam Total Coal Isoline

Fault

Jess Fork Fault - Dashed Where
Location / Existence Has Been Questioned

Anticline

Syncline

Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary

Oakwood CBM Field

Nora CBM Field

VP-3 Mine CBM Well Location with Direction of
Hydraulic Fracture Propagation
(Island Creek CC. Engr. Dept., 1997)

Cross Sections (See Appendix E)

Local Sections
- A1 - A2
- A2 - A3
- B1 - B2
- G1 - G2
- J1 - J2

Regional Sections
- C1 - C2 Henika
- D1 - D2 Jacobeen
- E1 - E2 Harris
- F1 - F2 Englund
- H1 - H3 Sandia

12,000 0 12,000 24,000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
A1 Regional.dwg mh

Virginia Tech
A2 Small Scale CO_2 Injection Test

Structure - Pocahontas No. 3 Seam

SECARB/DOE Desorption Hole Location
Tested by MM&A (2009 / 2014)

Pocahontas No. 3 Seam Deep Mining
(as of August 2017)

Fault

Jess Fork Fault - Dashed Where
Location / Existence Has Been Questioned

Anticline

Syncline

Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary

400 — Pocahontas No. 3 Seam Structure Elevation
Isoline in Feet (Contour Interval = 20 Feet)

Boundary of Structure Mapping

See Cross Section
Exhibit E9

See Map A3

CH-1-2014
M-1
M-2
CO_2 Injection Site
2015

2010
SECARB Pilot
CO_2 Injection Well
RU-84
(BD-114-M2)

Bull Gap Syncline
Little Paw Paw Fault
Bishop - Bradshaw Fault
(Canebrake)
Patterson Mountain Fault Extension
Harman Fault
Prater Fault
Hurricane Creek Anticline
Hurricane Creek Syncline
IP-8 Fault
Keen Mountain Fault
Russell Fork Fault
Dry Fork Anticline
Pocahontas Syncline
Southwood Mountain Anticline
Buffalo Mountain Fault

Grundy
Harman
Prater
Vansant
Tookland
Deel
Grundy Airport
Patterson
Roth
Pilgrims
Bradshaw
Janet
Oakwood
Keene Mountain
Mount Heron
Leemaster
Deskins
Marvin
Skeggs
Grimsleyville
Rowe
Clell
Vandyke
Keen Mtn
Honaker
Jewell Ridge
Richlands
Duty
Big A Mtn

WV
VA
BUCHANAN CO
TAZEWELL CO
RUSSELL CO
DICKENSON CO

460

2 0 2 4
Scale in Miles
Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

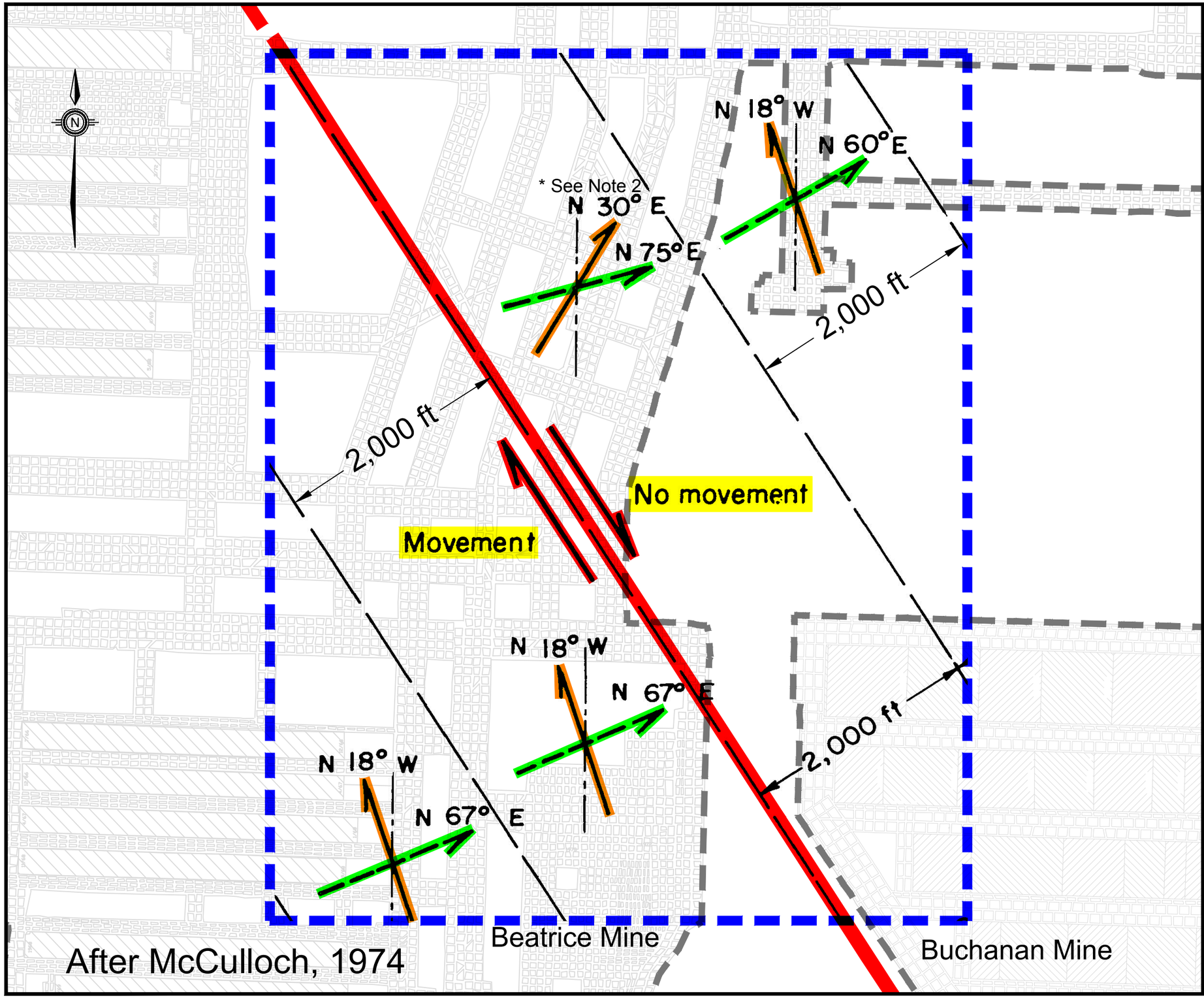
VCER101 Bluefield, VA 11/17
A2 Structure.dwg mh

Virginia Tech

A3

Small Scale CO_2 Injection Test

Structure - Beatrice Mine Cleat Adjacent to Keen Mountain Fault



Pocahontas No. 3 Seam Deep Mining (as of August 2017)

Keen Mountain Fault

Face Cleat

Butt Cleat

Notes:

1. See Map A2 for location.
2. Atypical face cleat orientation at this site may be due to close proximity to fault.

1000 0 1000 2000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17

A3 Beatrice Cleat.dwg mh

A4
(Full View)

Virginia Tech
Small Scale CO_2 Injection Test

Lineaments

- SECARB/DOE Desorption Hole Location Tested by MM&A (2009 / 2014)
- Pocahontas No. 3 Seam Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Boundary of MM&A 1991 Study
- Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary
- Floor Gas Outburst

Lineament Classification Based on Multiple Imagery Sources

- Primary Lineament
- Secondary Lineament
- Tertiary Lineament
- Ⓐ Location Where Mapped Fault or Floor Gas Outburst and Lineament Features are Appoximately Coincident and / or Parallel.

2 0 2 4

Scale in Miles

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
A4&A5 Linears.dwg mh

A5
(Intermediate View)

Virginia Tech
Small Scale CO_2 Injection Test

Lineaments

SECARB/DOE Desorption Hole Location
Tested by MM&A (2014)

Pocahontas No. 3 Seam Deep Mining
(as of August 2017)

Fault

Jess Fork Fault - as per Consol Drawing File;
Location / Existence Has Been Questioned

Boundary of MM&A 1991 Study

Grundy
Vansant

USGS 7.5 Minute Quadrangle Boundary

Lineament Classification Based on Multiple Imagery Sources

Primary Lineament

Secondary Lineament

Tertiary Lineament

Leemaster

Deskins

Skegg

Jess Fork Fault

CH-1-2014

M-1

M-2

Rowe

VP-8 Fault

2015
CO_2 Injection Site

ter Vansant

ty Big A Mtn

N

3000 0 3000 6000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
A4&A5 Linears.dwg mh

A6
(Close-up View)

Virginia Tech
Small Scale CO_2 Injection Test

Lineaments and Seismic Features

CB-DD7 — CO_2 Injection Well Location And Identification

M-1 — Monitoring Well Location and Identification

CB-DD9 — Well Projected onto Seismic Line

Area of Review (AOR)
Monitoring Area

Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned

Vansant / Big A Mountain — USGS 7.5 Minute Quadrangle Boundary

1-5 H3 H2 U D — Sandia Seismic Section with 5 Inferred Fault Locations and Relative Direction of Displacement; Horizontal extent of faults unknown
(U = Upthrown D = Downthrown)

Lineament Classification Based on Multiple Imagery Sources

- Primary Lineament
- Secondary Lineament
- Tertiary Lineament

Note: See Section 4 of report text for seismic sections.

1000 0 1000 2000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
A6 Linears.dwg mh

Virginia Tech
A7 Small Scale CO_2 Injection Test

Aeromagnetic Map

SECARB/DOE Desorption Hole Location
Tested by MM&A (2009 / 2014)

Pocahontas No. 3 Seam Deep Mining
(as of August 2017)

11,300 Magnetic Field Isolines in Gammas

GSW — GNE Axial Orientation of Aeromagnetic Line

Fault

Jess Fork Fault - Dashed Where
Location / Existence Has Been Questioned

Anticline

Syncline

Grundy / Vansant USGS 7.5 Minute Quadrangle Boundary

A1 — A2 Line of Cross Section Shown on Seam Maps

Magnetic Field Categories (Gammas)

11,000 - 11,100	11,300 - 11,400
11,100 - 11,200	11,400 - 11,500
11,200 - 11,300	> 11,500

2 0 2 4

Scale in Miles

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
A7 Aeromagnetic.dwg mh

Virginia Tech
A8 Small Scale CO_2 Injection Test

Overburden Thickness
Pocahontas No. 3 Seam

- SECARB/DOE Desorption Hole Location Tested by MM&A (2009 / 2014)
- 1600 — Overburden Thickness Isoline (Contour Interval = 200 Feet)
- Pocahontas No. 3 Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary
- Less Than 1600'
- 1600'-2000'
- Greater Than 2000'

8000 0 8000 16000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
A8 Ovb.dwg mh

Northwest Quadrant

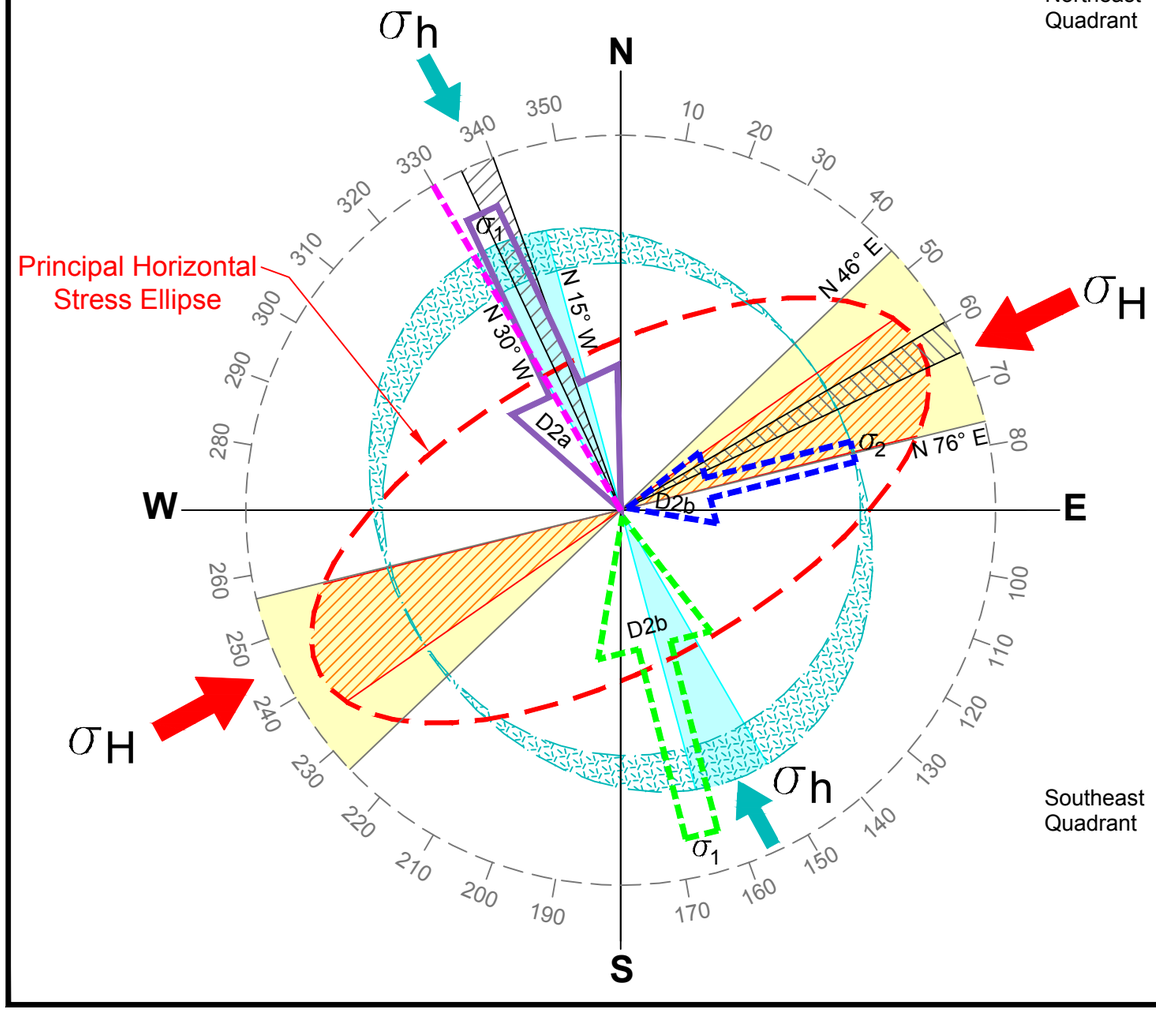
14 Beatrice Mine: Observed Face Cleat
N 18° W at 3 of 4 Sites - See Map A3
(McCulloch, et al, 1974)

15 Core Hole No. CH-1-2014
Estimated Borehole Breakout Range
N 15° W - N 30° W (MM&A, 2014)

16 Primary Lineament Trend
Dominant Direction N 20° - 25° W
See Map A4 (MM&A, 1991)

17 D2a Faults - Mean Maximum Paleo Stress
N 25° W (Byington, 2007)

18 VP-3 Mine Localized Structural Trend
Slump / Horst / Graben Features
N 30° W - See Cross Section Exhibit 8
(MM&A, 2015)



Northeast Quadrant

1 Regional Horizontal Stress: Va, Ky, & Wv
~ N 55° - 66° E (Zoback, et al, 1989)

2 VP-3: Well Frac Direction N 55° - 57° E
(Island Creek CC. Engr. Dept., 1997)

3 Buchanan No. 1 Mine: Observed Hydraulic Fractures
N 56° - 61° E (10/19/2016 & 8/23/2017)
See Maps A1 and D1 - D4(* see note 1 below)

4 Beatrice Mine: Observed Butt Cleat
N 60° - 75° E - See Map A3 (McCulloch, et al, 1974)

5 Monitoring Well C-1
Average Maximum Principal
Compressive Stress N 70° E
(Schlumberger, 2015)

6 VP-3 Mine: Maximum
Principal Compressive Stress
N 76° E - See Map A4 (Campoli, et al, 1990)

7 Primary Lineament Trend
Secondary Direction N 60° - 65° E
(MM&A, 1991)

8 Current Maximum Stress Orientation
N 74° E (Byington, 2007)

9 Dry Fork Anticline Axial Trend
N 61° E (Byington, 2007)

10 D2b Anticlines - Mean Intermediate Paleo Stress
N 76° E - See Map D6 (Byington, 2007)

11 Buchanan Mine: Observed Trend of Coal / Roof
Slickensides and Slips in Southern Area
~N 46° - 76° E - See Maps D5 & D6 (Wickline, 2017)

Southeast Quadrant

12 VP-3 Mine: Minimum
Principal Compressive Stress
S 16° E (Campoli, et al, 1990)
(~Cutter Roof Orientation)

13 D2b Anticlines - Mean Maximum Paleo Stress
S 14° E - See Map D6 (Byington, 2007)

Virginia Tech
A9 Small Scale CO_2 Injection Test

Stress Field - Composite

Range of Maximum Principal Compressive Stress (N 55° - 76° E)

Range of Minimum Principal Compressive Stress (N 15° - 30° W)

Theoretical Borehole Spall Zone

Primary Lineament Trends in Keen Mountain Area (N 20° - 25° W and N 60° - 65° E)

Range of Southern Buchanan Mine Slick-Slip Zone (~N 46° - 76° E)

Current Stress Vectors

σH Maximum Principal Horizontal Compressive Stress Direction

σh Minimum Principal Horizontal Compressive Stress Direction

Paleo Stress Vectors (* see note 2 below)

σ_1 D2a Faults - Mean Maximum Stress (N 25° W)

σ_1 D2b Anticlines - Mean Maximum Stress (S 14° E)

σ_2 D2b Anticlines - Mean Intermediate Stress (N 76° E)

VP-3 Mine Localized Structural Trend (N 30° W)

*Notes:

1. Hydraulic fractures observed in 2016/2017 by personnel from: Coronado Coal, Virginia Tech, and MM&A
2. Paleo stress vectors correlate to the orientation of faults and anticlines based on Byington's description of Deformation Events "D2a and D2b".

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VCER101 Bluefield, VA 11/17
A9 Stress Field.dwg mh

Virginia Tech
A10 Small Scale CO_2 Injection Test

Regional Geologic Map in Relation to CO2 Injection Wells

CBM Study Area
CBM Wells
Shale Study Area
HW-1003
Pine Mountain Thrust Sheet
(Undifferentiated Formational Boundaries)
Valley and Ridge Province
Virginia
Tennessee
North Carolina
Kingsport
Knoxville
Asheville

- Conventional Oil and Gas Well
- CO2 Injection Well
- Surface Faults

Geologic Age

- Pennsylvanian
- Mississippian

14 0 14 28

Scale in Miles

Coordinate System: Tennessee State Plane Nad 27

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VCER101 Bluefield, VA 11/17
A10 Geologic.dwg mh

14 Appendix B – Regional Coal Thickness, Gas Content and Production Trends

B1 ..... Regional Net Coal Thickness (Full View) Map
B2 ..... Regional Net Coal Thickness (Enlarged View) Map
B3 ..... Regional Gas Content Trend – Lee and Pocahontas Formations (Pre-Development) Map
B4 ..... Regional Gas Content Trend –Pocahontas No. 3 Seam (Pre-Development) Map
B5 ..... Gas-in-Place Per Acre (Full View) Map
B6 ..... Gas-in-Place Per Acre (Enlarged View) Map
B7 ..... CBM Development Timing Map
B8 ..... Well Locations Map
B9 ..... CO_2 Injection Test Site Aerial Image

B1
(Full View)

Virginia Tech
Small Scale CO_2 Injection Test

Regional Net Coal Thickness

- CNX Gas CBM Well
- Equitable CBM Well
- Range CBM Well
- Appalachian Energy CBM Well
- SECARB/DOE Desorption Hole Location Tested by MM&A (2009 / 2014)
- 16.96' — Net Coal Thickness Value in Feet
- 14 — Net Coal Thickness Isoline (Upper Horsepen to Pocahontas No. 1); Contour Interval = 2.0 Feet
- Pocahontas No. 3 Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary

Net Coal Thickness

< 8 Feet	20 - 24 Feet
8 - 12 Feet	24 - 28 Feet
12 - 16 Feet	28 - 32 Feet
16 - 20 Feet	> 32 Feet

2 0 2 4

Scale in Miles

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
B1&B2 Net Coal.dwg mh

Boundary of Thickness Mapping

Generalized Stratigraphic Column

Scale 1000' 1100' 1200' 1300' 1400' 1500' 1600' 1700' 1800' 1900'

U. Horsepen 10
U. Horsepen 20
U. Horsepen 30
Poca #11
Poca #10 - 10
Poca #10 - 20
Poca #9 - 10
Poca #9 - 20
Poca #7 - 10
Poca #7 - 20
Poca #5 - 10
Poca #5 - 20
Poca #4 - 10
Poca #4 - 20
Poca #4 - 30
Poca #3 - 10
Poca #3 - 20
Poca #3 - 30
Poca #3 - 40
Poca #3 - 50
Poca #2 - 10
Poca #1 - 10

Grundy
Harman
Grundy
Prater
Vansant
Tookland
Deel
Vansant
Grundy Airport
Janey
Oakwood
Mavisdale
Keen Mountain
Mount Heron
Leeansaar
Deskins
Skeggs
Patterson
Patterson
Roth
Pilgrims
Bradshaw
Marvin
Grimsleyville
Rowe
Vansant
Keen Mt
Honaker
Jewell Ridge
Richlands
Duty
Duty
Slate Mtn
Prater
Vansant
2015 CO_2 Injection Site
2014 SECARB/DOE Observation Well #2
2014 SECARB/DOE Observation Well #1
2015 SECARB/DOE Observation Well #3
2015 SECARB/DOE Observation Well #4
2015 SECARB/DOE Observation Well #5
2015 SECARB/DOE Observation Well #6
2015 SECARB/DOE Observation Well #7
2015 SECARB/DOE Observation Well #8
2015 SECARB/DOE Observation Well #9
2015 SECARB/DOE Observation Well #10
2015 SECARB/DOE Observation Well #11
2015 SECARB/DOE Observation Well #12
2015 SECARB/DOE Observation Well #13
2015 SECARB/DOE Observation Well #14
2015 SECARB/DOE Observation Well #15
2015 SECARB/DOE Observation Well #16
2015 SECARB/DOE Observation Well #17
2015 SECARB/DOE Observation Well #18
2015 SECARB/DOE Observation Well #19
2015 SECARB/DOE Observation Well #20
2015 SECARB/DOE Observation Well #21
2015 SECARB/DOE Observation Well #22
2015 SECARB/DOE Observation Well #23
2015 SECARB/DOE Observation Well #24
2015 SECARB/DOE Observation Well #25
2015 SECARB/DOE Observation Well #26
2015 SECARB/DOE Observation Well #27
2015 SECARB/DOE Observation Well #28
2015 SECARB/DOE Observation Well #29
2015 SECARB/DOE Observation Well #30
2015 SECARB/DOE Observation Well #31
2015 SECARB/DOE Observation Well #32
2015 SECARB/DOE Observation Well #33
2015 SECARB/DOE Observation Well #34
2015 SECARB/DOE Observation Well #35
2015 SECARB/DOE Observation Well #36
2015 SECARB/DOE Observation Well #37
2015 SECARB/DOE Observation Well #38
2015 SECARB/DOE Observation Well #39
2015 SECARB/DOE Observation Well #40
2015 SECARB/DOE Observation Well #41
2015 SECARB/DOE Observation Well #42
2015 SECARB/DOE Observation Well #43
2015 SECARB/DOE Observation Well #44
2015 SECARB/DOE Observation Well #45
2015 SECARB/DOE Observation Well #46
2015 SECARB/DOE Observation Well #47
2015 SECARB/DOE Observation Well #48
2015 SECARB/DOE Observation Well #49
2015 SECARB/DOE Observation Well #50
2015 SECARB/DOE Observation Well #51
2015 SECARB/DOE Observation Well #52
2015 SECARB/DOE Observation Well #53
2015 SECARB/DOE Observation Well #54
2015 SECARB/DOE Observation Well #55
2015 SECARB/DOE Observation Well #56
2015 SECARB/DOE Observation Well #57
2015 SECARB/DOE Observation Well #58
2015 SECARB/DOE Observation Well #59
2015 SECARB/DOE Observation Well #60
2015 SECARB/DOE Observation Well #61
2015 SECARB/DOE Observation Well #62
2015 SECARB/DOE Observation Well #63
2015 SECARB/DOE Observation Well #64
BD-114 (#2)
BD-114 (#1)
WV
VA
TAZEWELL CO
RUSSELL CO
DICKENSON CO
Bishop - Bradshaw Fault (Canebrake)
Projected from Maintain Fault Extension Zone
Jess Fault
Little Paw Paw Fault
Mountain Top Fault
Pistol Ridge Fault
Russell York Fault
Buffalo Mountain Fault
Russelvain Fault
460

B2
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

Regional Net Coal Thickness

CNX Gas CBM Well

20.2 — Old Net Coal Thickness Value in Feet

SECARB/DOE Desorption Hole Location Tested by MM&A (2014)

16.96' — New Net Coal Thickness Value in Feet

Net Coal Thickness Isoline (Upper Horsepen to Pocahontas No. 1); Contour Interval = 2.0 Feet

Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned

Area of Review (AOR) - Red
Monitoring Area - Green

Net Coal Thickness

< 8 Feet	16 - 20 Feet
8 - 12 Feet	20 - 24 Feet
12 - 16 Feet	24 - 28 Feet

Note: See Map B1 for Location.

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
B1&B2 Net Coal.dwg mh

Jess Fork Fault

CH-1-2014
16.96'

M-1
14.40'

M-2
15.02'

1/4 MILE RADIUS

1/2 MILE RADIUS

Generalized Stratigraphic Column

Scale 1000'

U. Horsepen 10
U. Horsepen 20
U. Horsepen 30
Poca #11
Poca #10 - 10
Poca #10 - 20
Poca #9 - 10
Poca #9 - 20
Poca #7 - 10
Poca #7 - 20
Poca #5 - 10
Poca #5 - 20
Poca #4 - 10
Poca #4 - 20
Poca #4 - 30
Poca #3 - 10
Poca #3 - 20
Poca #3 - 30
Poca #3 - 40
Poca #3 - 50
Poca #2 - 10
Poca #1 - 10
Pocahontas

Virginia Tech

B3 Small Scale CO_2 Injection Test

Regional Gas Content Trend Lee and Pocahontas Formations (Pre-Development)

- SECARB/DOE Desorption Hole Location Tested by MM&A (2009 / 2014)
- CNX Gas CBM Well
- Equitable CBM Well
- Range CBM Well
- Appalachian Energy CBM Well
- 390 — Average Gas Content Value (As-Received); Upper Horsepen To Pocahontas No. 1 Seams (scf/t)
- 412* — Average Gas Content Value (As-Received); Anomalous Data Omitted From Average (scf/t)
- 485 — Average Gas Content Value (As-Received); Projected From Pocahontas No. 3 Seam Data Only (scf/t)
- 400 — Gas Content Isoline; Upper Horsepen to Pocahontas No. 1 Seams; Contour Interval = 25 scf/t
- Pocahontas No. 3 Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary

Gas Content Range - As-Received (Original, Pre-Development)

< 250 scf/t	400 - 450 scf/t
250 - 300 scf/t	450 - 500 scf/t
300 - 350 scf/t	> 500 scf/t
350 - 400 scf/t	

2 0 2 4

Scale in Miles

Coordinate System: Virginia South State Plane Nad 27

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B3 Gas Content Lee&Poca.dwg

mh

Generalized Stratigraphic Column

Scale 1000' – 1900'

U. Horsepen 10
U. Horsepen 20
U. Horsepen 30
Poca #11
Poca #10 - 10
Poca #10 - 20
Poca #9 - 10
Poca #9 - 20
Poca #7 - 10
Poca #7 - 20
Poca #5 - 10
Poca #5 - 20
Poca #4 - 10
Poca #4 - 20
Poca #4 - 30
Poca #3 - 10
Poca #3 - 20
Poca #3 - 30
Poca #3 - 40
Poca #3 - 50
Poca #2 - 10
Poca #1 - 10
Pocahontas

Virginia Tech
B4 Small Scale CO_2 Injection Test

Regional Gas Content Trend Pocahontas No. 3 Seam (Pre-Development)

- SECARB/DOE Desorption Hole Location Tested by MM&A (2009 / 2014)
- CNX Gas CBM Well
- Equitable CBM Well
- Range CBM Well
- Appalachian Energy CBM Well
- 482 Core Hole with Pocahontas No. 3 Seam "as Received" Gas Content Value (scf/t)
- 400 Gas Content Isoline - Contour Interval = 50 Standard Cubic Feet Per Ton (scf/t)
- Pocahontas No. 3 Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Grundy / Vansant USGS 7.5 Minute Quadrangle Boundary

Pocahontas No. 3 Seam Gas Content (Original, Pre-Development)

- 250 - 300 scf/t
- 300 - 350 scf/t
- 350 - 400 scf/t
- 400 - 450 scf/t
- 450 - 500 scf/t
- 500 - 550 scf/t
- 550 - 600 scf/t
- > 600 scf/t

2 0 2 4

Scale in Miles

Coordinate System: Virginia South State Plane Nad 27

Generalized Stratigraphic Column

Scale 1000' 1100' 1200' 1300' 1400' 1500' 1600' 1700' 1800' 1900'

U. Horsepen 10
U. Horsepen 20
U. Horsepen 30
Poca #11
Poca #10 - 10
Poca #10 - 20
Poca #9 - 10
Poca #9 - 20
Poca #7 - 10
Poca #7 - 20
Poca #5 - 10
Poca #5 - 20
Poca #4 - 10
Poca #4 - 20
Poca #4 - 30
Poca #3 - 10
Poca #3 - 20
Poca #3 - 30
Poca #3 - 40
Poca #3 - 50
Poca #2 - 10
Poca #1 - 10

VCER101 Bluefield, VA 11/17
B4 Gas Content P3.dwg mh

B5
(Full View)

Virginia Tech
Small Scale CO_2 Injection Test

Gas-in-Place Per Acre

- CO_2 Injection Well Location
- CNX Gas CBM Well
- Range CBM Well
- Equitable CBM Well
- Gas-in-Place Per Acre Isoline (Upper Horsepen to Pocahontas No. 1); Contour Interval = 1.0 MMCF
- CBM Field Grid
- Pocahontas No. 3 Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary
- Area of Review (AOR) - Red
  Monitoring Area - Green

Gas-in-Place Per Acre (MMCF)

< 10 MMCF	16 - 18 MMCF
10 - 12 MMCF	18 - 20 MMCF
12 - 14 MMCF	> 20 MMCF
14 - 16 MMCF	

2 0 2 4

Scale in Miles

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
B5&B6 Gas In Place.dwg mh

Generalized Stratigraphic Column

Scale

1000' U. Horsepen 10 / U. Horsepen 20 / U. Horsepen 30
1100'
1200' Poca #11 / Poca #10 - 10 / Poca #10 - 20
1300' Poca #9 - 10 / Poca #9 - 20
1400' Poca #7 - 10
1500' Poca #7 - 20
1600' Poca #5 - 10
1700' Poca #5 - 20 / Poca #4 - 10 / Poca #4 - 20 / Poca #4 - 30
1800' Poca #3 - 10 / Poca #3 - 20 / Poca #3 - 30 / Poca #3 - 40 / Poca #3 - 50 / Poca #2 - 10 / Poca #1 - 10
1900'

Grundy
Harman
Prater
Vansant
Tookland
Deel
Grundy Airport
Patterson
Roth
Pilgrims
Janey
Oakwood
Mavisdale
Keen Mountain
Mount Heron
Deskins
Marvin
Skeggs
Grimsleyville
Vandyke
Rowe
Cleli
Jewell Ridge
Richlands
Bradshaw
WV
VA
460
Bishop - Bradshaw Fault (Canebrake)
Pocahontas - Keen Mountain Fault Extension Zone
Little Paw Paw Fault
Russell Fork Fault
Pistol Grip Fault
Bluefield - Pocahontas Fault
2015 CO_2 Injection Site
BUCHANAN CO
TAZEWELL CO
RUSSELL CO
DICKENSON CO

B6
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

Gas-in-Place Per Acre

- CO_2 Injection Well Location
- CNX Gas CBM Well
- Equitable CBM Well
- BK112 / 12.7 — Gas-in-Place Per Acre Value (MMCF); With CBM Development Unit Identification Number
- Gas-in-Place Per Acre Isoline (Upper Horsepen to Pocahontas No. 1); Contour Interval = 1.0 MMCF
- CBM Field Grid
- Pocahontas No. 3 Deep Mining (as of August 2017)
- Fault
- Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned
- Grundy / Vansant — USGS 7.5 Minute Quadrangle Boundary
- Area of Review (AOR) - Red
  Monitoring Area - Green

Gas-in-Place Per Acre (MMCF)

< 10 MMCF	16 - 18 MMCF
10 - 12 MMCF	18 - 20 MMCF
12 - 14 MMCF	> 20 MMCF
14 - 16 MMCF	

3000 0 3000 6000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
B5&B6 Gas In Place.dwg mh

Virginia Tech

B7

Small Scale CO_2 Injection Test

CBM Development Timing

VP-3 Mine

Jess Fork Fault

Hurricane Creek Anticline

VP-8 Fault

Syncline

DD-7

DD-7A

DD-8

Grundy

Vansant

Big A Mtn

CO_2 Injection Well Location

Pocahontas No. 3 Structure Elevation Isoline; Contour Interval = 20 Feet

Pocahontas No. 3 Deep Mining (as of August 2017)

Fault

Jess Fork Fault - Dashed Where Location / Existence Has Been Questioned

Anticline

Syncline

USGS 7.5 Minute Quadrangle Boundary

Area of Review (AOR) - Red
Monitoring Area - Green

CBM Completion Dates

- 1990 - 1994
- 1995 - 1999
- 2000 - 2004
- 2005 - 2009
- 2010 - 2013
- Undefined Year

3000 0 3000 6000

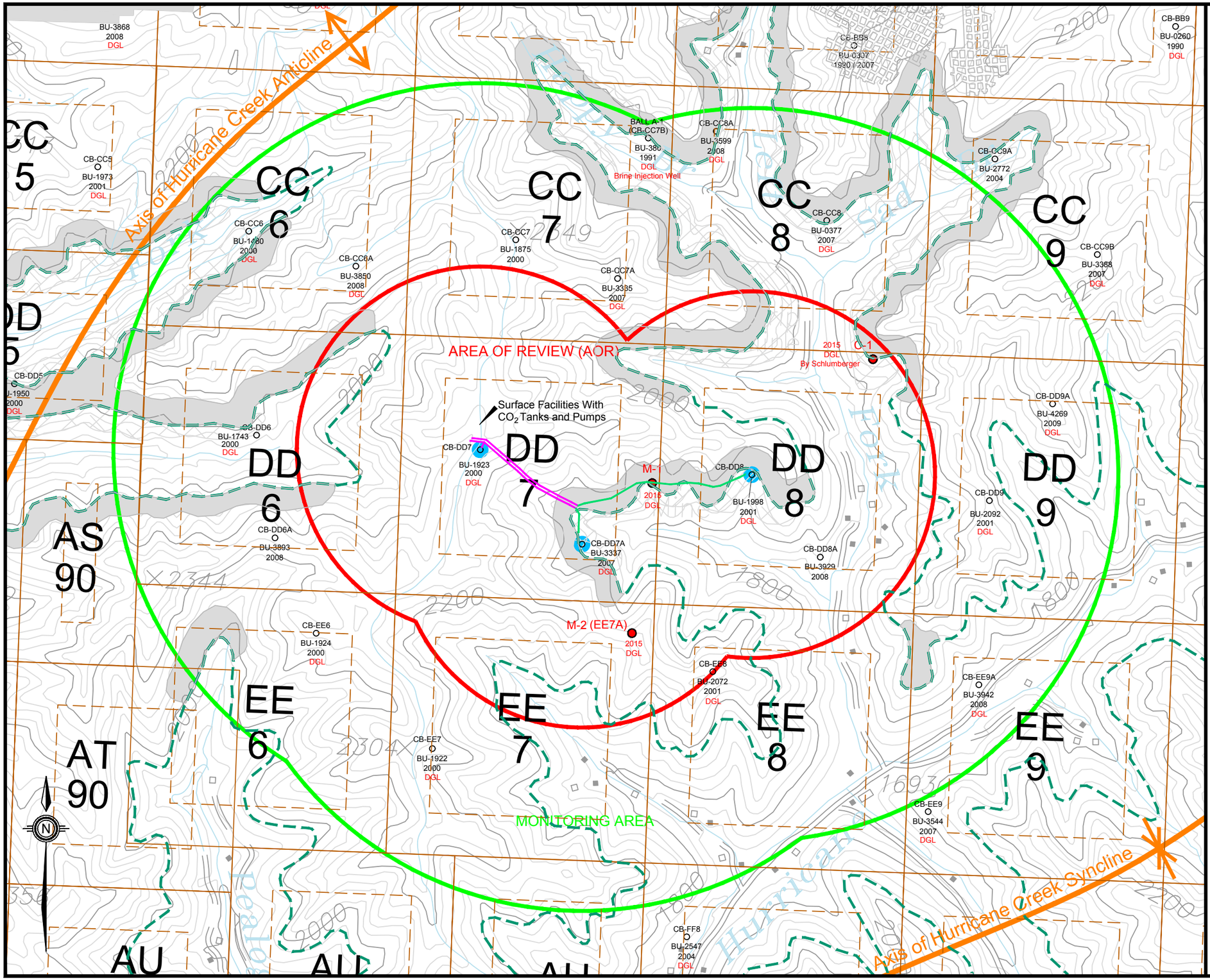
Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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B7 CBM Timing.dwg mh



Virginia Tech

B8

Small Scale CO_2 Injection Test

Well Locations

- CO_2 Injection Well Location
- M-1 — Monitoring Well/Spot Core Location and Identification
- CB-EE7 — CBM Well Location and Identification
- BU-4102 — VDMME File Number
- 1992 — Year(s) Drilled and / or Completed
- DGL — MM&A Digital Geophysical Log Available (Unless Otherwise Noted)
- CC 10 — Oakwood CBM Field Grid
- Area of Review (AOR) - Red
  Monitoring Area - Green
- Kennedy Seam Outcrop Provided by VDMME
- Kennedy Seam Previous Contour Mining
- CO_2 Injection Pipeline
- Buried CO_2 Injection Pipeline

700 0 700 1400

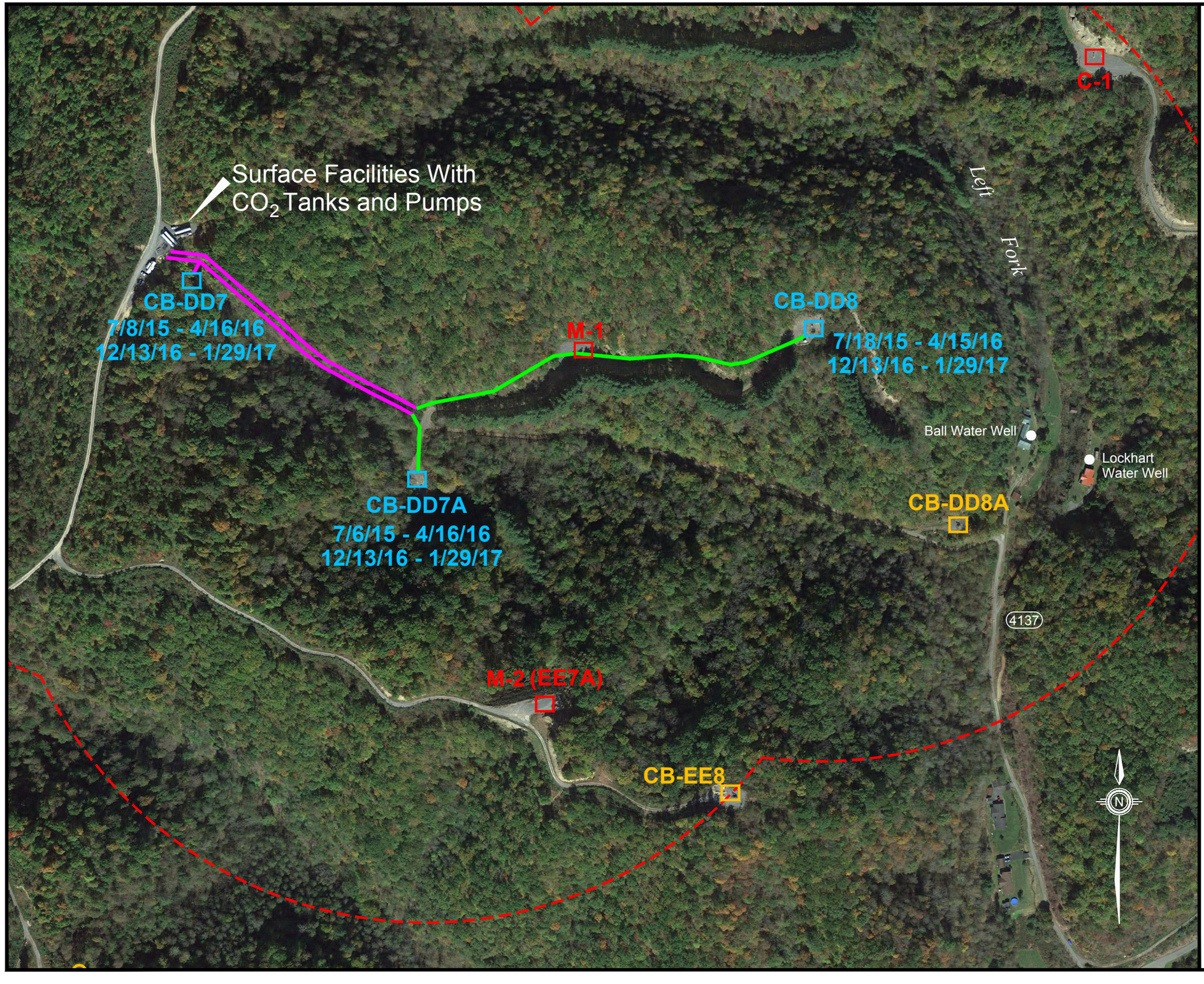
Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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B8 Wells.dwg mh



Virginia Tech

B9

Small Scale CO_2 Injection Test

Image of CO_2 Injection Test Site

CB-DD8 — CO_2 Injection Well Location and Identification With Dates of injection

M-1 — Monitoring Well/Spot Core Location and Identification

CB-EE8 — CBM Well Location and Identification

Area of Review (AOR)

CO_2 Injection Pipeline

Buried CO_2 Injection Pipeline

Note: Date of Google Earth Image: 10/18/15

300 0 300 600

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

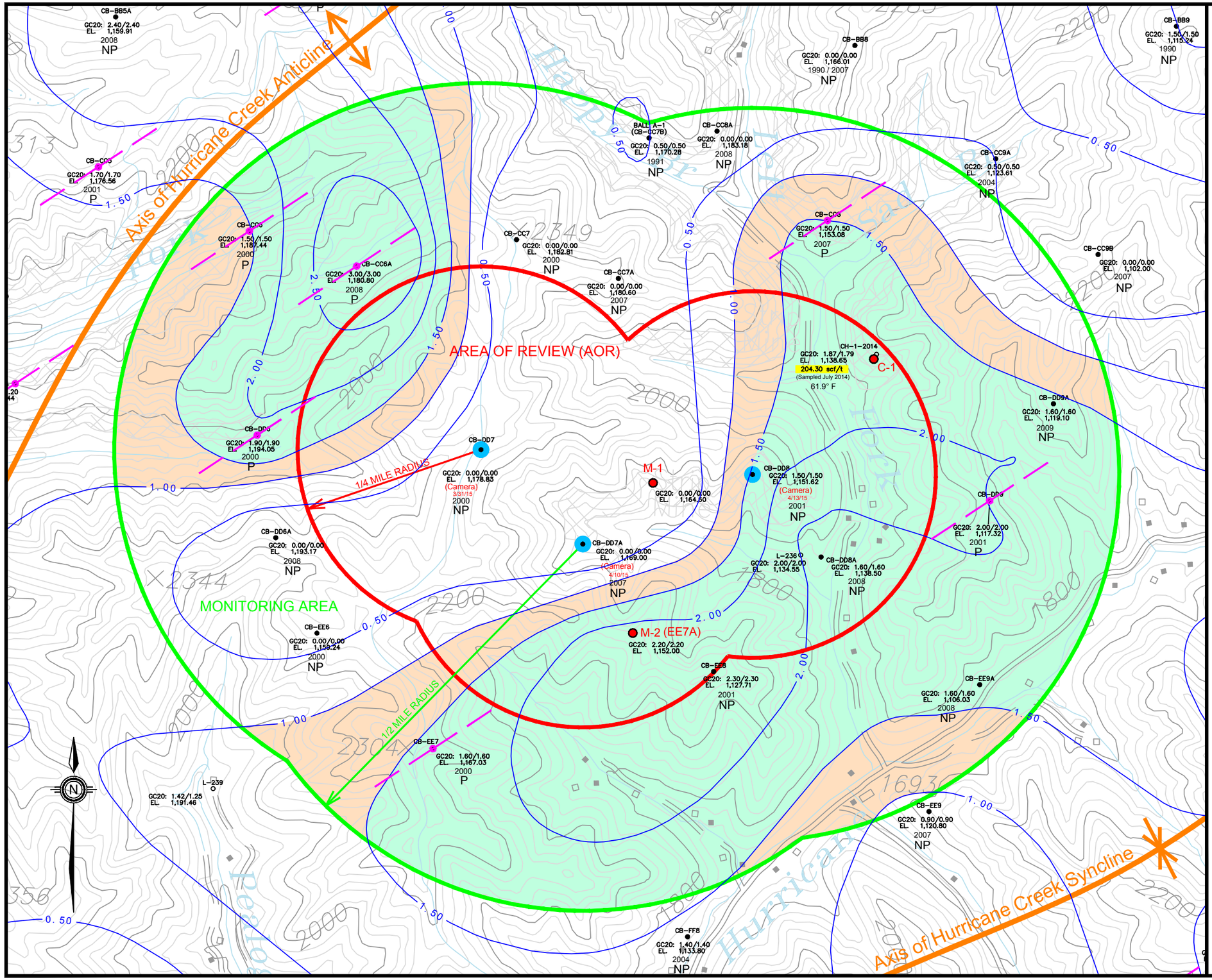
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B9 Aerial.dwg mh

15 Appendix C – CBM Injection Site: Seam Thickness, Perforations, Gas Content and Temperature

C1 ..... Greasy Creek (20) Map
C2 ..... Seaboard (20) Map
C3 ..... Lower Seaboard (10 & 20) Map
C4 ..... Upper Horsepen (10) Map
C5 ..... Upper Horsepen (20 & 30) Map
C6 ..... Pocahontas No. 11 / War Creek Map
C7 ..... Pocahontas No. 10 (10) Map
C8 ..... Pocahontas No. 10 (20) Map
C9 ..... Pocahontas No. 9 (10) Map
C10 ..... Pocahontas No. 9 (20) Map
C11 ..... Pocahontas No. 7 (10) Map
C12 ..... Pocahontas No. 5 (10) Map
C13 ..... Pocahontas No. 5 (20) Map
C14 ..... Pocahontas No. 4 (10, 20, & 30) Map
C15 ..... Pocahontas No. 3 (10, 20, & 30) Map
C16 ..... Pocahontas No. 3 (40) Map
C17 ..... Pocahontas No. 3 (50) Map
C18 ..... Pocahontas No. 2 (10) Map
C19 ..... Composite Seam Thickness – Greasy Creek 20 - Pocahontas No. 2 (10) Map
C20 ..... Total Perforated Coal Thickness Map
C21 ..... First 5-Years Gas Production Map
C22 ..... Best 5-Years Gas Production Map



C1

Virginia Tech
Small Scale CO_2 Injection Test

Greasy Creek (20) Bench

(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.1,115.24 — Elevation at Base of Seam in Feet

1.50/1.50 — Total Seam / Total Coal Thickness in Feet

204.30 scf/t (Sampled July 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation

61.9° F — Borehole Temperature in Degrees Fahrenheit

2.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

700 0 700 1400

Scale in Feet

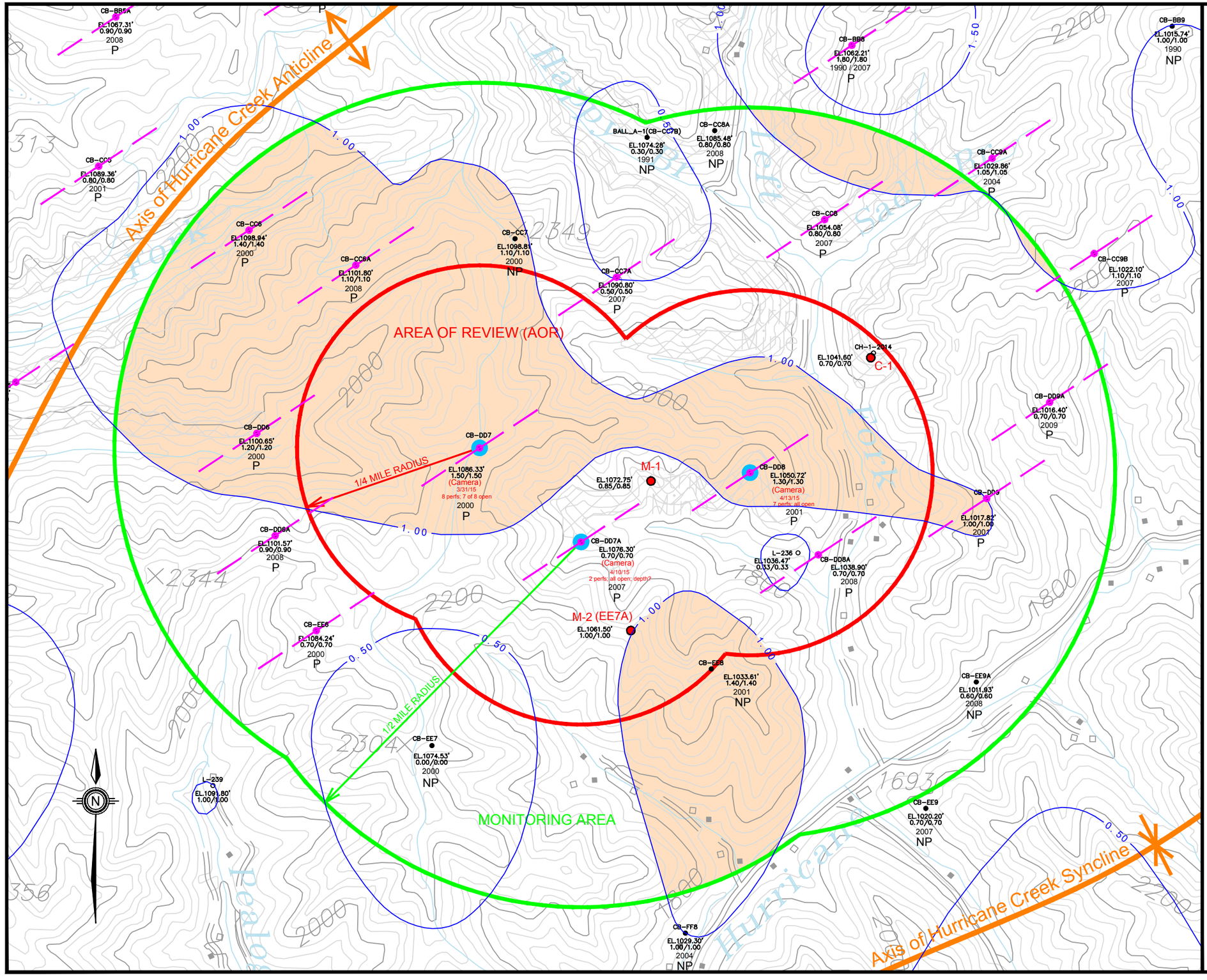
Coordinate System: Virginia South State Plane Nad 27

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C1 GC20.dwg mh

Virginia Tech
C2 Small Scale CO_2 Injection Test

Seaboard (20) Bench



(Camera) 4/13/15 7 perfs; all open	CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations
M-1	Monitoring Well/Spot Core Location and Identification
CH-1-2014	Core Hole Location and Identification
CB-EE7 2000	CBM Well Location, Identification, and Year(s) Completed
EL.1,015.74	Elevation at Base of Seam in Feet
1.00/1.00	Total Seam / Total Coal Thickness in Feet
P	CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius
NP	Reported No Perforation
1.0	Total Coal Thickness Isoline in Feet
	Area of Review (AOR) - Red Monitoring Area - Green
	Total Coal 1.0 - 1.5 Feet Thick

Note: No Gas Content Data Available

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
C2 SE20.dwg mh

Virginia Tech

C3

Small Scale CO_2 Injection Test

Lower Seaboard (10 & 20) Bench

(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH–1–2014 — Core Hole Location and Identification

CB–EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.975.24 — Elevation at Base of Seam in Feet

100/1.00 — Total Seam / Total Coal Thickness in Feet

409.2 scf/t (Sampled July 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation

63.5° F — Borehole Temperature in Degrees Fahrenheit

1.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

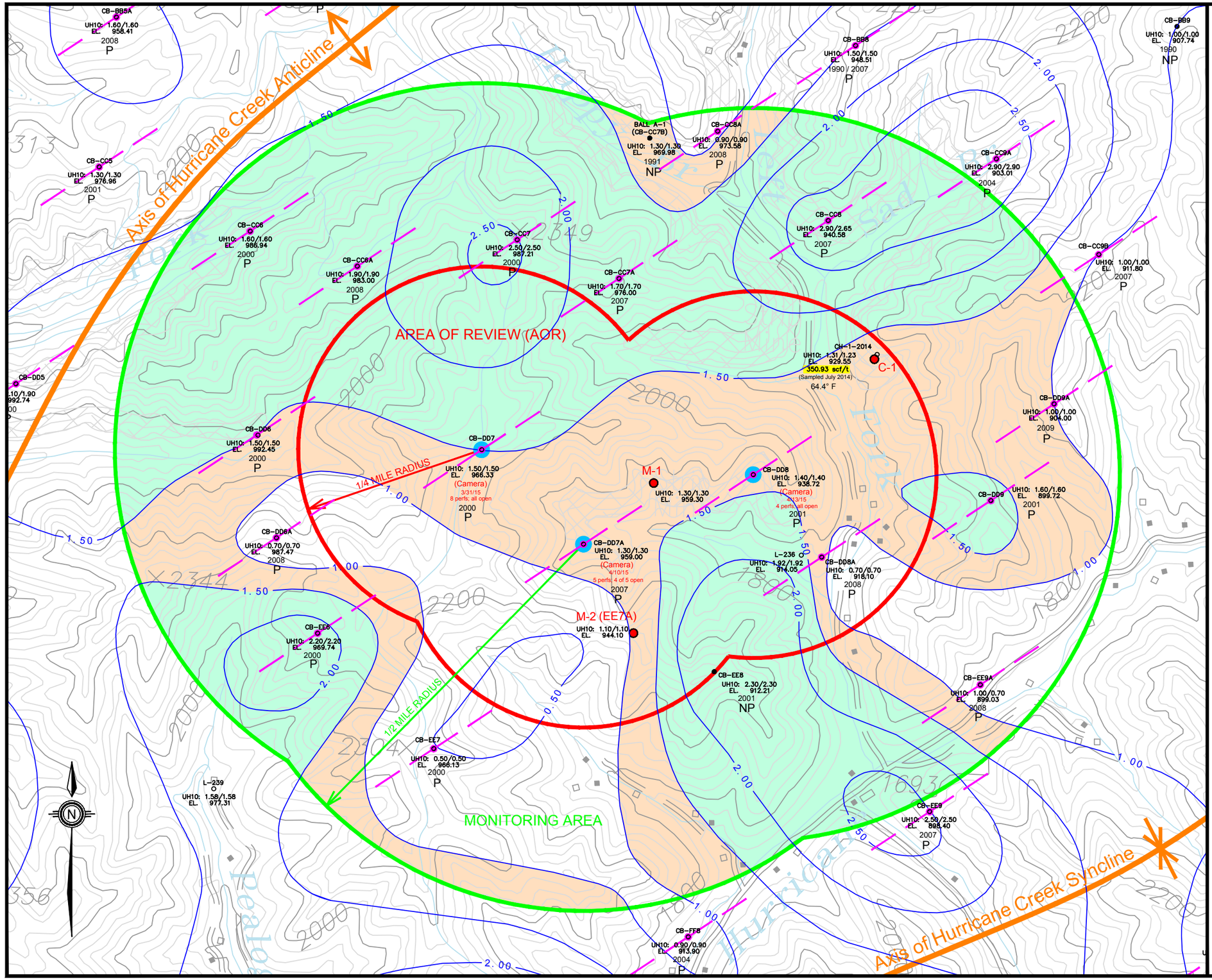
MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C3 LS10–20.dwg mh

C4

Virginia Tech
Small Scale CO_2 Injection Test

Upper Horsepen (10) Bench



CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

Monitoring Well/Spot Core Location and Identification

Core Hole Location and Identification

CBM Well Location, Identification, and Year(s) Completed

Elevation at Base of Seam in Feet

Total Seam / Total Coal Thickness in Feet

As-Received Gas Content, Standard Cubic Feet/Ton

CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

Reported No Perforation

Borehole Temperature in Degrees Fahrenheit

Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

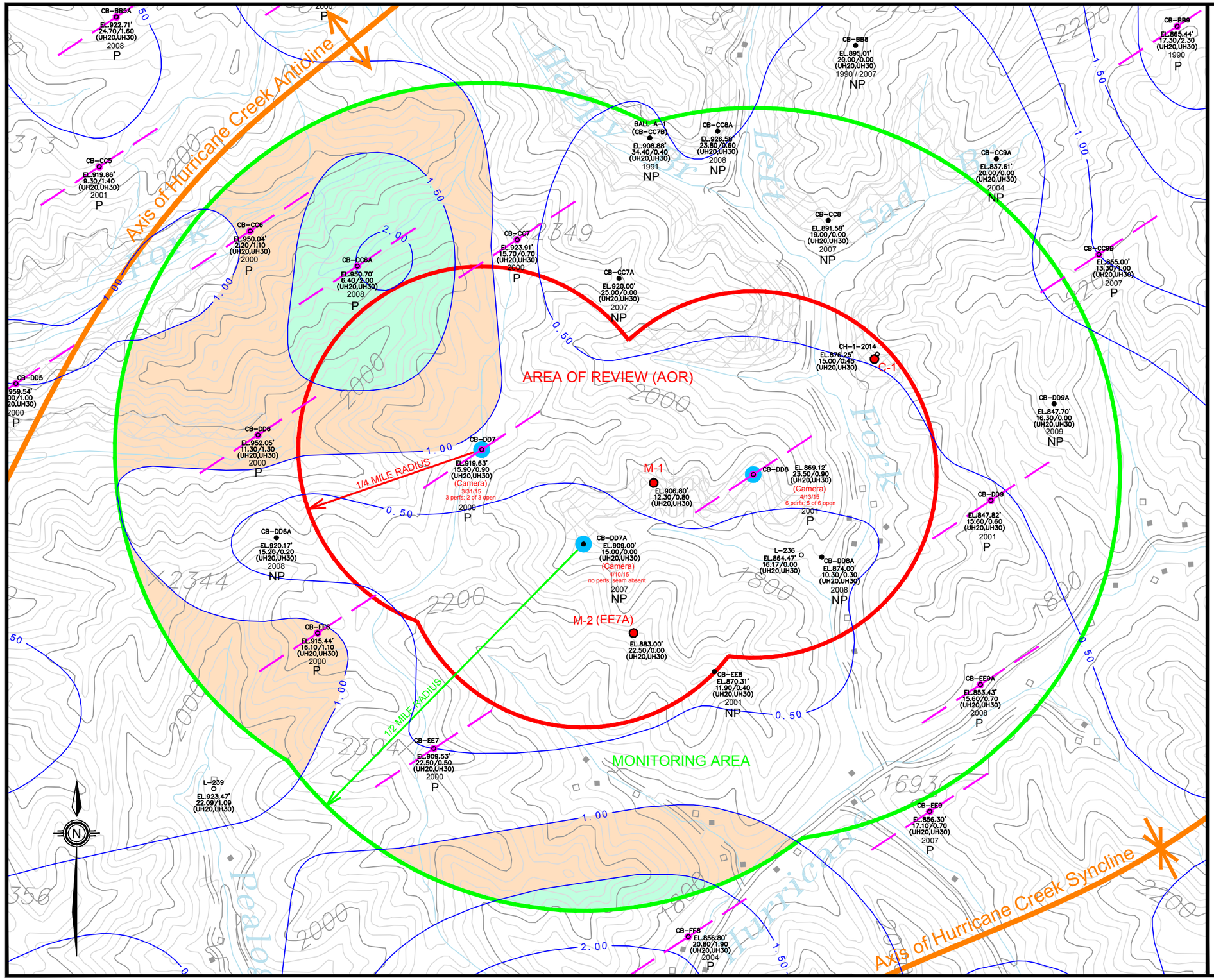
700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
C4 UH10.dwg mh



Virginia Tech

C5

Small Scale CO_2 Injection Test

Upper Horsepen (20 & 30) Bench

(Camera) 4/13/15 7 perfs; all open	CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations
M-1	Monitoring Well/Spot Core Location and Identification
CH-1-2014	Core Hole Location and Identification
CB-EE7 2000	CBM Well Location, Identification, and Year(s) Completed
EL.867.30	Elevation at Base of Seam in Feet
1.00/1.00	Total Seam / Total Coal Thickness in Feet
P	CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius
NP	Reported No Perforation
1.0	Total Coal Thickness Isoline in Feet
	Area of Review (AOR) - Red Monitoring Area - Green
	Total Coal 1.0 - 1.5 Feet Thick
	Total Coal Greater Than 1.5 Feet Thick

Note: No Gas Content Data Available

700 0 700 1400

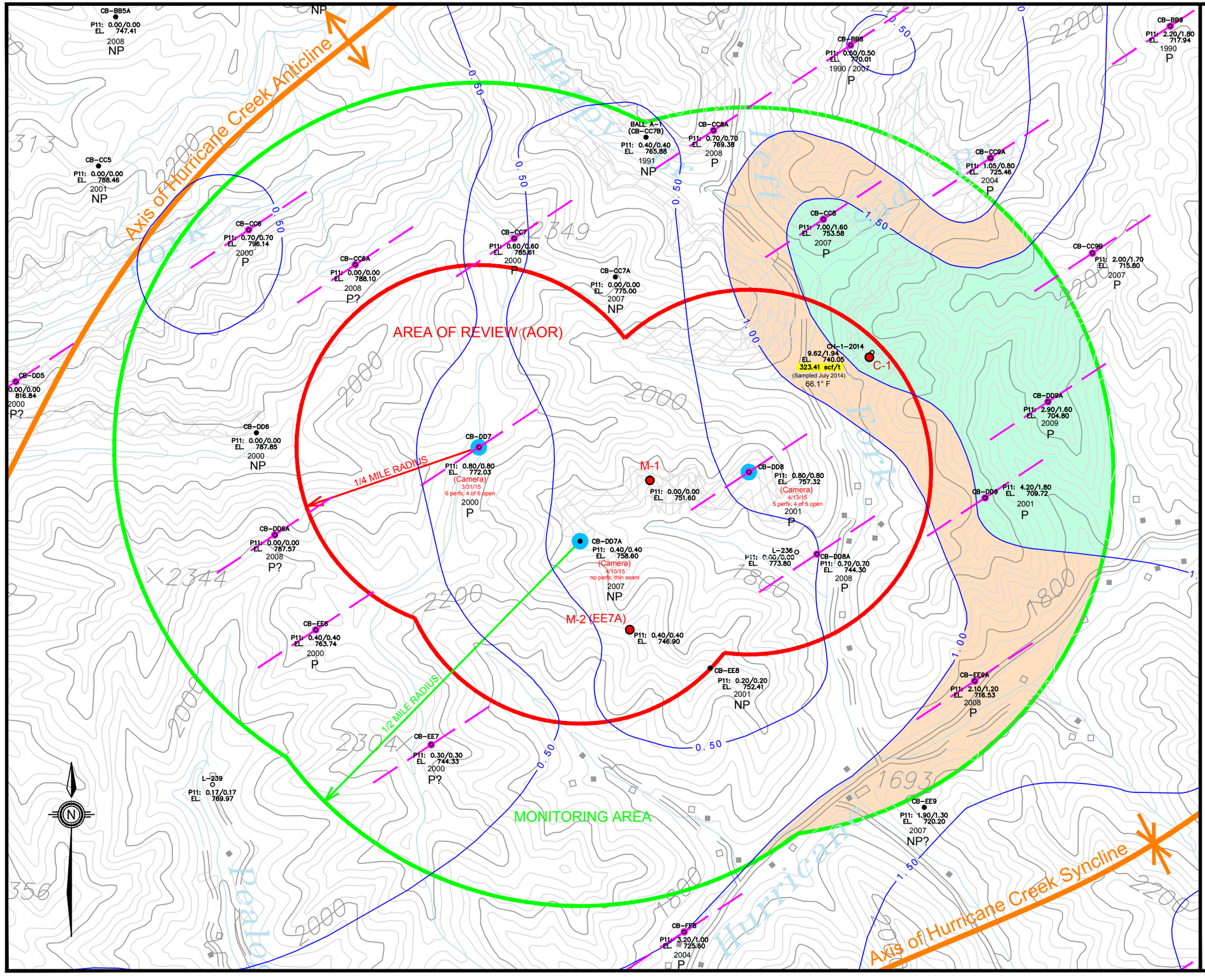
Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17

C5 UH20-30.dwg mh



Virginia Tech

C6

Small Scale CO_2 Injection Test

Pocahontas No. 11 / War Creek Bench

(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.717.94 — Elevation at Base of Seam in Feet

2.20/1.80 — Total Seam / Total Coal Thickness in Feet

323.41 scf/t (Sampled July 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius (? Where Questionable)

NP — Reported No Perforation

61.1° F — Borehole Temperature in Degrees Fahrenheit

1.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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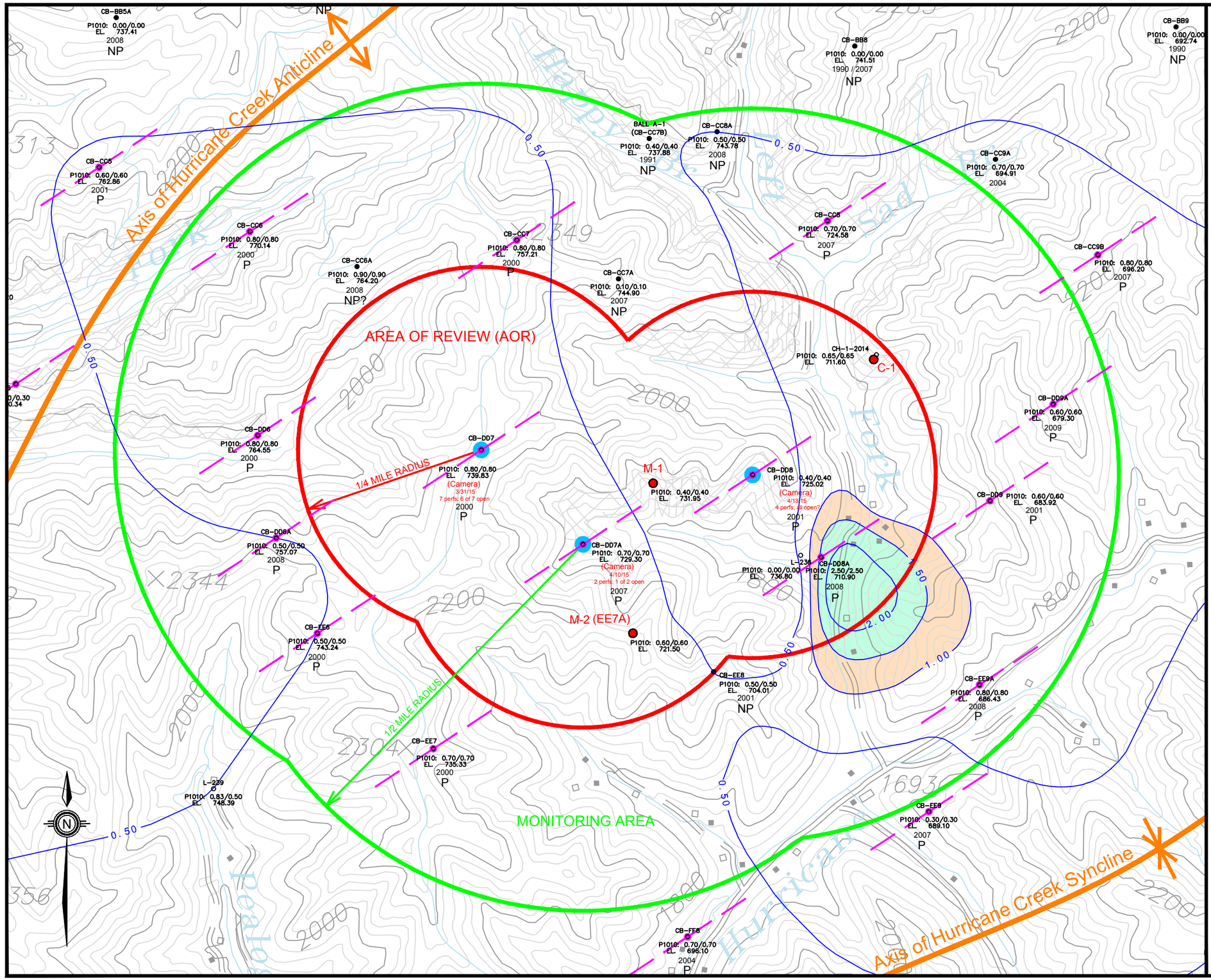
VCER101 Bluefield, VA 11/17
C6 P11.dwg mh

Virginia Tech

C7

Small Scale CO_2 Injection Test

Pocahontas No. 10 (10) Bench



(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.696.20 — Elevation at Base of Seam in Feet

0.80/0.80 — Total Seam / Total Coal Thickness in Feet

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation (? Where Questionable)

1.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

Note: No Gas Content Data Available

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C7 P1010.dwg mh

Virginia Tech

C8

Small Scale CO_2 Injection Test

Pocahontas No. 10 (20) Bench

- CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations
- Monitoring Well/Spot Core Location and Identification
- Core Hole Location and Identification
- CBM Well Location, Identification, and Year(s) Completed
- Elevation at Base of Seam in Feet
- Total Seam / Total Coal Thickness in Feet
- As-Received Gas Content, Standard Cubic Feet/Ton
- CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius
- Reported No Perforation
- Borehole Temperature in Degrees Fahrenheit
- Total Coal Thickness Isoline in Feet
- Area of Review (AOR) - Red
  Monitoring Area - Green
- Total Coal 1.0 - 1.5 Feet Thick
- Total Coal Greater Than 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17

C8 P1020.dwg mh

Virginia Tech

C9 — Small Scale CO_2 Injection Test

Pocahontas No. 9 (10) Bench

CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

Monitoring Well/Spot Core Location and Identification

Core Hole Location and Identification

CBM Well Location, Identification, and Year(s) Completed

Elevation at Base of Seam in Feet

Total Seam / Total Coal Thickness in Feet

As-Received Gas Content, Standard Cubic Feet/Ton

CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius (? Where Questionable)

Reported No Perforation

Borehole Temperature in Degrees Fahrenheit

Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

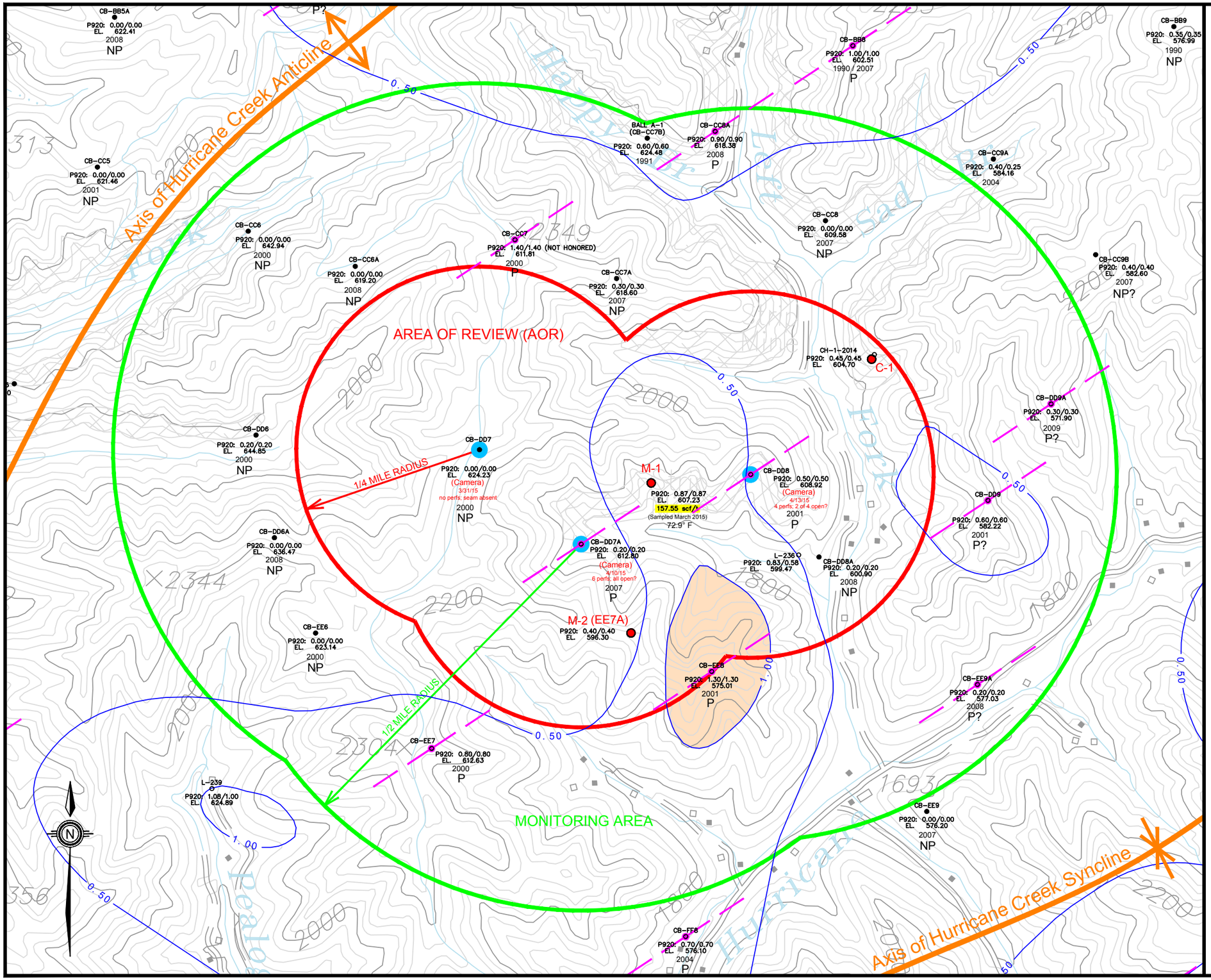
700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C9 P910.dwg mh



Virginia Tech

C10 Small Scale CO_2 Injection Test

Pocahontas No. 9 (20) Bench

(Camera) 4/13/15 7 perfs; all open	CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations
M-1	Monitoring Well/Spot Core Location and Identification
CH-1-2014	Core Hole Location and Identification
CB-EE7 2000	CBM Well Location, Identification, and Year(s) Completed
EL.576.99	Elevation at Base of Seam in Feet
0.35/0.35	Total Seam / Total Coal Thickness in Feet
157.55 scf/t (Sampled March 2014)	As-Received Gas Content, Standard Cubic Feet/Ton
P	CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius (? Where Questionable)
NP	Reported No Perforation (? Where Questionable)
70.7° F	Borehole Temperature in Degrees Fahrenheit
1.0	Total Coal Thickness Isoline in Feet
	Area of Review (AOR) - Red Monitoring Area - Green
	Total Coal 1.0 - 1.5 Feet Thick

700 0 700 1400

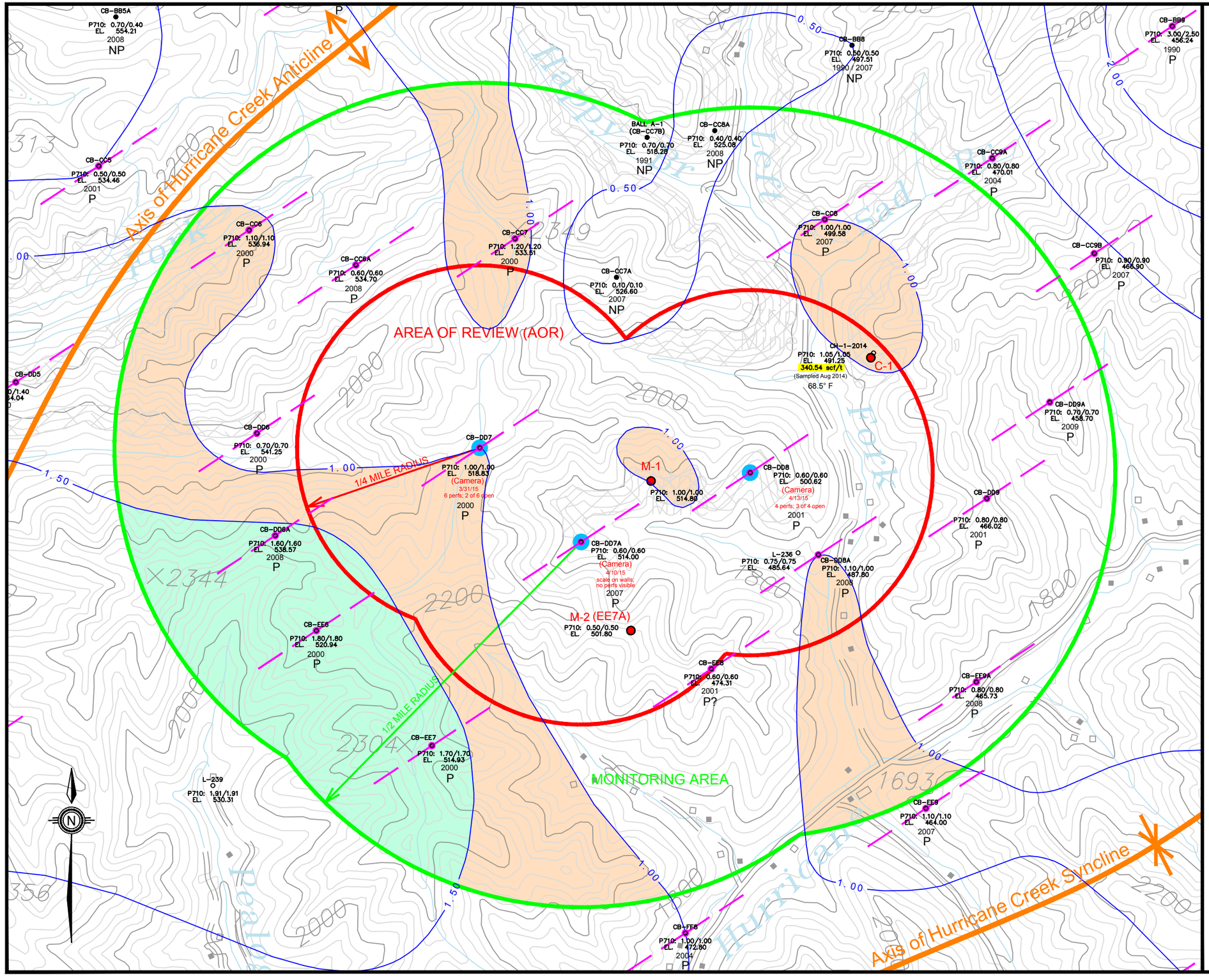
Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17

C10 P920.dwg mh



C11

Virginia Tech
Small Scale CO_2 Injection Test

Pocahontas No. 7 (10) Bench

(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.579.44 — Elevation at Base of Seam in Feet

3.00/2.50 — Total Seam / Total Coal Thickness in Feet

340.54 scf/t (Sampled Aug 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation

68.5° F — Borehole Temperature in Degrees Fahrenheit

2.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

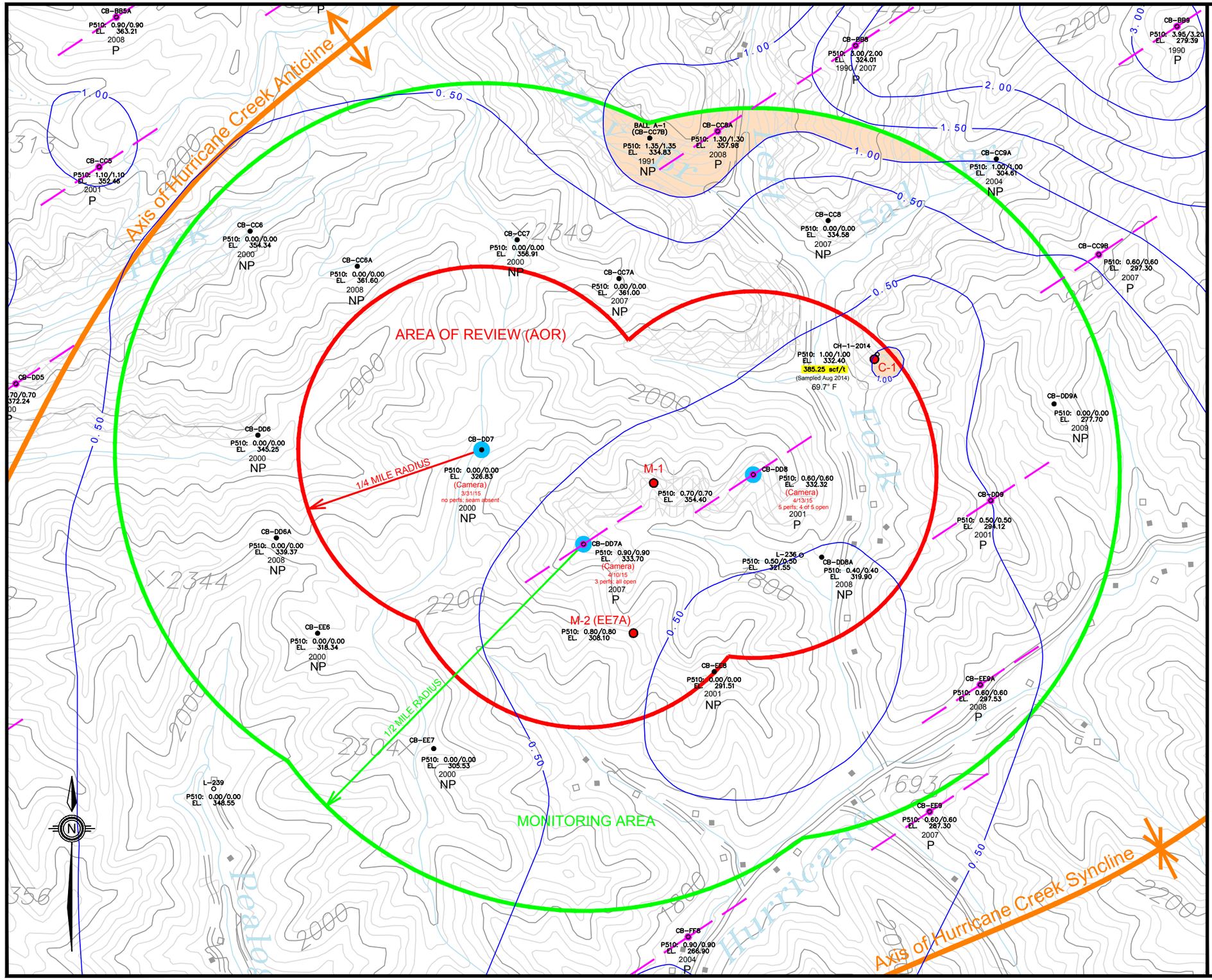
700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C11 P710.dwg mh



Virginia Tech

C12 Small Scale CO_2 Injection Test

Pocahontas No. 5 (10) Bench

(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.304.61 — Elevation at Base of Seam in Feet

1.00/1.00 — Total Seam / Total Coal Thickness in Feet

204.30 scf/t (Sampled Aug 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation

69.7° F — Borehole Temperature in Degrees Fahrenheit

2.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C12 P510.dwg mh

Virginia Tech
C13 Small Scale CO_2 Injection Test

Pocahontas No. 5 (20) Bench

CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

Monitoring Well/Spot Core Location and Identification

Core Hole Location and Identification

CBM Well Location, Identification, and Year(s) Completed

Elevation at Base of Seam in Feet

Total Seam / Total Coal Thickness in Feet

As-Received Gas Content, Standard Cubic Feet/Ton

CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

Reported No Perforation

Borehole Temperature in Degrees Fahrenheit

Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

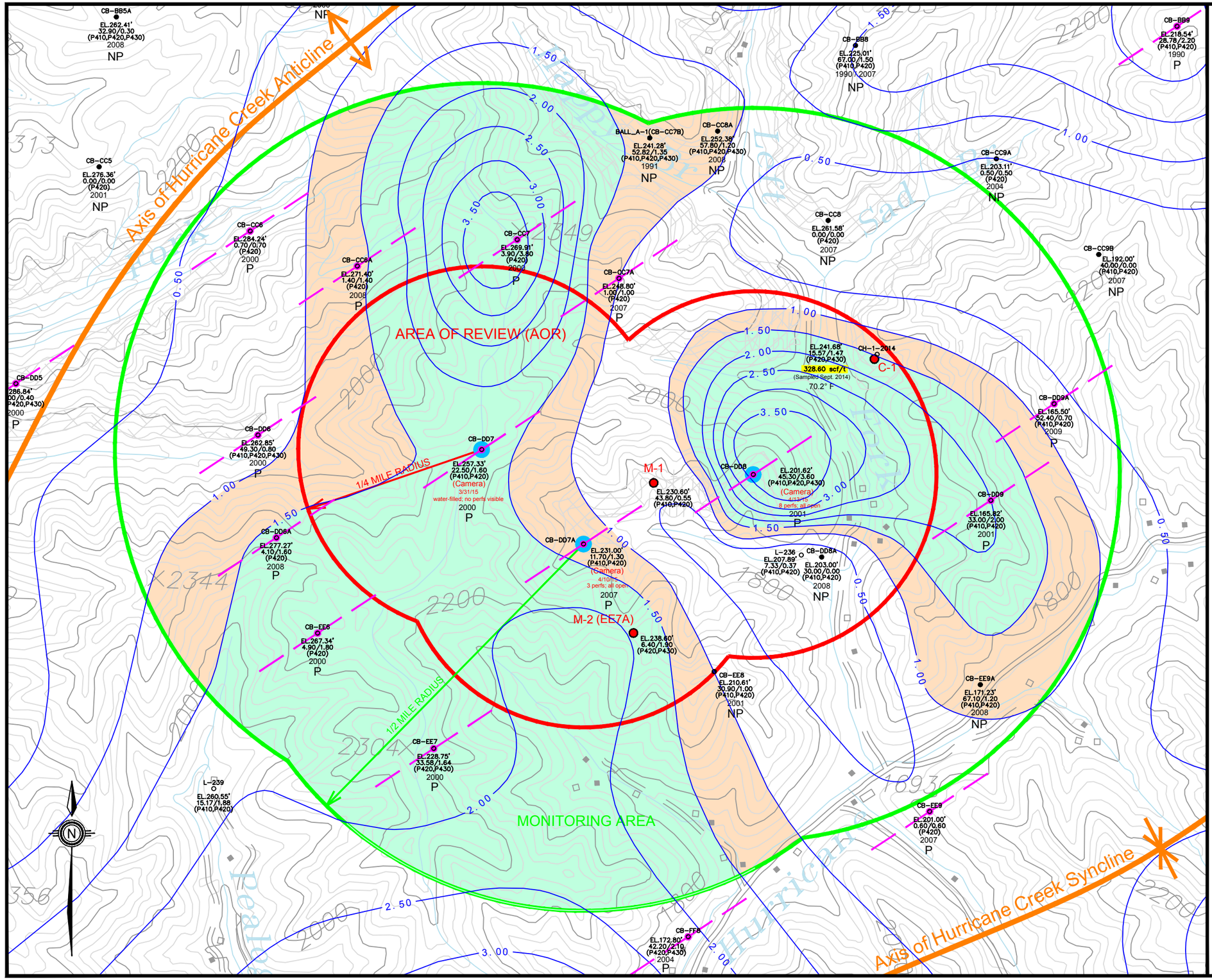
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Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C13 P520.dwg mh



C14

Virginia Tech
Small Scale CO_2 Injection Test

Pocahontas No. 4 (10, 20 & 30) Bench

(Camera) 4/13/15 7 perfs; all open	CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations
M-1	Monitoring Well/Spot Core Location and Identification
CH-1-2014	Core Hole Location and Identification
CB-EE7 2000	CBM Well Location, Identification, and Year(s) Completed
EL.218.54	Elevation at Base of Seam in Feet
3.20/3.20	Total Seam / Total Coal Thickness in Feet
328.60 scf/t (Sampled Sept 2014)	As-Received Gas Content, Standard Cubic Feet/Ton
P	CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius
NP	Reported No Perforation
70.2° F	Borehole Temperature in Degrees Fahrenheit
1.0	Total Coal Thickness Isoline in Feet
	Area of Review (AOR) - Red Monitoring Area - Green
	Total Coal 1.0 - 1.5 Feet Thick
	Total Coal Greater Than 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

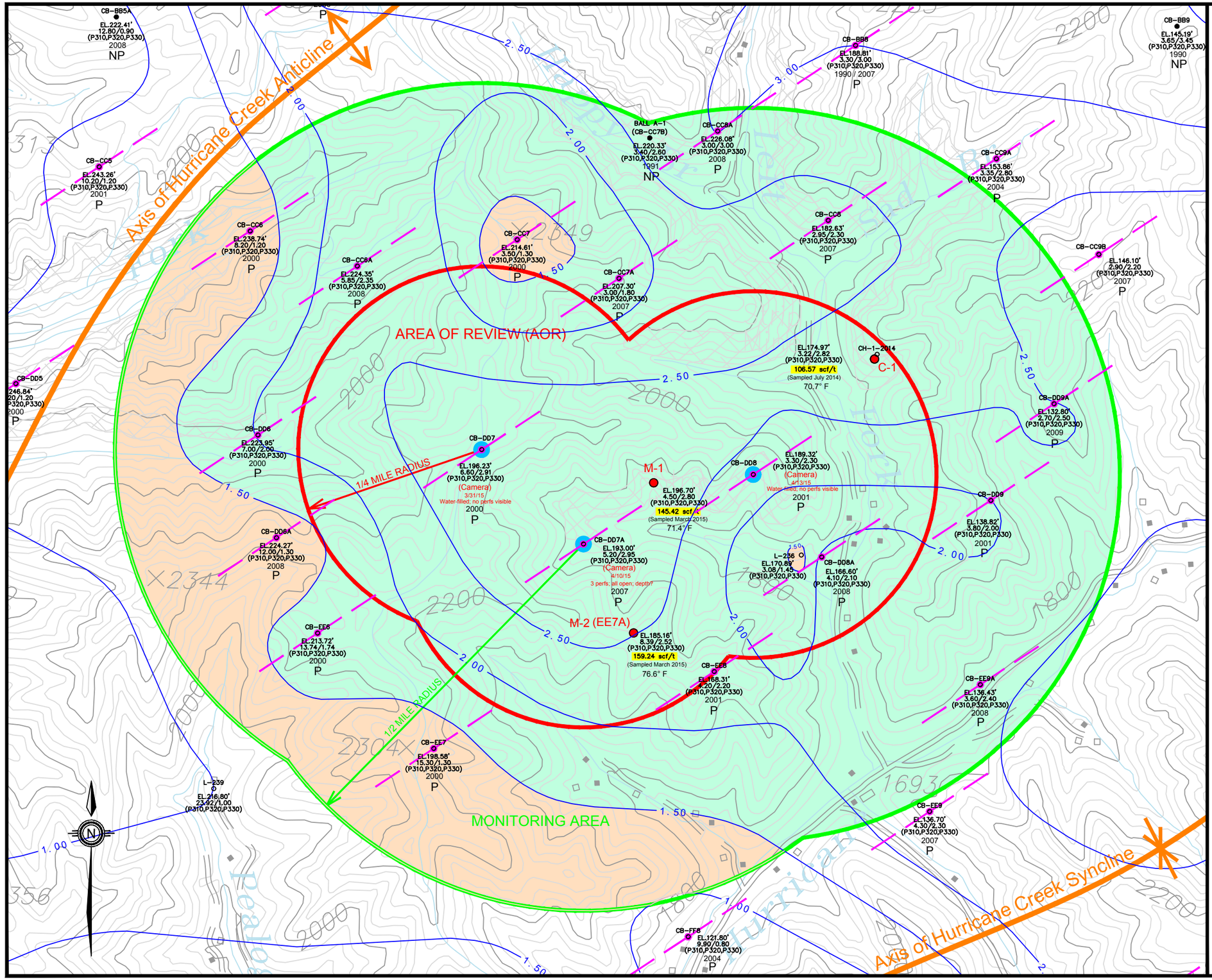
MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C14 P42030.dwg mh

C15

Virginia Tech
Small Scale CO_2 Injection Test

Pocahontas No. 3 (10, 20, & 30) Bench



(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.147.10 — Elevation at Base of Seam in Feet

1.90/1.70 — Total Seam / Total Coal Thickness in Feet

106.57 scf/t (Sampled July 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation

71.4° F — Borehole Temperature in Degrees Fahrenheit

2.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Total Coal Greater Than 1.5 Feet Thick

700 0 700 1400

Scale in Feet

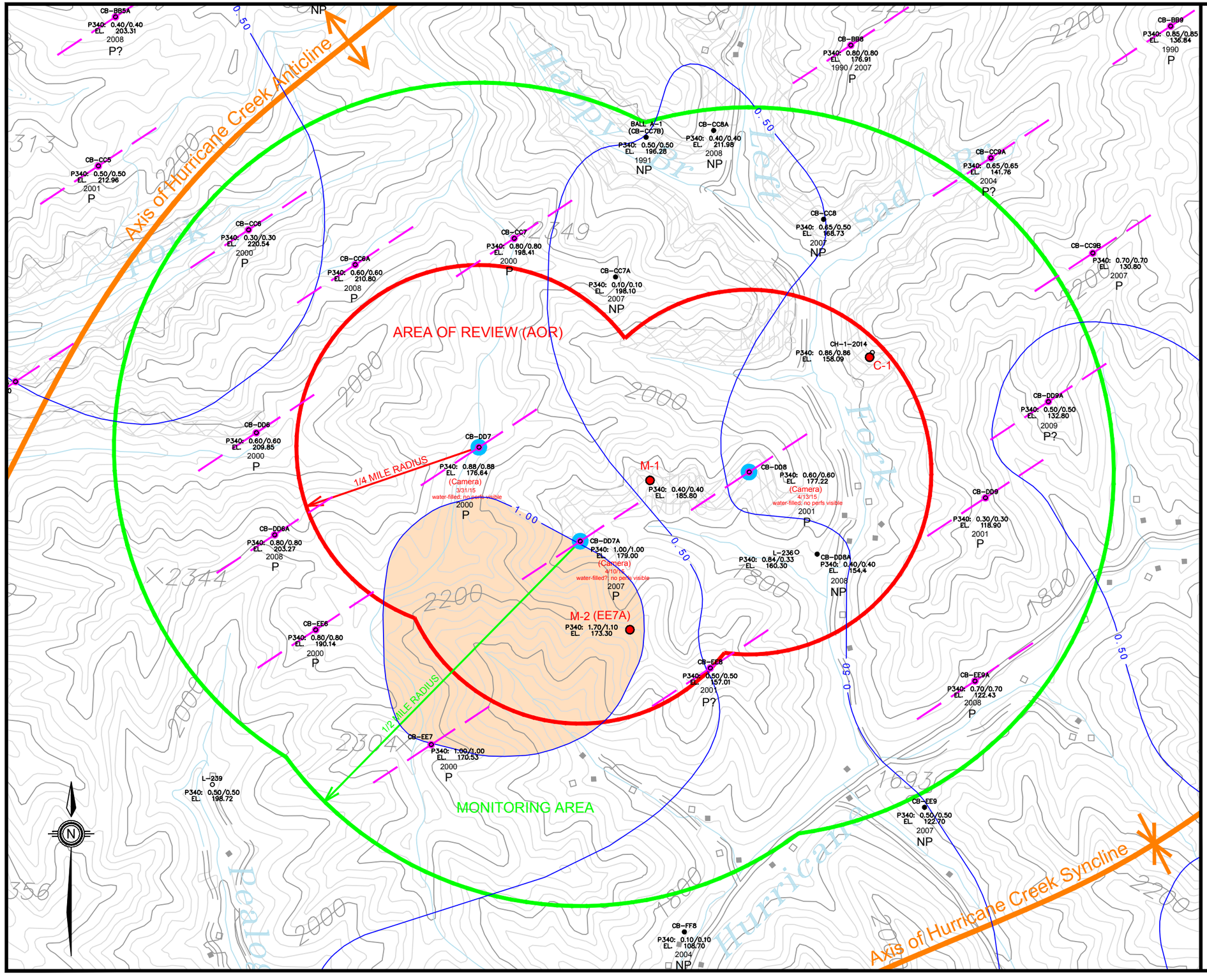
Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C15 P3102030.dwg mh

Virginia Tech
C16 Small Scale CO_2 Injection Test

Pocahontas No. 3 (40) Bench



(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.136.84 — Elevation at Base of Seam in Feet

0.65/0.65 — Total Seam / Total Coal Thickness in Feet

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius (? Where Questionable)

NP — Reported No Perforation

1.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C16 P340.dwg mh

Virginia Tech

C17 Small Scale CO_2 Injection Test

Pocahontas No. 3 (50) Bench

CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

Monitoring Well/Spot Core Location and Identification

Core Hole Location and Identification

CBM Well Location, Identification, and Year(s) Completed

Elevation at Base of Seam in Feet

Total Seam / Total Coal Thickness in Feet

CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius (? Where Questionable)

Reported No Perforation

Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

Note: No Gas Content Data Available

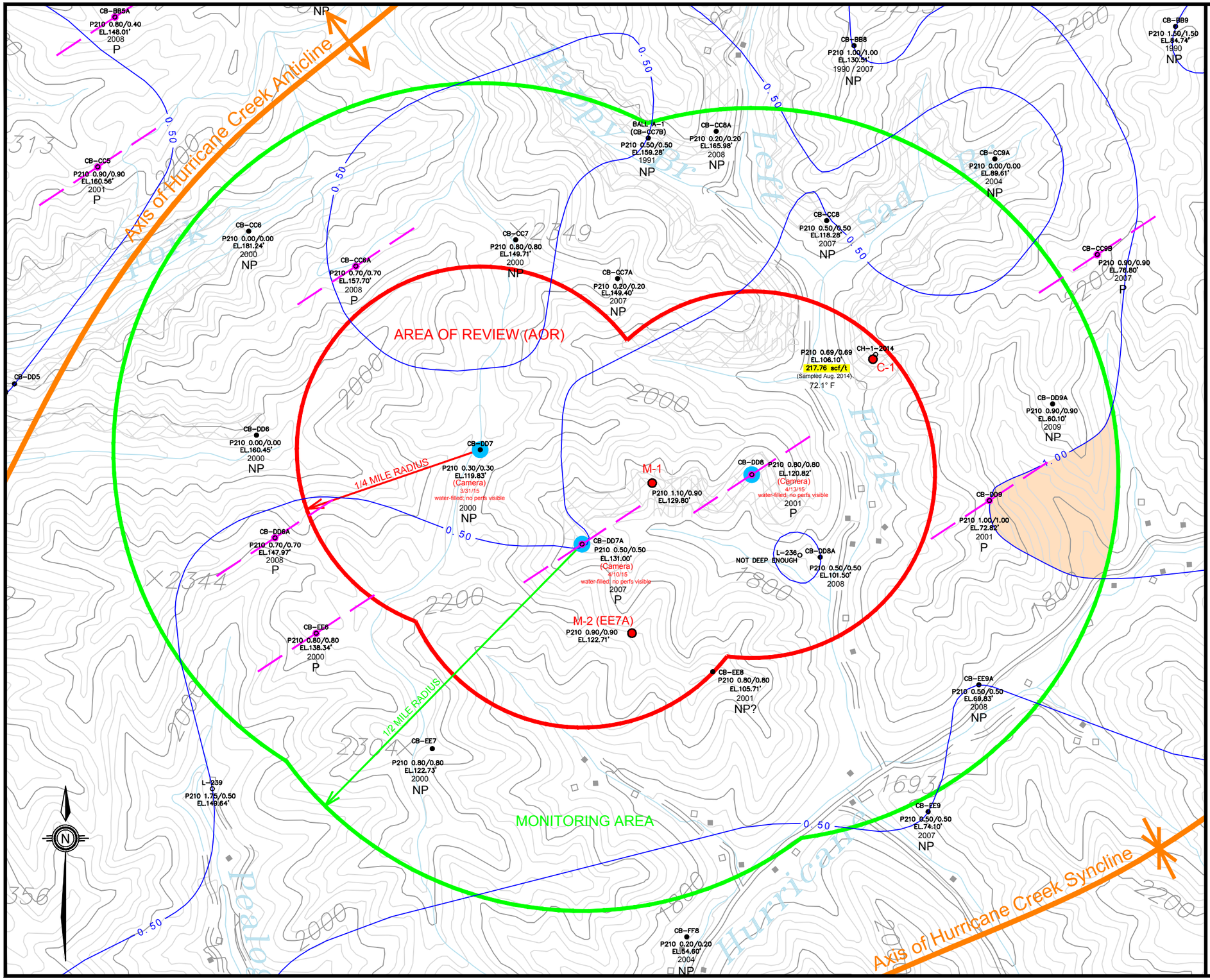
700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C17 P350.dwg mh



Virginia Tech

C18 — Small Scale CO_2 Injection Test

Pocahontas No. 2 (10) Bench

(Camera) 4/13/15 7 perfs; all open — CO_2 Injection Well Location With Date of Downhole Camera Log and Description of Perforations

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

EL.76.80 — Elevation at Base of Seam in Feet

0.90/0.90 — Total Seam / Total Coal Thickness in Feet

217.78 scf/t (Sampled Aug 2014) — As-Received Gas Content, Standard Cubic Feet/Ton

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

NP — Reported No Perforation (? Where Questionable)

61.9° F — Borehole Temperature in Degrees Fahrenheit

1.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Total Coal 1.0 - 1.5 Feet Thick

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
C18 P210.dwg mh

Virginia Tech

C19

Small Scale CO_2 Injection Test

Composite Seam Thickness

Greasy Creek 20 - Pocahontas No. 2 (10)

CO_2 Injection Well Location

M-1 — Monitoring Well/Spot Core Location and Identification

CH-1-2014 — Core Hole Location and Identification

CB-EE7 2000 — CBM Well Location, Identification, and Year(s) Completed

10.0 — Total Coal Thickness Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Composite Coal Thickness

- < 12 Feet
- 12 - 16 Feet
- 16 - 20 Feet
- < 20 Feet

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
C19 Composite.dwg mh

Virginia Tech

C20

Small Scale CO_2 Injection Test

Total Perforated Coal Thickness

CO_2 Injection Well Location With Date of Initial CBM Production

M-1 Monitoring Well/Spot Core Location and Identification

CB–EE7
20.55
2000
CBM Well Location and Identification
Total Thickness of Perforated Coals in Feet
Year Completed

P CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

10.0 Total Thickness of Perforated Coal Isoline in Feet

Area of Review (AOR) - Red
Monitoring Area - Green

Perforated Coal Thickness Categories

- < 12 Feet
- 12 - 16 Feet
- 16 - 20 Feet
- > 20 Feet

Note: Stratigraphic Interval of Perforated Coal Seams Within the Monitoring Area Extends From the Greasy Creek (20) Through the Squire Jim 3 Seam

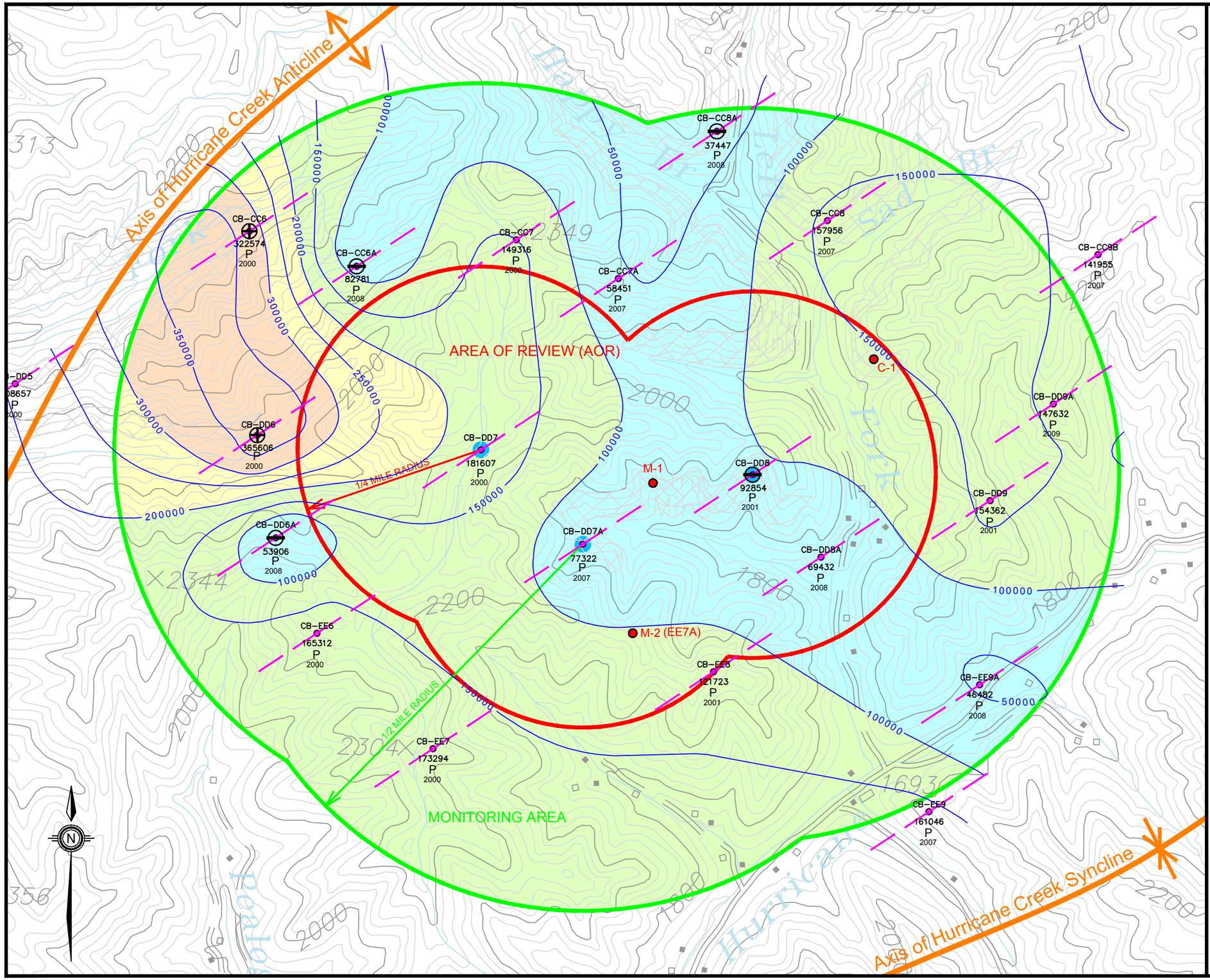
700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C20 Perfed Coal Thick.dwg mh



Virginia Tech

C21

Small Scale CO_2 Injection Test

First 5-Years Gas Production

CO_2 Injection Well Location With Date of Initial CBM Production

M-1 Monitoring Well/Spot Core Location and Identification

CB-EE7 141955 2000 — CBM Well Location and Identification, 5-Year Produced Gas Volume (MCF), Year Completed

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

Over-Performing Well

Under-Performing Well

150000 — 5-Year Produced Gas Isoline in MCF

Area of Review (AOR) - Red
Monitoring Area - Green

Gas Production (Thousand Cubic Feet, MCF)

- < 100,000
- 100,000 - 200,000
- 200,000 - 300,000
- > 300,000

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
C21 1st 5 Years.dwg mh

Virginia Tech

C22

Small Scale CO_2 Injection Test

Best 5-Years Gas Production

CO_2 Injection Well Location With Date of Initial CBM Production

M-1 Monitoring Well/Spot Core Location and Identification

CB–EE7 / 141955 / 2000 — CBM Well Location and Identification, 5-Year Produced Gas Volume (MCF), Year Completed

P — CBM Well Location With Reported Perforation, Direction of Hydraulic Fracture Propagation, and 500' Radius

150000 — 5-Year Produced Gas Isoline in MCF

Area of Review (AOR) - Red
Monitoring Area - Green

Gas Production (Thousand Cubic Feet, MCF)

- < 100,000
- 100,000 - 200,000
- 200,000 - 300,000
- > 300,000

700 0 700 1400

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
C22 Best 5 Yrs.dwg mh

Axis of Hurricane Creek Anticline

Axis of Hurricane Creek Syncline

AREA OF REVIEW (AOR)

MONITORING AREA

1/4 MILE RADIUS

1/2 MILE RADIUS

CB–CC6 325494 P 2000

CB–CC6A 83791 P 2008

CB–CC7 182637 P 2000

CB–CC7A 73882 P 2007

CB–CC8A 49350 P 2008

CB–CC8 203144 P 2007

CB–CC9B 141955 P 2007

CB–DD5 2477 P

CB–DD6 367179 P 2000

CB–DD6A 55675 P 2008

CB–DD7 185542 P 2000

CB–DD7A 78468 P 2007

CB–DD8 105537 P 2001

CB–DD8A 76459 P 2008

CB–DD9 235712 P 2001

CB–DD9A 150622 P 2009

CB–EE6 170799 P 2000

CB–EE7 226979 P 2000

CB–EE8 140443 P 2001

CB–EE9 190988 P 2007

CB–EE9A 49260 P 2008

M-1

M-2 (EE7A)

C-1

16 Appendix D – Buchanan No. 1 Mine – Hydraulic Fractures / Localized Structures

D1 ..... 3 East Mains – Area of Investigation (10/19/16) Map
D2 .....Site 2 Photographs of Sand-Filled Hydraulic Fractures (10/19/16)
D3 ..... Site 2 Close-Up Photographs of Sand-Filled Hydraulic Fractures (10/19/16)
D4 ..... 3 East Development – Area of Investigation (8/23/17) Map
D5 ..... 4 East Development – Area of Investigation (8/23/17) Map
D6 ..... 5 East Development – Area of Investigation (8/23/17) Map
D7 .....Area of Slick-Slip Underground Mapping (after Wickline, 2017) Map
D8 ..... Slick-Slip Observations (after Wickline, 2017) Map
D9 ..... 3 East Development – Area of Investigation (10/10/17) Map

D1
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

Buchanan No. 1 Mine - 3 East Mains Area of Investigation (10/19/16)

3 EAST MAINS

Site 1

Site 2

Pocahontas No. 3 Seam Deep Mining

Rail

Area of Visual Inspection

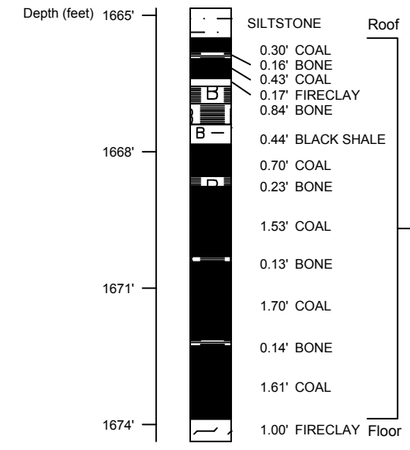
30611 Spad Location 195 Cross-Cut ID

N58°E P46 08/17/2012 — CBM Well Location With Completion Date and Observed Hydraulic Fracture Orientation

N55°E — CBM Well Location with Assumed Direction of Hydraulic Fracture Propagation and 500' Radius

Note: See Map A1 for location.

Core Hole VA232
Stratigraphic Column



150 0 150 300

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
D1&D4–D6&D9 Buch 1.dwg mh

D2
(Full to Intermediate View)

Virginia Tech
Small Scale CO_2 Injection Test

Buchanan No. 1 Mine (10/19/16) Site 2 - Photographs of Sand-Filled Hydraulic Fractures

Photo 1
Full Seam View

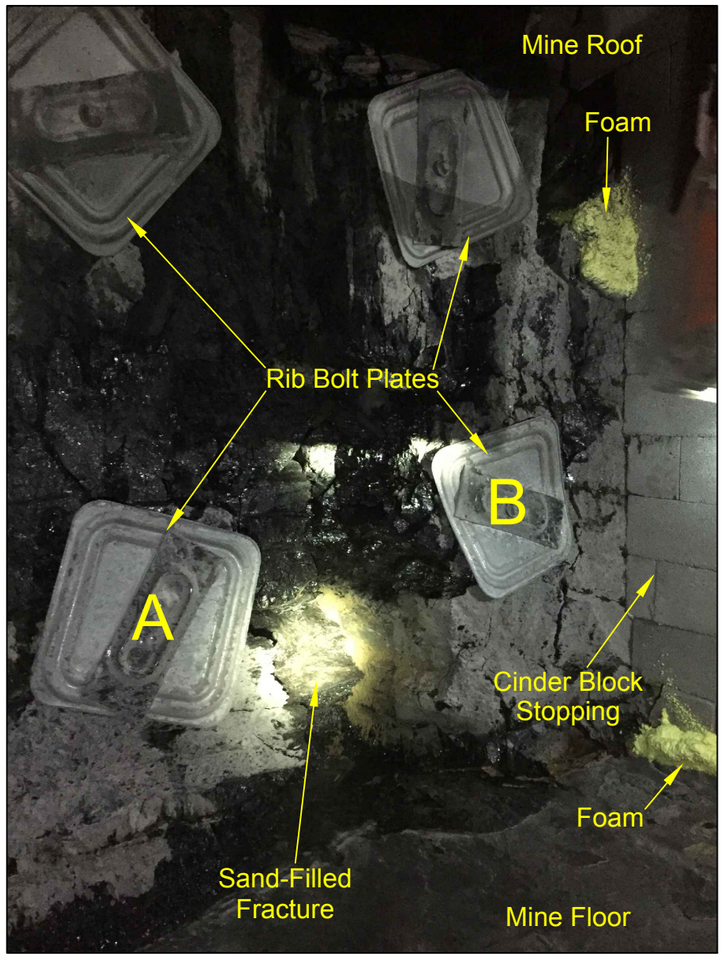
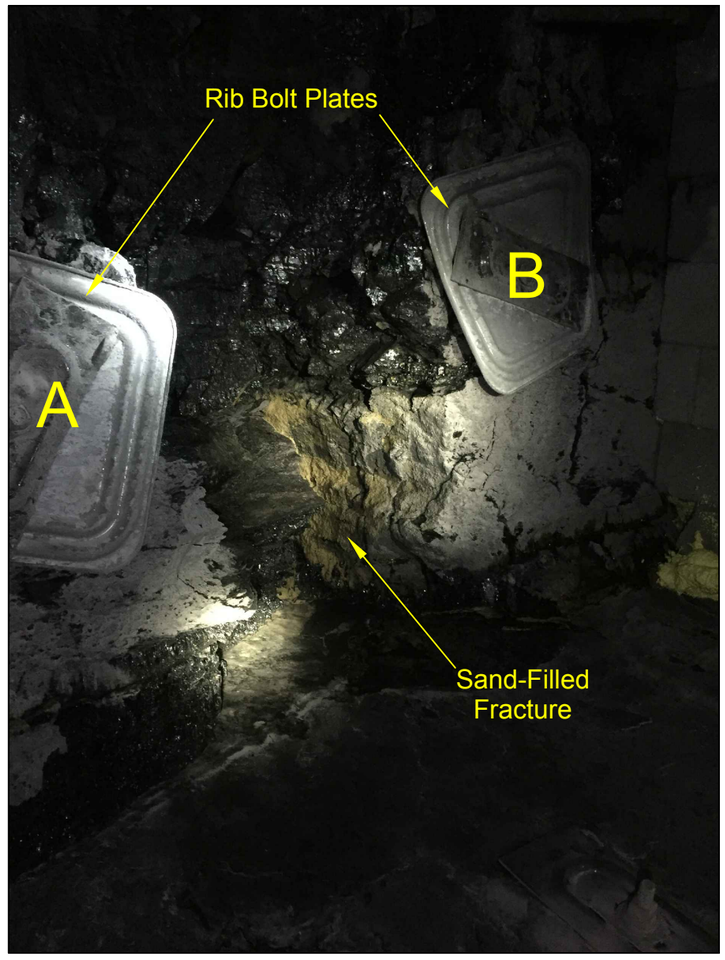


Photo 2
Intermediate View



Note:

Hydraulic fractures associated with CBM Well P46.

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D2&D3 Photos.dwg mh

D3
(Nearest View)

Virginia Tech
Small Scale CO_2 Injection Test

Buchanan No. 1 Mine (10/19/16) Site 2 - Close-Up Photographs of Sand-Filled Hydraulic Fractures

Photo 3
Nearest View

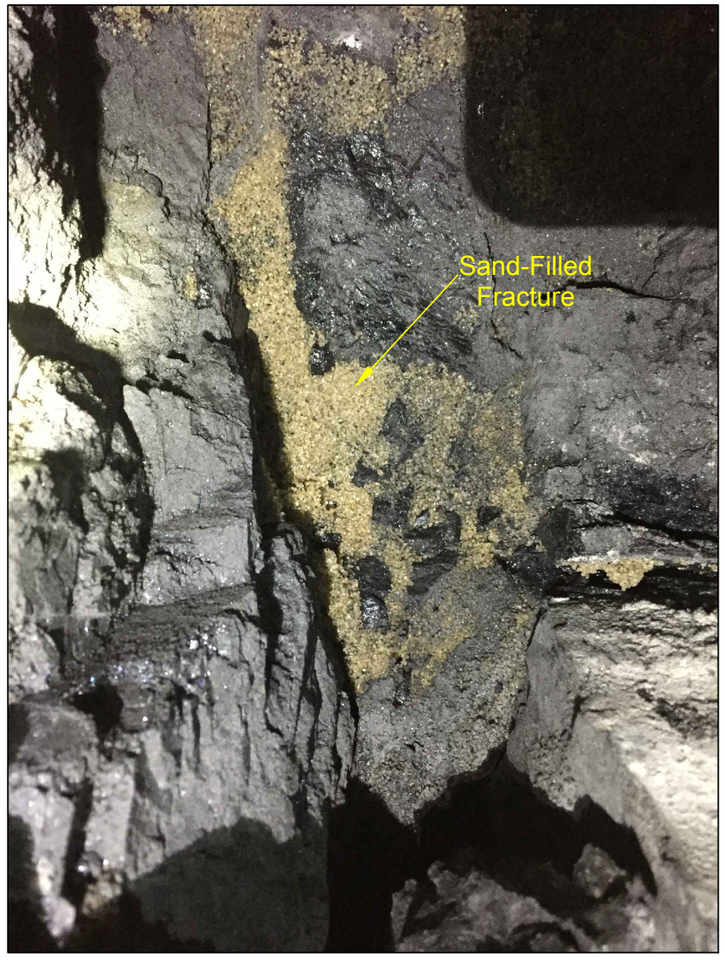


Photo 4
Nearest View With Scale



(Steel Tape Units in Inches)

Note:

Hydraulic fractures associated with CBM Well P46.

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VCER101 Bluefield, VA 11/17
D2&D3 Photos.dwg mh

D4
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

Buchanan No. 1 Mine - 3 East Development Area of Investigation (8/23/17)

Pocahontas No. 3 Seam Deep Mining

Rail

Area of Visual Inspection

30459 Spad Location

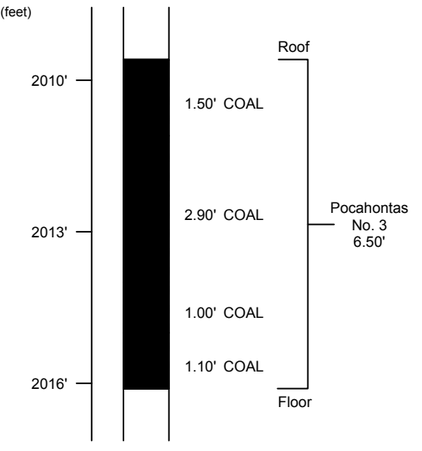
25 Cross-Cut ID

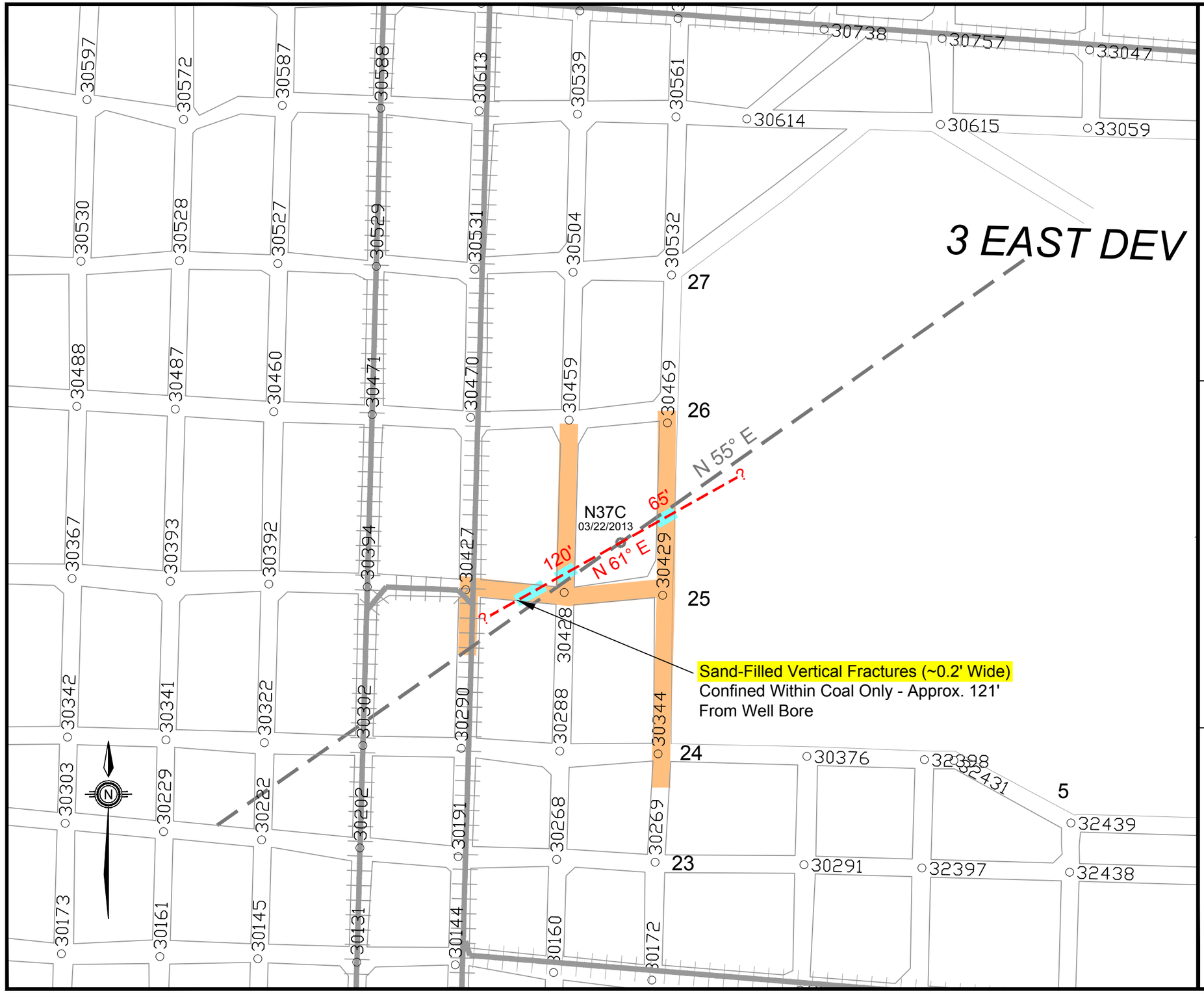
N61°E
N37C
03/22/2013
CBM Well Location With Completion Date and Observed Hydraulic Fracture Orientation

N55°E
CBM Well Location with Assumed Direction of Hydraulic Fracture Propagation and 500' Radius

Note: See Map A1 for location.

CBM Well N37C Stratigraphic Column





100 0 100 200

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

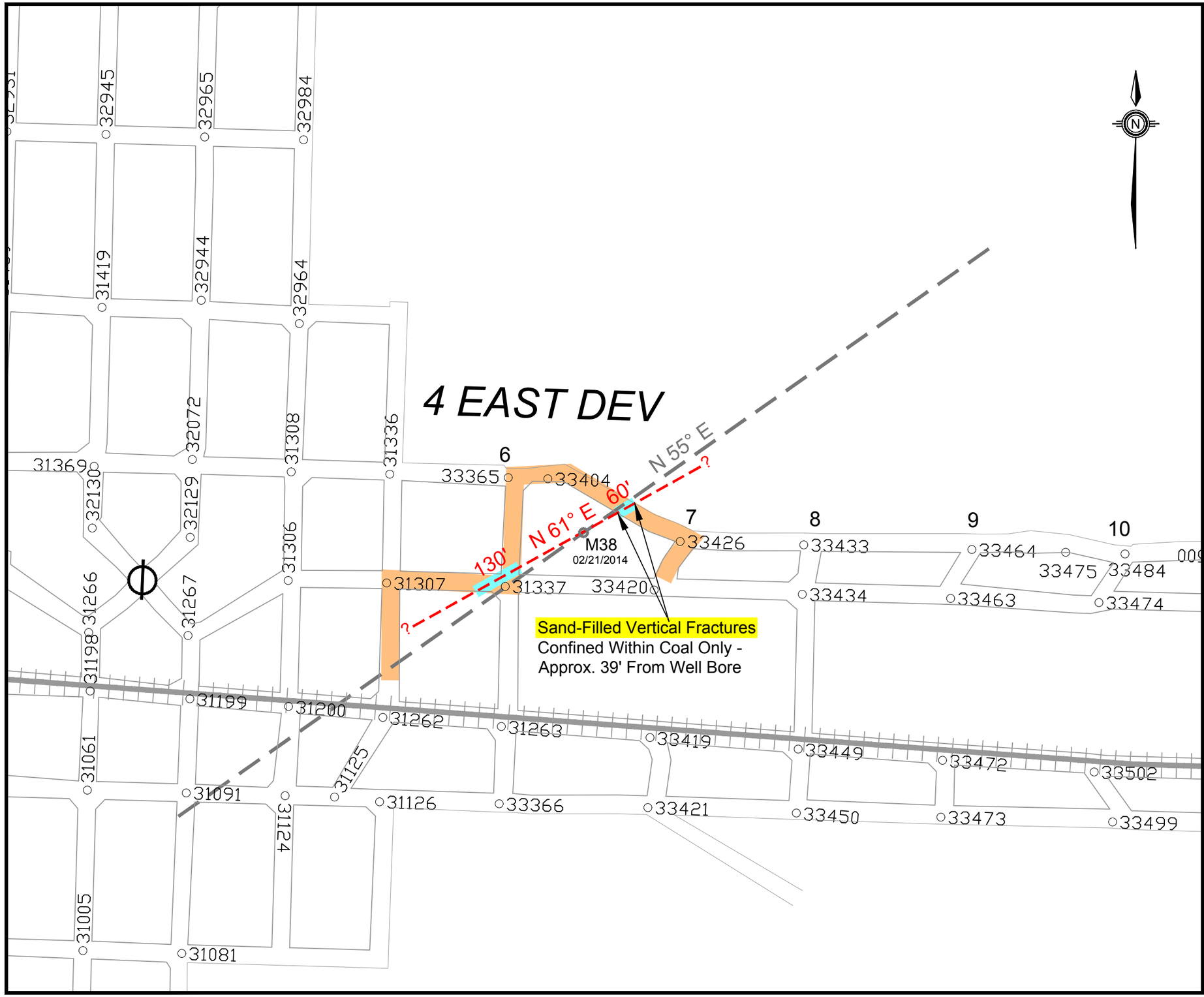
MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
D1&D4–D6&D9 Buch 1.dwg mh

D5
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

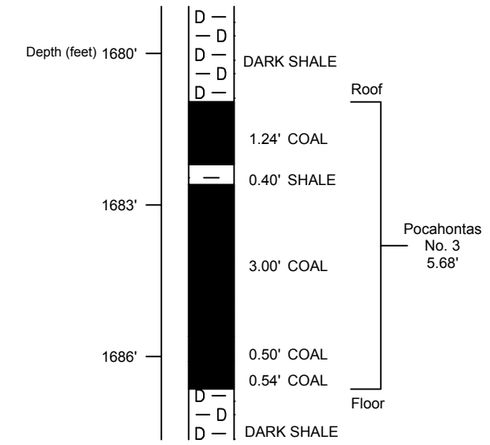
Buchanan No. 1 Mine - 4 East Development
Development Area of Investigation (8/23/17)



- Pocahontas No. 3 Seam Deep Mining
- Rail
- Area of Visual Inspection
- ○33433 Spad Location — 10 Cross-Cut ID
- N61°E — M38 02/21/2014 — CBM Well Location With Completion Date and Observed Hydraulic Fracture Orientation
- N55°E — CBM Well Location with Assumed Direction of Hydraulic Fracture Propagation and 500' Radius

Note: See Map A1 for location.

CBM Well M38
Stratigraphic Column



100 0 100 200

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
D1&D4–D6&D9 Buch 1.dwg mh

1 WEST MAINS

5

33768 33735 33744 33745 33733 33734

33703 33705 33702 33701 33671 33672 33678 33679

33656 33655 33635 33634 33622 33633 33636

33534 33566 33604 33603 33565 33553 33523 33525

33503 33480 33435 33436 33505 33504 33524

33368 33396 33402 33418 33483 33482 33466

33334 33325 33324 33315 33322 33323 33335 33336 33349

33296 33295 33275 33248 33245 33246 33274 33294 33313

33716 33354 33696

49 48 47 46 45

N 56° E

100'

120'

?

?

M37B
07/28/2016

33481

N55°E

Zone of Vertical & Horizontal
Sand-Filled Fractures
Approx. 26' From Well Bore

33403 33401 33506 33673 33698 33801 33386 33697 33367 33695

5

5 EAST DEV

D6
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

Buchanan No. 1 Mine - 5 East Development Area of Investigation (8/23/17)

Pocahontas No. 3 Seam Deep Mining

Rail

Area of Visual Inspection

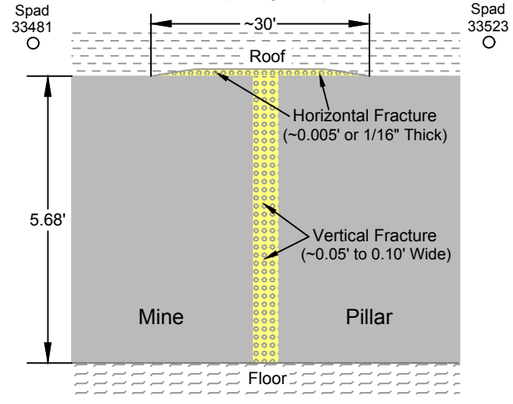
33506 Spad Location 5 Cross-Cut ID

N56°E
M37B
07/28/2016
CBM Well Location With Completion Date and Observed Hydraulic Fracture Orientation

N55°E
CBM Well Location with Assumed Direction of Hydraulic Fracture Propagation and 500' Radius

Note: See Map A1 for location.

(A) Schematic Diagram of Observed M37B Hydraulic Fractures
(Facing West)



(Not to Scale)

100 0 100 200

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
D1&D4–D6&D9 Buch 1.dwg mh



D7

Buchanan No. 1 Mine Area of Slick-Slip Underground Mapping

K — Areas of Intense Slick - Slip Zones With Average Orientation

Mapped Slickenside Location (N 71° E)

Note: See Map A1 for location.

1000 0 1000 2000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

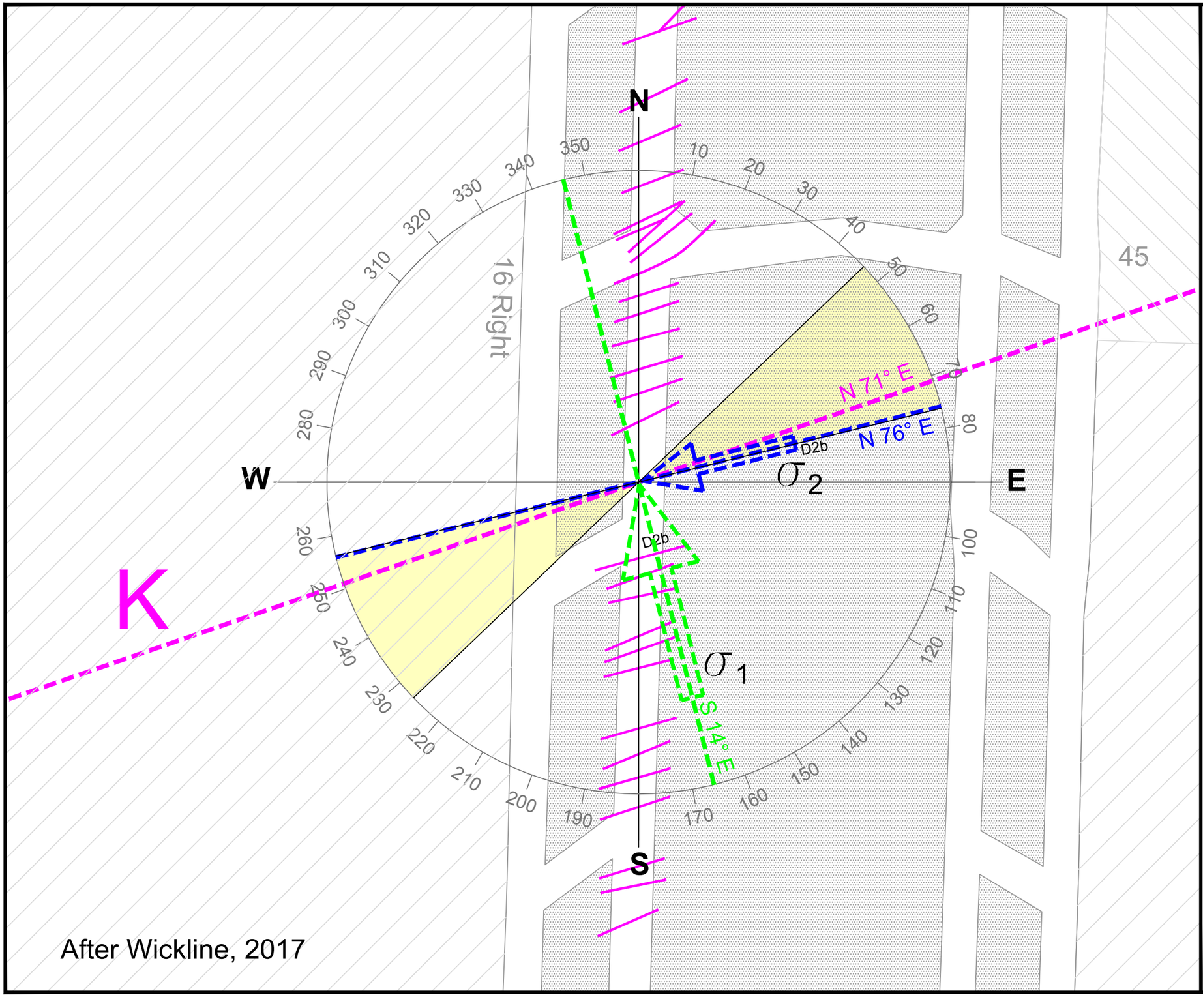
MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17

D7&D8 Slick-slip.dwg mh

Virginia Tech
D8 Small Scale CO_2 Injection Test

Buchanan No. 1 Mine
Slick - Slip Observations



After Wickline, 2017

Range of Southern Buchanan Mine Slick-Slip Zone (~N 46° - 76° E)

Mapped Slickenside Location

K — Areas of Intense Slick - Slip Zones With Average Orientation (N 71° E)

45 — Cross Cut Number

Paleo Stress Vectors (* see note 1 below)

σ_1 — D2b Anticlines - Mean Maximum Stress (S 14° E)

σ_2 — D2b Anticlines - Mean Intermediate Stress (N 76° E)

*Notes:

1. See Map A1 and D7 for location.
2. Paleo stress vectors correlate to the orientation of anticlines based on Byington's description of Deformation Event "D2b".

50 0 50 100

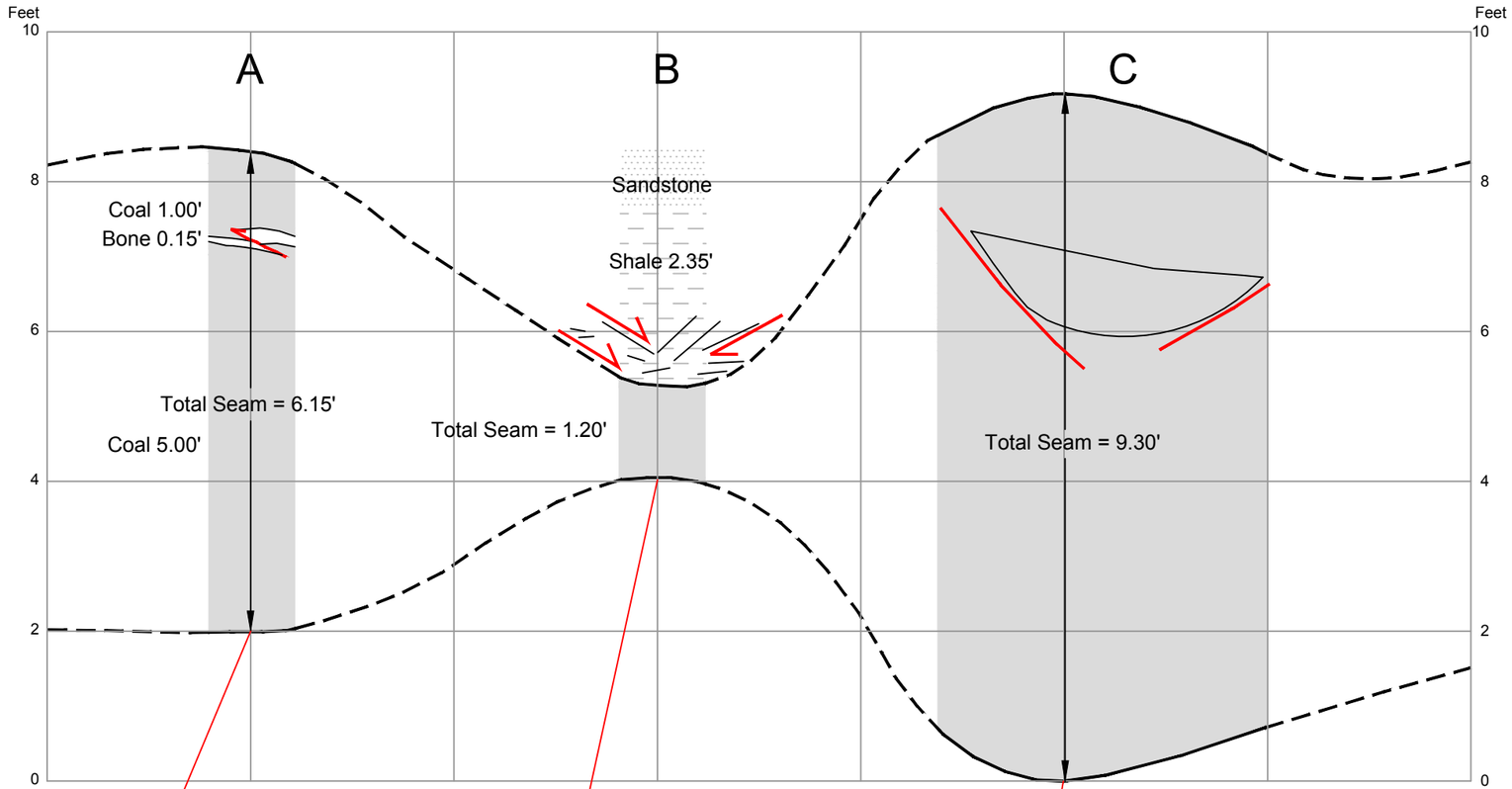
Scale in Feet

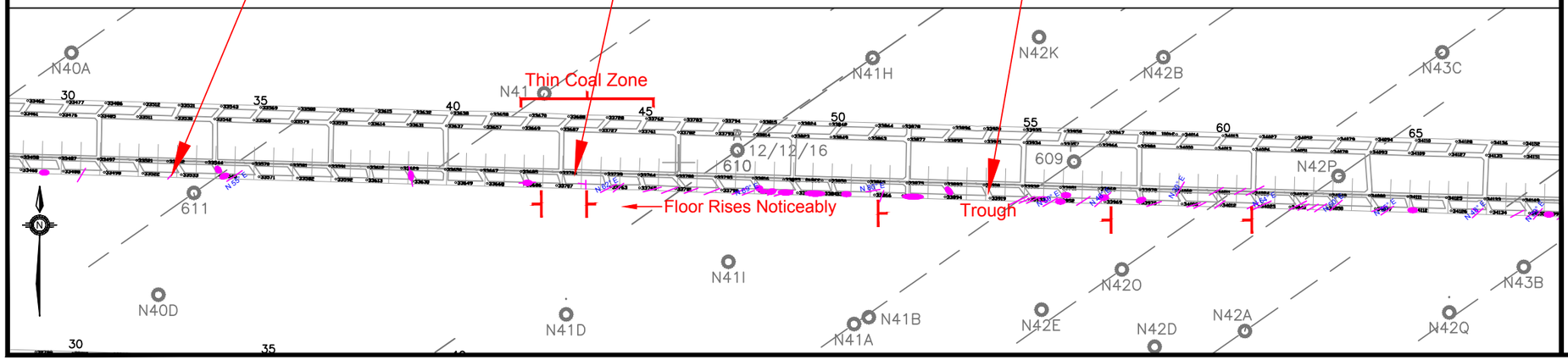
Coordinate System: Virginia South State Plane Nad 27

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VCER101 Bluefield, VA 11/17
D7&D8 Slick-slip.dwg mh

Schematic Diagram of Structural and Stratigraphic Relationships Between Cross Cuts 33 and 61





D9
(Enlarged View)

Virginia Tech
Small Scale CO_2 Injection Test

Buchanan No. 1 Mine - 3 East Development Area of Investigation (10/10/17)

- Pocahontas No. 3 Seam Deep Mining
- Rail
- ○33433 Spad Location 10 Cross-Cut ID
- N80°E Linear Slickenside / Horseback Location (~N 30° E to N 80° E)
- Dome-Shaped "Horseback" Location
- N40A CBM Well Location with Assumed Direction of Hydraulic Fracture Propagation and 500' Radius
- Apparent Strike / Dip Direction
- Slip / Fault With Direction of Apparent Movement Where Observed by Coronado and MM&A Staff

Note: See Map A1 for location.

500 0 500 1000

Scale in Feet

Coordinate System: Virginia South State Plane Nad 27

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
D1&D4–D6&D9 Buch 1.dwg mh

17 Appendix E – CBM Site Regional and Local Cross-Sections

Exhibit E1..... Cross Section A1 – A2 (Injection Site)
Exhibit E2..... Cross Section A2 – A3 (Injection Site)
Exhibit E3..... Cross Section B1 – B2 (Injection Site)
Exhibit E4..... CB-DD7 Video Log Images
Exhibit E5...C1 – C2 – Schematic Profile of Regional Structural / Stratigraphic Relationships (Henika)
Exhibit E6.....D1 – D2 – Regional Cross Section of Pennsylvanian – Devonian Strata
Exhibit E7.....E1 – E2 – Schematic Profile of Regional Structural / Stratigraphic Relationships (Harris)
Exhibit E8.....F1 – F2 – – Regional Cross Section of Mississippian - Pennsylvanian Strata
Exhibit E9.....G1 – G2 – VP-3 Mine Localized Structural Trends

West
A1

855' | 1781' | 1614' | 1000' | 642' | 791'

East
A2

2008
CB-DD5A

2000
CB-DD5

2000
CB-DD6

2000
7/18/15 - 4/16/16
12/13/16 - 1/29/17
Injection Well
CB-DD7

MM&A Video Camera Log
3/31/2015 With Workover Report

Weatherford CO
Injection Analysis
3/22/2016
(See Exhibit 4)

2007
7/6/15 - 4/16/16
12/13/16 - 1/29/17
Injection Well
CB-DD7A

MM&A Video Camera
Log 4/10/2015 With
Workover Report

2015
Desorption
Monitoring Well
(Spot Core)
M-1
(Completed March 2015)

MM&A Video
Camera Log
4/13/2015 With
Workover Report

1998
7/18/15 - 4/16/16
12/13/16 - 1/29/17
Injection Well
CB-DD8
Ties to B1-B2

Weatherford CO
Injection Analysis
3/23/2016
(See Exhibit 5)

Tiller 1
Tiller
U.Seaboard 1
U.Seaboard 2
Greasy Creek - 20
Seaboard - 20
Lower Seaboard - 10 & 20
Upper Horsepen - 10
Upper Horsepen - 30
Poca #11
Poca # 10 - 10
Poca #10 - 20
Poca #9 - 10
Poca #9 - 20
Poca #8 - 10
Poca #7 - 10
Poca #7 - 20
Poca #5 - 10
Poca #5 - 20
Poca #4
Poca #3 - 10 & 20
Poca #3 - 30
Poca #3 - 40
Poca #3 - 50
Poca #2 - 10

Hensley Shale
Upper Confining Unit

Middle Confining Unit

Lower Confining Unit

Basal Lee Sandstone

T.D. 2078.16
Gamma Density

T.D. 1949.50
Gamma Caliper

T.D. 1948.60
Gamma Caliper

T.D. 2319.00
Gamma Caliper

T.D. 2000.00
Gamma Density

T.D. 1868.50
Gamma Density

Cross Section Exhibit E1
A1 - A2 (Injection Site)

Notes:
1. See Map A1 for location.
2. See Exhibit E4 video segments for CB-DD7.
3. Datum: Pocahontas No. 9 Seam

Lithologies

- Blank
- Bone
- Coal
- Coal with Shale
- Dark Shale
- Fireclay
- Hard Sandstone
- Sandstone
- Sandstone with Coal Spar(s)
- Sandstone with Shale Streak(s)
- Sandy Shale
- Shale With Sandstone Streak(s)
- Unknown
- Unknown Lithology

2007 — CBM Well Completion Year

1 — CBM Well Completion Zone

CO_2 Injection Dates
7/18/15 - 4/16/16

* — Completed Coal Seam

8 perfs; all open — CO_2 Injection Zone With Description of Perforations

① — Location of 2015 Video Segment

Water Observed By Video Camera in 2015

Quartz Arenite

Shale Confining Unit

Desorption

Gas Content Test

scf/t	Canister ID
204.3	212

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
E1–E3 Xsecs ABC.dwg mh

West
A2

East
A3

675' | 148' | 1283' | 2734'

1998
7/18/15 - 4/16/16
12/13/16 - 1/29/17
Injection Well

CB-DD8
Ties to A1-A2 and B1-B2

MM&A Video Camera Log
4/13/2015
With Workover Report

Weatherford CO
Injection Analysis
3/23/2016
(See Exhibit 5)

Core Hole
L-236

2008
CB-DD8A

2001
CB-DD9

2009
CB-EE10

Tiller 1
Tiller
Hensley Shale
Upper Confining Unit
U.Seaboard 1
U.Seaboard 2
Middle Confining Unit
Greasy Creek - 20
Lower Confining Unit
Seaboard - 20
L.Seaboard - 10
L.Seaboard - 20
U.Horsepen - 10
U.Horsepen - 30
M.Horsepen - 10
M.Horsepen - 10
Poca #11
Poca #10 - 10
Poca #10 - 20
Poca #9 - 10
Poca #9 - 20
Note: Completion report does not show that this seam was perforated.
Poca #7 - 10
Basal Lee Sandstone
Poca #5 - 10
Poca #5 - 20
Poca #4
Poca #3 - 10
Poca #3 - 40
Poca #3 - 20
Poca #3 - 50
Poca #2 - 10

7 perfs; all open
4 perfs; all open
6 perfs; 5 of 6 open
6 perfs; all open
5 perfs; 4 of 5 open
4 perfs; all open
4 perfs; 2 of 4 open
5 perfs; all open - one very large
4 perfs; 3 of 4 open
8 perfs; 7 of 8 open
5 perfs; 4 of 5 open
8 perfs; 5 of 8 open
8 perfs; all open
Water filled at 1690' - perfs not visible

T.D. 1868.50
Gamma Density

T.D. 1880.00
Gamma Density

T.D. 2125.70
Gamma Density

T.D. 2417.53

Cross Section Exhibit E2
A2 - A3 (Injection Site)

Notes:
1. See Map A1 for location.
2. Datum: Pocahontas No. 9 Seam

Lithologies

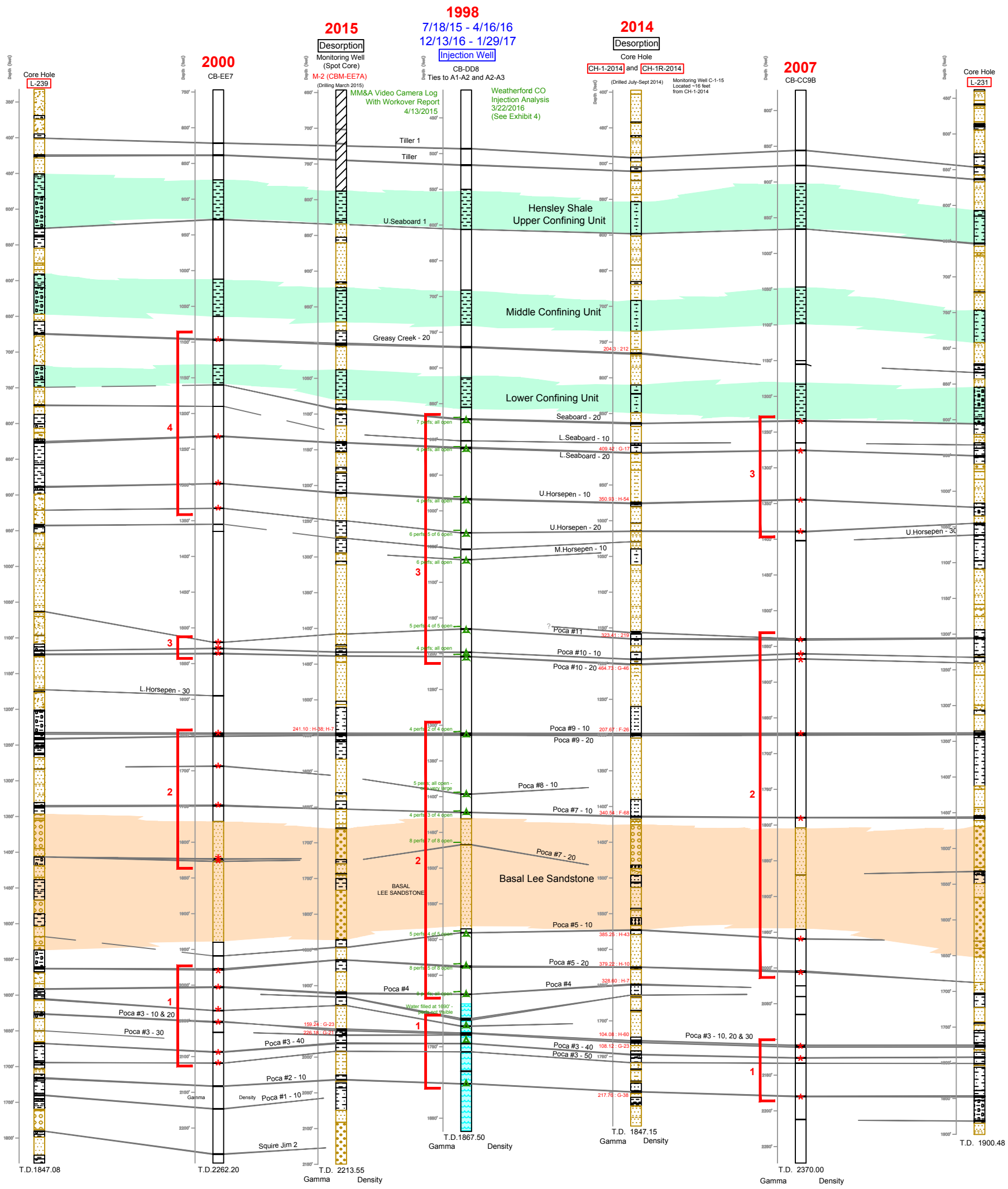
- Blank
- Bone
- Coal
- Coal with Shale
- Dark Shale
- Fireclay
- Hard Sandstone
- Sandstone
- Sandstone with Coal Spar(s)
- Sandstone with Shale Streak(s)
- Sandy Shale
- Shale With Sandstone Streak(s)
- Unknown
- Unknown Lithology

- 2007 — CBM Well Completion Year
- 1 — CBM Well Completion Zone
- 7/18/15 - 4/16/16 — CO_2 Injection Dates
- * — Completed Coal Seam
- 8 perfs; all open — CO_2 Injection Zone With Description of Perforations
- Water Observed By Video Camera in 2015
- Quartz Arenite
- Shale Confining Unit
- L-236 — Core Hole

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VCER101 Bluefield, VA 11/17
E1–E3 Xsecs ABC.dwg mh

West B1 — 1610' — 1551' — 1516' — A2 — 1205' — 1781' — 2122' — East B2



Cross Section Exhibit E3
B1 - B2 (Injection Site)

Notes:
1. See Map A1 for location.
2. Datum: Pocahontas No. 9 Seam

Lithologies

- Black Shale
- Blank
- Bone
- Bone with Coal
- Boney Coal
- Coal
- Coal With Bone
- Coal With Shale
- Crystallized Sandstone
- Dark Shale
- Fireclay
- Hard Sandstone
- Sandstone
- Sandstone with Coal Spar(s)
- Sandstone with Shale Streak(s)
- Sandy Shale
- Shale
- Shale with Coal Streak(s)
- Shale with Sandstone Streak(s)
- Unknown Lithology

- 2007 — CBM Well Completion Year
- 1 [— CBM Well Completion Zone
- 7/18/15 - 4/16/16 — CO_2 Injection Dates
- * — Completed Coal Seam
- 8 perfs; all open — CO_2 Injection Zone With Description of Perforations
- Water Observed By Video Camera in 2015
- Quartz Arenite
- Shale Confining Unit
- L-239 — Core Hole

Desorption

Gas Content Test

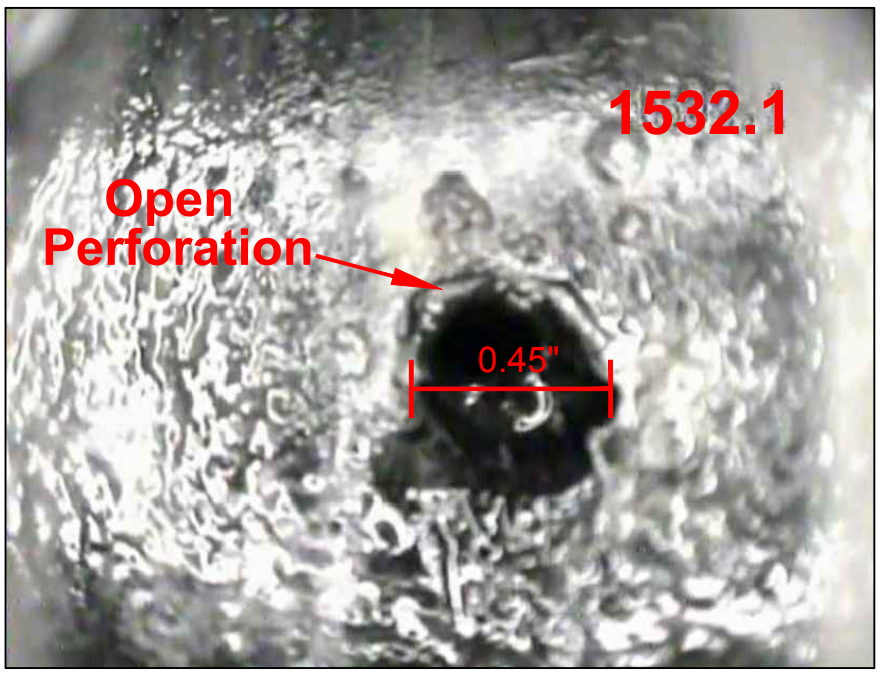
scf/t	Canister ID
204.3	212

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
E1–E3 Xsecs ABC.dwg mh

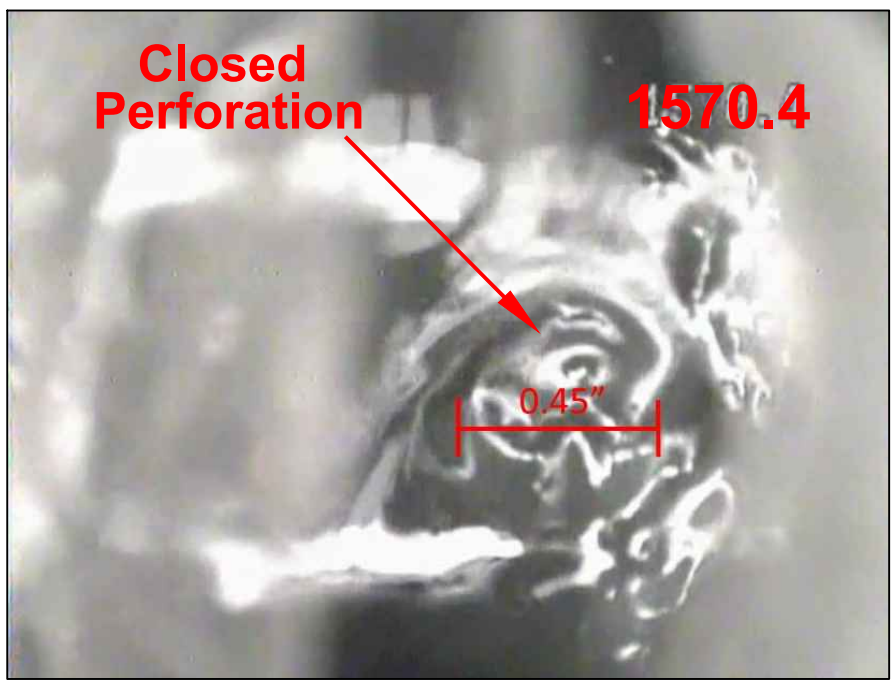
1

1st Segment
Poca #11 Perf Zone
(Side-Looking View)



2

2nd Segment
Poca #10 Perf Zone
(Side-Looking View)



3

3rd Segment
Poca #7 Perf Zone
(Downhole View)

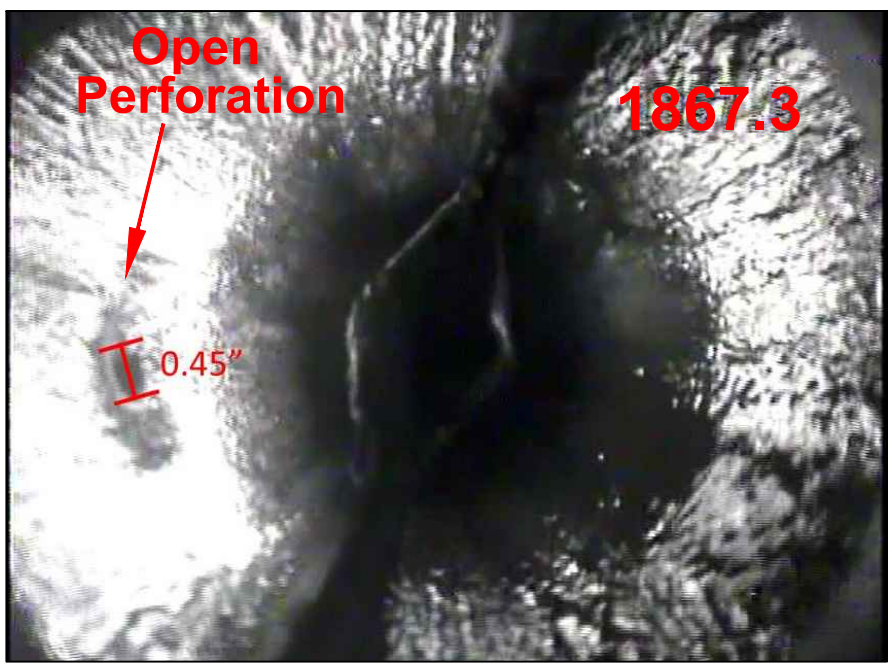


Exhibit E4

CB-DD7 Video Log Images

Notes:

1. See Exhibit E1 for location.
2. Perforated on November 14, 2000
3. Video taken on March 31, 2015

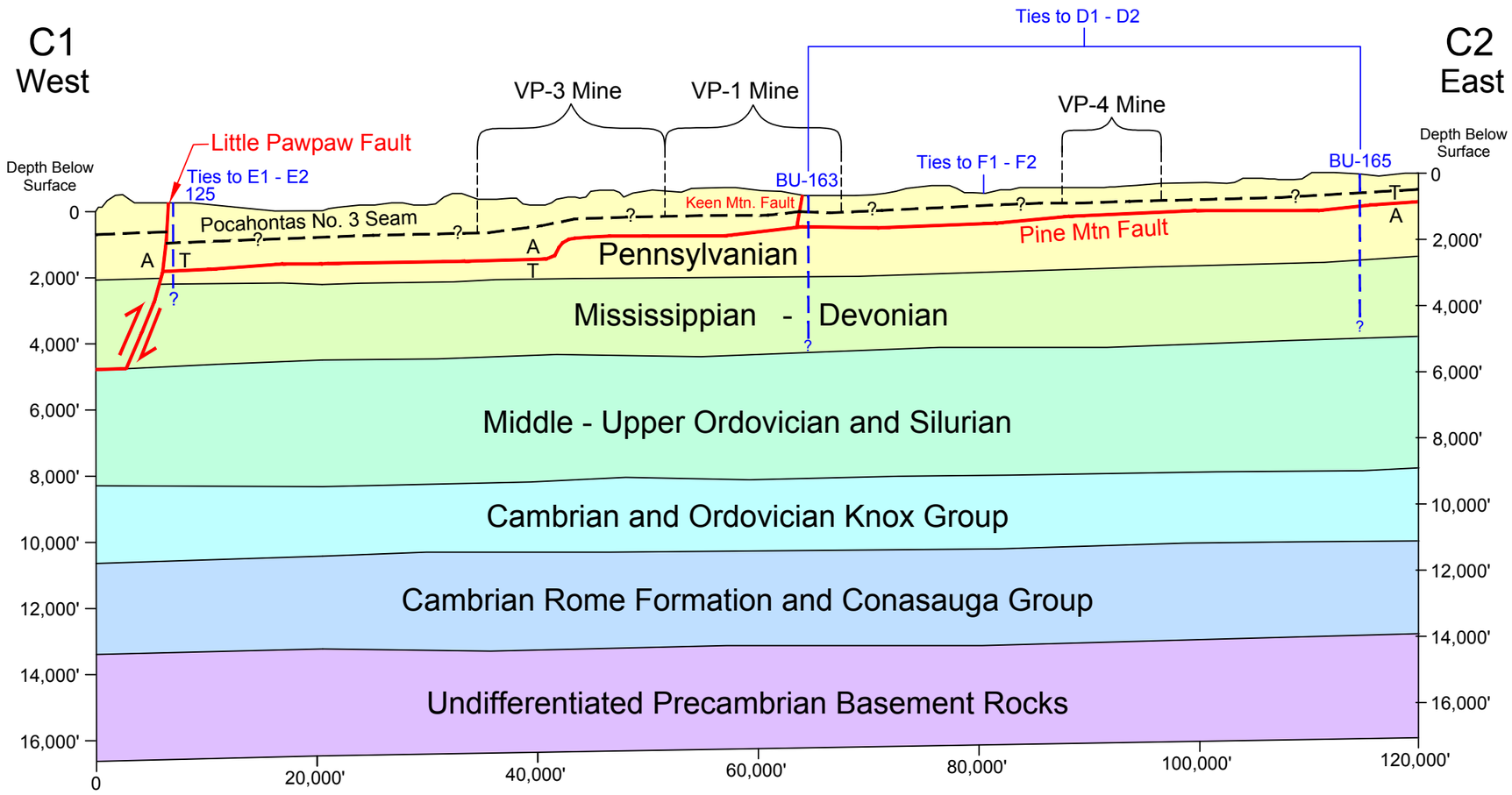
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VCER101 Bluefield, VA 11/17
E4 Video Logs.dwg mh

Virginia Tech

Cross Section Exhibit E5 — Small Scale CO_2 Injection Test

C1 - C2 Schematic Profile of Regional Structural / Stratigraphic Relationships



(After Henika, 1993 /1994)

	Fault With Arrow Indicating Relative Direction of Movement
A	Relative Movement Away From Observer
T	Relative Movement Toward Observer

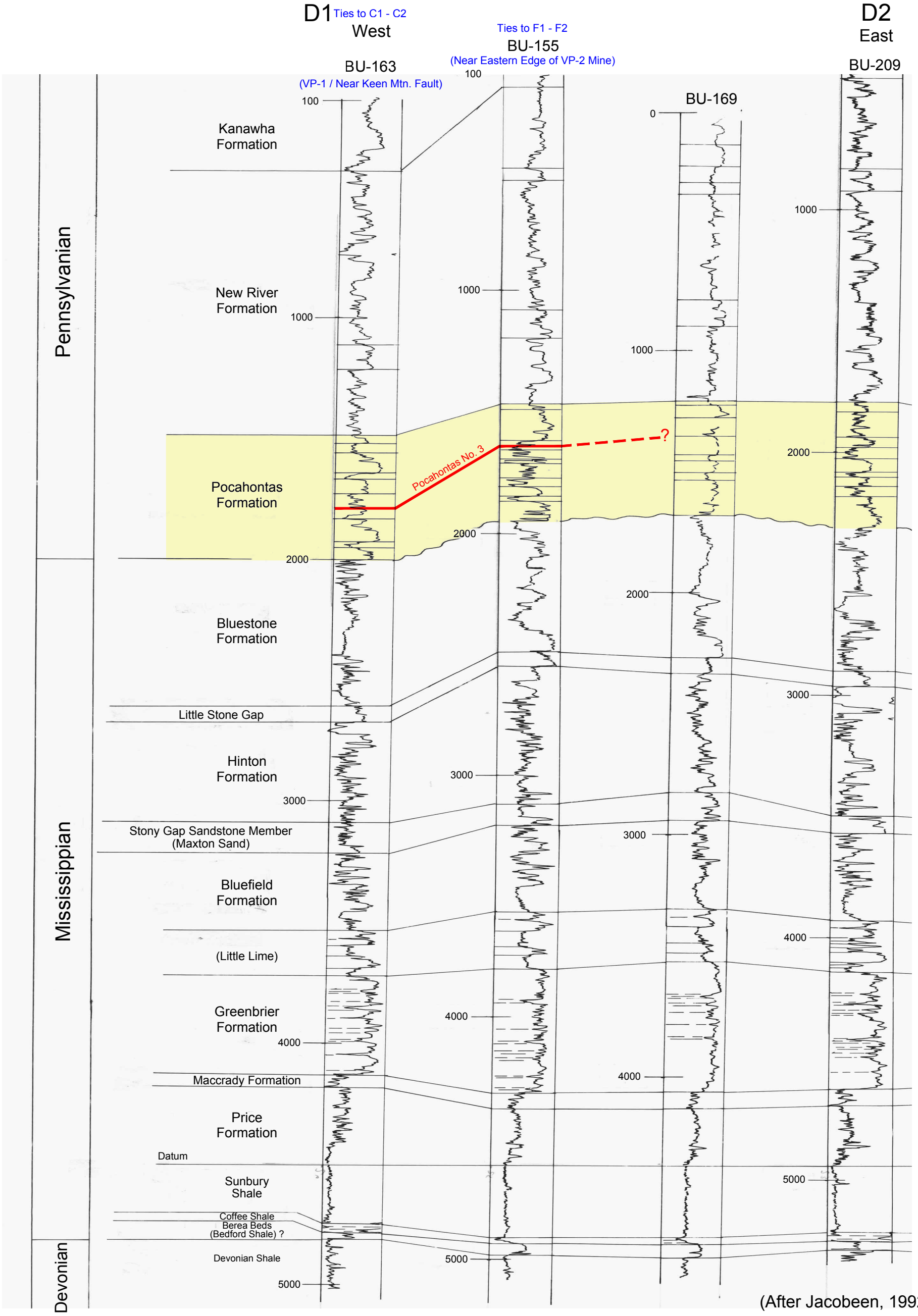
Notes:

1. See map A1 for location.
2. Vertical exaggeration is 3x horizontal.
3. True stratigraphic position of Pocahontas No. 3 Seam (as depicted herein) in relation to the Pine Mountain Fault is uncertain; precise depths cannot be determined at this scale of presentation.
4. Reference: "Internal structure of the coal-bearing portion of the Cumberland Overthrust Block in Southwestern Virginia and adjoining areas", William S. Henika, Virginia Division of Mineral Resources Publication 131, 1994, pages 100-120.
5. Refer to Cross Section D1 - D2, E1 - E2 and F1 - F2 within this Appendix.

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
E5 Xsec C.dwg

mh



(After Jacobeen, 1992)

Cross Section Exhibit E6

D1 - D2 Regional Cross Section of Pennsylvanian - Devonian Strata

Vertical Scale: 1" = 400'
Horizontal Scale: Not to Scale

(Note: Gamma Curve Direction Reversed in This Exhibit)

Notes:

1. See map A1 for location.
2. Reference: "Oil and Gas Well Analyses of Hydrocarbon Potential of Buchanan, Dickenson, and Wise Counties Virginia", Frank H. Jacobeen Jr., Open File Report 92-2, VDMR, 1992, pages 1-17.
3. Refer to Cross Sections C1 - C2 and F1 - F2 within the Appendix.

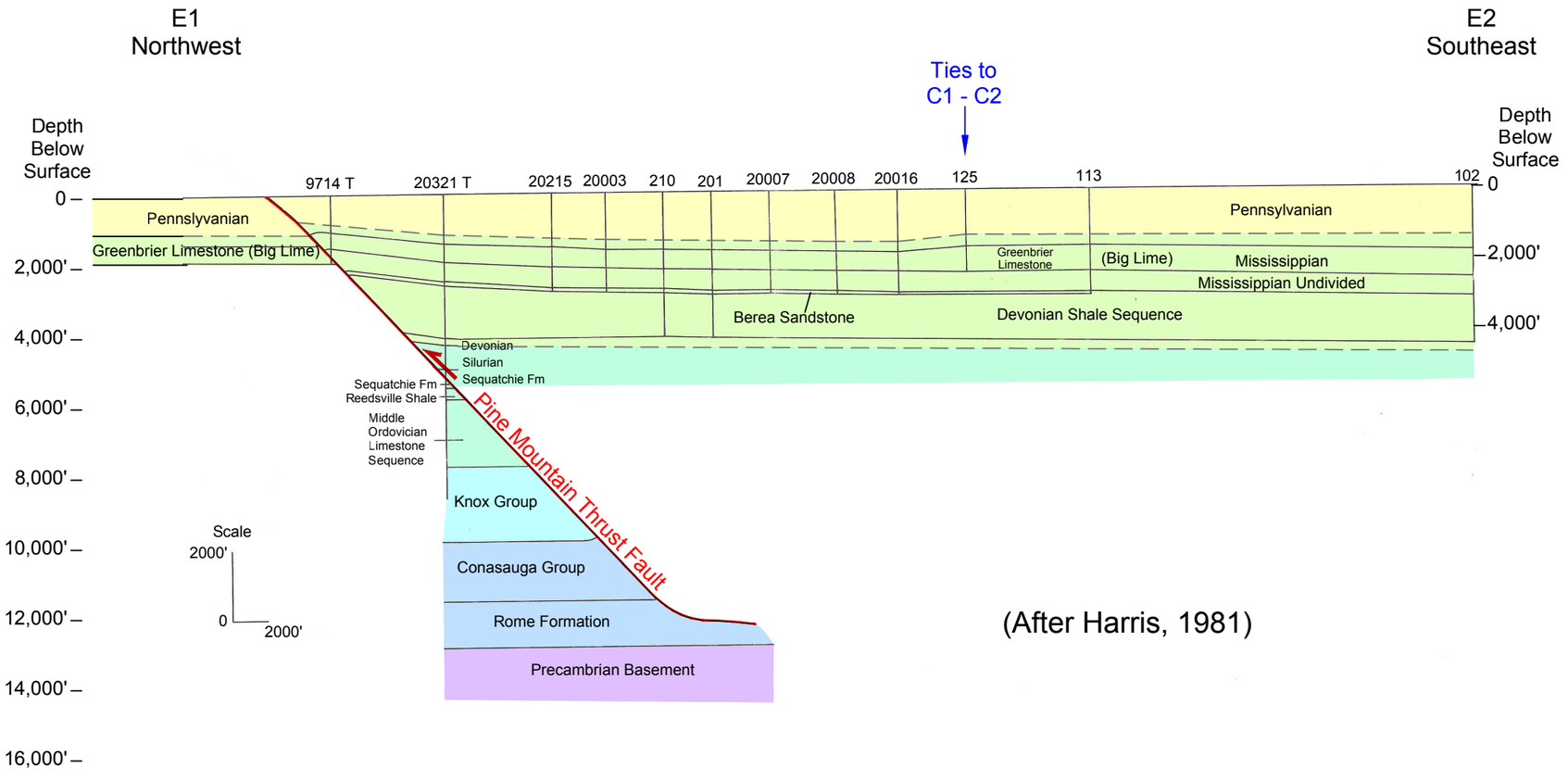
MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
E6 Xsec D.dwg mh

Virginia Tech

Cross Section Exhibit E7 — Small Scale CO_2 Injection Test

E1 - E2 Schematic Profile of Regional Structural / Stratigraphic Relationships



(After Harris, 1981)

Fault With Arrow Indicating Relative Direction of Movement

Notes:

1. See map A1 for location.
2. Vertical exaggeration is 2x horizontal.
3. "Fracture systems in the Eastern Overthrust Belt" Leonard D. Harris, Open File Report 81-1129, U.S. Geological Survey, 1981, pages 1-22.
4. Boundary between Pennsylvanian and Mississippian Strata is approximate.
5. Refer to Cross Section C1 - C2 within the Appendix.

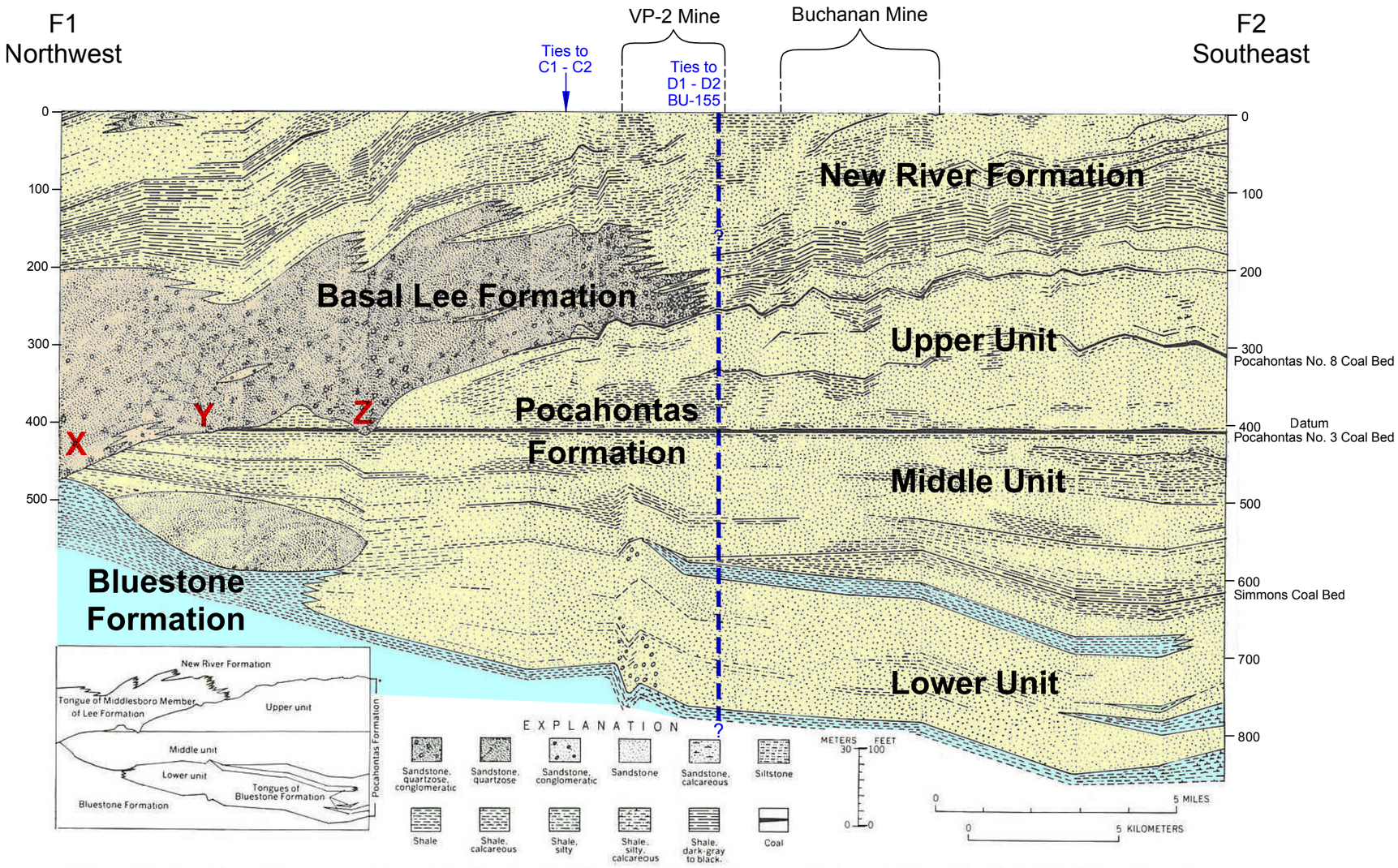
MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
E7 Xsec E.dwg mh

Virginia Tech

Cross Section Exhibit E8 — Small Scale CO_2 Injection Test

F1 - F2 Regional Cross Section of Mississippian - Pennsylvanian Strata



(After Englund, 1974)

Notes:

1. See map A1 for location.
2. Reference: "Sandstone distribution patterns in the Pocahontas Formation of southwest Virginia and southern West Virginia", Kenneth J. Englund, Geological Society of America, Special Paper 148, pages 79-95.
3. Refer to Cross Section C1 - C2 and D1 - D2 within the Appendix.
4. "X" Complete truncation of the Pocahontas Formation by the Lee Formation.
5. "Y" Scouring of Pocahontas No. 3 Seam to the north.
6. "Z" Localized scouring of Pocahontas No. 3 Seam.

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VCER101 Bluefield, VA 11/17
E8 Xsec F.dwg mh

Virginia Tech
Small Scale CO_2 Injection Test

Cross Section Exhibit E9

G1 - G2: VP-3 Mine Localized Structural Trends

Profile

- Lower Quartz Arenite (LQA) Sandstone
- Poca No.4 Seam
- Hard Laminated / Crystallized Sandstone Located in Immediate Roof
- Poca No.3 Seam
- Inferred Fault with Relative Direction of Movement

Datum: Mean Sea Level

Scale

Horizontal: 1 Inch = 300 Feet

Vertical: 1 Inch = 10 Feet

Map

- VP-3 Mine Workings with Cross Cut ID's

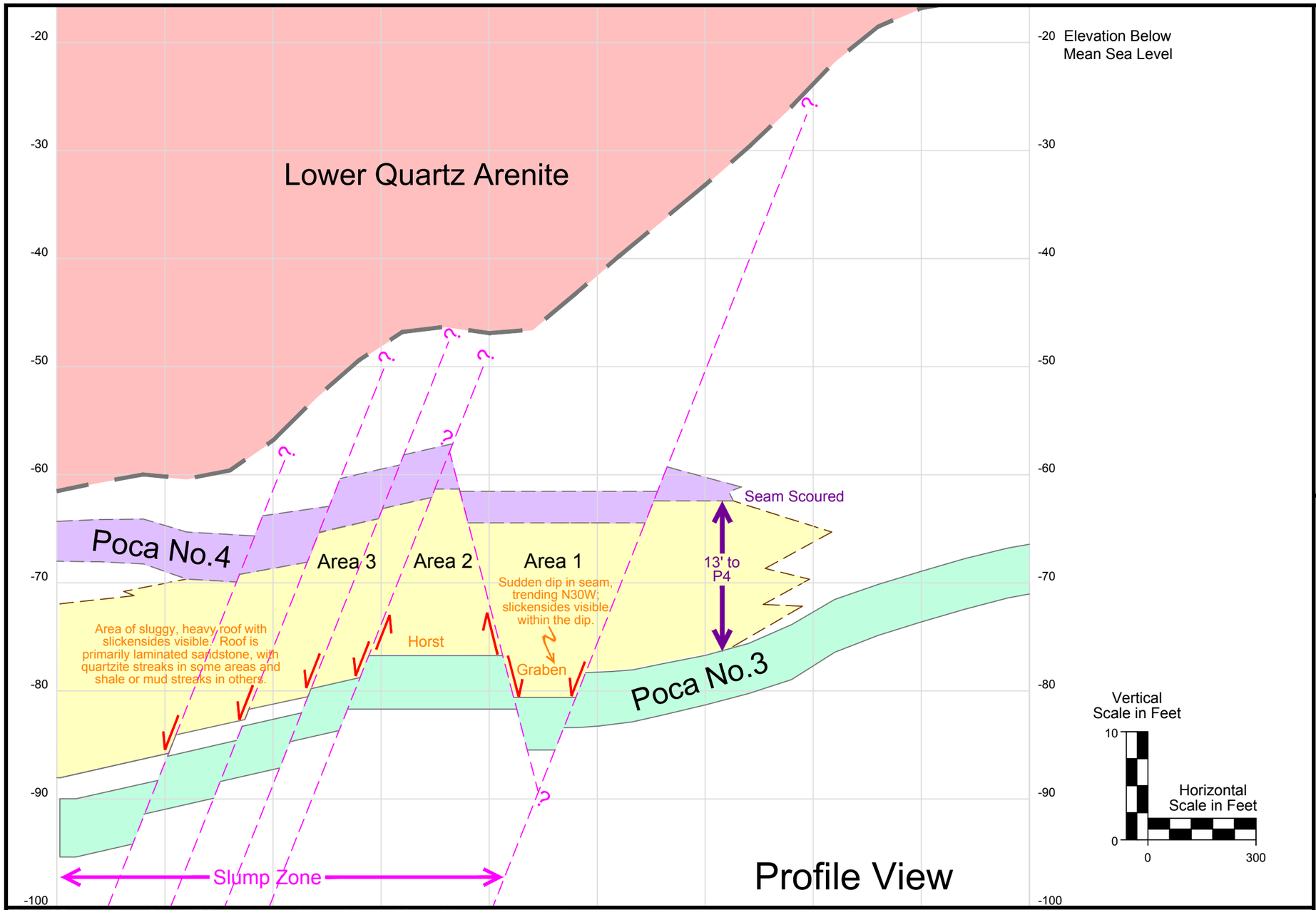
Feature Described by Mining Personnel

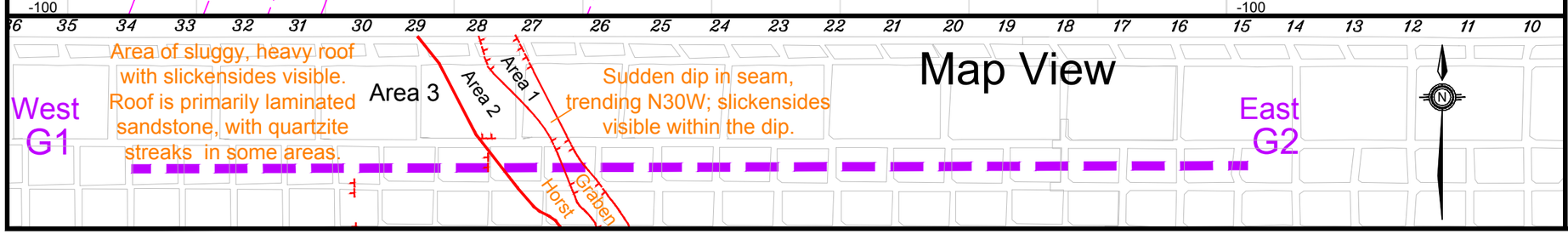
- Poor Roof / Structurally Disturbed Zone
- Graben Like Displacement Feature with Dip Direction

Scale: 1 Inch = 300 Feet

Note:

1. See map A1 for location.

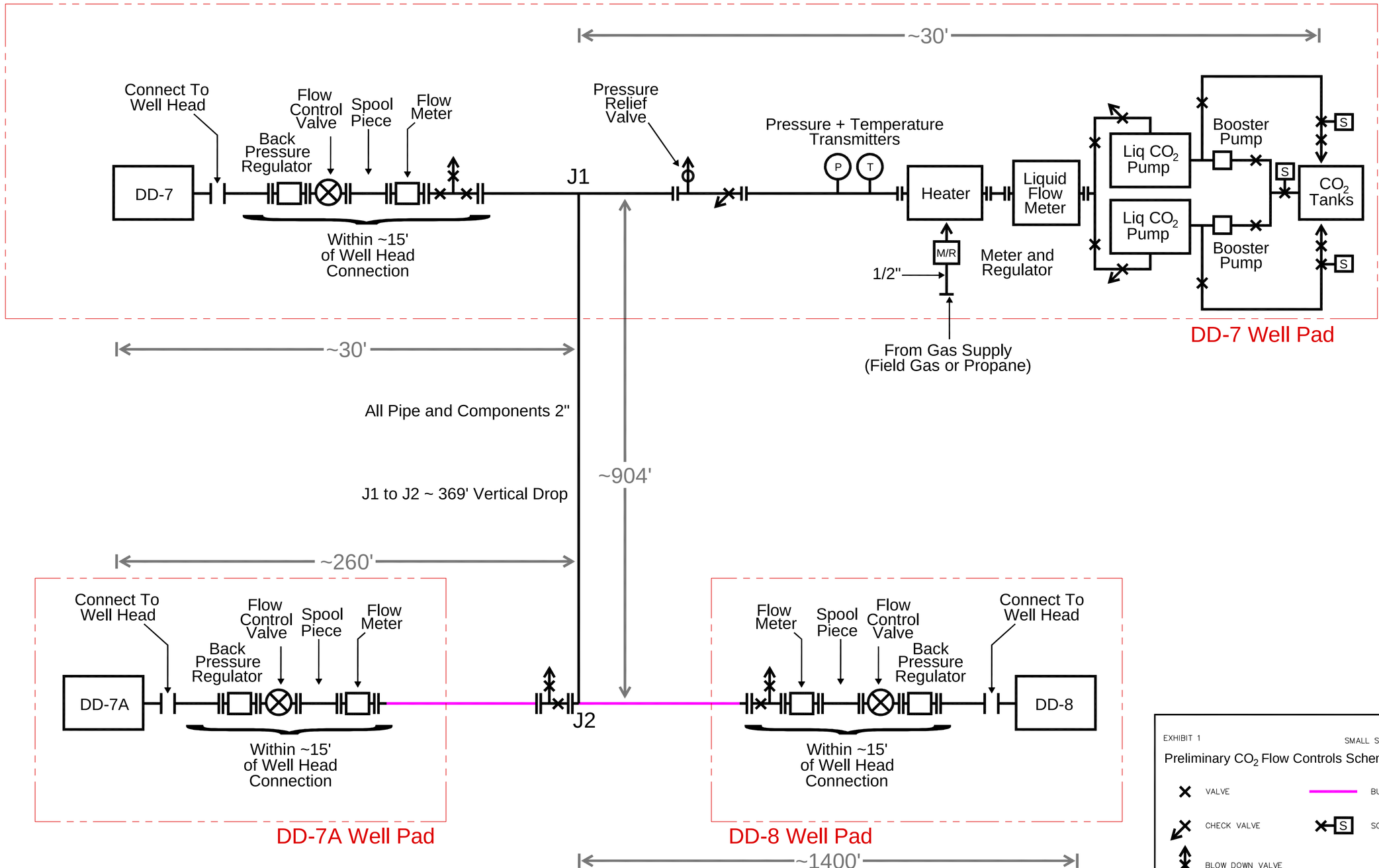




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VCER101 Bluefield, VA 11/17
E9 Xsec G.dwg mh

18 Appendix F – Injection Skid Design



Cardno MM&A
Shaping the Future

VCER101 Kingsport, TN 10/13
FlowControls_10_2_13.dwg CC

EXHIBIT 1

VIRGINIA TECH
SMALL SCALE CO_2 INJECTION TEST

Preliminary CO_2 Flow Controls Schematic, 10/2/13

VALVE

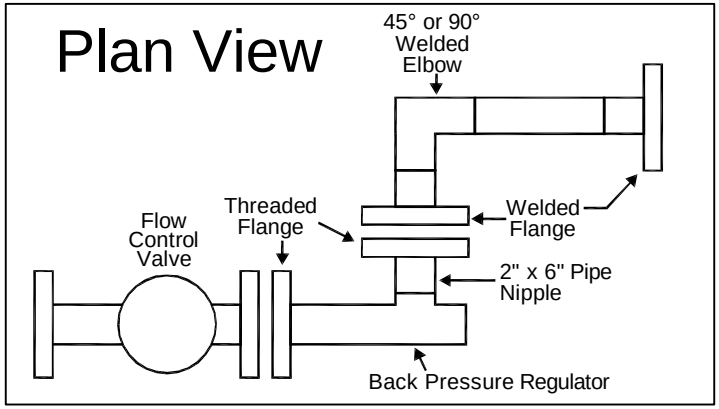
BURIED PIPELINE

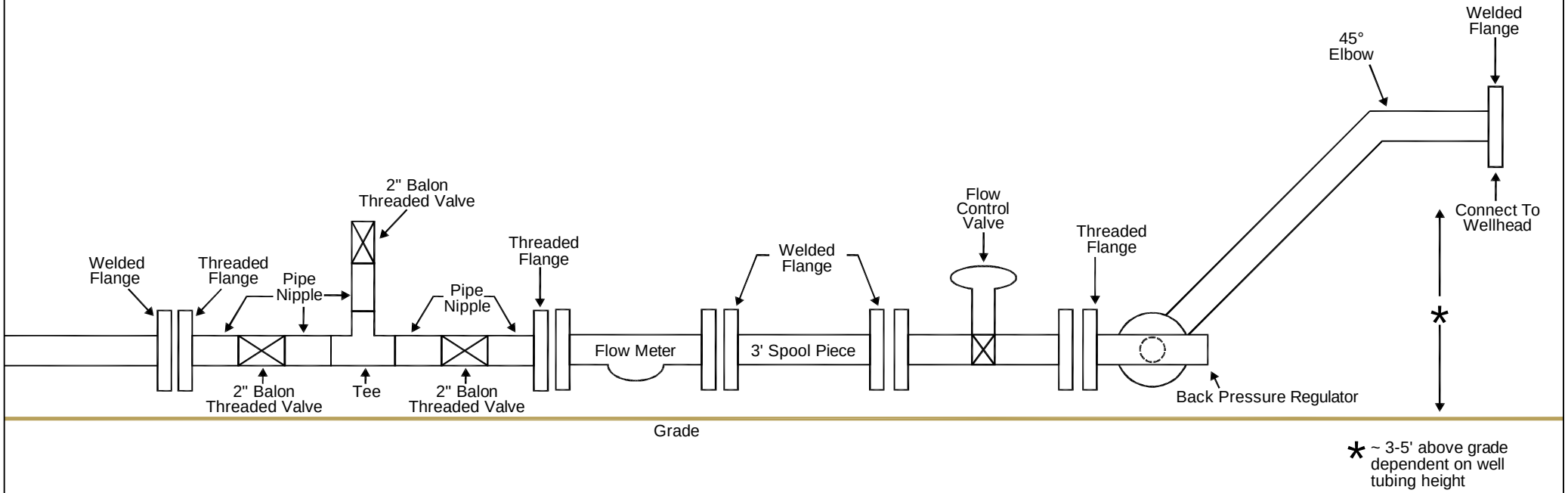
CHECK VALVE

S SOLENOID–ACTUATED VALVE

BLOW DOWN VALVE

DD-7 End of Pipeline Flow Controls





* ~ 3-5' above grade dependent on well tubing height

CO_2 Flow - Gas and Liquid Phases Summary

NPS: 2" Schedule 40

Assumed Average Temperature: 70°F

Injection Well	Required Daily Rate (tons/day)	Required Flow Rate (Mcf/d)	EPA Maximum BHP (psia)	EPA Maximum Surface Pressure (psia)	Minimum Surface Liquid Pressure (psia)	Maximum Surface Gas Pressure (psia)
DD-7	20	350	1,583	853	854	850
DD-7A	20	350	1,262	943	854	850
DD-8	20	350	1,737	1,354	854	850

CO_2 Flow Phase: Gas

NPS: 2" Schedule 40

OD: 2.375"

Wall: 0.154"

Assumed Average Temperature: 70°F

Pipeline Segment	Upstream Elevation (feet)	Downstream Elevation (feet)	Segment Length (feet)	Upstream Pressure (psia)	Downstream Pressure (psia)	Average Pressure (psia)	Average Density (kg/m^3)	Specific Gravity	Viscosity (cP)	Z-Factor	Required Daily Rate (tons/day)	Required Flow Rate (Mcf/d)	Calculated Flow Rate (Mcf/d)
Tank - DD7	2,300	2,300	30	836	835	835.5	163.554	133.765	0.01761	0.62017	20	350	369
Tank-J2	2,300	1,920	904	836	850	843.0	165.360	135.242	0.01768	0.61809	40	699	700
J2 -DD7A	1,920	1,934	260	850	826	838.0	164.231	134.318	0.01764	0.61939	20	350	351
J2 - DD8	1,920	1,919	1,400	850	766	808.0	157.458	128.779	0.01737	0.62721	20	350	350

CO_2 Flow Phase: Liquid

NPS: 2" Schedule 40

OD: 2.375"

Wall: 0.154"

Assumed Average Temperature: 70°F

Pipeline Segment	Upstream Elevation (feet)	Downstream Elevation (feet)	Segment Length (feet)	Required Downstream Pressure (psia)	Friction Pressure Loss (psi)	Head Pressure (psi)	Calculated Upstream Pressure (psia)	Actual Upstream Pressure (psia)	Average Calculated Pressure (psia)	Average Density (kg/m3)	Dynamic Viscosity (cP)	Pressure Gradient (psi/foot)	Estimated Daily Rate (tons/day)	Calculated Flow Rate (gal/day)
Tank - DD7	2,300	2,300	30	853	0.004	0.0	853	1,212	853	858.980	0.08604	0.372	20	5,580
Tank - J2	2,300	1,920	904	1,354	0.385	142.4	1,212	1,212	1,283	865.527	0.08749	0.375	40	11,075
J2 - DD7A	1,920	1,934	260	943	0.033	-4.7	948	1,354	945	782.737	0.07379	0.339	20	6,123
J2 - DD8	1,920	1,919	1,400	1,354	0.168	0.4	1,354	1,354	1,354	837.137	0.08039	0.362	20	5,726

Note: Stra□ bales to be placed at entrance and outlet of all culverts and at all drainage □indo□s until area is stabili□ed. Erosion and sediment control □ill be handled by silt fencing.

AREA OF REVIEW (AOR)

MONITORING AREA

1/4 MILE RADIUS

1/2 MILE RADIUS

CO_2 Tanks and Pumps on Location

M-1

M-2

C-1

BU-1923

BU-1998

BU-3337

BU-0380

BU-3599

BU-307

BU-260

BU-2772

BU-4102

BU-354

BU-3388

BU-1973

BU-1480

BU-1875

BU-3850

BU-3335

BU-377

BU-1950

BU-1743

BU-4269

BU-2092

BU-3893

BU-3929

BU-3385

BU-3384

BU-1924

BU-2072

BU-3942

BU-1922

BU-3544

BU-2547

BU-2143

BU-3629

BU-4114

BU-3628

BU-4510

BU-2121

BU-1610

BU-4461

Ball Water Well 56'

Lockhart Water Well 50'

Happy Br

Left Fork Sad Lick

Strip Mine

Strip Mine

Pealog Br

Hurricane Creek

Parett Fletcher

600

600

600

MAP 1

VIRGINIA TECH
SMALL SCALE CO_2 INJECTION TEST

CO_2 Pipeline (REV 09/02/14)

- CO_2 PIPELINE
- BURIED CO_2 PIPELINE
- SILT FENCING
- BU-1998 — CNX GAS CBM WELL WITH COUNTY PERMIT NUMBER AND COMPANY WELL NUMBER
- BU-0380 — SALTWATER DISPOSAL WELL WITH COUNTY PERMIT NUMBER
- CARDNO MM&A CO_2 INJECTION WELL
- AREA OF REVIEW
- MONITORING AREA
- 31 / 23' — WATER WELL WITH COUNTY IDENTIFICATION NUMBER AND TOTAL DEPTH OF WELL (FEET)
- M-1 — PROPOSED MONITORING WELL
- C-1 — PROPOSED CHARACTERIZATION WELL

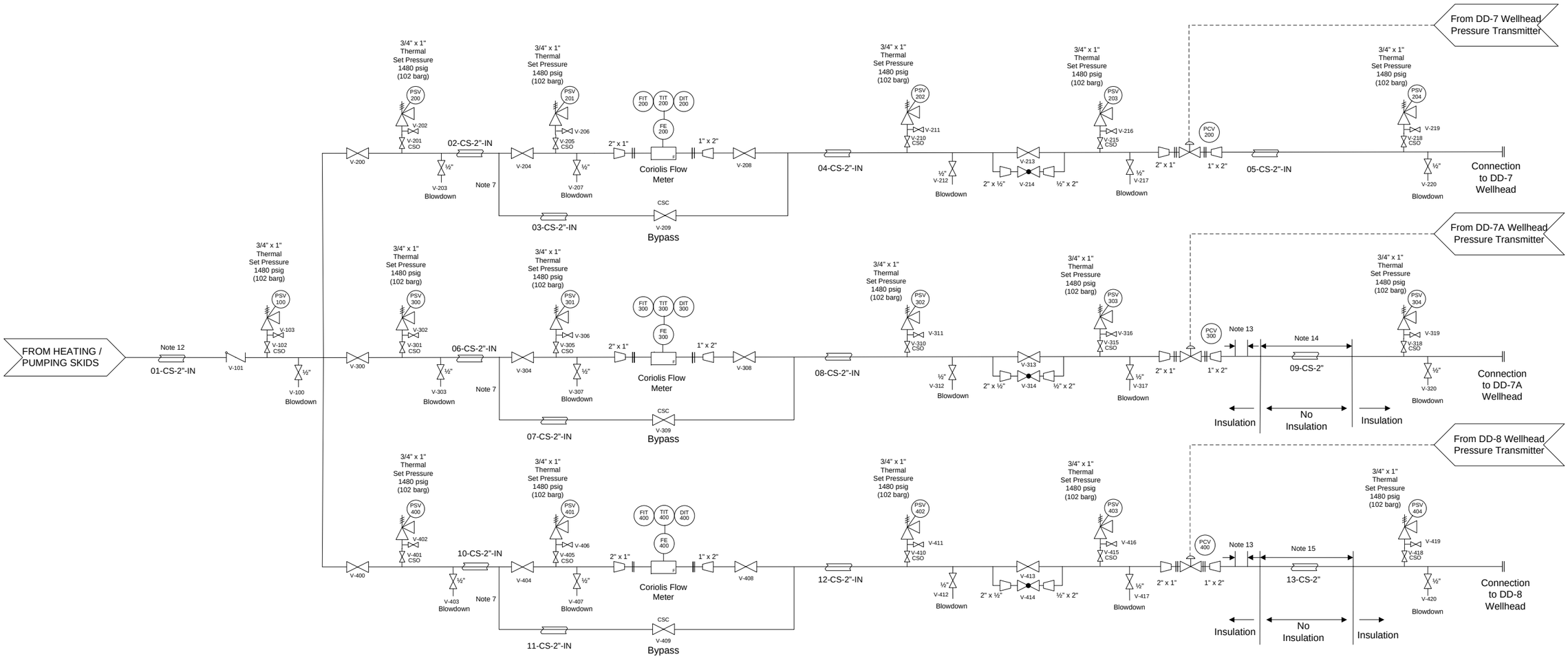
0 600 1,200 1,800

SCALE: 1" = 600'

COORDINATE SYSTEM: NAD 27, VIRGINIA SOUTH STATE PLANE

Cardno MM&A
Shaping the Future

VCER101 Kingsport, TN 8/14
600_CO2PL_9_11_2014.dwg GC



LEGEND

Pressure Regulating Valve	TE Temperature Element	TI Temperature Indicator	PAHH Pressure Alarm High High	TALL Temperature Alarm Low Low	
Ball Valve	PT Pressure Transmitter	TT Temperature Transmitter	PAH Pressure Alarm High	TAL Temperature Alarm Low	
Globe Valve	TIT Temperature Indicator Transmitter	TC Temperature Controller	PALL Pressure Alarm Low Low	NC Normally Closed	
Pressure Relief Valve	PS Pressure Switch	PI Pressure Indicator	PAL Pressure Alarm Low	FO Fail Open	
Check Valve	PC Pressure Controller	PIT Pressure Indicator Transmitter	TAHH Temperature Alarm High High	CSO Car Seal Open	
Control Valve	SC Speed Controller	DT Density Transmitter	TAH Temperature Alarm High	CSC Car Seal Closed	
Flow Meter				Needle Valve	

Notes

1. All pipe to be Sch. 40 or heavier if required for MAWP.
2. Line Numbering System: LINE # - MAT'L – SIZE - INSULATE
3. Insulate above-ground piping.
4. Pressure relief valves will be mounted on a 12" riser pipe. The riser pipe is not insulated.
5. Blowdown vent connections to be made from the bottom of the pipe with vent discharge downward.
6. Discharge of pressure relief valves to be routed in the downward direction with release point near ground level.
7. Bypass piping length to consider thermal expansion.
8. All manual block, bleed and blowdown valves are drilled-ball type for liquid CO2 service.
9. All blowdown, bleed valves, and PSVs require 316 SS valve body and internals.
10. Block valves for pressure indicators, transmitters, and switches are ½" and bleed valves are ¼".
11. Inlet block valves for PSVs are 3/4" and bleed valves are ¼" unless otherwise indicated.
12. The pumping system may require recycle valve to limit manifold pressure, and pressure and temperature transmitters may be required downstream of the heater. It is assumed that these valves and instrumentation are outside of Trimeric scope.
13. This represents a distance of approximately 904 feet of piping that will be run above ground down a 41% grade.
14. This represents a distance of approximately 260 feet of underground piping.
15. This represents a distance of approximately 1,400 feet of underground piping.

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHECKED	APPROVED	APPROVED
A	10/5/14	Initial Draft	AJS	RWM		
B	10/31/14	Add globe valves	AJS	RWM		
C	11/18/14	Add flanges, remove end of skid isolation valves	AJS			

FILENAME: CARDNO CO2 INJECTION PID REV C 111814.VSD
DATE: 11/18/14
DRAWN BY: Andrew Sexton

TRIMERIC CORPORATION
P.O. Box 826
Buda, Texas 78610

Cardno MM&A SECARB CO_2 Injection Process and Instrumentation Diagram Pipeline

CLIENT/SITE: Cardno MM&A / Buchanan County VA
JOB NUMBER: 50139.01
DRAWING NUMBER: P&ID-001
SCALE: NONE

Micro Motion Sizing Summary

Flow Calculation Summary Report Index

High purity carbon dioxide_CMFS100M_1_FCS
High purity carbon dioxide_CMFS100M_2_FCS

Configuration Data Sheet Report Index

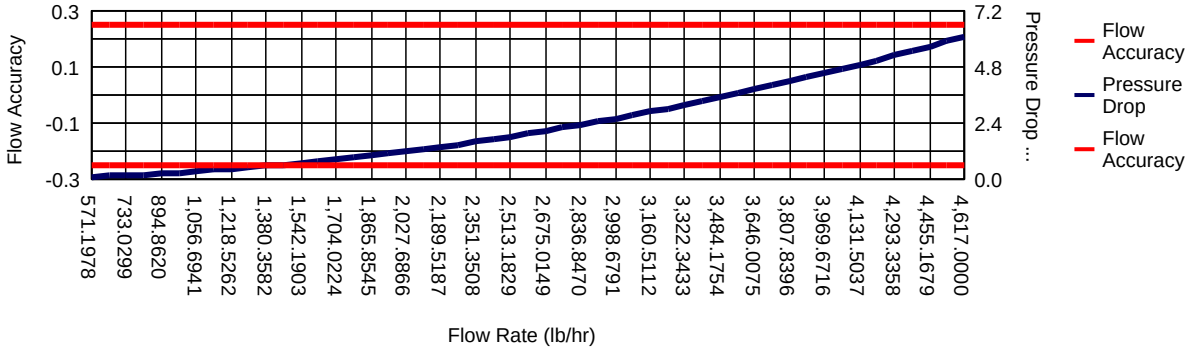
High purity carbon dioxide___CDS
High purity carbon dioxide___CDS

Micro Motion Calculation Summary

Date:			09/17/14			
Company:			-			
Project Name:			-			
Service:			-			
Sensor Model #:			CMFS100M330N2BAEKZZ			
Sensor Tag(s):			-			
Transmitter Model #:			2700R12ABAEZZZPK			
Transmitter Tag(s):			-			
Wetted Material:			316L SS			
Fluid:			Custom: High purity carbon dioxide			
Fluid State:			Gas			
Mass Flow Accuracy at Operating Flow (+/- % of Rate):			0.2500			
Density Accuracy at all Rates (+/-):			0.0312	lb/ft3		
Pressure Drop at Operating Flow:			6.0907	psi		
Sensor Minimum Pressure at operating conditions:			392.6862	psig		
Velocity at Operating Flow:			87.8454	ft/sec		
			Min	**Operating***	**Max**	**Design**	**Units**
Flow Rate:			-	4,617.0000	-	-	lb/hr
Pressure:			-	400.0000	-	-	psig
Process Fluid Temperature:			-	100.0000	-	-	F
Ambient Temperature:			-	80.0000	-	-	F
Density:			-	3.5100	-	-	lb/ft3
Viscosity:			-	0.0166	-	-	cP
Gas Only	**Base Reference Temperature:**	F	60.0000			Density:	
	Base Reference Pressure:	psia	14.7000				
	Base Reference Density:	lb/ft3	0.1340				
Process Connection:			1-inch CL600 ASME B16.5 F316/F316L Weld neck flange Raised face				
Process Connection Pressure Rating:			1440 psig				
@Temperature:			100 F				

Flow Rate	**lb/hr**	**Mass Flow Accuracy +/- % of**	**Rate**	**Pressure Drop***	**psi**	**Velocity***	**ft/sec**	**Re**
4617.0000		0.25		6.09		87.8500		1130000
4212.4198		0.25		5.08		80.1500		1047000
3807.8396		0.25		4.16		72.4500		962600
3403.2593		0.25		3.33		64.7500		878700
2998.6791		0.25		2.59		57.0500		794800
2594.0989		0.25		1.95		49.3600		711000
2189.5187		0.25		1.40		41.6600		627100
1784.9385		0.25		0.93		33.9600		543200
1380.3582		0.25		0.56		26.2600		459300
975.7780		0.25		0.29		18.5700		375400
571.1978		0.25		0.10		10.8700		291500

Sizing Details



*All pressure drop and velocity results are based on the process conditions (except flow rate) that are entered in the Operating column.

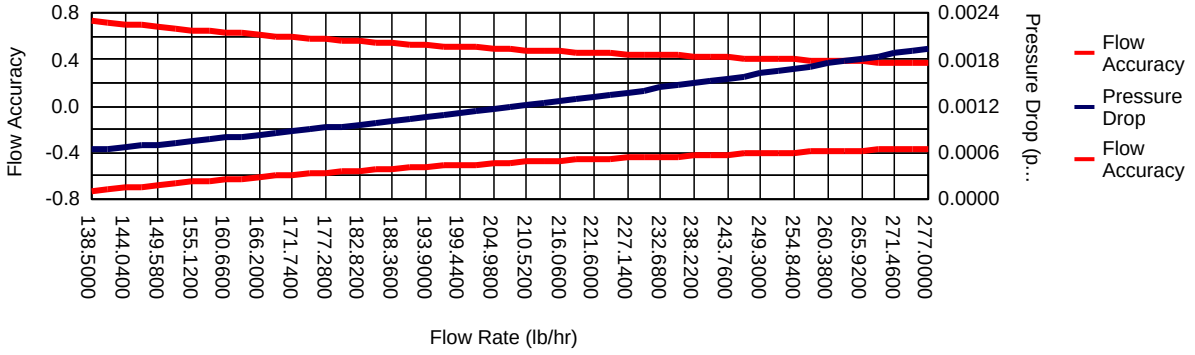
Notes:	-		
Prepared By:	JOSE_VALVERDE	**Project ID:**	-
Oracle	Version: 11.5.10.2	**Application:**	High purity carbon dioxide

Micro Motion Calculation Summary

Date:			09/17/14			
Company:			-			
Project Name:			-			
Service:			-			
Sensor Model #:			CMFS100M330N2BAEKZZ			
Sensor Tag(s):			-			
Transmitter Model #:			2700R12ABAEZZZPK			
Transmitter Tag(s):			-			
Wetted Material:			316L SS			
Fluid:			Custom: High purity carbon dioxide			
Fluid State:			Liquid			
Mass Flow Accuracy at Operating Flow (+/- % of Rate):			0.1000			
Density Accuracy at all Rates (+/-):			0.0312	lb/ft3		
Pressure Drop at Operating Flow:			0.0019	psi		
Sensor Minimum Pressure at operating conditions:			1,399.9978	psig		
Velocity at Operating Flow:			0.3120	ft/sec		
			Min	**Operating***	**Max**	**Design**	**Units**
Flow Rate:			-	277.0000	-	-	lb/hr
Pressure:			-	1,400.0000	-	-	psig
Process Fluid Temperature:			-	40.0000	-	-	F
Ambient Temperature:			-	80.0000	-	-	F
Density:			-	59.3000	-	-	lb/ft3
Viscosity:			-	0.1034	-	-	cP
Gas Only	**Base Reference Temperature:**	F	-			Density:	
	Base Reference Pressure:	psia	-				
	Base Reference Density:	lb/ft3	-				
Process Connection:			1-inch CL600 ASME B16.5 F316/F316L Weld neck flange Raised face				
Process Connection Pressure Rating:			1440 psig				
@Temperature:			40 F				

Flow Rate	**lb/hr**	**Mass Flow Accuracy +/- % of**	**Rate**	**Pressure Drop***	**psi**	**Velocity***	**ft/sec**	**Re**
277.0000		0.37		0.00		0.3120		74210
263.1500		0.39		0.00		0.2964		66980
249.3000		0.41		0.00		0.2808		59760
235.4500		0.43		0.00		0.2652		52530
221.6000		0.46		0.00		0.2496		45310
207.7500		0.49		0.00		0.2340		38080
193.9000		0.52		0.00		0.2184		30850
180.0500		0.56		0.00		0.2028		23630
166.2000		0.61		0.00		0.1872		16400
152.3500		0.67		0.00		0.1716		9175
138.5000		0.73		0.00		0.1560		1949

Sizing Details



*All pressure drop and velocity results are based on the process conditions (except flow rate) that are entered in the Operating column.

Notes:	-		
Prepared By:	JOSE_VALVERDE	**Project ID:**	-
Oracle	Version: 11.5.10.2	**Application:**	High purity carbon dioxide

Date:	17-SEP-14	**Micro Motion Configuration Data Sheet**	Page | 4			
Company	TRIMERIC CORP		Spec No	-	Rev.	
			Contract	-	P.O	-
Service:	High purity carbon dioxide		Req.	-	By	-
Manufacturer:	Micro Motion, Inc.		Chk'd	-	Appr.	-

Service	1	**Sensor Tag(s):**						
	2	**Transmitter Tag(s):**						
	3	Fluid State | Fluid Name	-	High purity carbon dioxide				
	4	Flow Min|Oper|Max|Design	-	4617	-	-	lb/hr	
	5	Pressure Min|Oper|Max|Design	-	400	-	-	psig	
	6	Temperature Min|Oper|Max|Design	-	100	-	-	F	
	7	Specific Gravity/Density (Operating)	3.51 lb/ft3					
	8	Viscosity (Operating)	.0166 cP					
Sensor	9	**Product No|Proposal Line No.|Qty**	**CMFS100M330N2BAEKZZ**				**1.1**	**2**
	10	Description	SENSOR,CMFS100M					
	11	**ETO#:|ETO Description**	**-**	**-**				
	12	**ETO#:|ETO Description**	-	-				
	13	Process Connections	1-inch CL600 ASME B16.5 F316/F316L Weld neck flange Raised face					
	14	Approval	CSA (US and Canada): Class I, Division 1, Groups A, B, C, D					
	15	Wetted Parts	316L SS					
	16	Mass Flow Accuracy @OpFlow(%rate)	.25	%				
	17	Density Accuracy @ All Rates	.03121	lb/ft3				
	18	Pressure Drop @ Op Flow	6.09072	psi				
	19	Calibration Type|Rate|Units	Standard	-	kg/min			
	20	Custom Calibration Points	-					
	21	Density for Volume to Mass Conversion	-					
	22	Special Units Text|Totalizer Text	-	-				
	23	Base Units: Flow|Time|Conversion	-	-	-			
	24	Warning	-					
	25	Sensor Notes	-					
Transmitter	26	**Product No|Proposal Line No.|Qty**	**2700R12ABAEZZZPK**				**1.36**	**2**
	27	Description	TRANSMITTER,2700					
	28	**ETO#:|ETO Description**	**-**	**-**				
	29	**ETO#:|ETO Description**	-	-				
	30	Input Power	-					
	31	Approval	-					
	32	Transmitter Flow Units: Mass | Vol	lb/hr	USGPM				
	33	Transmitter Units: Density | Temp	lb/ft3	F				
	34	Special Mass Units Test | Totalizer Text	-	-				
	35	Base Mass Units: Flow | Time | Conv	-	-	0			
	36	Special Vol Units Test | Totalizer Text	-	-				
	37	Base Vol Units: Flow | Time | Conv	-	-	0			
	38	Output 1 Type Variable	Analog 1	Mass Flow Rate				
	39	Scaling LRV URV Units	4-20mA	0	4617	lb/hr		
	40	Output 2 Type Variable	Frequency	Mass Flow Rate				
	41	Setting Rate - Units	0Hz	0	-	lb/hr		
	42	Output 3 Type Variable	RS-485 Communications	-				
	43	Scaling LRV URV Units	-	0	0	-		
	44	Transmitter Notes	-					
Cable	45	**Product No|Proposal Line No.|Qty**	**-**				**-**	**-**
	46	Description	-					
Peripheral	47	**Product No|Proposal Line No.|Qty**	**-**				**-**	**-**
	48	Description	-					
	49	**ETO#:|ETO Description**	**-**	**-**				
	50	**ETO#:|ETO Description**	-	-				
	51	Power	-					
	52	**Peripheral Tag(s):**	**-**					
	53	Peripheral Notes	-					
Notes	54	**-**						

Prepared By: JOSE_VALVERDE
Oracle Version: 11.5.10.2

Project Id: 373795
Application: High purity carbon dioxide

Date:	17-SEP-14	**Micro Motion Configuration Data Sheet**	Page | 5			
Company	TRIMERIC CORP		Spec No	-	Rev.	
			Contract	-	P.O	-
Service:	High purity carbon dioxide		Req.	-	By	-
Manufacturer:	Micro Motion, Inc.		Chk'd	-	Appr.	-

Service	1	**Sensor Tag(s):**						
	2	**Transmitter Tag(s):**						
	3	Fluid State | Fluid Name	-	High purity carbon dioxide				
	4	Flow Min|Oper|Max|Design	-	277	-	-	lb/hr	
	5	Pressure Min|Oper|Max|Design	-	1400	-	-	psig	
	6	Temperature Min|Oper|Max|Design	-	40	-	-	F	
	7	Specific Gravity/Density (Operating)	59.3 lb/ft3					
	8	Viscosity (Operating)	.1034 cP					
Sensor	9	**Product No|Proposal Line No.|Qty**	**CMFS100M330N2BAEKZZ**				**2.1**	**1**
	10	Description	SENSOR,CMFS100M					
	11	**ETO#:|ETO Description**	**-**	**-**				
	12	**ETO#:|ETO Description**	-	-				
	13	Process Connections	1-inch CL600 ASME B16.5 F316/F316L Weld neck flange Raised face					
	14	Approval	CSA (US and Canada): Class I, Division 1, Groups A, B, C, D					
	15	Wetted Parts	316L SS					
	16	Mass Flow Accuracy @OpFlow(%rate)	.1	%				
	17	Density Accuracy @ All Rates	.03121	lb/ft3				
	18	Pressure Drop @ Op Flow	.00195	psi				
	19	Calibration Type|Rate|Units	Standard	-	kg/min			
	20	Custom Calibration Points	-					
	21	Density for Volume to Mass Conversion	-					
	22	Special Units Text|Totalizer Text	-	-				
	23	Base Units: Flow|Time|Conversion	-	-	-			
	24	Warning	-					
	25	Sensor Notes	-					
Transmitter	26	**Product No|Proposal Line No.|Qty**	**2700R12ABAEZZZPK**				**2.36**	**1**
	27	Description	TRANSMITTER,2700					
	28	**ETO#:|ETO Description**	**-**	**-**				
	29	**ETO#:|ETO Description**	-	-				
	30	Input Power	-					
	31	Approval	-					
	32	Transmitter Flow Units: Mass | Vol	lb/hr	USGPM				
	33	Transmitter Units: Density | Temp	lb/ft3	F				
	34	Special Mass Units Test | Totalizer Text	-	-				
	35	Base Mass Units: Flow | Time | Conv	-	-	0			
	36	Special Vol Units Test | Totalizer Text	-	-				
	37	Base Vol Units: Flow | Time | Conv	-	-	0			
	38	Output 1 Type Variable	Analog 1	Mass Flow Rate				
	39	Scaling LRV URV Units	4-20mA	0	277	lb/hr		
	40	Output 2 Type Variable	Frequency	Mass Flow Rate				
	41	Setting Rate - Units	0Hz	0	-	lb/hr		
	42	Output 3 Type Variable	RS-485 Communications	-				
	43	Scaling LRV URV Units	-	0	0	-		
	44	Transmitter Notes	-					
Cable	45	**Product No|Proposal Line No.|Qty**	**-**				**-**	**-**
	46	Description	-					
Peripheral	47	**Product No|Proposal Line No.|Qty**	**-**				**-**	**-**
	48	Description	-					
	49	**ETO#:|ETO Description**	**-**	**-**				
	50	**ETO#:|ETO Description**	-	-				
	51	Power	-					
	52	**Peripheral Tag(s):**	**-**					
	53	Peripheral Notes	-					
Notes	54	**-**						

Prepared By: JOSE_VALVERDE
Oracle Version: 11.5.10.2

Project Id: 373795
Application: High purity carbon dioxide

Control Valve Sizing Sheet

Title:	Alpha Process - Danny Kincaid - 09-30-2014	Revision:		Valve Tag:	PCV-200
Company:		Created by:	Tiffany Fiedler	DWG:	
Project:		Date:	9/30/2014	Service:	

Process Data

Valve Style:	Research	Media	Carbondioxide
Characteristic:	Linear	Phase	Liquid
Cv (Max)/Trim Designation	2.5	Pipe Size:	1"

		Max Flow	Norm Flow	Min Flow
Flow Rate	lb/h	4617	3503	276
Inlet Pressure	psi(g)	1200	500	500
Outlet Pressure	psi(g)	852	400	35
Pressure Drop	psi(g)	348	100	465
Temperature	°F	48.0	48.0	100.0
Density	g/cm³	0.91	0.09	0.07
Dynamic Viscosity	g/(cm s)	0.00	0.00	0.00
Vapor Pressure	psi(g)	620.49	620.49	1055.29

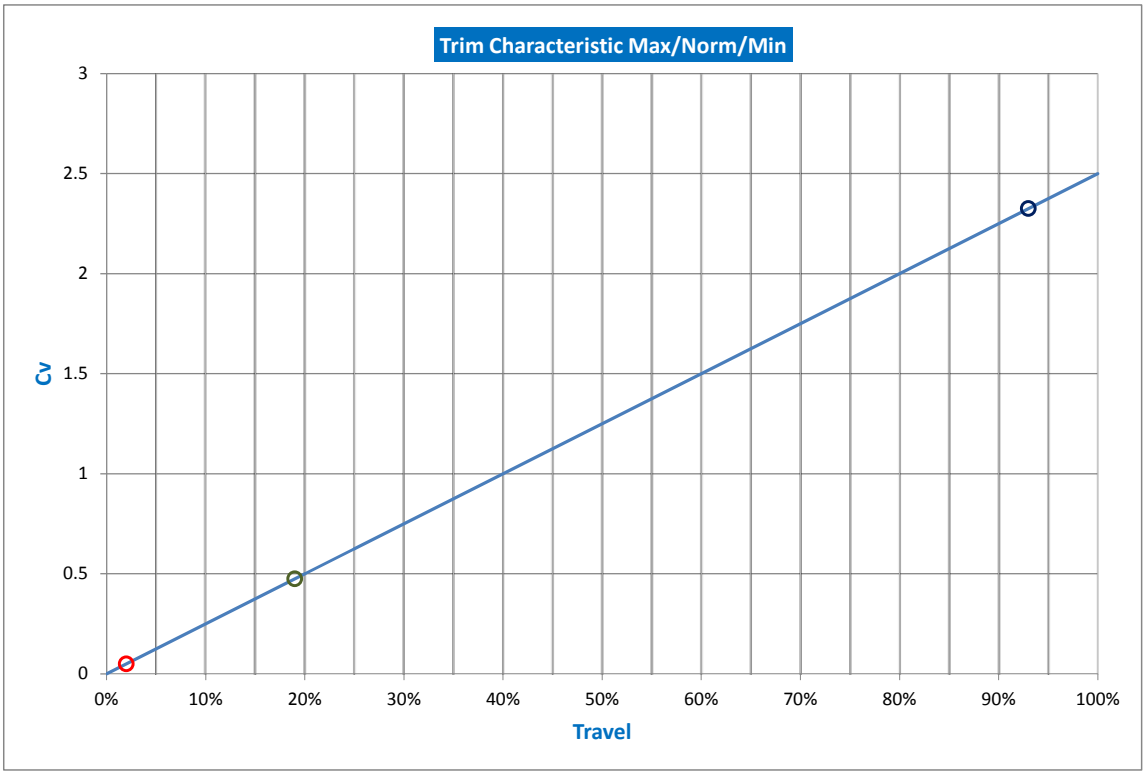
Calculated Data

Calculated Cv	GPM(US)	0.517123342	2.321427822	0.094584554
Travel	%	19.1	92.7	1.8
Noise Level	dB(A)	67.0	64.3	
Flow State		Incipient cavitation		
Flow Type		Turbulent flow		

Powered by: CONVAL

Travel	Cv
0%	0.0000
5%	0.1250
10%	0.2500
20%	0.5000
25%	0.6250
30%	0.7500
40%	1.0000
50%	1.2500
60%	1.5000
70%	1.7500
75%	1.8750
80%	2.0000
90%	2.2500
100%	2.5000

Control Points	Cv
Max	
19%	0.4750
Nom	
93%	2.3250
Min	
2%	0.0500



Badger Meter

RCV
RESEARCH CONTROL® | ReCo® VALVES

Control Valve Sizing Sheet

Title:	Alpha Process - Danny Kincaid - 09-30-2014	Revision:		Valve Tag:	PCV-300
Company:		Created by:	Tiffany Fiedler	DWG:	
Project:		Date:	9/30/2014	Service:	

Process Data

Valve Style:	Research	Media	Carbondioxide
Characteristic:	Linear	Phase	Liquid
Cv (Max)/Trim Designation	2.5	Pipe Size:	1"

		Max Flow	Norm Flow	Min Flow
Flow Rate	lb/h	4617	3503	276
Inlet Pressure	psi(g)	1200	500	500
Outlet Pressure	psi(g)	943	400	35
Pressure Drop	psi(g)	257	100	465
Temperature	°F	48.0	48.0	100.0
Density	g/cm³	0.91	0.09	0.07
Dynamic Viscosity	g/(cm s)	0.00	0.00	0.00
Vapor Pressure	psi(g)	620.49	620.49	1055.29

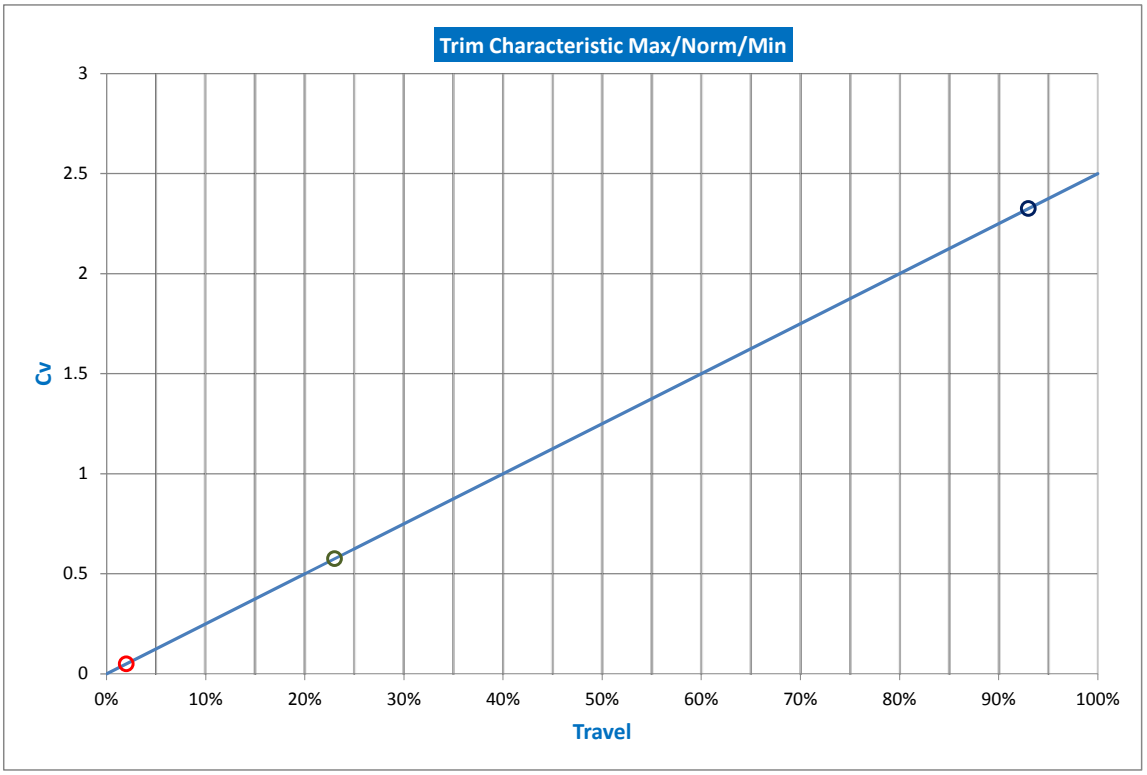
Calculated Data

Calculated Cv	GPM(US)	0.601751506	2.321427822	0.094584554
Travel	%	22.5	92.7	1.8
Noise Level	dB(A)	56.4	64.3	
Flow State		Non-critical		
Flow Type		Turbulent flow		

Powered by: CONVAL

Travel	Cv
0%	0.0000
5%	0.1250
10%	0.2500
20%	0.5000
25%	0.6250
30%	0.7500
40%	1.0000
50%	1.2500
60%	1.5000
70%	1.7500
75%	1.8750
80%	2.0000
90%	2.2500
100%	2.5000

Control Points	Cv
Max	
23%	0.5750
Nom	
93%	2.3250
Min	
2%	0.0500



Badger Meter

Control Valve Sizing Sheet

Title:	Alpha Process - Danny Kincaid - 09-30-2014 - PCV400	Revision:		Valve Tag:	PCV-400
Company:		Created by:	Tiffany Fiedler	DWG:	
Project:		Date:	9/30/2014	Service:	

Process Data

Valve Style:	Research	Media	Carbondioxide
Characteristic:	Linear	Phase	Liquid
Cv (Max)/Trim Designation	2.5	Pipe Size:	1"

		Max Flow	Norm Flow	Min Flow
Flow Rate	lb/h	4617	3503	276
Inlet Pressure	psi(g)	1200	500	500
Outlet Pressure	psi(g)	1153	400	35
Pressure Drop	psi(g)	47	100	465
Temperature	°F	48.0	48.0	100.0
Density	g/cm³	0.91	0.09	0.07
Dynamic Viscosity	g/(cm s)	0.00	0.00	0.00
Vapor Pressure	psi(g)	620.49	620.49	1055.29

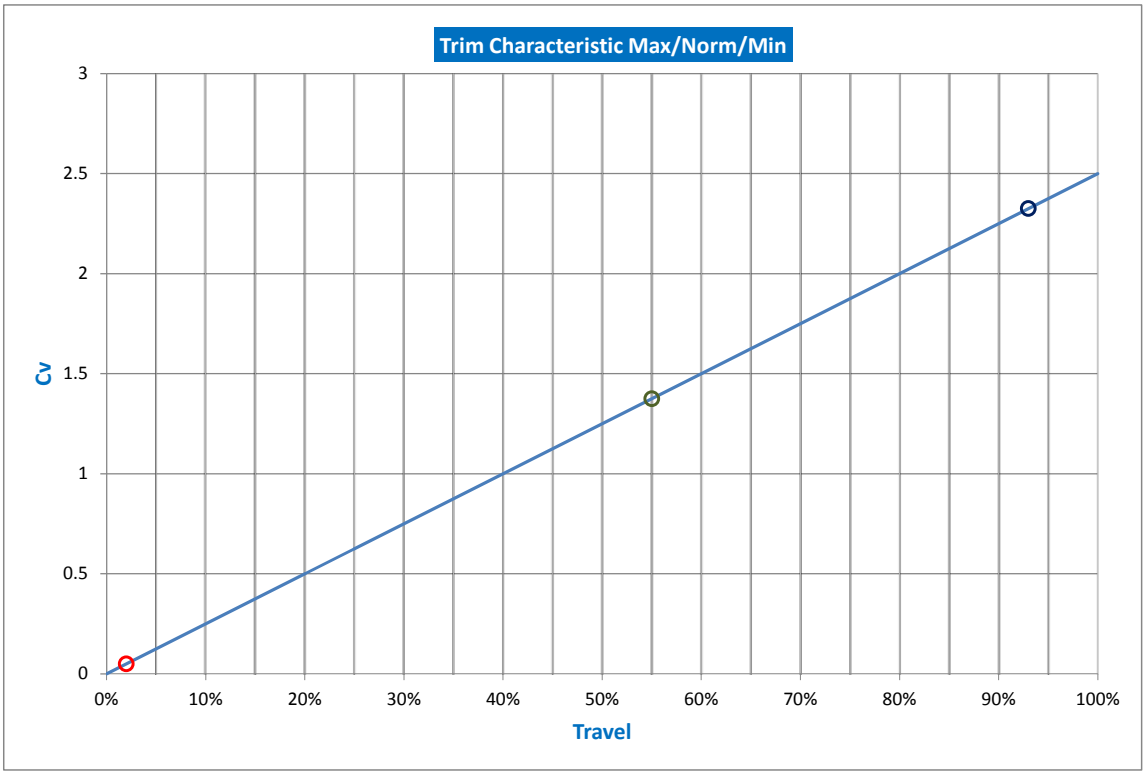
Calculated Data

Calculated Cv	GPM(US)	1.40713191	2.321427822	0.094584554
Travel	%	55.4	92.7	1.8
Noise Level	dB(A)	42.5	64.3	
Flow State		Non-critical		
Flow Type		Turbulent flow		

Powered by: CONVAL

Travel	Cv
0%	0.0000
5%	0.1250
10%	0.2500
20%	0.5000
25%	0.6250
30%	0.7500
40%	1.0000
50%	1.2500
60%	1.5000
70%	1.7500
75%	1.8750
80%	2.0000
90%	2.2500
100%	2.5000

Control Points	Cv
Max	
55%	1.3750
Nom	
93%	2.3250
Min	
2%	0.0500



Badger Meter

19 Appendix G – Permitting Documents

Commonwealth of Virginia
Department of Mines, Minerals, and Energy
Division of Gas and Oil
P.O. Drawer 159, Lebanon, VA 24266
Telephone: (276) 415-9700

PERMIT FOR GAS AND OIL OPERATIONS

This certifies that Permit No. *4707-02*
Operation Name *CBM DD-7 W/PL*
Has been issued to: (Company) *Cardno MM&A*
Whose main office is located at *534 Industrial Park RD*
Bluefield, VA 24605

Applicant *Edward K Diminick*

This permit is issued on this 4th day of February, 2015

This permit was requested for Permit Modification under

The permitted operations are located in the Hurricane district of BUCHANAN County.

THIS PERMIT IS ISSUED BY THE DIRECTOR PURSUANT TO CHAPTER 22.1, TITLE 45.1 OF THE CODE OF VIRGINIA,

Being an Act to require permits for gas and oil operations and to fix conditions for issuance thereof; to provide for the safe and environmentally sound operations performed by the Permittee and for the inspection thereof; to provide for a method of maximizing gas, oil, mineral and coal resources; to protect correlative rights of persons owning interest in gas and oil resources; to provide for enforcement by the Director.

This permit shall expire 2/4/2017 unless the permittee has commenced operation as determined by the inspector.

Fee Paid $300.00
File No BU-1923

API/US Well#: 450270192300

TO BE POSTED AT THE OPERATIONS SITE

Commonwealth of Virginia
Department of Mines, Minerals, and Energy
Division of Gas and Oil
P.O. Drawer 159, Lebanon, VA 24266
Telephone: (276) 415-9700

PERMIT FOR GAS AND OIL OPERATIONS

This certifies that Permit No. *7787-02*
Operation Name *CBM DD7A W/PL*
Has been issued to: (Company) *Cardno MM&A*
Whose main office is located at *534 Industrial Park RD*
Bluefield, VA 24605

Applicant *Edward K Diminick*

This permit is issued on this 21st day of January, 2015

This permit was requested for Permit Modification under

The permitted operations are located in the Hurricane district of BUCHANAN County.

THIS PERMIT IS ISSUED BY THE DIRECTOR PURSUANT TO CHAPTER 22.1, TITLE 45.1 OF THE CODE OF VIRGINIA,

Being an Act to require permits for gas and oil operations and to fix conditions for issuance thereof; to provide for the safe and environmentally sound operations performed by the Permittee and for the inspection thereof; to provide for a method of maximizing gas, oil, mineral and coal resources; to protect correlative rights of persons owning interest in gas and oil resources; to provide for enforcement by the Director.

This permit shall expire 1/21/2017 unless the permittee has commenced operation as determined by the inspector.

Fee Paid $300.00
File No BU-3337

API/US Well#: 450270333700

TO BE POSTED AT THE OPERATIONS SITE

Commonwealth of Virginia
Department of Mines, Minerals, and Energy
Division of Gas and Oil
P.O. Drawer 159, Lebanon, VA 24266
Telephone: (276) 415-9700

PERMIT FOR GAS AND OIL OPERATIONS

This certifies that Permit No. *4824-02*
Operation Name *CBM DD-8 W/PL*
Has been issued to: (Company) *Cardno MM&A*
Whose main office is located at *534 Industrial Park RD*
Bluefield, VA 24605

Applicant *Edward K Diminick*

This permit is issued on this 21st day of January, 2015

This permit was requested for Permit Modification under

The permitted operations are located in the Hurricane district of BUCHANAN County.

THIS PERMIT IS ISSUED BY THE DIRECTOR PURSUANT TO CHAPTER 22.1, TITLE 45.1 OF THE CODE OF VIRGINIA,

Being an Act to require permits for gas and oil operations and to fix conditions for issuance thereof; to provide for the safe and environmentally sound operations performed by the Permittee and for the inspection thereof; to provide for a method of maximizing gas, oil, mineral and coal resources; to protect correlative rights of persons owning interest in gas and oil resources; to provide for enforcement by the Director.

This permit shall expire 1/21/2017 unless the permittee has commenced operation as determined by the inspector.

Fee Paid $300.00
File No BU-1998

API/US Well#: 450270199800

TO BE POSTED AT THE OPERATIONS SITE

Commonwealth of Virginia
Department of Mines, Minerals, and Energy
Division of Gas and Oil
P.O. Drawer 159, Lebanon, VA 24266
Telephone: (276) 415-9700

PERMIT FOR GAS AND OIL OPERATIONS

This certifies that Permit No. *4707-01*
Operation Name *CBM DD-7 W/PL*
Has been issued to: (Company) *Cardno MM&A*
Whose main office is located at *534 Industrial Park RD*
Bluefield, VA 24605

Applicant *Edward K Diminick*

This permit is issued on this 11th day of September, 2000

This permit was requested for *Transfer of Permit Rights*
under
VR 480-05-22.1 S 1.12

The permitted operations are located in the Hurricane district of BUCHANAN County.

THIS PERMIT IS ISSUED BY THE DIRECTOR PURSUANT TO CHAPTER 22.1, TITLE 45.1 OF THE CODE OF VIRGINIA,

Being an Act to require permits for gas and oil operations and to fix conditions for issuance thereof; to provide for the safe and environmentally sound operations performed by the Permittee and for the inspection thereof; to provide for a method of maximizing gas, oil, mineral and coal resources; to protect correlative rights of persons owning interest in gas and oil resources; to provide for enforcement by the Director.

This permit shall expire 9/11/2002 unless the permittee has commenced operation as determined by the inspector.

Fee Paid $75.00
File No BU-1923

API/US Well#: 450270192300

TO BE POSTED AT THE OPERATIONS SITE

Commonwealth of Virginia
Department of Mines, Minerals, and Energy
Division of Gas and Oil
P.O. Drawer 159, Lebanon, VA 24266
Telephone: (276) 415-9700

PERMIT FOR GAS AND OIL OPERATIONS

This certifies that Permit No. *7787-01*
Operation Name *CBM DD7A W/PL*
Has been issued to: (Company) *Cardno MM&A*
Whose main office is located at *534 Industrial Park RD*
Bluefield, VA 24605

Applicant *Edward K Diminick*

This permit is issued on this 3rd day of January, 2007

This permit was requested for *Transfer of Permit Rights*
under
VR 480-05-22.1 S 1.12

The permitted operations are located in the Hurricane district of BUCHANAN County.

THIS PERMIT IS ISSUED BY THE DIRECTOR PURSUANT TO CHAPTER 22.1, TITLE 45.1 OF THE CODE OF VIRGINIA,

Being an Act to require permits for gas and oil operations and to fix conditions for issuance thereof; to provide for the safe and environmentally sound operations performed by the Permittee and for the inspection thereof; to provide for a method of maximizing gas, oil, mineral and coal resources; to protect correlative rights of persons owning interest in gas and oil resources; to provide for enforcement by the Director.

This permit shall expire 1/3/2009 unless the permittee has commenced operation as determined by the inspector.

Fee Paid $75.00
File No BU-3337

API/US Well#: 450270333700

TO BE POSTED AT THE OPERATIONS SITE

Commonwealth of Virginia
Department of Mines, Minerals, and Energy
Division of Gas and Oil
P.O. Drawer 159, Lebanon, VA 24266
Telephone: (276) 415-9700

PERMIT FOR GAS AND OIL OPERATIONS

This certifies that Permit No. *4824-01*
Operation Name *CBM DD-8 W/PL*
Has been issued to: (Company) *Cardno MM&A*
Whose main office is located at *534 Industrial Park RD*
Bluefield, VA 24605

Applicant *Edward K Diminick*

This permit is issued on this 13th day of December, 2000

This permit was requested for *Transfer of Permit Rights*
under
VR 480-05-22.1 S 1.12

The permitted operations are located in the Hurricane district of BUCHANAN County.

THIS PERMIT IS ISSUED BY THE DIRECTOR PURSUANT TO CHAPTER 22.1, TITLE 45.1 OF THE CODE OF VIRGINIA,

Being an Act to require permits for gas and oil operations and to fix conditions for issuance thereof; to provide for the safe and environmentally sound operations performed by the Permittee and for the inspection thereof; to provide for a method of maximizing gas, oil, mineral and coal resources; to protect correlative rights of persons owning interest in gas and oil resources; to provide for enforcement by the Director.

This permit shall expire 12/13/2002 unless the permittee has commenced operation as determined by the inspector.

Fee Paid $75.00
File No BU-1998

API/US Well#: 450270199800

TO BE POSTED AT THE OPERATIONS SITE

Cardno
Shaping the Future

Via Email

Cardno, Inc.

200 East Main Street
Suite 301
Kingsport, TN 37660
USA

Phone +1 423 279 9775
Fax +1 423 279 9777

www.cardno.com

January 29, 2016

Mr. Jon M. Capacasa
Director
Water Protection Division
U. S. Environmental Protection Agency - Region III
1650 Arch Street
Philadelphia, PA 19103-2029

Subject: UIC Permit VAS2R002BBUC – Annual Report

Dear Mr. Capacasa:

Cardno began injecting carbon dioxide into the three wells under the above referenced permit in early July 2015. Through the end of the calendar year, we have injected 12,522 bbls (2,022 metric tons) into well DD-7, 11,767 bbls (1,900 metric tons) into well DD-7A, and 12,180 bbls (1,967 metric tons) into well DD-8. Please accept the annual reports (Form 7520-11) for each well attached to this email. Also enclosed are monthly carbon dioxide sample analyses from our supplier.

If you have any questions or need other information please call or email.

Sincerely,

Ed Diminick

Edward K. Diminick, P.E.
Sr. Petroleum Engineer
Engineering & Environmental Services
Cardno, Inc.
Direct Line +1 423-482-0887
Email: ed.diminick@cardno.com

/rgw
Enclosures

OMB No. 2040-0042 Approval Expires 12/31/2018

United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

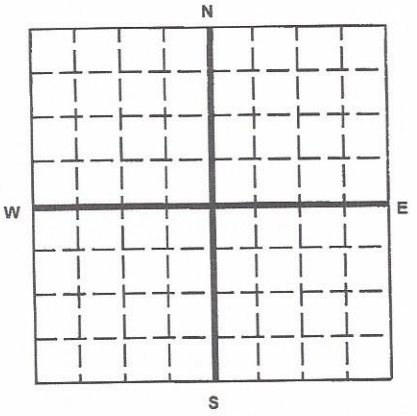
Name and Address of Existing Permittee
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660

Name and Address of Surface Owner
Woodrow Presley
1134 Shady Rest Road, Vansant, VA 24656

State: Virginia
County: Buchanan
Permit Number: VAS2R971BBUC

Surface Location Description
* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate Well and Outline Unit on Section Plat - 640 Acres



Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) ___ Line of quarter section
and * ft. from (E/W) ___ Line of quarter section.

WELL ACTIVITY
- ☐ Brine Disposal
- ☑ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT
- ☐ Individual
- ☑ Area

Number of Wells: 3

Lease Name: Landon Wyatt, Jr. et al **Well Number:** DD-7

MONTH YEAR	INJECTION PRESSURE AVERAGE PSIG	INJECTION PRESSURE MAXIMUM PSIG	TOTAL VOLUME INJECTED BBL	TOTAL VOLUME INJECTED METRIC TONS	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MINIMUM PSIG	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MAXIMUM PSIG
July-2015	169	299	2,192	354	0	1
August-2015	121	155	718	116	0	7
September-2015	229	311	1,468	237	0	8
October-2015	216	271	1,833	296	0	1
November-2015	365	464	2,818	455	0	6
December-2015	542	680	3,493	564	0	7
		Totals	12,522	2,022		
	* VA uses State	Plane Coord. or	Lat/Long not	Sec/Twp/Range		
	Latitude	Longitude				
	37° 08' 20" N	82° 05' 04" W				

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*: Edward K. Diminick, P.E., Sr. Petroleum Engineer

Signature: Edward K Diminick

Date Signed: 1/29/16

EPA Form 7520-11 (Rev. 12-11)

OMB No. 2040-0042 Approval Expires 12/31/2018

United States Environmental Protection Agency
Washington, DC 20460

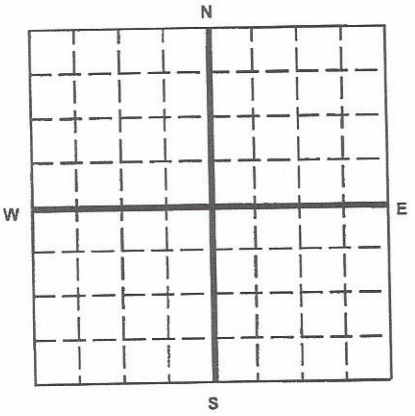
ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660

Name and Address of Surface Owner
Landon Wyatt
P.O. Box 11000, Danville, VA 24543

State: Virginia
County: Buchanan
Permit Number: VAS2R971BBUC

Locate Well and Outline Unit on Section Plat - 640 Acres



Surface Location Description
* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit
Surface Location * ft. frm (N/S) ___ Line of quarter section
and * ft. from (E/W) ___ Line of quarter section.

WELL ACTIVITY
- ☐ Brine Disposal
- ☑ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT
- ☐ Individual
- ☑ Area

Number of Wells: 3

Lease Name: Harrison-Wyatt, LLC Big Axe Well Number: DD-7A

MONTH YEAR	INJECTION PRESSURE AVERAGE PSIG	INJECTION PRESSURE MAXIMUM PSIG	TOTAL VOLUME INJECTED BBL	TOTAL VOLUME INJECTED METRIC TONS	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MINIMUM PSIG	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MAXIMUM PSIG
July-2015	217	291	2,644	427	0	1
August-2015	234	291	1,369	221	0	1
September-2015	253	310	1,034	167	0	1
October-2015	295	375	1,771	286	0	1
November-2015	480	607	2,335	377	0	0
December-2015	668	734	2,613	422	0	5
		Totals	11,767	1,900		
	* VA uses State	Plane Coord. or	Lat/Long not	Sec/Twp/Range		
	Latitude	Longitude				
	37 08' 13" N	82 04' 55" W				

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*: Edward K. Diminick, P.E., Sr. Petroleum Engineer

Signature: Edward K Diminick

Date Signed: 1/29/16

EPA Form 7520-11 (Rev. 12-11)

OMB No. 2040-0042 Approval Expires 12/31/2018

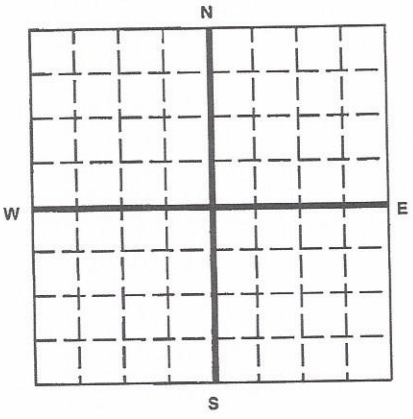
United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660

Name and Address of Surface Owner
Landon Wyatt
P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description
* 1/4 of 1/4 of 1/4 of 1/4 of Section * Township Range

Locate well in two directions from nearest lines of quarter section and drilling unit
Surface Location * ft. frm (N/S) Line of quarter section
and * ft. from (E/W) Line of quarter section.

WELL ACTIVITY
- ☐ Brine Disposal
- ☑ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT
- ☐ Individual
- ☑ Area

Number of Wells 3

Lease Name Landon Wyatt, Jr, et al Big Axe Well Number DD-8

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
July-2015	204	258	1,466	237	0	1
August-2015	327	442	2,440	394	0	1
September-2015	371	420	1,387	224	0	0
October-2015	320	362	1,765	285	0	0
November-2015	442	525	2,564	414	0	0
December-2015	511	602	2,558	413	0	22
		Totals	12,180	1,967		
	* VA uses State	Plane Coord. or	Lat/Long not	Sec/Twp/Range		
	Latitude	Longitude				
	37 08' 19" N	82° 04' 40" W				

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K Diminick	1/29/16

PRAXAIR

Making our planet more productive

Praxair, Inc

Marmet, WV (#587)

2015 Sample Batch Test Results – July, Aug, Sept, Oct, Nov, Dec

JULY

- Batch NO: CD-587-071515-1-0819
- Product delivered under: CD-587-071515-GENO70AF-1453

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	1.1 ppm
ODOR	None Detected
TASTE	None Detected
THC	3.9 ppm
TSULF	0.034 ppm

AUGUST

- Batch No: CD-587-081215-1-0902
- Product delivered under: CD-587-081215-GENO70AE-1043

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	6.3 ppm
TSULF	0.030 ppm

SEPTEMBER

- Batch No: CD-587-090815-1-0712
- Product delivered under: CD-587-090815-GENO70AF-2051

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm

NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	2.2 ppm
TSULF	< 0.025 ppm

OCTOBER

- Batch No: CD-587-101615-1-0820
- Product delivered under: CD-587-101615-GENO70AE-1922

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	1.9 ppm
TSULF	< 0.025 ppm

NOVEMBER

- Batch No: CD-587-111115-1-0705
- Product delivered under: CD-587-111115-GENO70AF-1923

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	4.2 ppm
TSULF	< 0.025 ppm

DECEMBER

- Batch No: CD-587-121615-1-0734
- Product delivered under: CD-587-121615-GENO70AF-2218

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm

NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	6.5 ppm
TSULF	< 0.025 ppm

Cardno
Shaping the Future

Via Email

Cardno, Inc.

200 East Main Street
Suite 301
Kingsport, TN 37660
USA

Phone **+1 423 279 9775**
Fax +1 423 279 9777

www.cardno.com

January 27, 2017

Ms. Dominique Lueckenhoff
Director
Water Protection Division
U. S. Environmental Protection Agency - Region III
1650 Arch Street
Philadelphia, PA 19103-2029

Subject: UIC Permit VAS2R002BBUC – 2016 Annual Report

Dear Ms. Lueckenhoff:

Cardno MM&A continued injecting carbon dioxide into the three wells under the above referenced permit in 2016. During the calendar year, we injected 9,401 bbls (1,518 metric tons) into well DD-7, 9,141 bbls (1,476 metric tons) into well DD-7A, and 10,645 bbls (1,719 metric tons) into well DD-8. Please accept the annual reports (Form 7520-11) for each well attached to this email. Also enclosed are monthly carbon dioxide sample analyses from our supplier for the respective month injection took place.

If you have any questions or need other information please call or email.

Sincerely,

Edward K. Diminick

Edward K. Diminick, P.E.
Sr. Petroleum Engineer
Engineering & Environmental Services
Cardno MM&A, Inc.
Direct Line +1 423-482-0887
Email: ed.diminick@mma1.com

/rgw
Enclosures

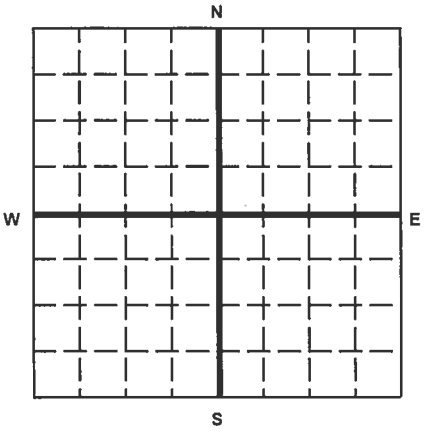
OMB No. 2040-0042 Approval Expires 12/31/2018

United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee	Name and Address of Surface Owner
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660	Woodrow Presley 1134 Shady Rest Road, Vansant, VA 24656

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description

* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) ___ Line of quarter section and * ft. from (E/W) ___ Line of quarter section.

* Virginia uses State Plane Coord. or Lat/Long not Sec/Twp/Range

Lat: 37 08' 20" N Long: 82 05' 04" W

WELL ACTIVITY
- [ ] Brine Disposal
- [x] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT
- [ ] Individual
- [x] Area

Number of Wells 3

Lease Name Landon Wyatt, Jr. et al Well Number DD-7

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
January-2016	540	689	1,548	250	0	5
February-2016	620	657	2,372	383	0	0
March-2016	658	688	2,273	367	0	0
April-2016	673	702	1,201	194	0	0
May-2016	Shut-in				0	0
June-2016	Shut-in				0	0
July-2016	Shut-in				0	0
August-2016	Shut-in				0	0
September-2016	Shut-in				0	0
October-2016	Shut-in				0	0
November-2016	Shut-in				0	0
December-2016	373	527	2,007	324	0	0

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K. Diminick	1/27/17

EPA Form 7520-11 (Rev. 12-11)

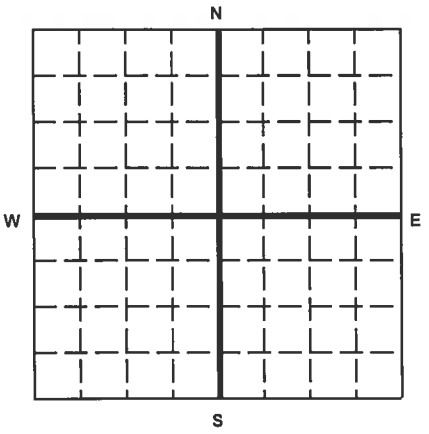
OMB No. 2040-0042 Approval Expires 12/31/2018

United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee	Name and Address of Surface Owner
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660	Landon Wyatt P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description

* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) ___ Line of quarter section and * ft. from (E/W) ___ Line of quarter section.

* Virginia uses State Plane Coord. or Lat/Long not Sec/Twp/Range

Lat: 37 08' 13" N Long: 82 04' 55" W

WELL ACTIVITY

- [ ] Brine Disposal
- [x] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT

- [ ] Individual
- [x] Area

Number of Wells 3

Lease Name Harrison-Wyatt, LLC Big Axe Well Number DD-7A

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
January-2016	716	790	1,982	320	0	5
February-2016	677	705	1,623	262	0	4
March-2016	705	731	1,883	304	0	2
April-2016	720	743	1,554	251	0	0
May-2016	Shut-in				0	0
June-2016	Shut-in				0	0
July-2016	Shut-in				0	0
August-2016	Shut-in				0	0
September-2016	Shut-in				0	0
October-2016	Shut-in				0	0
November-2016	Shut-in				0	0
December-2016	470	611	2,099	339	0	0

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K. Diminick	1/27/17

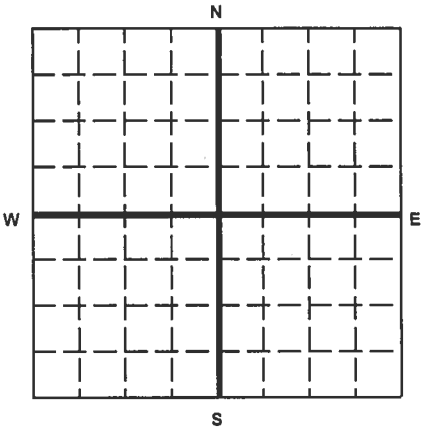
OMB No. 2040-0042 Approval Expires 12/31/2018

United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee	Name and Address of Surface Owner
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660	Landon Wyatt P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description

* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) ___ Line of quarter section and * ft. from (E/W) ___ Line of quarter section.

* Virginia uses State Plane Coord. or Lat/Long not Sec/Twp/Range

Lat: 37 08' 19" N Long: 82 04' 40" W

WELL ACTIVITY
- [ ] Brine Disposal
- [x] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT
- [ ] Individual
- [x] Area

Number of Wells 3

Lease Name Landon Wyatt, Jr, et al Big Axe Well Number DD-8

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
January-2016	585	644	3,208	518	0	7
February-2016	599	632	1,876	303	0	9
March-2016	648	670	2,440	394	0	8
April-2016	655	668	1,282	207	0	7
May-2016	Shut-in				2	3
June-2016	Shut-in				1	4
July-2016	Shut-in				3	6
August-2016	Shut-in				3	5
September-2016	Shut-in				4	5
October-2016	Shut-in				1	4
November-2016	Shut-in				0	3
December-2016	437	574	1,839	297	0	0

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K. Diminick	1/27/17

EPA Form 7520-11 (Rev. 12-11)

PRAXAIR
Making our planet more productive

Praxair, Inc Marmet, WV (#587)

2016 Sample Batch Test Results – Jan, Feb, March, April

JANUARY

- Batch No: CD-587-010816-1-0656
- Product delivered under: CD-587-010816-GENO10AQ-1641

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	5.6 ppm
TSULF	< 0.025ppm

FEBRUARY

- Batch No: CD-587-021116-1-0728
- Product delivered under: CD-587-021116-GENO70AE-1457

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	1.3 ppm
ODOR	None Detected
TASTE	None Detected
THC	8.3 ppm
TSULF	< 0.025 ppm

MARCH

- Batch No: CD-587-030916-1-0705
- Product delivered under: CD-587-030916-GENO70AF-2254

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm

NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	3.3 ppm
TSULF	< 0.025 ppm

APRIL

- Batch No: CD-587-040516-1-0712
- Product delivered under: CD-587-040516-GENO10AJ-1222

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	4.4 ppm
TSULF	< 0.025 ppm

DECEMBER '16

- **Batch No:** CD-587-120516-1-0712
- **Product delivered under:** CD-587-120516-PPSI70AE-1606

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	5.8 ppm
TSULF	< 0.025 ppm

Cardno
Shaping the Future

Via Email

Cardno, Inc.

200 East Main Street
Suite 301
Kingsport, TN 37660
USA

Phone **+1 423 341 0354**

December 18, 2017

Ms. Rosalind Moore
Water Protection Division
U. S. Environmental Protection Agency - Region III
Mail Code: 3WP22
1650 Arch Street
Philadelphia, PA 19103-2029

Subject: UIC Permit VAS2R002BBUC – 2017 Annual Report

Dear Ms. Moore:

Cardno MM&A injected carbon dioxide into the three wells under the above referenced permit only through January 29, 2017. During the calendar year, we injected 2,675 bbls (432 metric tons) into well DD-7, 2,582 bbls (417 metric tons) into well DD-7A, and 3,790 bbls (612 metric tons) into well DD-8. Please accept the annual reports (Form 7520-11) for each well attached to this email. Also enclosed is a carbon dioxide sample analysis from our supplier for the respective month injection took place.

If you have any questions or need other information please call or email.

Sincerely,

Edward K. Diminick

Edward K. Diminick, P.E.
Sr. Petroleum Engineer
Engineering & Environmental Services
Cardno MM&A, Inc.
Direct Line +1 423-482-0887
Email: ed.diminick@mma1.com

Enclosures

OMB No. 2040-0042 Approval Expires 12/31/2018

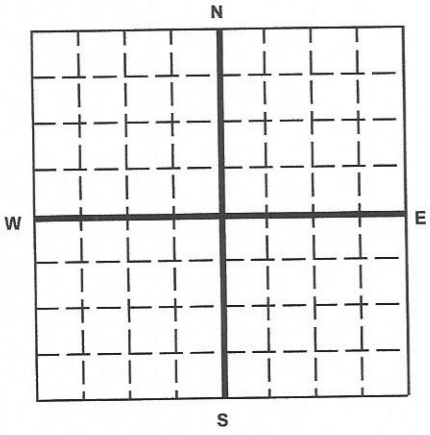
United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660

Name and Address of Surface Owner
Woodrow Presley
1134 Shady Rest Road, Vansant, VA 24656

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description
* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) ___ Line of quarter section and * ft. from (E/W) ___ Line of quarter section.

* Virginia uses State Plane Coord or Lat/Long not Sec/Twp/Range

Lat: 37 08' 20" N Long: 82 05' 04" W

WELL ACTIVITY
- ☐ Brine Disposal
- ☑ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT
- ☐ Individual
- ☑ Area

Number of Wells 3

Lease Name: Landon Wyatt, Jr. et al Well Number: DD-7

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
January-2017	604	645	2,675	432	0	0
	Injection	program	completed			

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K Diminick	12/18/17

EPA Form 7520-11 (Rev. 12-11)

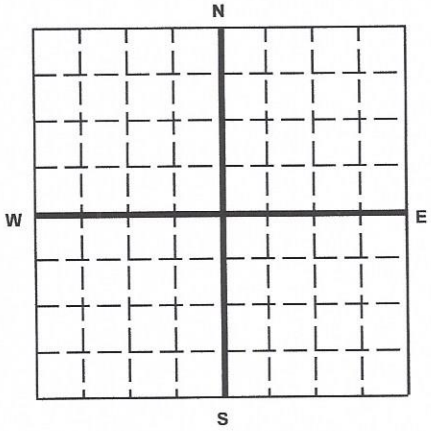
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United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee	Name and Address of Surface Owner
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660	Landon Wyatt P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description

* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

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Surface Location * ft. frm (N/S) ___ Line of quarter section and * ft. from (E/W) ___ Line of quarter section. Lat: 37 08' 13" N Long: 82 04' 55" W

WELL ACTIVITY

- [ ] Brine Disposal
- [x] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT

- [ ] Individual
- [x] Area

Number of Wells 3

Lease Name Harrison-Wyatt, LLC Big Axe Well Number DD-7A

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
January-2017	666	707	2,582	417	0	0
	Injection	program	completed			

Certification

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Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K. Diminick	12/18/17

EPA Form 7520-11 (Rev. 12-11)

OMB No. 2040-0042 Approval Expires 12/31/2018

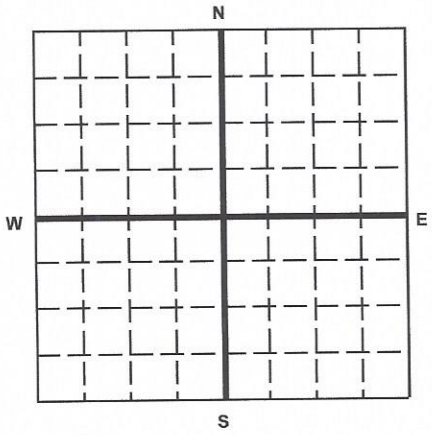
United States Environmental Protection Agency
Washington, DC 20460

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660

Name and Address of Surface Owner
Landon Wyatt
P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VAS2R971BBUC

Surface Location Description
* 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section * Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit
* Virginia uses State Plane Coord. or Lat/Long not Sec/Twp/Range

Surface Location * ft. frm (N/S) ___ Line of quarter section and * ft. from (E/W) ___ Line of quarter section. Lat: 37 08' 19" N Long: 82 04' 40" W

WELL ACTIVITY
- [ ] Brine Disposal
- [x] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT
- [ ] Individual
- [x] Area

Number of Wells 3

Lease Name Landon Wyatt, Jr, et al Big Axe Well Number DD-8

	INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	METRIC TONS	MINIMUM PSIG	MAXIMUM PSIG
January-2017	627	663	3,790	612	0	22
	Injection	program	completed			

Certification

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Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, P.E., Sr. Petroleum Engineer	Edward K Diminick	12/18/17

EPA Form 7520-11 (Rev. 12-11)

PRAXAIR

Making our planet more productive

Praxair, Inc

Marmet, WV (#587)

2016-2017 Sample Batch Test Results – Nov '16, Dec '16, Jan '17

NOVEMBER '16

- Batch No: CD-587-113016-1-0726
- Product delivered under: CD-587-113016-PPSI10AQ-1504

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	4.4 ppm
TSULF	< 0.025 ppm

DECEMBER '16

- Batch No: CD-587-120516-1-0712
- Product delivered under: CD-587-120516-PPSI70AE-1606

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	5.8 ppm
TSULF	< 0.025 ppm

JANUARY '17

- Batch No: CD-587-010617-1-0731
- Product delivered under: CD-587-0101617-PPSI10AD-1836

Component	Result
ACET	< 0.05 ppm
APEAR	None Detected
ASSAY	99.99%
C6H6	< 5 ppb
CO	< 2.5 ppm
H20	< 0.5 ppm
NH3	< 0.5 ppm
NO	< 0.5 ppm
NO2	< 0.5 ppm
NVR	None Detected
O2	< 1.0 ppm
ODOR	None Detected
TASTE	None Detected
THC	7.2 ppm
TSULF	< 0.025 ppm

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

May 1, 2015

Mr. Ed Diminick, P.E.
Senior Petroleum Engineer
Cardno MM&A
200 East Main Street, Suite 301
Kingsport, TN 37660

Dear Mr. Diminick:

EPA Region III Underground Injection Control (UIC) Program staff have completed their review of the completion report and attachments, submitted under EPA UIC permit VAS2R971BBUC, for the injection of carbon dioxide (CO2) into the following injection wells located in the Oakwood Coal Bed Methane Field located in Buchanan County, VA:

DD-7
DD-7A
DD-8

These completion reports are acceptable and this letter formally authorizes you to commence injection into these wells in accordance with the conditions stipulated in your permit.

Please let me know when you commence injection into these wells. If you should have any questions, please give me a call at 215-814-5464.

Sincerely,

S. Stephen Platt
Ground Water & Enforcement Branch (3WP22)
Office of Drinking Water & Source Water Protection

NABORS COMPLETION & PRODUCTION SERVICES CO.

NORTH-SEP-11c-SALES & SERVICE TICKET

TICKET			
DATE	4/17/15	4/17/15	
PAGE		1 of	1

CHARGE TO: CNX-CARDNO		LEASE NAME OR PROJECT: DD-7	
ADDRESS		STATE: VA	COUNTY: BUCHANAN
ADDRESS		FIELD	WELL PERMIT NUMBER
OWNER		SERVICE ENGINEER: JAMES KEATON	

AFE / PURCHASE ORDER / CONTRACT / REFERENCE	JOB TYPE	ON LOCATION	COMPLETED
	PRESSURE TEST	TIME 8:00 / DATE	TIME 2:00 / DATE

SIGNATURE: X Ed Diminick — NAME (PLEASE PRINT): EDWARD DIMINICK

I have read, understood and agreed to the terms and conditions printed on the reverse side hereof which include, but are not limited to, LIMITED WARRANTY, INDEMNITY, RELEASE and PAYMENT and represent that I have full power and authority to execute this agreement.

LOC	ITEM REFERENCE	QTY	DESCRIPTION	DISC ACCT	UNIT PRICE	AMOUNT
33	20-200-0001	25	Mileage DOT Units, Cmt - per unit, per one-way mile		6.00	150.00
33	20-200-0002	25	Mileage non-DOT Units, Cmt - per unit, per mile	-	3.40	85.00
33	35-405-0002	2	Acid Inhibitor 2 (AI-2) - per gallon	-	220.00	440.00
33				-	-	-
33	20-225-0020	1	Pressure Pumped 1,001 to 2,000 psi, first 3 hrs - per unit	-	2,120.00	2,120.00
33	00-000-0000	1	AQUAKAR		268.00	268.00
				-	-	-
				-	-	-
				13.00	-	-
				-	-	-
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				Continuation Page	$	-

CUSTOMER OR AGENT SIGNATURE / COMMENTS

X Ed Diminick

Receipt: The customer or customer's agent acknowledges that the equipment, materials and services were received as listed on this field ticket.

Subtotal	$	3,063.00
Special Discount 39.00%	$	(1,194.57)
Line Item Discounts	$	-
Special Allowance $ -	$	-
Subtotal	$	1,868.43
Fuel Surcharges	$	-
AMOUNT DUE ===>	$	**1,868.43**

Unless satisfactory credit terms have been established prior to services payment in advance may be required. All invoices rendered for services performed by Nabors Completion & Production Services Co. shall be paid as indicated on the invoice within thirty days (30) from date of receipt. If not paid within thirty (30) days the unpaid amount is subject to interest at one and one half percent (1 ½%) per month (eighteen percent per annum). All discounts indicated on the invoice are based upon payment within the invoice payment term and are subject to being cancelled by Nabors Completion & Production Services Co. if not paid within terms. If it should be necessary to employ an attorney to collect the amount due, you will be held liable for attorneys' fees and collection costs. Nabors Completion & Production Services Co. price book is incorporated herein by reference, which also contains all invoice payment terms.

NABORS COMPLETION & PRODUCTION SERVICES CO.

CEMENT JOB LOG

Nabors Completion & Production Service CO.
1380 RT 286 East Suite #121
Indiana, PA 15701
Telephone 724-465-8904

CUSTOMER	DATE	INVOICE NUMBER
CNX-CARDNO	4/17/2015	

LEASE NAME	JOB TYPE	COUNTY	STATE
DD-7	PRESSURE TEST		VA

SERVICE SUPERVISOR:	Service Center:
JAMES KEATON	Nabors - Norton,VA

	YES	NO	N/A	COMMENTS
CEMENT CIRCULATED TO SURFACE			X	BBLS
WELL CIRCULATED			X	bbls
PLUG LANDED ON DEPTH			X	PMHr:min
FLOAT(S) HELD			X	
PLUG CONTAINER RETURNED			X	

	N/U WT	SIZE	FROM	TO	MAX PSI
CASING					
TUBING		2 3/8	1110	SURFACE	2000
OPEN HOLE					
PERFORATIONS					
DISPLACEMENT DEPTH					

ID	AMOUNT (SK-GAL-BBL)	SLURRY/FLUID COMPOSITION	YIELD (ft/sk)	Mix Ratio	Density (lb/gal)	Mix Water (BBLS)	Slurry Vol (BBLS)
1	SKS						
2	1GAL	AQUAKAR					
3	2GAL	AI-2					
4							
5							
6							

TIME	RATE (BPM)	VOLUME (BBLS)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION
8:00					Arrive on Location / Inspect for Hazards
					Pre-Job Safety Meeting/WAIT
					Rig Equipment in
					Pressure test lines and Equipment
9:20		16			PUMP TREATED H20/SD/WAIT
10:35				1505/1500	PRESSURE TEST TUBING/HOLD
					BLEED OFF/WAIT
11:20				1250	TEST PRESSURE RELIEF VALVE
11:40				1120/1120	TEST ANNULUS/HOLD
12:10					BLEED OFF
1:00					RIG DOWN JOB COMPLETE

wellPORT

CEMENT REPORT

NABORS

Title Page

Field Ticket
XXXXX-000000000-0035

Date
Fri, Apr 17, 2015

Service Center
Norton (33)
Nabors Completion & Production Services
580 Hawthorn Dr
Norton VA 24273
276-679-5861
276-679-5863

Service Representative(s)
JAMES KEATON

Job Type
PRESSURE TEST

Lease Project
DD-7

Number / ID

Township

County
BUCHANAN

State
VA

Physical Location

Country

Customer Cardno MM+A
c/o CNX GAS CO LLC ( )

Mailing Address
PO BOX 947

BLUE FIELD VA 24605

Division / District

Customer Representative(s)
GOOD GUY(CARDNO)

PO/RFQ/AFE Code

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Cement Report

Client Information

Client	CNX GAS CO LLC
Address	PO BOX 947
City State Zip	BLUE FIELD VA 24605
Representative	GOOD GUY(CARDNO)

Lease/Project/Well Information

Job Type	PRESSURE TEST
Lease or Project	DD-7
County	BUCHANAN
State	VA

Service Center Information

Service Center	Norton
Location Code	33
NCPS Entity	Nabors Completion & Production Services
Location Address	580 Hawthorn Dr
City State Zip	Norton VA 24273
Phone	276-679-5861
Fax	276-679-5863

Pre-Job Information

Well Information

Casing Size	2 3/8
Casing Weight	4.6
Casing Connection	—
Casing I.D.	—
Hole Size	—
Calculated Annular Excess %	—
BHST	—
T.D.	—
Casing Length	1110
Shoe Joint	—
Float Collar	—
Calculated T.O.C.	—
Previous Casing Depth	—
Previous Casing Size	—
Previous Casing Weight	—
Drill Pipe Size	—
Drill Pipe Weight	—

Call-Out Information

A NABORS COMPANY
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Cement Report

Service Center(s)	Same
Bulk Location(s)	Same
Pumping Equipment	1132
Auxilliary Equipment	—
Time Called Out	—
Time On Location	9:00
Planned Time of Job	9:00
Weather Conditions	COOL

PRESSURE TEST

PRESSURE TEST - Total(s)

Time	Comment
12:13:10	---

PRESSURE TEST - Job Log

Time	Comment	Tubing-psi	Anu psi	Pmp Job	PUMP1f (2)	DENcmt
09:19:27	Establish Rate	-26	1	1.17	2.0	0.21
09:21:27	Establish Rate	-20	3	5.17	2.0	0.22
09:23:28	Establish Rate	-16	5	9.17	2.0	0.22
09:25:28	Establish Rate	-19	3	12.55	0.8	0.22
09:27:28	Establish Rate	-19	-1	14.14	0.8	0.22
09:29:28	Establish Rate	-8	-27	15.12	0.0	0.24
10:33:58	Establish Rate	257	-5	15.45	0.0	0.68
10:35:58	Establish Rate	1505	-2	15.47	0.0	2.76
10:37:58	Establish Rate	1501	-1	15.48	0.0	2.75
10:39:58	Establish Rate	1501	-1	15.48	0.0	2.75
10:41:58	Establish Rate	1504	-6	15.49	0.0	2.76
10:43:58	Establish Rate	1506	2	15.49	0.0	2.76
10:45:58	Establish Rate	1504	-1	15.49	0.0	2.76
10:47:58	Establish Rate	1502	-7	15.50	0.0	2.75
10:49:58	Establish Rate	1501	-5	15.50	0.0	2.75
10:51:58	Establish Rate	1495	-5	15.51	0.0	2.74
10:53:58	Establish Rate	1502	-2	15.51	0.0	2.76
10:55:58	Establish Rate	1503	-2	15.51	0.0	2.76
10:57:58	Establish Rate	1501	-6	15.52	0.0	2.75
10:59:58	Establish Rate	1501	3	15.52	0.0	2.75
11:01:58	Establish Rate	1503	-1	15.53	0.0	2.76
11:03:58	Establish Rate	1502	0	15.53	0.0	2.75
11:05:58	Establish Rate	5	-2	15.53	0.0	0.26
11:18:29	Establish Rate	1540	-2	15.65	0.0	2.82
11:20:30	Establish Rate	1193	1	15.74	0.0	2.24
11:22:30	Establish Rate	1170	-2	15.75	0.0	2.20
11:24:30	Establish Rate	1244	-8	15.76	0.0	2.32
11:26:30	Establish Rate	1505	5	15.76	0.0	2.76
11:28:30	Establish Rate	1250	4	15.77	0.0	2.33
11:37:52	Establish Rate	33	1121	15.85	0.0	0.38
11:39:52	Establish Rate	31	1123	15.86	0.0	0.37
11:41:52	Establish Rate	32	1120	15.86	0.0	0.38
11:43:52	Establish Rate	35	1116	15.87	0.0	0.38

A NABORS COMPANY
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Cement Report

Time	Comment	Tubing-psi	Anu psi	Pmp Job	PUMP1f (2)	DENcmt
11:45:52	Establish Rate	34	1125	15.87	0.0	0.38
11:47:52	Establish Rate	35	1122	15.87	0.0	0.38
11:49:52	Establish Rate	38	1124	15.88	0.0	0.39
11:51:52	Establish Rate	41	1125	15.88	0.0	0.39
11:53:52	Establish Rate	37	1119	15.89	0.0	0.38
11:55:52	Establish Rate	40	1126	15.89	0.0	0.39
11:57:52	Establish Rate	36	1124	15.90	0.0	0.38
11:59:52	Establish Rate	40	1127	15.90	0.0	0.39
12:01:52	Establish Rate	47	1122	15.91	0.0	0.40
12:03:52	Establish Rate	45	1124	15.91	0.0	0.40
12:05:52	Establish Rate	45	1130	15.92	0.0	0.40
12:07:52	Establish Rate	47	1128	15.92	0.0	0.40
12:09:52	Establish Rate	46	1121	15.93	0.0	0.40
12:11:52	Establish Rate	1	9	15.93	0.0	0.33
12:13:10	End Job	-2	4	15.93	0.0	0.32

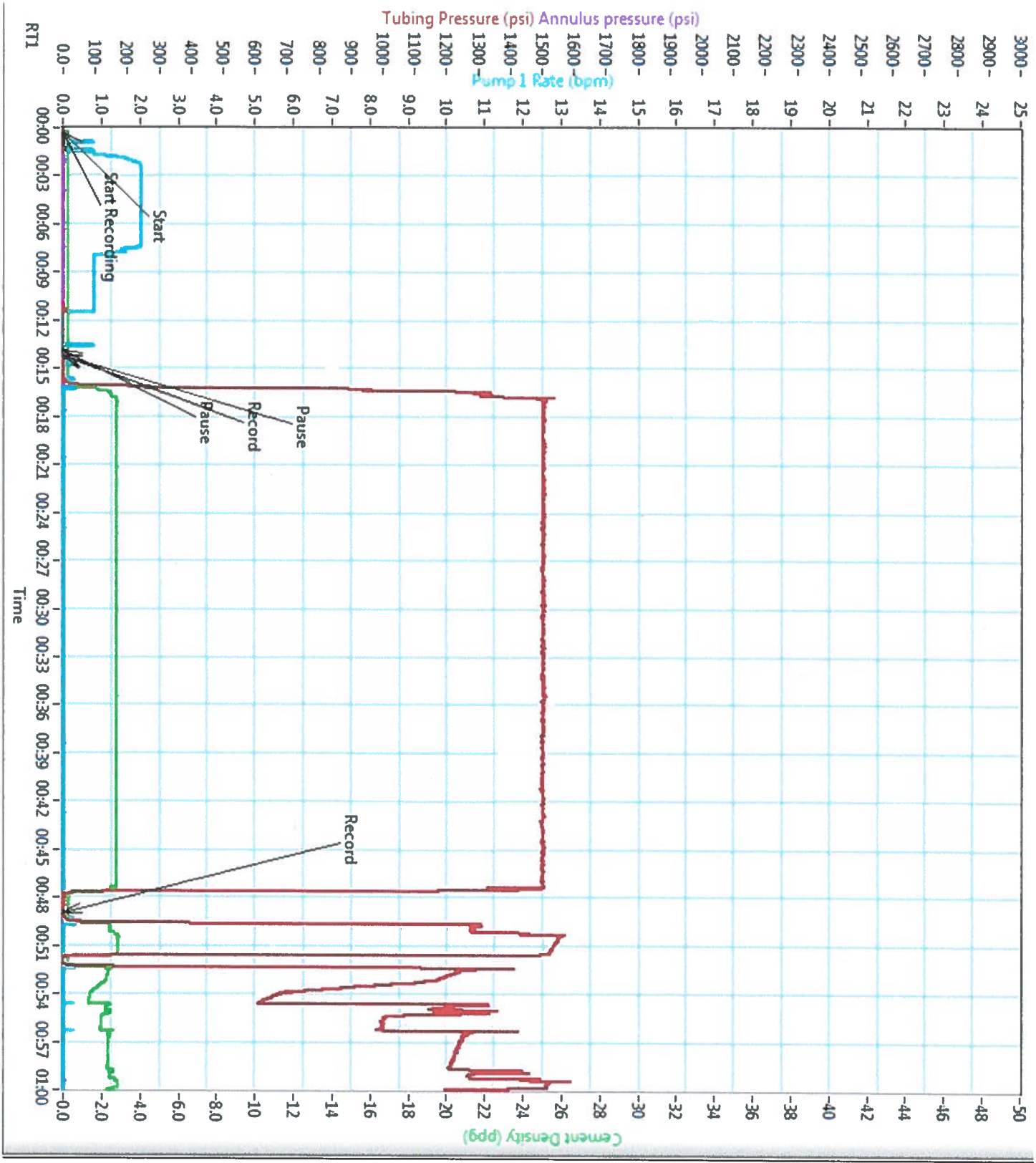
PRESSURE TEST - Key & Unit(s)

Name	Abbreviation	Units
Tubing Pressure	Tubing-psi	psi
Annulus pressure	Anu psi	psi
Pump Stage Vol	Pmp Stg (2)	bbl
Pump Job Vol	Pmp Job	bbl
Pump 1 Rate	PUMP1f (2)	bpm
Cement Density	DENcmt	ppg

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Cement Report

PRESSURE TEST - Recorded Time Plot 1 - 1 of 2

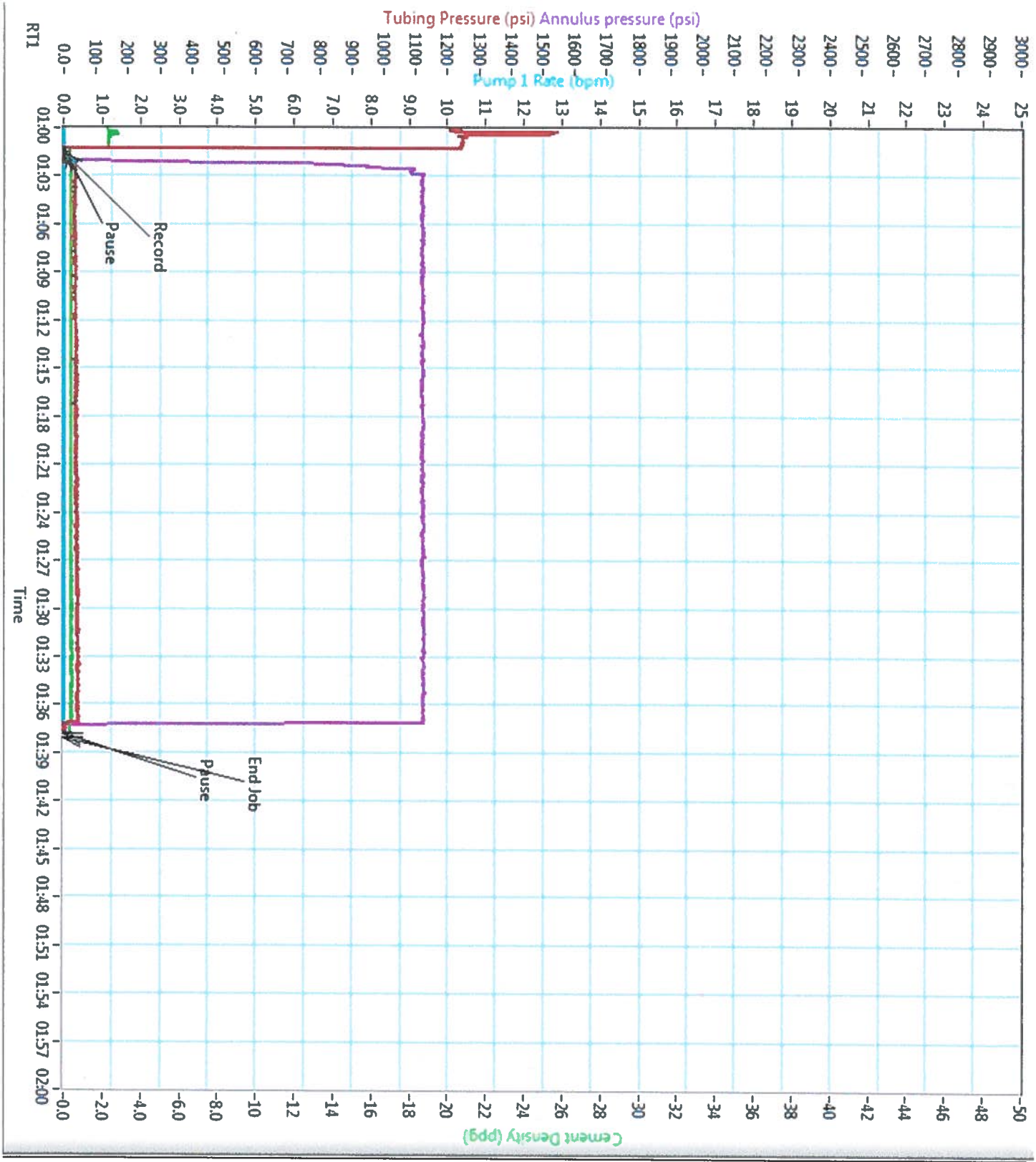


PRESSURE TEST - Recorded Time Plot 1 - 1 of 2

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Cement Report

PRESSURE TEST - Recorded Time Plot 1 - 2 of 2



PRESSURE TEST - Recorded Time Plot 1 - 2 of 2

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Post-Job Information

Post Job Summary

Pressure Test
Initial Circulating Rate
Initial Circulating Pressure
Lead Slurry Sacks
Lead Slurry Volume
Tail Slurry Sacks
Tail Slurry Volume
Bottom Plug Displacement
Top Plug Displacement
Cmt Vol Circulated to Surface
Average Displacement Rate
Final Circulating Rate
Final Circulating Pressure
Plug Bumped?
Pressure When Plug Bumped
Floats Hold?

Disclaimer

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NABORS COMPLETION & PRODUCTION SERVICES CO.

NORTH-SEP-11c-SALES & SERVICE TICKET

TICKET	
DATE	4/16/15
PAGE	1 of 1

CHARGE TO	CNX-CARDNO
LEASE NAME OR PROJECT	DD-7A
ADDRESS	
STATE	VA
COUNTY	BUCHANAN
ADDRESS	
FIELD	
WELL PERMIT NUMBER	
OWNER	
SERVICE ENGINEER	JAMES KEATON
AFE / PURCHASE ORDER / CONTRACT / REFERENCE	
JOB TYPE	PRESSURE TEST
ON LOCATION TIME	8:00
ON LOCATION DATE	
COMPLETED TIME	2:00
COMPLETED DATE	
SIGNATURE	X Ed Dominick
NAME (PLEASE PRINT)	Ed Dominick

I have read, understood and agreed to the terms and conditions printed on the reverse side hereof which include, but are not limited to, *LIMITED WARRANTY, INDEMNITY, RELEASE* and PAYMENT and represent that I have full power and authority to execute this agreement.

LOC	ITEM REFERENCE	QTY	DESCRIPTION	DISC ACCT	UNIT PRICE	AMOUNT
33	20-200-0001	25	Mileage DOT Units, Cmt - per unit, per one-way mile		6.00	150.00
33	20-200-0002	25	Mileage non-DOT Units, Cmt - per unit, per mile	-	3.40	85.00
33	35-405-0002	2	Acid Inhibitor 2 (AI-2) - per gallon	-	220.00	440.00
33				-	-	-
33	20-225-0020	1	Pressure Pumped 1,001 to 2,000 psi, first 3 hrs - per unit	-	2,120.00	2,120.00
33	00-000-0000	1	AQUAKAR		268.00	268.00
				-	-	-
				-	-	-
				13.00	-	-
				-	-	-
-				-	-	-
-				-	-	-
-				-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
-		-		-	-	-
			Continuation Page		$	-

CUSTOMER OR AGENT SIGNATURE / COMMENTS

X Ed Dominick

Receipt: The customer or customer's agent acknowledges that the equipment, materials and services were received as listed on this field ticket.

Subtotal		$	3,063.00
Special Discount	39.00%	$	(1,194.57)
Line Item Discounts		$	-
Special Allowance	$ -	$	-
Subtotal		$	1,868.43
Fuel Surcharges		$	-
AMOUNT DUE ===>		**$**	**1,868.43**

Unless satisfactory credit terms have been established prior to services payment in advance may be required. All invoices rendered for services performed by Nabors Completion & Production Services Co. shall be paid as indicated on the invoice within thirty days (30) from date of receipt. If not paid within thirty (30) days the unpaid amount is subject to interest at one and one half percent (1 ½%) per month (eighteen percent per annum). All discounts indicated on the invoice are based upon payment within the invoice payment term and are subject to being cancelled by Nabors Completion & Production Services Co. if not paid within terms. If it should be necessary to employ an attorney to collect the amount due, you will be held liable for attorneys' fees and collection costs. Nabors Completion & Production Services Co. price book is incorporated herein by reference, which also contains all invoice payment terms.

NABORS COMPLETION & PRODUCTION SERVICES CO.

CEMENT JOB LOG

Nabors Completion & Production Service CO.
1380 RT 286 East Suite #121
Indiana, PA 15701
Telephone 724-465-8904

CUSTOMER	DATE	INVOICE NUMBER
CNX-CARDNO	4/16/2015	

LEASE NAME	JOB TYPE	COUNTY	STATE
DD-7A	PRESSURE TEST		VA

SERVICE SUPERVISOR:	Service Center:
JAMES KEATON	Nabors - Norton,VA

	YES	NO	N/A	COMMENTS
CEMENT CIRCULATED TO SURFACE			X	BBLS
WELL CIRCULATED			X	bbls
PLUG LANDED ON DEPTH			X	PMHr:min
FLOAT(S) HELD			X	
PLUG CONTAINER RETURNED			X	

	N/U WT	SIZE	FROM	TO	MAX PSI
CASING					
TUBING		2 3/8	747	SURFACE	2000
OPEN HOLE					
PERFORATIONS					
DISPLACEMENT DEPTH					

ID	AMOUNT (SK-GAL-BBL)	SLURRY/FLUID COMPOSITION	YIELD (ft/sk)	Mix Ratio	Density (lb/gal)	Mix Water (BBLS)	Slurry Vol (BBLS)
1	SKS						
2	1GAL	AQUAKAR					
3	2GAL	AI-2					
4							
5							
6							

TIME	RATE (BPM)	VOLUME (BBLS)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION
9:00					Arrive on Location / Inspect for Hazards
					Pre-Job Safety Meeting/WAIT
					Rig Equipment in
					Pressure test lines and Equipment
0:00		11.1			PUMP TREATED H20/SD/WAIT
11:28				1520/1513	PRESSURE TEST TUBING/HOLD
					BLEED OFF/WAIT
12::15				1250	TEST PRESSURE RELIEF VALVE
12:58				1080/1080	TEST ANNULUS/HOLD
					BLEED OFF
1:30					RIG DOWN JOB COMPLETE

wellPORT

CEMENT REPORT

NABORS

Title Page

Field Ticket
XXXXX-000000000-0034

Date
Thu, Apr 16, 2015

Service Center
Norton (33)
Nabors Completion & Production Services
580 Hawthorn Dr
Norton VA 24273
276-679-5861
276-679-5863

Service Representative(s)
JAMES KEATON

Job Type
PRESSURE TEST

Lease Project
DD-7A

Number / ID

Township

County
BUCHANAN

State
VA

Physical Location

Country

Customer Cardno MM+A
c/o CNX GAS CO LLC ( )

Mailing Address
PO BOX 947

BLUE FIELD VA 24605

Division / District

Customer Representative(s)
GOOD GUY

PO/RFQ/AFE Code

Blank Page

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Cement Report

Client Information

Client	CNX GAS CO LLC
Address	PO BOX 947
City State Zip	BLUE FIELD VA 24605
Representative	GOOD GUY

Lease/Project/Well Information

Job Type	PRESSURE TEST
Lease or Project	DD-7A
County	BUCHANAN
State	VA

Service Center Information

Service Center	Norton
Location Code	33
NCPS Entity	Nabors Completion & Production Services
Location Address	580 Hawthorn Dr
City State Zip	Norton VA 24273
Phone	276-679-5861
Fax	276-679-5863

Pre-Job Information

Well Information

Casing Size	2 3/8
Casing Weight	4.6
Casing Connection	—
Casing I.D.	—
Hole Size	—
Calculated Annular Excess %	—
BHST	—
T.D.	—
Casing Length	747
Shoe Joint	—
Float Collar	—
Calculated T.O.C.	—
Previous Casing Depth	—
Previous Casing Size	—
Previous Casing Weight	—
Drill Pipe Size	—
Drill Pipe Weight	—

Call-Out Information

A NABORS COMPANY
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Cement Report

Service Center(s)	Same
Bulk Location(s)	Same
Pumping Equipment	1132
Auxilliary Equipment	---
Time Called Out	---
Time On Location	9:00
Planned Time of Job	9:00
Weather Conditions	COOL

PRESSURE TEST

PRESSURE TEST - Total(s)

Time	Comment
13:01:52	---

PRESSURE TEST - Job Log

Time	Comment	Tubing-psi	Anu psi	Pmp Job	PUMP1f (2)	DENcmt
09:35:52	Establish Rate	1	-3	0.00	0.0	0.37
09:37:52	Establish Rate	-38	2	2.04	1.3	0.30
09:39:52	Establish Rate	-34	-2	4.63	1.3	0.31
09:41:53	Establish Rate	-33	-7	7.21	0.8	0.31
09:43:53	Establish Rate	-23	-38	8.16	0.0	0.33
11:24:28	Establish Rate	690	-7	8.18	0.0	1.52
11:26:28	Establish Rate	1517	-8	8.18	0.0	2.89
11:28:28	Establish Rate	1519	-9	8.19	0.0	2.90
11:30:28	Establish Rate	1519	-9	8.19	0.0	2.89
11:32:28	Establish Rate	1518	-5	8.19	0.0	2.90
11:34:28	Establish Rate	1518	-5	8.20	0.0	2.90
11:36:29	Establish Rate	1516	-10	8.20	0.0	2.89
11:38:29	Establish Rate	1518	-8	8.21	0.0	2.90
11:40:29	Establish Rate	1517	-4	8.21	0.0	2.89
11:42:29	Establish Rate	1516	-4	8.21	0.0	2.89
11:44:30	Establish Rate	1510	-4	8.22	0.0	2.88
11:46:30	Establish Rate	1515	-7	8.22	0.0	2.89
11:48:30	Establish Rate	1513	-3	8.23	0.0	2.89
11:50:30	Establish Rate	1518	-0	8.23	0.0	2.90
11:52:30	Establish Rate	1521	-3	8.24	0.0	2.90
11:54:30	Establish Rate	1513	-6	8.24	0.0	2.89
11:56:30	Establish Rate	60	-3	8.24	0.0	0.47
12:10:30	Establish Rate	1242	-7	8.26	0.0	2.44
12:12:30	Establish Rate	866	-1	8.26	0.0	1.81
12:14:30	Establish Rate	1253	-8	8.27	0.0	2.45
12:22:35	Establish Rate	2	307	8.30	0.0	0.14
12:24:35	Establish Rate	22	1082	8.31	0.0	0.17
12:26:35	Establish Rate	19	1079	8.31	0.0	0.17
12:28:35	Establish Rate	21	1078	8.32	0.0	0.17
12:30:35	Establish Rate	20	1079	8.32	0.0	0.17
12:32:35	Establish Rate	20	1083	8.32	0.0	0.17
12:34:35	Establish Rate	17	1084	8.33	0.0	0.16
12:36:35	Establish Rate	18	1085	8.33	0.0	0.16

A NABORS COMPANY
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Cement Report

Time	Comment	Tubing-psi	Anu psi	Pmp Job	PUMP1f (2)	DENcmt
12:38:35	Establish Rate	22	1084	8.34	0.0	0.17
12:40:35	Establish Rate	19	1079	8.34	0.0	0.17
12:42:35	Establish Rate	18	1080	8.35	0.0	0.16
12:44:35	Establish Rate	21	1081	8.35	0.0	0.17
12:46:35	Establish Rate	19	1072	8.36	0.0	0.17
12:48:35	Establish Rate	15	1070	8.36	0.0	0.16
12:50:36	Establish Rate	19	1077	8.37	0.0	0.17
12:52:36	Establish Rate	18	1075	8.37	0.0	0.16
12:54:36	Establish Rate	16	1072	8.38	0.0	0.16
12:56:36	Establish Rate	13	1073	8.38	0.0	0.16
12:58:36	Establish Rate	17	1070	8.39	0.0	0.16
13:00:36	Establish Rate	-2	4	8.40	0.0	0.13
13:01:52	End Job	-1	2	8.40	0.0	0.13

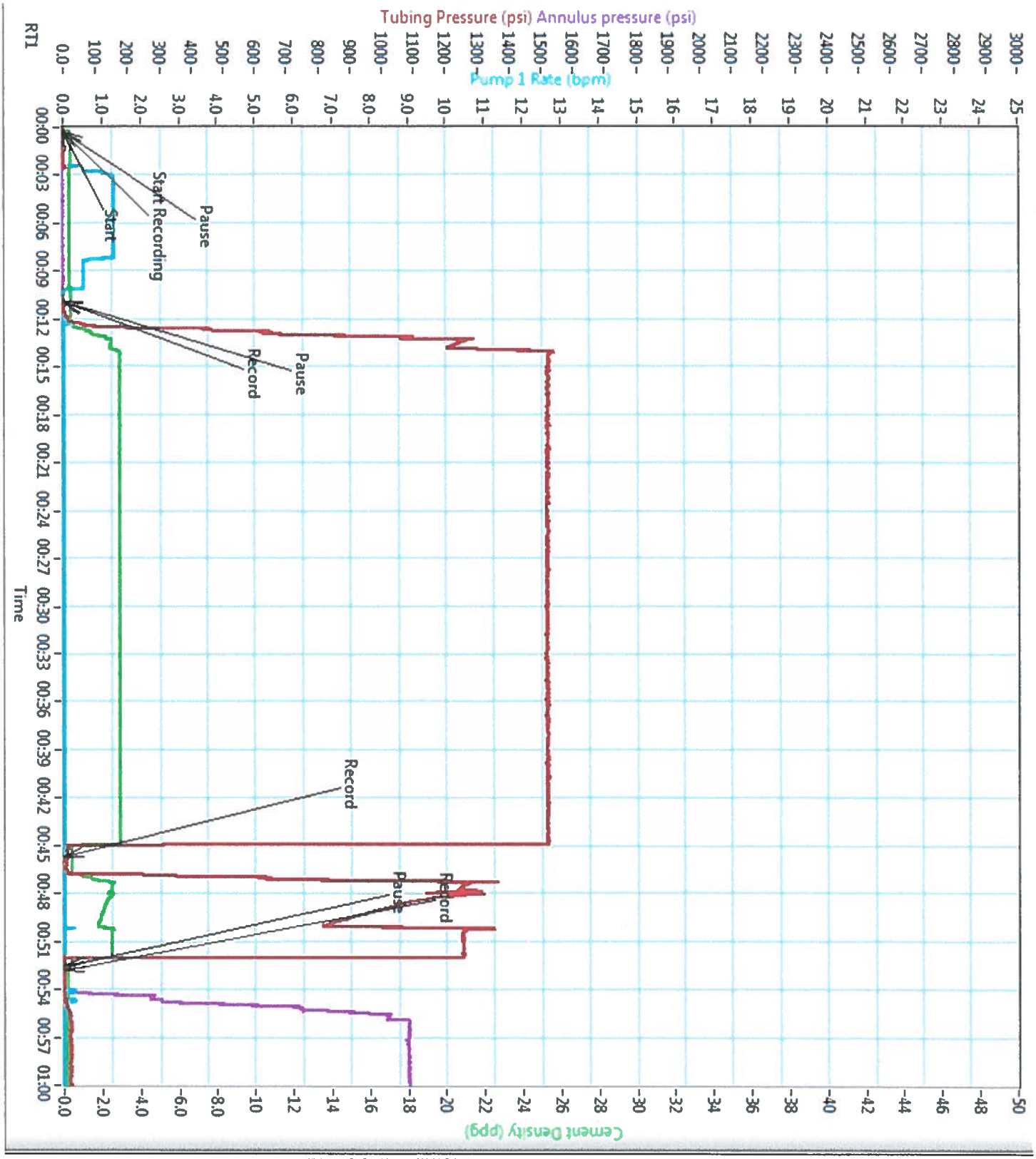
PRESSURE TEST - Key & Unit(s)

Name	Abbreviation	Units
Tubing Pressure	Tubing-psi	psi
Annulus pressure	Anu psi	psi
Pump Stage Vol	Pmp Stg (2)	bbl
Pump Job Vol	Pmp Job	bbl
Pump 1 Rate	PUMP1f (2)	bpm
Cement Density	DENcmt	ppg

A NABORS COMPANY
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Cement Report

PRESSURE TEST - Recorded Time Plot 1 - 1 of 2

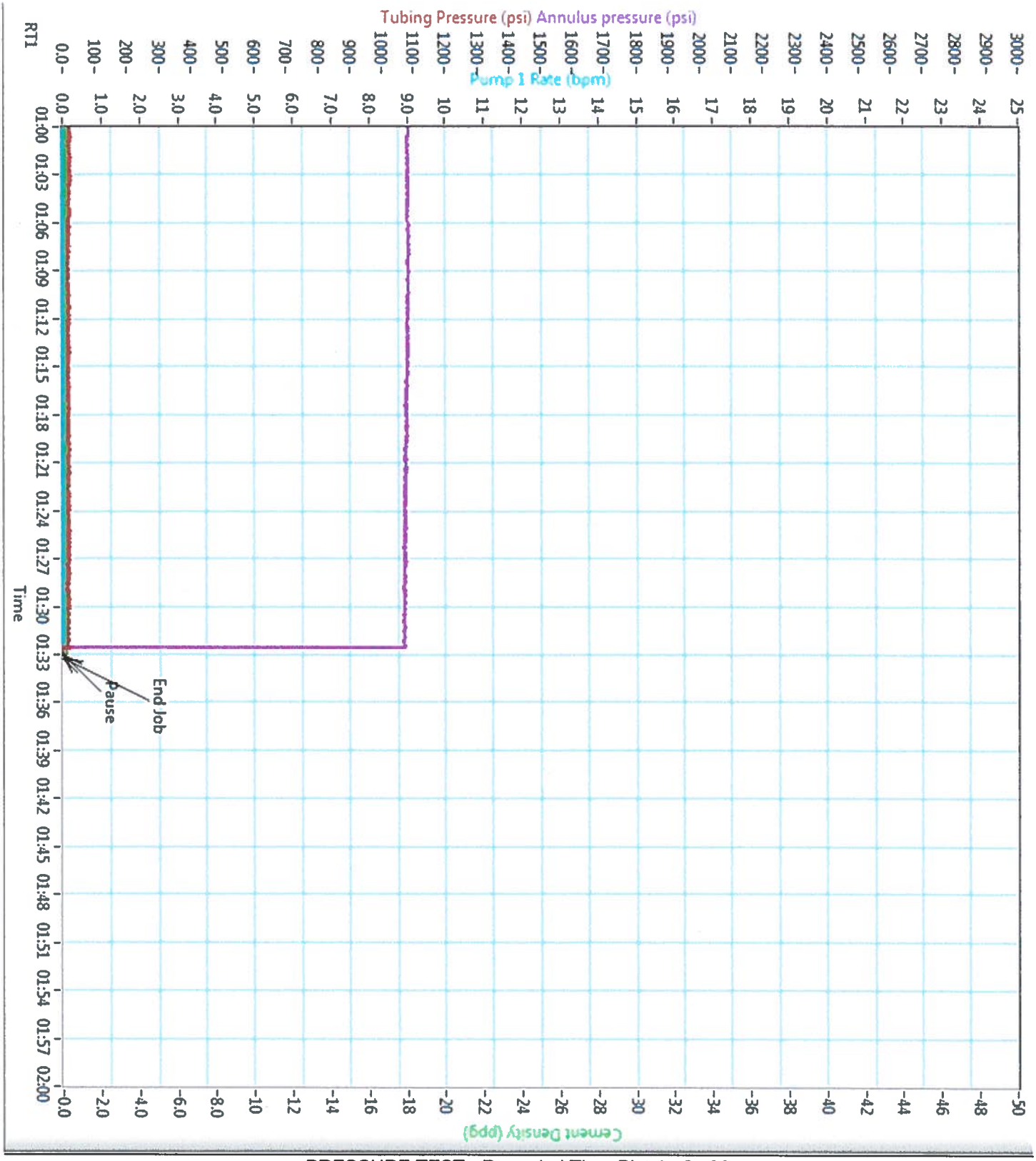


PRESSURE TEST - Recorded Time Plot 1 - 1 of 2

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Cement Report

PRESSURE TEST - Recorded Time Plot 1 - 2 of 2



PRESSURE TEST - Recorded Time Plot 1 - 2 of 2

A NABORS COMPANY
(c) 2012 wellPORT Report; Nabors Completion & Production Services

Post-Job Information

Post Job Summary

Pressure Test
Initial Circulating Rate
Initial Circulating Pressure
Lead Slurry Sacks
Lead Slurry Volume
Tail Slurry Sacks
Tail Slurry Volume
Bottom Plug Displacement
Top Plug Displacement
Cmt Vol Circulated to Surface
Average Displacement Rate
Final Circulating Rate
Final Circulating Pressure
Plug Bumped?
Pressure When Plug Bumped
Floats Hold?

Disclaimer

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NABORS COMPLETION & PRODUCTION SERVICES CO.

NORTH-SEP-11c-SALES & SERVICE TICKET

TICKET			
DATE	4/15/15		
PAGE	1	of	1

CHARGE TO	LEASE NAME OR PROJECT
CNX-CARDNO	DD-8

ADDRESS	STATE	COUNTY
	VA	BUCHANAN

ADDRESS	FIELD	WELL PERMIT NUMBER

OWNER	SERVICE ENGINEER
	JAMES KEATON

AFE / PURCHASE ORDER / CONTRACT / REFERENCE	JOB TYPE	ON LOCATION	COMPLETED
	PRESSURE TEST	TIME 1:30	TIME 5:00
		DATE	DATE

SIGNATURE	NAME (PLEASE PRINT)	
X Ed Dimmick	Ed Dimmick	I have read, understood and agreed to the terms and conditions printed on the reverse side hereof which include, but are not limited to, LIMITED WARRANTY, INDEMNITY, RELEASE and PAYMENT and represent that I have full power and authority to execute this agreement.

LOC	ITEM REFERENCE	QTY	DESCRIPTION	DISC ACCT	UNIT PRICE	AMOUNT
33	20-200-0001	25	Mileage DOT Units, Cmt - per unit, per one-way mile		6.00	150.00
33	20-200-0002	25	Mileage non-DOT Units, Cmt - per unit, per mile	-	3.40	85.00
33	35-405-0002	2	Acid Inhibitor 2 (AI-2) - per gallon	-	220.00	440.00
33				-	-	-
33	20-225-0020	1	Pressure Pumped 1,001 to 2,000 psi, first 3 hrs - per unit	-	2,120.00	2,120.00
33	00-000-0000	1	AQUAKAR		268.00	268.00
				-	-	-
				-	-	-
				13.00	-	-
				-	-	-
-				-	-	-
-				-	-	-
-				-	-	-
-		-		-	-	-
-		-		-	-	-
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				Continuation Page	$	-

CUSTOMER OR AGENT SIGNATURE / COMMENTS

X Ed Dimmick

Receipt: The customer or customer's agent acknowledges that the equipment, materials and services were received as listed on this field ticket.

Subtotal		$	3,063.00
Special Discount	39.00%	$	(1,194.57)
Line Item Discounts		$	-
Special Allowance	$ -	$	-
Subtotal		$	1,868.43
Fuel Surcharges		$	-
AMOUNT DUE ===>		$	**1,868.43**

Unless satisfactory credit terms have been established prior to services payment in advance may be required. All invoices rendered for services performed by Nabors Completion & Production Services Co. shall be paid as indicated on the invoice within thirty days (30) from date of receipt. If not paid within thirty (30) days the unpaid amount is subject to interest at one and one half percent (1 ½%) per month (eighteen percent per annum). All discounts indicated on the invoice are based upon payment within the invoice payment term and are subject to being cancelled by Nabors Completion & Production Services Co. if not paid within terms. If it should be necessary to employ an attorney to collect the amount due, you will be held liable for attorneys' fees and collection costs. Nabors Completion & Production Services Co. price book is incorporated herein by reference, which also contains all invoice payment terms.

NABORS COMPLETION & PRODUCTION SERVICES CO.

CEMENT JOB LOG

Nabors Completion & Production Service CO.
1380 RT 286 East Suite #121
Indiana, PA 15701
Telephone 724-465-8904

CUSTOMER	DATE	INVOICE NUMBER
CNX-CARDNO	4/15/2015	

LEASE NAME	JOB TYPE	COUNTY	STATE
DD-8	PRESSURE TEST		VA

SERVICE SUPERVISOR:
JAMES KEATON

Service Center:
Nabors - Norton,VA

	YES	NO	N/A	COMMENTS
CEMENT CIRCULATED TO SURFACE			X	BBLS
WELL CIRCULATED			X	bbls
PLUG LANDED ON DEPTH			X	PMHr:min
FLOAT(S) HELD			X	
PLUG CONTAINER RETURNED			X	

	N/U WT	SIZE	FROM	TO	MAX PSI
CASING					
TUBING		2 3/8	771	SURFACE	2000
OPEN HOLE					
PERFORATIONS					
DISPLACEMENT DEPTH					

ID	AMOUNT (SK-GAL-BBL)	SLURRY/FLUID COMPOSITION	YIELD (ft/sk)	Mix Ratio	Density (lb/gal)	Mix Water (BBLS)	Slurry Vol (BBLS)
1	SKS						
2	1GAL	AQUAKAR					
3	2GAL	AI-2					
4							
5							
6							

TIME	RATE (BPM)	VOLUME (BBLS)	PRESSURE (PSI) TUBING	PRESSURE (PSI) CASING	DESCRIPTION
8:00					Arrive on Location / Inspect for Hazards
					Pre-Job Safety Meeting/WAIT
					Rig Equipment in
					Pressure test lines and Equipment
8:15		11.4			PUMP TREATED H20/SD/WAIT
10:44				1710/1678	PRESSURE TEST TUBING/HOLD
					BLEED OFF/WAIT
11::05 AM				1230	TEST PRESSURE RELIEF VALVE
12:00				1320/1305	TEST ANNULUS/HOLD
					BLEED OFF
12:30					RIG DOWN JOB COMPLETE

wellPORT

CEMENT REPORT

NABORS

Title Page

Field Ticket
XXXXX-000000000-0033

Date
Wed, Apr 15, 2015

Service Center
Norton (33)
Nabors Completion & Production Services
580 Hawthorn Dr
Norton VA 24273
276-679-5861
276-679-5863

Service Representative(s)
JAMES KEATON

Job Type
PRESSURE TEST

Lease Project
DD-8

Number / ID

Township

County
BUCHANAN

State
VA

Physical Location

Country

Customer Cardno MM+A
c/o CNX GAS CO LLC ( )

Mailing Address
PO BOX 947

BLUE FIELD VA 24605

Division / District

Customer Representative(s)
GOOD GUY

PO/RFQ/AFE Code

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Cement Report

Client Information

Client	CNX GAS CO LLC
Address	PO BOX 947
City State Zip	BLUE FIELD VA 24605
Representative	GOOD GUY

Lease/Project/Well Information

Job Type	PRESSURE TEST
Lease or Project	DD-8
County	BUCHANAN
State	VA

Service Center Information

Service Center	Norton
Location Code	33
NCPS Entity	Nabors Completion & Production Services
Location Address	580 Hawthorn Dr
City State Zip	Norton VA 24273
Phone	276-679-5861
Fax	276-679-5863

Pre-Job Information

Well Information

Casing Size	2 3/8
Casing Weight	4.6
Casing Connection	—
Casing I.D.	—
Hole Size	—
Calculated Annular Excess %	—
BHST	—
T.D.	—
Casing Length	771
Shoe Joint	—
Float Collar	—
Calculated T.O.C.	—
Previous Casing Depth	—
Previous Casing Size	—
Previous Casing Weight	—
Drill Pipe Size	—
Drill Pipe Weight	—

Call-Out Information

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Cement Report

Service Center(s)	Same
Bulk Location(s)	Same
Pumping Equipment	1132
Auxilliary Equipment	—
Time Called Out	---
Time On Location	8:00
Planned Time of Job	8:00
Weather Conditions	COOL/RAIN

PRESSURE TEST

PRESSURE TEST - Total(s)

Time	Comment
12:14:31	---

PRESSURE TEST - Job Log

Time	Comment	Tubing-psi	Anu psi	Pmp Job	PUMP1f (2)	DENcmt
08:14:00	Establish Rate	-2	-7	0.00	0.0	0.13
08:16:00	Establish Rate	-8	-2	1.81	1.0	0.12
08:18:00	Establish Rate	-11	-4	3.80	1.0	0.11
08:20:00	Establish Rate	-12	-0	5.81	1.0	0.11
08:22:00	Establish Rate	-11	-2	7.81	1.0	0.11
08:24:00	Establish Rate	3	2	8.99	0.0	0.14
10:12:33	Establish Rate	431	8	9.14	0.0	0.85
10:14:33	Establish Rate	1709	7	9.17	0.0	2.98
10:16:33	Establish Rate	1705	9	9.18	0.0	2.97
10:18:33	Establish Rate	1699	8	9.18	0.0	2.96
10:20:33	Establish Rate	1704	6	9.18	0.0	2.97
10:22:33	Establish Rate	1694	3	9.19	0.0	2.95
10:24:33	Establish Rate	1693	4	9.19	0.0	2.95
10:26:33	Establish Rate	1693	4	9.19	0.0	2.95
10:28:33	Establish Rate	1692	8	9.20	0.0	2.95
10:30:33	Establish Rate	1690	11	9.20	0.0	2.95
10:32:33	Establish Rate	1685	6	9.20	0.0	2.94
10:34:33	Establish Rate	1688	7	9.21	0.0	2.94
10:36:33	Establish Rate	1690	8	9.21	0.0	2.95
10:38:33	Establish Rate	1685	5	9.21	0.0	2.94
10:40:33	Establish Rate	1684	8	9.22	0.0	2.94
10:42:33	Establish Rate	1681	9	9.22	0.0	2.93
10:44:33	Establish Rate	1678	5	9.22	0.0	2.93
11:03:31	Establish Rate	1157	12	9.33	0.0	2.06
11:05:31	Establish Rate	841	14	9.35	0.0	1.53
11:14:22	Establish Rate	54	68	9.41	0.0	0.22
11:16:22	Establish Rate	2	16	9.41	0.0	0.14
11:18:22	Establish Rate	1	66	9.41	0.0	0.13
11:20:22	Establish Rate	-2	91	9.41	0.0	0.13
11:22:22	Establish Rate	5	-1	9.41	0.0	0.14
11:24:22	Establish Rate	4	-2	9.41	0.0	0.14
11:26:22	Establish Rate	15	1320	9.45	0.0	0.16
11:28:22	Establish Rate	13	1318	9.46	0.0	0.15

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Cement Report

Time	Comment	Tubing-psi	Anu psi	Pmp Job	PUMP1f (2)	DENcmt
11:30:22	Establish Rate	16	1320	9.46	0.0	0.16
11:32:22	Establish Rate	18	1318	9.47	0.0	0.16
11:34:22	Establish Rate	18	1314	9.47	0.0	0.16
11:36:22	Establish Rate	17	1314	9.47	0.0	0.16
11:38:22	Establish Rate	17	1310	9.48	0.0	0.16
11:40:22	Establish Rate	14	1311	9.48	0.0	0.15
11:42:22	Establish Rate	20	1312	9.49	0.0	0.16
11:44:22	Establish Rate	23	1310	9.49	0.0	0.17
11:46:22	Establish Rate	19	1309	9.49	0.0	0.16
11:48:22	Establish Rate	19	1312	9.50	0.0	0.16
11:50:22	Establish Rate	19	1309	9.50	0.0	0.16
11:52:22	Establish Rate	21	1309	9.51	0.0	0.17
11:54:22	Establish Rate	18	1306	9.51	0.0	0.16
11:56:23	Establish Rate	25	1304	9.52	0.0	0.17
11:58:23	Establish Rate	23	1305	9.52	0.0	0.17
12:00:23	Establish Rate	21	1272	9.52	0.0	0.17
12:02:23	Establish Rate	-39	2	9.53	0.0	0.07
12:04:23	Establish Rate	-3830	-3	10.26	0.7	-6.25
12:14:31	End Job	-3829	-3831	10.66	-4.8	-6.25

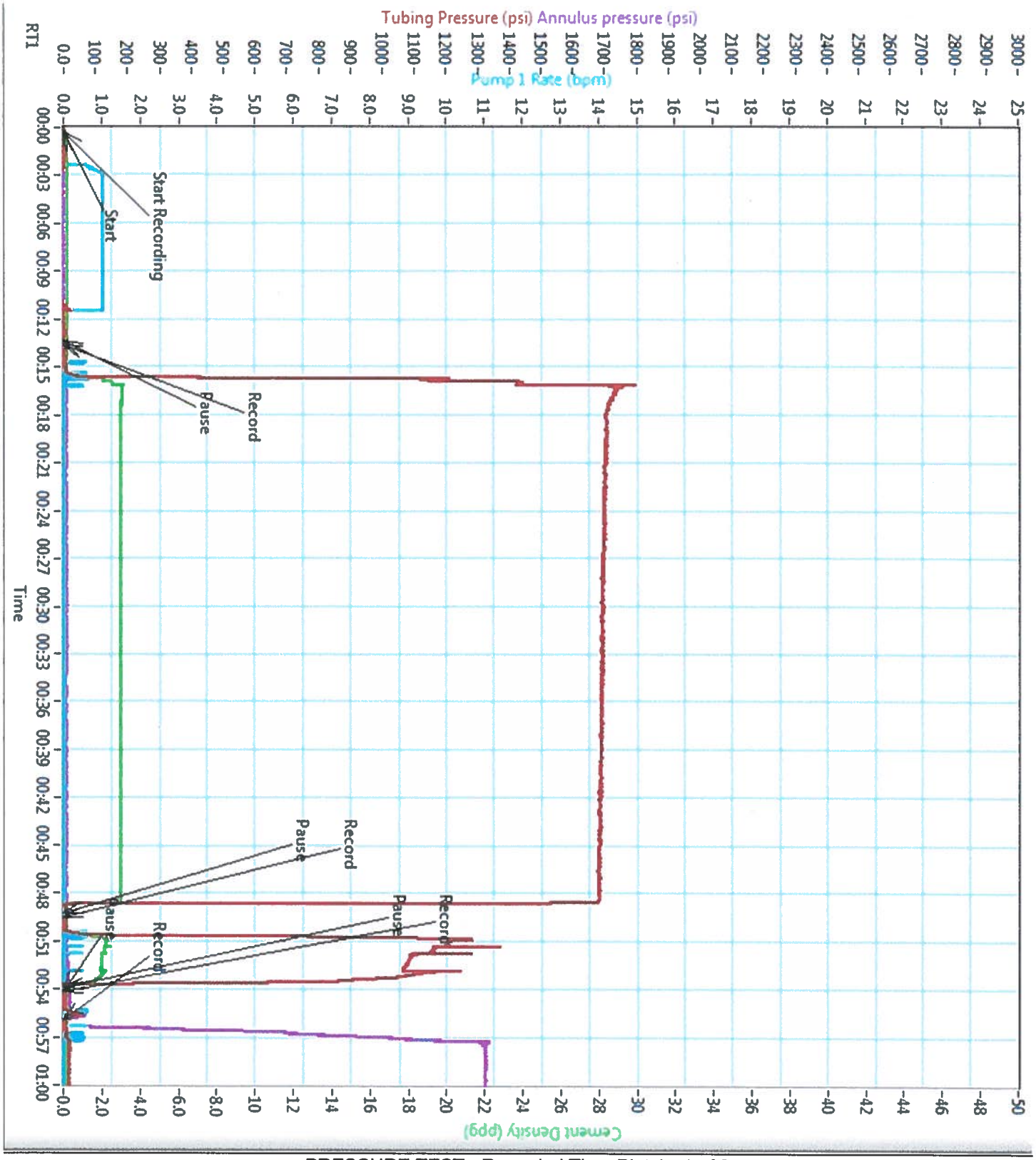
PRESSURE TEST - Key & Unit(s)

Name	Abbreviation	Units
Tubing Pressure	Tubing-psi	psi
Annulus pressure	Anu psi	psi
Pump Stage Vol	Pmp Stg (2)	bbl
Pump Job Vol	Pmp Job	bbl
Pump 1 Rate	PUMP1f (2)	bpm
Cement Density	DENcmt	ppg

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Cement Report

PRESSURE TEST - Recorded Time Plot 1 - 1 of 2

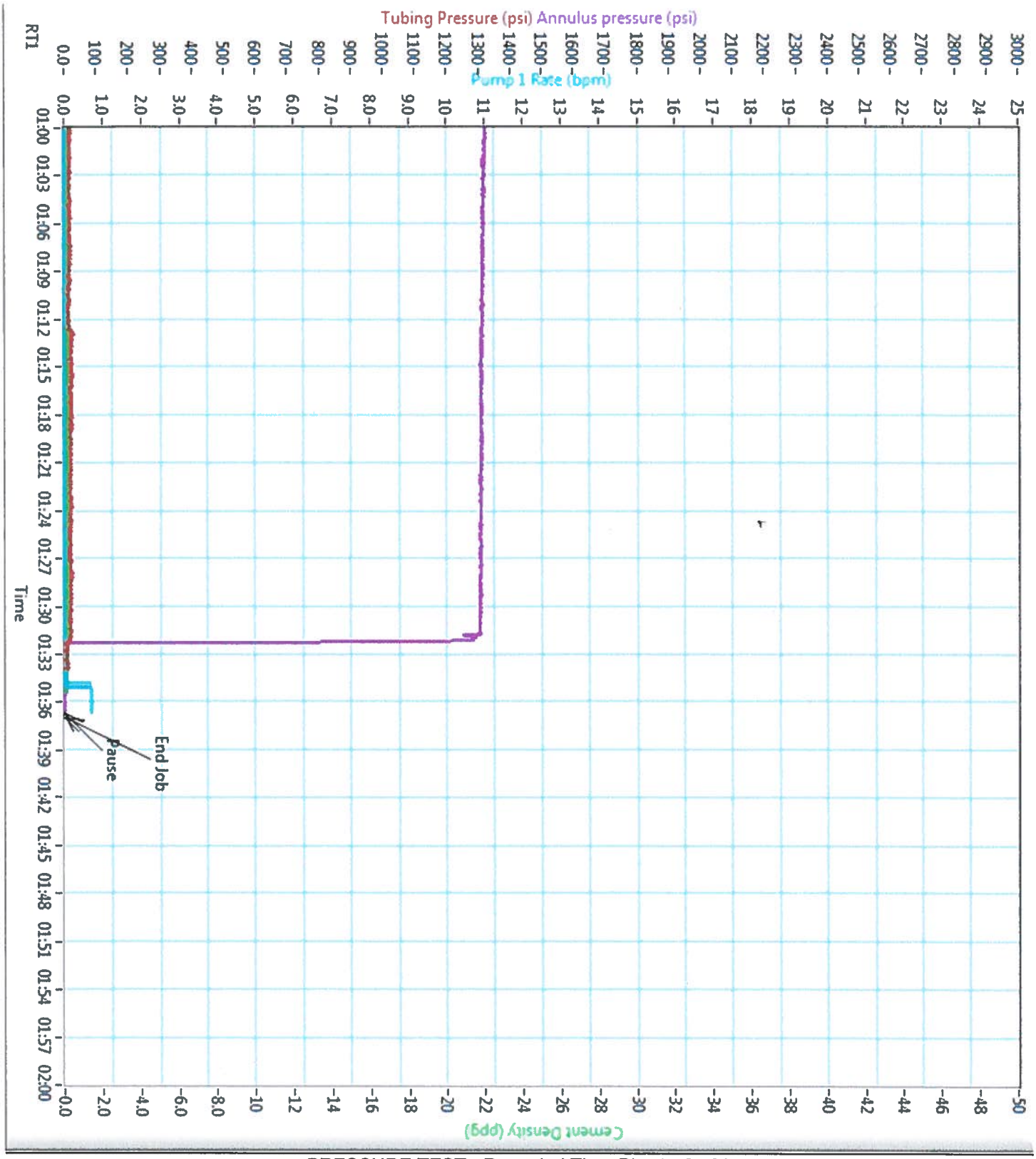


PRESSURE TEST - Recorded Time Plot 1 - 1 of 2

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Cement Report

PRESSURE TEST - Recorded Time Plot 1 - 2 of 2



PRESSURE TEST - Recorded Time Plot 1 - 2 of 2

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Post-Job Information

Post Job Summary

Pressure Test
Initial Circulating Rate
Initial Circulating Pressure
Lead Slurry Sacks
Lead Slurry Volume
Tail Slurry Sacks
Tail Slurry Volume
Bottom Plug Displacement
Top Plug Displacement
Cmt Vol Circulated to Surface
Average Displacement Rate
Final Circulating Rate
Final Circulating Pressure
Plug Bumped?
Pressure When Plug Bumped
Floats Hold?

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OMB No. 2040-0042 Approval Expires 11/30/2014

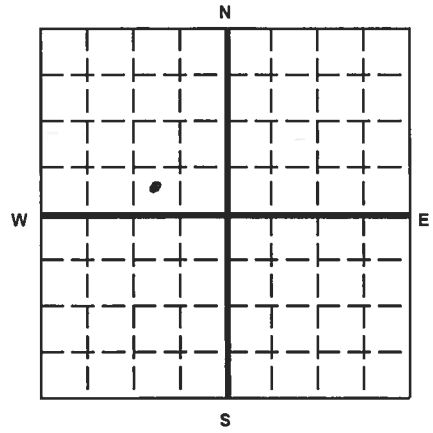
EPA

United States Environmental Protection Agency
Washington, DC 20460

COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY

Name and Address of Existing Permittee	Name and Address of Surface Owner
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660	Woodrow Presley 1134 Shady Rest Road, Vansant, VA 24656

Locate Well and Outline Unit on Section Plat - Acres = 80



State	County	Permit Number
Virginia	Buchanan	4707-02

Surface Location Description

* 1/4 of 1/4 of 1/4 of 1/4 of Section Township Range

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) line of quarter section
and * ft. from (E/W) Line of quarter section.

WELL ACTIVITY	TYPE OF PERMIT	
☐ Brine Disposal	☐ Individual	Estimated Fracture Pressure of Injection Zone
☑ Enhanced Recovery	☑ Area	1813 psig
☐ Hydrocarbon Storage	Number of Wells 3	

Anticipated Daily Injection Volume (Bbls)		Injection Interval	
Average	Maximum	Feet	to Feet
124	309	1216	2133

Anticipated Daily Injection Pressure (PSI)		Depth to Bottom of Lowermost Freshwater Formation Feet
Average	Maximum	
400	852	604

Type of Injection Fluid *(Check the appropriate block(s))*

☐ Salt Water ☐ Brackish Water ☐ Fresh Water
☐ Liquid Hydrocarbon ☑ Other

Lease Name	Well Number
Landon Wyatt, Jr. et al	DD-7

Name of Injection Zone: Lee and Pocahontas Formations of Pennsylvania-aged coals

Date Drilling Began	Date Well Completed	Permeability of Injection Zone
10/30/2000	11/14/2000	0.1 mD - 20 mD

Date Drilling Completed	Porosity of Injection Zone
11/02/2000	0.5% - 1%

CASING AND TUBING			CEMENT		HOLE	
OD Size	Wt/Ft - Grade - New or Used	Depth	Sacks	Class	Depth	Bit Diameter
12-3/4"	33 lb/ft-L/S ERW- New	12'	2	A	12'	15"
7"	17 lb/ft - AT50 - New	840'	65	A	840'	8-7/8"
4-1/2"	9.5 lb/ft - J55 - New	2182'	220	A	2182'	6-1/2"
2-3/8"	4.7 lb/ft - J55 - New	1119'	N/A	N A	N A	N/A

INJECTION ZONE STIMULATION		WIRE LINE LOGS, LIST EACH TYPE	
Interval Treated	Materials and Amount Used	Log Types	Logged Intervals
1216' - 1385'	310 sks sand - 230 bbl H2O - 355 MSCF N2	GRay - Caliper - Density - Devia	Surface to 2177'
1531' - 1570'	168 sks sand - 178 bbl H2O - 281 MSCF N2	GRay - Caliper - Density - Devia	Surface to 2177'
1674' - 1866'	292 sks sand - 193 bbl H2O - 318 MSCF N2	GRay - Caliper - Densi - Devia	Surface to 2177'
1997' - 2133'	151 sks sand - 171 bbl H2O - 230 MSCF N2	GRay - Caliper - Density - Devia	Surface to 2177'
* VA uses State	Plane Coordinates or Lat/Long not Sec/Twp/Ran	DD7 Latitude 37 08' 20"	Longitude 82 05' 04"

Complete Attachments A -- E listed on the reverse.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, Sr. Petroleum Engineer	Edward K Diminick	04 27 2015

EPA Form 7520-10 (Rev. 12-11)

ATTACHMENTS for COMPLETION REPORT 7520-10

DD-7 Well

A. See attached schematics of surface and subsurface as built well.
B. Previously submitted to Steve Platt on 4/20/15.
C. In Buchanan County, Virginia, fresh water typically occurs less than 300 feet deep according to EPA 816-R-04-003 report. Underground sources of drinking water could potentially be found from surface to the Pennsylvanian-aged Jawbone seam which occurs at 758 feet in this well. Attached is a resistivity log of the surface hole in the C-1 characterization well drilled in March 2015. The C-1 well is offset to the northeast from the three injection wells and also within the Area of Review. The Jawbone is at 378 feet and 401 feet on this log. The freshest water occurs from 30 feet to 75 feet and again at 126 feet to 160 feet. From the Jawbone to 580 feet, the resistivity trends slightly lower indicating water is becoming more saline.

   Additionally, a water sample analysis is attached that shows water produced from 1216 feet and deeper has extremely high total dissolved solids and is not potable.

   The confining zones are identified on the attached cross section of the injection wells. There are three shale zones and the basal Lee sandstone. The Hensley Shale Member is the most significant shale confining zone. A paper titled “Seal Evaluation and Confinement Screening Criteria for Beneficial Carbon Dioxide Storage with Enhanced Coal Bed Methane Recovery in the Pocahontas Basin, Virginia” is attached that discusses the confining properties in detail.

   The cross section also identifies the injection formations with asterisks and the adjacent formations.

D. There are no defective wells in the area of review.
E. A final print of the geophysical log is attached.

OMB No. 2040-0042 Approval Expires 11/30/2014

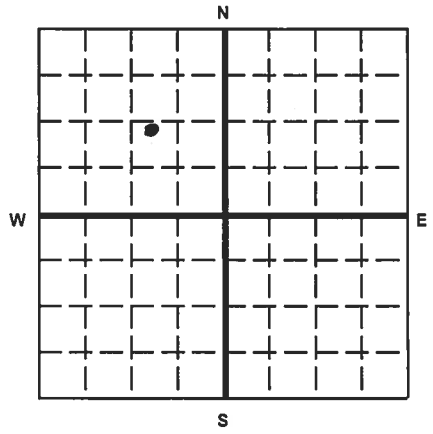
United States Environmental Protection Agency
Washington, DC 20460

COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY

Name and Address of Existing Permittee
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660

Name and Address of Surface Owner
Landon Wyatt
P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - Acres = 80



State	County	Permit Number
Virginia	Buchanan	7787-02

Surface Location Description
* 1/4 of 1/4 of 1/4 of /4 of Section Township Range

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) Line of quarter section and * ft. from (E/W) Line of quarter section.

WELL ACTIVITY
- ☐ Brine Disposal
- ☑ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT
- ☐ Individual
- ☑ Area

Number of Wells 3

Estimated Fracture Pressure of Injection Zone: 1792 psig

Anticipated Daily Injection Volume (Bbls)		Injection Interval	
Average	Maximum	Feet	to Feet
124	309	856	1757

Anticipated Daily Injection Pressure (PSI)		Depth to Bottom of Lowermost Freshwater Formation (Feet)
Average	Maximum	
451	943	234

Type of Injection Fluid *(Check the appropriate block(s))*
- ☐ Salt Water
- ☐ Brackish Water
- ☐ Fresh Water
- ☐ Liquid Hydrocarbon
- ☑ Other

Lease Name: Harrison-Wyatt, LLC Big Axe
Well Number: DD-7A
Name of Injection Zone: Lee and Pocahontas Formations of Pennsylvania-aged coals

Date Drilling Began: 01/20/2007
Date Well Completed: 02/20/2007
Date Drilling Completed: 01/24/2007
Permeability of Injection Zone: 0.1 mD - 20 mD
Porosity of Injection Zone: 0.5% - 1%

CASING AND TUBING			CEMENT		HOLE	
OD Size	Wt/Ft - Grade - New or Used	Depth	Sacks	Class	Depth	Bit Diameter
13-3/8"	37 lb/ft - AT50 - New	20'	N/A	N/A	20'	15"
7"	17 lb/ft - AT50 - New	253	60	A	253'	8-7/8"
4-1/2"	9.5 lb/ft - J55 - New	1807'	166	A	1807'	6-1/2"
2-3/8"	4.7 lb/ft - J55 - New	756'	N/A	N/A	N/A	N/A

INJECTION ZONE STIMULATION		WIRE LINE LOGS, LIST EACH TYPE	
Interval Treated	Materials and Amount Used	Log Types	Logged Intervals
856' - 975.5'	182 sks sand - 156 bbl H2O - 228 MSCF N2	GRay - Caliper - Density - Devia	Surface to 2004'
1203' - 1420'	299 sks sand - 203 bbl H2O - 288 MSCF N2	GRay - Caliper - Density - Devia	Surface to 2004'
1599' - 1803.5'	400 sks sand - 265 bbl H2O - 402 MSCF N2	GRay - Caliper - Density - Devia	Surface to 2004'
* VA uses State	Plane Coordinates or Lat/Long not Sec/Twp/Ran	DD-7A Latitude 37_08' 13"	Longitude 82 04' 55"

Complete Attachments A -- E listed on the reverse.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, Sr. Petroleum Engineer	Edward K Diminick	04 27 2015

EPA Form 7520-10 (Rev. 12-11)

ATTACHMENTS for COMPLETION REPORT 7520-10

DD-7A Well

A. See attached schematics of surface and subsurface as built well.
B. Previously submitted to Steve Platt on 4/20/15.
C. In Buchanan County, Virginia, fresh water typically occurs less than 300 feet deep according to EPA 816-R-04-003 report. Underground sources of drinking water could potentially be found from surface to the Pennsylvanian-aged Jawbone seam which occurs at 393 feet in this well. Attached is a resistivity log of the surface hole in the C-1 characterization well drilled in March 2015. The C-1 well is offset to the northeast from the three injection wells and also within the Area of Review. The Jawbone is at 378 feet and 401 feet on this log. The freshest water occurs from 30 feet to 75 feet and again at 126 feet to 160 feet. From the Jawbone to 580 feet, the resistivity trends slightly lower indicating water is becoming more saline.

   Additionally, a water sample analysis is attached that shows water produced from 856 feet and deeper has extremely high total dissolved solids and is not potable.

   The confining zones are identified on the attached cross section of the injection wells. There are three shale zones and the basal Lee sandstone. The Hensley Shale Member is the most significant shale confining zone. A paper titled Seal Evaluation and Confinement Screening Criteria for Beneficial Carbon Dioxide Storage with Enhanced Coal Bed Methane Recovery in the Pocahontas Basin, Virginia is attached that discusses the confining properties in detail.

   The cross section also identifies the injection formations with asterisks and the adjacent formations.

D. There are no defective wells in the area of review.
E. A final print of the geophysical log is attached.

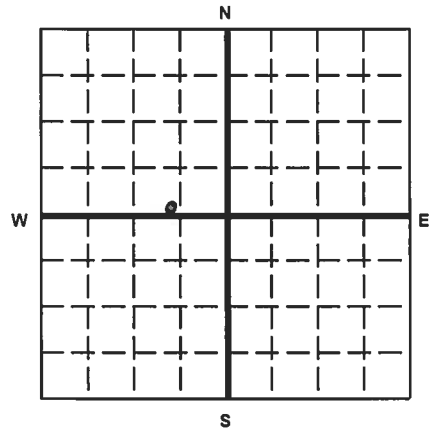
OMB No. 2040-0042 Approval Expires 11/30/2014

United States Environmental Protection Agency
Washington, DC 20460

COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY

Name and Address of Existing Permittee	Name and Address of Surface Owner
Cardno MM&A - 200 East Main Street, Suite 301, Kingsport, TN 37660	Landon Wyatt P.O. Box 11000, Danville, VA 24543

Locate Well and Outline Unit on Section Plat - [redacted] Acres = 80



State	County	Permit Number
Virginia	Buchanan	4824-02

Surface Location Description

* 1/4 of [ ] 1/4 of [ ] 1/4 of [ ] 1/4 of Section [ ] Township [ ] Range [ ]

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location * ft. frm (N/S) [ ] line of quarter section
and * ft. from (E/W) [ ] Line of quarter section.

WELL ACTIVITY	TYPE OF PERMIT	
☐ Brine Disposal	☐ Individual	Estimated Fracture Pressure of Injection Zone
☑ Enhanced Recovery	☑ Area	2486 psig
☐ Hydrocarbon Storage	Number of Wells 3	

Anticipated Daily Injection Volume (Bbls)		Injection Interval	
Average	Maximum	Feet	to Feet
124	309	871	1802

Anticipated Daily Injection Pressure (PSI)		Depth to Bottom of Lowermost Freshwater Formation (Feet)
Average	Maximum	
556	1153	219

Type of Injection Fluid *(Check the appropriate block(s))*

☐ Salt Water ☐ Brackish Water ☐ Fresh Water ☐ Liquid Hydrocarbon ☑ Other

Lease Name	Well Number
Landon Wyatt, Jr, et al Big Axe	DD-8

Name of Injection Zone: Lee and Pocahontas Formations of Pennsylvania-aged coals

Date Drilling Began	Date Well Completed
02/14/2001	03/05/2001

Permeability of Injection Zone: 0.1 mD - 20 mD

Date Drilling Completed: 02/15/2001

Porosity of Injection Zone: 0.5% - 1%

CASING AND TUBING			CEMENT		HOLE	
OD Size	Wt/Ft - Grade - New or Used	Depth	Sacks	Class	Depth	Bit Diameter
12-3/4"	33 lb/ft-L/S ERW- New	21'	N/A	N/A	21'	15"
7"	17 lb/ft - AT50 - New	223'	60	A	223'	8-7/8"
4-1/2"	9.5 lb/ft - J55 - New	1822'	220	A	1822'	6-1/2"
2-3/8"	4.7 lb/ft - J55 - New	780'	N/A	N/A	N/A	N/A

INJECTION ZONE STIMULATION		WIRE LINE LOGS, LIST EACH TYPE	
Interval Treated	Materials and Amount Used	Log Types	Logged Intervals
871' - 1205'	402 sks sand - 253 bbl H2O - 321 MSCF N2	GR-Caliper-Density-Temp-Dev	205' to 1867'
1311' -1677.5'	412 sks sand - 268 bbl H2O - 441 MSCF N2	GR-Caliper-Density-Temp-Dev	205' to 1867'
1710.5' - 1802'	300 sks sand - 211 bbl H2O - 365 MSCF N2	GR-Caliper-Density-Temp-Dev	205' to 1867'
* VA uses State	Plane Coordinates or Lat/Long not Sec/Twp/Ran	DD-8 Latitude 37 08' 19"	Longitude 82 04' 40"

Complete Attachments A -- E listed on the reverse.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, Sr. Petroleum Engineer	Edward K. Diminick	04/27/2015

EPA Form 7520-10 (Rev. 12-11)

ATTACHMENTS for COMPLETION REPORT 7520-10

DD-8 Well

A. See attached schematics of surface and subsurface as built well.
B. Previously submitted to Steve Platt on 4/20/15.
C. In Buchanan County, Virginia, fresh water typically occurs less than 300 feet deep according to EPA 816-R-04-003 report. Underground sources of drinking water could potentially be found from surface to the Pennsylvanian-aged Jawbone seam which occurs at 401 feet in this well. Attached is a resistivity log of the surface hole in the C-1 characterization well drilled in March 2015. The C-1 well is offset to the northeast from the three injection wells and also within the Area of Review. The Jawbone is at 378 feet and 401 feet on this log. The freshest water occurs from 30 feet to 75 feet and again at 126 feet to 160 feet. From the Jawbone to 580 feet, the resistivity trends slightly lower indicating water is becoming more saline.

   Additionally, a water sample analysis is attached that shows water produced from 871 feet and deeper has extremely high total dissolved solids and is not potable.

   The confining zones are identified on the attached cross section of the injection wells. There are three shale zones and the basal Lee sandstone. The Hensley Shale Member is the most significant shale confining zone. A paper titled Seal Evaluation and Confinement Screening Criteria for Beneficial Carbon Dioxide Storage with Enhanced Coal Bed Methane Recovery in the Pocahontas Basin, Virginia is attached that discusses the confining properties in detail.

   The cross section also identifies the injection formations with asterisks and the adjacent formations.

D. There are no defective wells in the area of review.
E. A final print of the geophysical log is attached.

OMB No. 2040-0042 Approval Expires 11/30/2014

United States Environmental Protection Agency

Underground Injection Control Permit Application

(Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, 40 CFR 144)

I. EPA ID Number		T/A	C
U			

Read Attached Instructions Before Starting

For Official Use Only

Application approved mo day year	Date received mo day year	Permit Number	Well ID	FINDS Number

II. Owner Name and Address

Owner Name: CNX Gas Company, LLC

Street Address: 627 Claypool Hill Mall Road

Phone Number: (276) 596-5000

City: Cedar Bluff | State: VA | ZIP CODE: 24609

III. Operator Name and Address

Owner Name: Cardno MM&A

Street Address: 10376 Wallace Alley Street

Phone Number: (423) 279-9775

City: Kingsport | State: TN | ZIP CODE: 37663

IV. Commercial Facility

- [ ] Yes
- [x] No

V. Ownership

- [x] Private
- [ ] Federal
- [ ] Other

VI. Legal Contact

- [ ] Owner
- [x] Operator

VII. SIC Codes

1311

VIII. Well Status *(Mark "x")*

- [ ] A. Operating — Date Started mo day year:
- [ ] B. Modification/Conversion
- [x] C. Proposed

IX. Type of Permit Requested *(Mark "x" and specify if required)*

- [ ] A. Individual
- [x] B. Area

Number of Existing Wells	Number of Proposed Wells	Name(s) of field(s) or project(s)
0	3 Wells: DD-7, DD-7A, DD-8	Oakwood CBM Field

X. Class and Type of Well *(see reverse)*

A. Class(es) (enter code(s))	B. Type(s) (enter code(s))	C. If class is "other" or type is code 'x,' explain	D. Number of wells per type (if area permit)
II	R		3

XI. Location of Well(s) or Approximate Center of Field or Project

Latitude Deg	Min	Sec	Longitude Deg	Min	Sec	Township and Range Sec	Twp	Range	1/4 Sec	Feet From	Line	Feet From	Line
37	10	00	82	02	30								

XII. Indian Lands (Mark 'x')

- [ ] Yes
- [x] No

XIII. Attachments

(Complete the following questions on a separate sheet(s) and number accordingly; see instructions)

For Classes I, II, III, (and other classes) complete and submit on a separate sheet(s) Attachments A--U (pp 2-6) as appropriate. Attach maps where required. List attachments by letter which are applicable and are included with your application.

XIV. Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

A. Name and Title *(Type or Print)*	B. Phone No. *(Area Code and No.)*
Edward K. Diminick, Senior Petroleum Engineer	(423) 279-9775
C. Signature: Edward K Diminick	D. Date Signed: 2/22/13

EPA Form 7520-6 (Rev. 12-11)

Well Class and Type Codes

Class I Wells used to inject waste below the deepest underground source of drinking water.

Type "I" Nonhazardous industrial disposal well
"M" Nonhazardous municipal disposal well
"W" Hazardous waste disposal well injecting below USDWs
"X" Other Class I wells (not included in Type "I," "M," or "W")

Class II Oil and gas production and storage related injection wells.

Type "D" Produced fluid disposal well
"R" Enhanced recovery well
"H" Hydrocarbon storage well (excluding natural gas)
"X" Other Class II wells (not included in Type "D," "R," or "H")

Class III Special process injection wells.

Type "G" Solution mining well
"S" Sulfur mining well by Frasch process
"U" Uranium mining well (excluding solution mining of conventional mines)
"X" Other Class III wells (not included in Type "G," "S," or "U")

Other Classes Wells not included in classes above.
Class V wells which may be permitted under §144.12.
Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	Attachments
I new well	A, B, C, D, F, H – S, U
existing	A, B, C, D, F, H – U
II new well	A, B, C, E, G, H, M, Q, R; optional – I, J, K, O, P, U
existing	A, E, G, H, M, Q, R, – U; optional – J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M – S, U
existing	A, B, C, D, F, H, J, K, M – U
Other Classes	To be specified by the permitting authority

INSTRUCTIONS - Underground Injection Control (UIC) Permit Application

Paperwork Reduction Act: The public reporting and record keeping burden for this collection of information is estimated to average 224 hours for a Class I hazardous well application, 110 hours for a Class I non-hazardous well application, 67 hours for a Class II well application, and 132 hours for a Class III well application. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, DC 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

This form must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for permit by the Director.

I. **EPA I.D. NUMBER** - Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. **OWNER NAME AND ADDRESS** - Name of well, well field or company and address.

III. **OPERATOR NAME AND ADDRESS** - Name and address of operator of well or well field.

IV. **COMMERCIAL FACILITY** - Mark the appropriate box to indicate the type of facility.

V. **OWNERSHIP** - Mark the appropriate box to indicate the type of ownership.

VI. **LEGAL CONTACT** - Mark the appropriate box.

VII. **SIC CODES** - List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VIII. **WELL STATUS** - Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if wells(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

IX. **TYPE OF PERMIT** - Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

X. **CLASS AND TYPE OF WELL** - Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of the application. When selecting type X please explain in the space provided.

XI. **LOCATION OF WELL** - Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR Part 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

XII. **INDIAN LANDS** - Place an "X" in the box if any part of the facility is located on Indian lands.

XIII. **ATTACHMENTS** - Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page of the Attachments.

XIV. **CERTIFICATION** - All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

INSTRUCTIONS - Attachments

Attachments to be submitted with permit application for Class I, II, III and other wells.

A. **AREA OF REVIEW METHODS** - Give the methods and, if appropriate, the calculationsused to determine the size of the area of review (fixed radius or equation).The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.

B. **MAPS OF WELL/AREA AND AREA OF REVIEW** - Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (ifapplicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, anddrinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells;

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. **CORRECTIVE ACTION PLAN AND WELL DATA** - Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

Class I

A description of each well's types, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include thecorrective action proposed to be taken by the applicant under 40 CFR 144.55.

Class II

In addition to requirement for Class I, in the case of Class II wellsoperating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. **MAPS AND CROSS SECTION OF USDWs** - Submit maps and cross sections indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. **NAME AND DEPTH OF USDWs (CLASS II)** - For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. **MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA** - Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells.)

G. **GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II)** - For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. **OPERATING DATA** - Submit the following proposed operating data for each well (including all those to be covered by area permits): (1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure; (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. **FORMATION TESTING PROGRAM** - Describe the proposed formation testing program For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the testing must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the program formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. **STIMULATION PROGRAM** - Outline any proposed stimulation program.

K. **INJECTION PROCEDURES** - Describe the proposed injection procedures including pump, surge, tank, etc.

L. **CONSTRUCTION PROCEDURES** - Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to packer for Class I.)

M. **CONSTRUCTION DETAILS** - Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. **CHANGES IN INJECTED FLUID** - Discuss expected changes in pressure, native fluid displacement, and direction of movement of injection fluid. (Class III wells only.)

O. **PLANS FOR WELL FAILURES** - Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or wells failures, so as to prevent migration of fluids into any USDW.

P. **MONITORING PROGRAM** - Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. **PLUGGING AND ABANDONMENT PLAN** - Submit a plan for plugging and abandonment of the well including: (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used; (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

R. **NECESSARY RESOURCES** - Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. **AQUIFER EXEMPTIONS** - If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon production, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR Sections 144.7 and 146.04.

T. **EXISTING EPA PERMITS** - List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc.

U. **DESCRIPTION OF BUSINESS** - Give a brief description of the nature of the business.

Class II
Underground Injection Control
Permit Application
Buchanan County, VA

XIII. Attachments

A. Area of Review Methods

The three proposed injection wells requested for conversion from existing coal bed methane (***CBM***) gas production wells in this permit are located in the Hurricane District of Buchanan County in southwest Virginia.

The area of review was determined by drawing a fixed radius of ¼ mile from each of the three CBM gas wells that will be converted to injection wells.

The owners of record of land within the area of review are listed below.

1. Woodrow Presley
   1134 Shady Rest Rd
   Vansant, VA 24656

2. Landon Wyatt
   PO Box 11000
   Danville, VA 24543

3. Bernice Breeding et al.
   a. Bernice N. Breeding
      3779B Mount Vernon
      Mount Vernon, GA 30445
   b. Keithal Breeding
      4622 Hurricane Creek Road
      Vansant, VA 24656

4. Ines Ball
   RT 1 Box 188
   Vansant, VA 24656

6. Beulah Lockhart
   1304 Roy Ball Hollow Road
   Vansant, VA 24656

7. John Brown
   PO Box 149
   Midway, WV 25878

5. William, Rice Jr. et al.
   a. William H. Rice Jr.
      19861 Youngs Cliff Rd.
      Sterling, VA 20165
   b. Rick Compton
      64545 E. Belfrys Ct. East
      Bealeton, VA 22712
   c. Rita Talbert
      171 Van Horn Lane
      Stafford, VA 22554
   d. Linda Edwards
      118 Charlton Rd.
      Winchester, VA 22602
   e. Anita Benson
      158 Millstone Dr.
      Verona, VA 24482
   f. Michael Boyd
      775 Kenneth Place SE
      Leesburg, VA 20175
   g. Jim Corona
      46 Essex Square
      Sterling, VA 20165
   h. Jack Lester
      44453 Whiteford Square #201
      Ashburn, VA 20147
   i. Charlotte Marpoe
      138 Louise Ave.
      Wewahitchka, FL 32465

B. Maps of Well/Area and Area of Review

See attached *Map 1*.

C. Corrective Action Plan and Well Data

Three existing wells which are currently being operated as CBM production wells will be converted to CO_2 injection wells. All known wells within the injection wells' area of review which penetrate the injection zones are identified below and on the map in *Section B*. The CO_2 injection pressures will be lower than the fracture pressures of the injection formations. All wells located within the area of review have 7" casing set below the fresh water zone and four of the five are cemented from their setting depth to the surface. All wells also have 4½" casing set well below the underground sources of drinking water. Each of these casing strings is cemented to the surface providing protection to prevent movement of fluid into underground sources of drinking water ("corrective action").

Three new monitoring wells will also be drilled before injection begins. Each well will have casing set below all possible underground sources of drinking water, and the casing will be cemented to surface.

Wells located within Area of Review

Well Name	DD-7
Virginia Permit Number	4707
Virginia File Number	BU-1923
Well Type	CBM Production – This will be converted to an injection well.
Construction	Cased hole - cemented to surface
Location	Latitude 37° 10' 00" Longitude 82° 05' 00"
Date Drilled	11/1/2000
Depth	2319'
Date Completed/Stimulation	11/4/2000 4 stage foam fracture
Perforations/Fracture Pressure	1997'-2133'/1589 psig, 1674'-1866'/2433 psig, 1531'-1570'/3111 psig, 1216'-1385'/2897 psig
Conductor Casing	12¾" set at 15' – 2 cu. ft. of cement to surface
Surface Casing	7" set at 846' – 77 cu. ft. of cement and 69 cu. ft. of gel to surface
Production Casing	4½" casing set at 2182' – 372 cu. ft. of cement to surface
Electric Logs	Caliper, Gamma Ray, Density, and Temperature Deviation
Deviation Survey	Bottom hole location 0.62° from true vertical

Well Name	DD-7A
Virginia Permit Number	7787
Virginia File Number	BU-3337
Well Type	CBM Production – This will be converted to an injection well.
Construction	Cased hole - cemented to surface
Location	Latitude 37° 10' 00" Longitude 82° 02' 30"
Date Drilled	1/24/2007
Depth	2000'
Date Completed/Stimulation	2/20/2007 3 stage foam fracture
Perforations/Fracture Pressure	1599'-1803.5'/2245 psig, 1203'-1420'/1650 psig, 856'-975.5'/3191 psig
Conductor Casing	13⅜" set at 20' – not cemented
Surface Casing	7" set at 253' – 71 cu. ft. of cement to surface
Production Casing	4½" casing set at 1807' – 279 cu. ft. of cement to surface
Electric Logs	Caliper, Gamma Ray, Density, and Temperature Deviation
Deviation Survey	Bottom hole location 0.65° from true vertical

Well Name	DD-8
Virginia Permit Number	4824
Virginia File Number	BU-1998
Well Type	CBM Production – This will be converted to an injection well.
Construction	Cased hole - cemented to surface
Location	Latitude 37° 10' 00" Longitude 82° 02' 30"
Date Drilled	2/15/2001
Depth	1868'
Date Completed/Stimulation	3/15/2001 3 stage foam fracture
Perforations/Fracture Pressure	1710.5'-1802'/3197 psig, 1311'-1677.5'/3117 psig, 871'-1205'/2374 psig
Conductor Casing	12¾" set at 21' – cemented to surface
Surface Casing	7" set at 223' – 71 cu. ft. of cement to surface
Production Casing	4½" casing set at 1822' – 262 cu. ft. of cement to surface
Electric Logs	Caliper, Gamma Ray, Density, and Temperature Deviation
Deviation Survey	Bottom hole location 0.55° from true vertical

Well Name	DD-8A
Virginia Permit Number	9523
Virginia File Number	BU-3929
Well Type	CBM Production – This well will be used for monitoring.
Construction	Cased hole - cemented to surface
Location	Latitude 37° 10' 00" Longitude 82° 02' 30"
Date Drilled	8/21/2008
Depth	1880'
Date Completed/Stimulation	9/8/2008 3 stage foam fracture
Perforations/Fracture Pressure	1269'-1589'/2504 psig, 1013'-1155'/1562 psig, 718'-840'/2465 psig
Conductor Casing	13⅜" set at 20' – not cemented
Surface Casing	7" set at 309' – 71 cu. ft. of cement to surface
Production Casing	4½" casing set at 1634' – 287 cu. ft. of cement to surface
Electric Logs	Caliper, Gamma Ray, Density, and Temperature Deviation
Deviation Survey	Bottom hole location 1.01° from true vertical

Well Name	EE-8
Virginia Permit Number	4917
Virginia File Number	BU-2072
Well Type	CBM Production – This well will be used for monitoring.
Construction	Cased hole - cemented to surface
Location	Latitude 37° 10' 00" Longitude 82° 02' 30"
Date Drilled	6/8/2001
Depth	2202'
Date Completed/Stimulation	6/22/2001 3 stage foam fracture
Perforations/Fracture Pressure	1216'-1222'/2917 psig, 914'-1145'/3542 psig, 789'-821'/2011 psig
Conductor Casing	12¾" set at 19' – 2 cu. ft. of cement to surface
Surface Casing	7" set at 222' – 71 cu. ft. of cement to surface
Production Casing	4½" casing set at 2115' – 313 cu. ft. of cement to surface
Electric Logs	Caliper, Gamma Ray, Density, and Temperature Deviation
Deviation Survey	Bottom hole location 1.04° from true vertical

D. Maps and Cross Section of USDWs

This section does not apply to Class II wells.

E. Name and Depth of USDWs (Class II)

Water wells in Buchanan County, Virginia are typically 50 to 200 feet deep with fresh water typically occurring less than 300 feet deep according to EPA 816-R-04-003 report. The USDWs are anticipated to occur in sandstone, siltstone, and coal seam lithologies from the surface to the Pennsylvanian-aged Jawbone seam of the Norton Formation which occurs at a depth of 250 feet or greater.

F. Maps and Cross Sections of Geologic Structure of Area

This section does not apply to Class II wells.

G. Geological Data on Injection and Confining Zones (Class II)

G.1 Geologic Description of Injection Zones

The proposed injection zones identified in CBM wells DD-7, DD-7A, and DD-8 consist of several medium to low volatile bituminous coalbeds occurring in the Pennsylvanian-aged Lee and Pocahontas Formations. Coal depths for the proposed injection seams range from 856 feet (Seaboard seam in well DD-7A) to 2,133 feet (Pocahontas No. 3 seam in well DD-7). Surface breakdown pressures for the completed seams were recorded while hydraulically stimulating DD-7, DD-7A, and DD-8 and range from 1589 psig to 3197 psig.

The project technical team developed a structural cross section trending through the three proposed injection wells and two adjacent CBM production wells proposed to be used as monitoring wells (see *Exhibit 1*). The Norton, Lee and Pocahontas Formation coals have been correlated across the injection site area using seam nomenclature and coal thickness data which was provided by CNX Gas, LLC, a key project partner and owner of the wells. The completed coal seams proposed for injection are delineated with red asterisks on *Exhibit 1*.

Coal thicknesses of the proposed injection seams range from 0.4 to 2.5 feet and average approximately 1.1 feet per seam. Porosities of the coal seams are expected to range from 0.5 to 1.0 percent. Coal permeability is anticipated to range from 0.1 to 20.0 millidarcies (md) based on regional coal permeability values and reservoir modeling results. The Lee and Pocahontas Formation coals are expected to have moderately developed face and butt cleats and exhibit induced fractures due to hydraulic stimulation of the CBM wells.

G.2 Geologic Description of Confining Zones

The confining zones delineated in the proposed injection wells DD-7, DD-7A, and DD-8 include rocks comprising the Pennsylvanian-aged Norton, Lee, and Pocahontas Formations. The confining zones are comprised of low-permeability shale, siltstone, and sandstone. Regional stratigraphic cross sections and geologic mapping demonstrate that these confining zones are laterally extensive in Buchanan County, Virginia.

Three primary shale confining units (green shaded horizons on *Exhibit 1*), including the Hensley Shale, have been correlated and results show that these units can provide adequate seals for the injected CO_2. The average thicknesses of Confining Units 1, 2, and 3 (Hensley Shale) in CBM wells DD-7, DD-7A, and DD-8 are 34, 57, and 70 feet, respectively. The expected permeability of these shale confining units is expected to range from 0.001 to 0.1 md with corresponding very low porosity. All of these low-permeability shale units occur stratigraphically above the proposed coal seam injection zones, and below the anticipated deepest fresh water zone (lowermost USDW).

The tightly-cemented basal Lee Sandstone unit (orange shaded horizon on *Exhibit 1*) has also been correlated and provides an additional seal for CO_2 injected and residing in the Pocahontas Formation coals. These quartz-rich sandstones average approximately 172 feet thick in CBM wells DD-7, DD-7A, and DD-8 and have only minor porosity with low permeability. Regionally, the measured porosity values for this sandstone range from 0.1 to 5.0 percent and the permeability values range from 0.0014 to 0.0420 md (Grimm et al, 2011). Locally, the porosity development and permeability in these sandstones are reduced by diverse cementation types and compaction.

H. Operating Data

Operating Data	DD-7	DD-7A	DD-8
Average injection rate (tonnes*/day)	20	20	20
Maximum injection rate (tonnes/day)	50	50	50
CO_2 volume to be injected (tonnes)	3,000-10,000	3,000-10,000	3,000-10,000
Average injection pressure (psia)	1,000	1,000	1,000
Maximum injection pressure (psia)	1,445	1,500	2,150
Nature of annulus fluid	Air	Air	Air
CO_2 source	Commercial Supplier	Commercial Supplier	Commercial Supplier
CO_2 analysis	See *Exhibit 2***	See *Exhibit 2***	See *Exhibit 2***

* tonnes = metric tons

** A contract with a CO_2 supplier has not yet been completed and is pending. The CO_2 analyses prepared by Airborne Labs International, Inc. are considered representative of the injectate, and were provided by a potential supplier, Airgas Carbonic, from its Hopewell, Virginia and Augusta, Georgia facilities.

Exhibit 2

Airborne Labs International, Inc.

22C World's Fair Drive Somerset, NJ 08873 Voice: 732-302-1950 Fax: 732-302-3035
Email: airbornelabs@aol.com Website: www.airbornelabs.com

Carbon Dioxide (CO_2) Analysis
ISBT *No-Haz* Beverage-Grade Program©

Airgas Carbonic
103 Industrial Ave.
Hopewell, VA 23860
Phone: 804-458-9754 ext 21/C: 804-641-9236, (Fax: 804-458-9756)
Attn.: Mr. Bruce Worsham, Mr. Matt Erwin and Mr. Roger Weber
E-Mail: bruce.worsham@airgas.com; matt.erwin@airgas.com ; roger.weber@airgas.com;

ALI Track No.: 12-0966
Received On: 10/05/12
Report Date: 10/10/12
Payment Mode: PO/CC/Wire
Sample Date: 10/03/12

Sample ID.: Vaporized Liquid CO_2 / Gaseous CO_2: "PTS 4th QTR Finished Prod; PTS Sample Connection in QA Lab"
Sample ID.: Received in 2L *True Blue* MLB Polybag 1.2 + MiniCyl 1.0 + NVR 8.0 *No-Haz* Kits
Process Stage: Final

Test Description/Units:	Result	LOQ	ISBT Limit
CO_2 Identification (Positive/ Negative by USP [DT]):	positive	5	positive
Comments: Positive ID = Positive Detector Tube Response.			
CO_2 Purity (% v/v, ISBT 2.0 [GC/DID]):	99.99+	5	99.9 min
Comments: Obtained by NCG subtraction method using Minicyl sample			
Water Vapor (H_2O, ppm v/v, ISBT 3.0 [FTIR]):	--	1	20 max
Oxygen (O_2, ppm v/v, ISBT 4.0 [GC/DID]):	1.3	1	30 max
Comments: Result represents Total O_2 + Ar ppm v/v.			
Nitrogen (N_2, ppm v/v, ISBT 4.0 [GC/DID]):	3.1	1	na
Carbon Monoxide (CO, ppm v/v, ISBT 5.0 [GC/DID]):	nd	1	10 max
Ammonia (NH_3, ppm v/v, ISBT 6.0 [DT]):	nd	0.5	2.5 max
Oxides of Nitrogen (NO_x, ppm v/v, ISBT 7.0 [DT]):	nd	0.5	5 max*
Comments: *Speciation required if above 2.5 ppm v/v. Maximum 2.5 ppm of either or both NO & NO_2			
Nitric Oxide (NO, ppm v/v, ISBT 7.1 [DT]):	nd	0.5	2.5 max
Nitrogen Dioxide (NO_2, ppm v/v, ISBT 7.2 [DT]):	nd	0.5	2.5 max
Non-Volatile Residue (NVR, ppm w/w, ISBT 8.0 [Grav]):	nd	2	10 max
Comments: No visible matter observed.			
Non-Volatile Organic Residue (NVOR, ppm w/w, ISBT 8.0 [Grav]):	nd	2	5 max
Comments: No NVOR film observed.			
Phosphine (PH_3, ppm v/v, ISBT SM 3.0 [DT]):	nd	0.25	0.3 max
Comments:			
Total Hydrocarbons (THC, ppm v/v as CH_4, ISBT 10.0):			
Flash Vaporized Liquid Phase:	0.7	0.1	50 max
Total Non-Methane Hydrocarbons (TNMHC, ppm v/v as CH_4, ISBT 10.1):	0.2	0.1	20 max
Methane (CH_4, ppm v/v, ISBT 10.1 [GC]):	0.5	0.1	50 (see THC)
Methanol (MeOH, ppm v/v, ISBT 9.0 [GC]):	nd	0.1	10 (see THC)
Acetaldehyde (AA, ppm v/v, ISBT 11.0 [GC]):	nd	0.05	0.2 max
Total Other Volatile Oxygenates (TOVO, ppm v/v, ISBT 11.0 [GC]):	trace	0.1	na
Comments: Obtained by summation of all speciated VOX target impurities less AA, MeOH & EtOH			
Aromatic Hydrocarbon Content (ppb v/v as Benzene, ISBT 12.0 [GC]):	nd	2	20 max
Comments: Benzene = nd, Toluene = nd, Ethyl Benzene = nd, omp Xylenes = nd			
Total Sulfur Content* (TSC* ppm v/v as S, ISBT 14.0):	nd	0.01	0.1 max
Comments: Obtained by summation of all speciated VSC target impurities less SO_2			
Sulfur Dioxide (SO_2, ppm v/v, ISBT 14.0 [GC]):	nd	0.05	1 max
Sensory Tests			
Appearance in Water (Pass/Fail, ISBT 16.0):	pass	na	clear
Odor & Taste in Water (Pass/Fail, ISBT 16.0):	pass	na	none
Comments:			
Supplemental Tests			
Hydrogen Cyanide (HCN, ppm v/v by ISBT SM-1.0 [GC]):	nd	0.2	nd
Vinyl Chloride (VCl, ppm v/v by ISBT SM-2.0 [GC]):	nd	0.1	nd
Ethylene Oxide (ETO, ppm v/v by ISBT 11.0 [GC]):	nd	0.1	nd

Sample ID: Airgas Carbonic

ALI Track No.: 12-0966

Speciated Volatile Hydrocarbons (VHC, ppm v/v by ISBT 10.1)	Result	LOQ	ISBT Limit
Ethane:	nd	0.1	see THC
Ethylene:	nd	0.1	see THC
Propane:	nd	0.1	see THC
Propylene:	nd	0.1	see THC
Isobutane:	nd	0.1	see THC
n-Butane:	nd	0.1	see THC
Butene:	nd	0.1	see THC
Isopentane:	nd	0.1	see THC
n-Pentane:	nd	0.1	see THC
Hexanes+:	trace	0.1	see THC

Comments: *C_6+ results include VOX compounds and C_6+ alkanes/alkene hcs. Pk ID based upon tr match vs target analyte std. CH_4 result on pg 1.

Speciated Volatile Sulfur Compounds (VSC, ppm v/v by ISBT 14.0)			
Hydrogen Sulfide (H_2S):	nd	0.01	see TSC
Carbonyl Sulfide (COS):	nd	0.01	see TSC
Methyl Mercaptan:	nd	0.01	see TSC
Ethyl Mercaptan:	nd	0.01	see TSC
Dimethyl Sulfide:	nd	0.01	see TSC
Carbon Disulfide:	nd	0.01	see TSC
t-Butyl Mercaptan:	nd	0.01	see TSC
Isopropyl Mercaptan:	nd	0.01	see TSC
n-Propyl Mercaptan:	nd	0.01	see TSC
Methyl Ethyl Sulfide:	nd	0.01	see TSC
2-Butyl Mercaptan:	nd	0.01	see TSC
i-Butyl Mercaptan:	nd	0.01	see TSC
Diethyl Sulfide:	nd	0.01	see TSC
n-Butyl Mercaptan:	nd	0.01	see TSC
Dimethyl Disulfide:	nd	0.01	see TSC
Unknown VSC:	nd	0.01	see TSC

Comments: Peak ID based upon t$_r$ match against target analyte standards. Note: SO_2 + TSC* results reported on pg. 1.

Speciated Volatile Oxygenates (VOX, ppm v/v, by ISBT 11.0)			
Dimethyl Ether:	nd	0.1	see THC
Diethyl Ether:	trace	0.1	see THC
Propionaldehyde:	nd	0.1	see THC
Acetone:	nd	0.1	see THC
t-Butanol:	nd	0.1	see THC
Ethanol:	nd	0.1	see THC
Isopropanol:	nd	0.1	see THC
Ethyl Acetate:	nd	0.1	see THC
Methyl Ethyl Ketone:	nd	0.1	see THC
2-Butanol:	nd	0.1	see THC
n-Propanol:	nd	0.1	see THC
Isobutanol:	nd	0.1	see THC
n-Butanol:	nd	0.1	see THC
Isoamyl Acetate:	nd	0.1	see THC
Isoamyl Alcohol:	nd	0.1	see THC
Unknown VOX:	nd	0.1	see THC

Comments: Peak ID based upon t$_r$ match against target analyte standards. AA and ETO results reported on pg. 1.

LOQ = Limit of Quantitation (lowest amount of analyte quantitatively determined with suitable precision and accuracy) MDL = method detection limit (lowest amount of analyte detected). trace = unquantified amount observed between MDL and LOQ. nd = indicates the impurity was not detected (below MDL). -- = test not performed. na = not available. LT = less than the amount specified. GT = greater than the amount specified. % = percent. ppm = parts per million. ppb = parts per billion. v/v = volume analyte/volume sample. w/w = weight analyte/weight sample. [result] indicates the result was obtained by the method listed within brackets. TSC* = ISBT Total Sulfur Content exluding SO_2. Unit Conversions: 1ppm v/v = 1µL/L = 1000 ppb = 0.0001% v/v. Date format: MM/DD/YY.

Report Summary:

Customer request for a std ISBT No-Haz LCO_2 test pgm.

This sample meets all ISBT purity criteria for bev-grade LCO_2.

Reviewed by / Date:

Nicole James 10/10/12

Nicole James - Laboratory Manager

Attachments: none
Addendum: Signatures, Instrument & Notebook data on-file
Measurement Uncertainty available upon request
F-21.7v3 (8/12)

Accreditation # 68099

Airborne Labs International, Inc.

22C World's Fair Drive Somerset, NJ 08873 Voice: 732-302-1950 Fax: 732-302-3035
Email: airbornelabs@aol.com Website: www.airbornelabs.com

Carbon Dioxide (CO_2) Analysis

ISBT *No-Haz* Beverage-Grade Program©

AC Industries
727 Laney Walker Boulevard Ext.
Augusta, GA 30901
Phone: 706-724-2900 (Fax: 706-724-7799)
Attn.: Mr. Clay Carter, Mr. Bill Alexander and Mr. Matt Erwin
E-Mail: clay.carter@airgas.com; matt.erwin@airgas.com; aci.liquid@airgas.com
Sample ID.: Vaporized Liquid CO_2 / Gaseous CO_2: "Product to Storage"
Sample ID.: Received in 2L *True Blue* MLB Polybag 1.2 + MiniCyl 1.0 + NVR 8.0 *No-Haz* Kits

ALI Track No.: 12-1171
Received On: 12/17/12
Report Date: 12/19/12
Payment Mode: PO/CC/Wire

Sample Date: 12/13/12
Process Stage: Final

Test Description/Units:	Result	LOQ	ISBT Limit
CO_2 Identification (Positive/ Negative by USP [DT]):	positive	5	positive
Comments: Positive ID = Positive Detector Tube Response.			
CO_2 Purity (% v/v, ISBT 2.0 [GC/DID]):	99.99+	5	99.9 min
Comments: Obtained by NCG subtraction method using Minicyl sample			
Water Vapor (H_2O, ppm v/v, ISBT 3.0 [FTIR]):	--	1	20 max
Oxygen (O_2, ppm v/v, ISBT 4.0 [GC/DID]):	trace	1	30 max
Comments: Result represents Total O_2 + Ar ppm v/v.			
Nitrogen (N_2, ppm v/v, ISBT 4.0 [GC/DID]):	2.2	1	na
Carbon Monoxide (CO, ppm v/v, ISBT 5.0 [GC/DID]):	nd	1	10 max
Ammonia (NH_3, ppm v/v, ISBT 6.0 [DT]):	nd	0.5	2.5 max
Oxides of Nitrogen (NO_x, ppm v/v, ISBT 7.0 [DT]):	nd	0.5	5 max*
Comments: *Speciation required if above 2.5 ppm v/v. Maximum 2.5 ppm of either or both NO & NO_2			
Nitric Oxide (NO, ppm v/v, ISBT 7.1 [DT]):	nd	0.5	2.5 max
Nitrogen Dioxide (NO_2, ppm v/v, ISBT 7.2 [DT]):	nd	0.5	2.5 max
Non-Volatile Residue (NVR, ppm w/w, ISBT 8.0 [Grav]):	nd	2	10 max
Comments: No visible matter observed.			
Non-Volatile Organic Residue (NVOR, ppm w/w, ISBT 8.0 [Grav]):	nd	2	5 max
Comments: No NVOR film observed.			
Phosphine (PH_3, ppm v/v, ISBT SM 3.0 [DT]):	nd	0.25	0.3 max
Comments:			
Total Hydrocarbons (THC, ppm v/v as CH_4, ISBT 10.0):			
Flash Vaporized Liquid Phase:	0.9	0.1	50 max
Total Non-Methane Hydrocarbons (TNMHC, ppm v/v as CH_4, ISBT 10.1):	nd	0.1	20 max
Methane (CH_4, ppm v/v, ISBT 10.1 [GC]):	0.9	0.1	50 (see THC)
Methanol (MeOH, ppm v/v, ISBT 9.0 [GC]):	nd	0.1	10 (see THC)
Acetaldehyde (AA, ppm v/v, ISBT 11.0 [GC]):	nd	0.05	0.2 max
Total Other Volatile Oxygenates (TOVO, ppm v/v, ISBT 11.0 [GC]):	nd	0.1	na
Comments: Obtained by summation of all speciated VOX target impurities<u>less</u> AA, MeOH & EtOH			
Aromatic Hydrocarbon Content (ppb v/v as Benzene, ISBT 12.0 [GC]):	nd	2	20 max
Comments: Benzene = nd, Toluene = nd, Ethyl Benzene = nd, omp Xylenes = nd			
Total Sulfur Content* (TSC* ppm v/v as S, ISBT 14.0):	nd	0.01	0.1 max
Comments: Obtained by summation of all speciated VSC target impurities<u>less</u> SO_2			
Sulfur Dioxide (SO_2, ppm v/v, ISBT 14.0 [GC]):	nd	0.05	1 max
<u>Sensory Tests</u>			
Appearance in Water (Pass/Fail, ISBT 16.0):	pass	na	clear
Odor & Taste in Water (Pass/Fail, ISBT 16.0):	pass	na	none
Comments:			
<u>Supplemental Tests</u>			
Hydrogen Cyanide (HCN, ppm v/v by ISBT SM-1.0 [GC]):	nd	0.2	nd
Vinyl Chloride (VCl, ppm v/v by ISBT SM-2.0 [GC]):	nd	0.1	nd
Ethylene Oxide (ETO, ppm v/v by ISBT 11.0 [GC]):	nd	0.1	nd

Sample ID: AC Industries **ALI Track No.:** 12-1171

Speciated Volatile Hydrocarbons (VHC, ppm v/v by ISBT 10.1)	Result	LOQ	ISBT Limit
Ethane:	nd	0.1	see THC
Ethylene:	nd	0.1	see THC
Propane:	nd	0.1	see THC
Propylene:	nd	0.1	see THC
Isobutane:	nd	0.1	see THC
n-Butane:	nd	0.1	see THC
Butene:	nd	0.1	see THC
Isopentane:	nd	0.1	see THC
n-Pentane:	nd	0.1	see THC
Hexanes+:	nd	0.1	see THC

Comments: Pk ID based upon tr match vs target analyte std. CH_4 result on pg 1.

Speciated Volatile Sulfur Compounds (VSC, ppm v/v by ISBT 14.0)			
Hydrogen Sulfide (H_2S):	nd	0.01	see TSC
Carbonyl Sulfide (COS):	nd	0.01	see TSC
Methyl Mercaptan:	nd	0.01	see TSC
Ethyl Mercaptan:	nd	0.01	see TSC
Dimethyl Sulfide:	nd	0.01	see TSC
Carbon Disulfide:	nd	0.01	see TSC
t-Butyl Mercaptan:	nd	0.01	see TSC
Isopropyl Mercaptan:	nd	0.01	see TSC
n-Propyl Mercaptan:	nd	0.01	see TSC
Methyl Ethyl Sulfide:	nd	0.01	see TSC
2-Butyl Mercaptan:	nd	0.01	see TSC
i-Butyl Mercaptan:	nd	0.01	see TSC
Diethyl Sulfide:	nd	0.01	see TSC
n-Butyl Mercaptan:	nd	0.01	see TSC
Dimethyl Disulfide:	nd	0.01	see TSC
Unknown VSC:	nd	0.01	see TSC

Comments: Peak ID based upon t$_r$ match against target analyte standards. Note: SO_2 + TSC* results reported on pg. 1.

Speciated Volatile Oxygenates (VOX, ppm v/v, by ISBT 11.0)			
Dimethyl Ether:	nd	0.1	see THC
Diethyl Ether:	nd	0.1	see THC
Propionaldehyde:	nd	0.1	see THC
Acetone:	nd	0.1	see THC
t-Butanol:	nd	0.1	see THC
Ethanol:	nd	0.1	see THC
Isopropanol:	nd	0.1	see THC
Ethyl Acetate:	nd	0.1	see THC
Methyl Ethyl Ketone:	nd	0.1	see THC
2-Butanol:	nd	0.1	see THC
n-Propanol:	nd	0.1	see THC
Isobutanol:	nd	0.1	see THC
n-Butanol:	nd	0.1	see THC
Isoamyl Acetate:	nd	0.1	see THC
Isoamyl Alcohol:	nd	0.1	see THC
Unknown VOX:	nd	0.1	see THC

Comments: Peak ID based upon t$_r$ match against target analyte standards. AA and ETO results reported on pg. 1.

LOQ = Limit of Quantitation (lowest amount of analyte quantitatively determined with suitable precision and accuracy) **MDL** = method detection limit (lowest amount of analyte detected). **trace** = unquantified amount observed between MDL and LOQ. **nd** = indicates the impurity was not detected (below MDL). -- = test not performed. na = not available. LT = less than the amount specified. GT = greater than the amount specified. % = percent. **ppm** = parts per million. ppb = parts per billion. v/v = volume analyte/volume sample. w/w = weight analyte/weight sample. **(result)** indicates the result was obtained by the method listed within brackets. **TSC*** = ISBT Total Sulfur Content exluding SO_2. **Unit Conversions:** 1ppm v/v = 1µL/L = 1000 ppb = 0.0001% v/v. **Date format:** MM/DD/YY.

Report Summary:

Customer request for a std ISBT No-Haz LCO_2 test pgm.

This sample meets all ISBT purity criteria for bev-grade LCO_2.

Reviewed by / Date:

Nicole James 12/19/12

Nicole James - Laboratory Manager

Attachments: none
Addendum: Signatures, Instrument & Notebook data on-file
Measurement Uncertainty available upon request
F-21.7v3 (8/12)

Accreditation # 68099

I. Formation Testing Program

A robust logging and formation testing program is planned for this project. The physical and chemical characteristics of the injection zones will be determined through comprehensive core analyses. The coal seams of the Lee and Pocahontas formations into which the CO_2 will be injected will have offset well core samples taken in the immediate vicinity of the three planned injection wells. The cores will be obtained from the geologic characterization well which is planned to be drilled in April 2013. The tentative location is identified as C-1 on *Map 1* in *Section B*. Once the drilling reaches a depth just above the shallowest planned injection zone, the drilling operation will change to a coring acquisition operation. This operation will attempt to recover a continuous core through the Lee and Pocahontas formations. The samples from the coal seams and other strata will be tested in core laboratories for routine core analysis, with rock mechanics properties to determine permeability, porosity, stress and strain, gas composition and adsorption isotherms. A proximate analysis will also be performed to determine the amount of volatile matter, ash and moisture. Additionally, an ultimate analysis will provide data on elemental content of the coal seams and mineralogical makeup.

All of the coal seams proposed for CO_2 injection were initially stimulated using a nitrogen foam fracture stimulation to enhance production of the CBM gas production wells. Stimulation records were interpreted to determine the bottom-hole fracture (breakdown) pressures. The injection pressure will be no greater than 90% of the fracture pressure, as measured at the depth of perforations, at each injection well. This limit represents a 100 psi safety margin (or greater) below the recorded minimum bottom-hole fracture pressure.

Fluid pressure data from the formations planned for CO_2 injection will be obtained from the characterization and monitoring wells (see M-1 and M-2 on *Map 1* in *Section B*) that will be drilled. The monitoring wells will allow the retrieval of data using bottom-hole pressure gauges or tubing and packer assemblies instrumented with monitoring devices and components installed down hole with surface readout and remote capability. The cores recovered from the geologic characterization well will be analyzed as discussed above, and open hole logs and formation fluid recovery will assist with the determination of baseline formation fluid pressures and composition.

J. Stimulation Program

Gas productive coal seams in the three CBM wells proposed for conversion to injection wells were hydraulically stimulated (see *Section C.*) prior to being placed into production. There is no plan to stimulate these coal seams again, keeping CO_2 injection pressures below fracture pressure.

K. Injection Procedures

Currently, the three CBM production wells proposed for conversion to injection wells produce minor gas volumes from multiple perforated intervals as identified in *Section C*. Completion plans are for setting a packer on tubing in each well above the shallowest set of perforations. CO_2 will be injected through the tubing and able to contact all of the perforated intervals of the coal seams.

The tubing/casing annulus pressure will be continuously monitored to determine:

- if CO_2 is exiting in the injection intervals
- if the packer seal assembly retains mechanical integrity
- to ensure that the injection pressure does not exceed the pressure rating of the tubing, tubing head and packer elements.

A safety device will be installed on the tubing annulus to automatically shut down the CO_2 injection system if the annular pressure reaches the safety limit. The limit will be at least 100 psig below the tubing head rating. The safety device will be tested in the field prior to injection to ensure it functions properly.

The injection facility surface equipment will be primarily located on the DD-7 CBM well pad. This injection equipment will include CO_2 storage tanks, a heater, and the injection pump. A satellite location near Vansant, Virginia will be used as a CO_2 transfer station to prepare CO_2 loads for injection. Over the road tractor-trailer transports with 20-ton capacity will haul loads of CO_2 from the supply source to storage tanks at the satellite location. Smaller, more maneuverable off road 10-ton mini-trucks will then transfer CO_2 from the satellite location storage to the injection station at the DD-7 injection well. A pipeline will be constructed to flow CO_2 from the pump individually to the wellheads on proposed injection wells DD-7, DD-7A and DD-8. A pressure regulator and flow control valve will be installed at the wellhead of each injection well. The pressure regulator will ensure that the approved injection pressure is not exceeded and the flow control valve will allow a balance to be maintained among the injection rates at the three wells. A monitoring and alarm system will be installed on the surface equipment to ensure safe operations. An operations technician will also observe the CO_2 transfer process, make adjustments as required during injection periods, and respond to potential alarms on the system.

L. Construction Procedures

The three proposed injection wells were drilled and completed as CBM production wells between 2000 and 2007. Each well has 7" surface casing set below the fresh water zones encountered in this area and two wells, DD-7A and DD-8, are cemented from their setting depth to the surface. The cement records for these casings are attached for review in *Exhibit 3*. The 7" casing in well DD-7 is also set below all possible underground sources of drinking water (lowermost USDWs). This casing is cemented from its setting depth of 846 feet to 555 feet and from 132 feet to the surface. The annular space from 555 feet to 132 feet is filled with bentonite gel (see *Exhibit 6* in *Section M*). The 4½" casing in all three wells was cemented from total depth to the surface and serves to protect all possible underground sources of drinking water. The cement records and cement bond logs for these well casings are attached in *Exhibits 4* and *5*, respectively. Since both casing strings (7" and 4½") in each well are set below the fresh water zones, they provide multiple levels of protection for all fresh water zones in the local area. Details of the casing sizes, setting depths, and volumes of cement used in each injection well are present in *Section C*.

Deviation surveys were conducted on each well and indicate that each well is very close to being true vertical with minimal deviation present. The bottom-hole locations have less than 25 feet lateral departure from the surface location with the largest deviation being 0.65°. The operator ran open hole electric logs consisting of caliper, gamma ray, density, and temperature deviation prior to setting the production casing string. In addition, cased hole cement bond logs, which define and determine the quality of the cement bond in the annulus, were obtained prior to stimulating the well.

No cores were obtained during the drilling of these wells. However, as previously stated, a geologic characterization well is planned to obtain cores of the injection formations, and will be drilled as an offset to these wells. The recovered cores will be analyzed and tested as described in *Section I*.

Prior to commencing injection operations, a mechanical integrity test will be performed in each well to confirm well completion integrity. The integrity of the casing will be tested above the shallowest perforation in each well after the packer is set. The tubing/casing annulus will be filled with a fluid, most likely nitrogen gas, and pressured to 10% above the maximum allowable injection pressure and monitored for leak-off. The pressure in the annulus will be monitored for 30 minutes to ensure the packer, casing or tubing completion is not leaking. A pressure drop of 5% or less during this period will qualify the well as having mechanical integrity. This criterion is required by UIC rules and the EPA Region 3 office. After completion of this test, the annulus will be vented to evacuate the test fluid. The injection operations will be conducted without fluid in the annulus. If there is a packer or tubing failure during injection, pressure will be indicated on the annular pressure gauge monitor and operations will be suspended to diagnose and remediate the problem.

Exhibit 3

HALLIBURTON

JOB SUMMARY

ORDER NO. 70006

TICKET # 951141	TICKET DATE 10/30/00	
REGION North America	NWA/COUNTRY Northeast	BDA / STATE Eastern Va.	COUNTY Buchanan
MBU ID / EMP # 100103 106774	EMPLOYEE NAME M. Beardsley	PSL DEPARTMENT Zonal Isolation	
LOCATION Abingdon Va.	COMPANY Buchanan Production Co. C. Unused	CUSTOMER REP / PHONE 540-498-8225	
TICKET AMOUNT	WELL TYPE 13- Coal Degas	API / UWI #	
WELL LOCATION Oakwood Va.	DEPARTMENT Cement	JOB PURPOSE CODE 7" Surface Csg.	
LEASE / WELL # DD-7	SEC / TWP / RNG		

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS
M. Beardsley		106774					
T. Hatfield		106729					
T. Lester		106730					

HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES
420958	140	10 HUD					
53228	140	10 STCL					
52615	140	BULK THR					

Form Name _____ Type: _____
Form Thickness _____ From _____ To _____
Packer Type _____ Set At _____
Bottom Hole Temp. 70° Pressure _____
Misc. Data _____ Total Depth 870'

	CALLED OUT	ON LOCATION	JOB STARTED	JOB COMPLETED
DATE	10/30/00	10/30/00	10/30/00	10/30/00
TIME	15:00	19:00	21:40	21:55

TOOLS AND ACCESSORIES

TYPE AND SIZE	QTY	MAKE
Float Collar		
Float Shoe		
Guide Shoe		
Centralizers Basket	7"	Hall Liberty
Bottom Plug		
Top Plug	N/A	
Head		
Packer		
Other		

WELL DATA

	NEW/USED	WEIGHT	SIZE	FROM	TO	MAX ALLOW
Casing	New	17.0	7"	KB	850	
Liner						
Liner						
Tbg/D.P.						
Tbg/D.P.						
Open Hole						SHOTS/FT.
Perforations						
Perforations						
Perforations						

MATERIALS

Treat Fluid _____ Density _____ Lb/Gal
Disp. Fluid _____ Density _____ Lb/Gal
Prop. Type _____ Size _____ Lb. _____
Prop. Type _____ Size _____ Lb. _____
Acid Type _____ Gal. _____ % _____
Acid Type _____ Gal. _____ % _____
Surfactant _____ Gal. _____ In _____
NE Agent _____ Gal. _____ In _____
Fluid Loss _____ Gal/Lb _____ In _____
Gelling Agent _____ Gal/Lb _____ In _____
Fric. Red. _____ Gal/Lb _____ In _____
Breaker _____ Gal/Lb _____ In _____
Blocking Agent _____ Gal/Lb _____
Perfpac Balls _____ Qty. _____
Other Hallibuton Lost Circ 2 units
Other _____
Other _____
Other _____

HOURS ON LOCATION

DATE	HOURS
10/30/00	7
TOTAL	

OPERATING HOURS

DATE	HOURS
10/30/00	1.5
TOTAL	

DESCRIPTION OF JOB

Surface Csg
Balance
PK 7

ORDERED _____ HYDRAULIC HORSEPOWER Avail. _____ Used _____
TREATED _____ AVERAGE RATES IN BPM Disp. _____ Overall _____
FEET _____ CEMENT LEFT IN PIPE Reason _____

CEMENT DATA

STAGE	SACKS	CEMENT	BULK/SKS	ADDITIVES	YIELD	LBS/GAL
1	65	Standard	Bulk	3% Cal. Chl. 1/4 #/SK Flocele	1.18	15.6

Circulating _____ Displacement _____ Preflush: Gal - BBl _____ Type _____
Breakdown _____ Maximum _____ Load & Bkdn: Gal - BBl _____ Pad: BBl - Gal 1 - 2
Average _____ Frac Gradient _____ Treatment Gal - BBl 5 Disp: BBl - Gal 2
Shut In: Instant _____ 5 Min _____ 15 Min _____ Cement Slurr Gal - BBl _____
Total Volume Gal - BBl Keep Csg 4 13 BBL

Frac Ring #1 | Frac Ring #2 | Frac Ring #3 | Frac Ring #4

THE INFORMATION STATED HEREIN IS CORRECT

CUSTOMER'S REPRESENTATIVE SIGNATURE

HALLIBURTON

JOB LOG

ORDER NO. 70008

REGION: North America	NWA/COUNTRY	TICKET #	TICKET DATE
MBU ID / EMP #	EMPLOYEE NAME	BDA / STATE	COUNTY
LOCATION	COMPANY	PSL DEPARTMENT	
TICKET AMOUNT	WELL TYPE	CUSTOMER REP / PHONE	
WELL LOCATION	DEPARTMENT	API / UWI #	
LEASE / WELL # DD 7	SEC / TWP / RNG	JOB PURPOSE CODE 7" cmt	

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS

CHART NO.	TIME	RATE (BPM)	VOLUME (BBL/GAL)	PUMPS T	PUMPS C	PRESS.(psi) Tbg	PRESS.(psi) Csg	JOB DESCRIPTION / REMARKS
	19:00							On location Safety Meet'g Set up
								Job Plan & Safety Meeting Onside
	21:40		1					Pump H2O Ahead
			2					Pump Cmt 15.6 LB/Gal (40SKS)
								Drop H2O
								Dump Cmt Down Backside
	21:55		4					Mix Cement 15.6 LB/Gal (Backside)
								Shut Down 255KS
			20					Wash Up
								Rack Up
								Safety Meeting
	23:10							DEF Location
								Thank You
								Michael & Crew

Ph

HALLIBURTON — Job Summary

SALES ORDER NUMBER	TICKET DATE
4873790	01/22/07

REGION	NWA / COUNTRY	BDA	STATE	COUNTY
United States	Northeast/United States	EASTERN	VA	Buchanan

MBU ID / EMPL #	H.E.S EMPLOYEE NAME	PSL DEPARTMENT
106727	Tom Hagerdon	Cementing

LOCATION	COMPANY	CUSTOMER REP / PHONE
Norton, VA	CNX	Driller on Rig

TICKET AMOUNT	WELL TYPE	API/UWI #
	13 - COAL DEGAS	

WELL LOCATION	DEPARTMENT	SAP BOMB NUMBER	Description
Honaker	Cementing	7521	Cement Surface Casing-010

LEASE NAME	Well No.	SEC / TWP / RNG	HES FACILITY (CLOSEST TO WELL SITE)
CNX	DD-7A		Norton, Va

HES EMP NAME / EMP # / (EXPOSURE HOURS)	HRS	HRS	HRS	HRS
Hagerdon, Thomas 106727	20			
Peak, Jason 344399	20			

H.E.S. UNIT #S / (R / T MILES)	R / T MILES	R / T MILES	R / T MILES	R / T MILES
10704316 PU	25			
10012012 TCM	25			

Form. Name _____ Type: _____
Form. Thickness _____ From _____ To _____
Packer Type _____ Set At _____
Bottom Hole Temp. _____ Pressure _____
Retainer Depth _____ Total Depth _____

Date	Called Out	On Location	Job Started	Job Completed
	1/22/2007	1/22/2007	1/22/2007	1/22/2007
Time	08:00	12:30	13:13	13:32

Tools and Accessories

Type and Size	Qty	Make
Float Collar		
Float Shoe		
Centralizers		
Top Plug		
HEAD		
Baskets		
Weld-A		
Guide Shoe		
BTM PLUG		

Well Data

	New/Used	Weight	Size	Grade	From	To	Max. Allow
Casing	N	17.0	7		GL	253	
Liner			13 3/8			20	
Liner							
Tubing							
Drill Pipe							
Open Hole			8 7/8			270	
Perforations							
Perforations							
Baskets						88	

Materials

Mud Type		Density	Lb/Gal
Disp. Fluid		Density	Lb/Gal
Prop. Type		Size	Lb
Prop. Type		Size	Lb
Acid Type		Gal.	%
Acid Type		Gal.	%
Surfactant		Gal.	In
NE Agent		Gal.	In
Fluid Loss		Gal/Lb	In
Gelling Agent		Gal/Lb	In
Fric. Red.		Gal/Lb	In
Breaker		Gal/Lb	In
Blocking Agent		Gal/Lb	
Perfpac Balls		Qty.	
Other	100# N/S GEL		
Other			
Other			
Other			
Other			

Hours On Location

Date	Hours
1/22	2.0
Total	2.0

Operating Hours

Date	Hours
1/22	0.5
Total	0.5

Description of Job
Cement 7" Casing

Baffles

Hydraulic Horsepower
Ordered _____ Avail. _____ Used _____

Average Rates in BPM
Treating _____ Disp. _____ Overall _____

Cement Left in Pipe
Feet _____ Reason SHOE JOINT

Cement Data

Stage	Sacks	Cement	Bulk/Sks	Additives	W/Rq.	Yield	Lbs/Gal
1	60	STD	B	3% CC, 1/4#/SK POL-E FLAKE	5.20	1.18	15.60
				Water Temp 36			
				PH 6.5			

Summary

Circulating		Displacement		Preflush: BBl	5.00	Type:	6% GEL
Breakdown		MAXIMUM		Load & Bkdn: Gal - BBl		Pad,Bbl -Gal	
Lost Returns-Y		Lost Returns-NO		Excess /Return BBl		Calc.Disp Bbl	
Cmt Rtrn#Bbl	1	Actual TOC		Calc. TOC:		Actual Disp.	10.5
Average		Frac. Gradient		Treatment: Gal - BBl		Disp:Bbl	
Shut In: Instant		5 Min.	15 Min	Cement Slurry BBl	12.6		
				Total Volume BBl			

Frac Ring #1 | Frac Ring # 2 | Frac Ring # 3 | Frac Ring # 4

THE INFORMATION STATED HEREIN IS CORRECT

CUSTOMER REPRESENTATIVE _____ SIGNATURE

HALLIBURTON	Job Log	SALES ORDER NUMBER	TICKET DATE
		4873790	01/22/07

REGION	NWA / COUNTRY	BDA / STATE	COUNTY
United States	Northeast/United States	EASTERN	Buchanan
MBU ID / EMPL #	**H.E.S EMPLOYEE NAME**	**PSL DEPARTMENT**	
106727	Tom Hagerdon	Cementing	
LOCATION	**COMPANY**	**CUSTOMER REP / PHONE**	
Norton, VA	CNX	Driller on Rig	
TICKET AMOUNT	**WELL TYPE**	**API/UWI #**	
	13 - COAL DEGAS		
WELL LOCATION	**DEPARTMENT**	**JOB PURPOSE CODE**	
Honaker	Cementing	Cement Surface Casing-010	
LEASE NAME / **Well No**	**SEC / TWP / RNG**	**HES FACILITY (CLOSEST TO WELL)**	
CNX / DD-7A		Norton,Va	

HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS	HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS	HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS	HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS
Hagerdon, Thomas 106727	2.0						
Peak, Jason 344399	2.0						

Chart No.	Time	Rate (BPM)	Volume (BBL/GAL)	Rate N2	Press.(PSI) CSG.	Press.(PSI) Tbg	Job Description / Remarks
	12:30						ON LOCATION
							JOB SITE ASSESMENT
							SAFETY MEETING
							RIG UP
							JOB PLAN AND SAFETY MEETING
	13:13						START JOB
					500		TEST LINES
		3.0	10.0				PUMP H20
		3.5	5.0				PUMP GEL
		2.5	10.0				PUMP H20
	13:22	3.5	12.6		50		MIX & PUMP CEMENT @ 13.6#/GAL
							SHUT DOWN, DROP PLUG
	13:26	2.5	10.5		107		PUMP DISPLACEMENT
	13:32						SHUT DOWN
							DID NOT LAND PLUG @ CUSTOMER'S REQUEST
							CLOSE IN WELL
							RELEASE PSI OFF LINES
	13:32						END JOB
							CIRCULATED 1 BBL CEMENT TO PIT
							WASH TRUCK & LINES
							RIG DOWN
							SAFETY MEETING
	14:30						OFF LOCATION

HALLIBURTON

JOB SUMMARY

ORDER NO. 70006

TICKET # 113225	TICKET DATE 2-14-01		
REGION North America	NWA/COUNTRY U.S.A.	BDA / STATE VC	COUNTY Buchanan
MBU ID / EMP # 100102 106824	EMPLOYEE NAME R. Wheatly	PSL DEPARTMENT ZI	
LOCATION Montcla	COMPANY BPC	CUSTOMER REP / PHONE Randy Beal	
TICKET AMOUNT	WELL TYPE 013	API / UWI #	
WELL LOCATION Buchanan Co. VA	DEPARTMENT ZI	JOB PURPOSE CODE 015	
LEASE / WELL # BPC 1008	SEC / TWP / RNG Oakwood		

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS
Wheatly 106824							
Sleaton 106730							

HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNI NUMBERS	R/T MILES
421556							
53559							

Form Name _____ Type: _____
Form Thickness _____ From _____ To _____
Packer Type _____ Set At _____
Bottom Hole Temp. _____ Pressure _____
Misc. Data _____ Total Depth _____

	CALLED OUT	ON LOCATION	JOB STARTED	JOB COMPLETED
DATE	2-14-01	2-14-01	2-14-01	2-14-01
TIME	8:30	13:00	1331	1

TOOLS AND ACCESSORIES

TYPE AND SIZE	QTY	MAKE
Float Collar		
Float Shoe		
Guide Shoe	1	HES
Centralizers		
Bottom Plug		
Top Plug	1	HES
Head	1	HES
Packer		
Other Rent-A	1	HES

WELL DATA

	NEW/USED	WEIGHT	SIZE	FROM	TO	MAX ALLOW
Casing	New	17	7"	KB	223	200
Liner						
Liner						
Tbg/D.P.						
Tbg/D.P.						
Open Hole						SHOTS/FT.
Perforations						
Perforations						
Perforations						

MATERIALS

Treat Fluid _____ Density _____ Lb/Gal
Disp. Fluid _____ Density _____ Lb/Gal
Prop. Type _____ Size _____ Lb. _____
Prop. Type _____ Size _____ Lb. _____
Acid Type _____ Gal. _____ % _____
Acid Type _____ Gal. _____ % _____
Surfactant _____ Gal. _____ In _____
NE Agent _____ Gal. _____ In _____
Fluid Loss _____ Gal/Lb _____ In _____
Gelling Agent _____ Gal/Lb _____ In _____
Fric. Red. _____ Gal/Lb _____ In _____
Breaker _____ Gal/Lb _____ In _____
Blocking Agent _____ Gal/Lb _____
Perfpac Balls _____ Qty. _____
Other _____
Other _____
Other _____
Other _____

HOURS ON LOCATION

DATE	HOURS
2-14	1.5
TOTAL	

OPERATING HOURS

DATE	HOURS
2-14	1.5
TOTAL	

DESCRIPTION OF JOB

7" 20# csg

HYDRAULIC HORSEPOWER
ORDERED _____ Avail. _____ Used _____
AVERAGE RATES IN BPM
TREATED _____ Disp. _____ Overall _____
CEMENT LEFT IN PIPE
FEET _____ Reason _____

CEMENT DATA

STAGE	SACKS	CEMENT	BULK/SKS	ADDITIVES	YIELD	LBS/GAL
1	60	STD	B	3% CC ¼# Sk Flocele	1.18	15.6

Circulating _____ Displacement _____
Breakdown _____ Maximum _____
Average _____ Frac Gradient _____
Shut In: Instant _____ 5 Min _____ 15 Min _____

Preflush: Gal - BBl _____ Type _____
Load & Bkdn: Gal - BBl _____ Pad: BBl - Gal 5
Treatment Gal - BBl _____ Disp: BBl - Gal 9.5
Cement Slurr Gal - BBl 12.6
Total Volume Gal - BBl _____

Frac Ring #1	Frac Ring #2	Frac Ring #3	Frac Ring #4

THE INFORMATION STATED HEREIN IS CORRECT

CUSTOMER'S REPRESENTATIVE SIGNATURE _____

HALLIBURTON

JOB LOG

ORDER NO. 70006

TICKET #		TICKET DATE	
REGION: North America	NWA/COUNTRY	BDA / STATE	COUNTY
MBU ID / EMP #	EMPLOYEE NAME	PSL DEPARTMENT	
LOCATION	COMPANY	CUSTOMER REP / PHONE	
TICKET AMOUNT	WELL TYPE	API / UWI #	
WELL LOCATION	DEPARTMENT	JOB PURPOSE CODE: 7" cmt	
LEASE / WELL #: DD 8	SEC / TWP / RNG		

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS

CHART NO.	TIME	RATE (BPM)	VOLUME (BBL/GAL)	PUMPS T	PUMPS C	PRESS. (psi) Tbg	PRESS. (psi) Csg	JOB DESCRIPTION / REMARKS
	1300							on loc
								Saf Mtg
								Tgs Position
								Start Jts
	1331						500	Pt Test + Release
		4	8					Pump H20
		4	9					Mix + pump cmt @ 15.8#
								Shut Down
								Release Plug
			9.5					Displace
							130	Land Plug
								Shut Down Close in well
	1351							Release PSI
								Rig Down
								Clean up
	1430							Job Over
								Thank you
								Josh Miller & Crew

Exhibit 4

HALLIBURTON

JOB SUMMARY

ORDER NO. 70006

TICKET # 951145	TICKET DATE 11-2-00		
REGION North America	NWA/COUNTRY U.S.A.	BDA / STATE Va	COUNTY Buchanan
MBU ID / EMP # 100102 106824	EMPLOYEE NAME R. Wheatley	PSL DEPARTMENT 2I	
LOCATION Norton Va	COMPANY B.P.C.	CUSTOMER REP / PHONE [illegible]	
TICKET AMOUNT	WELL TYPE 013	API / UWI #	
WELL LOCATION	DEPARTMENT 2I	JOB PURPOSE CODE 035	
LEASE / WELL # BPC 1007	SEC / TWP / RNG Oakwood		

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS
R. Wheatley 106824							
T. Mason Jr 106727							
S. Hoyle 107280							

HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES
421356		[illegible]					
53559							
50887							

Form Name _____ Type: _____
Form Thickness _____ From _____ To _____
Packer Type _____ Set At _____
Bottom Hole Temp. _____ Pressure _____
Misc. Data _____ Total Depth _____

DATE	CALLED OUT	ON LOCATION	JOB STARTED	JOB COMPLETED
DATE	11-2-00	11-2-00	11-2-00	11-2-00
TIME	8:00	9:00	9:55	11:30

TOOLS AND ACCESSORIES

TYPE AND SIZE	QTY	MAKE
Float Collar		
Float Shoe		
Guide Shoe		
Centralizers		
Bottom Plug		
Top Plug LD	1	HES
Head	1	HES
Packer	1	HES
Other		

WELL DATA

	NEW/USED	WEIGHT	SIZE	FROM	TO	MAX ALLOW
Casing	New	9.50	4½	GL	2183	1,500
Liner						
Liner						
Tbg/D.P.						
Tbg/D.P.						
Open Hole						SHOTS/FT.
Perforations						
Perforations						
Perforations						

MATERIALS

Treat Fluid _____ Density _____ Lb/Gal
Disp. Fluid _____ Density _____ Lb/Gal
Prop. Type _____ Size _____ Lb. _____
Prop. Type _____ Size _____ Lb. _____
Acid Type _____ Gal. _____ % _____
Acid Type _____ Gal. _____ % _____
Surfactant _____ Gal. _____ In _____
NE Agent _____ Gal. _____ In _____
Fluid Loss _____ Gal/Lb _____ In _____
Gelling Agent _____ Gal/Lb _____ In _____
Fric. Red. _____ Gal/Lb _____ In _____
Breaker _____ Gal/Lb _____ In _____
Blocking Agent _____ Gal/Lb _____
Perfpac Balls _____ Qty. _____
Other _____
Other _____
Other _____
Other _____

HOURS ON LOCATION

DATE	HOURS
11-2	2.5
TOTAL	2.5

OPERATING HOURS

DATE	HOURS
11-2	1.5
TOTAL	1.5

DESCRIPTION OF JOB

4½ Casing

HYDRAULIC HORSEPOWER
ORDERED _____ Avail. _____ Used _____
AVERAGE RATES IN BPM
TREATED _____ Disp. _____ Overall _____
CEMENT LEFT IN PIPE
FEET _____ Reason _____

CEMENT DATA

STAGE	SACKS	CEMENT	BULK/SKS	ADDITIVES	YIELD	LBS/GAL
1	220	HLC	B.	6% D-1 3% S-1	1.69	13.1

Circulating _____ Displacement _____
Breakdown _____ Maximum _____
Average _____ Frac Gradient _____
Shut In: Instant _____ 5 Min _____ 15 Min _____

Preflush: Gal - BBl 30 Type 6% Gel
Load & Bkdn: Gal - BBl _____ Pad: BBl - Gal 36
Treatment Gal - BBl _____ Disp: BBl - Gal 31
Cement Slurr Gal - BBl 66
Total Volume Gal - BBl _____

Frac Ring #1 _____ Frac Ring #2 _____ Frac Ring #3 _____ Frac Ring #4 _____

THE INFORMATION STATED HEREIN IS CORRECT

CUSTOMER'S REPRESENTATIVE SIGNATURE [illegible]

HALLIBURTON

JOB LOG

ORDER NO. 70008

REGION: North America	NWA/COUNTRY	TICKET #	TICKET DATE
MBU ID / EMP #	EMPLOYEE NAME	BDA / STATE	COUNTY
LOCATION	COMPANY	PSL DEPARTMENT	
TICKET AMOUNT	WELL TYPE	CUSTOMER REP / PHONE	
WELL LOCATION	DEPARTMENT	API / UWI #	
LEASE / WELL # DD 7	SEC / TWP / RNG	JOB PURPOSE CODE 4 1/2 cmt	

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS

CHART NO.	TIME	RATE (BPM)	VOLUME (BBL)(GAL)	PUMPS T	PUMPS C	PRESS. (psi) Tbg	PRESS. (psi) Csg	JOB DESCRIPTION / REMARKS
	900							On loc
								Safety meeting
								Rig to mud line
								Set up
								Tag bottom
								Start csg
	955							
							500	PSI test - Release
								Drop ball set packer
		5	30					
		2	6				132	Set packer
		5	18					Drop ball
		5	30					Pump 1/2 bbl
		1	5					Pump 6 bbl Gel
		5	66					H20 spacer
								Mix & pump cement 13.1
								Shut down
								Wash lines
								Release plug
								Displace
		5	30					
		2	6				1130	Land plug
	1047						1100	Test csg
								Release psi
								Float Held
								Rig down
	1130							Leave loc
								Thank you
								Stuart Watson
								+ Crew.

HALLIBURTON — Job Summary

SALES ORDER NUMBER	TICKET DATE
4879234	01/26/07

REGION: United States	NWA / COUNTRY: Northeast/United States	BDA: EASTERN	STATE: Va.	COUNTY: Buchanan
MBU ID / EMPL #: NOO107 106560	H.E.S EMPLOYEE NAME: JE Brown	PSL DEPARTMENT: Cementing		
LOCATION: Norton, VA	COMPANY: CNX	CUSTOMER REP / PHONE:		
TICKET AMOUNT: $5,971.36	WELL TYPE: Coal DeGas	API/UWI #:		
WELL LOCATION: Honaker VA	DEPARTMENT: Cementing	SAP BOMB NUMBER: 7523	Description: Cement Production Casing-035	
LEASE NAME: CNX	Well No.: DD-7A	SEC / TWP / RNG:	HES FACILITY (CLOSEST TO WELL SITE): Norton,Va	

HES EMP NAME / EMP # / (EXPOSURE HOURS)	HRS	HRS	HRS	HRS
Brown, J (Eddie) 106560	3.0			
Slemp, Chad 296890	3.0			
Boggs, Edward 403142	3.0			
Marshel Arther 405890	3.0			

H.E.S. UNIT #S / (R / T MILES)	R / T MILES	R / T MILES	R / T MILES	R / T MILES
10418458 PU	25			
10011522 TCM	25			
10011872 TD	25			

Form. Name _____ Type: _____
Form. Thickness _____ From _____ To _____
Packer Type _____ Set At _____
Bottom Hole Temp. _____ Pressure _____
Retainer Depth _____ Total Depth _____

Date	Called Out	On Location	Job Started	Job Completed
	1/26/2007	1/26/2007	1/26/2007	1/26/2007
Time	07:00	12:00	13:11	14:12

Tools and Accessories

Type and Size	Qty	Make
Float Collar		
Float Shoe		
Centralizers		
Top Plug		
HEAD		
Baskets		
Weld-A		
Guide Shoe		
BTM PLUG		

Well Data

	New/Used	Weight	Size	Grade	From	To	Max. Allow
Casing	N	9.5	4 1/2		G	1,806	
Liner							
Liner							
Tubing							
Drill Pipe							
Open Hole			6 1/2		263	2,000	
Perforations							
Perforations							
Perforations							

Materials

Mud Type _____ Density _____ Lb/Gal
Disp. Fluid _____ Density _____ Lb/Gal
Prop. Type _____ Size _____ Lb _____
Prop. Type _____ Size _____ Lb _____
Acid Type _____ Gal. _____ % _____
Acid Type _____ Gal. _____ % _____
Surfactant _____ Gal. _____ In _____
NE Agent _____ Gal. _____ In _____
Fluid Loss _____ Gal/Lb _____ In _____
Gelling Agent _____ Gal/Lb _____ In _____
Fric. Red. _____ Gal/Lb _____ In _____
Breaker _____ Gal/Lb _____ In _____
Blocking Agent _____ Gal/Lb _____
Perfpac Balls _____ Qty. _____
Other _____
Other _____
Other 500 lb Gel 12 sks
Other _____
Other _____

Hours On Location

Date	Hours
1/26	3.0
Total	3.0

Operating Hours

Date	Hours
1/26	1.0
Total	1.0

Description of Job

Cement Prod. Csg
4 1/2

Hydraulic Horsepower
Ordered _____ Avail. _____ Used _____
Average Rates in BPM
Treating _____ Disp. _____ Overall _____
Cement Left in Pipe
Feet _____ Reason _____

Cement Data

Stage	Sacks	Cement	Bulk/Sks	Additives	W/Rq.	Yield	Lbs/Gal
1	165	Hall-Light		3% CaICh.	8.80	1.89	13.10
				Water temp. 36 PH 6.5			

Summary

Circulating _____ Displacement _____ Preflush: BBI 30.00 Type Gel
Breakdown _____ MAXIMUM _____ Load & Bkdn: Gal - BBI 50 Pad:Bbl -Gal _____
Lost Returns-Y _____ Lost Returns-NO _____ Excess /Return BBI _____ Calc.Disp Bbl _____
Cmt Rtrn#Bbl _____ Actual TOC _____ Calc. TOC: _____ Actual Disp. 30
Average _____ Frac. Gradient _____ Treatment: Gal - BBI _____ Disp:Bbl _____
Shut In: Instant _____ 5 Min. _____ 15 Min _____ Cement Slurry BBI 49.0
Total Volume BBI 169.00

Frac Ring #1 | Frac Ring # 2 | Frac Ring # 3 | Frac Ring # 4

THE INFORMATION STATED HEREIN IS CORRECT
CUSTOMER REPRESENTATIVE _____ SIGNATURE

HALLIBURTON — Job Log

SALES ORDER NUMBER	TICKET DATE
4879234	01/26/07

REGION: United States	NWA / COUNTRY: Northeast/United States	BDA / STATE: EASTERN	COUNTY: Buchanan
HSU ID / EMPL #: NOO107 106560	H.E.S EMPLOYEE NAME: JE Brown	PSL DEPARTMENT: Cementing	
LOCATION: Norton, VA	COMPANY: CNX	CUSTOMER REP / PHONE:	
TICKET AMOUNT: $5,971.36	WELL TYPE: Coal DeGas	API/UWI #:	
WELL LOCATION: Honaker VA.	DEPARTMENT: Cementing	JOB PURPOSE CODE: Cement Production Casing-035	
LEASE NAME: CNX — Well No.: DD-7A	SEC / TWP / RNG:	HES FACILITY (CLOSEST TO WELL SITE): Norton,Va	

HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS	HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS	HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS	HES EMP NAME/EMP # (EXPOSURE HOURS)	HRS
Brown, J (Eddie) 106560	3.0						
Slemp, Chad 296890	3.0						
Boggs, Edward 403142	2.0						
Marshel Arther 405690	3.0						

Chart No.	Time	Rate (BPM)	Volume (BBL)(GAL)	Rate N2	Press.(PSI) CSG.	Press.(PSI) Tbg	Job Description / Remarks
	12:00						On Location
							Safety meeting / Job Plan
							Spot trucks
							Rig up
							Safety meeting / Job Plan
	13:11						Start Job
					1500		Test Lines
		5.0	40.0		40		Pump H20 (Drop ball & Load plug)
		3.0	15.0		0-1250		Pump H20 (Set Packer)
		4.0	5.0		70		Pump H20
		4.0	30.0		85		Pump Gel (Well circuated)
		4.0	5.0		65		Pump H20
		4.5	49.0		100		Pump Cement (166 sks)
							Shut down / Wash lines
							Drop plug
		5.0	30.0		0-550		Disp plug
					1150		Land plug
							Release psi
	14:12						End Job
							Wash up
							Rig down
							Safety meeting
	15:00						Off Location
							Circulated about 5 bbl. Cement to pit

HALLIBURTON

JOB SUMMARY

ORDER NO. 70005

REGION: North America	NWA/COUNTRY: Northeast	BDA / STATE: Eastern	TICKET #: 1132226
MBU ID / EMP #: 106560	EMPLOYEE NAME: Jonathan E Brown	PSL DEPARTMENT: ZI	
LOCATION: Norton	COMPANY: BPC	CUSTOMER REP / PHONE: Calvin Ward	
TICKET AMOUNT: 5,928.43	WELL TYPE: GAS	AP WI #:	
WELL LOCATION: Oakwood	DEPARTMENT: 10003	JOB PURPOSE CODE: 035 4½ Cement Job	
LEASE/WELL #: BPC DD-8	SEC / TWP / RNG:		

HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOS
G Folk 106,802						
J Watkins 106129						
E Silvis 106674						
E Brown 106560						

HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	HES UNIT NUMBERS	R/T MILES	U
422011 P.U.						
52559 T.Cm.						
52613 T.O.						
402604						

Form Name _____ Type: _____
Form Thickness _____ From _____ To _____
Packer Type _____ Set At _____
Bottom Hole Temp. _____ Pressure _____
Misc. Data _____ Total Depth _____

DATE / TIME	CALLED OUT	ON LOCATION	JOB STARTED	JOB COMPLETED
DATE	02/19/01	02/19/01	02/19/01	02/19/01
TIME	09:30	12:30	12:00	1:00

TOOLS AND ACCESSORIES

TYPE AND SIZE	QTY	MAKE
Float Collar		
Float Shoe		
Guide Shoe		
Centralizers		
Bottom Plug		
Top Plug		
Head		
Packer		
Other		

WELL DATA

	NEW/USED	WEIGHT	SIZE	FROM	TO	MAX ALLOW
Casing	W	9.5	4½	G	1822	1000
Liner						
Liner						
Tbg/D.P.						
Tbg/D.P.						
Open Hole						SHOTS/FT.
Perforations						
Perforations						
Perforations						

MATERIALS

Treat Fluid _____ Density _____ Lb/Gal
Disp. Fluid _____ Density _____ Lb/Gal
Prop. Type _____ Size _____ Lb. _____
Prop. Type _____ Size _____ Lb. _____
Acid Type _____ Gal. _____ % _____
Acid Type _____ Gal. _____ % _____
Surfactant _____ Gal. _____ In _____
NE Agent _____ Gal. _____ In _____
Fluid Loss _____ Gal/Lb _____ In _____
Gelling Agent _____ Gal/Lb _____ In _____
Fric. Red. _____ Gal/Lb _____ In _____
Breaker _____ Gal/Lb _____ In _____
Blocking Agent _____ Gal/Lb _____
Perfpac Balls _____ Qty. _____
Other _____
Other _____
Other _____
Other _____

HOURS ON LOCATION

DATE	HOURS
02/19/01	2
TOTAL	2

OPERATING HOURS

DATE	HOURS
02/19/01	2
TOTAL	2

DESCRIPTION OF JOB

4½ Cement Job

ORDERED _____ HYDRAULIC HORSEPOWER Avail. _____ Used _____
TREATED _____ AVERAGE RATES IN BPM Disp. _____ Overall _____
FEET _____ CEMENT LEFT IN PIPE Reason _____

CEMENT DATA

STAGE	SACKS	CEMENT	BULK/SKS	ADDITIVES	YIELD	LBS/GAL
	159	Halliburton Light	B	6% Gel. 3% Calcium Chloride	1.69	13.1

Circulating _____ Displacement 29 bbl
Breakdown _____ Maximum _____
Average _____ Frac Gradient _____
Shut In: Instant _____ 5 Min _____ 15 Min _____

Preflush: Gal - BBl 30
Load & Bkdn: Gal - BBl 40
Treatment Gal - BBl _____
Cement Slurr Gal - BBl 46
Total Volume Gal - BBl 180

Type 6% Gel
Pad: BBl - Gal _____
Disp: BBl - Gal 29

Frac Ring #1	Frac Ring #2	Frac Ring #3	Frac Ring #4

THE INFORMATION STATED HEREIN IS CORRECT

CUSTOMER'S REPRESENTATIVE SIGNATURE Calvin Tanner

HALLIBURTON

JOB LOG

ORDER NO. 70008

REGION: North America	NWA/COUNTRY	TICKET #	TICKET DATE
MBU ID / EMP #	EMPLOYEE NAME	BDA / STATE	COUNTY
LOCATION	COMPANY	PSL DEPARTMENT	
TICKET AMOUNT	WELL TYPE	CUSTOMER REP / PHONE	
WELL LOCATION	DEPARTMENT	API / UWI #	
LEASE / WELL #: D.D 8	SEC / TWP / RNG	JOB PURPOSE CODE: 4 1/2 cmt	

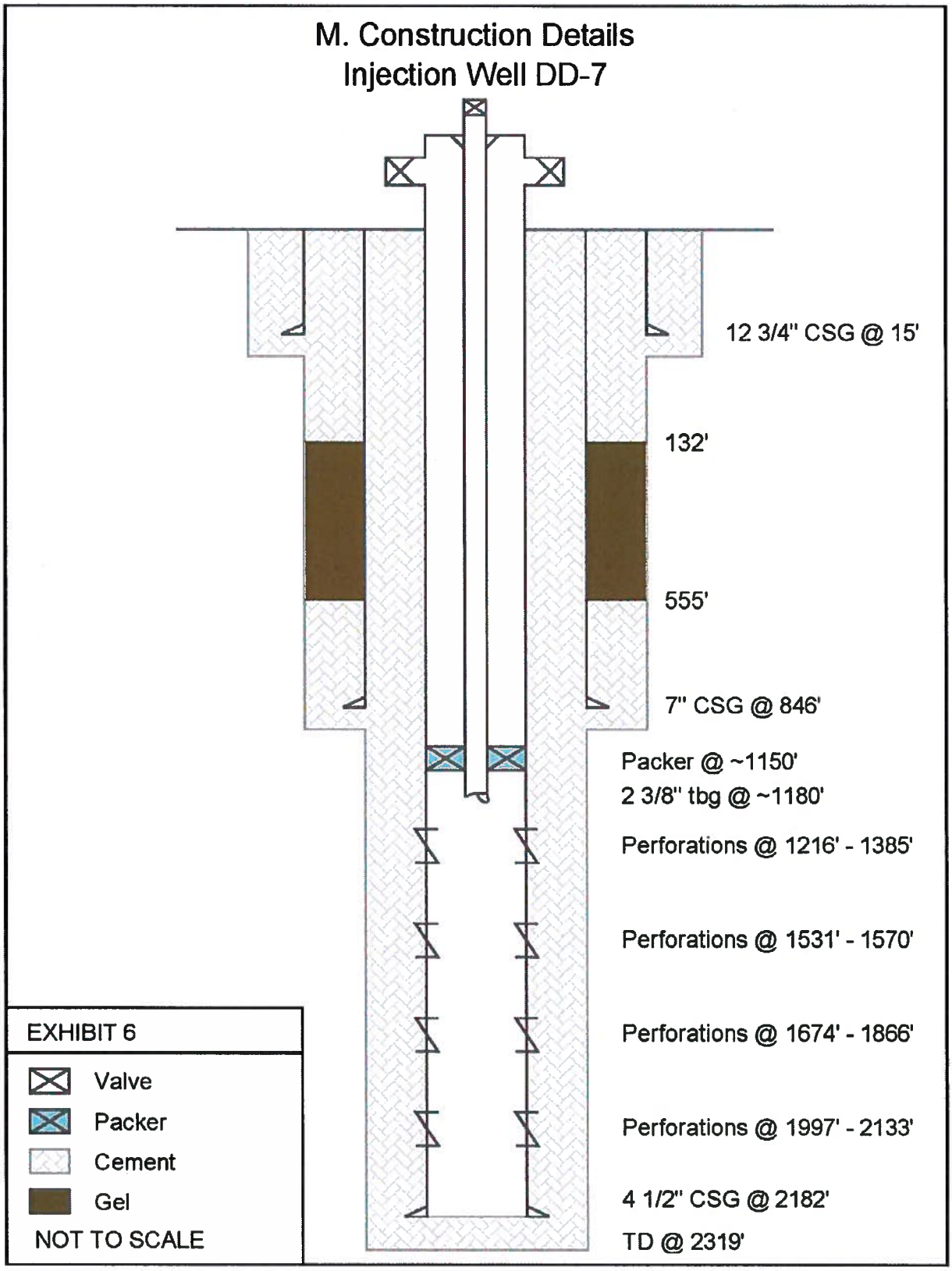
HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS	HES EMP NAME/EMP#/(EXPOSURE HOURS)	HRS
	2						
	2						
	2						
	2						

CHART NO.	TIME	RATE (BPM)	VOLUME (BBL) (GAL)	PUMPS T	PUMPS C	PRESS. (psi) Tbg	PRESS. (psi) Csg	JOB DESCRIPTION / REMARKS
	11:30							On Location
								Safety meeting
								Rig up
								discuss Job
	2:00							start Job
		4	30				30	Load casing w/
								drop ball & latch plug Continue
		7	2				400	Set Packer
	12:15	5					70	pump Gel
		4					100	Circulate well total 49 bbl.
		5	46				100	Pump 11/2 bbl 13.1 cement
		3	3					Wash lines & drop plug
		4	29				500	displace plug
	2:55						1100	land plug
								Release pressure
								Wash up truck
								Rig down
	01:30							leave Location

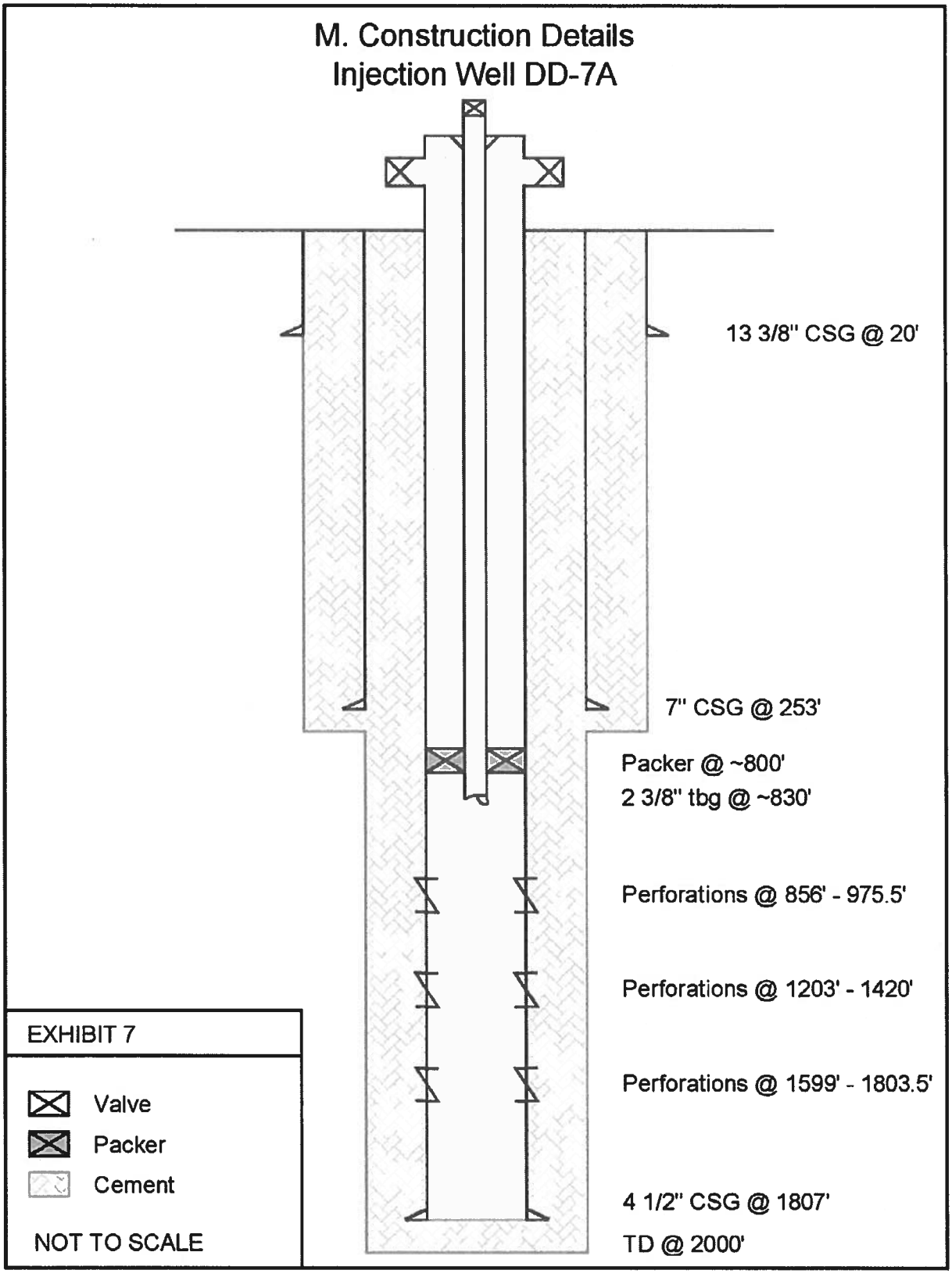
M. Construction Details

See proposed injection well completion schematics that are attached as *Exhibits 6, 7, 8,* and *9*. Multiple thin coal seams are perforated within each perforation interval indicated on the attached exhibits.

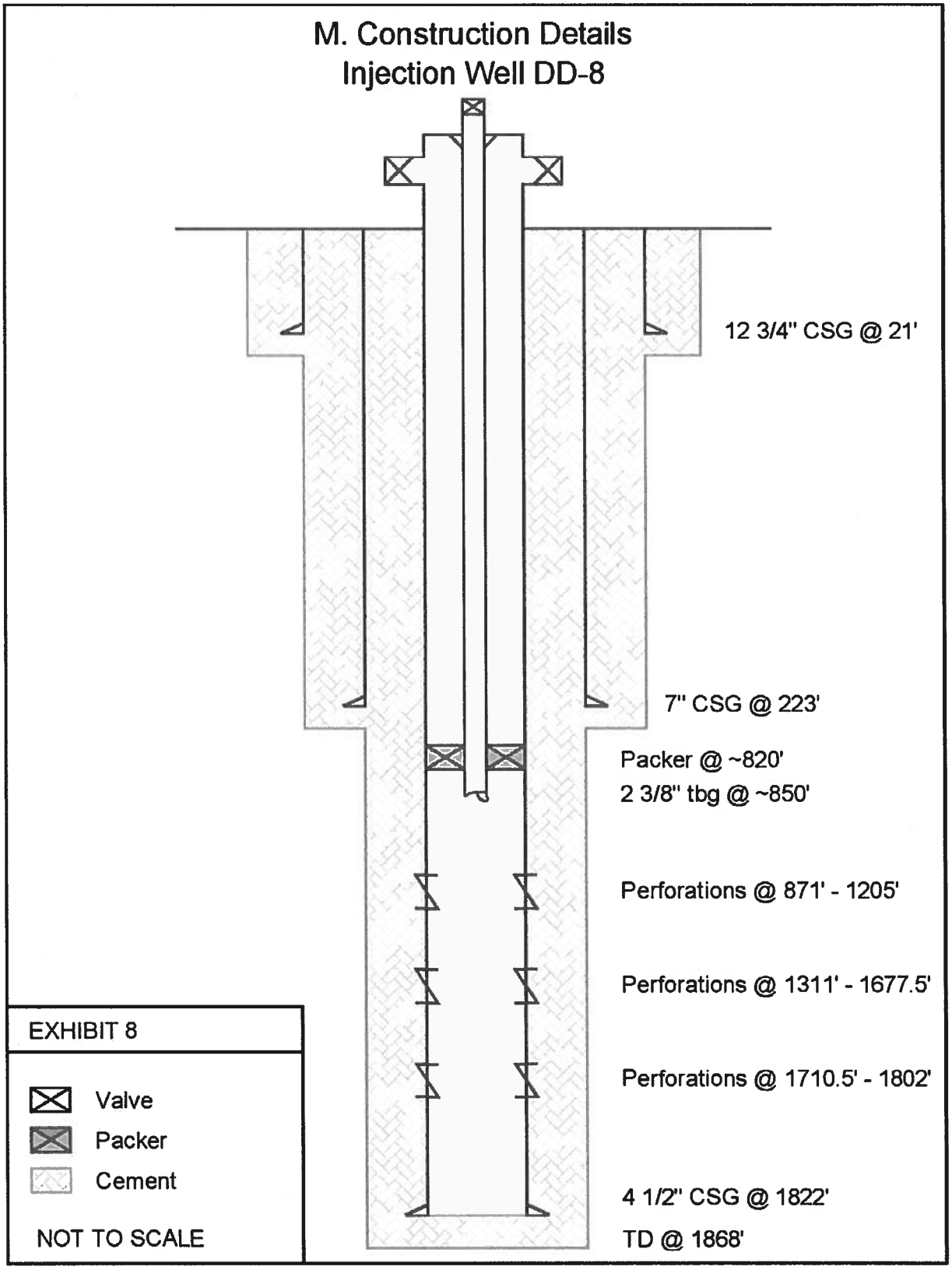
M. Construction Details
Injection Well DD-7

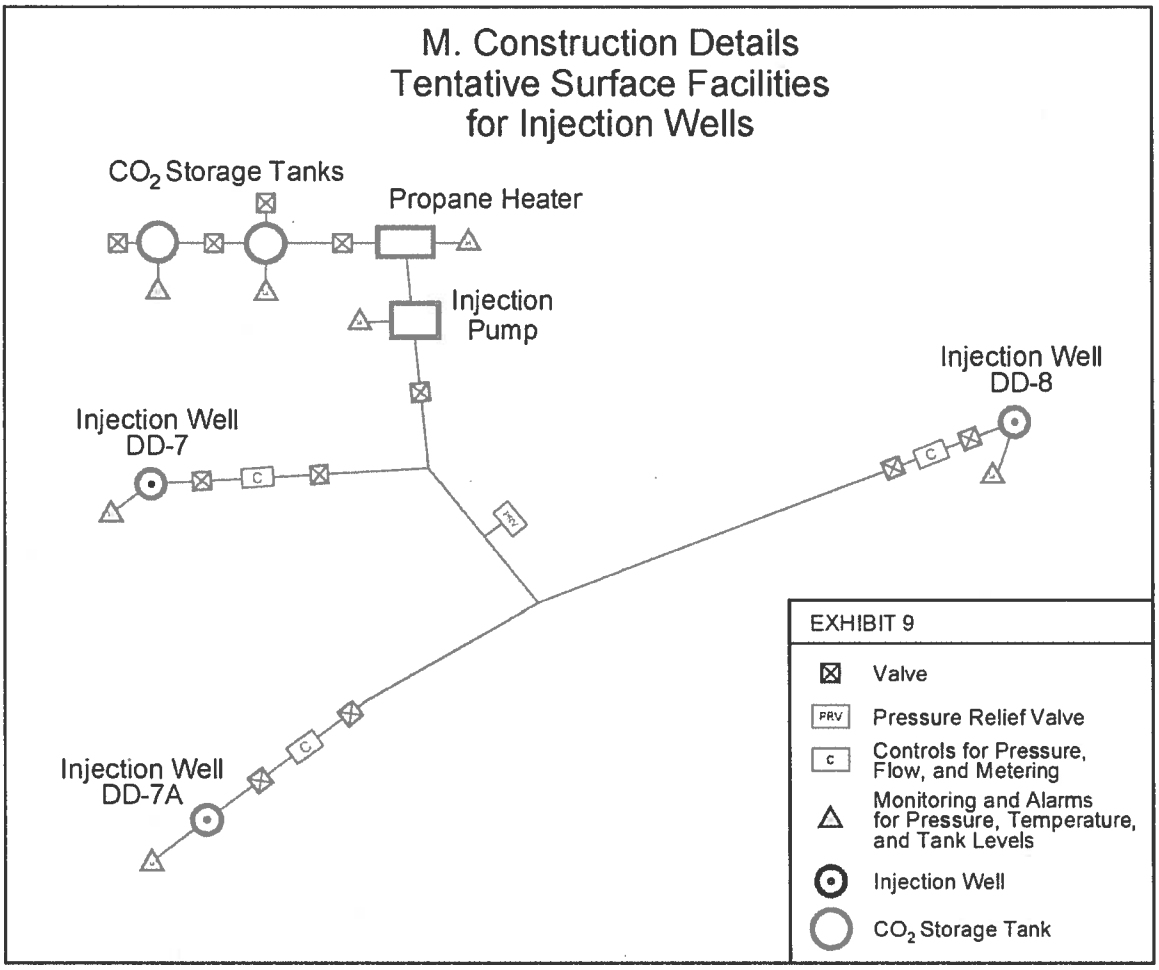


M. Construction Details
Injection Well DD-7A



M. Construction Details
Injection Well DD-8




M. Construction Details
Tentative Surface Facilities
for Injection Wells
CO_2 Storage Tanks
Propane Heater
Injection Pump
Injection Well DD-8
Injection Well DD-7
Injection Well DD-7A
C
PRV
EXHIBIT 9
Valve
Pressure Relief Valve
Controls for Pressure, Flow, and Metering
Monitoring and Alarms for Pressure, Temperature, and Tank Levels
Injection Well
CO_2 Storage Tank

N. Changes in Injected Fluid

Does not apply to Class II wells.

O. Plans for Well Failures

In the event of failure during injection, the well will be shut-in and EPA personnel will be notified verbally as soon as possible within 24 hours. Immediate notification will be provided via email, and follow-up written notification will be sent within five days. Diagnosis and a procedure for well repairs will be provided to the EPA for approval, and re-establishment of mechanical integrity via testing will be demonstrated and performed before injection resumes.

P. Monitoring Program

The wellheads on each of the three proposed injection wells will have instruments and sensors present to monitor the pressures in the tubing and tubing/casing annulus, injection flow rates, cumulative injection volumes and the surface temperature of the CO_2 injected. These data will be recorded continuously during the project on a chart or digital device. A field site technician will also monitor the operations on a daily basis.

This project will also include two monitoring wells and a geologic characterization well. These wells will be used to test the effectiveness of the CO_2 injection in all of the tested coal seams. Seven inch surface casing will be set below the underground sources of drinking water and cemented to the surface. Each well will be drilled through the deepest coal seam that has been perforated in the proposed injection wells so that all the seams to be injected into will be exposed. After running a suite of open hole logs, this portion of the wellbore will remain as an open hole. A packer and tubing assembly is planned to enable monitoring of different coal seams separately as indicated from injection capability and activity. Gas samples will be taken weekly and possibly more frequently before and after CO_2 breakthrough occurs.

In addition to the new monitoring wells, the existing CBM production wells that offset the proposed injection wells will also be used for surveillance as a monitoring array. The gas and water flow rates, gas compositions, and wellhead pressures will be tracked during the project to define changes and report findings.

See *Map 1* for the distances from the injection wells to the proposed characterization and monitoring wells.

Q. Plugging and Abandonment Plan

We do not expect to plug and abandon the injection wells. Upon completion of the CO_2 project, which is expected to last approximately one year, the injection wells will be converted back to CBM gas production wells and CNX Gas, LLC will resume operating all of the wells.

However, if these wells must be plugged and abandoned, a plan is provided herein. According to Virginia Division of Gas and Oil regulation 4VAC25-150-435, a cement plug must be set from 50 feet below the bottom of each coal seam to 50 feet above the top of the coal seam. However, when accounting for 50 feet above and below each of the multiple perforated intervals, the cement plugs would either overlap or be very close to one another. Thus, one Class A cement plug would be set from total depth to 50 feet above the shallowest perforation. Gel would fill the casing from that point to 60 feet from the surface. One barrel of Class A cement would then be used to set a second plug to seal the final 60 feet to surface. The estimated cost to plug and abandon each well is $20,047 and is attached as *Exhibit 10*. Service company quotes to conduct this work are also provided as *Exhibits 11* and *12*.

The balance plug cement method would be used to set the cement plugs and the gel. Prior to setting the plugs, each well would be placed in a state of static equilibrium by allowing the pressure that was created from injecting the CO_2 to bleed-off and dissipate into the reservoir. Gel would be pumped down the tubing and into the tubing/casing annulus to ensure that the well is killed prior to pulling the tubing and packer from the wellbore. Plugging operations would then occur. EPA Form 7520-14 and final plugged and abandoned well schematics showing the proposed cement plugs for each injection well are attached as *Exhibits 13, 13A, 14, 14A, 15* and *15A*.

Cardno MM&A

Exhibit 10

Q. Plugging and Abandonment Plan

P&A Estimate for Injection Well

		Comments
Well Service Rig	$4,155	L&D Well Services quote - 2 days rig time/tongs/supervisor
Water	$160	Truck to deliver water
Cement Service	$10,177	Nabors Completion & Production Services quote
Cardno MM&A Engineer	$3,400	2 days supervision
Trucking/Dozer/Reclaim	$1,200	Transport tubing, dirt work and seed location
Contingency	$955	5% - cased hole work
Total Estimate	$20,047	

Exhibit 11

Estimate

L & D Well Services, Inc

PO Box 1192
Vansant, VA 24656

Name / Address
Cardno MM&A

Date	Estimate #
1/25/2013	14
Project	
DD-7 Plugging	

Item	Description	Qty	U/M	Cost	Total
Rig 1		20	hr	151.25	3,025.00
Tubing Tongs		2	day	65.00	130.00
Supervisor		2	Per Well	500.00	1,000.00
			Total		$4,155.00

Phone #	Fax #	E-mail
276-597-7211	276-597-7078	ldwellservice@gmail.com

Customer Sig... _____

Exhibit 12

Prepared for		Prepared by
Cardno MM&A		NCPS
Ed Diminick		David Daniel
10376 Wallace Alley St.Kingsport TN. 37663		Norton Va.
423-279-9775	NABORS COMPLETION & PRODUCTION SERVICES CO.	606-402-1409
0		276-926-4295

2013 Drilling and Rework Program

Well # DD-7

Price Code	Description	Amount	Units of Sale	Unit Cost	Total Cost
20-200-0001	Mileage DOT Units, Cmt - per unit, per one-way mile	150	ut-mi	$ 6.00	$ 585.00
20-200-0002	Mileage non-DOT Units, Cmt - per unit, per mile	50	ut-mi	$ 3.40	$ 110.50
20-200-0007	Minimum Cement Delivery - per unit, per job	1	unit	$ 635.00	$ 412.75
20-215-0001	Bulk Blending Service - per sack	110	sk	$ 2.70	$ 193.05
20-226-0004	Pumping Service Plugging, 1st 4 hours - per unit	1	unit	$ 3,060.00	$ 1,989.00
20-226-0010	Additional Hours Plugging - per unit, per hour	2	ut-hr	$ 836.00	$ 1,086.80
25-305-1000	Cement-Standard - per sack	110	sk	$ 35.70	$ 1,963.50
25-330-0020	Bentonite (Gel) - per pound	6000	lb	$ 0.92	$ 3,588.00
20-200-9998	Fuel Surcharge, Cmt - as applied	1	ea	$ 248.22	$ 248.22

Gross Price $ 16,429.22

Special Line Item Discounts Applied $ 10,176.82

This Price Is Good For 6 Hours on Location

Company	Cardno MM&A
Company Rep.	Ed Diminick
Well Number	DD-7
Well Type	Injection Well
Type job	Plug & Abandon
Location	Oakwood Field,Buchanan County

Exhibit 13

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

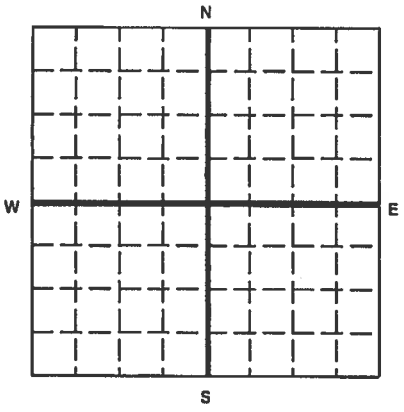
United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility
Well DD-7, Vansant Quadrangle, Buchanan County, VA
Latitude 37° 10' 00" Longitude 82° 05' 00"

Name and Address of Owner/Operator
Cardno MM&A, 10376 Wallace Alley Street, Kingsport, TN 37663

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VA - 4707

Surface Location Description
___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit
Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION
- ☐ Individual Permit
- ☑ Area Permit
- ☐ Rule

Number of Wells 3

WELL ACTIVITY
- ☐ CLASS I
- ☑ CLASS II
  - ☐ Brine Disposal
  - ☑ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ CLASS III

Lease Name Landon Wyatt Well Number DD-7

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
12-3/4		15	15	15"
7"	20	846	846	8-7/8"
4-1/2"	9.5	2182	2182	6-1/2"

METHOD OF EMPLACEMENT OF CEMENT PLUGS
- ☑ The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	4-1/2	4-1/2					
Depth to Bottom of Tubing or Drill Pipe (ft.	2182	60					
Sacks of Cement To Be Used (each plug)	79	5					
Slurry Volume To Be Pumped (cu. ft.)	92.7	5.5					
Calculated Top of Plug (ft.)	1166	0					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6					
Type Cement or Other Material (Class III)	Class A	Class A					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (If any)

From	To	From	To
1216'	1385'		
1531'	1570'		
1674'	1866'		
1997'	2133'		

Estimated Cost to Plug Wells
$20,047

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, Sr. Petroleum Engineer	Edward K Diminick	2/22/13

EPA Form 7520-14 (Rev. 12-11)

Q. Plugging and Abandonment Plan
Injection Well DD-7

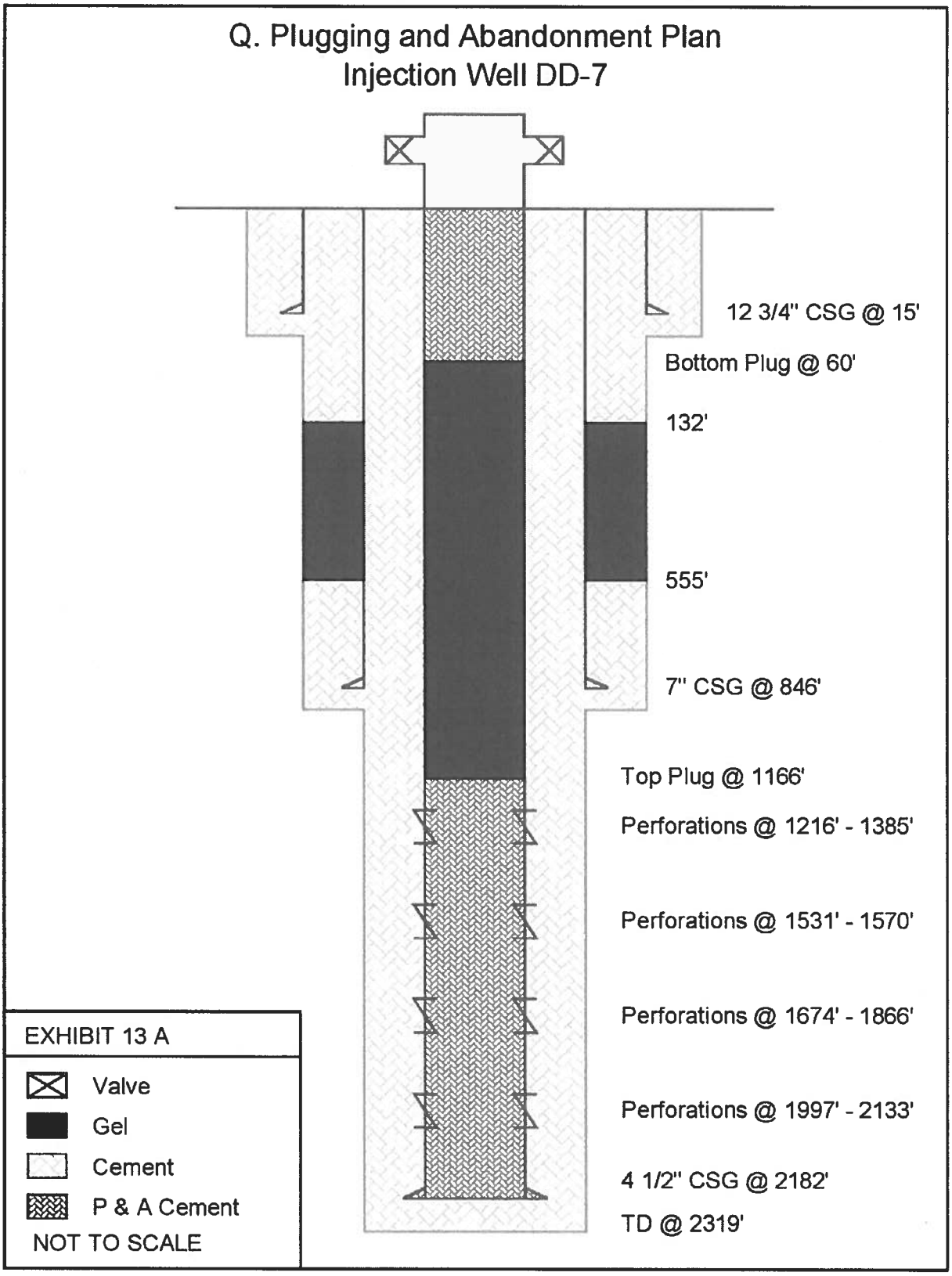


Exhibit 14

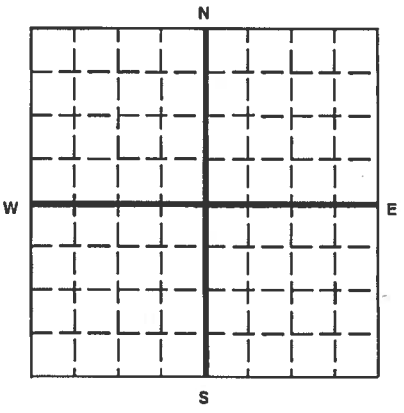
OMB No. 2040-0042 Approval Expires 11/30/2014

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Well DD-7A, Vansant Quadrangle, Buchanan County, VA Latitude 37° 10' 00" Longitude 82° 02' 30"	Cardno MM&A, 10376 Wallace Alley Street, Kingsport, TN 37663

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VA - 7787

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- ☐ Individual Permit
- ☑ Area Permit
- ☐ Rule

Number of Wells 3

WELL ACTIVITY

- ☐ CLASS I
- ☑ CLASS II
  - ☐ Brine Disposal
  - ☑ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ CLASS III

Lease Name Landon Wyatt Well Number DD-7A

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
13-3/8		20	20	15"
7"	20	253	253	8-7/8"
4-1/2"	9.5	1807	1807	6-1/2"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- ✓ The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	4-1/2	4-1/2					
Depth to Bottom of Tubing or Drill Pipe (ft	1807	60					
Sacks of Cement To Be Used (each plug)	77	5					
Slurry Volume To Be Pumped (cu. ft.)	91.3	5.5					
Calculated Top of Plug (ft.)	806	0					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6					
Type Cement or Other Material (Class III)	Class A	Class A					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (If any)

From	To	From	To
856'	975.5'		
1203'	1420'		
1599'	1803.5'		

Estimated Cost to Plug Wells

$20,047

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, Sr. Petroleum Engineer	Edward K Diminick	2/22/13

EPA Form 7520-14 (Rev. 12-11)

Q. Plugging and Abandonment Plan
Injection Well DD-7A

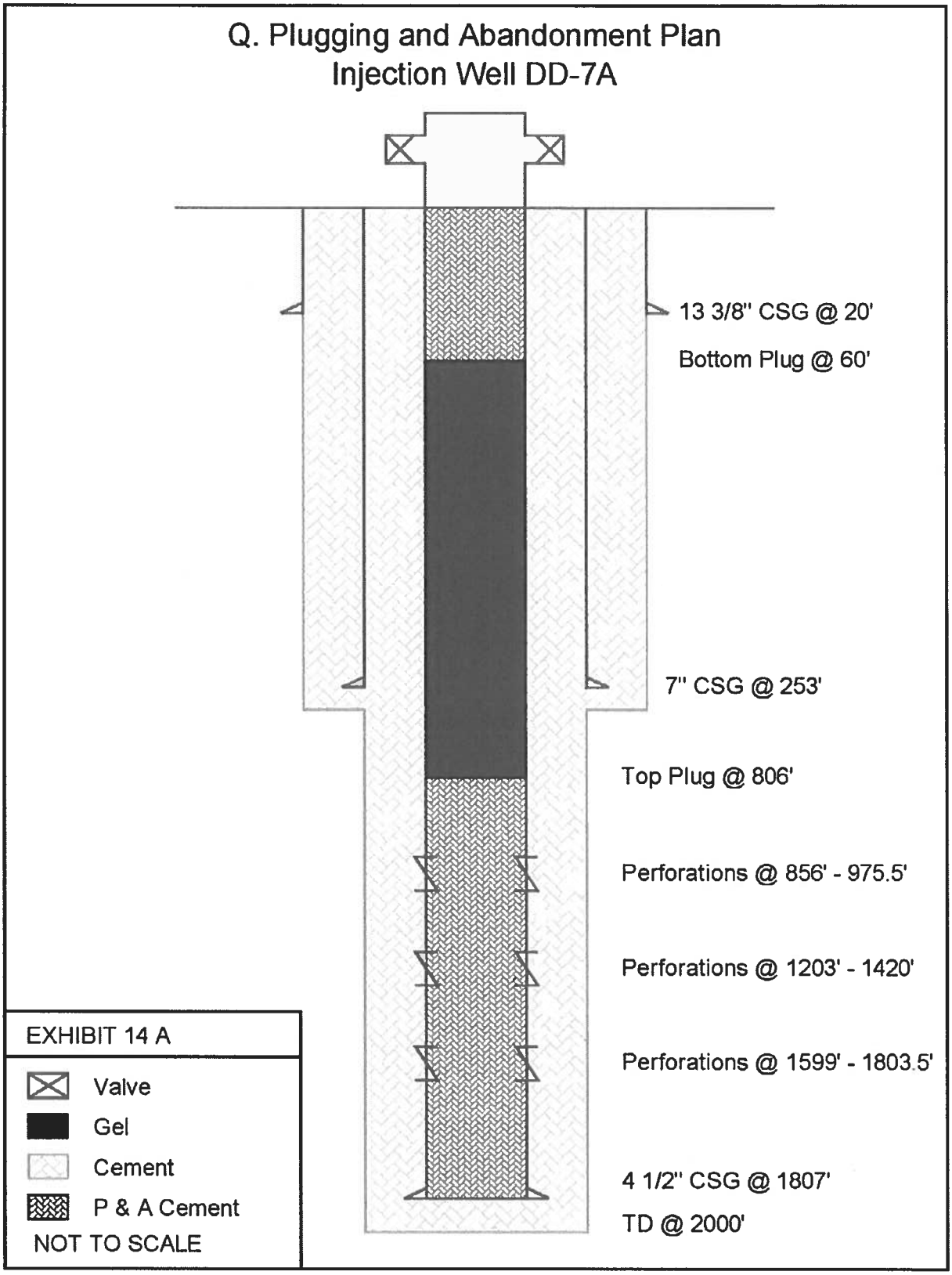


Exhibit 15

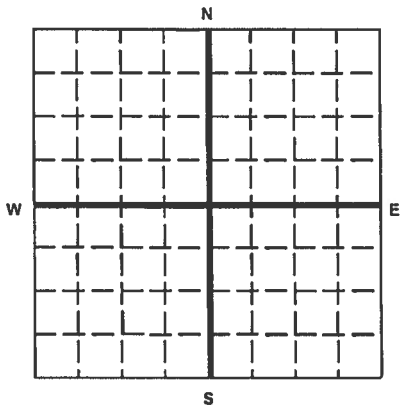
OMB No. 2040-0042 Approval Expires 11/30/2014

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Well DD-8, Vansant Quadrangle, Buchanan County, VA Latitude 37° 10' 00" Longitude 82° 02' 30"	Cardno MM&A, 10376 Wallace Alley Street, Kingsport, TN 37663

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Virginia	Buchanan	VA - 4824

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION
- [ ] Individual Permit
- [x] Area Permit
- [ ] Rule

Number of Wells 3

WELL ACTIVITY
- [ ] CLASS I
- [x] CLASS II
  - [ ] Brine Disposal
  - [x] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Lease Name Landon Wyatt Well Number DD-8

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
12-3 4		21	21	15"
7"	2	223	223	8-7/8"
4-1 2"	9.5	1822	1 22	6-1/2"

METHOD OF EMPLACEMENT OF CEMENT PLUGS
- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (Inche	4-1/2	4-1/2					
Depth to Bottom of Tubing or Drill Pipe (ft.	1822	60					
Sacks of Cement To Be Used (each plug)	77	5					
Slurry Volume To Be Pumped (cu. ft.)	91.3	5.5					
Calculated Top of Plug (ft.)	821	0					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.6	15.6					
Type Cement or Other Material (Class III)	Class A	Class A					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (If any)

From	To	From	To
871'	1205'		
1311'	1677.5'		
1710.5'	1802'		

Estimated Cost to Plug Wells

$20,047

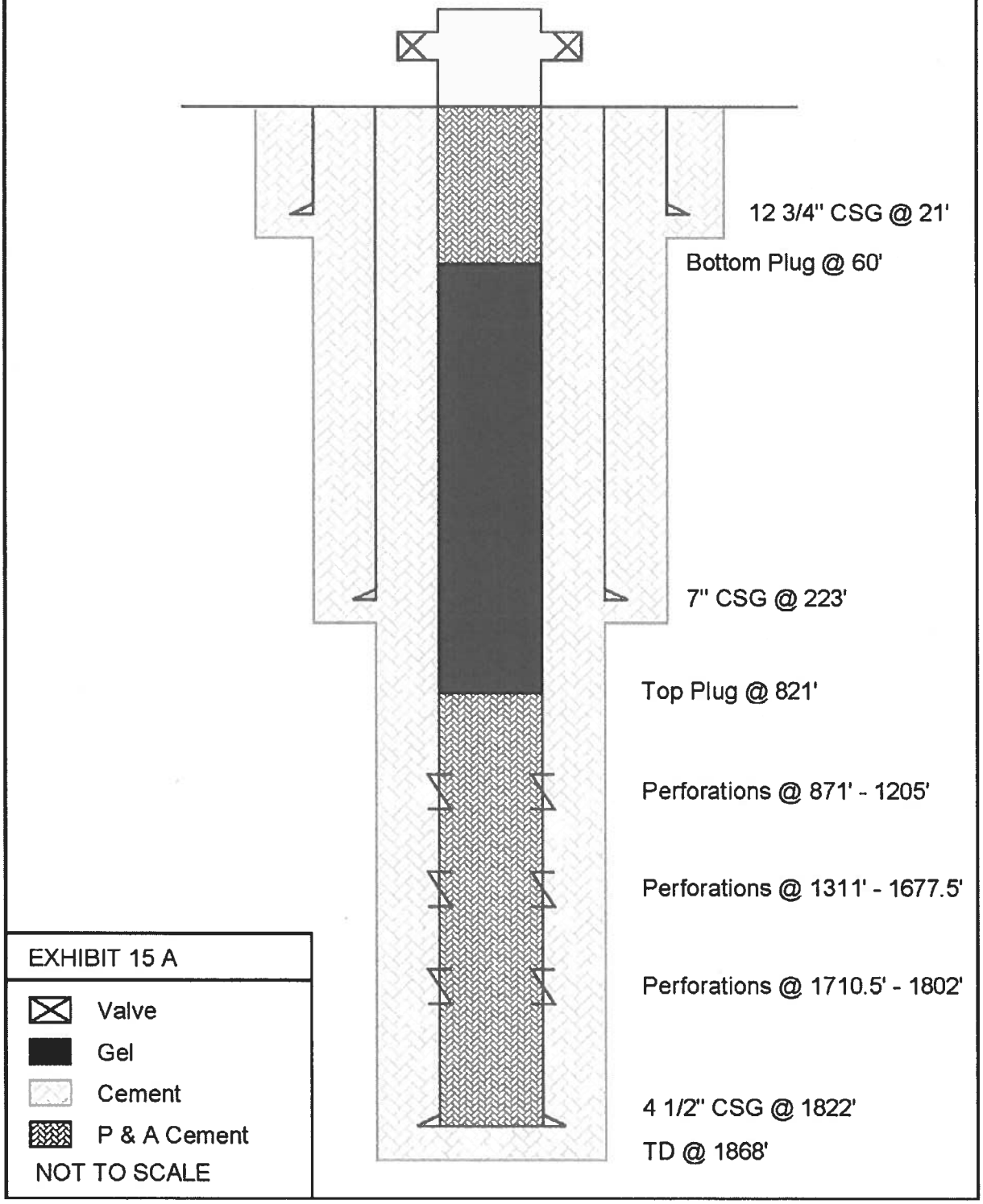
Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Edward K. Diminick, Sr. Petroleum Engineer	Edward K Diminick	2/22/13

EPA Form 7520-14 (Rev. 12-11)

Q. Plugging and Abandonment Plan
Injection Well DD-8



R. Necessary Resources

An Irrevocable Standby Letter of Credit, Standby Trust Agreement, Schedule A, and Certificate of Acknowledgement for Standby Trust Fund Agreement are included in this section.

BB&T

Branch Banking & Trust Co.

1309 Stafford Drive
Princeton, WV 24740

IRREVOCABLE STANDBY LETTER OF CREDIT

U.S. Environmental Protection Agency
Underground Injection Control
Financial Responsibility Requirement

To: Regional Administrator
Environmental Protection Agency Region 3
Ground Water & Enforcement Branch (3WP22)
1650 Arch Street
Philadelphia, PA 19103-2029

Dear Sir or Madam:

We hereby establish our Irrevocable Standby Letter of Credit No. 9570097196-00004 in your favor, at the request and for the account of

Marshall Miller & Associates, Inc. DBA Cardno MM&A
534 Industrial Park Drive
P.O. Box 848
Bluefield, VA 24605

up to the aggregate amount of sixty-thousand one-hundred forty-one U.S. dollars ($), available upon presentation of:

1. Your sight draft, bearing reference to this letter of credit No.9570097196-00004, and
2. Your signed statement reading as follows: "I certify that the amount of the draft is payable pursuant to regulations issued under authority of the Safe Drinking Water Act."

This letter of credit is effective as of February 14, 2013 and shall expire on December 31, 2013 but such expiration date shall be automatically extended for a period of at least 1 year later on December 31 and each successive expiration date, unless, at least 120 days before the current expiration date, we notify both you and Marshall Miller & Associates, Inc. DBA Cardno MM&A

by certified mail that we have decided not to extend this letter of credit beyond the current expiration date. In the event you are so notified, any unused portion of the credit shall be available upon presentation of your sight draft for 120 days after the date of receipt by both you and Marshall Miller & Associates, Inc. DBA Cardno MM&A, as shown on the signed return receipts.

Whenever this letter of credit is drawn on under and in compliance with the terms of this credit, we shall duly honor such draft upon presentation to us, and we shall deposit the amount of the draft directly into the standby trust fund of Marshall Miller & Associates, Inc. DBA Cardno MM&A in accordance with your instructions.

W. Larry Ratliff — (Signature)

2/14/18 — (Date)

W. Larry Ratliff — (Name)

SVP — (Title)

This credit is subject to:

( ) the most recent edition of the Uniform Customs and Practice for Documentary Credits, published by the International Chamber of Commerce,

OR

(x) the Uniform Commercial Code.

BB&T

Branch Banking & Trust Co.

1309 Stafford Drive
Princeton, WV 24740

STANDBY TRUST AGREEMENT

U.S. Environmental Protection Agency Underground Injection Control
Financial Responsibility Requirement

THIS TRUST AGREEMENT (the "Agreement") is entered into as of February 14, 2013 by and between Marshall Miller & Associates, Inc. DBA Cardno MM&A, owner or operator, a Virginia corporation (the "Grantor"), and Branch Banking & Trust Co. (the "Trustee"), a financial institution.

Whereas, the United States Environmental Protection Agency ("EPA"), an agency of the United States Government, has established certain regulations applicable to the Grantor, requiring that an owner or operator of an injection well shall provide assurance that funds will be available when needed for plugging and abandonment of the injection well or wells,

Whereas, the Grantor has elected to establish a trust to provide all or part of such financial assurance for the facility or facilities identified herein, and

Whereas, the Grantor, acting through its duly authorized officers, has selected the Trustee to be the trustee under this Agreement, and the Trustee is willing to act as trustee,

NOW THEREFORE, the Grantor and the Trustee agree as follows:

Section 1. Definitions. As used in this Agreement: (a) The term "Grantor" means the owner or operator who enters into this Agreement and any successors or assigns of the Grantor. (b) The term " Trustee" means the Trustee who enters into this Agreement and any successor Trustee. (c) Facility or activity means any "underground injection well" or any other facility or activity that is subject to regulation under the Underground Injection Control Program.

Section 2. Identification of Facilities and Cost Estimates. This Agreement pertains to the facilities and cost estimates identified on attached Schedule A.

Section 3. Establishment of Fund. The Grantor and the Trustee hereby establish a trust fund (the "'Fund") for the purpose of assuring compliance with the plugging and abandonment requirements established by EPA for the facilities identified on Schedule A. The Underground Injection Control regulations which govern the authorization to inject include a requirement for such financial assurance that the well or wells shall be plugged and abandoned at the time designated by EPA. The Grantor and the Trustee acknowledge that the Fund and all expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of EPA. The Grantor and the Trustee intend that no third party have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, IN

TRUST, as hereinafter provided. The Trustee shall not be responsible, nor shall it undertake any responsibility, for the amount or adequacy of any additional payments necessary to discharge any liabilities of the Grantor established by EPA, nor shall the Trustee have any duty to collect such additional amounts from the Grantor.

Section 4. Payment for Plugging and Abandonment. The Trustee shall make payments from the Fund only for the costs of plugging and abandonment ("P&A") of the injection wells covered by this Agreement and the associated P&A Plan, only after EPA has advised the Trustee that work has been completed under the P&A Plan that complies with 40 C.F.R. § 144.28 and/or § 144.52. The Trustee shall not refund to the Grantor any amounts from the Fund unless and until EPA has advised the Trustee that the P&A Plan has been successfully completed. The Trustee shall not release any funds to the Grantor that are necessary to cover liability for any injection wells covered by this Agreement that remain unplugged.

Section 5. Payments Comprising the Fund. Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee.

- *Section 6. Trustee Management. The Trustee shall invest and reinvest the principal and income of the Fund and keep the Fund invested as a single fund, without distinction between principal and income, in accordance with general investment policies and guidelines which the Grantor may communicate in writing to the Trustee from time to time, subject, however, to the provisions of this Section. In investing, reinvesting, exchanging, selling, and managing the Fund, the Trustee shall discharge his duties with respect to the trust fund solely in the interest of the beneficiary and with the care, skill, prudence, and diligence under the circumstances then prevailing which persons of prudence, acting in a like capacity and familiar with such matters, would use in the conduct of an enterprise of a like character and with like aims; except that:*

  (i) Securities or other obligations of the Grantor, or any other owner or operator of the facilities, or any of their affiliates as defined in the Investment Company Act of 1940, as amended, 15 U.S.C. 80a-2.(a), shall not be acquired or held, unless they are securities or other obligations of the Federal or a State government;

  (ii) The Trustee is authorized to invest the Fund in time or demand deposits of the Trustee, to the extent insured by an agency of the Federal or State government; and

  (iii) The Trustee is authorized to hold cash awaiting investment or distribution uninvested for a reasonable time and without liability for the payment of interest thereon.

Section 7. Commingling and Investment. The Trustee is expressly authorized in its discretion: (a) To transfer from time to time any or all of the assets of the Fund to any common, commingled, or collective trust fund created by the Trustee in which the Fund is eligible to participate, subject to all of the provisions thereof, to be commingled with the assets of other trusts participating therein; and (b) To purchase shares in any investment company registered under the Investment Company Act of 1940, 15 U. S. C. 80a-1 *et seq.*, including one which may be created, managed, underwritten, or to which investment advice is rendered or the shares of which are sold by the Trustee. The Trustee may vote shares in its discretion.

Section 8. Express Powers of Trustee. Without in any way limiting the powers and discretions conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered: (a) To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition; (b) To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted; (c) To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depositary with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve bank, but the books and records of the Trustee shall at all times show that all such securities are part of the Fund; (d) To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the Federal or State government; and (e) To compromise or otherwise adjust all claims in favor of or against the Fund.

Section 9. Taxes and Expenses. All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and all other proper charges and disbursements of the Trustee shall be paid from the Fund.

Section 10. Annual Valuation. The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the appropriate EPA Regional Administrator a statement confirming the value of the Trust. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund. The failure of the Grantor to object in writing to the Trustee within 90 days after the statement has been furnished to the Grantor and the EPA Regional Administrator shall constitute a conclusively binding assent by the Grantor, barring the Grantor from asserting any claim or liability against the Trustee with respect to matters disclosed in the statement.

Section 11. Advice of Counsel. The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any question arising as to the construction of this Agreement of any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

Section 12. Trustee Compensation. The Trustee shall be entitled to reasonable compensation for its

services as agreed upon in writing from time to time with the Grantor.

Section 13. Successor Trustee. The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor trustee and this successor accepts the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall specify the date on which it assumes administration of the trust in a writing sent to the Grantor, the EPA Regional Administrator, and the present Trustee by certified mail 10 days before such change becomes effective. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

Section 14. Instructions to the Trustee. All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by such persons as are designated in the attached Exhibit A or such other designees as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the EPA Regional Administrator to the Trustee shall be in writing, signed by the EPA Regional Administrators of the Regions in which the facilities are located, or their designees, and the Trustee shall act and shall be fully protected in acting in accordance with such orders, requests, and instructions. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or a termination of the authority of any person to act on behalf of the Grantor or EPA hereunder has occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or EPA, except as provided for herein.

Section 15. Notice of Nonpayment. The Trustee shall notify the Grantor and the appropriate EPA Regional Administrator, by certified mail within 10 days following the expiration of the 30- day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period. After the pay-in period is completed, the Trustee shall not be required to send a notice of nonpayment.

Section 16. Amendment of Agreement. This Agreement may be amended by an instrument in writing executed by the Grantor, the Trustee, and the appropriate EPA Regional Administrator, or by the Trustee and the appropriate EPA Regional Administrator if the Grantor ceases to exist.

Section 17. Irrevocability and Termination. Subject to the right of the parties to amend this Agreement as provided in Section 16, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor, the Trustee, and the EPA Regional Administrator, or by the Trustee and the EPA Regional Administrator if the Grantor ceases to exist. Upon termination of the Trust, all remaining

trust property, less final trust administration expenses, shall be delivered to the Grantor.

Section 18. Immunity and Indemnification. The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any directions by the Grantor or the EPA Regional Administrator issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Trust Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all expenses reasonably incurred in its defense in the event the Grantor fails to provide such defense.

Section 19. Choice of Law. This Agreement shall be administered, construed, and enforced according to the laws of the State of Virginia.

Section 20. Interpretation. As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

IN WITNESS WHEREOF the parties have caused this Agreement to be executed by their respective representatives duly authorized and their seals to be hereunto affixed and attested as of the date first above written.

GRANTOR		TRUSTEE	
By:	Cathy S Yost Cathy Yost		W. Larry Ratliff
Its:	CFO Title	Its:	SVP Title
Attest:		Attest:	
Its:	Title	Its:	Title

Seal

Embossed Hereon Is My
Commonwealth Of Virginia Notary Public Seal
My Commission Expires June 30, 2013
MARIE KELLEY CHEEKS

Seal

Before me came the individual whose identity I confirmed as Cathy S. Yost, and whose true signature is set forth above; wherefore have I set my hand and seal this 14th day of February, 2013.

Marie Kelley Cheeks
Notary Public

My Commission No.
172625

Before me came the individual whose identity I confirmed as W. Larry Ratliff, and whose true signature is set forth above; wherefore have I set my hand and seal this 14 day of February, 2013.

Notary Public

NOTARY PUBLIC OFFICIAL SEAL
SANDRA HILL
STATE OF WEST VIRGINIA
1309 Stafford Dr.
Princeton, WV 24740
My Commission Expires Oct. 21, 2017

SCHEDULE A

Identification of Facilities and Cost Estimates

Schedule A is referenced in the standby trust agreement dated February 14, 2013 by and between Cardno MM&A (Name of owner or operator), the "Grantor" and BB&T Branch Banking and Trust (Name of trustee), the "Trustee"

EPA identification number	
Name of facility	CO_2 Project
Address of facility	Hurricane District, Buchanan County, VA
Current plugging and abandonment cost estimate	$20,047 per well
Total for 3 wells	$60,141
Date of estimate	January 25, 2013
Well number	Injection Well DD-7
Well Number	Injection Well DD-7A
Well Number	Injection Well DD-8

CERTIFICATE OF ACKNOWLEDGMENT
FOR
STANDBY TRUST FUND AGREEMENT

STATE OF Virginia

COUNTY OF Tazewell

On this 13rh day of February, 2013 , before me personally came Cathy Yost to me known, who, being by me duly sworn, did depose

and say that he/she resides at 534 Industrial Park Rd, Bluefield VA 24605

That he/she is CFO of Cardno MM&A

(Title) (Corporation)

the corporation described in and which executed the above instrument; the he/she knows the seal of said corporation; that the seal affixed to such instrument is such corporate seal; that it was so affixed by order of the Board of Directors of said corporation, and that he/she signed his/her name thereto by like order.

Embossed Hereon Is My
Commonwealth Of Virginia Notary Public Seal
My Commission Expires June 30, 2013
MARIE KELLEY CHEEKS

(Notary Public)

My Commission No.
172625

(Seal)

S. Aquifer Exemptions

Not seeking an exemption.

T. Existing EPA Permits

Cardno MM&A does not hold any existing EPA permits.

U. Description of Business

Cardno MM&A is a 200-person energy, environmental and engineering consulting firm headquartered in Bluefield, Virginia. We are an operating subsidiary of a much larger, multi-national consulting and services firm, Cardno, Ltd., based in Brisbane, Australia. Personnel from the oil and gas office of Cardno MM&A located in Kingsport, Tennessee will oversee the planning and operations of this UIC project. The applicable SIC code is 1311, Crude Petroleum and Natural Gas.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Mr. Ed Diminick, P.E.
Senior Petroleum Engineer
Cardno MM&A
10376 Wallace Alley Street
Kingsport, TN 37663

RE: Underground Injection Control (UIC) Permit VAS2R971BBUC

Dear Mr. Diminick:

The U.S. Environmental Protection Agency, Region III (EPA) is issuing the above referenced final permit, which authorizes Cardno MM&A to operate three (3) class 2R injection wells in Buchanan County, Virginia. EPA has taken all the necessary regulatory steps for the issuance of this permit, including opening the draft permit for public comment and offering the opportunity for a public hearing.

In accordance with Part II, Section C3 of the enclosed permit, and the federal UIC regulations at 40 C.F.R. § 146.8, Cardno MM&A must demonstrate the mechanical integrity of an individual well prior to commencing injection into that well. A representative of EPA's Water Protection Division Director must be present to witness each mechanical integrity test. Please advise me as to when you would like to schedule mechanical integrity tests for the injection wells.

Please contact me at (215) 814-5427 if you have any questions on the permit, or the UIC program in general. Thank you very much for your cooperation and patience throughout the permitting process.

Very Respectfully,

Michael P. Eller
Ground Water and Enforcement Branch (3WP22)

Enclosures
Final UIC Permit # VAS2R971BBUC

Printed on 100% recycled/recyclable paper with 100% post-consumer fiber and process chlorine free.
Customer Service Hotline: 1-800-438-2474

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

UNDERGROUND INJECTION CONTROL (UIC) PERMIT NUMBER VAS2R971BBUC AUTHORIZATION TO OPERATE A CLASS II-R INJECTION WELL

In compliance with provisions of the Safe Drinking Water Act, as amended (42 U.S.C. §§ 300f-300j-11, commonly known as the SDWA), and implementing regulations promulgated by the U. S. Environmental Protection Agency at Parts 144 – 146, of Title 40 of the Code of Federal Regulations,

Cardno MM&A
10376 Wallace Alley Street
Kingsport, Tennessee 37663

is authorized by this Permit as the Permittee to inject carbon dioxide in accordance with the provisions of this Permit, through three (3) Class II-R injection wells (Well DD-7, well DD-7A, and well DD-8, hereinafter collectively, "Injection Wells") into bituminous coal beds in the Pennsylvanian Lee and Pocahontas formations, in accordance with the conditions set forth herein. The coordinates for the Injection Wells are:

DD-7: Latitude 37° 08' 20" N, Longitude 82° 05' 0.4" W
DD-7A: Latitude 37° 08' 13" N, Longitude 82° 04' 55" W
DD-8: Latitude 37° 08' 19" N, Longitude 82° 04' 40" W

The Injection Wells will be located at:

Oakwood Coal Bed Methane Field
Hurricane District
Buchanan County, Virginia
(hereinafter, "the Facility")

All references to Title 40 of the Code of Federal Regulations are to regulations that are in effect on the date that this Permit becomes effective.

This Permit shall become effective on December 19, 2013.

This Permit shall remain in effect until the earlier of the following activities: (i) the proper plugging and abandonment of said Injection Wells following when they cease to operate; or (ii) the conversion of the Injection Wells into production wells.

Signed this 19th day of December, 2013.

Jon M. Capacasa, Director
Water Protection Division

PART I

A. Effect of Permit

Cardno MM&A (hereinafter, "Permittee") is allowed to engage in underground injection into the Injection Wells in accordance with the conditions of this Permit. The Permittee shall not allow the underground injection activity, otherwise authorized by this Permit, to cause or contribute to the movement of fluid containing any contaminant into any Underground Sources of Drinking Water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 C.F.R. Part 141, or if it may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit is prohibited. Issuance of this Permit does not convey property rights or mineral rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with terms of this Permit does not constitute a defense to any action brought under Parts C or D of the Federal Safe Drinking Water Act, 42 U.S.C. §§ 300f-300j-11 (SDWA) or any other common or statutory law for any breach of any other applicable legal duty.

B. Permit Actions

This Permit can be modified, revoked and reissued or terminated for cause as specified in 40 C.F.R. §§ 144.12, 144.39 and 144.40. Also, the Permit is subject to minor modifications as specified in 40 C.F.R. § 144.41. The filing of a request for a Permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the Permittee shall not stay the applicability or enforceability of any Permit condition.

C. Severability

The provisions of this Permit are severable, and if any provision of this Permit or the Permittee's application, dated February 22, 2013, and revised May, 2013, is held invalid, the remainder of this Permit shall not be affected thereby.

D. General Requirements

1. Duty to Comply. The Permittee shall comply with all Underground Injection Control (UIC) Program regulations, 40 C.F.R. Parts 144-146, and with the conditions of this Permit, except to the extent and for the duration that EPA authorizes such noncompliance by an emergency Permit issued under 40 C.F.R. 144.34. Any Permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, Permit termination, revocation and reissuance, modification, or for denial of a Permit renewal application.

2. Need to Halt or Reduce Activity Not a Defense. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

3. Duty to Mitigate. The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

4. Proper Operation and Maintenance. The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

5. Duty to Provide Information. The Permittee shall furnish to the Director of the EPA Region 3 Water Protection Division ("Director"), within a time specified by the Director, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with this Permit. The Permittee shall also furnish to the Director, upon request, copies of any records required to be kept by this Permit. If the Permittee becomes aware of any incomplete or incorrect information in the Permit Application or subsequent reports, the Permittee shall promptly submit information addressing these deficiencies. For purposes of this Permit, reports that are required to be submitted "in writing," or in "written" format may be submitted electronically through email or facsimile, unless otherwise specified herein.

6. Inspection and Entry. Upon the presentation of credentials and other documents as may be required by law, the Permittee shall allow the Director, or an authorized representative, to:

a. Enter upon and inspect the Facility;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit; and

c. Sample any substances or monitor any parameters at any location within the Facility, at reasonable times, for the purposes of assuring Permit compliance or as otherwise authorized by SDWA.

7. Penalties. Any person who violates a requirement of this Permit is subject to administrative or civil penalties, fines and other enforcement actions under the SDWA. Any person who willfully violates Permit conditions may be subject to criminal prosecution under the SDWA.

8. Transfer of Permits. This Permit is not transferable to any person except after written notice is sent to the Director on EPA Form 7520; approval is received from the Director; and the requirements of 40 C.F.R. § 144.38 are satisfied. The Director may require modification or revocation of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA or its implementing regulations. The

transferee is not authorized to inject under this Permit unless and until the Director notifies it that it is so authorized through issuance of a revised permit identifying the transferee as the permittee.

9. Signatory Requirements.

a. The Permittee shall sign all reports required by this Permit and other information requested by the Director as follows:

(1) for a corporation, by a responsible corporate officer of at least the level of vice-president;

(2) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively; or

(3) for a Municipality, State, Federal, or other public agency by either a principal executive or a ranking elected official or appointee.

b. A duly authorized representative of the individual designated in paragraph a. above may also sign only if:

(1) the authorization is made in writing by a person described in paragraph I.9.a. above;

(2) the authorization specifies either an individual or a position having responsibility for the overall operation of the Facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and

(3) the written authorization is submitted to the Director.

c. If an authorization under paragraph b. of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the Facility, a new authorization satisfying the requirements of paragraph b. of this section must be submitted to the Director prior to or together with any reports, information or applications to be signed by an authorized representative.

d. Any person signing a document under paragraph a. or b. of this section shall make the following certification:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person(s) who manage the system, or those persons directly responsible for gathering the

information, the information submitted is to the best of my knowledge and belief, true accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

10. Confidentiality of Information.

a. In accordance with 40 C.F.R. Part 2 (Public Information) and § 144.5, any information submitted to the Director pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 C.F.R. Part 2.

b. EPA will deny any claims of confidentiality for the following information:

(1) The name and address of any Permit applicant or Permittee; and

(2) Information which deals with the existence, absence, or level of contaminants in drinking water.

11. Reapplication. If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, the Permittee must submit a complete application for a new Permit at least 100 days before this Permit expires.

12. State Laws. Nothing in this Permit shall be construed to preclude the institution of any legal action or to relieve the Permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation.

PART II

A. General

The Permittee shall sign and certify copies of all reports and notifications required by this Permit in accordance with the requirements of Section I.D.9 of this Permit and submit such information to the Director at the following address:

Ground Water & Enforcement Branch (3WP22)
Office of Drinking Water & Source Water Protection
U. S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, Pennsylvania 19103

B. Record Retention

1. The Permittee shall retain records of all monitoring and other information required by this Permit, including the following (if applicable), for a period of at least five years from the date of the sample, measurement, report or application, unless such records are required to be retained for a longer period of time under paragraph II.B.2, below. This period may be extended by the Director at any time. If the period is extended, the Director may notify the Permittee in writing and the Permittee must comply with the new period.

a. All data required to complete the Permit Application form for this Permit and any supplemental information submitted under 40 C.F.R. § 144.31;

b. Calibrations, maintenance records and all original strip chart recordings for continuous monitoring instrumentation; and

c. Copies of all reports required by this Permit.

2. The Permittee shall retain records concerning the nature and composition of all injected fluids, as listed in paragraphs II.C.3. and II.C.4. of this Permit, until three years after the completion of any plugging and abandonment procedures, or when the wells are converted back into production wells, whichever comes first. After three years from the earlier of the completion of plugging and abandonment, or conversion back into production wells, the Permittee shall continue to retain such records unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records.

3. Records of monitoring information shall include:

a. The date, exact place, and the time of sampling or measurements;

b. The individual(s) who performed the sampling or measurements;

c. A precise description of both sampling methodology and the handling (custody) of samples;

d. The date(s) analyses were performed;

e. The individual(s) who performed the analyses;

f. The analytical techniques or methods used; and

g. The results of such analyses.

C. Monitoring Requirements

1. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The Permittee shall obtain representative sample(s) of the carbon dioxide that is injected into the Injection Wells and conduct analysis(es) of the

sample(s) in accordance with the approved methods provided at 40 C.F.R. § 136.3, or methods and test procedures otherwise approved by the Director. The Permittee shall identify in its monitoring records the types of tests and methods used to generate the monitoring data.

2. For each Injection Well, the Permittee shall monitor and record surface injection pressure, annular pressure, flow rate and cumulative volume continusously, beginning on the date on which each Injection Well commences operation and ending when the Injection Well is plugged and abandoned, or is converted back into a production well, whichever comes first. The Permittee shall compile the monitoring data quarterly to complete the Annual Report referenced at II.D.8 herein.

3. The Permittee shall make a demonstration of mechanical integrity, in accordance with 40 C.F.R. § 146.8, prior to the commencement of injection into any of the Injection Wells. After the initial demonstration of mechanical integrity, the Permittee shall make a demonstration of mechanical integrity for each Injection Well in accordance with 40 C.F.R. § 146.8 at least once every five years that this Permit is in effect, by conducting a mechanical integrity test. The Permittee shall conduct subsequent five-year demonstrations within five years of the date that the previous demonstration was made. In addition to the above requirement, the Permittee shall conduct a mechanical integrity test demonstration whenever protective casing or tubing is removed from any Injection Well, whenever a packer is reseated, or when failure of any Injection Well is evident. The Permittee may continue injection into a given Injection Well only if it has successfully demonstrated to the Director the mechanical integrity of the permitted Injection Well. The Permittee shall cease injection operations into a given Injection Well if a loss of mechanical integrity becomes evident or if it cannot demonstrate mechanical integrity for that Injection Well.

4. The Permittee shall perform all environmental measurements required by the Permit, including but not limited to: measurements of pressure, temperature, mechanical integrity, and chemical analysis, in accordance with EPA guidance on quality assurance.

D. Reporting and Notification Requirements.

1. Report on Permit Review. Within 30 days of receipt of this Permit, a duly-authorized representative of Permittee shall report in writing to the Director that he or she has read and is personally familiar with all terms and conditions of this Permit.

2. Commencing Injection. The Permittee shall not commence injection into a given Injection Well until injection tubing and packer have been installed in that Injection Well in accordance with paragraph III.A.2. of this Permit and all of the following conditions have been satisfied for that Injection Well:

a. The Permittee has submitted written notice of completion of construction (EPA Form 7520-10) to the Director;

b. The Permittee has demonstrated to EPA that the Injection Well has mechanical integrity in accordance with 40 C.F.R. § 146.8 and the Permittee has received written notice from the Director that such demonstration is satisfactory; and

c.(i) The Director has inspected or otherwise reviewed the Injection Well and finds that it is in compliance with the conditions of the Permit; or

c.(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the Injection Well within 13 days of the date of the notice in paragraph (a) of this Permit condition, in which case, prior inspection or review is waived and the Permittee may commence injection.

3. Twenty-four Hour Reporting.

a. The Permittee shall report to the Director any noncompliance which may endanger, or has endangered, human health or the environment. The Permittee shall provide such report orally (phone numbers: [215] 814-5469 or [215] 814-5445) within 24 hours of the time the Permittee becomes aware of the circumstances. The Permittee shall include the following as information in the oral report:

(i) Any monitoring or other information which indicates that any contaminant may endanger, or has endangered, an underground source of drinking water.

(ii) Any noncompliance with a Permit condition, or malfunction of the injection system, which may cause, or has caused, fluid migration into or between underground sources of drinking water, or failure of mechanical integrity test demonstrations.

b. The Permittee shall provide a written submission within five days of the time the Permittee becomes aware of the circumstances described in Paragraph II.D.3.a. above. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

4. Anticipated Noncompliance. The Permittee shall give advance notice in writing to the Director at least thirty (30) days prior to any planned changes to the Facility, which may result in noncompliance with any Permit requirements.

5. Other Noncompliance. The Permittee shall report to the Director all other instances of noncompliance in writing within ten (10) days of the time the Permittee becomes aware of the circumstances. The reports shall contain the information listed in Paragraph II.D.e of this Permit.

6. Planned Changes. The Permittee shall give written notice to the Director as soon as possible of any planned physical alterations or additions to the Facility.

7. Conversion. The Permittee shall notify the Director in writing thirty (30) days prior to the conversion of an Injection Well to an operating status other than an injection well.

8. Annual Reports. The Permittee shall submit a written Annual Report to the Director no later than January 31 of the year following the year for which the report is submitted. The Annual Report shall summarize the results of the monitoring required by Permit Condition II.C. of this Permit. The Annual Report shall include the compiled quarterly monitoring records of injected fluids, the results of any mechanical integrity test(s), and any major changes in characteristics or sources of injected fluids. The Permittee shall complete and submit this information with its Annual Report EPA Form 7520-11 (Annual Disposal/Injection Well Monitoring Report).

9. Final Report. The Permittee shall submit a written Final Report to the Director summarizing the results of injection activities no later than January 31 of the year following the year in which the Injection Wells are plugged and abandoned or converted back into production wells, whichever comes first.

10. Plugging and Abandonment Reports and Notifications.

a. The Permittee shall notify the Director in writing at least forty-five (45) days before the plugging and abandonment of any Injection Well. The Director may allow a shorter notice period upon written request.

b. The Permittee shall submit any revisions to the Plugging and Abandonment Plan attached to and incorporated into this permit (Attachment 1), to the Director no less than 45 days prior to plugging and abandonment on EPA Plugging and Abandonment Form 7520-14. The Permittee shall not commence plugging and abandonment until it receives written approval of the revisions to the Plan from the Director.

c. Within sixty (60) days after plugging any Injection Well, the Permittee shall submit a written report to the Director which shall consist of either:

(i) A statement that the injection well was plugged in accordance with the plan previously submitted to and approved by the Director; or

(ii) Where actual plugging differed from the plan previously submitted, an updated version of the plan, on the form supplied by the Director, specifying the different procedures used. Any deviation from a previously approved plan which may endanger a USDW is cause for the Director to require the operator to reenter and plug the well in accordance with UIC regulations.

d. The Permittee shall ensure that the report is certified as accurate by the person who performed the plugging operation, in accordance with paragraph I.9.d. herein.

11. Mechanical Integrity Tests. The Permittee shall notify the Director in writing of its intent to conduct a mechanical integrity test at least thirty (30) days prior to such a demonstration.

12. Cessation of Injection Activity. After the Permittee has ceased injection into any Injection Well for two (2) years, the Permittee shall plug and abandon such Injection Well in accordance with the Plugging and Abandonment Plan (Attachment 1 hereto), unless either of the following apply:

a. (i) The Permitttee provides written notice to the Director that describes actions and/or procedures, including compliance with the technical requirements applicable to the Injection Well(s), that are necessary to ensure that the Injection Well(s) will not endanger USDWs during any period of temporary abandonment, unless waived, in writing by the Director; (ii) the Permittee receives written notice from the Director that the actions and/or procedures described in the notice are satisfactory; and (iii) the Permittee implements the actions or procedures as described in the written notice to the Director provided in Paragraph II.D.12.a herein; or

b. The Injection Well is converted back into a production well.

E. Mechanical Integrity Standards

1. Standards. The Permittee shall maintain the mechanical integrity of all Injection Wells pursuant to 40 C.F.R. § 146.8.

2. Request from Director. The Director may, by written notice, require the Permittee to demonstrate mechanical integrity of any Injection Well at any time during the term of this Permit, and the Permittee must comply with the Director's request.

PART III

A. Construction Requirements

1. Injection. Notwithstanding any other provision of this Permit, the Permittee shall inject through the Injection Wells only into formations which are separated from any Underground Source of Drinking Water (USDW) by a confining zone, as defined at 40 C.F.R. § 146.3, that is free of known open faults or fractures within the Area of Review as defined at 40 C.F.R. § 146.3.

2. Tubing and Packer. The Permittee shall install at each Injection Well tubing and packer inside the long-string casing set above the uppermost injection zone, as defined at 40 C.F.R. § 146.3, of each Injection Well. The Permittee shall ensure that injection occurs only through such tubing and packer.

3. Mechanical Integrity. The Permittee is prohibited from conducting injection operations into any Injection Well until it demonstrates: (i) that the given Injection Well has mechanical integrity in accordance with 40 C.F.R. § 146.8; and (ii) the Permittee has received notice from the Director that such a demonstration is satisfactory in accordance with the paragraph II.D.2 of this Permit.

4. Corrective Action. Prior to injection into any Injection Well, the Permittee shall complete corrective action by plugging and abandoning any "abandoned wells," as defined at 40 C.F.R. § 146.3, within the "Area of Review," as defined at 40 C.F.R. § 146.3, that could provide conduits for fluid migration into USDWs. If an abandoned well is discovered within the Area of Review after injection commences, the Permittee shall notify the Director upon discovery, and within five (5) days of such discovery, the Permittee shall submit to the Director for approval a plan for corrective action, consistent with the requirements of 40 C.F.R. Parts 144 - 146.

B. Operating Requirements

1. Injection Formation. The Permittee shall limit its injection to coal beds within the Lee and Pocahontas Formations located in the following subsurface intervals:

Well DD-7: 1216 to 1385 ft, 1531 to 1570 ft, 1674 to 1866 ft, and 1997 to 2133 ft.
Well DD-7A: 856 to 975.5 ft, 1203 to 1420 ft, and 1599 to 1803.5 ft.
Well DD-8: 871 to 1205 ft, 1311 to 1677.5 ft, and 1710.5 to 1802 ft.

2. Injection Fluid. The Permittee shall not inject into any Injection Well(s) any hazardous substances, as defined by 40 C.F.R. Part 261, or any other fluid, other than carbon dioxide.

3. Injection Volume Limitation. The Permittee shall ensure that injection volume does not exceed 50 metric tons per day, per Injection Well.

4. Injection Pressure Limitation. The Permittee shall not exceed the following maximum bottom-hole injection pressures:

Well DD-7: 1583 psi (surface pressure = 852 psi)
Well DD-7A: 1262 psi (surface pressure = 943 psi)
Well DD-8: 1535 psi (surface pressure = 1153 psi)

Surface injection pressure may be adjusted to account for the variable gas phase changes that may occur with carbon dioxide during injection, but at all times, the maximum bottom-hole pressure must never be exceeded.

The Permittee is prohibited from injecting carbon dioxide at a pressure which initiates new fractures or propagates existing fractures in the confining zone, as defined at 40 C.F.R. § 146.3, adjacent to USDWs or which causes the movement of injection or formation fluids into a USDW.

5. For all of the Injection Wells, the Permittee is prohibited from injecting between the outermost casing protecting any USDW and the well bore, and also from injecting into any USDW.

C. Plugging and Abandonment.

1. Plugging and Abandonment. If the Permittee must plug and abandon any Injection Well(s), the Permittee shall plug and abandon such Injection Well(s) in accordance with the EPA-approved Plugging and Abandonments Plan (EPA Form 7520-14) (Attachment 1 hereto).

2. The Permittee shall plug and abandon the Injection Wells in such a manner that fluids shall not move into or between USDWs.

D. Financial Responsibility

1. The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection wells in accordance with 40 C.F.R. § 144.52(a)(7) in the amount of at least $20,047 per Injection Well. A well may not be constructed, reworked or operated if the financial responsibility for that well has not been established for that Injection Well. Further, the Permittee shall provide documentation to the Director that financial responsibility has been established for the Injection Well(s) prior to construction, rework or operation in the form of a revised financial responsibility demonstration submitted by Branch Banking and Trust Co., the established Trustee. The Permittee shall not substitute an alternative demonstration of financial responsibility from that which the Director has approved, unless it has previously submitted evidence of that alternative demonstration to the Director and the Director notifies him or her that the alternative demonstration of financial responsibility is acceptable. The Director may require the Permittee to submit a revised demonstration of Financial Responsibility if the Director has reason to believe that the original demonstration is no longer adequate to cover the costs of plugging and abandonment.

2. Insolvency of Financial Institution. In the event of the bankruptcy of the Trustee or issuing institution of the financial mechanism, or a suspension or revocation of the authority of the Trustee institution to act as a trustee or the institution issuing the financial mechanism to issue such an instrument, the Permittee must immediately notify the Director in writing. The Permittee shall submit an alternative demonstration of financial responsibility acceptable to the Director within sixty days after such an event.

CONCURRENCES

YMBOL	3WP22	3RC20	3WP22	3WP20	3WP00			
URNAME	ELLER	KIER	JOHNSON	BINETTI	CAPACASA			
ATE	MPE 6DEC13	12/13						

PA Form 1320-1 (12-70)

OFFICIAL FILE COPY

Jamieson

Table I
PROPOSED INJECTION WELLS - MAXIMUM INJECTION PRESSURES

Based on ISIP

DD-7

1st stage	75Q foam	
Breakdown	1589	psig
ISIP FF-8A	1359	psig
Depth	2065	feet
BHP from ISIP	**1583**	psig
Liquid CO_2 Density Calculated	6.81	ppg
Maximum Allowable WHP	**851**	psig

2nd stage	75Q foam	
Breakdown	2433	psig
ISIP	3203	psig
Depth	1770	feet
BHP from ISIP	3395	psig
Liquid CO_2 Density Calculated	6.81	ppg
Maximum Allowable WHP	2768	psig

3rd stage	75Q foam	
Breakdown	3111	psig
ISIP	2423	psig
Depth	1551	feet
BHP from ISIP	2591	psig
Liquid CO_2 Density Calculated	6.81	ppg
Maximum Allowable WHP	2042	psig

4th stage	75Q foam	
Breakdown	2897	psig
ISIP	1930	psig
Depth	1301	feet
BHP from ISIP	2071	psig
Liquid CO_2 Density Calculated	6.81	ppg
Maximum Allowable WHP	1610	psig

* Estimated from nearby wells below that had same coal seams fractured as 1st stage in DD-7

Well	ISIP	
DD-5	2146	psig
FF-8A	1359	psig
DD-7A	1883	psig
AVG ISIP	1796	psig

DD-7A

1st stage	75Q foam	
Breakdown	2245	psig
ISIP	1883	psig
Depth	1701	feet
BHP from ISIP	2067	psig
Liquid CO_2 Density Calculated	6.71	ppg
Maximum Allowable WHP	1474	psig

2nd stage	75Q foam	
Breakdown	1650	psig
ISIP	1503	psig
Depth	1312	feet
BHP from ISIP	1645	psig
Liquid CO_2 Density Calculated	6.71	ppg
Maximum Allowable WHP	1187	psig

3rd stage	75Q foam	
Breakdown	3191	psig
ISIP	1163	psig
Depth	916	feet
BHP from ISIP	**1262**	psig
Liquid CO_2 Density Calculated	6.71	ppg
Maximum Allowable WHP	**943**	psig

DD-8

1st stage	75Q foam	
Breakdown	3197	psig
ISIP	2067	psig
Depth	1756	feet
BHP from ISIP	2257	psig
Liquid CO_2 Density Calculated	7.10	ppg
Maximum Allowable WHP	1609	psig

2nd stage	75Q foam	
Breakdown	3117	psig
ISIP	1885	psig
Depth	1494	feet
BHP from ISIP	2047	psig
Liquid CO_2 Density Calculated	7.10	ppg
Maximum Allowable WHP	1495	psig

3rd stage	75Q foam	
Breakdown	2374	psig
ISIP **	1425	psig
Depth	1038	feet
BHP from ISIP	**1535**	psig
Liquid CO_2 Density Calculated	7.10	ppg
Maximum Allowable WHP	**1152**	psig

** Estimated from nearby wells below that had same coal seams fractured as 3rd stage in DD-8

Well	ISIP	
DD-7 (2)	1930	psig
DD-7A	1163	psig
DD-8A	1022	psig
DD-9A	1586	psig
AVG ISIP	1425.25	psig

ISIP = Instantaneous Shut-in Pressure
BHP = Bottom hole pressure
WHP = Well head pressure
psig = Pounds/square inch gauge
ppg = Pounds per gallon

(2) UH and LS coal seams fractured in 4th stage

Specific gravity of Liquid CO_2 = 0.818

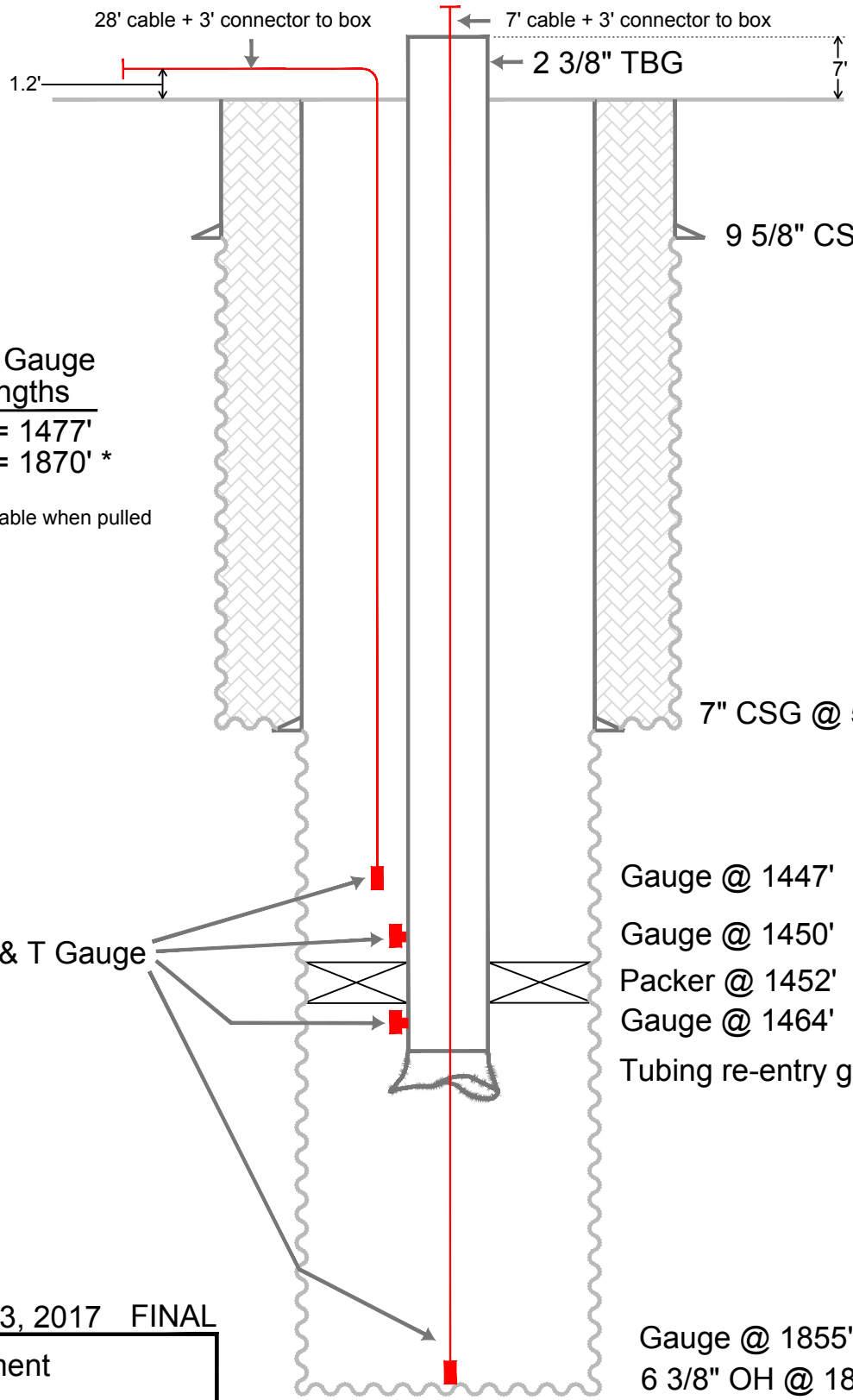
Specific gravity of Liquid CO_2 = 0.806

Specific gravity of Liquid CO_2 = 0.852

Revised: September 13, 2013

20 Appendix H – Wellbore Schematics

Characterization Well
C-1



Pressure Gauge Cable Lengths

Annulus = 1477'
Tubing = 1870' *

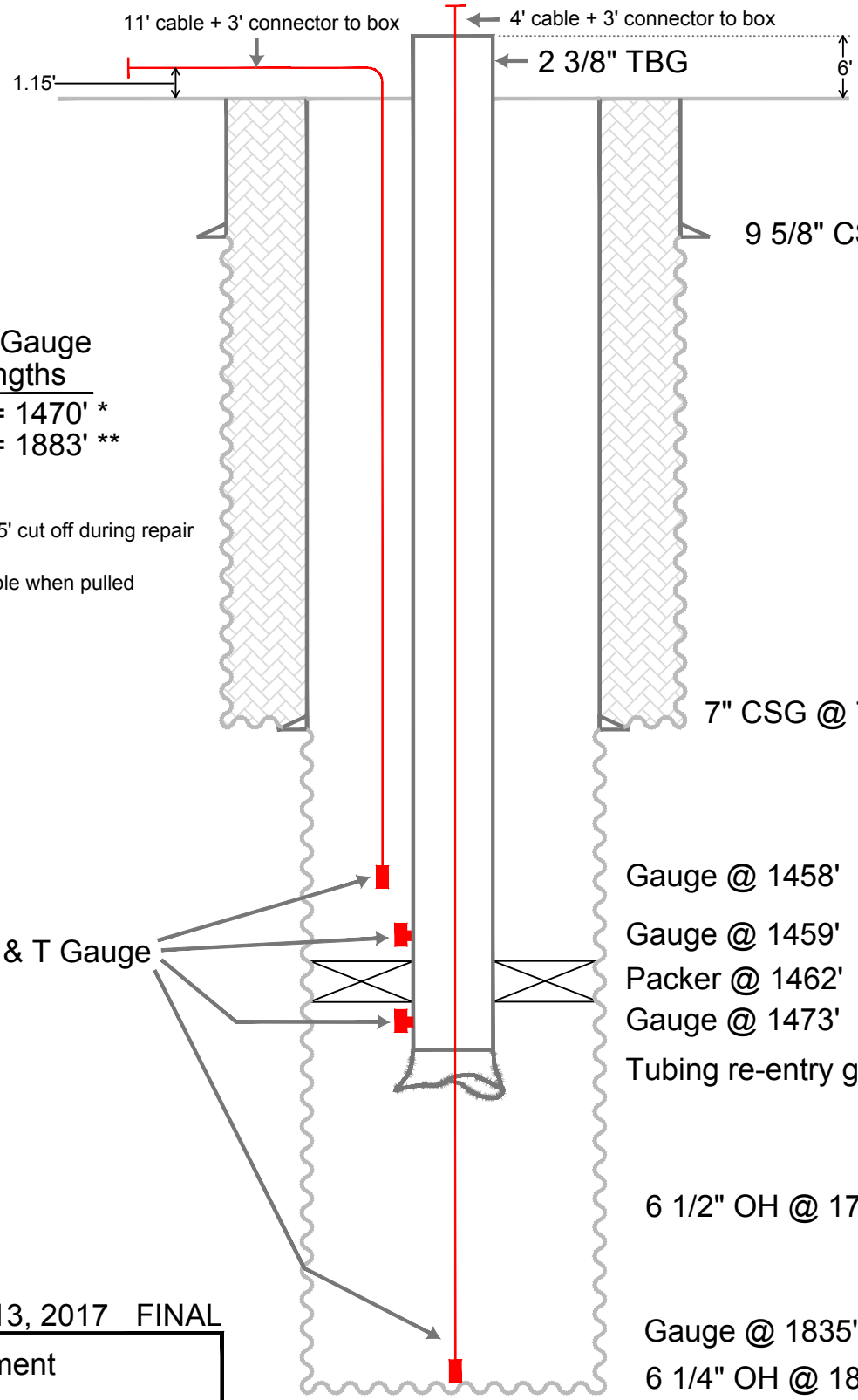
* Measured cable when pulled out of well.

December 13, 2017 FINAL

Cement

NOT TO SCALE

Monitoring Well
M-1



Pressure Gauge Cable Lengths

Annulus = 1470' *
Tubing = 1883' **

* An additional 15' cut off during repair

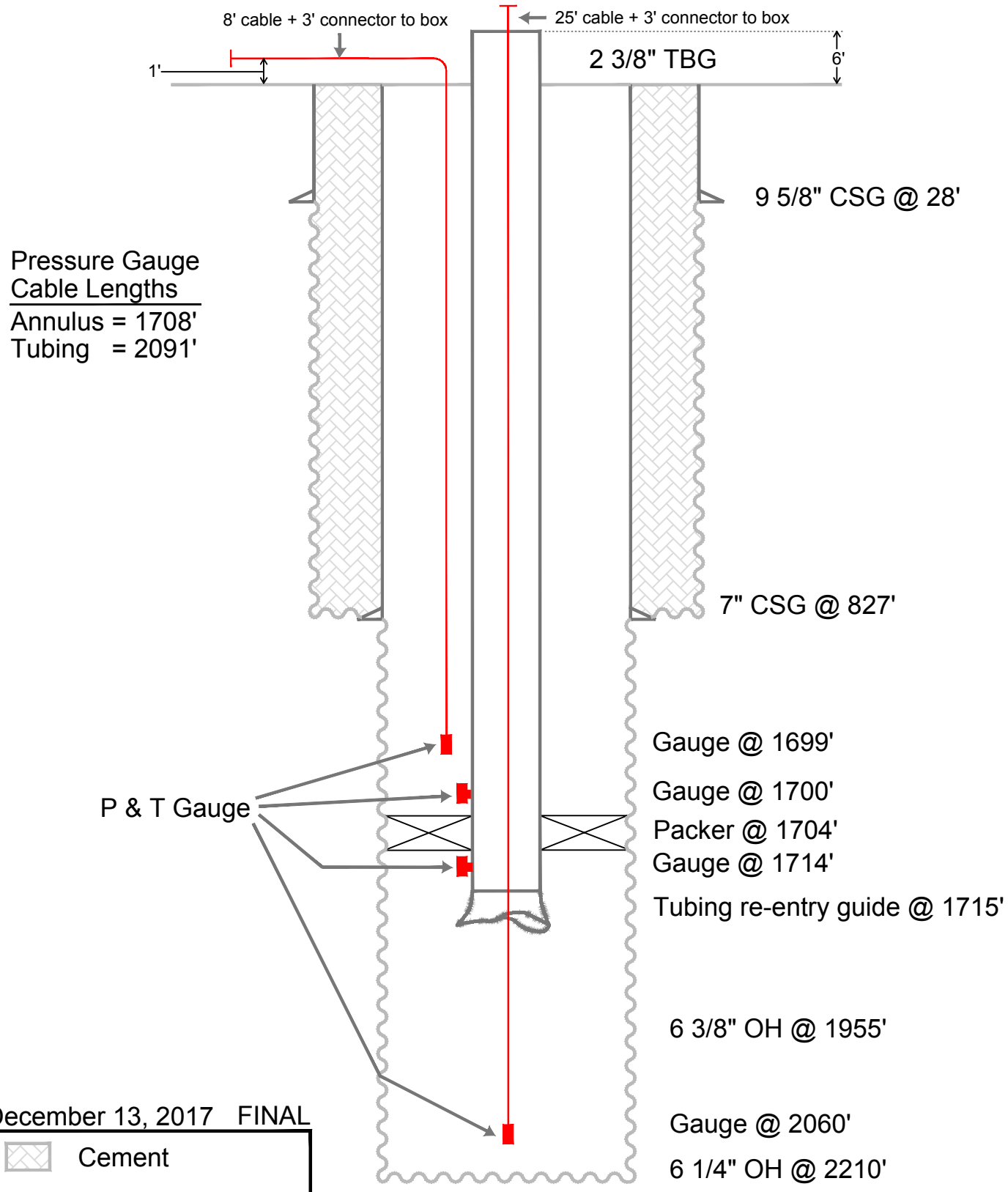
** Measured cable when pulled out of well.

December 13, 2017 FINAL

Cement

NOT TO SCALE

Monitoring Well
M-2



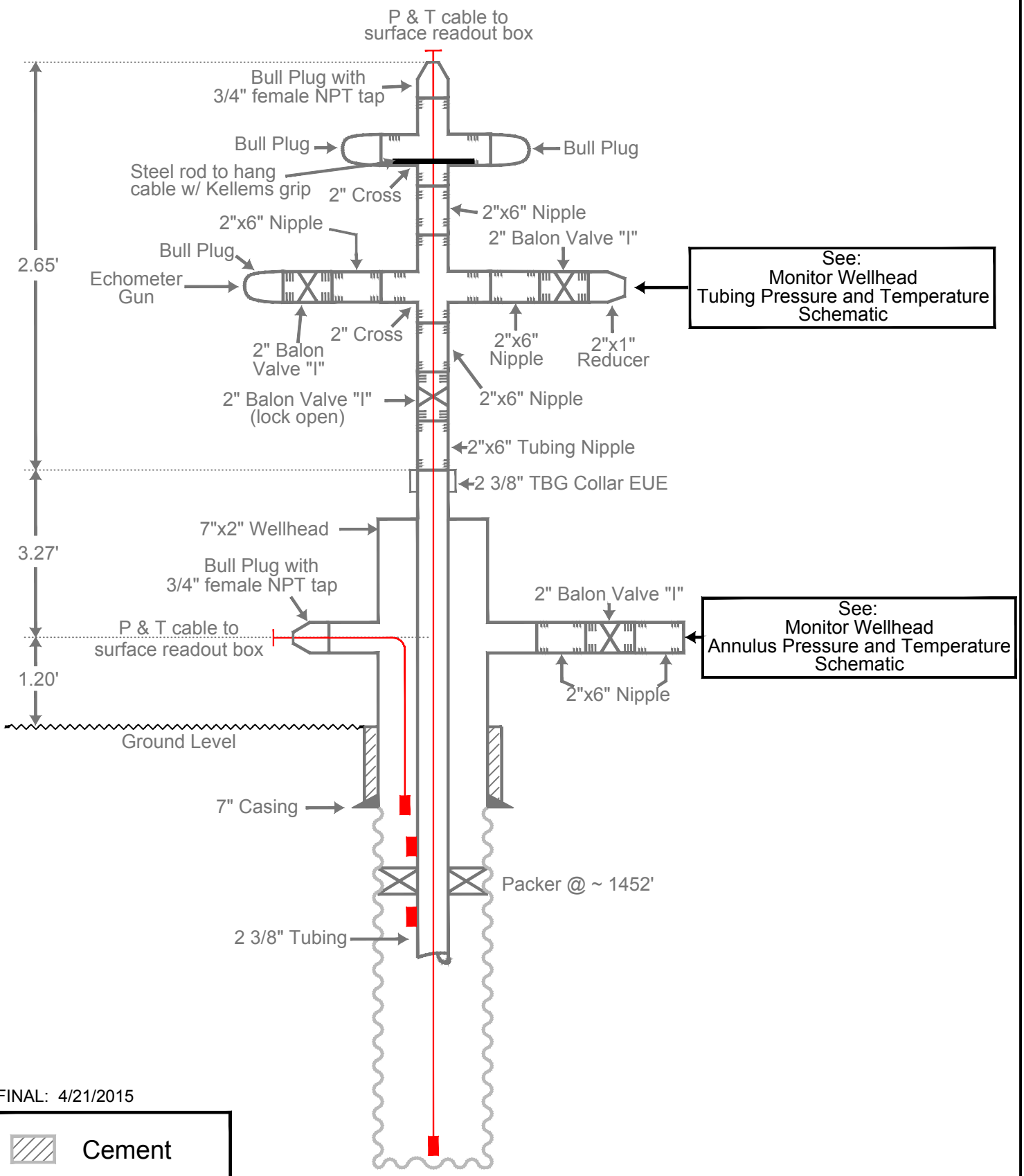
December 13, 2017 FINAL

Cement

NOT TO SCALE

C-1 Monitor Wellhead

(as built)

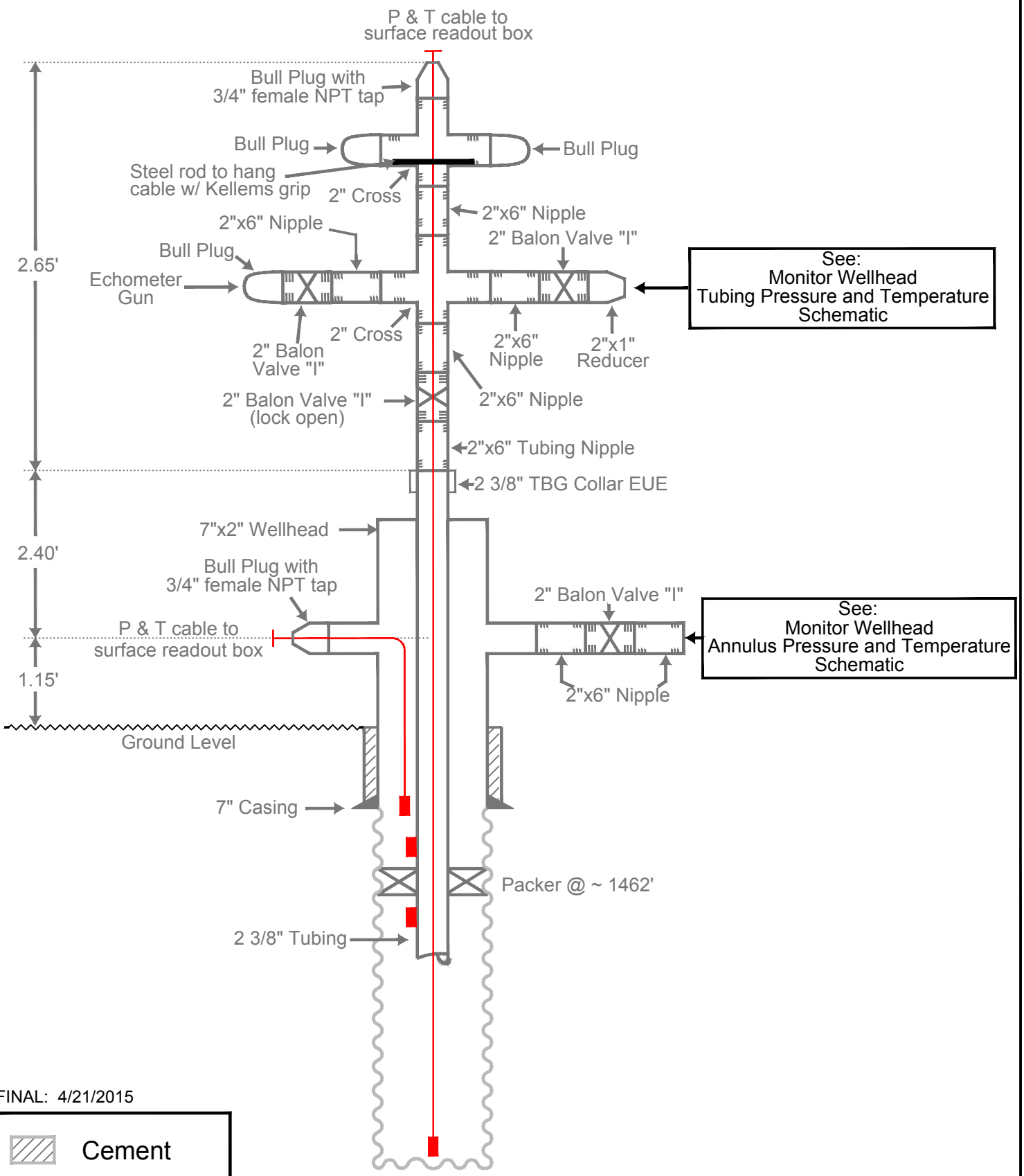


FINAL: 4/21/2015

Cement

NOT TO SCALE

M-1 Monitor Wellhead
(as built)

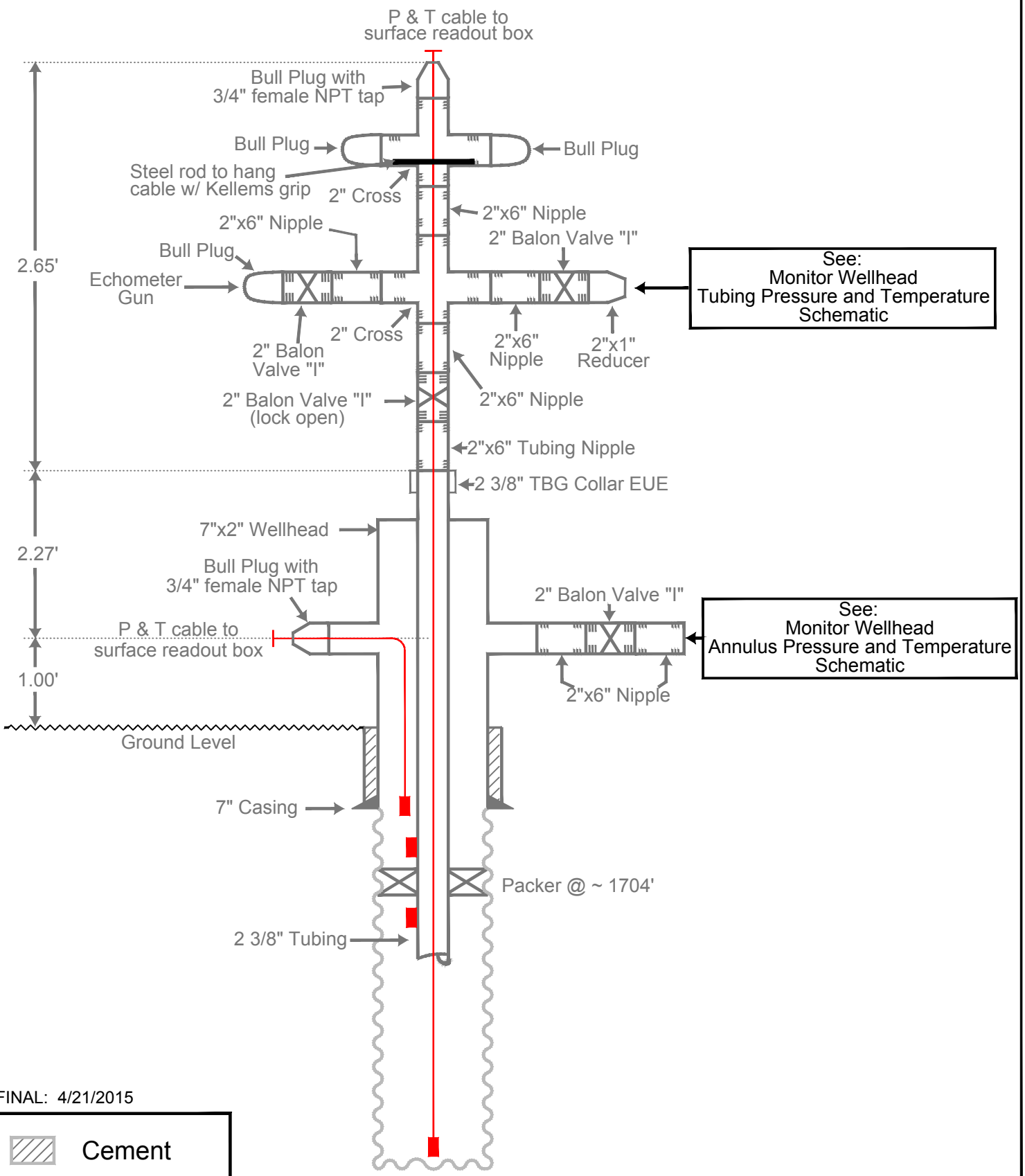


FINAL: 4/21/2015

Cement

NOT TO SCALE

M-2 Monitor Wellhead
(as built)



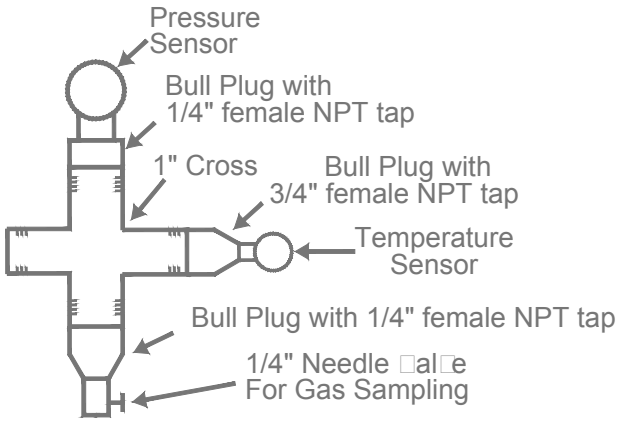
FINAL: 4/21/2015

Cement

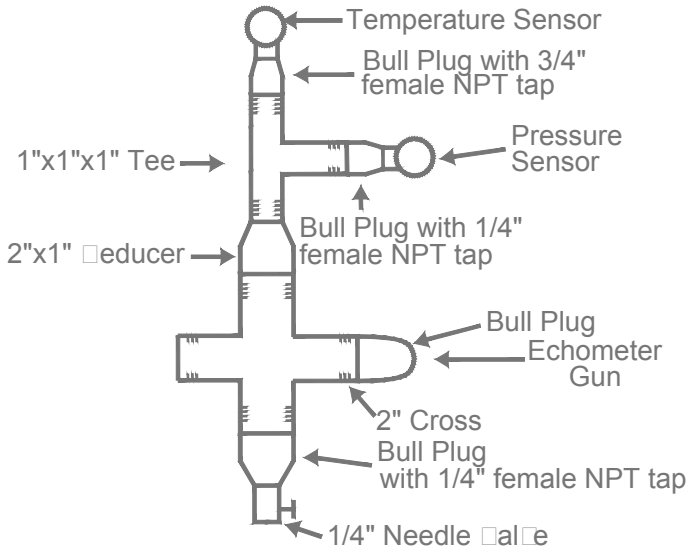
NOT TO SCALE

Monitor Wellhead

Tubing Pressure & Temperature Schematic



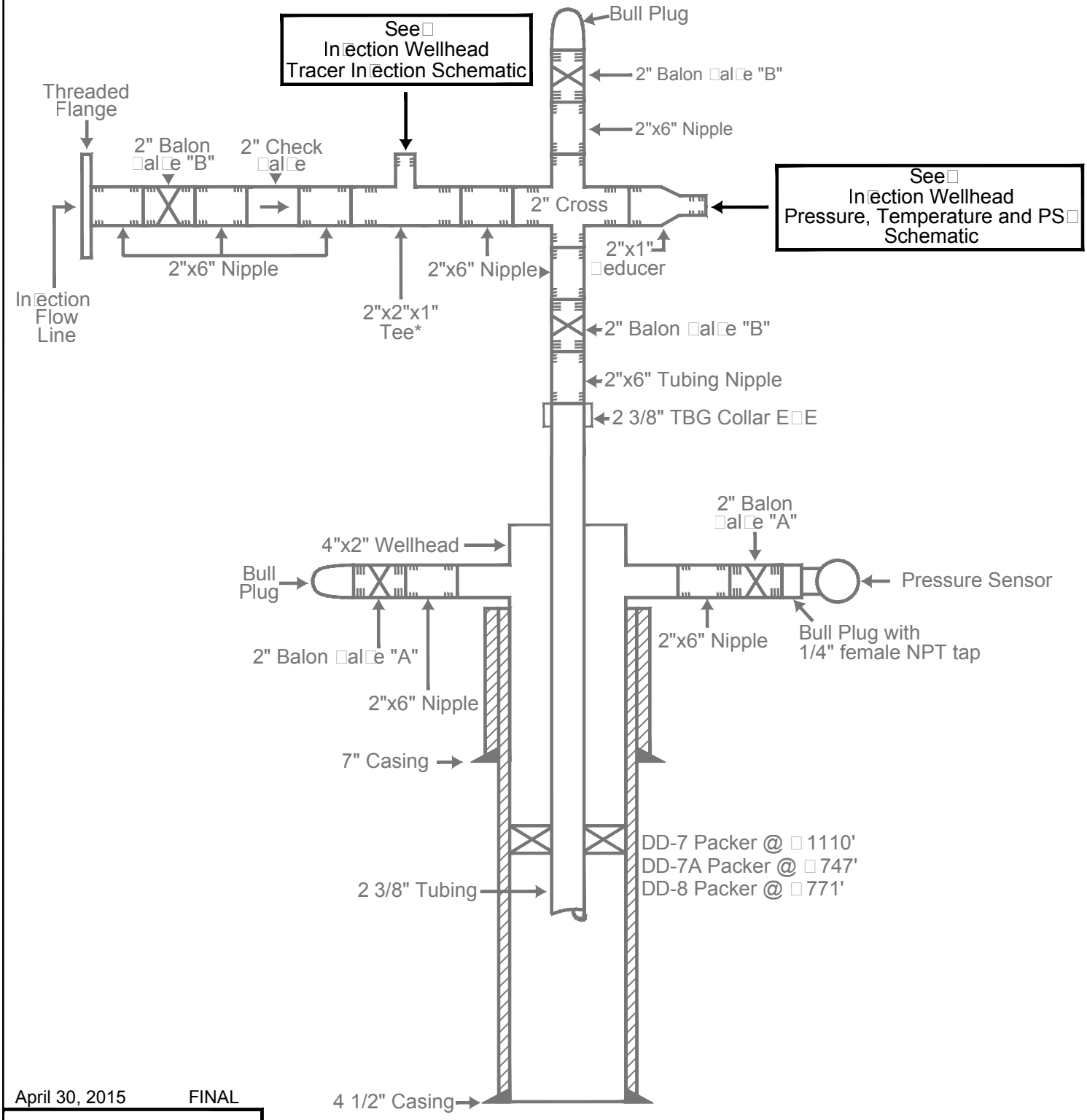
Annulus Pressure & Temperature Schematic



April 21, 2105 FINAL

NOT TO SCALE

In□ection Wellhead



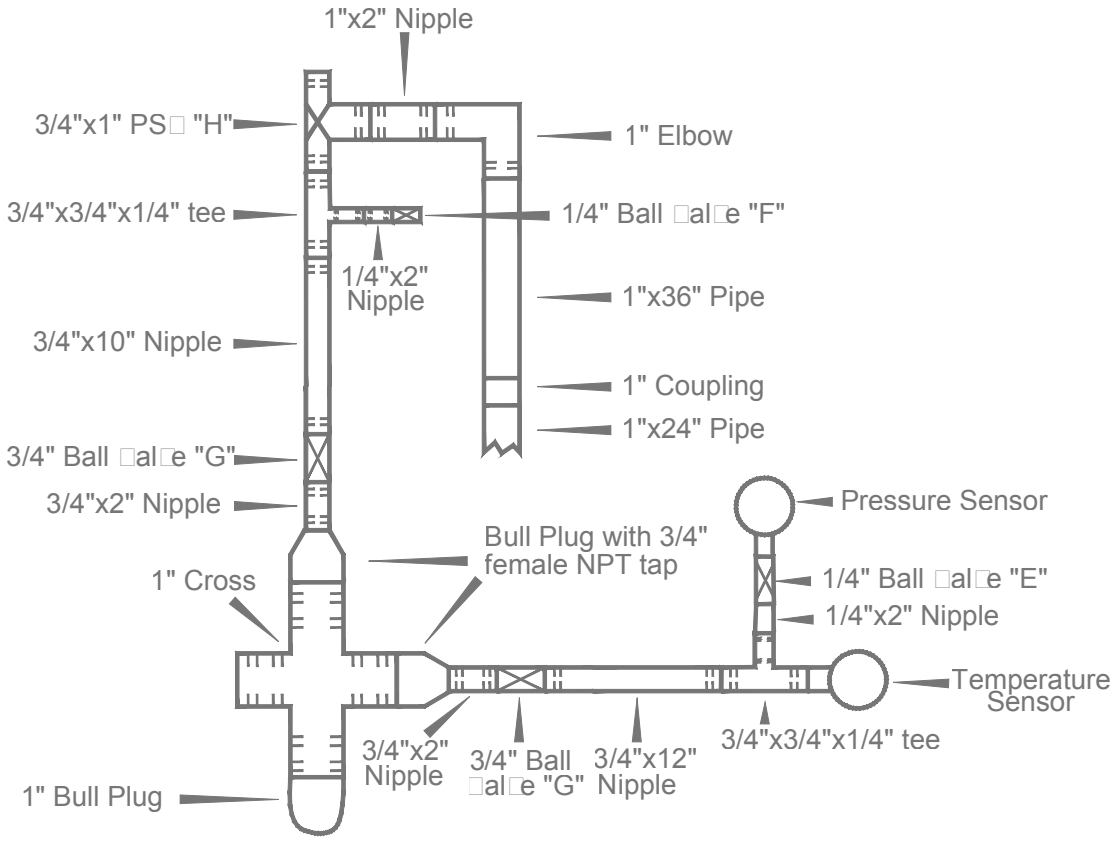
April 30, 2015 FINAL

Cement

NOT TO SCALE

* Lay tee in horizontal position

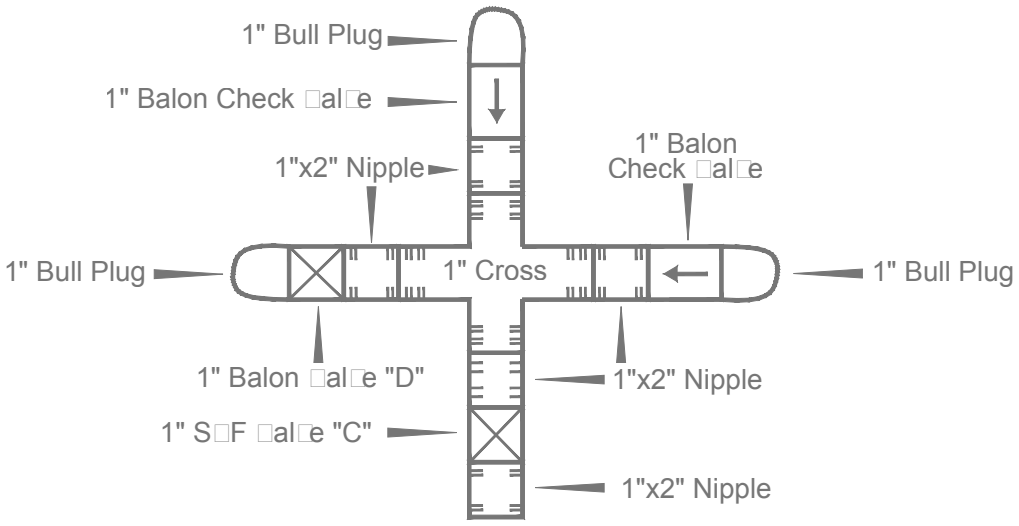
In□ection Wellhead Pressure, Temperature and PS□ Schematic



5/21/2015 FINAL

NOT TO SCALE

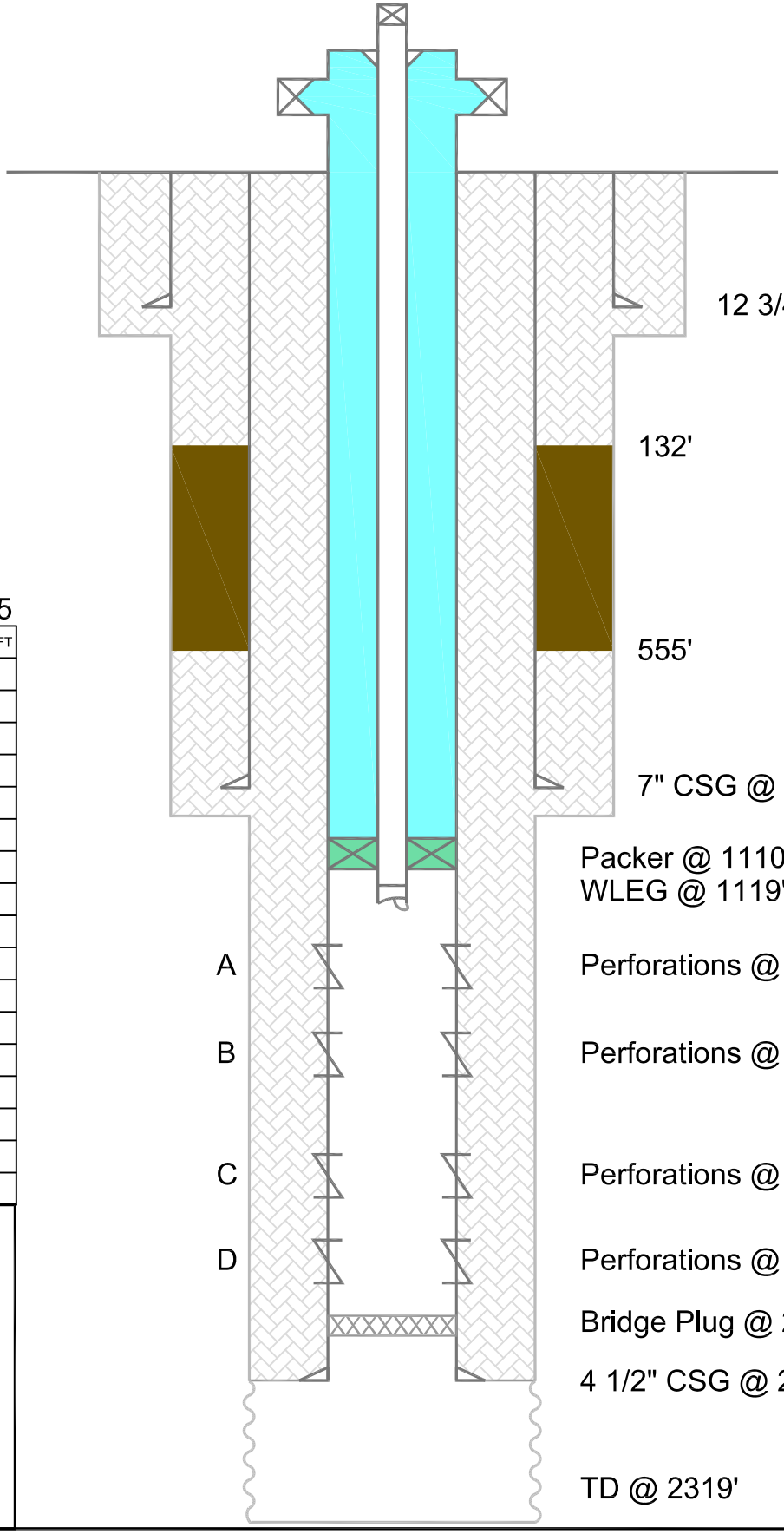
In□ection Wellhead
Tracer In□ection Schematic



04/22/2015 FINAL

NOT TO SCALE

Permit Modification
Injection Well DD-7



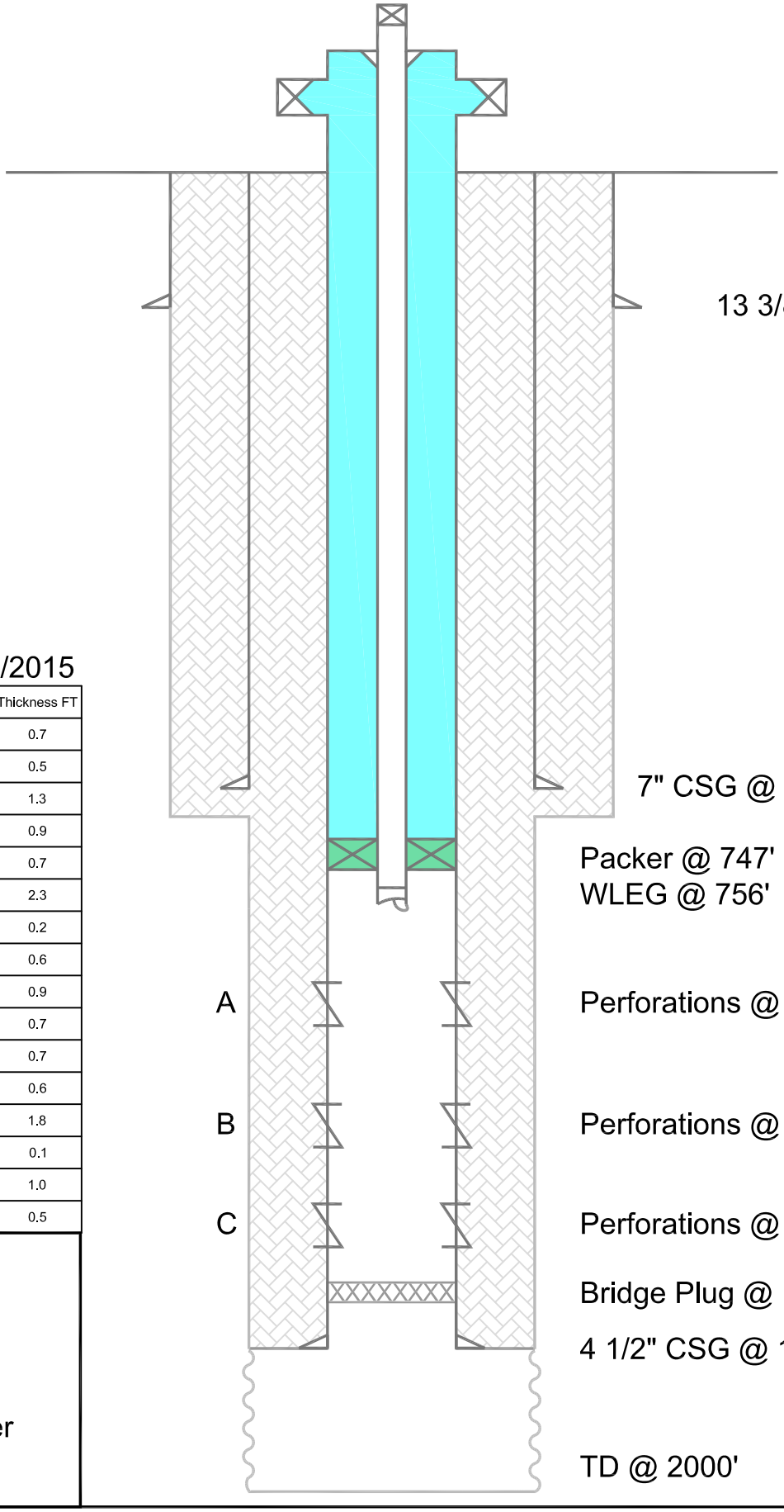
FINAL 4/22/2015

	Coal Seam	Depth FT	Thickness FT
A	Seaboard (20)	1216	1.5
A	Lower Seaboard (10,20)	1260	1.6
A	Upper Horsepen (10)	1336	1.5
A	Upper Horsepen (20)	1383	0.9
B	Pocahontas No. 11	1531	0.8
B	Pocahontas No. 10	1564	1.8
C	Pocahontas No. 9 (10)	1674	2.5
C	Pocahontas No. 9 (30)	1700	1.4
C	Pocahontas No. 7 (10)	1784	1.0
C	Pocahontas No. 7 (20)	1866	0.6
D	Pocahontas No. 5 (20)	1997	1.0
D	Pocahontas No. 4 (10)	2024	1.0
D	Pocahontas No. 4 (20)	2046	0.6
D	Pocahontas No. 3 (10,20)	2100	2.2
D	Pocahontas No. 3 (30)	2107	0.7
D	Pocahontas No. 3 (40)	2126	0.9
D	Pocahontas No. 3 (50)	2130	1.1

Valve
Packer
Cement
Inhibited Water
Gel

NOT TO SCALE

Permit Modification
Injection Well DD-7A



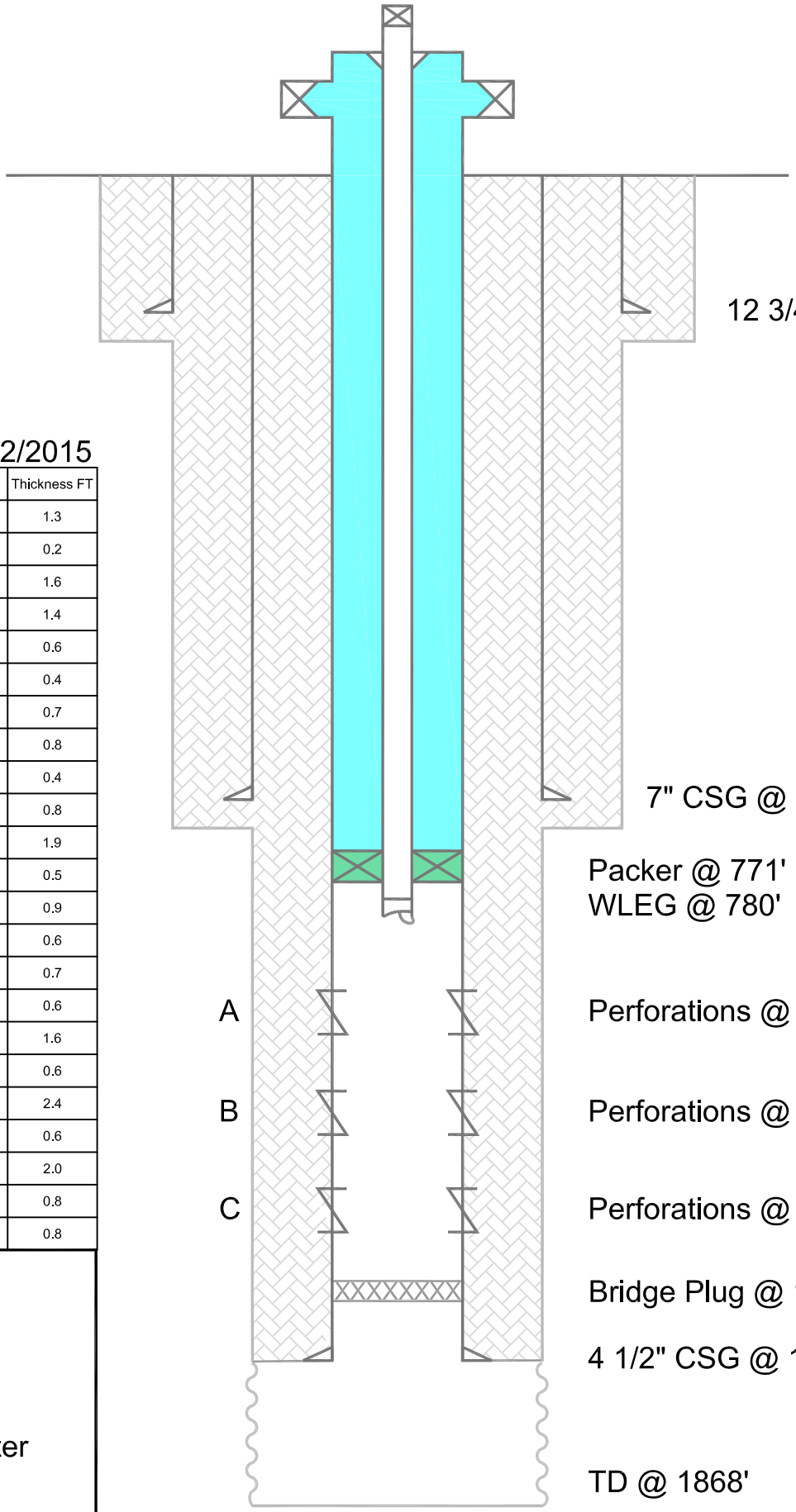
FINAL 4/22/2015

	Coal Seam	Depth FT	Thickness FT
A	Seaboard (20)	856	0.7
A	Lower Seaboard (20)	902	0.5
A	Upper Horsepen (10)	975	1.3
B	Pocahontas No. 11 (3)	1203	0.9
B	Pocahontas No. 10	1207	0.7
B	Pocahontas No. 9 (10)	1316	2.3
B	Pocahontas No. 9 (20)	1322	0.2
B	Pocahontas No. 7 (10)	1419	0.6
C	Unknown Coal	1599	0.9
C	Pocahontas No. 5 (20)	1637	0.7
C	Pocahontas No. 4 (20)	1691	0.7
C	Unknown Coal	1702	0.6
C	Pocahontas No. 3 (10)	1735	1.8
C	Pocahontas No. 3 (30)	1740	0.1
C	Pocahontas No. 3 (40)	1757	1.0
C	Pocahontas No. 2	1802	0.5

Valve
Packer
Cement
Inhibited Water

NOT TO SCALE

Permit Modification
Injection Well DD-8



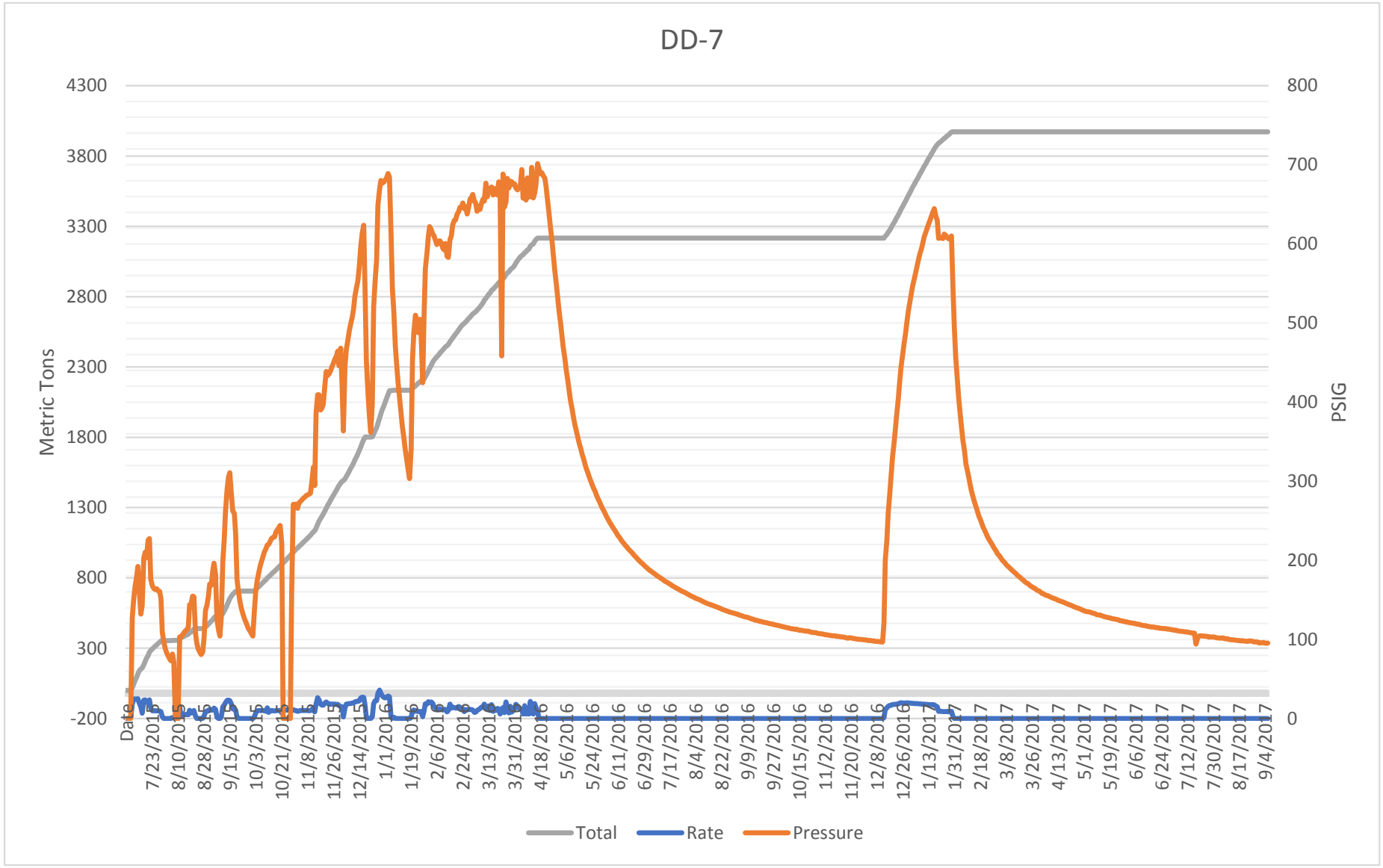
FINAL 4/22/2015

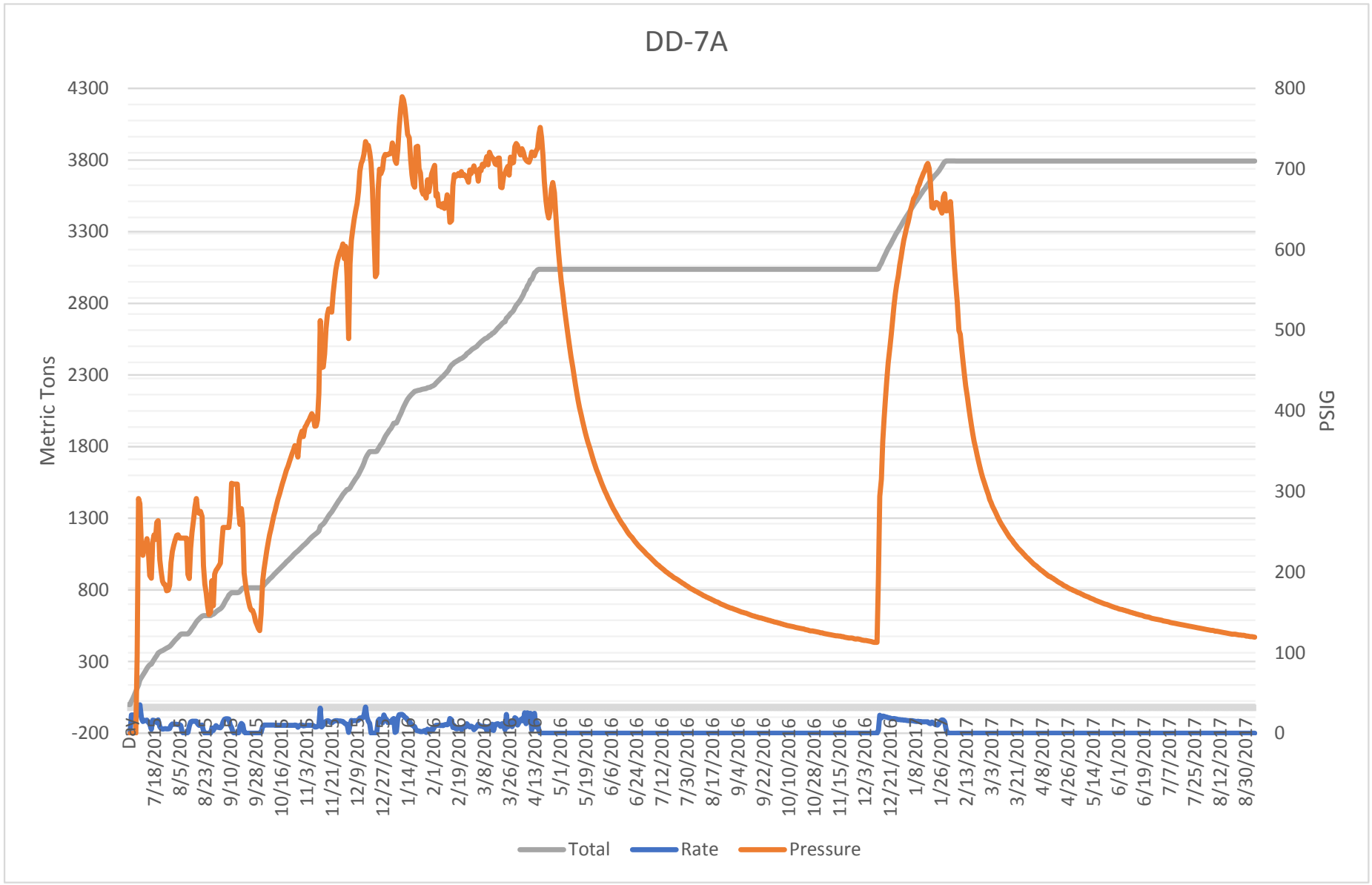
	Coal Seam	Depth FT	Thickness FT
A	Seaboard (20)	871	1.3
A	Lower Seaboard (10)	902	0.2
A	Lower Seaboard (20)	912	1.6
A	Upper Horsepen (10)	984	1.4
A	Upper Horsepen (20)	1031	0.6
A	Unknown Coal	1054	0.4
A	Middle Horsepen (10)	1068	0.7
A	Pocahontas No. 11	1165	0.8
A	Pocahontas No. 10 (10)	1198	0.4
A	Pocahontas No. 10 (20)	1204	0.8
B	Pocahontas No. 9 (10)	1311	1.9
B	Pocahontas No. 9 (20)	1314	0.5
B	Unknown Coal	1397	0.9
B	Pocahontas No. 7 (10)	1422	0.6
B	Pocahontas No. 7 (20)	1467	0.7
B	Pocahontas No. 5 (10)	1591	0.6
B	Pocahontas No. 4 (10)	1637	1.6
B	Pocahontas No. 4 (20)	1677	0.6
C	Pocahontas No. 3 (10,20)	1711	2.4
C	Pocahontas No. 3 (30)	1721	0.6
C	Pocahontas No. 3 (40,50)	1731	2.0
C	Pocahontas No. 2	1746	0.8
C	Pocahontas No. 1	1802	0.8

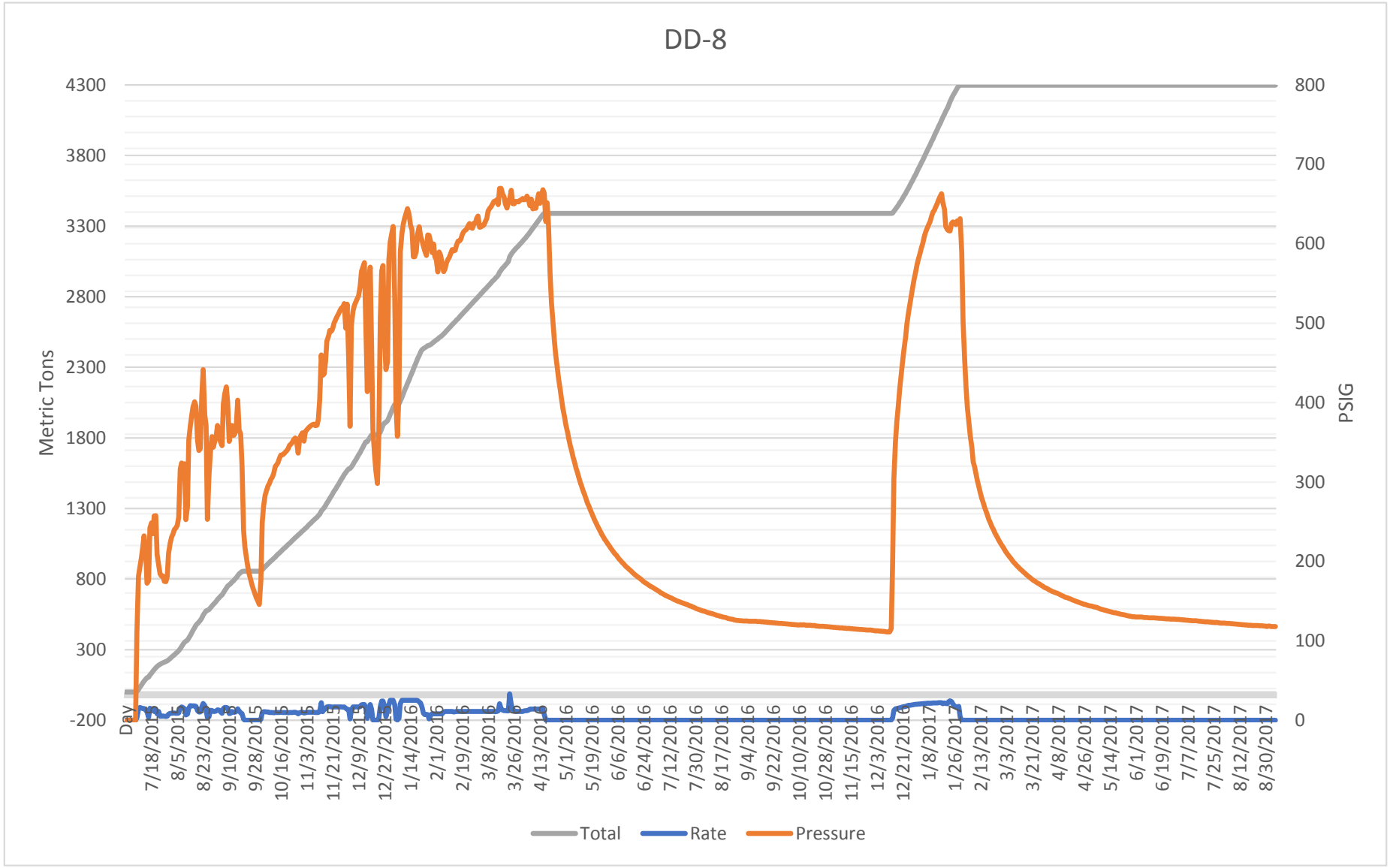
Valve
Packer
Cement
Inhibited Water

NOT TO SCALE

21 Appendix I – Injection Graphs


DD-7
Metric Tons
PSIG
4300
3800
3300
2800
2300
1800
1300
800
300
-200
800
700
600
500
400
300
200
100
0
Date
7/23/2015
8/10/2015
8/28/2015
9/15/2015
10/3/2015
10/21/2015
11/8/2015
11/26/2015
12/14/2015
1/1/2016
1/19/2016
2/6/2016
2/24/2016
3/13/2016
3/31/2016
4/18/2016
5/6/2016
5/24/2016
6/11/2016
6/29/2016
7/17/2016
8/4/2016
8/22/2016
9/9/2016
9/27/2016
10/15/2016
11/2/2016
11/20/2016
12/8/2016
12/26/2016
1/13/2017
1/31/2017
2/18/2017
3/8/2017
3/26/2017
4/13/2017
5/1/2017
5/19/2017
6/6/2017
6/24/2017
7/12/2017
7/30/2017
8/17/2017
9/4/2017
Total
Rate
Pressure


DD-7A
Metric Tons
PSIG
4300
3800
3300
2800
2300
1800
1300
800
300
-200
800
700
600
500
400
300
200
100
0
Total
Rate
Pressure


DD-8
Metric Tons
PSIG
4300
3800
3300
2800
2300
1800
1300
800
300
-200
800
700
600
500
400
300
200
100
0
Day
7/18/2015
8/5/2015
8/23/2015
9/10/2015
9/28/2015
10/16/2015
11/3/2015
11/21/2015
12/9/2015
12/27/2015
1/14/2016
2/1/2016
2/19/2016
3/8/2016
3/26/2016
4/13/2016
5/1/2016
5/19/2016
6/6/2016
6/24/2016
7/12/2016
7/30/2016
8/17/2016
9/4/2016
9/22/2016
10/10/2016
10/28/2016
11/15/2016
12/3/2016
12/21/2016
1/8/2017
1/26/2017
2/13/2017
3/3/2017
3/21/2017
4/8/2017
4/26/2017
5/14/2017
6/1/2017
6/19/2017
7/7/2017
7/25/2017
8/12/2017
8/30/2017
Total
Rate
Pressure

22 Appendix J – Production Logging

Weatherford®



Production Log Interpretation

Well Report Review Copy

CARDNO
DD-7
Field: OAKWOOD

8/25/2016

Prepared by:
Busola Odunuga
10 Desta Drive, Suite 350E, Midland, TX 79705
432.254.6553

In making interpretations of data our employees will give the customer the benefit of their best judgement, but since all interpretations are based on interfaces from electrical or other measurements, we cannot and we do not guarantee the accuracy of any interpretation. We shall not be liable or responsible for any loss, cost, damage, or expenses whatsoever incurred by the customer resulting from any interpretation made by our employees.

CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 4

2. LOGGING OBJECTIVES FOR PLT 5

3. LOGGING PROCEDURE 5

4. SEQUENCE OF EVENTS 6

5. TOOL DIAGRAM 7

6. INJECTION LOG INTERPRETATION 8
6.1 DATA QUALITY CONTROL AND DISCUSSION 8
6.2 PROFILE CALCULATIONS 10
6.3 FLOW PROFILE DETERMINATION 11

7. DENSITY PROFILE 12

APPENDIX I: Well Diagram 13
APPENDIX II: Curve Mnemonics 14

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CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

LIST OF FIGURES

Figure 1: Injection log procedure
Figure 2: Sequence of Events
Figure 3: Tool String Diagram Tool OD: 1.693”
Figure 4: Injection passes- DD7
Figure 5: Injection profile computed
Figure 6: Injection flow profile
Figure 7: Density Curve (150FPM_up pass) from (1113-2136)ft

In making interpretations of data our employees will give the customer the benefit of their best judgement, but since all interpretations are based on interfaces from electrical or other measurements, we cannot and we do not guarantee the accuracy of any interpretation. We shall not be liable or responsible for any loss, cost, damage, or expenses whatsoever incurred by the customer resulting from any interpretation made by our employees.

CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

1. EXECUTIVE SUMMARY

Weatherford Wireline Services were commissioned to perform an injection log (PLT) survey on DD7 for Cardno on March 22, 2016. The objective of the survey was to determine injection zones

A Weatherford PLT tool string consisting of GR, CCL, temperature, pressure, radioactive density, 1.69" spinner was used in the logging job.

Conclusions:

- Raw data shows qualitatively active perforations are interval (1216-1385)ft, (1531-1570)ft, and (1674-1866)ft. This is confirmed by changes in flow profile
- Perforation (1531-1570)ft and (1674-1866)ft, had the highest change in flow profile. Therefore we can infer these zones took in most of CO2
- Qualitatively temperature, there are distinct changes in temperature which corresponds in changes in the spinner sensor in all the passes taken
- The best pass used to create the injection profile was up pass at 150fpm
- Percent contribution is computed using the differential rps between 0% flow at the bottom of the perforations and 100% flow above the perforations. The change in Spinner rps at a given perforation from 0% flow divided by the total rps change resulting in the percent contribution computed.
- A drop in density is observed at perforation (1216-1385)ft. This indicates the zone at which the change in density begins to occur after CO2 injection

	Formation Name	Depth (ft)	Perforation (ft)		Spinner UP 150(RPS)	% Contribution	Tons/day
A	Seaboard (20)	1216	1216	1385	-4.415	0	0
A	Lower Seaboard (10, 20)	1260			-4.415	49%	38.92
A	Upper Horsepen (10)	1336			-4.144	0%	0
A	Upper Horsepen (20)	1383					
B	Pocahontas No. 11	1531	1531	1570	-4.144	0	0
B	Pocahontas No. 10	1564			-4.144	31%	24.7
C	Pocahontas No. 9 (10)	1674	1674	1866	-3.972	20%	16.37
C	Pocahontas No. 9 (30)	1700			-3.858	0%	0
C	Pocahontas No. 7 (10)	1784					
C	Pocahontas No. 7 (20)	1866					
D	Pocahontas No. 5 (20)	1997	1997	2133	-3.858	0%	0
D	Pocahontas No. 4 (10)	2024					
D	Pocahontas No. 4 (20)	2046					
D	Pocahontas No. 3 (10, 20)	2100					
D	Pocahontas No. 3 (30)	2107					
D	Pocahontas No. 3 (40)	2126					
D	Pocahontas No. 3 (50)	2130					
				0 % Flow	-3.858	0%	0
					Total	100%	80

Table 1: Total Injection rate

In making interpretations of data our employees will give the customer the benefit of their best judgement, but since all interpretations are based on interfaces from electrical or other measurements, we cannot and we do not guarantee the accuracy of any interpretation. We shall not be liable or responsible for any loss, cost, damage, or expenses whatsoever incurred by the customer resulting from any interpretation made by our employees.

CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

2. LOGGING OBJECTIVES FOR PLT

The aim of the survey was to identify injection zones

3. LOGGING PROCEDURE

The tool string was composed as follows from top to bottom of E-line:

- Weight bars
- CCL
- GR
- Pressure Gauge
- Density
- Temperature sensor/ Flowmeter.

Job Procedure

DD7 Well

String	Direction	Cable Speed	Interval	Well condition	BH contents	Remarks
PLT	Down	RIH	Surface to 1150ft_MD	Injecting	CO2	Looking for interfaces
Take a 5 minutes station at 1150ft						
PLT	Down	100	1150ft_MD (EOT) to 2150ft_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
PLT	Up	100	2150ft_MD to 1150ft (EOT)_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
PLT	Down	150	1150ft_MD (EOT) to 2150ft_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
PLT	Up	150	2150ft_MD to 1150ft (EOT)_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
Calibration Passes						
PLT	Down	50	1385ft_MD to 1531ft_MD	Injecting	CO2	
PLT	Up	50	1531ft_MD to 1385ft_MD	Injecting	CO2	
Take a 5 minutes station at 2140ft and 1950ft						

Figure 1: Injection log procedure

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CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

4. SEQUENCE OF EVENTS

(Provided by T. Pawliuk, Weatherford US Specialty Engineer)

Production Logging Job Notes

Company	Cardno
Well Name	DD7
Field	Horsepen
Date	22-Mar-16
Field Engineer	T. PAWLIUK
Correlation Log Used	Geological Logging Systems Gamma-Caliper Log dated 10/30/2000

	Pressure Tested
Lubricator Test	

	Gas (MCFD)	Oil (BPD)	Water (BPD)	Pressure (PSI)	Temperature (F)
Flow Rates					

Surface Pressure while logging	615
Hours well was flowing before logging	

PL RAW DATA file name shall be of the form XX_YY_ZZ.LAS, where:
XX: well condition, SI (shut in) or absent if flowing conditions
YY= logging direction DN (down pass) or UP (up pass)
ZZ= Cable speed in feet per minute (fpm)

Flowing Passes

Passes	Time	Date	
150 DOWN	17:51		
150 UP	18:08		NO SPINNER
150 DOWN	18:30		
150 UP	18:40		GAMMA RAY OFF DEPTH FOR SOME REASON, USED CCL AND FM CHARACTER TO GET ON DEPTH
100 DOWN	19:00		RESTARTED WLS, GR STOPPED WORKING
100 UP	19:13		
50 DOWN CAL			
50 UP CAL	19:52		

Stationary Data

Depth (ft)	Time	Date	
1150	17:00	22-Mar-16	INITIALLY FMS AT 0.4RPS, CALLED OUT TO GET MORE INJECTION
1150B	19:28		
1385	19:41		
1950	20:03		JUST STOPPED TURNING... BELOW THRESHOLD. MOVED TOOL UP AND DOWN TO TRY TO RESTART SPINNER BUT IT DIED AGAIN
2140	20:19		

Remarks (Include any issues while logging)

DENSITY CALS BEFORE 1: AIR-15081.1 WATER-6455.4, BEFORE 2: AIR-15129.3 WATER-6422.8, AFTER: AIR-15120.6 WATER-6320.7

Notes:
If the well was flowing at unsteady conditions, specify how flow rate and pressure change while logging
If correlation is provided please upload in preview.

14:25	power up to fdt in prep of cal		
14:30	cal fluid density		
15:00	stab on		
	leaky o ring in lubricator		
	break off replace, equalize again		
	injecting 44-46 tons per day	707	mcfd
15:45	Run in hole, centrollers hanging us up in valve/tubing		
16:10	pooh to add sinker bar		
16:45	stab onto well		
17:00	STAT AT 1150		
	FM ONLY AT .2-.3RPS, GETTING THEM TO MAX OUT THE INJECTION		
17:20	799.6PSI		
17:40	798.2PSI INJECTING 80 TONS/DAY	1285	mcfd
21:00	OUT OF WELL		
21:05	AFTER CAL DENSITY		

Figure 2: Sequence of Events

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CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

5. TOOL DIAGRAM

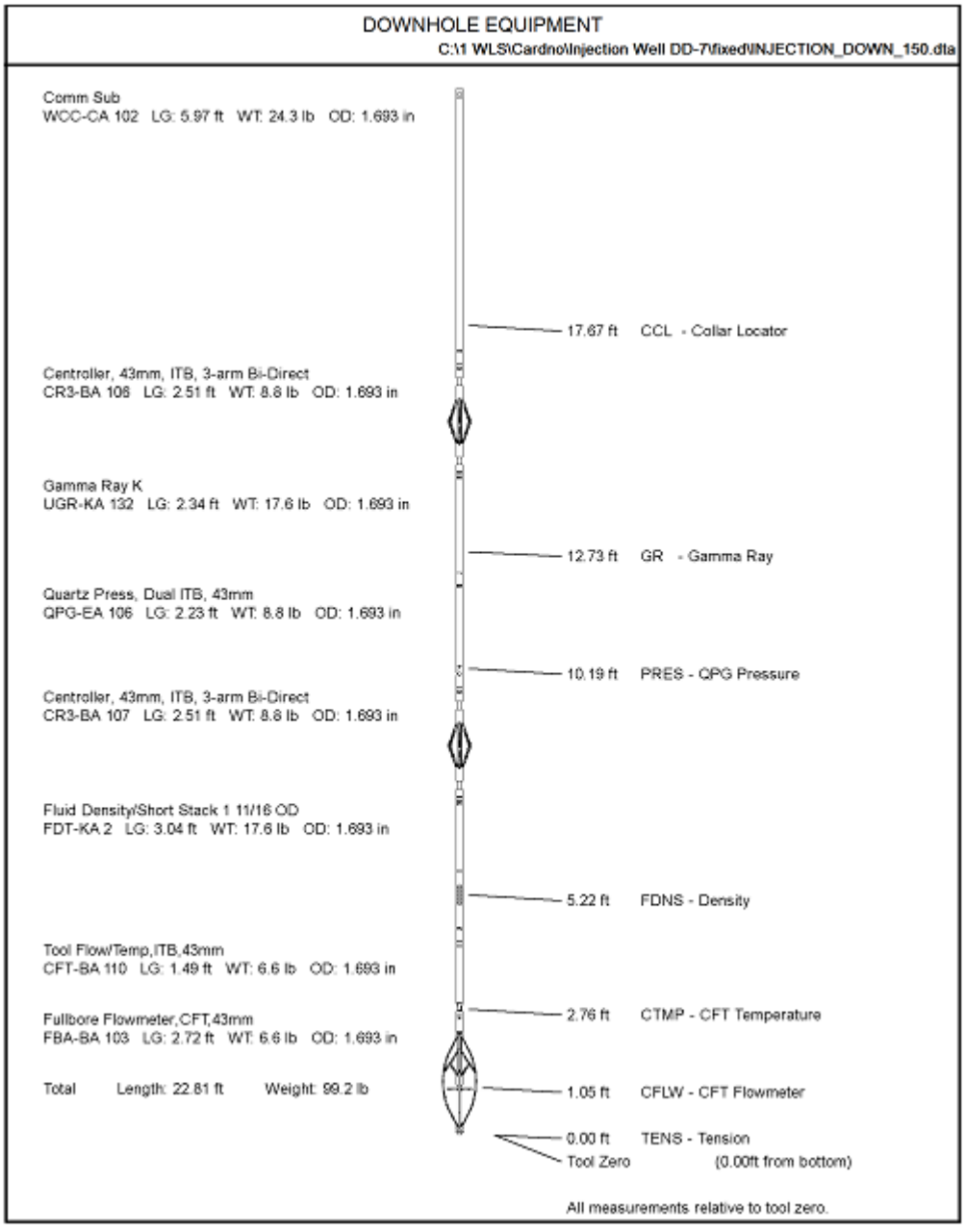


Figure 3: Tool String Diagram Tool OD: 1.693”

In making interpretations of data our employees will give the customer the benefit of their best judgement, but since all interpretations are based on interfaces from electrical or other measurements, we cannot and we do not guarantee the accuracy of any interpretation. We shall not be liable or responsible for any loss, cost, damage, or expenses whatsoever incurred by the customer resulting from any interpretation made by our employees.

6. INJECTION LOG INTERPRETATION

OVERVIEW

The analysis was performed as follow:

- The data preparation to filter the data.
- The flow meter analysis to compute the injection profile.
- The profile determination to identify the potential injecting zones.
- The computation of percentage per injecting zones based on surface flow rate reported by client.

6.1 DATA QUALITY CONTROL AND DISCUSSION

The main sensors are:-

- *Spinner flowmeter*: for an estimate of mixture flow rate.
- *Temperature*: mainly for qualitative interpretation, but is sometimes very useful and can confirm or deny conclusions drawn from other measurements.
- *Pressure*: needed for reference, for the computation of inflow performance and the calculation of fluid properties
- *Caliper, CCL and Gamma Ray*: needed for depth control or casing ID. The gamma ray curve can additionally help identify reservoir zones and scaling problems.

Log Quality Check –**Figure 4**: Injection passes- DD7

- **Gamma Ray:** The curves generally stack.
- **Pressure:** Pressure log shows pressure changing between passes.
- **Spinner:** The spinner data were consistent however, the data only shows small changes that indicates injection
- **Line Speed:** Line speed data was corrected to the line speed values for the up passes
- **Density:** Density remains consistent until perforation at (1216-1385)ft where a decrease in density is observed
- **Temperature:** There are clearly defined temperatures from pass to pass

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CUSTOMER	:	CARDNO	WELL No.	:	DD7
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

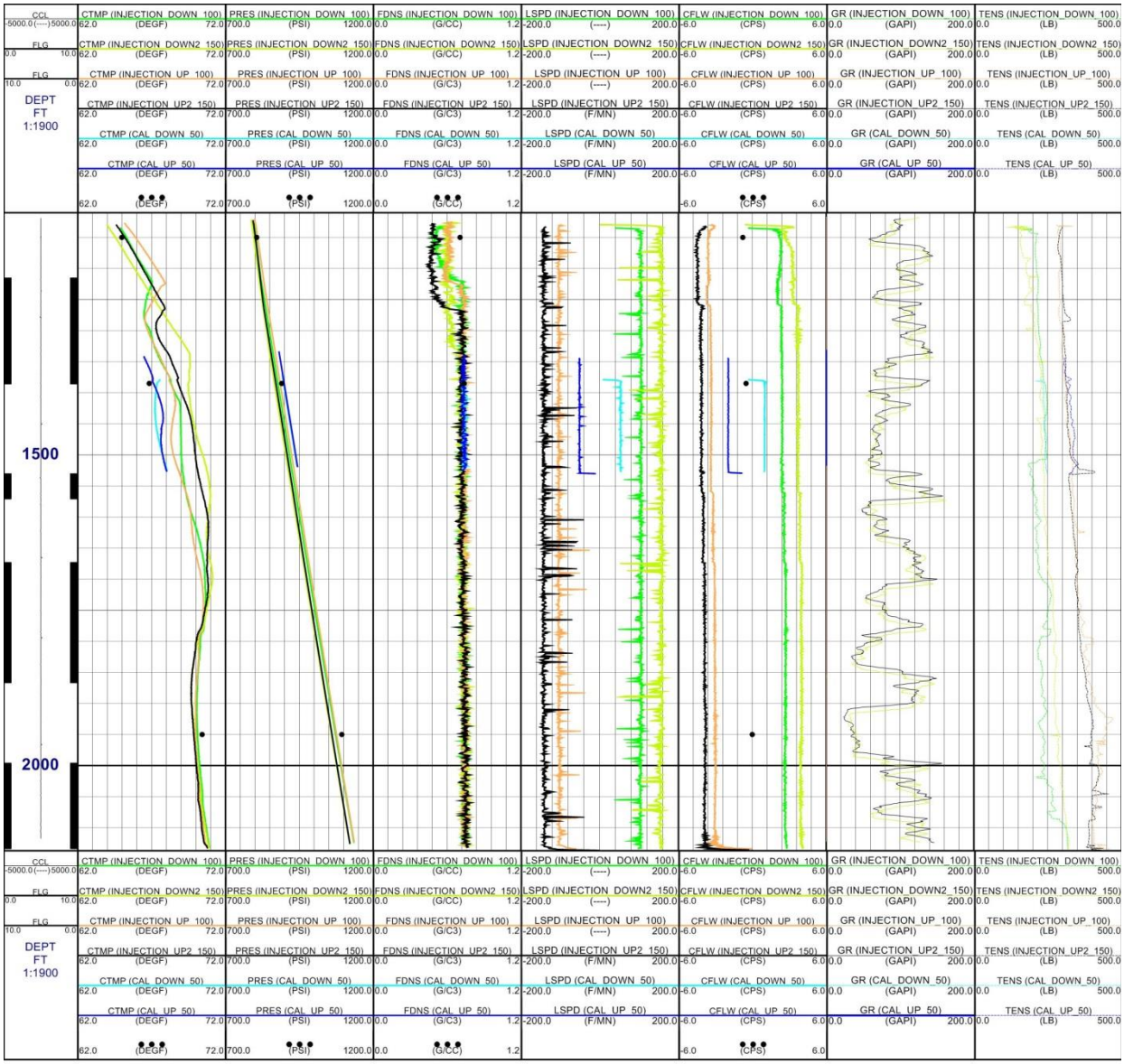


Figure 4: Injection passes- DD7

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DATE	:	MARCH 22, 2016	REPORT NO.	:	2016-001

6.2 PROFILE CALCULATIONS

The up pass at 150fpm was used to get the injection profile. This pass was chosen due to the average consistency in the overall data. Where the spinner is showing the minimum value is the total flow rate, 100% flow. The maximum value for spinner is 0% flow.

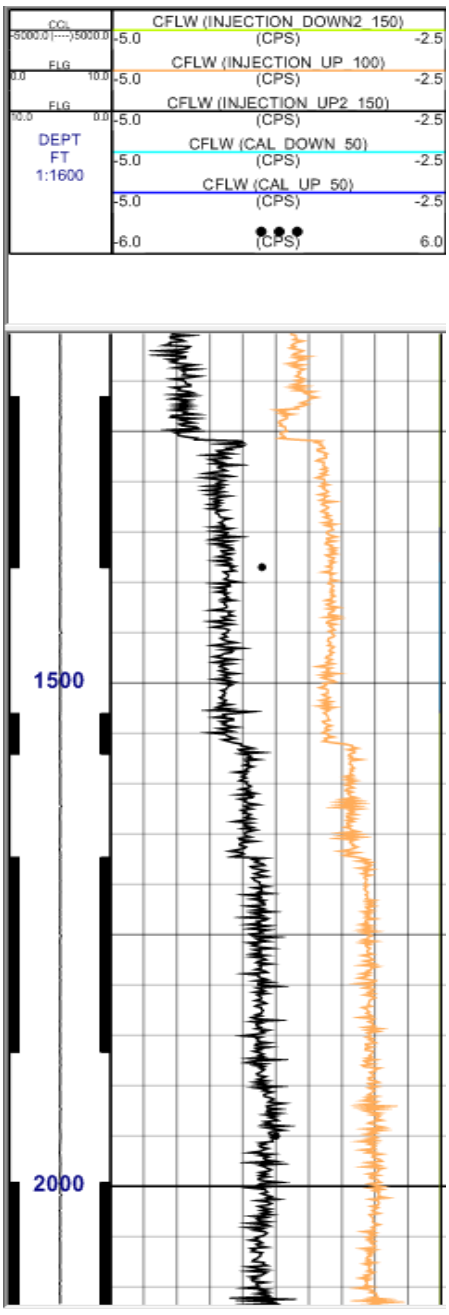


Figure 5: injection profile computed

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6.3 FLOW PROFILE DETERMINATION

The direction of the spinner data is used to determine the flow profile. A zone is specified as an injection zone based on the change in direction in the spinner curve. The figure below summarizes the zoning of the profile parameters. This is used in computing the % contributions and allocating injection rates based on the total amount injected while logging

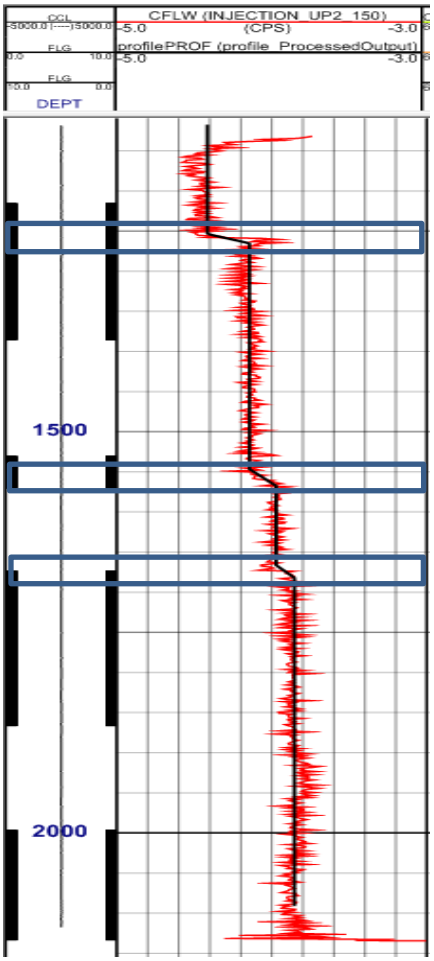


Figure 6: Injection flow profile

Perforation		Spinner_UP_150 (RPS)	% contribution	Tons/day
1216	1385	-4.415	49%	38.92
1531	1570	-4.144	31%	24.70
1674	1866	-3.972	20%	16.37
1997	2133	-3.858	0%	0.00
	0% flow	-3.858	0%	0.00
		Total	100%	80.00

Table 2: Percentage Injecting Zones

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7. DENSITY PROFILE

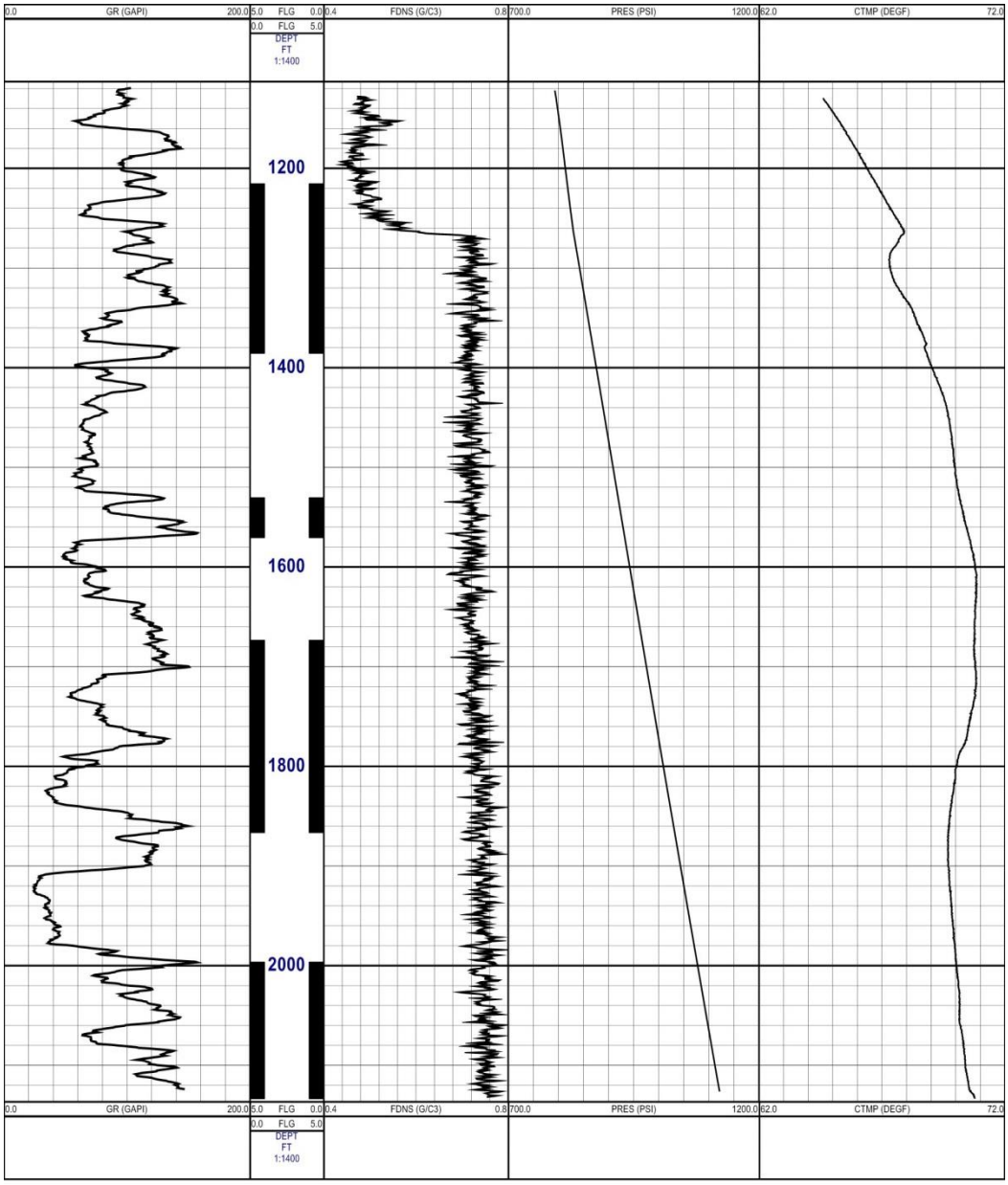
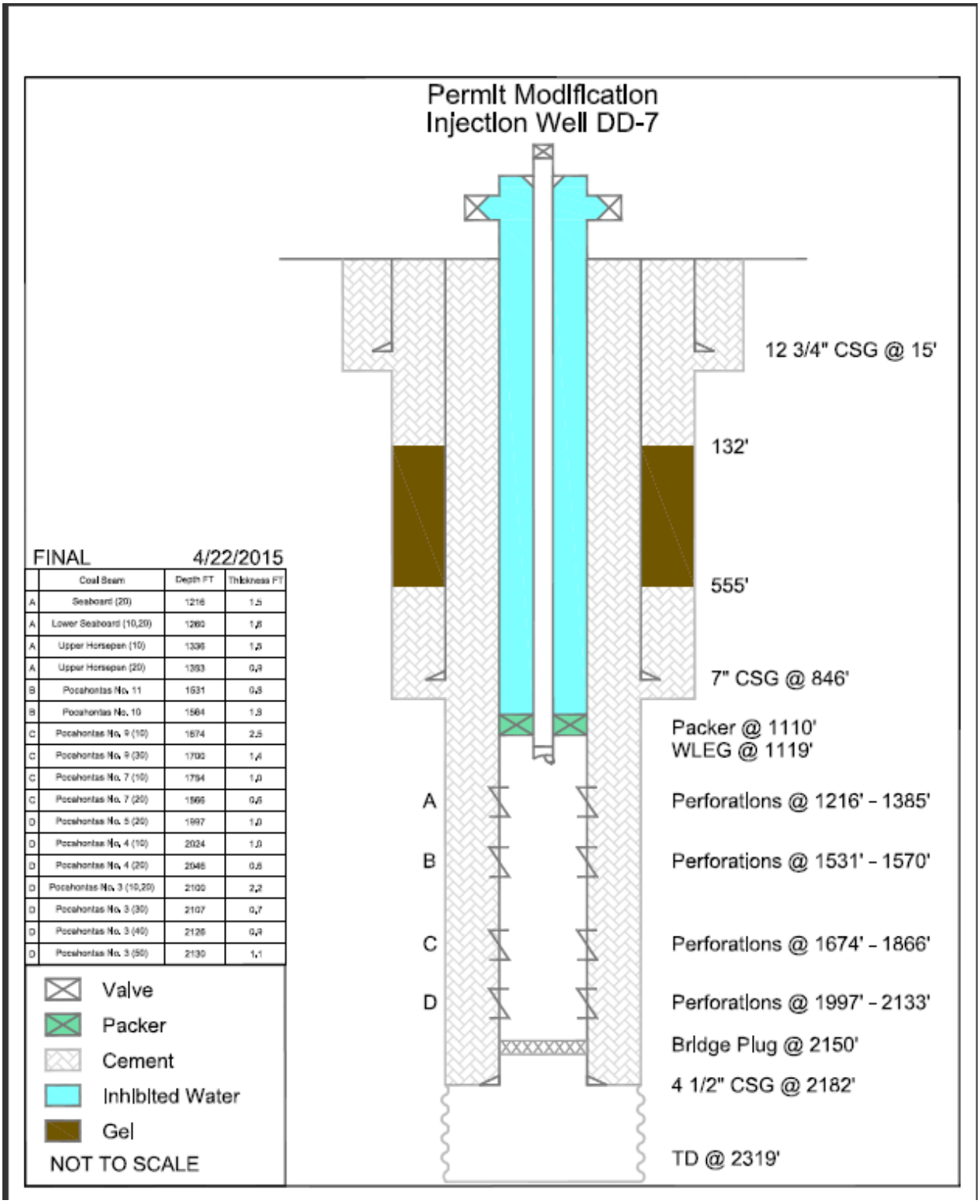


Figure 7: Density Curve UP(150FPM) from (1113-2136)ft

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APPENDIX I: Well Diagram



	Coal Seam	Depth FT	Thickness FT
A	Seaboard (20)	1216	1.5
A	Lower Seaboard (10,20)	1260	1.8
A	Upper Horsepen (10)	1336	1.5
A	Upper Horsepen (20)	1353	0.9
B	Pocahontas No. 11	1531	0.8
B	Pocahontas No. 10	1564	1.3
C	Pocahontas No. 9 (10)	1674	2.5
C	Pocahontas No. 9 (30)	1700	1.4
C	Pocahontas No. 7 (10)	1794	1.0
C	Pocahontas No. 7 (20)	1866	0.6
D	Pocahontas No. 5 (20)	1997	1.0
D	Pocahontas No. 4 (10)	2024	1.0
D	Pocahontas No. 4 (20)	2046	0.8
D	Pocahontas No. 3 (10,20)	2100	2.2
D	Pocahontas No. 3 (30)	2107	0.7
D	Pocahontas No. 3 (40)	2126	0.9
D	Pocahontas No. 3 (50)	2130	1.1

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APPENDIX II – Curve Mnemonics

MNEMONICS	UNITS	DESCRIPTION
DEPTH	FT	LOGGED DEPTH
CCL	MV	COLLAR LOCATOR
GR	GAPI	GAMMA RAY
PRES	PSI	PRESSURE
FDNS	C/CC	RADIOACTIVE DENSITY
CTMP	DEGF	TEMPERATURE
CFLW	RPS	FLOWMETER/SPINNER
TENS	LB	TENSION
LSPD	FPM	LINE SPEED

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Weatherford®



Production Log Interpretation

Well Report Review Copy

CARDNO
DD-8
Field: OAKWOOD

8/25/2016

Prepared by:
Dahiana Mejia
15710 JFK Blvd, Houston TX, 77032
832.284.3731

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CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 4

2. LOGGING OBJECTIVES FOR PLT 5

3. LOGGING PROCEDURE 5

4. SEQUENCE OF EVENTS 6

5. TOOL DIAGRAM 7

6. INJECTION LOG INTERPRETATION 8
6.1 DATA QUALITY CONTROL AND DISCUSSION 8
6.2 PROFILE CALCULATION 10

7. DENSITY PROFILE 13

APPENDIX I: Well Diagram 14
APPENDIX II – Curve Mnemonics 15

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DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

LIST OF FIGURES

Figure 1: Injection log procedure
Figure 2: Sequence of Events
Figure 3: Tool String Diagram Tool OD: 1.693”
Figure 4: Injection passes- DD8
Figure 5: Injection Profile Computed
Figure 6: Injection flow profile
Figure 7: Density Curve from 1800ft to surface

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FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

1. EXECUTIVE SUMMARY

Weatherford Wireline Services were commissioned to perform an injection log (PLT) survey on DD8 for Cardno on March 23, 2016. The objective of the survey was to determine injecting zones.

A Weatherford PLT tool string consisting of GR, CCL, temperature, pressure, radioactive density, 1.69" jewel spinner was used in the logging job.

Conclusions:

- Raw data shows qualitatively active perforations between 871ft and 1040ft.
- Majority of CO2 went to the top of perforation at (871-1205)ft (had the highest change in injection profile).
- Spinner data was affected by yo-yo making difficult to detect injecting zones with low injection rate at the time of logging.
- Density curve is provided from surface to the bottom of the logging interval to show CO2 density changes against pressure and temperature. See figure 7.
- Bottom perforation was partially logged due to the tag depth.
- The injection profile was calculated from the 150B down pass.

	Formation Names	Depth (ft)	Perforations (ft)		DW_150 (RPS)	%_DW 150B	Tons/day
A	Seaboard (20)	871	871	902	1.3	100	58
A	Lower Seaboard (10)	902	902	1205	0	0	0
A	Lower Seaboard (20)	912					
A	Upper Horsepen (10)	984					
A	Upper Horsepen (20)	1031					
A	Unknown Coal	1054					
A	Middle Horsepen (10)	1068					
A	Pocahontas No. 11	1165					
A	Pocahontas No. 10 (10)	1198					
A	Pocahontas No. 10 (20)	1204					
B	Pocahontas No. 9 (10)	1311	1311	1677	0	0	0
B	Pocahontas No. 9 (20)	1314					
B	Unknown Coal.	1397					
B	Pocahontas No. 7 (10)	1433					
B	Pocahontas No. 7 (20)	1467					
B	Pocahontas No. 5 (10)	1591					
B	Pocahontas No. 4 (10)	1637					
B	Pocahontas No. 4 (20)	1677					
C	Pocahontas No. 3 (10,20)	1711	1710	1802	0	0	0
C	Pocahontas No. 3 (30)	1721					
C	Pocahontas No. 3 (40,50)	1731					
C	Pocahontas No. 2	1746					
C	Pocahontas No. 1	1802					

Table 1: Total Injection rate

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DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

2. LOGGING OBJECTIVES FOR PLT

The aim of the survey was to identify injection zones

3. LOGGING PROCEDURE

The tool string was composed as follows from top to bottom of E-line:

- Weight bars
- CCL
- GR
- Pressure Gauge
- Density
- Temperature sensor/ Jewel Flowmeter.

Job Procedure

String	Direction	Cable Speed	Interval	Well condition	BH contents	Remarks
PLT	Down	RIH	Surface to 820ft_MD	Injecting	CO2	Looking for interfaces
Take a 5 minutes station at 820ft						
PLT	Down	100	820ft_MD (EOT) to 1806ft_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
PLT	Up	100	1806ft_MD to 820ft (EOT)_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
PLT	Down	150	820ft_MD (EOT) to 1806ft_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
PLT	Up	150	1806ft_MD to 820ft (EOT)_MD	Injecting	CO2	Check spinner response, if necessary repeat the pass
Calibration Passes						
PLT	Down	50	1205ft_MD to 1311ft_MD	Injecting	CO2	
PLT	Up	50	1311ft_MD to 1205ft_MD	Injecting	CO2	
Take a 5 minutes station at 1700ft and 1800ft						

Figure 1: Injection log procedure

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DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

4. SEQUENCE OF EVENTS

(Provided by T. Pawliuk, Weatherford US Specialty Engineer)

Production Logging Job Notes

Company	Cardno
Well Name	DD-8
Field	OAKWOOD
Date	23-Mar-16
Field Engineer	T. PAWLIUK
Correlation Log Used	Geological Logging Systems Gamma-Caliper Log dated 12/16/2001

	Pressure Tested
Lubricator Test	650

	Gas (TPD)	Oil (BPD)	Water (BPD)	Pressure (PSI)	Temperature (F)
Flow Rates	58				

Surface Pressure while logging	650
Hours well was flowing before logging	

PL RAW DATA file name shall be of the form XX_YY_ZZ.LAS, where:
XX: well condition, SI (shut in) or absent if flowing conditions
YY= logging direction DN (down pass) or UP (up pass)
ZZ= Cable speed in feet per minute (fpm)

Flowing Passes	Times are in Texas time because it matches up with the laptop		
Passes	Time	Date	
150 DOWN			
150 UP	14:05		
RATE CHANGE 58 TON/DAY			
150 DOWN b	14:53		
150 up c	15:02		
100 down			REDUCED LOGGING INTERVAL TO A MAX DEPTH OF 1740' BECAUSE WE HAD ISSUES WITH THE FM PICKING UP STUFF AND DYING
150 UP D			
100 DOWN B	15:33		
100 UP			NO FM 1720-1400, AND FM NOT TURNING WHILE STATIONARY AT TOP OF INTERVAL. PULL INTO TUBING TO TRY TO CLEAN
70 DOWN	15:58		
100 UP B	16:15		

Stationary Data		
Depth (ft)	Time	Date
820	13:50	23-Mar-16
RATE CHANGE		
820	14:42	
1700		
1800	17:00	

Remarks (Include any issues while logging)			
DENSITY CALS BEFORE: AIR-15188.5 WATER-6352.1, AFTER: AIR-15157.2WATER-6339.9			
11:45	dummy run		
12:43	power up to fdt in prep of cal		
12:53	cal fluid density		
13:08	TEST TOOL		
13:13	STAB ON		
13:15	EQUILIZE		650PSI
13:22	RIH		
13:35	AT 820	INJECTING ABOUT 60 TONS, TRY TO GET THEM TO BUMP IT UP TO 80, 858PSI, .67G/CC,0.6RPS	
13:50	STAT820		
14:15	THEY HAD TO DROP INJECTION RATE		
	MY SPINNER HAD STALLED DURING THE UP PASS AS WELL SO I CAME INTO TUBING ANYWAYS TO GIVE IT A CLEANING		
14:40	RESTART LOGGING PASSES ATT NEW INJECTION RATE		

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Figure 2: Sequence of Events

5. TOOL DIAGRAM

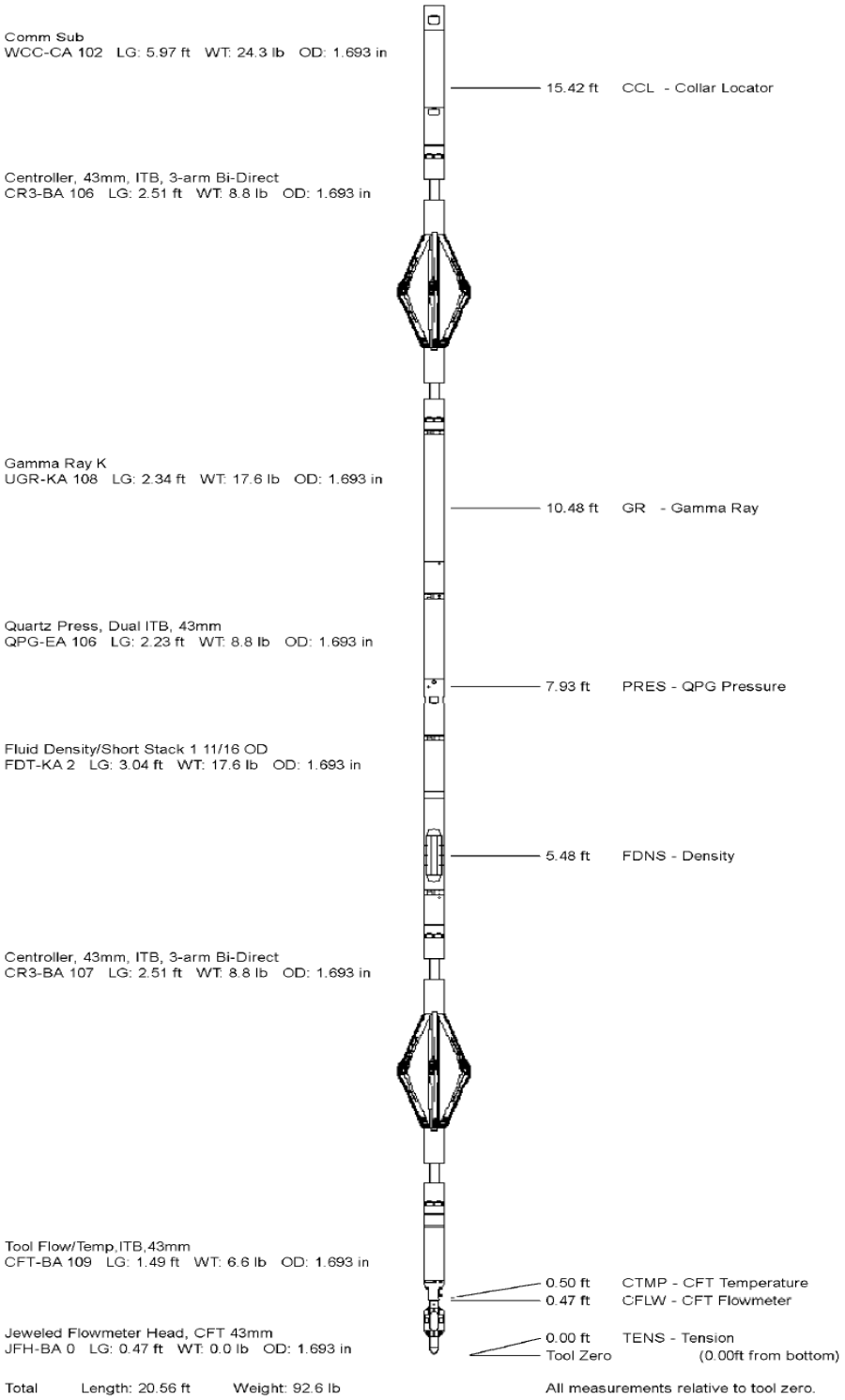


Figure 3: Tool String Diagram Tool OD: 1.693”

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6. INJECTION LOG INTERPRETATION

OVERVIEW

The analysis was performed as follow:

- The data preparation to filter the data.
- The flow meter analysis to compute the injection profile.
- The profile determination to identify the potential injecting zones.
- The computation of percentage per injecting zones based on surface flow rate reported by client.

6.1 DATA QUALITY CONTROL AND DISCUSSION

The main sensors are:

- *Spinner flowmeter*: for an estimate of mixture flow rate.
- *Temperature*: mainly for qualitative interpretation, but is sometimes very useful and can confirm or deny conclusions drawn from other measurements.
- *Pressure*: needed for calculation of fluid properties and can be used to compute fluid density in wellbore.
- *Caliper, CCL and Gamma Ray*: needed for depth control or casing ID. The gamma ray curve can additionally help identify reservoir zones and scaling problems.

Log Quality Check –**Figure 4**: Injection passes- DD8

- **Gamma Ray:** The curves generally stack.
- **Pressure:** Repeatability pass to pass.
- **Spinner:** The spinner data was affected by yo-yo, seem in the erratic motion of the tension, making difficult to identify low injecting zones.
- **Line Speed:** Line speed data was very spiky.
- **Density:** Density remains consistent over whole logging interval. Good repeatability pass to pass.
- **Temperature:** Cannot be determined from temperature data clear injecting zones.

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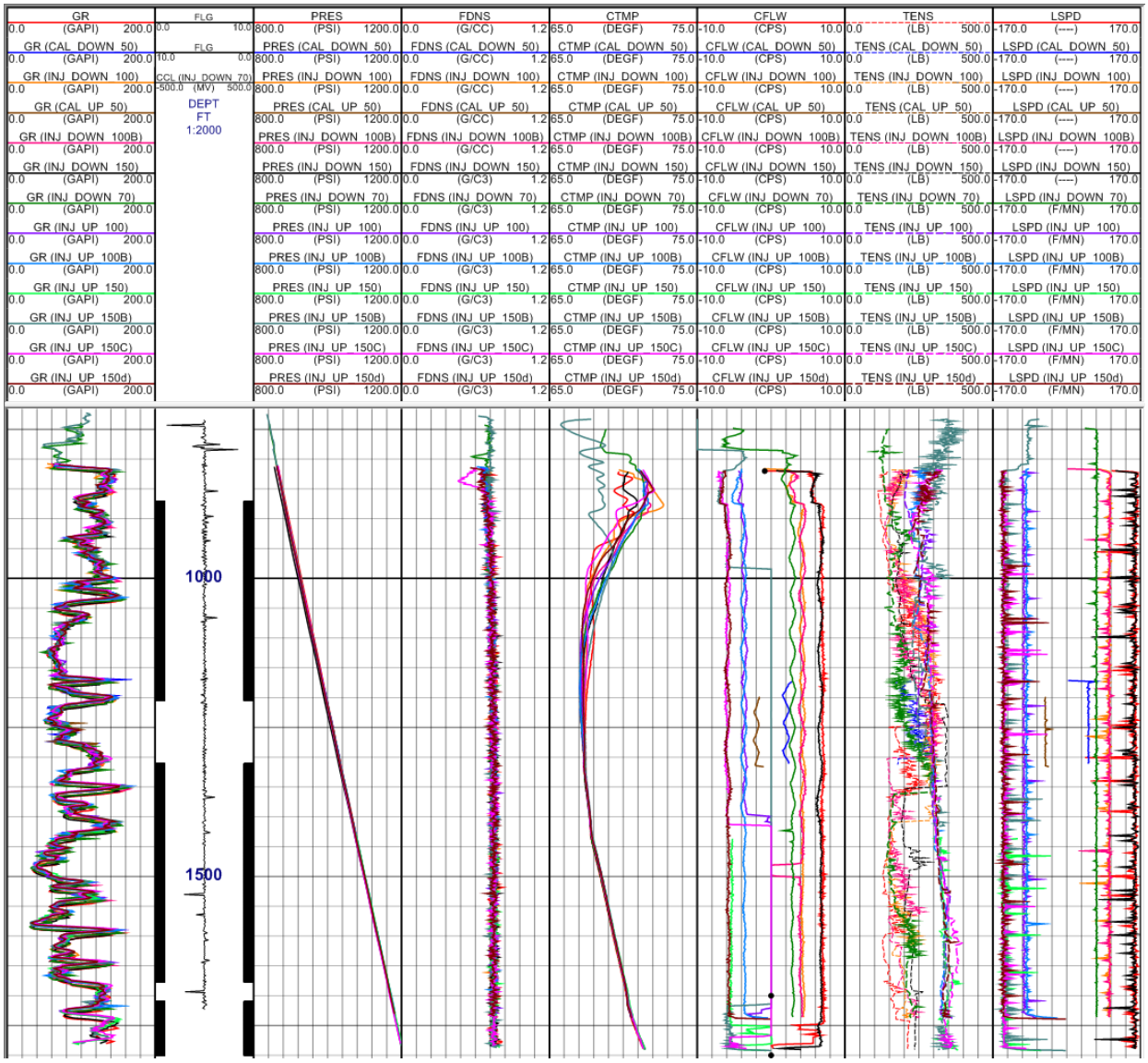


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6.2 PROFILE CALCULATION

The down pass at 150B was used to get the injection profile. Where the spinner is showing the minimum value is the total flow rate, 100% flow. The maximum value for spinner is 0% flow.

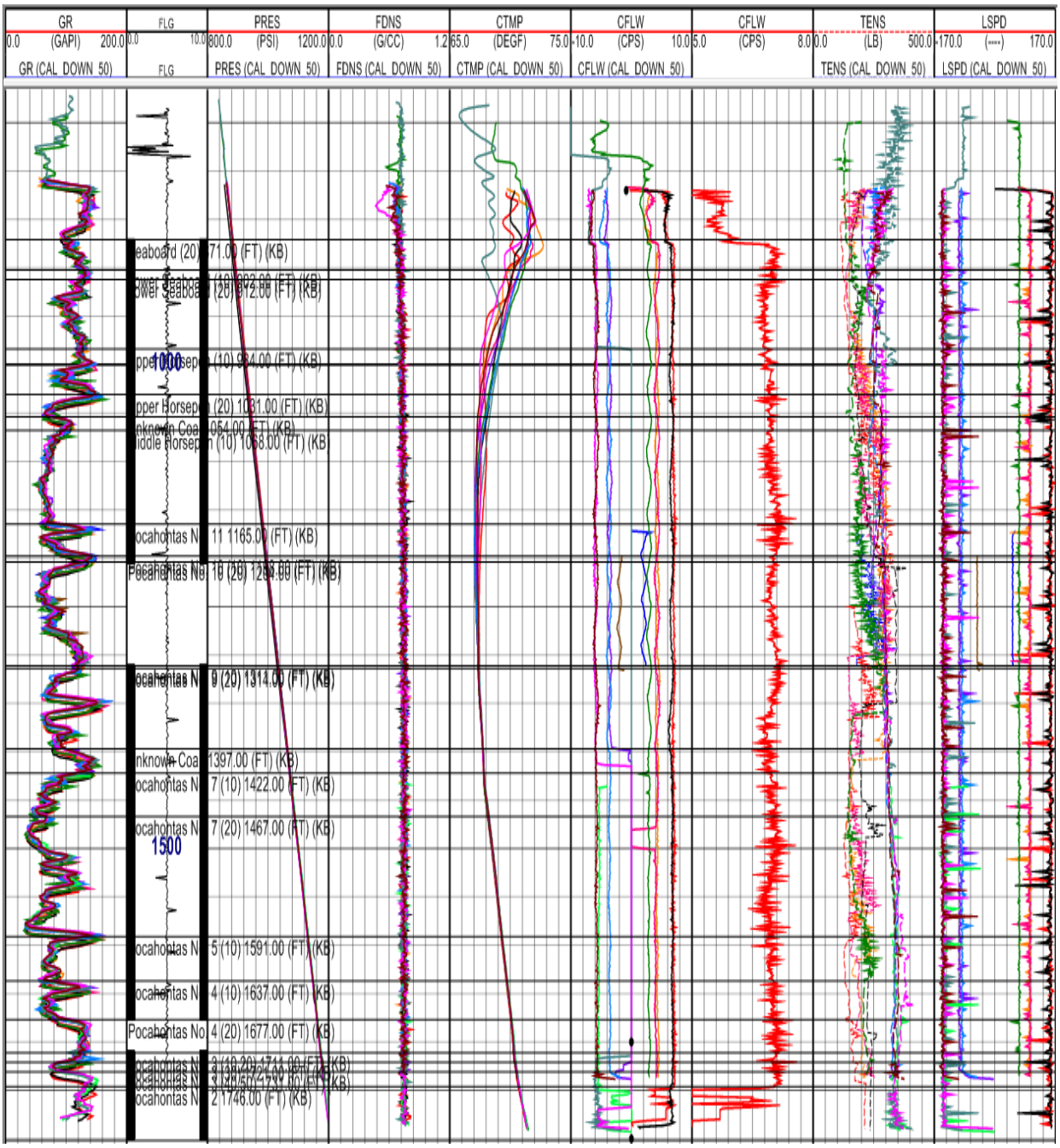


Figure 5: Injection Profile Computed

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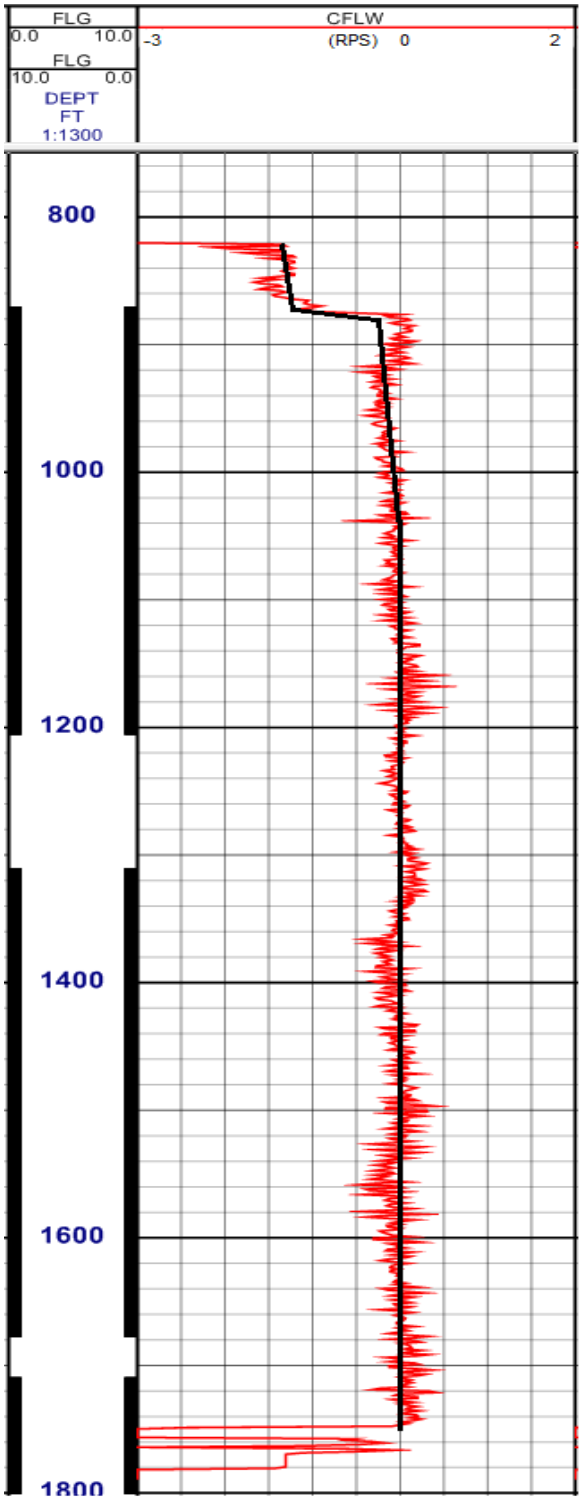


Figure 6: Injection flow profile

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B	Pocahontas No. 7 (20)	1467					
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B	Pocahontas No. 4 (10)	1637					
B	Pocahontas No. 4 (20)	1677					
C	Pocahontas No. 3 (10,20)	1711	1710	1802	0	0	0
C	Pocahontas No. 3 (30)	1721					
C	Pocahontas No. 3 (40,50)	1731					
C	Pocahontas No. 2	1746					
C	Pocahontas No. 1	1802					

Table 2: Percentage Injecting Zones

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7. DENSITY PROFILE

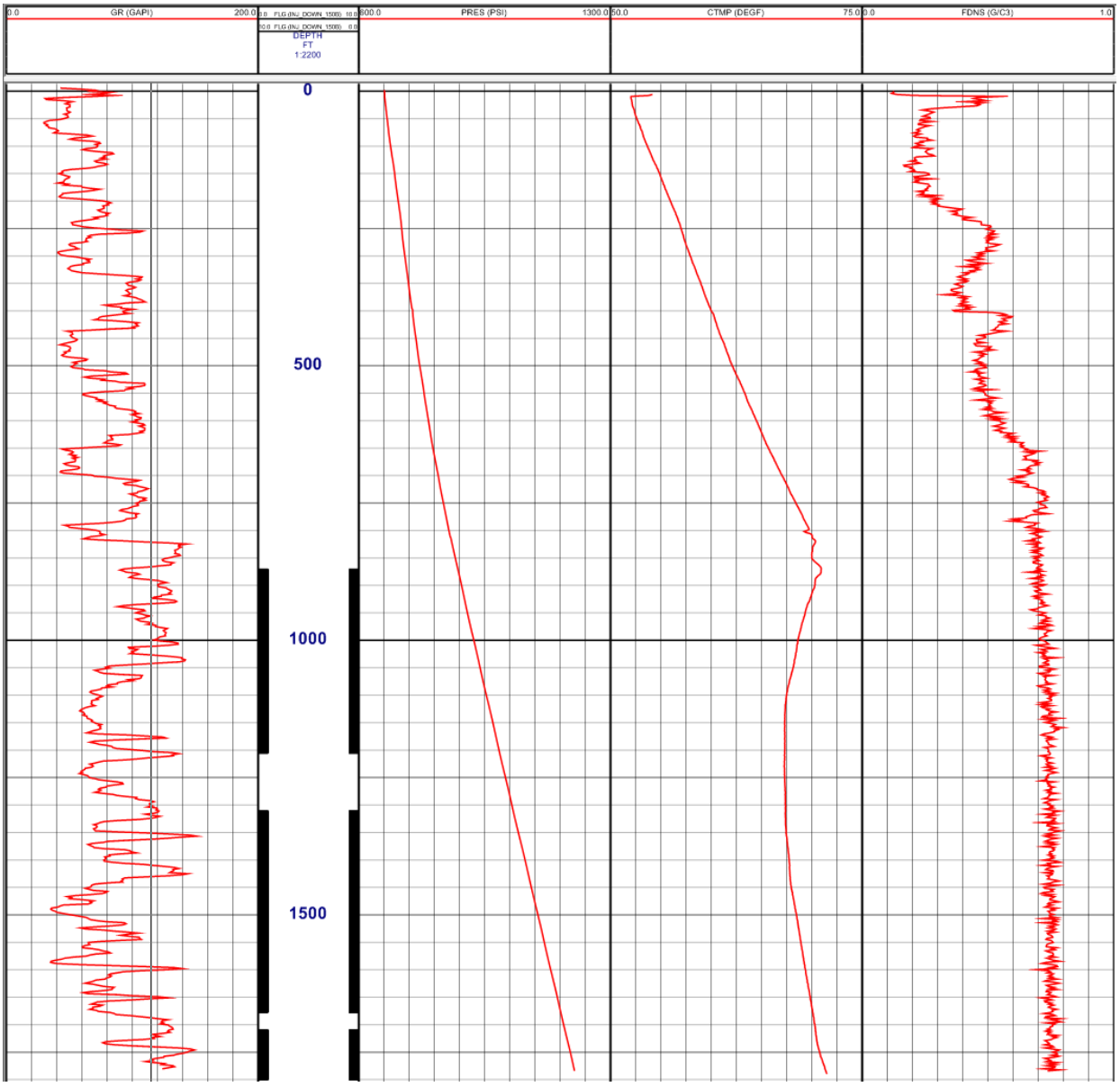
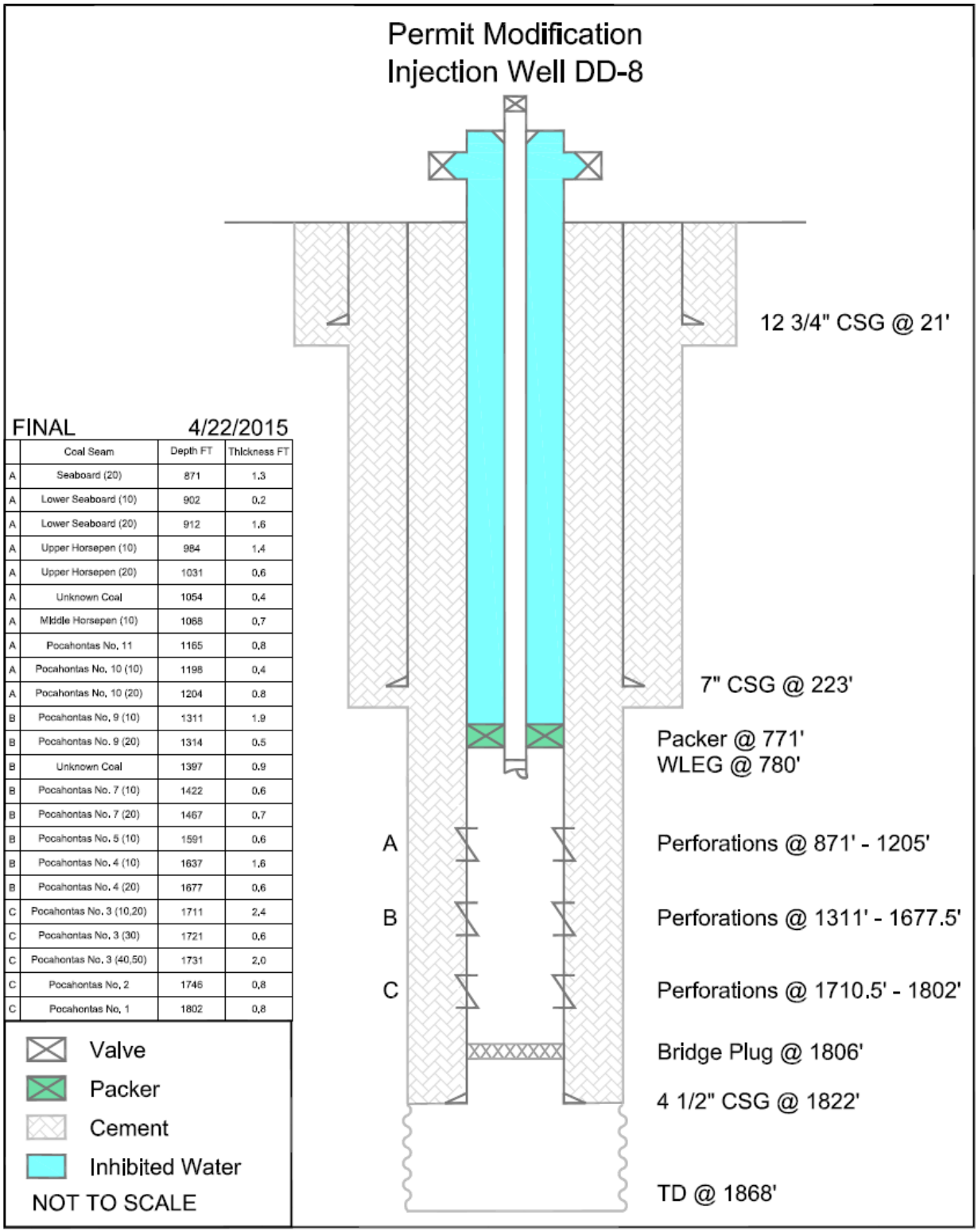


Figure 7: Density Curve from 1800ft to surface

In making interpretations of data our employees will give the customer the benefit of their best judgement, but since all interpretations are based on interfaces from electrical or other measurements, we cannot and we do not guarantee the accuracy of any interpretation. We shall not be liable or responsible for any loss, cost, damage, or expenses whatsoever incurred by the customer resulting from any interpretation made by our employees.

CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

APPENDIX I: Well Diagram



FINAL 4/22/2015

	Coal Seam	Depth FT	Thickness FT
A	Seaboard (20)	871	1,3
A	Lower Seaboard (10)	902	0,2
A	Lower Seaboard (20)	912	1,6
A	Upper Horsepen (10)	984	1,4
A	Upper Horsepen (20)	1031	0,6
A	Unknown Coal	1054	0,4
A	Middle Horsepen (10)	1068	0,7
A	Pocahontas No. 11	1165	0,8
A	Pocahontas No. 10 (10)	1198	0,4
A	Pocahontas No. 10 (20)	1204	0,8
B	Pocahontas No. 9 (10)	1311	1,9
B	Pocahontas No. 9 (20)	1314	0,5
B	Unknown Coal	1397	0,9
B	Pocahontas No. 7 (10)	1422	0,6
B	Pocahontas No. 7 (20)	1467	0,7
B	Pocahontas No. 5 (10)	1591	0,6
B	Pocahontas No. 4 (10)	1637	1,6
B	Pocahontas No. 4 (20)	1677	0,6
C	Pocahontas No. 3 (10,20)	1711	2,4
C	Pocahontas No. 3 (30)	1721	0,6
C	Pocahontas No. 3 (40,50)	1731	2,0
C	Pocahontas No. 2	1746	0,8
C	Pocahontas No. 1	1802	0,8

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FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

APPENDIX II – Curve Mnemonics

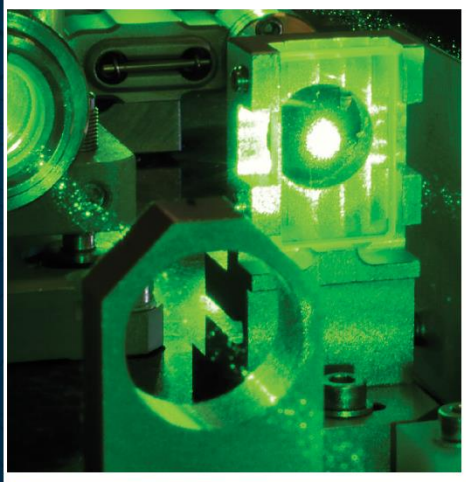
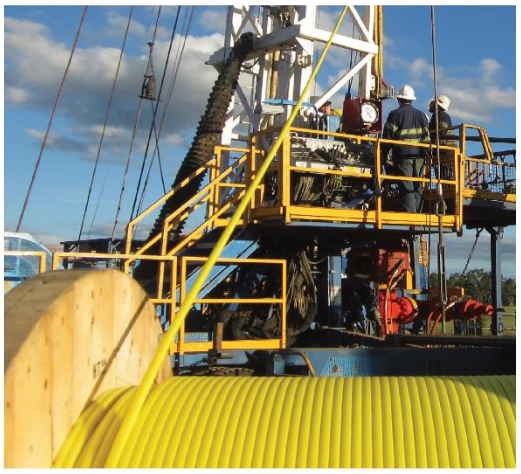
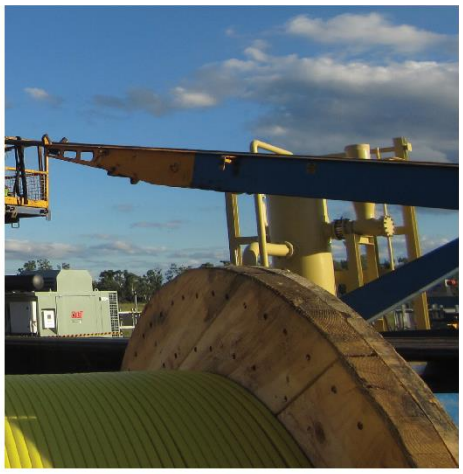
MNEMONICS	UNITS	DESCRIPTION
DEPTH	FT	LOGGED DEPTH
CCL	MV	COLLAR LOCATOR
GR	GAPI	GAMMA RAY
PRES	PSI	PRESSURE
FDNS	C/CC	RADIOACTIVE DENSITY
CTMP	DEGF	TEMPERATURE
CFLW	RPS	FLOWMETER/SPINNER
TENS	LB	TENSION
LSPD	FPM	LINE SPEED

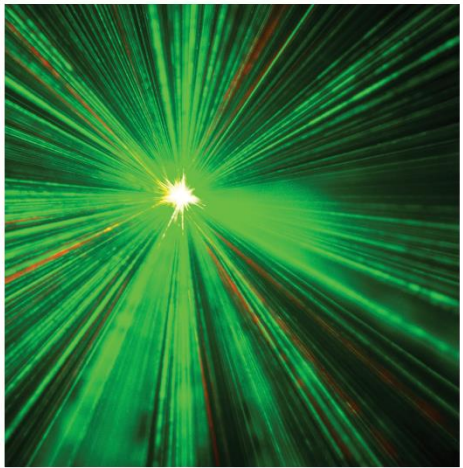
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23 Appendix K – Flowback Logging

WELLDOG
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Provision of CarbonTracker Services



Proposed:	Nino Ripepi
Position:	Assistant Professor, Department of Mining and Minerals Engineering, Virginia Tech.
Date:	30th June 2017
Reference:	US-138-VTE-SSS-2017
Service:	CarbonTracker Technical Service
Location:	Buchanan County, Virginia

Introduction

Please find attached a proposal for supply of WellDog's CarbonTracker technical service for Virginia Tech's enhanced coalbed methane project. The primary goal of the proposed work is to determine in which intervals and coals seams carbon dioxide injected from three wells has sequestered.

CarbonTracker Service

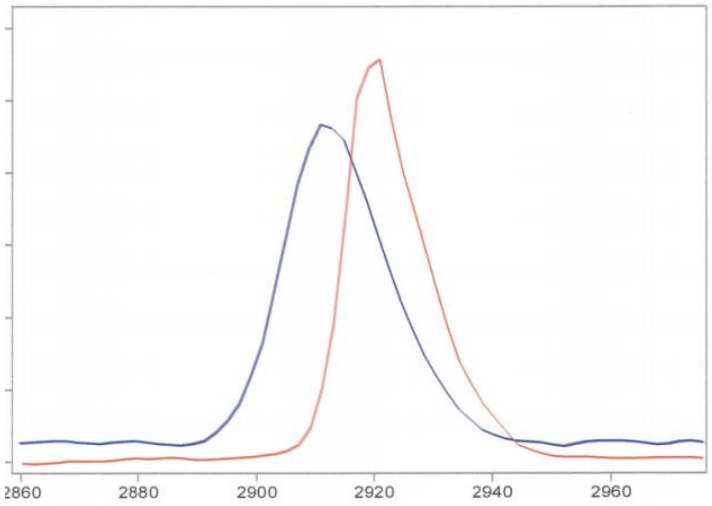
The CarbonTracker service uses a proprietary downhole Reservoir Raman System based on Raman spectroscopy to chemically identify and quantify gases and liquids in injector and collector wellbores. WellDog has pioneered the use of Raman spectroscopy to analyze coalbed reservoir systems. Over the past 10 years, WellDog has collected hundreds of thousands of spectra on simulated and real-world coal seams, both in the laboratory and down hole, for methane and higher order hydrocarbons as well as carbon dioxide, nitrogen and other species. WellDog is the only company in the world with the capability to do these measurements, particularly in-situ.

Raman spectroscopy is a well-established laboratory chemical analysis technique. It was invented after the discovery of the Raman Effect in 1928, for which Sir Chandasekhra Venkata won the Nobel Prize for Physics in 1930.

The Raman Effect occurs when light scatters from a molecule with a slightly changed energy, i.e. color, due to excitation of the molecule's chemical bonds. The change in energy, resulting in a change in color, is representative of the excited bond energy. As a result, observing the colors of light scattered from a material indicates which molecular species are present in the material. Raman spectroscopy observes these colors by collecting the scattered light and then separating and detecting the colors that make up the light.

A challenge in using Raman spectroscopy is that only one photon in a million are changed when scattering from a material. The energy of the other photons remains unchanged. In order to increase the number of changed photons measured the spectrometers employ lasers and sophisticated filters and sensors.

A benefit of Raman spectroscopy is that water molecules do not alter the energy state of many photons that scatter from it. As a result, Raman spectroscopy is not overly sensitive to water, making it ideally suited for analyzing species dissolved in water or in the presence of water vapor. In its 80-year history, Raman spectroscopy has been used to analyze many chemical species and chemical systems. Because of its sensitivity to the molecular structure of chemicals, Raman spectroscopy is called a "fingerprint" technique – every chemical gives a unique Raman signal, or

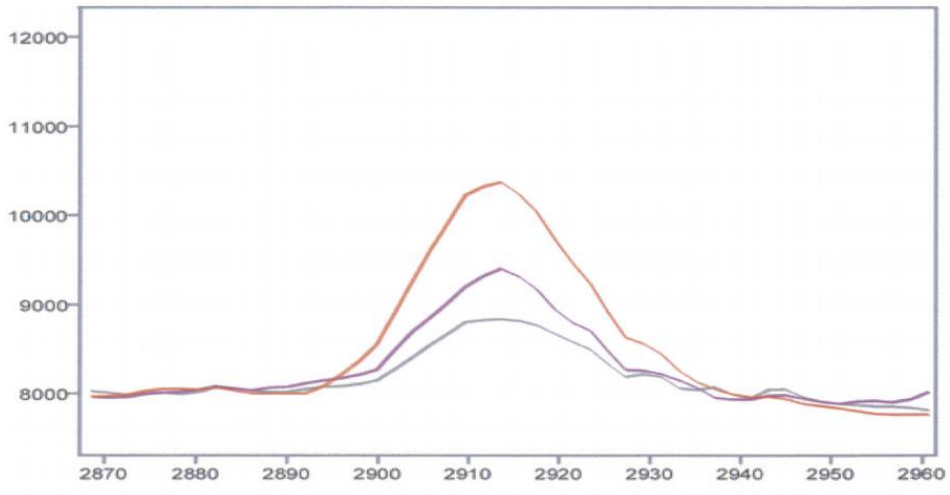


spectrum. More than 300 books have been published relating to fingerprints of various chemical systems.

The figure at left shows two example Raman spectra collected at the energies (colors) characteristic of methane gas and methane dissolved in water. The gaseous methane peak at 2917 wavenumbers is broadened and reduced in energy slightly when compared to the methane solution gas peak at 2912 wavenumbers, due to interaction between methane and the water molecules, making it possible to distinguish chemical phases of methane also.

In addition to providing chemical fingerprints, Raman spectroscopy allows direct quantification of chemical concentrations in mixtures. For example, a series of peaks for methane dissolved in water are shown in the top figure below. The size of those peaks can be used in turn to build a quantitative calibration between instrument response and methane partial pressure, as shown in the bottom figure below. As the partial pressure is increased, the instrument response increases linearly.

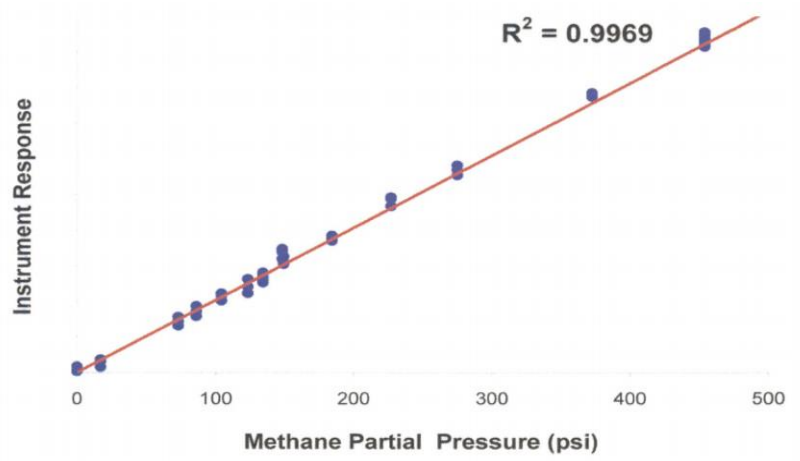
Through careful instrument design and maintenance, this instrument response can be calibrated to concentration or partial pressure of the methane. Similar calibrations can be built for the various forms of carbon dioxide dissolved in water or in gaseous phase (see figure at bottom). As a result, WellDog is able to quantitatively determine hydrocarbon and carbon dioxide gas levels in coalbed reservoirs.



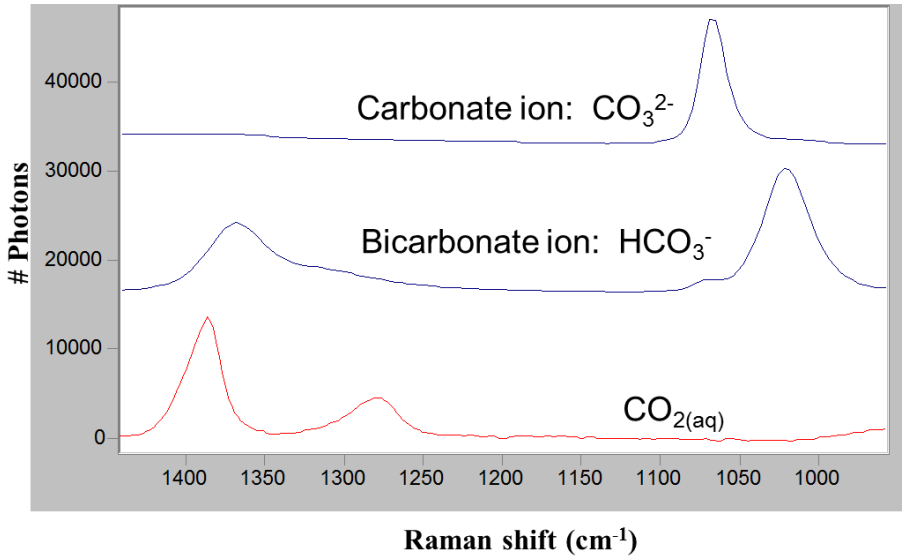
Raman spectra of (bottom to top) 190, 297, and 564 psi production methane gas.

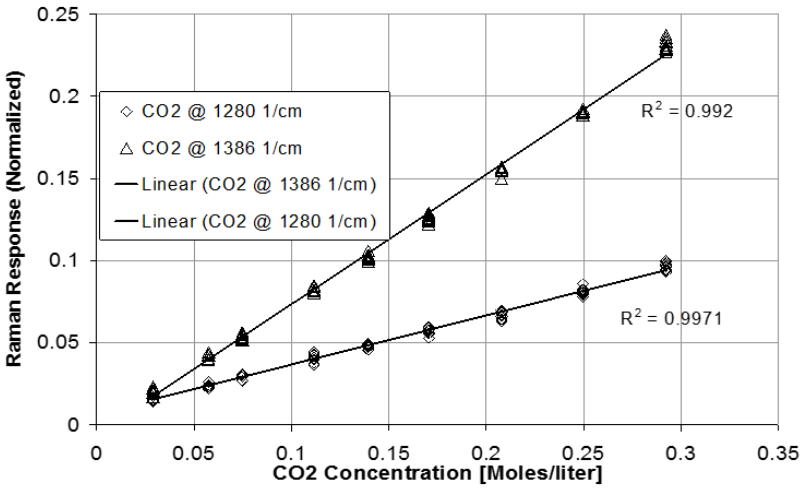
Reservoir Technology Center
1525 Industry Drive
Laramie, Wyoming 82070 USA

+1 (307) 742 6340
info@welldog.com
www.welldog.com



Example correlation between WellDog instrument response and methane partial pressure





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Project Scope

- Project Deliverables
  - Supply of technical services to identify location of sequestered CO_2
  - Supply of technical services to measure amount of sequestered CO_2
  - Supply of downhole Reservoir Raman System and supporting wireline equipment
  - Supply of skilled field and technical support staff
  - Optional supply of zone isolation straddle packer string
  - Optional supply of in well pressure monitoring and Pressure Transient Analysis Capability
- Wellbore Condition Assumptions
  - Maximum test depth: ca. 2,100 feet
  - Maximum reservoir pressure: ca. 200 psi
  - Maximum reservoir temperature: ca. 70°F
  - Casing size:4 ½”
- Test Wells
  - 3 Injection wells
    - DD-7A: 3 perforated intervals
    - DD-8: 3 perforated intervals
    - DD-7: 4 perforated intervals
  - 1 Producing well
    - DD-8A: 3 perforated intervals
- Proposed Test Program
  - Overview
    - Data collected at each step will be reviewed to revise, if needed, the optimal path forward.
    - The test program philosophy will be to use wireline logging and wireline-set bridge plugs to fulfil as much of the deliverables as possible in order to maximize data-per-dollar spent.
  - Preparation
    - Step 1: Collect historical completion and operational data
      - These data will help WellDog confirm test plan, pressure control needs, and likely species that will be observed in the wells
    - Step 2: Mobilize to location / Joint Safety Assessment
      - WellDog will mobilize top site before the packers and tubing are pulled.
      - Before wireline field operations commence, WellDog and the wireline company will perform a JSA to ensure all risks are identified and managed effectively.
  - Wireline Operations-entire wellbore
    - Step 3: Pull tubing and packer in well #1
    - Step 4: Measure gases and liquids in the wellbore
      - The Reservoir Raman System will be used to log the entire wellbore.
      - This run will indicate the water depth and confirm the presence of CO_2 in the wellbore.
      - This run may indicate at which depth(s) the CO_2 has been injected and provide guidance for subsequent zone isolation efforts.
    - Step 5: Amend wellbore
      - This can be done using a number of inexpensive methods, such as circulating with nitrogen, swabbing water in the well, or simply letting the well flow while continuing to log.

        - Step 6: Measure the amended wellbore (if not done continuously during amendment)
            - Again, look for any changes or any zones of interest that were not determined in the initial OH run.
            - Changes to the vertical distribution of CO_2 in the wellbore may reveal information about which zones have accepted CO_2 injectant.
    - Wireline Operations-isolated zones
        - Step 7: Isolate zone(s) of interest with Bridge Plug
            - Each zone will be isolated in a stepwise fashion, presumably from top to bottom, in order to attempt to isolate the source of CO_2 flowback gas.
        - Step 8: Measure CO_2 from the isolated zones
            - The Reservoir Raman System will be lowered into the wellbore and used to log the CO_2 gas present above the bridge plug for each isolated zone.
        - Step 9: Repeat for individual coal seams
            - If appropriate, individual coal seams will be similarly isolated and analyzed using the same method.
    - Step 10: Repeat steps 3-9 for the other two injection wells, and (optional) producing well.
    - Step 11: Demobilize wireline operations
    -

    Optional rig-based operations:

        - Step 12: Mobilize to location / Joint Safety Assessment
            - WellDog will mobilize to site.
            - Before rig-based field operations commence, WellDog and the rig company will perform a JSA to ensure all risks are identified and managed collectively.
        - Step 13: Isolate zone(s) of interest with Straddle Packer
            - Straddle packer will be inserted into wellbore and used to isolate zone(s) of interest.
        - Step 14: Measure CO_2 from the isolated zones
            - The Reservoir Raman System will be lowered into the wellbore and used to log the CO_2 gas present in the tubing above the straddle packer for each isolated zone.
        - Step 15: Repeat for individual coal seams
            - If appropriate, individual coal seams will be similarly isolated and analyzed using the same method.
        - Step 16: Repeat steps 12-15 for the other two injection wells, and (optional) producing well.
        - Step 17: Demobilize rig-based operations

- Operational Assumptions
    - Requirements for optional rig-based operations
        - Rig deployed service, work over rig required and supplied by operator
        - Rig pump needs to be capable of pumping 1,000 psi at surface
        - Work string needs to be pressure sealing, scale free and drifted with ID greater than 3.25”
        - WellDog to provide nitrogen gas
    - Clean site power and Wi-Fi connectivity (Cell Phone capability is acceptable)

24 Appendix L – Outreach Materials

- What is Carbon Dioxide?
- Frequently Asked Questions
- CO_2 Monitoring, Verification, and Accounting (MVA)
- Buchanan County Field Site Fact Sheet
- Project Timeline
- Geological Characteristics
- Carbon Dioxide Transport to the Site
- Monitoring, Verification and Accounting Details

WHAT IS CARBON DIOXIDE?

Carbon dioxide (CO_2) is a chemical compound containing one carbon (C) and two oxygen (O) atoms. CO_2 is a colorless, odorless, tasteless, non-flammable gas. When chilled to -109.3° F, it can also become solid, and is commonly known as dry ice.



CO_2 is exhaled by humans and animals, released whenever anything burns or decomposes, used to carbonate sodas and decaffeinate coffee and tea, as a coolant (dry ice), and in fire extinguishers.

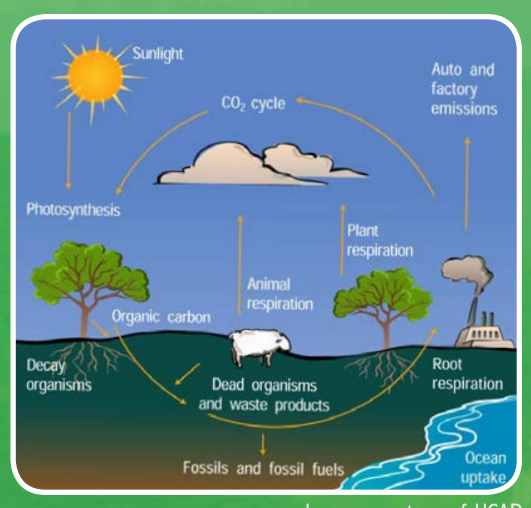


Image courtesy of UCAR

In a natural process called the carbon cycle, carbon, in the form of CO_2, is exchanged between plants, animals, and the Earth.



Carbon dioxide is regularly transported by pipeline, tanker truck, and rail for food and industrial grade use. CO_2 transport for geologic storage will be accomplished in the same manner.

Carbon dioxide is essential to plant life and helps create the greenhouse effect that keeps our planet livable.



Scientific studies have shown CO_2 to be a "greenhouse gas" and contributor to global climate change when introduced in the atmosphere in unnaturally large amounts, such as from the transportation sector and from coal and natural gas power plants. Some of this excess CO_2 can be captured, transported, and used to extract oil and gas from natural reservoirs that were once thought to be depleted. The Virginia Center for Coal and Energy Research (VCCER) research project, Injecting Carbon Dioxide into Unconventional Reservoirs, will evaluate whether the CO_2 can be permanently and safely stored in the depleted reservoirs.

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Virginia Center for Coal and Energy Research
www.energy.vt.edu

FREQUENTLY ASKED QUESTIONS

WHAT IS CARBON DIOXIDE (CO_2)?

Carbon dioxide is a chemical compound, formed of one atom of carbon and two atoms of oxygen, is a major component of the exhaled breath of humans and animals, and has a wide range of commercial uses, from the production of lasers to the carbonation of soft drinks. This compound exists naturally from the Earth's environment, and it is produced in a variety of ways, including through the combustion of fossil fuels (coal, oil, or natural gas), as a byproduct of industrial processes, and from transportation. This gas is a topic of interest because it is classified by environmental and climate scientists among the greenhouse gases, which impact the Earth's environment when they reach high concentrations in the atmosphere.

WHAT IS CO_2 MANAGEMENT?

The goal of CO_2 management is the reduction of the amount of CO_2 released into the atmosphere by any of several methods. Some methods seek to reduce the amount of CO_2 produced by increasing the efficiency of fossil fuel energy systems; switching to alternative, renewable energy methods such as wind and solar; and through energy conservation techniques by individuals and the private and public sectors. Removing CO_2 once it has entered the atmosphere is difficult, at best, so new methods focus on capturing CO_2 before it is released into the atmosphere, utilizing it to increase oil or natural gas production, or by transporting and storing it in a variety of ways, including underground.

WHAT IS CARBON CAPTURE AND STORAGE (CCS), OR CARBON CAPTURE, UTILIZATION AND STORAGE (CCUS)?

Carbon capture and storage, or as it is also called, carbon capture, utilization, and storage, are methods of carbon management that involve capturing CO_2 before it is released into the atmosphere and either using it for other purposes or storing it in underground geological formations. Sometimes, the injection of CO_2 into an underground formation for the purposes of long-term storage also enhances the recovery of oil or gas, valuable commodities that can in turn be used for energy production.

HOW IS THAT RELEVANT TO THIS PROJECT IN BUCHANAN COUNTY?

In this project, we will employ CCUS to store 20,000 tons of CO_2 in unmineable coal seams in Buchanan County and to use it to increase, or 'enhance,' the production of natural gas that is found in the coal seams. The wells that will be used to inject the CO_2 have already been producing natural gas for years, and as those reservoirs become depleted, the remaining natural gas is hard to recover. The injected CO_2 has the effect of displacing the remaining natural gas so that it can be recovered and used for energy production.

CAN CO_2 BE STORED IN FORESTS, TREES, WETLANDS, GRASSLANDS, AND SOIL?

"Terrestrial" storage is also a possibility, but while terrestrial storage options are being used and researched today, they are not believed to have the potential to store enough CO_2 to result in a significant decrease in the amount of CO_2 in the atmosphere. Also, there is a question about whether terrestrial storage will be effective for long-term storage, since when croplands and soil are tilled, or when trees and grass storing CO_2 are cut or decay, the CO_2 is released into the atmosphere again. For these reasons, some scientists and engineers see geological storage as the primary option for reducing the future emissions of CO_2 into the atmosphere.

WHY STORE, OR "SEQUESTER," CO_2?

Greenhouse gases, including CO_2, naturally trap a portion of the sun's energy in the Earth's atmosphere, and this maintains the temperatures needed to keep our planet hospitable to life. However, human (anthropogenic) activity, including the use of fossil fuels, adds CO_2 and other greenhouse gases to the atmosphere. Some scientists are concerned that the anthropogenic greenhouse gases entering the atmosphere are causing increased warming and that this warming will affect climate on a global scale. This concern is being addressed by international efforts and by individual countries. Conservation, more efficient fossil fuel power systems, renewable energy, and geologic storage are all tools to help reduce CO_2 intensity. CO_2 storage is one of several actions that would help to control anthropogenic CO_2 emissions to the atmosphere.

FREQUENTLY ASKED QUESTIONS

WHAT ROLE DOES THIS PROJECT PLAY IN THE BIGGER PICTURE OF CCUS?

In order for carbon capture and storage to play a significant role in reducing the amount of human-caused (anthropogenic) CO_2 into the atmosphere, large-scale storage projects, on the level of millions of tons of stored CO_2, will have to be commercially viable. Several large-scale storage projects of this scope and size exist in the world today. In order to explore opportunities for such large-scale CO_2 storage projects in different types of geological formations, the U.S. Department of Energy awards grants to partnerships of academia and private industry. These research grants include a) funding for characterization of the various geologies across the country, to be sure that adequate seals and other storage mechanisms exist to provide safe, effective long-term storage, and b) funding for smaller-scale projects to test the behavior of injected CO_2 into the various formations. Is this kind of storage a viable way of managing CO_2? While it is believed to be, the way to demonstrate this is to study the geology of various formations and regions in great detail and then conduct successful small scale pilot projects. Beginning as early as 2005, the VCCER has successfully completed both characterization projects and small-scale tests. The Buchanan County test, where up to 20,000 metric tons of CO_2 will be injected into unmineable coal seams, is the next step beyond the 1,000 metric ton test that the VCCER managed from 2008 to 2010, in Russell County, Virgina.

Again, the Central Appalachian basin, in Southwest Virginia, is believed to have extensive storage potential for CO_2, and with the successful completion of this test, the region could be the beneficiary of substantial economic activity from large-scale projects in the future.

HOW MIGHT I, AS A CITIZEN OF BUCHANAN COUNTY, EXPECT TO BENEFIT FROM THIS PROJECT?

As a joint partnership of academia (the VCCER at Virginia Tech) and industry, this approximately $14 million research project will bring increased economic activity in the region during the duration of the project (2011-2014), as workers and contractors come to work and attend conferences and meetings, staying at hotels, eating at local restaurants, and patronizing gas stations, convenience stores, hardware stores, and supermarkets, among other businesses. This activity is of benefit to the community. There is increased likelihood of much larger projects in the future because of the success of projects such as this today.

IS THIS SAFE?

It should be recognized that CO_2 is not a toxic substance. For millions of years, CO_2 has been and is stored naturally, along with other gases such as methane, in various geological formations. Testing will ensure that injected CO_2 does not migrate into surface or underground water reservoirs. We have conducted significant geological characterization of the coal seams that will store the CO_2 to verify the existence of adequate mechanisms, including specific types of rock formations that serve as barriers, or seals, that lie above the coal seams and prevent the CO_2 from migrating upwards.

At a microscopic level, coal contains pores, that are filled with methane. In the case of storage in coal seams, it is well-known that CO_2 "adsorbs," or bonds, to the discrete pores in coal very tightly. Methane in the pores has adsorbed to the coal surfaces for millions of years. CO_2 bonds even more closely, causing the methane to be "kicked out" naturally when the CO_2 is injected in. The same mechanisms that have kept the methane in the coal serve to ensure that the CO_2 will stay in place for many years to come.

HOW WOULD WE KNOW IF THERE WAS A CONTAINMENT ISSUE DURING, OR AFTER, THE PROJECT?

The Virginia Center for Coal and Energy Research, in conjunction with industry and government partners, has designed a monitoring program that will reveal if a CO_2 escape occurs, so that it can be addressed quickly. This monitoring program begins even before the CO_2 is injected, establishing baseline measurements for the amount of CO_2 that is already in the air and soil, so that it can be determined if a new source of CO_2 is introduced. Monitoring continues well after the project, to make sure no CO_2 is emitted into the atmosphere.

FREQUENTLY ASKED QUESTIONS

WHERE DOES THE CO_2 USED FOR THIS TEST COME FROM?

This CO_2 will be purchased from a commercial vendor and transported to the injection site by truck and pipeline, where it will be stored onsite until it is injected. For future research and commercial projects, the CO_2 could be provided in much larger volumes by using technologies to capture the CO_2 at nearby energy plants such as Dominion Virginia Power's Virginia City Hybrid Energy Center in Wise County, Virginia, and other nearby industrial plants and factories.

HOW CAN I LEARN MORE ABOUT CCUS AS A MEANS OF MANAGING CARBON?

We suggest you start with the U.S. Department of Energy's carbon capture and storage website (http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research), as a way of learning about our energy needs and resources, and how we can best ensure that everyone has access to clean, affordable energy with a minimal impact on the environment.

FREQUENTLY ASKED QUESTIONS

DEFINITIONS OF KEY TERMS

SEQUESTRATION
Sequestration means storage. To sequester CO_2 is to store it, as opposed to emitting it into the atmosphere.

MIGRATION
The movement of CO_2 in underground formations is called migration.

UNMINEABLE, AS IN "UNMINEABLE COAL SEAM"
An unmineable coal seam is one that it is not economically or technically feasible to mine. For instance, some coal seams are too thin to be economical to mine.

(GEOLOGICAL) CHARACTERIZATION
Before injecting CO_2 into underground formations, the extent and properties of the formations must be carefully examined and analyzed, as well as what kinds of geological formations and structures lie above and below. The process of studying these geological formations is called 'characterization.'

CONVENTIONAL (VS. 'UNCONVENTIONAL') RESERVOIR
The primary differences between conventional and unconventional reservoirs are based on oil or gas resource characteristics, the available exploration and production technologies, the economic environment, and the scale, frequency, and duration of production from the resource. A conventional reservoir has buoyant forces keeping hydrocarbons, such as oil and natural gas, in place below a local geological formation or structure that traps the resource and serves as a seal, or caprock. When oil or natural gas is produced from conventional reservoirs, it flows readily to the surface through a well. Unconventional resource is an umbrella term for oil and gas that is produced by means that do not meet the criteria for conventional production. Unconventional reservoirs may be larger in scale and lack the influence of buoyant forces that would allow the resources to be produced as easily as conventional resources. Coalbed methane, gas hydrates, shale gas, fractured reservoirs, and tight gas sands are considered unconventional resources.

ANTHROPOGENIC
The term 'anthropogenic' means created by humans or caused by human activity.

MONITORING FOR CO_2 STORAGE AND ENHANCED COALBED METHANE RECOVERY IN THE COAL SEAMS OF THE CENTRAL APPALACHIAN BASIN

MVA Introduction and Background

In 2012, the Virginia Center for Coal and Energy Research (VCCER) at Virginia Tech was awarded a grant from the US Department of Energy to store approximately 20,000 tons of Carbon Dioxide (CO_2) in thin, unmineable coal seams in Buchanan County, Virginia. This project was awarded on the basis of a previously successful project carried out by the VCCER and industrial partners, in which approximately 1,000 tons of CO_2 was injected into similar coal seams in Russell County, Virginia, and a DOE 'characterization' project that led to the study of various geological formations in southwestern Virginia, which demonstrated sufficient storage capacity to pursue future, larger scale projects such as the current one.

The purpose of this project is to learn more about the behavior of CO_2 as it bonds with the surface of the coal, and to determine long-term storage possibilities, as the CO_2 displaces the methane(CH_4) already in the coal, so that the methane can be recovered (enhanced coalbed methane recovery). The successful completion of such a project requires the atmosphere, surface, and subsurface of the region of the injection to be monitored to verify that the CO_2 remains underground, migrates where models predict that it will, and effectively displaces the methane. Such a monitoring project has come to be referred to as 'Monitoring, Verification and Accounting,' or MVA. The previous storage project in Russell County is considered successful because a well-designed MVA program verified those three things. An MVA program has been designed for the Buchanan County project as well.

The DOE, through its National Energy Technology Laboratory, sets forth the following goals for MVA in its guide document, Best Practices for: Monitoring, Verification and Accounting of CO_2 Stored in Deep Geological Formations (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_document.pdf).

- Improve understanding of storage processes and confirm their effectiveness
- Evaluate the interactions of CO_2 with formation solids and fluids
- Assess environmental, safety, and health (ES&H) impacts in the event of any migration of CO_2 to the atmosphere
- Evaluate and monitor any required remediation efforts should migration occur
- Provide a technical basis to assist in legal issues resulting from any impact of sequestration technology.

MVA Application to Buchanan County Project

Every carbon storage project has a unique geological profile, with unique features and topography. Different features and topographies favor different MVA tests and strategies, requiring an MVA program designed specifically for that setting. This section describes the features found at the Buchanan County injection site and the subsequent design of the MVA program for the project.

This project has four phases, and it is important to understand an MVA program in terms of each of the four. The following is a description of what goes on in MVA during each of the phases.

1. **Pre-operation:** During the Pre-operation Phase, the MVA plan is designed, drawing on experience with the previous, similar but smaller, project in Russell County and the experience of other successful projects in the country. The topography of the region surrounding the injection is mapped, and the underground structures are determined through previous mapping and core sampling. Air, soil, and water samples are taken, setting "baselines" for CO_2 in the air, water, and soil, so it can be determined if those amounts change during the project.

MVA Application to Buchanan County Project (cont.)

2. **Operation:** The Operation Phase begins with the commencement of the injection of CO_2 into, in this case, a pre-existing well that has been used for recovery of methane from the pore spaces of the coal seams. It is most important to continue measurement in the air, soil, and underground reservoirs and coal seams to determine that no upward migration is occurring. In addition, monitoring in this phase helps determine where and how fast the injected CO_2 is migrating, which is called determining the "extent of the plume," since the CO_2 radiates out underground in the coal seam. Other surrounding wells, called offset wells, are sampled to discover the extent of the plume. This process continues until all the CO_2, in this case approximately 20,000 tons, has been injected.

3. **Closure:** During the Closure Phase, equipment begins to be removed from the site, including the removal of the large tanks that stored the CO_2 near the injection site. The wells used during the project are returned to their prior production status. The site is restored to its previous condition, but monitoring to determine if CO_2 migration occurs in the atmosphere, soil and water continues as before.

4. **Post-closure:** Since the wells involved in this project will have been returned to their pre-injection use, occasional monitoring will continue after the project closes.

There are a variety of methods, or techniques, for monitoring in an MVA program, and several areas that must be sampled on any CCUS project. The MVA Poster includes a list of available monitoring techniques, only some of which are applicable to this project. The MVA Poster divides techniques into three different types, based on the area to be sampled. First, there is sampling of the atmosphere. Second, near-surface methods apply to surface water and soils. In the final column, subsurface methods are methods that sample under the ground, in the reservoirs and coal seams that make up the geology of the Central Appalachian Basin.

In the Russell County test, all three areas were sampled. Atmospheric methods utilized included infrared gas analyzers (IRGAs) to measure CO_2 concentration. Near-surface methods included soil CO_2 flux, surface water sampling, and shallow tracer detection.

For the subsurface in Russell County, seven offset production wells were sampled for gas composition, including CO_2 concentration and tracer breakthrough. A harmless tracer gas that isn't ordinarily found in CO_2 is injected with the CO_2 so that it can be determined whether the CO_2 found at the offset wells is actually the CO_2 that was injected, and not some CO_2 that might have been present before the injection.

Two new monitoring wells were tested, including:

- Pressure/temperature logging
- Spinner surveys
- Gas composition
- Formation water sampling
- Tracer analysis

MVA Application to Buchanan County Project (cont.)

Results of sampling during the Russell County project included:

- No leakage was detected by any sampling, including IRGAs, soil CO_2 and tracer detectors, and water sampling
- There was a rapid spread of CO_2. The monitoring well, M1, reached over 95% CO_2 concentration within hours of injection, and M2 within 8 days, demonstrating the connectivity of the wells.
- The tracer was detected far from the point of the injection. Tracer samples were positive at all seven close offsets wells, and at three far offset wells.
- There was evidence of CO_2 adsorption; that is, that the CO_2 had bonded with the coal and displaced the methane. There was increased methane (CH_4) and nitrogen (N_2) in flowback streams of the injection well.
- Increased CH_4 production at two offset wells, with no CO_2 breakthrough, indicated that there was enhanced coalbed methane production.

In the Buchanan County project, the objective is to inject up to 20,000 tons of CO_2 over a one-year period using three converted coalbed methane wells in order to assess the properties and behavior of the CO_2 during injection and to assess both CO_2 storage potential and the potential for enhanced coalbed methane recovery. The reservoir that the CO_2 will be injected into is comprised of 15-20 individual coal seams, with a combined thickness of 15-20 feet.

Site Characteristics:

- Structurally quiet, on flank of anticline
- Depleted reservoir
- Low-traffic
- Single, agreeable mineral owner

Several tests that were conducted in Russell County will be repeated in the Buchanan County test, including:

- Atmospheric monitoring with IRGAs to measure CO_2 concentration
- Surface methods including soil CO_2 flux, surface water sampling, and shallow tracer detection
- Offset well testing for gas composition (CO_2 concentration, tracers, ECBM)

There are several new monitoring tests that will be performed at the Buchanan County site that were not part of the Russell County project. Three monitoring wells will be installed at the Buchanan County test site in order to measure formation data, including reservoir pressure and gas content (CO_2, methane, tracer). One of these wells will also be used to collect core samples from coal seams and other parts of the formation. The samples will be assessed in a lab in order to determine important rock properties that will improve understanding of the reservoir and update the reservoir model. Unique tracer gases will be injected into each of the three injection wells with the CO_2 stream in order to determine how the spread of gas may differ at each location. Furthermore, unique tracers may also be used in different sets of coal seams to determine whether the spread of gas varies depending upon the properties of a specific seam. The presence of CO_2 will cause the deep coals to swell, an effect which is harmless but has been successfully detected in other settings using highly sensitive surface-based instruments. This technique, called surface deformation measurement, is capable of measuring less than a millimeter of movement in the earth and will be used at the Buchanan County site as an additional method to confirm the storage of CO_2 in the coal reservoir. Finally, a cutting-edge technology called tomographic fracture imaging (TFI) will be used to record the very weak acoustic energy (sound) caused by fluid moving through the coal reservoir. This energy can be mapped to define an approximate boundary for the spread of CO_2.

INJECTING CARBON DIOXIDE INTO UNCONVENTIONAL RESERVOIRS BUCHANAN COUNTY, VIRGINIA, SITE

www.energy.vt.edu

PROJECT OVERVIEW

Description:	The Virginia Center for Coal and Energy Research (VCCER) was awarded a cooperative agreement from the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), to accomplish the programmatic research goal of understanding the relationship between carbon dioxide (CO_2) and methane (CH_4) in underground geological formations such as coal and organic shale. Nearly 14,000 tons of CO_2 were injected into wells in the Oakwood coalbed methane field in Buchanan County, Virginia, and are being closely monitored in the post-injection phase of the project.
Project Goals:	The goal of the project is to gain experience and understanding by performing characterization, injection, and monitoring to test storage at various depths of coal seams, and to track the movement of CO_2 throughout the injection and post-injection phases. The primary objective is to test the ability of unmineable coal seams to store CO_2 and the potential for enhanced recovery of the methane in the coal at offset producing gas wells. This was done by subjecting the identified coal seams to injection for one year.
Funding:	The total project cost is approximately $15.5 million, of which $12.2 million is from DOE funds and the remainder from Virginia Tech and the private sector.
CO_2 Source:	Commercial grade CO_2 was purchased from a vendor and was delivered to the site by tractor trailer, small tanker trucks, and an on-site pipeline.
Project Duration:	October 1, 2011 - December 31, 2017
Site Selection and Previous Experience:	Geological characterization performed during earlier projects funded by the DOE/NETL led to the identification of promising areas for storage of CO_2 using existing wells in Buchanan County, Virginia. A previous project performed by the VCCER during January and February of 2009 successfully injected 1,000 tons of CO_2 in Russell County, Virginia.
Regulations:	Permitting for all activities under this project was managed by the VCCER in full compliance with the National Environmental Policy Act, the U.S. Environmental Protection Agency (EPA), and the Commonwealth of Virginia.
Research Partners:	Virginia Center for Coal and Energy Research, Virginia Tech; Virginia Department of Mines, Minerals and Energy; Marshall Miller & Associates; Southern States Energy Board; CONSOL Energy; Geological Survey of Alabama; Sandia Technologies; and Det Norske Veritas

INJECTING CARBON DIOXIDE INTO UNCONVENTIONAL RESERVOIRS
BUCHANAN COUNTY, VIRGINIA, SITE
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COMMUNITY BENEFITS

Economic Benefits:	Opportunities for local service providers; greater understanding of local resources that may support future, larger projects and job creation.
Project Recognition:	Promotion of regional energy research initiatives; attraction of visitors including high-profile elected officials, leaders of industry and academia, and other members of the public.
Public Outreach/ Community Voice:	Project representatives from the VCCER and industry partners met with the Buchanan County Board of Supervisors at their regularly scheduled meeting on February 4, 2013, to inform them of the project and answer questions and comments. A public open house, to which relevant citizens and stakeholders were invited, was held September 3, 2014, in Grundy, Virginia, before injection activities commenced. An open house to discuss project results is scheduled for October 13, 2017. Project information is also available on the web at www.energy.vt.edu/carbon-management.html.
Valuing Community Resources:	Data collection on local geology, air, water, soils, and regulations that will be valuable to any future activity bringing larger carbon capture and storage projects to Buchanan County; new maps and graphics to support community initiatives; project designed and scheduled to minimize disturbance to the environment and local activities.

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PROJECT TIMELINE

PHASE I - COMPLETED 10/1/2011 - 3/31/2013

Data Collection & Characterization
- Core sample analysis
- Geologic modeling
- Reservoir modeling
- Baselines for monitoring

Injection Design

Monitoring Design
- Well locations
- Geophysical surveys

Permitting & Agreements
- EPA class II UIC
- Virginia state drilling permits
- Access Agreements

PHASE II - IN PROGRESS 4/1/2013 - 9/30/2015

Site Preparation
- Conversion of production wells
- Drill characterization and monitor wells
- Install additional monitor stations

CO_2 Injection
- 10/01/2014 - 9/31/2015

Monitoring
- Atmosphere
- Surface
- Reservoir

PHASE III - FUTURE 10/1/2015 - 9/30/2016

Site Closure
- Conversion of injection and monitor wells
- Site restoration

Post-injection Characterization
- Data analysis and interpretation
- Post-injection monitoring
- Reservoir modeling

Ongoing Activities: Management and Planning, Risk Analysis and Assessment, Characterization, Modeling, Monitoring, Education and Outreach

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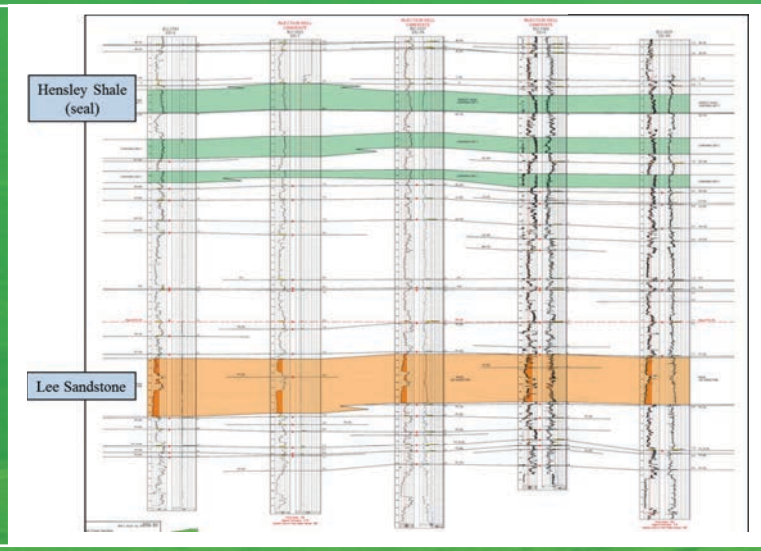
GEOLOGICAL CHARACTERISTICS OF THE POCAHONTAS AND LEE COAL SEAMS

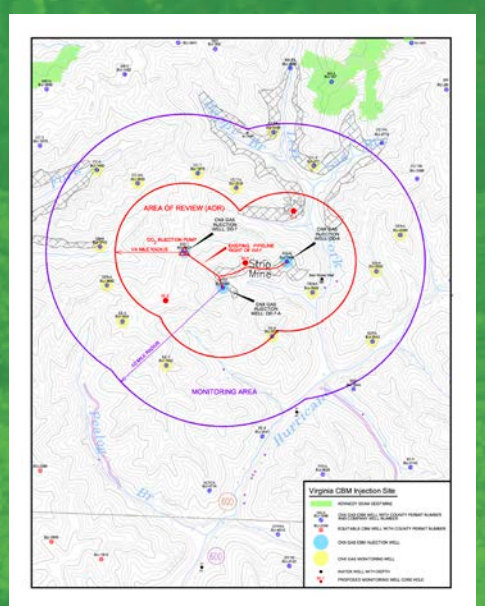
Geological characterization was performed to determine the most suitable location to test CO_2 storage and enhanced coalbed methane recovery. The Pocahontas and Lee Formations were determined to have suitable, stacked coal seams that are favorable to project goals.



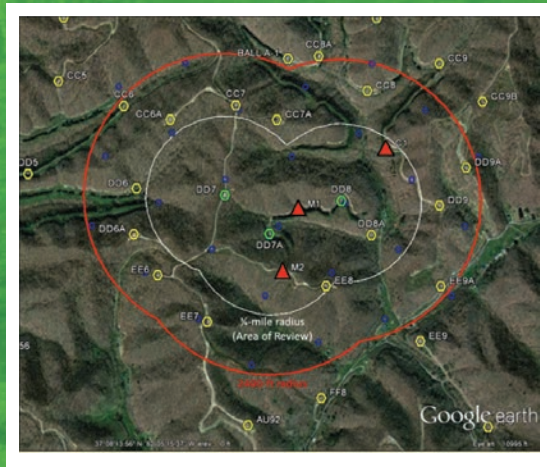
The site for the injection of 20,000 tons of CO_2 over a three-year period is in southwest Buchanan County, 7.5 miles northwest of the site of the Russell County injection. The coal reservoir at the Buchanan County site includes 15 to 20 seams which are currently producing gas. Averaging only one foot in thickness, their combined thickness ranges from 15 to 20 feet. The seam depths range from 900 to 2,100 feet.

Local stratigraphy indicates several confining units, or seals, that will prevent any CO_2 from migrating upward. First, the areas in green depict three low-permeabilty shales, the upper of which, the Hensley shale, overlie the coal seams. The Lee sandstone, in beige, is a thick, low-permeability sandstone underneath the Hensley shale.





This map shows the three injection wells, DD-7, DD-7A, and DD-8, on the Hurricane Creek anticline, which lies in the Oakwood Field, and their location relative to the former Pocahontas No. 3 mine (also called the VP8 mine).



This map shows the topography of the study area, including the three injection wells (DD-7, DD-7A, and DD-8), three monitoring wells (M1, M2, and C1), and several offset wells (in yellow). Modeling indicates that the ¼ mile radius from the wells, marked in white, will be the extent of the 'plume,' or the maximum area to which the CO_2 will migrate. The red boundary marks the area that will be monitored.

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CO_2 TRANSPORT TO THE BUCHANAN COUNTY FIELD SITE

Transportation of CO_2 is a safe and well-understood process. It is transported safely every day throughout the US. This poster explains how the CO_2 will get from the manufacturing plant to the injection site.



20-ton highway truck or 70-ton railcar transports liquid CO_2 from an industrial source in the eastern U.S. to a location near Vansant, VA.

Liquid CO_2 is transferred from highway truck to storage vessels or stored in railcars.
Stored at 250 PSIG, -10° F.

Off-highway truck transfers liquid CO_2 1.9 miles on gravel road to storage vessels.

Stored at 250 PSIG, -10° F at injection well DD7

In-line propane heater heats CO_2 to gas phase at approximately 70° F for initial injection then maintains 40° F temperature or greater for the duration.

Tri-plex pump pressurizes CO_2 to 400–1100 PSIG

CO_2 is pumped directly into DD7 and through 2,300 feet of pipeline into wells DD7A and DD8 at 400–1,100 PSIG



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CO_2 MONITORING, VERIFICATION AND ACCOUNTING (MVA)

Buchanan County CO_2 Injection into Unmineable Coal Seams with Enhanced Coalbed Methane Recovery

WHY MONITOR FOR CO_2?

To ensure and verify that geologic storage of CO_2 is safe and effective

Benefits of monitoring:

- Protection of the surrounding atmosphere, soil, potable groundwater and other surface and subsurface ecosystems
- The safety of project workers and the public

Goals of MVA:

- Improve understanding of storage processes and confirm their effectiveness
- Evaluate interactions of CO_2 with solids and fluids in the formation
- Assess environmental, safety, and health impacts should the CO_2 migrate
- Evaluate and monitor measures should a containment issue occur
- Provide a basis for assisting in legal issues should they occur

HOW DO YOU MONITOR FOR CO_2?

Atmospheric monitoring, including:

- CO_2 detectors
- Laser systems
- Tracers (isotopes)

Near-surface monitoring, including:

- Ecosystem stress monitoring
- Tracers
- Groundwater monitoring
- Thermal hyperspectral imaging
- Tiltmeters

Subsurface monitoring, including:

- Multi-component 3-D surface seismic time-lapse survey
- Vertical seismic profile
- Electromagnetic induction tomography (EMIT)
- Gamma ray logging

MVA OVER THE LIFE OF THE PROJECT

Pre-injection:

- Design MVA plan
- Begin monitoring to establish baselines for CO_2 in soil, water, atmosphere

Injection:

- Monitor closely during the duration of the injection (1 year), to ensure well-head integrity, health and safety

Post-injection:

- Monitor during project closure
- Ongoing monitoring after project closure, to ensure long-term project effectiveness

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25 Appendix M – Commercialization Plan

25.1 Executive Summary

The Virginia Center for Coal and Energy Research (VCCER) has injected small quantities of carbon dioxide (CO_2) into two unconventional storage reservoirs in Appalachia. As an element of the project closeout, the project team is preparing this Commercialization Plan. The Commercialization Plan addresses three objectives: 1) to summarize the work completed with emphasis on unconventional storage reservoirs vs conventional enhanced oil recovery (EOR) storage; 2) to recommend research initiatives that will advance the field work to Technology Readiness Level six (TRL6) for systems verification in a relevant environment; and 3) to provide a commercialization roadmap for CO_2 utilization and storage in unconventional reservoirs in Appalachia.

Injections of CO_2 were conducted in an organic shale bed in Tennessee and a coalbed methane (CBM) formation in Virginia. Based upon current and previous small quantity CO_2 injections, mechanisms for CO_2 trapping and enhanced hydrocarbon recovery in organic shales and coal bed methane formations are unlike the trapping/recovery mechanisms noted in CO_2 enhanced oil recovery. Oil recovery relies on CO_2 to sweep hydrocarbons from injection wells to production wells. The CO_2 huff-and-puff treatment that is conducted on organic shale and coal bed formations acts to "stimulate" hydrocarbon production, while retaining the bulk of the injected CO_2 for long-term storage.

Results from two previous Southeast Regional Carbon Sequestration Partnership (SECARB) Phase II projects in Central Appalachia (2009) and the Black Warrior Basin (2010) report that CO_2 stimulation of coal bed methane wells can result in post-injection increases in gas production of 50% above pre-injection levels. The increase in methane production seen in the results from the 2009 and 2010 projects were also seen in the VCCER Tennessee shale well project and are expected to be present in VCCER's Virginia CBM project.

Detailed post-injection production data (2009 – 2017) has been maintained on the SECARB Phase II CBM well in Russell County, Virginia. VCCER has modeled the pre-injection decline curve for the well and modeled the expected decline curve resulting from enhance methane production after CO_2 stimulation. The projected increase in methane production is approximately 40% per year. In addition, the assumed shut in date of the well could be extended by decades, due to higher annual gas production levels.

The 2010 Black Warrior Basin test was conducted in a mature CBM production well in the Blue Creek Degasification field in Alabama and included the injection of 3,250 barrels of water and 252 tons of CO_2 in a battery of slugs over two months. The results of injections showed that the "post-test production performance of the test well has improved substantially relative to that in the four years prior to CO_2 injection. Gas production for the first year after the injection tests was limited as the bulk of the injected

water flowed back to the wellbore. As the water rate decreased, the gas rate improved by >50% relative to the pre-injection rate. Long-term improvement of well performance is apparently related to a number of factors, including the removal of wellborn scale, dissolution of cleat-filling calcite and displacement of CH_4 as CO_2 is adsorbed into the reservoir matrix." (Pashin 2015)

In the VCCER Morgan County, Tennessee project a single-well (510 metric ton) CO_2 injection into an organic shale bed in 2014 showed an increase in methane production and an increase in gas liquids production during initial flow back. The ability to stimulate additional gas and gas liquids production from wet shales could provide additional revenues to justify CO_2 purchases. However, additional research, with larger CO_2 injections, must be conducted before any reliable conclusions can be drawn on enhanced gas liquids production.

A three-well (13,000 metric ton) CO_2 stimulation injection of coal bed methane seams in Buchanan County, Virginia was completed in 2017. Flow back began in December 2017. The VCCER project team will receive production data from the field operator in early 2018 and begin to chart post-stimulation gas production and decline curves.

Preliminary financial data for Russell County show that the potential return on investment from CO_2 purchased for well stimulation is attractive. Based upon current natural gas prices and projected cost of commercial well stimulation, CO_2 for well stimulation could command a premium over the commodity-level prices that exist for CO_2-EOR. However, additional pre-commercialization research is needed to fully understand the science involved in shale and CBM well stimulation.

The Technology Readiness Level (TRL) for CO_2 capture and storage technology commercialization generally starts with TRL7, an integrated pilot is demonstrated; and includes TRL8, systems tested and demonstrated at final scale; and TRL9, system proven and ready for final scale. However, in order for a commercialization roadmap to be successful, the process must begin prior to reaching the three final TRLs. Stakeholder engagement, knowledge sharing and capacity building should be conducted in parallel to research and development activities.

A major aspect of an integrated carbon capture, utilization and storage (CCUS) commercialization plan is to identify the capture and utilization opportunities, determine the level of commercial readiness (including gaps) and engage stakeholders representing the entire capture-to-storage value chain. An initial step in this process was to map shale gas and CBM resources within the region and down-select to sub-regional opportunities for shale and CBM well stimulation.

CO2 stimulation of shale wells in Appalachia could be an important technology advancement, but the data that has been collected is not sufficient to support commercial investments. It is recommended that additional tests be conducted in the Utica Shale and Marcellus Shale of Northern Appalachia and the Marcellus Shale of Central Appalachia. Clusters of shale wells, in close proximity to CO2 sources, have been identified and mapped in this study.

The regional evaluation of CBM well stimulation is based upon VCCER's Buchanan County, Virginia field test and two previous SECARB CBM field tests in Virginia and in Alabama's Black Warrior Basin. It is recommended that additional (and larger) sub-regional CO2 injections be conducted in Southern, Central and Northern Appalachia to supplement current findings on CBM well stimulation. Clusters of CBM wells have been mapped in Southern, Central, and Northern Appalachia, with the proximity to CO2 sources noted.

Potential sources of CO2 from fossil fueled power facilities and industrial facilities were matched to the sub-regional shale and CBM well locations. In the past, project team members participated in assessments of carbon capture readiness (2008) and an amine-based carbon capture conceptual design (2009) for the Virginia City Hybrid Energy Center (VCHEC) in St. Paul, Virginia. Since that time, the pilot-scale SECARB Anthropogenic Field Test and the commercial-scale Petra Nova Post-Combustion CO_2 Capture and Sequestration Project have provided substantial learning with regard to amine-based carbon capture. Available information on amine-based carbon capture has formed the basis for a regional evaluation of post-combustion CO_2 capture at a fossil fueled power facility.

Likewise, members of the project team participated in a technical and economic evaluation of carbon capture technologies for seven categories of industrial facilities. Sub-regional reviews have been conducted to determine which of the seven industrial facility categories are the most attractive for commercial CO2 capture in Southern, Central and Northern Appalachia. Further work will be needed to engage stakeholders from selected categories, and specific facility locations, to advance commercialization discussions.

Matching CO2 sources with potential shale and CBM users will require the development of transportation infrastructure. Unlike CO2 EOR, using CO2 for well stimulation does not require an initial up-front investment in dedicated pipeline networks. Captured CO2 can be stored on site as a centralized source of CO2 for nearby wells. A centralized storage facility could be serviced by 20-ton semi-trucks. While transportation via semi-truck will be a limiting factor in initial commercialization efforts, several attractive CO2 sources are located within 25 miles of CBM fields that are suitable for well stimulation with CO2. In the case of shale wells, CO2 sources are located within 10 miles of key well clusters. Also, the amount of CO2 captured and stored can be scaled up quickly in response to market demand.

A review of existing data has been conducted in order to identify gaps. The gaps of interest are those at lower technology readiness levels that reveal the science behind "… what makes CO_2 stimulation work in shale and CBM wells?" These gaps in science must be addressed in order to support investment decisions for commercialization.

The final element of the commercialization plan is a Roadmap Implementation Strategy. The implementation strategy is focused on stakeholder engagement, knowledge sharing and capacity building. Stakeholders will be interested in sources and uses of CO2, transportation routing, market factors, legislative incentives, permitting, socio-economics and environmental impacts.

25.2 Introduction

The Virginia Center for Coal and Energy Research (VCCER) has injected small quantities of carbon dioxide into two unconventional storage reservoirs in the Central Appalachian basin, a coalbed methane (CBM) formation in Virginia and an organic shale (Shale) bed in Tennessee. The primary focus of the study was to investigate CO_2 storage in conjunction with enhanced coalbed methane recovery (ECBM) and enhanced shale gas recovery (ESGR). As an element of the project closeout, the project team is preparing this Commercialization Plan. The Commercialization Plan addresses three objectives: 1) to summarize the work completed with emphasis on unconventional storage reservoirs vs conventional EOR storage; 2) to recommend research initiatives that will advance the field work to the technology readiness level of systems verification in a relevant environment; and 3) to provide a commercialization roadmap for CO_2 utilization and storage in unconventional reservoirs in Appalachia.

Currently the U.S. Department of Energy (DOE) and its National Energy Technology Laboratory (NETL) are supporting carbon capture research projects at various Technology Readiness Levels (TRL). TRLs have been developed for advanced power-generation systems and for carbon storage systems.

The DOE Fossil Energy (DOE-FE) research program is fundamentally an applied research portfolio, and because TRL1 reflects basic research, the portfolio is generally focused on advancing technology from TRL2 through TRL6 for the CCUS and Power Systems R&D program area (DOE 2012a).

Excerpts from DOE's "CO2 Storage Technology TRL Definitions and Descriptions" provide insight to TRL1 through TRL9 (DOE 2012a).

1) Basic principles observed and reported. Lowest level of technology readiness.
2) Technology concept and/or application formulated. Invention begins. Once basic principles are observed, practical applications can be invented.
3) Analytical and experimental critical function and/or characteristic proof of concept. Active R&D is initiated.
4) Component and/or system validation in a laboratory environment. The basic technological components are integrated to establish that the pieces will work together.
5) Laboratory-scale similar-system validation in a relevant environment. Laboratory validation of system/subsystem components.
6) Engineering/pilot-scale, prototypical system demonstrated in a relevant environment. Prototype system verified.
7) System prototype demonstrated in a plant environment. Integrated pilot system demonstrated.
8) Actual system completed and qualified through test and demonstration in a plant environment. System tested and demonstrated at final scale

9) Actual system operated over the full range of expected conditions. System proven and ready for final-scale geologic storage.

The DOE-FE portfolio is focused on basic research (TRL1) and applied research (TRL2 – TRL4), which transition to process and engineering development TRL5 – TRL6, and large scale testing and evaluation TRL7 – TRL9 (DOE 2012a). DOE's "2014 Technology Readiness Assessment" (DOE 2015) provided some additional detail for the DOE-FE CO_2 Storage Technology Definitions and Descriptions – TRL4 (Table 2, DOE 2015):

> TRL4: Component and/or system validation in a laboratory environment
> The basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.

The laboratory environment, in many cases, requires a field laboratory setting where technological components can be integrated to establish that the pieces will work together.

25.3 Objective 1: Work summary with emphasis on commercialization challenges for unconventional storage reservoirs vs conventional EOR storage.

25.3.1 Overview of CBM Projects

From 2011 until 2017, the Virginia Center for Coal and Energy Research (VCCER) managed and administered two US DOE/NETL funded projects in Central Appalachia to test the injectivity of CO2 into unmineable coal seams, verify the storage capacity and the potential for Enhanced Coal Bed Methane (ECBM) recovery. Prior to this current study, VCCER participated in one of two ECBM field tests for the SECARB Phase II project.

In January 2009, a SECARB Phase II Validation Test injected 1,007 short tons of CO2 into a legacy CBM well in Russell County, Virginia. The injection reservoir was comprised of 19 individual coal seams with a net thickness of 26 ft. The well was shut-in for 4 months and then returned to production and has been producing larger volumes of methane, sufficient to increase the estimated ultimate recovery of the well by over 40 percent that will pay for the cost of the CO2. 8-years later the well continues to produce well with the majority of CO2 stored in the coal seams.

In the current study, a larger test commenced in July 2015 in the same area as the SECARB test, with 13,500 tons of CO2 injected into three vertical CBM wells in Buchanan County, Virginia in two phases.

The injection was completed over a two-year period that included a 9-month soaking phase. Initial results are highlighted by favorable injection rates and pressures where injectivity was not compromised by coal-swelling. In addition, breakthrough occurred at only one off-set production well and only in one zone within the wellbore, meaning the CO2 was contained nearby the injection wells. The three wells returned to production in December 2017 and the very early results are promising.

25.3.2 Overview of Shale Gas Projects

VCCER administered a US DOE/NETL funded project to test the injectivity of CO2 into an unconventional shale reservoir in order to gauge the potential for CO2-enhanced hydrocarbon recovery with associated CO2 storage. Approximately 510 short tons of CO2 were successfully injected into a legacy horizontal production well completed in the Chattanooga Shale formation in Morgan County, Tennessee during March 2014. After the injection phase, the well was shut-in for 4.5 months to allow for the CO2 to equilibrate within the target formation. After the soaking phase was completed, the well was flowed back and returned to normal production. During this flowback phase, gas composition and flow rates were frequently monitored. Results indicated that there was a significant increase in gas flow rate during the first five months of the flowback phase, with a high percentage of CO2 retained in the target formation. There was also a significant increase in gas quality, such that the percent composition of NGLs (natural gas liquids), including ethane, propane, and butane, increased. The results from this field laboratory test confirm, at a low fidelity, the injectivity and storage potential of CO2 in organic shale formations.

25.3.3 Overview of U.S. Commercial scale projects

A key focus of CCUS commercialization is the matching of CO_2 source and utilization/storage sites. In the United States, all commercial sized CO_2 capture facilities use a pipeline to transport the CO_2 to injection sites. In all cases but one, commercial sized CO_2 capture systems in the United States use the CO_2 for Enhanced Oil Recovery (EOR). The one exception is the Illinois Industrial CCS project in Decatur, IL. A summary of several commercial scale CO_2 capture and transportation systems follows:

- Petra Nova Carbon Capture, operational since January 2017, is the world's largest post-combustion CO_2 capture system presently in operation. Production unit 8 of the W. A. Parish power plant near Houston, Texas, was retrofitted with a 1.4 million ton per annum (Mtpa) post-combustion CO_2 capture facility. The captured CO_2 is transported via pipeline to an oil field near Houston for enhanced oil recovery. (GCCSI 2016)
- The Terrell gas processing facility is one of the 'original' Val Verde natural gas processing plants in west Texas, that began capturing CO_2 as part of gas processing in the early 1970s. Captured CO_2 is transported via the Val Verde pipeline to McCamey, Texas, where it connects with the Canyon Reef Carriers (CRC) pipeline and the Pecos pipeline. The CO_2 is then distributed to mature oil fields for enhanced oil recovery. The Terrell facility has a CO_2 capture capacity of around 0.4-0.5 million tons per annum (Mtpa). (GCCSI 2016)

- The Lost Cabin gas plant, located in Wyoming, supplies CO_2 to compression facilities adjacent to the plant to enable CO_2 transport by pipeline. Carbon dioxide capture capacity is around 0.9 Mtpa, and since 2013, CO_2 has been delivered via a new build pipeline to the Bell Creek oil field in Montana for enhanced oil recovery. (GCCSI 2016)
- The Koch Nitrogen Company facility in Enid, Oklahoma produces nitrogen fertilizers, which result in a high purity, high concentration CO_2 off-gas. The CO_2 off-gas is processed at compression, cooling and dehydration facilities owned by Chaparral Energy and Merit Energy. The processed CO_2 of up to around 0.7 Mtpa is transported via pipeline to depleted oil fields in southern Oklahoma for enhanced oil recovery. (GCCSI 2016)
- Illinois Industrial CCS integrates new build compression and dehydration facilities to an existing corn-to-ethanol plant in Decatur, Illinois. The new facilities, when combined with existing facilities constructed under the (now completed) Illinois Basin Decatur Project, can achieve a total CO_2 injection capacity of approximately 1 Mtpa. Injection operations commenced in April 2017. The captured CO_2 is transported via pipeline to a nearby injection well for dedicated geological storage. (GCCSI 2016)

25.3.4 Differences between EOR and ECBM/ESGR

While EOR has been successful for many years, the process and analysis for a commercially viable project in CBM and Shale formations will likely need some modification from the general model that has been employed with CO2 EOR. As noted above, the commercial scale EOR facilities deliver the CO2 via a pipeline to one or more locations for injection. The use of a pipeline allows for large amounts of CO2, at predictable rates, to be delivered to a centralized location for use in EOR. There are significant differences between CO2 EOR and CO2 ECMB/ESGR that must be accounted for when contemplating a commercial scale implementation of CO2 ECBM or ESGR.

Following the primary recovery period, in which natural reservoir drive mechanisms expel hydrocarbons from the reservoir rock to the surface, conventional oilfield operators typically employ secondary recovery methods to increase oil production to economically sustainable levels. The most commonly used secondary recovery method is water flooding, which uses injected water to maintain reservoir pressure and displace oil through the formation towards the production wells. This technique is characterized as an immiscible flood as water and oil remain separated throughout the process. Although water flooding is very effective in increasing oil production initially, the immiscible nature of oil and water decreases the overall mobility of both water and oil and, as this effect becomes more pronounced with time, causes a portion of the oil – the residual oil – to remain trapped in the reservoir. Additional considerations include compatibility of the injected water with the reservoir connate water and the reservoir rock.

Water flooding is typically implemented by utilizing dedicated injector wells, which displace or sweep oil towards production wells. This process is made possible through the permeable and interconnected nature of conventional oil-bearing formations. By contrast, unconventional shale and CBM formations exhibit very low permeability in which economic production of hydrocarbons is only made possible through hydraulic fracture treatments. Although hydraulic fracturing enhances the permeability of reservoir rock in a localized area around the treated wellbore, the precise extent of the effective stimulation is subject to uncertainty and is typically not large enough to justify the development of dedicated injection wells. Furthermore, organic-rich shale and CBM formations contain significant portions of gas that is adsorbed onto the surface of pores, whose production is inhibited by the presence of water. As such, injecting water is counterproductive to increasing production of adsorbed gas content. For these and other reasons, there are currently no commercially viable secondary recovery methods for unconventional oil, shale gas, or CBM reservoirs.

Tertiary EOR methods are typically employed in conventional oilfields after secondary recovery is no longer effective and refer to the use of injected fluids other than water, most commonly CO2. Unlike water, CO2 and oil are mutually soluble or miscible such that they may form a single-phase mixture, which alleviates the deficiencies associated with a water flood. This single-phase mixture also exhibits reduced viscosity and interfacial tension between the oil and reservoir rock, both of which are favorable to increasing oil production.

Similar to water flooding, conventional oilfield operators typically utilize dedicated injector wells to displace oil towards production wells. This configuration is favorable for large scale and continuous CO2 EOR operations that service many wells for years at a time. However, the difficulties associated with low permeability formations are not amenable to dedicated injection wells, as mentioned above. Alternatively, production wells may be temporarily converted into injection wells for the duration of a stimulation procedure and converted back into production mode. By utilizing the production wellbore for enhanced recovery options, the risk of an injection well not making contact with the stimulated reservoir volume is eliminated, along with additional capital cost of constructing dedicated injection well. This reduced capital cost is exchanged for a period of non-productivity while the injection is taking place. This operating mode, coupled with the lower revenue profile results in a lower expected volume of CO2 required per well for ESGR and ECBM operations. However, because secondary recovery is not possible for unconventional shale and CBM fields, miscible flooding with CO2 is one of the very few methods of enhancing the productivity and life of aging unconventional shale and CBM fields. (Hyne 2012)

CBM/Shale fields tend to be significantly different from those associated with CO2 EOR. CBM and Shale fields are generally located in remote mountainous regions connected by a system of tortuous roads of varying degrees of completion. In some instances, the distance between wells may be less than a mile but travel times between wells by vehicle can be substantial due to road conditions and inability to move directly to the well due to challenging mountain terrain. The remoteness and difficulty of the terrain, coupled with the scattered nature of existing wells, could make the use of traditional CO2 EOR

pipeline infrastructure difficult to replicate. Initial commercialization efforts in CBM and Shale fields will need to receive CO2 at a centralized location and then transport it to the individual wells by semi-truck.

While transportation via semi-truck will be a limiting factor in initial commercialization efforts, several attractive CO2 sources are located within 100 miles of CBM and Shale fields that should react favorably to well stimulation with CO2. Existing and current studies in Appalachia on CO2 well stimulation for CBM and Shale do not contemplate multiple injections of CO2. Therefore, limitations would be placed on length-of-use of dedicated CO2 pipeline infrastructure. For this reason, the construction of a CO2 delivery pipeline to each field or well site would be prohibitively expensive. Additional studies may determine that multiple well stimulations continue to increase methane production and result in an increased need for a longer-term CO2 supply at each well. For purposes of this commercialization report, each well would only be considered for a single stimulation.

The overall amount of CO2 injected in each well varies but in the current study approximately 4,500 tons of CO2 was injected in each CBM well. Additional field laboratory research is needed to provide insight on how CBM and Shale formations react to large scale CO2 stimulation, and how the injected CO2 is retained in the target formations. In the current study the limited volumes of CO2 injected in each well, and the rates of injection, are not sufficient to support the commercial viability of a CO2 pipeline system that spans the entire distance from source to injection field. The current research suggests that, in the initial stages of commercialization, intermediate locations will be needed for transferring CO2 from pipelines to semi-truck carriers.

EOR has been occurring for more than 100 years and the use of CO2 in EOR has been studied for decades. Field operators have a great deal of research material and experience in determining how the CO2 will move and be retained in a formation. Operators can tailor a CO2 injection plan utilizing injection in multiple wells and/or zones to maintain injection rates equal to the rate of CO2 flow from capture facilities. The technological experience and research material available for CO2 EOR does not currently exist for CBM or shale formations.

It is unknown how CO2 will react during a larger scale CBM/Shale well stimulation where multiple wells will be injected simultaneously. To date, the current study is the largest CBM test in Appalachia and only involved 3 wells. A field test of 10-15 wells would be necessary "…to establish that all the pieces will work together." [(DOE 2015) TRL4] This will be a necessary step towards commercialization. It will provide a greater understanding in the way the individual wells and surrounding area react when CO2 is used to stimulate multiple wells simultaneously.

The well stimulation process for CBM and Shale wells does not require significant modifications. In current CO2 EOR fields, CO2 is injected into the formation via dedicated injection wells with resulting oil, water and CO2 collected from producing wells located around the injection wells. In many cases, new wells must be drilled or significant modifications must be made to existing wells to allow for CO2 EOR. The need for modifications for CBM and Shale well for CO2 stimulations, with associated CO2

storage, is not extensive. In most cases existing wells can be used for injection and production. The wells will need to be worked over with tubing, rods and pump removed, and then a packer set for the injection. After the injection, the wells will need to be reassembled and put back in production.

The overall depth of formations is very different with CBM formations than with CO2-EOR target formations. CBM formations generally occur at much shallower depths. The shallower depths result in much lower costs of infrastructure development, CO2 well stimulation, and CO2 retention. The injection depths at the project sites in Virginia were in stacked coal seams from 1,000 – 2,200 feet deep. The injection at the Tennessee shale project site was at 2,700 feet deep. Both field laboratory locations have multiple above-zone seals to ensure long term storage of retained CO2.

In CBM and Shale gas stimulation the existing well is used as both the injector and producing well. The process involves shutting down a producing well and making modifications to the well to allow for CO2 injection. The length of this injection period is dependent on the rate at which the formation can receive the CO2 and the availability of CO2. Several work stoppages occurred in the current project due to the unavailability of CO2 for the project. In a commercial operation, minimizing the length of the injection phase would be a primary goal in order to allow the well to return to production as quickly as possible. After injection, the well is left to "soak" for a period of time before beginning the process of returning the well to production. The optimal soaking time is unknown and additional field laboratory research should be done to determine what, if any, relationship exists between soaking time and production rates once the well is returned to production. After soaking, the well is allowed to flow for an initial period during which a portion of the injected CO2 returns to the surface. Of the original amount of CO2 injected in the current study, approximately 35% of the CO2 was released through production but the remaining 65% is stored in the formation. After the initial flow period, methane concentrations will begin to increase, and the well will be put back into production. This process of shutting the well and then soaking takes a producing well, albeit at lower production rates, out of service for a period of time. The lost production revenue during this time must be accounted for when looking at the financial viability of CO2 well stimulation in CBM and Shale fields.

The additional oil revenue generated by CO2 EOR is what has allowed CO2 EOR, with associated CO2 storage, to advance in certain regions of the United States. The additional oil revenue allows companies to invest in CO2 EOR projects because the production of the additional oil covers the costs associated with CO2 purchase and provides a return on the capital invested. The costs that must be covered include the cost to capture and transport the CO2 to the oil field as well as the additional field improvements that must occur to process the oil and separate CO2. In a CBM or Shale CO2 stimulation the additional costs of the CO2 stimulation must be covered by the additional methane recovered from wells once production restarts.

25.3.5 Methane production data from stimulated CBM and Shale wells

The difference between the old production levels and the new production levels after CO2 stimulation must represent a large enough difference to ultimately recover the cost of taking the well out of production, the cost of any well upgrades and the cost of the CO2 stimulation. Figures 25-1 show pre-stimulation production, post stimulation production and the percentage of CO2 retained in the formation for the Shale and CBM projects. Stimulation of both Shale and CBM wells resulted in increased production.

Figure 25-1 Morgan County, TN shale well production data

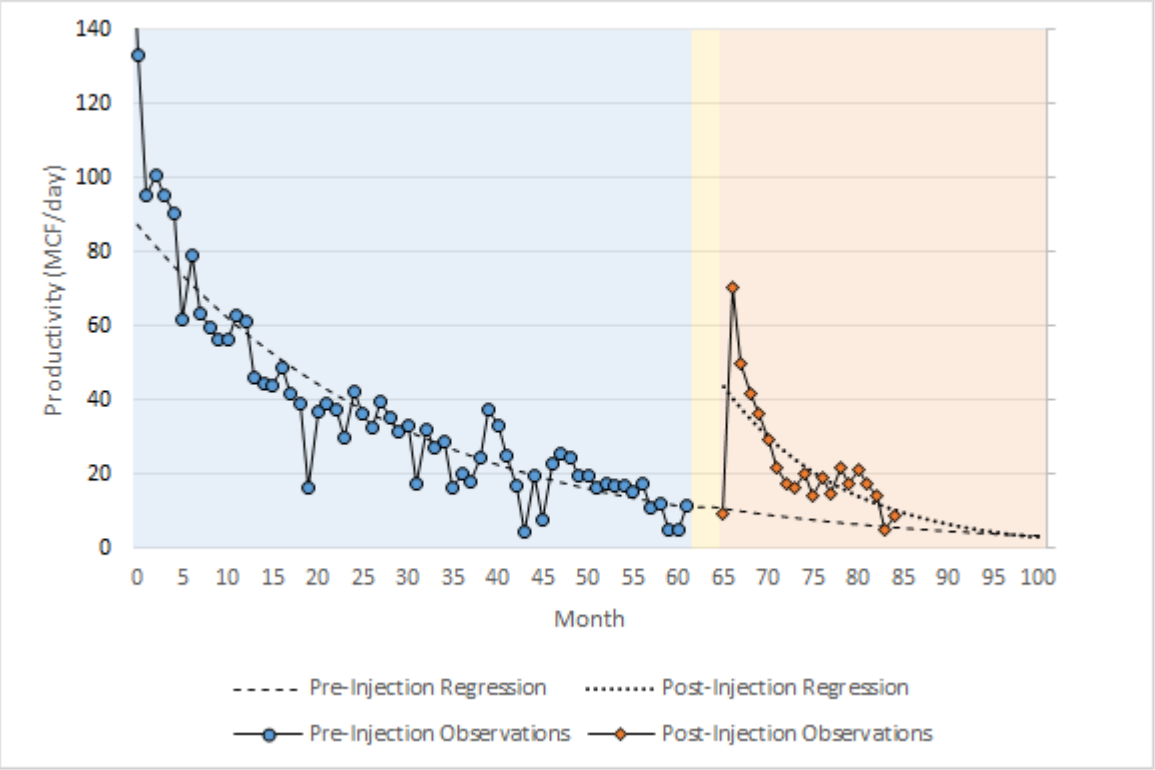


Figure 25-1 shows how the Morgan County, TN shale well reacted to CO_2 stimulation. The well was out of production for approximately 5 months to allow for injection and soaking. Production levels increased and then appear to return to pre-stimulation production levels in month 100 based on projected decline curves.

Figure 25-2 Morgan County, TN shale well CO_2 retention

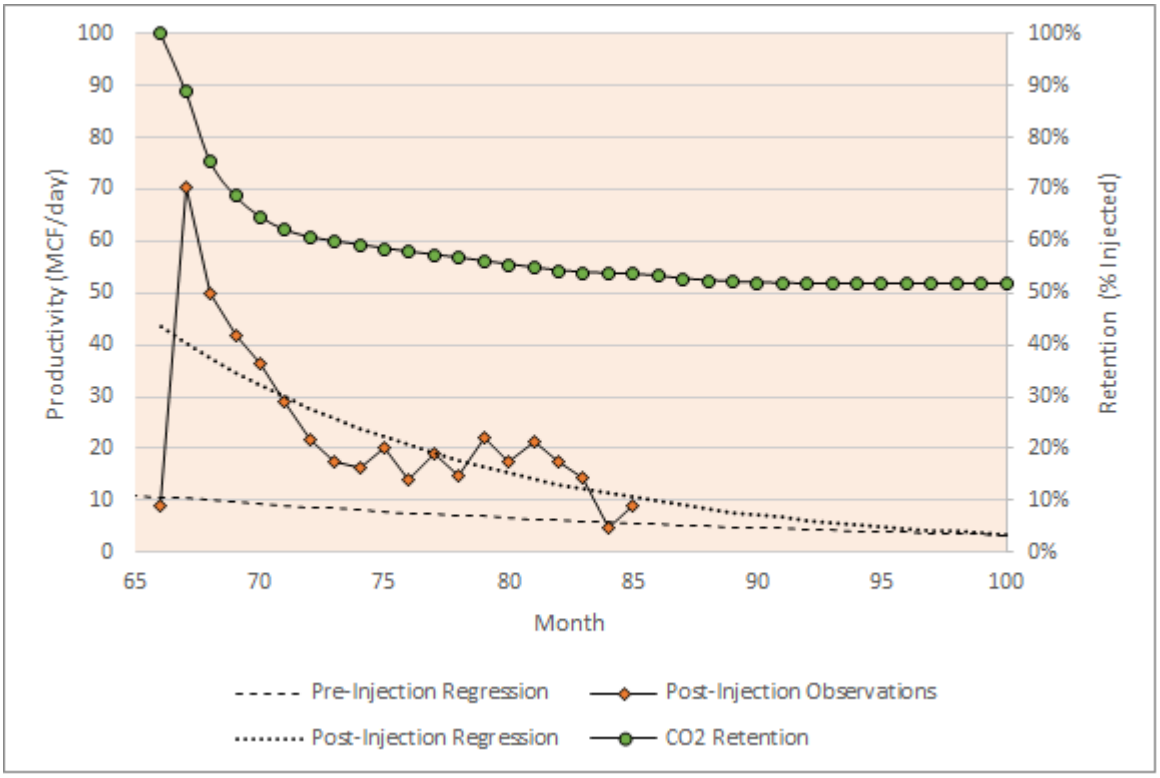


Figure 25-2 shows the amount of CO2 expected to be retained in the formation. Approximately 40% of the injected CO2 was released early in the production process but the amount of CO2 released levels off as production continues. Depending on the cost of CO2 and any possible incentive for storage, it may be beneficial to capture and reuse the vented CO2 in additional well stimulations.

Figure 25-3 Russell County, VA CBM well production data

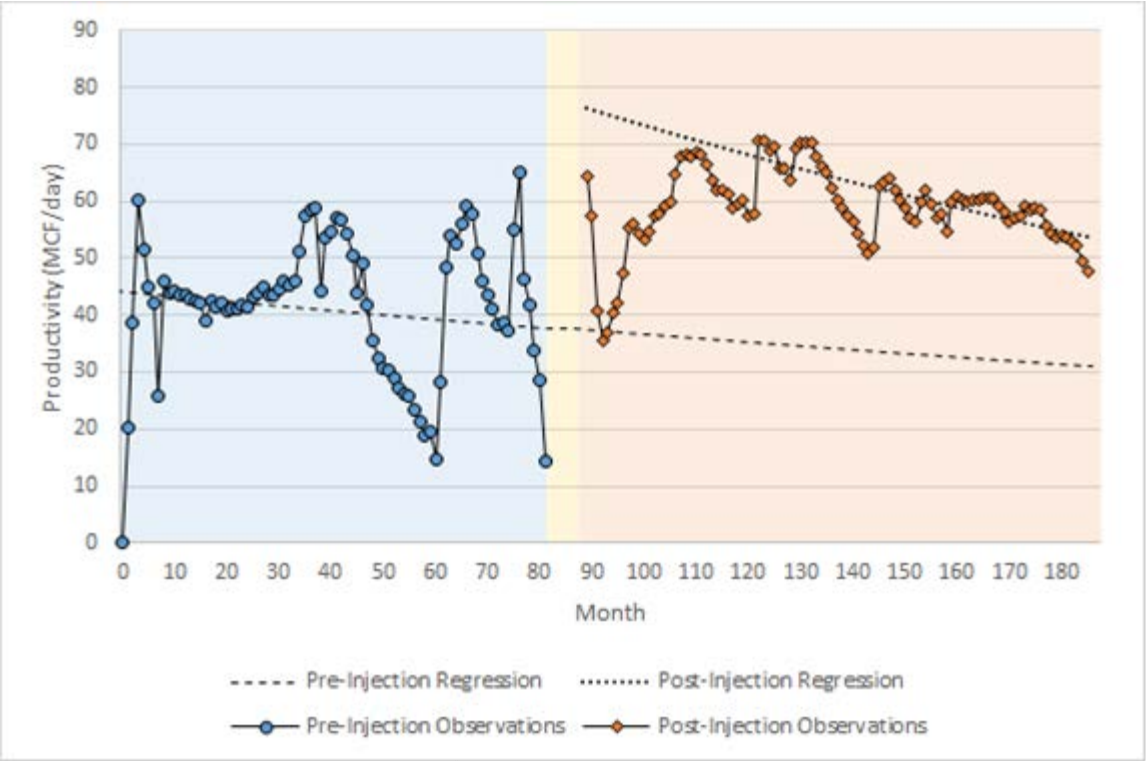


Figure 25-3 shows how the Russell County, VA CBM well reacted to CO2 stimulation. The well was out of production for approximately 10 months to allow for injection and soaking. While not as clear as the Shale study, production in the CBM well did increase after CO2 stimulation. The decline curves and additional methane produced is difficult to determine as the original production levels had a high degree of variability and post-stimulation production levels continue to be variable. Production has increased and additional studies on the production data from the Buchanan County, VA wells will provide additional data points to determine the commercial viability of ECBM.

Figure 25-4 Russell County, VA CBM well CO_2 retention

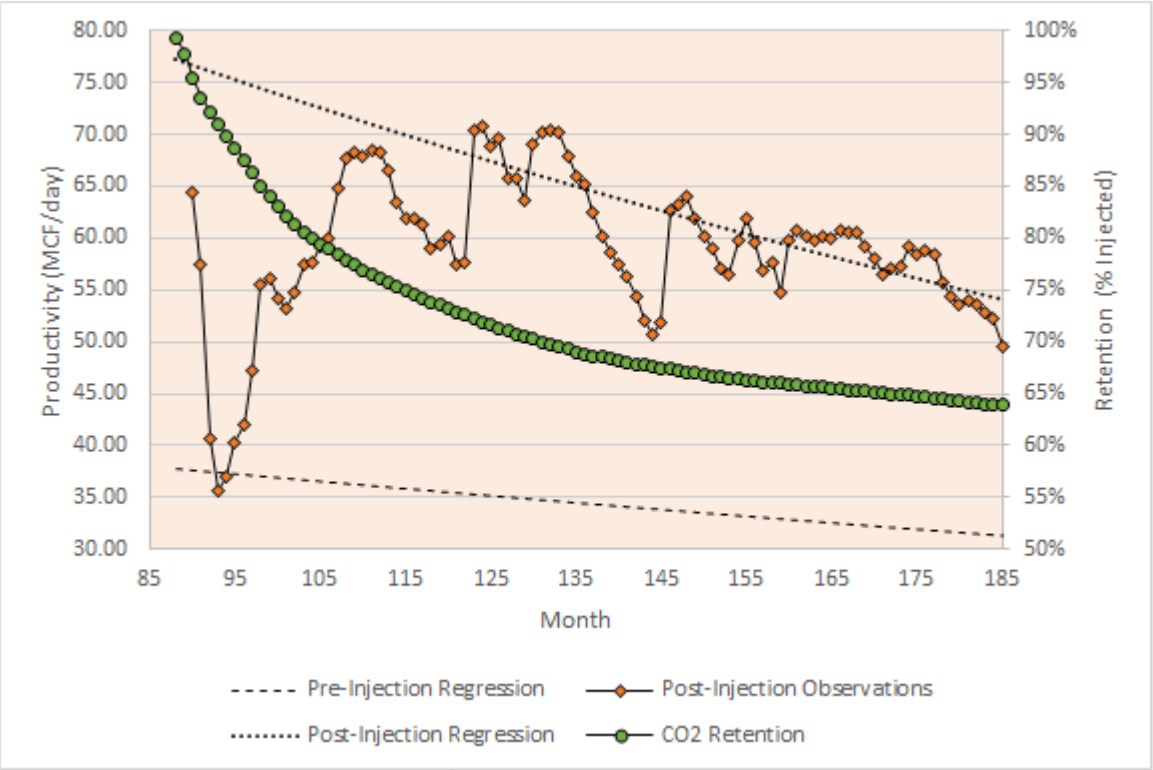


Figure 25-4 shows the amount of CO2 expected to be retained in the CBM formation. Like the shale project, ECBM results in CO2 being released during early production but begins to taper off as production continues. Final storage numbers cannot be determined until the well is shut-in. Depending on the cost of CO2 and any possible incentive for storage, it may be beneficial to capture and reuse the vented CO2 in additional well stimulations.

Studies have shown that the use of CO2 to stimulate CBM or Shale wells will increase the amount of methane recovered from the well (Pashin, 2015). The additional costs associated with ECBM and ESGR must be recovered by the additional methane production created by well stimulation. These costs include any well modifications, the foregone revenue while stimulating and soaking and the cost of purchasing and transporting the CO2. With CO2-EOR and CBM/SHALE Gas stimulation the selling price of the oil or methane is market based and individual operators or companies have limited options to impact the price received for oil or methane. One area where costs can be controlled is the input cost for the CO2. Working to source CO2 for the lowest cost provides significant value to the overall financial structure and can move projects closer to commercial operations even in periods of low oil and methane prices.

In VCCER's most recent CBM and Shale studies the CO2 was purchased from food grade distributors and trucked to the final injection sites. Detailed costs for purchase and delivery of the CO2 for the CBM and Shale studies is below:

For the Buchanan County, VA project, CO2 was trucked from Marmet, WV (near Charleston, WV) to Vansant, VA, a distance of 160 miles. The purchase price for CO2 from Praxair's Marmet facility was $89 per short ton of CO2 delivered to vessels in Vansant, VA. In addition, there are significant costs to move the CO2 to the injection wells, store in vessels at the injection well and pressurize and heat the liquid CO2 for injection. In addition, there are losses of CO2 due to the transfer. The all-in cost to inject 13,500 short tons of CO2 was $2.7 million or $200 per short ton.

For the injection into the horizontal shale gas well in Morgan County, TN, CO2 was purchased from Flo-CO2's plant at Jackson Dome in Mississippi. The CO2 was transported via highway truck 500 miles from Jackson, MS to Wartburg, TN at a cost of $220 per short ton delivered. Additional costs for site storage, pressurizing, heating and injecting the CO2 brought the all-in cost to inject 510 tons of CO2 to $230,000 or $460 per short ton.

Since the two field tests are small research projects there was no economies of scale associated with the projects. Additional research into CBM and Shale, and finding ways to reduce the purchase price and transportation cost of CO2 for use in CBM and Shale well stimulations, will allow projects to move closer to commercialization.

25.4 Objective 2: Recommend research initiatives that will advance the field work to the technology readiness level of systems verification in a relevant environment

Additional field laboratory research into ECBM and ESGR will continue to reduce the existing gaps in data and information related to how and why ECBM and ESGR, with associated CO_2 storage, can work. The reduction or elimination of these gaps will help move commercial scale ECBM and ESGR operators to develop business plans and invest in the Appalachian region to unlock additional methane resources in CBM and Shale formations, while storing CO_2. The reduction or elimination of gaps should be conducted in a manner that will advance the state of research in ECBM and ESGR beyond Technology Readiness Level 4. Some of the near-term opportunities include:

1. Buchanan County, VA – CBM Wells
    a. Monitoring of flowback, including CO_2 content and hydrocarbon composition, from the 3 injection wells placed back into production in December 2017
    b. History match the flowback results for predictive reservoir modeling and the assessment of associated CO_2 storage
    c. Update commercialization opportunities based on predictive modeling and flowback results
2. New CBM Injection Project with larger CO_2 volumes

a. Establish a field laboratory test plan for Appalachia that will further confirm CO_2 storage and utilization to level TRL4 for CBM
b. Conduct research on 10-15 CBM wells to approximate a relevant field laboratory environment to establish that the basic technological components are integrated and will work together
c. Study interactions between CBM wells in a 10 – 15 well test to guide commercialization efforts
d. Conduct multi-seam monitoring to better understand preferred flow paths to guide commercialization
e. Vary injection schemes by well to guide engineering development (TRL 5 – 6) and commercialization, including injection rates and soaking times

3. Shale Injection Project with larger CO_2 volumes
    a. Establish a field laboratory test plan for Appalachia that will advance CO_2 storage and utilization to level TRL4 for shale
    b. Conduct tests on 2-5 wells
    c. Focus on oil, condensate and NGL rich formations
    d. Assess multi-well tests to guide engineering development and commercialization by varying injection schemes and soaking time
    e. Conduct multi-injection CO_2 tests on a single well to understand if ESGR and CO_2 storage is repeatable in the same well
4. Hydraulic fracturing with CO_2 in CBM and Shale wells
    a. Establish a field laboratory test plan for Appalachia to assess hydraulic fracturing with CO_2
    b. Conduct tests on 2-5 wells
    c. Determine if production is enhanced with CO_2 fracturing
    d. Determine to what extent CO_2 is stored
    e. Determine if flowback CO_2 can be utilized for CO_2-EGR in the same or nearby wells

25.5 Objective 3: Commercialization roadmap for unconventional storage reservoirs in Appalachia

25.5.1 Introduction

The Technology Readiness Levels that are associated with CO2 capture and storage technology commercialization generally start with TRL7, an integrated pilot is demonstrated; and include TRL8, systems tested and demonstrated at final scale; and TRL9, system proven and ready for final scale. However, in order for a commercialization roadmap to be successful, the process must begin prior to reaching the three final TRLs, with a focus on stakeholder engagement, knowledge sharing and capacity building. Stakeholders will be interested in sources and uses of CO2, transportation routing, CO2

utilization and storage plans, market factors, incentives, permitting, socio-economics and environmental impacts.

A major aspect of an integrated carbon capture, utilization and storage commercialization plan is to identify the capture and utilization opportunities, determine the level of commercial readiness (including gaps) and engage stakeholders representing the entire capture-to-storage value chain. To facilitate a commercial assessment, several categories of carbon capture facilities were discussed and mapped for the Appalachian region. Also, CBM and shale gas resources within the region have been mapped. The regional maps and supporting information were used to down-select to sub-regional opportunities for carbon capture and CBM/shale well CO2 stimulation in Appalachia.

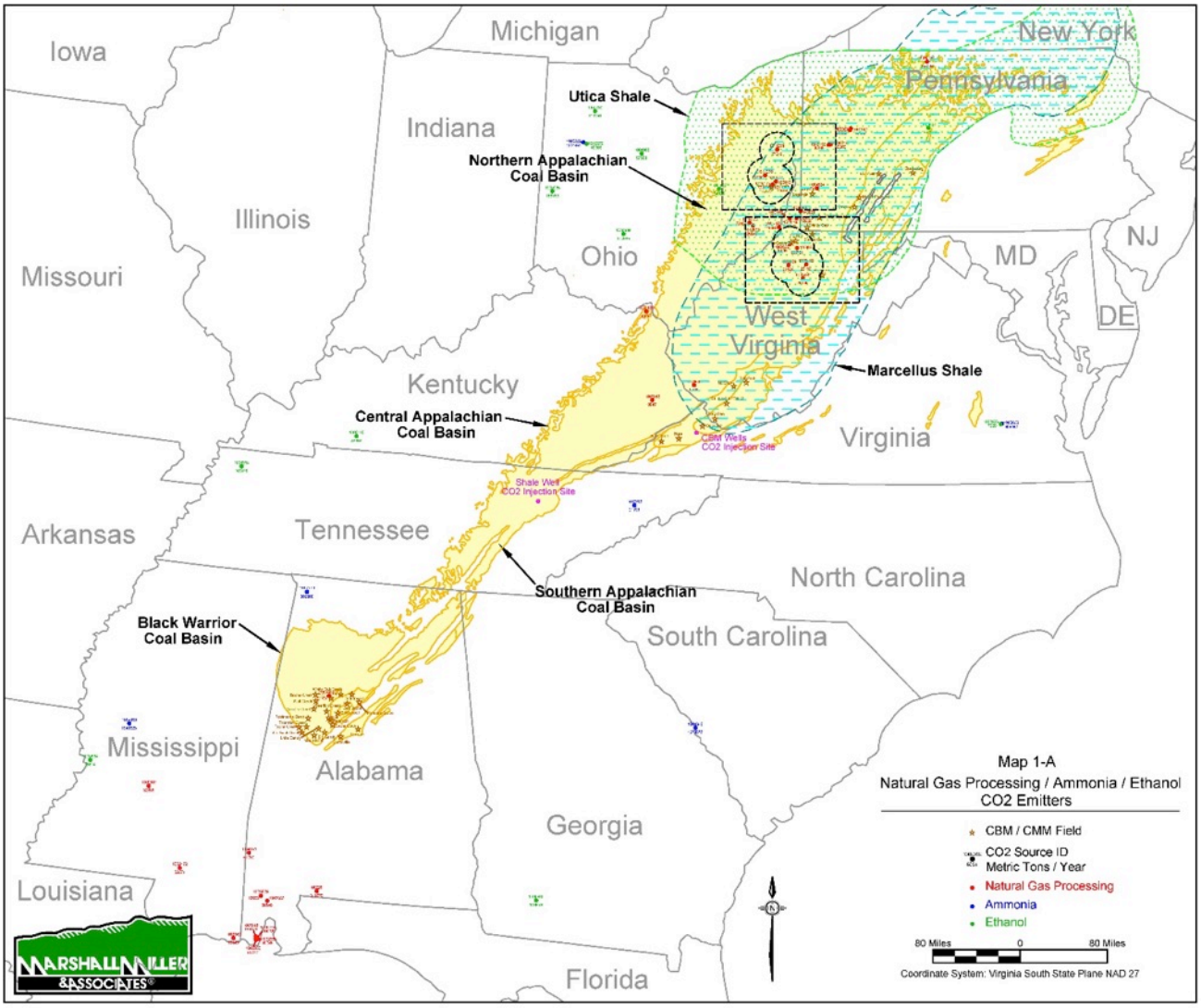
Potential sources of CO2 from fossil fueled power facilities and industrial facilities were matched to the sub-regional CBM and shale well locations. Members of the current project team participated in permitting of the fossil fueled Virginia City Hybrid Energy Center (VCHEC) facility in St. Paul, Virginia, and in developing design specifications to enable VCHEC to be “carbon capture capable” (HILL 2008).

For industrial CO2 capture facilities, the project team reviewed research conducted by NETL on nine categories of industrial CO2 emitters nationwide (NETL 2013) in order to determine suitable categories for the region. Specific locations of industrial facilities in or near the Appalachian region were mapped and matched with CBM and shale wells. Three industrial categories, natural gas processing, ethanol production, and ammonia production, were determined to be suitable CO2 capture candidates for CO2 utilization and storage in the Appalachian region. Figure 5 below provides a regional overview of the three industrial facilities and major shale and coal fields in Appalachia.

25.5.2 CBM/Shale well distribution in Appalachia

Within Appalachia, there are mature shale and coalbed gas producing formations with many existing CBM and shale wells that could be possible candidates for CO2 stimulation with associated CO2 storage (see Figure 25-5 below).

Figure 25-5 Low-cost CO_2 Emitters in Relation to Shale and CBM Gas-Producing Basins across the Appalachian Region



The Appalachian region could provide significant storage space for CO2. As a point of reference for the possible storage opportunity in Appalachia, the circles in the 2 highlighted squares in Figure 25-5 contain a total of 2,400 shale wells. The shale wells in the highlighted area represent a possible CO2 storage capacity of 6 million tons (based on injecting 5,000 tons of CO2 in each well and 50% storage in the formation) and a significant source of additional methane resources.

These storage estimates are preliminary and could be underestimating the actual storage potential for the region. The storage estimates assume a single 5,000-ton stimulation. Future studies may prove that it is possible to inject each well with a second CO2 stimulation. The limited breakthrough experienced on the CBM study would indicate the formations could accept additional CO2. The use of multiple

injections or larger CO2 injections could significantly increase the storage potential of the CBM and Shale fields in Appalachia.

Tax incentives available in 2017 through section 45Q of the tax code provide a limited amount of tax credits for geologic storage of CO2 or for the storage of CO2 via enhanced recovery of hydrocarbons. The limited amount of tax-credits remaining under 45Q creates a situation where no ECBM or ESGR project contemplated by this commercialization plan would benefit from the remaining tax credits authorized under 45Q. It is possible that legislation will be passed in the future that could increase the amount of tax credits available for future ECBM and ESGR projects. The ability for a project to claim tax-credits for storage will require extensive research and reporting to determine the amount of CO2 that is permanently stored in the formation.

25.5.3 Permanence of CO_2 storage

VCCER has monitored the two huff-and-puff projects for a number of years post-injection. The Russel County, VA CBM well has been monitored for 8 years and the Morgan County, TN shale gas well was monitored for 3 years. In each of these wells it is expected that a significant percentage of the injected CO2 will remain permanently stored in the reservoir.

The CBM injection site in Russell County, Virginia, has three shale confining units, including the Hensley Shale, that have been correlated and will provide adequate seals for the CO2 injection. Laboratory testing conducted during SECARB Phase II evaluation demonstrated that the Hensley Shale would be an adequate regional confining interval. The Hensley Shale is comprised of a microfabric of narrow pore throats between grains with modeled median pore throat size estimated at 0.26 µm (Grimm 2011).

Eight years after injection in the CBM wells, 65% of the 1,007 tons of CO2 injected is still in the reservoir. Decline curve analysis of the amount of CO2 being produced projects that greater than 60% of the injected CO2 will remain permanently stored.

Correlations at the shale test site in Morgan County, Tennessee show a primary confining unit, the Warsaw Limestone, which is a thick formation, comprised mostly of shale and argillaceous carbonate rocks. Secondary seals include the overlying Fort Payne, St. Louis, and Monteagle formations, which are comprised mostly of low porosity and low permeability limestone lithologies.

Three years after injection, greater than 50% of the 510 tons of CO2 injected is still in the reservoir. Decline curve analysis of the amount of CO2 being produced projects that nearly 50% of the injected CO2 will remain permanently stored.

25.5.4 CO_2 Sources in Appalachia

Naturally occurring sources of CO2 that are of commercial scale can be found at Jackson Dome in Mississippi and in proximity to the Permian Basin oil fields in western Texas. These natural sources of

CO2, in combination with anthropogenic sources from electric utilities and industry, provide CO2 that is being utilized for enhanced oil recovery, with associated CO2 storage.

There are no naturally occurring sources of CO2 in Appalachia that are of similar commercial scale to the natural sources located in Mississippi and near the Permian Basin. Any use of CO2 for enhancing hydrocarbon production in Appalachia will be dependent upon the commercialization of electric utility and industrial carbon capture technologies.

25.5.5 CO_2 from fossil fueled gasifiers and power plants

Carbon capture technologies for fossil fueled gasifiers and power plants fall into three major categories: Pre-combustion; Post-combustion and Oxygen-fired. While each of the three categories has systems that are at or near commercial deployment, there are many ongoing research activities aimed at increasing component/system efficiency and reducing cost.

Fossil fueled energy facilities, especially coal fired power plants, could be important sources of captured CO2 in the Appalachian region. However, absent any government regulations on CO2, all future investments made to capture CO2 will need to be financially attractive based on revenue generated from the sale of CO2 in the region. Also, generating a revenue source from CO2 would make existing coal fired power plants more attractive to maintain and operate.

In the past, project team members participated in assessments of carbon capture readiness (2008) and an amine-based carbon capture conceptual design (2009) for the 585-megawatt Virginia City Hybrid Energy Center (VCHEC) in St. Paul, Virginia. Since that time, the pilot-scale SECARB Anthropogenic Field Test and the commercial-scale Petra Nova Post-Combustion CO2 Capture and Sequestration Project have provided substantial experience with regard to amine-based carbon capture. Available information on amine-based carbon capture has formed the basis for a regional evaluation of post-combustion CO2 capture at a fossil fueled power facility.

Virginia City Hybrid Energy Center

During the permitting process for VCHEC (see Figure 25-6 below), questions were raised regarding the proposed fossil-fired plant's ability to meet CO2 reduction targets that were being discussed and could, in the future, become regulations. On January 8, 2008, Dr. Michael Karmis and Dr. Gerald Hill provided testimony to the Virginia State Corporation Commission (Docket No. PUE-2007-00066) related to carbon storage, as an element of "Carbon Capture Readiness," for the VCHEC facility. At the time Dr. Karmis (representing Virginia Tech) and Dr. Hill (representing the Southern States Energy Board), were team members of the Southeast Regional Carbon Sequestration Partnership (SECARB).

In 2009 Dominion worked with Dr. Karmis and his team to prepare a proposal for a carbon capture pilot plant at VCHEC with geologic storage. Dominion's engineering, procurement and construction (EPC) contractor, Shaw Engineering (Shaw) developed conceptual plans and drawings for a 1,500 ton per day (TPD) carbon capture system, based upon an advanced amine design. No specific vendors or exact technologies were identified at that time. Shaw, with assistance from Dr. Hill, prepared an envelope of design and operating parameters for a carbon capture unit.

Figure 25-6 Artist's depiction of conceptual carbon capture facility at VCHEC



Source: Shaw 2009

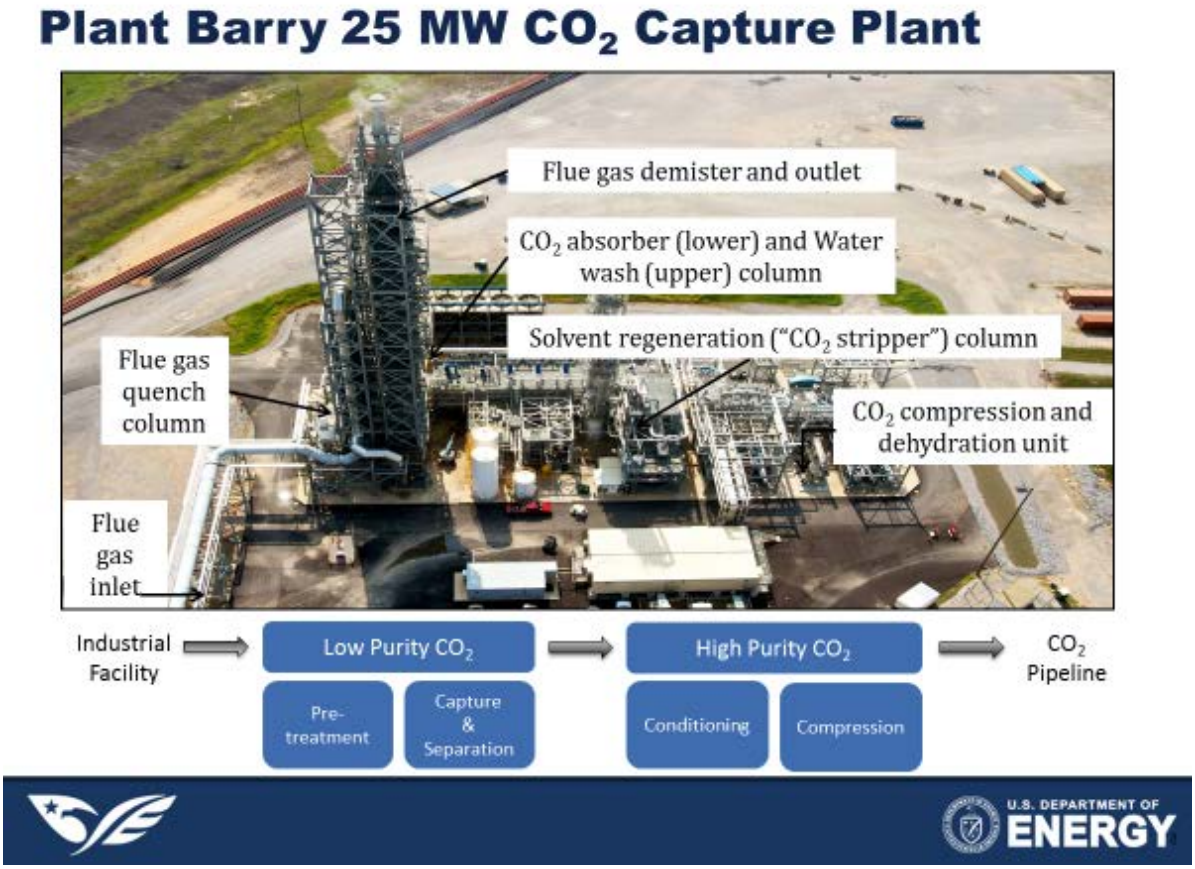
In July 2012, four years after construction began, the 585-megawatt VCHEC coal-fired power plant began commercial operations. Currently, the VCHEC is not subject to carbon regulation and it is not anticipated that such regulations will apply to the fossil-fueled facility in the immediate future. As previously noted, any investments made to capture CO2 will need to be financially attractive based on revenue generated from the sale of CO2 in the region. Subsequent to the VCHEC 2009 conceptual design, key advancements have been made on amine capture technology, including: The SECARB Anthropogenic CO2 Injection Field Test, and the Petra Nova Post-Combustion CO2 Capture and Sequestration Project.

SECARB Anthropogenic CO_2 Injection Field Test

The SECARB Anthropogenic CO2 Injection Field Test was performed from 2012 – 2014 in southwest Alabama near the town of Citronelle (see Figure 25-7 below). The CO2 source for the field test was Alabama Power's existing 2,657 MW Barry Electric Generating Plant (Plant Barry). A small amount of flue gas from Plant Barry (equivalent to the amount produced when generating 25 MW of electricity) was diverted from the plant and captured using the proprietary KS-1™ solvent advanced amine process developed by Mitsubishi Heavy Industries (MHI).

The CO2 capture facility at Plant Barry became operational in June 2011. In total, 114,104 metric tonnes of CO2 were injected during a two-year period. Figure 7 shows the treatment stages of the MHI pilot facility at Plant Barry.

Figure 25-7 CO_2 Treatment Stages at Plant Barry



Source: SSEB 2016

The MHI advanced amine unit at Plant Barry was a pilot-scale system, demonstrated in a relevant environment. Operational experience gained at the Plant Barry pilot project served as the basis for commercialization of the MHI advanced amine system at the Petra Nova project.

Petra Nova Post-Combustion CO_2 Capture and Sequestration Project

Petra Nova Parish Holdings, a joint venture between NRG Energy and JX Nippon Oil and Gas Exploration, has retrofitted an existing coal-fired power plant (W.A. Parish Generating Station) in Thompsons, Texas with a CO2 capture plant (see Figure 25-8 below). The Petra Nova project official ribbon cutting ceremony took place on April 13, 2017.

The project is demonstrating the ability of the CO2 capture technology supplied by Mitsubishi Heavy Industries to capture 90 percent of the CO2 emitted from a 240-megawatt-electrical (MWe) flue gas stream. The MHI CO2 capture technology, called the KM CDR Process® (Kansai Mitsubishi Carbon Dioxide Recovery), was jointly developed by MHI and the Kansai Electric Power Company. This process uses the proprietary KS-1™ solvent, which facilitates low energy requirements, low solvent consumption, and low waste products when compared with a conventional solvent (NETL 2017).

Figure 25-8 Petra Nova CO_2 capture and treatment facility



Source: SSEB 2016

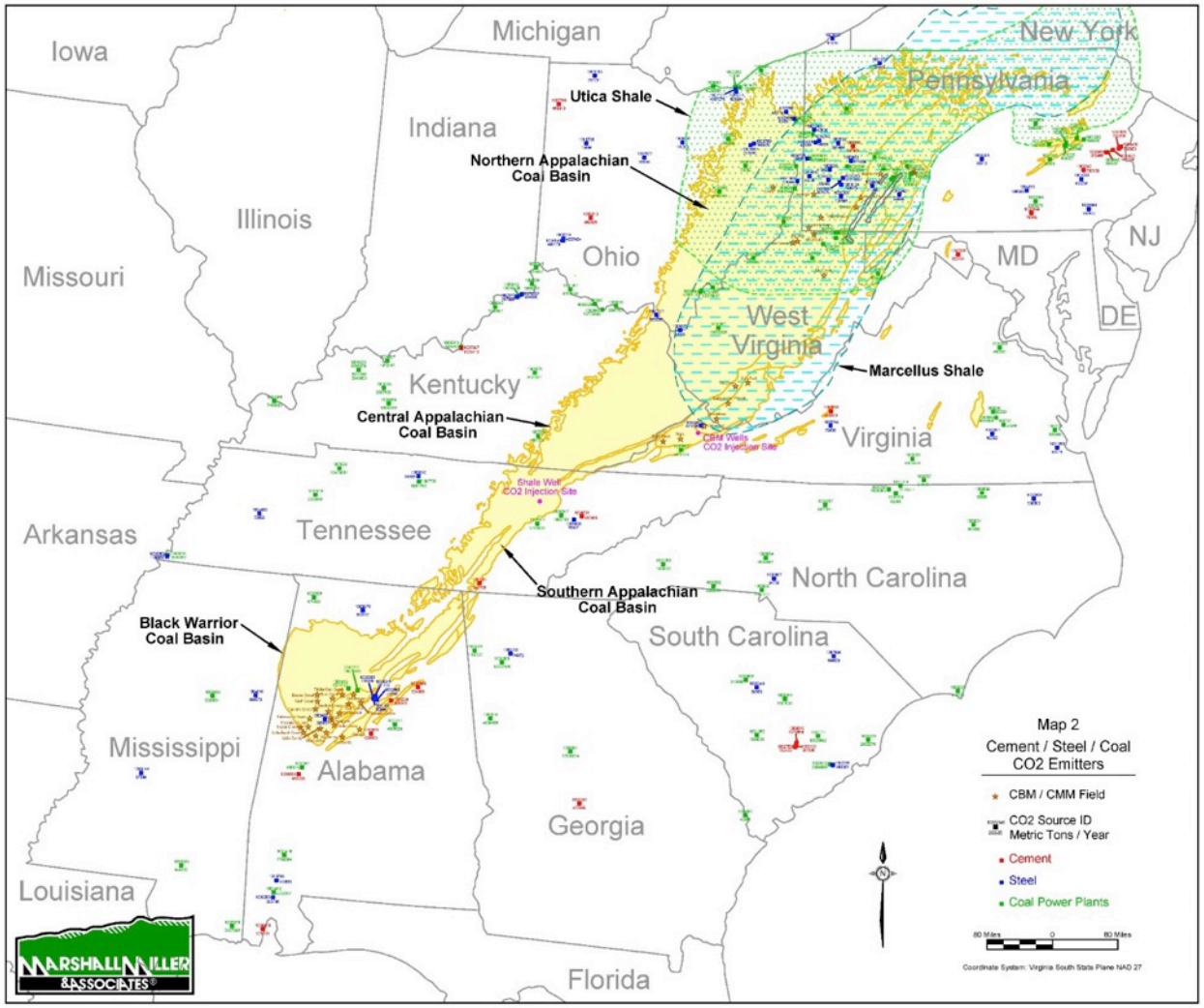
The project addresses the capture of CO2 from coal-based electricity production and its beneficial reuse via an advanced amine-based carbon capture process and reuse of the captured CO2 in an enhanced

oil recovery (EOR) application. The project is demonstrating that post-combustion CO2 capture and reuse can be done economically for existing plants when there is an opportunity to recover oil from nearby oilfields.

The captured CO2 is being used to enhance oil production at the West Ranch Oil Field, where it will remain stored underground as a result of EOR operations. The project is expected to boost production at West Ranch from 500 barrels per day to approximately 15,000 barrels per day. The field holds an estimated 60 million barrels of oil recoverable from EOR operations (NETL 2017).

Fossil fueled power plants have high volumes of stack gas but the CO2 concentrations are relatively low. Cement and steel plants are other fossil fuel based facilities that have stack gasses of high volumes and low concentrations. Figure 25-9 identifies the location of coal fired power plants as wells as cement and steel manufacturing facilities across the region.

Figure 25-9 Coal Power Plants, Cement and Steel Plants across the Appalachian Region



Research that leads to future cost reductions in CO2 capture, treatment and compression from fossil fueled facilities can lead to commercial viability. In addition, continued research on CO2 utilization and storage, including emerging CCUS markets, can identify potential revenue sources and accelerate project feasibility.

25.5.6 CO_2 from Industrial Sources

There have been many indications that carbon utilization will play a significant role in the development and commercialization of carbon capture and storage technologies. In 2017 NETL noted that "*An environmentally sustainable approach will be required to ensure the availability of the additional large volumes of CO2 that need to be injected in both oil and gas reservoirs and saline formations to ensure energy security. Therefore, a carbon management approach capable of lowering industrial emissions in a manner that is both economical and publicly acceptable in the long-term is desirable*" (NETL 2017).

According to DOE's Office of Energy Efficiency and Renewable Energy, 15 industrial sectors consume 95% of the energy used in the manufacturing sector (DOE 2012). Many industrial facilities such as oil refineries, the chemical sector, cement, aluminum, and steel production, among others, use fossil fuels for process heat as well as feedstocks. Blast furnace steel making, cement manufacturing, and some chemical facilities produce CO2 directly in their production processes and indirectly through energy consumption. In addition to the critical role that CCUS plays in decarbonizing the electric power sector, deep decarbonization of key sources in the industrial sector will not be possible without CCUS (IEA 2013).

DOE analysis shows that approximately 30 million metric tons per year of pure CO2 are currently being produced at industrial facilities located within 50 miles of existing CO2 pipeline networks. These sources provide valuable early permitting, infrastructure deployment and market opportunities, which in turn lower the cost of capturing CO2 from future industrial and power sector projects (DOE 2016).

CCUS and energy efficiency strategies go hand in hand in manufacturing and can work together to offset the associated costs of carbon capture. CCUS can also provide a valuable revenue stream to manufacturing companies that sell CO2 for EOR, or for other processes that utilize CO2 (DOE 2016)

Many industrial facilities produce CO2 as a byproduct and typically vent the CO2 to the atmosphere. In some cases, CO2 separation technologies are used to remove CO2 from other gases prior to sale or use. For example, natural gas processing facilities are employed to reduce CO2 concentrations in the product gas stream. The CO2 removed from natural gas processing facilities can be captured and compressed where it makes economic sense to do so.

Historically CO2 from commercial capture facilities has been used for enhanced oil recovery, as a chemical feedstock, and as a food grade carbonation source. The majority of CO2 currently captured

and stored by large-scale CCS projects is from industrial sources, mainly natural gas processing. As of June 2016, there were 15 large-scale CCS projects in operation across the globe, with a combined annual capture potential of 28 million tons per year (five million cars' equivalent). Of these 15 projects, 14 apply CCS to industrial processes (GCCSI 2016).

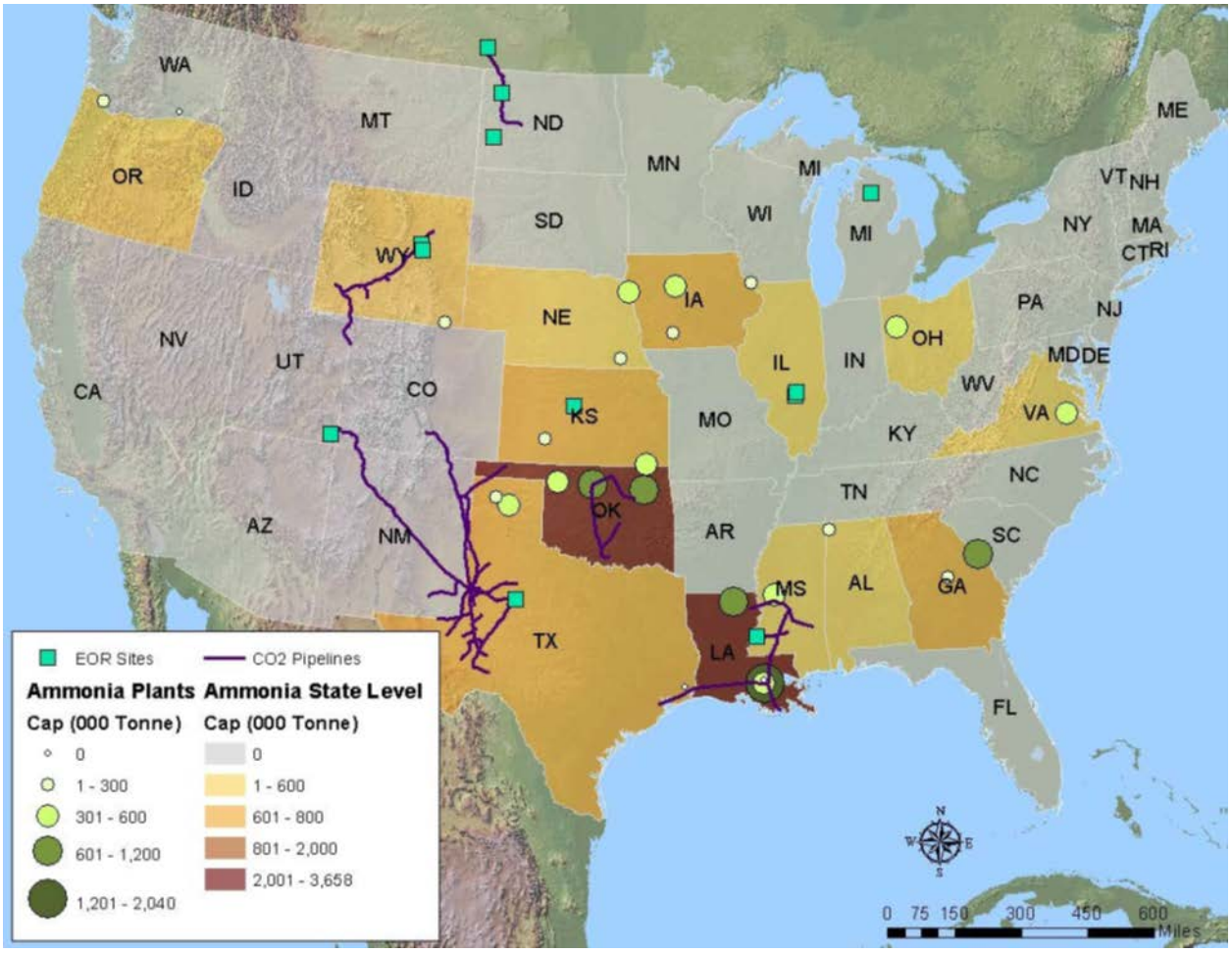
In 2013 NETL published a report on the costs associated with capturing carbon dioxide (CO2) from industrial processes. Only those processes with effluent streams containing concentrations higher than those found in flue gas from coal-fired power plants (CFPP, ~17 mol %) were considered. The following nine processes were chosen due to either the high purity or large quantity of CO2 available (NETL 2013). The processes are categorized based on high and low purity levels, respectively:

High Purity Sources (≥ 90 vol. %)	**Low Purity Sources (< 90 vol. %)**
Ethanol	Hydrogen (Refinery)
Ammonia	Iron/Steel
Natural Gas Processing	Cement
Ethylene Oxide (EO)	
Coal-to-Liquids (CTL)	
Gas-to-Liquids (GTL)	

High Purity Industrial CO_2

At the national level, NETL has mapped locations for high purity sources (≥ 90 vol. %) of Ammonia, Ethanol, Natural Gas Processing and Ethylene Oxide. Figures 25-10 through 25-13 below show the locations of these four industrial facility categories with respect to CO2 pipeline infrastructure. The NETL report does not include the Greencore Pipeline that became operational in 2013 and extends from the Lost Cabin natural gas processing plant in northeast Wyoming to the Bell Creek oil field in southeast Montana.

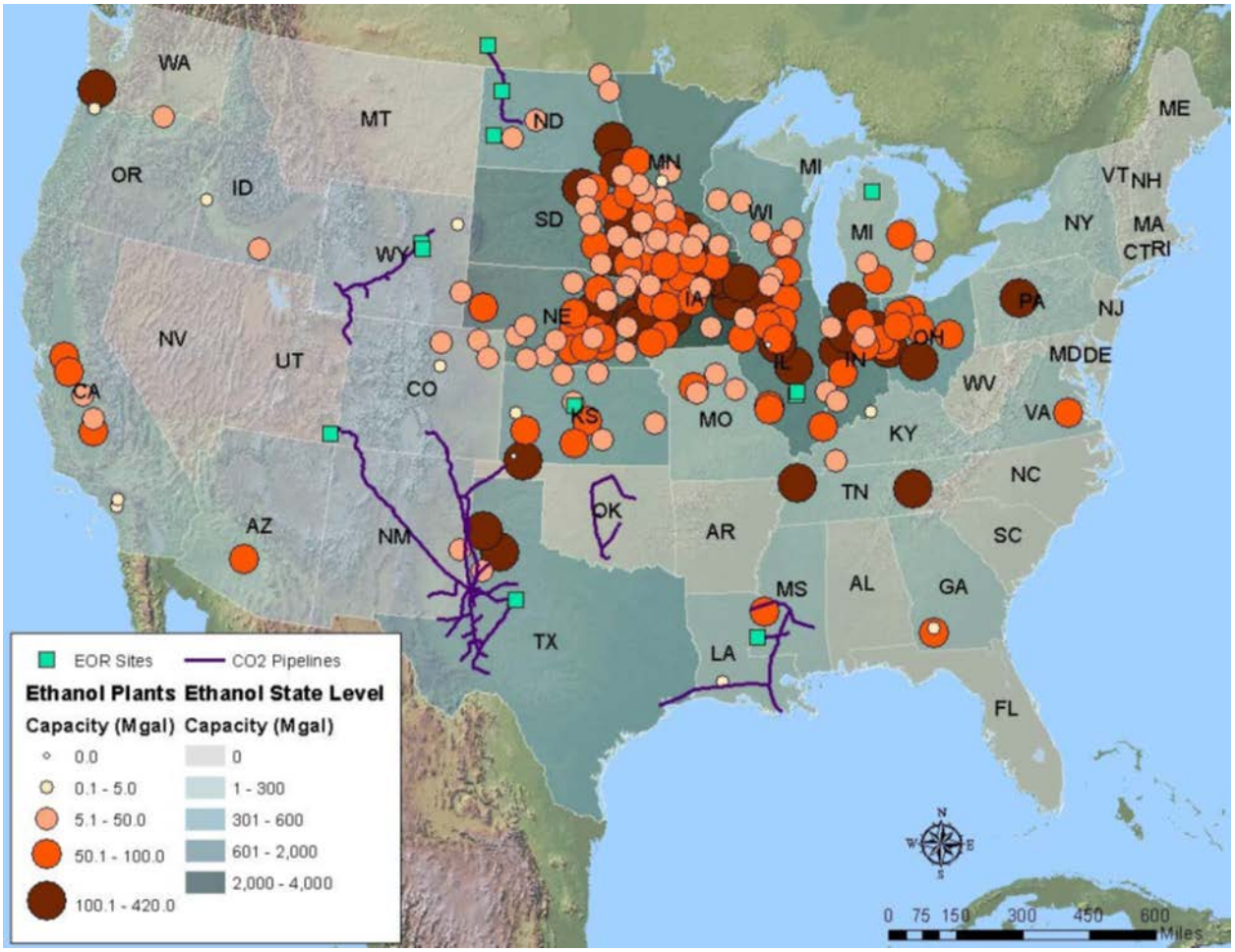
Figure 25-10 Ammonia Plants and CO_2 Pipelines



Source: NETL 2013

Ammonia can be thought of as a high-purity industrial source of CO2. In all but one plant in the U.S., the ammonia process reforms natural gas to form H2, CO, and CO2; however international ammonia production may be more largely based on coal as a feedstock over natural gas. The unconverted CO from reforming is then shifted to produce more H2 and CO2. Emissions of CO2 in an ammonia plant come from the flue gas from the primary reformer and the CO2 stripper vent that separates CO2 from the ammonia syngas. A portion of the CO2 removed from the post shift stream in many cases is captured and reused to produce urea. Urea is synthesized by reacting ammonia with CO2. The amount of CO2 captured and reused will vary from plant to plant. With CO2 removal crucial to the ammonia process, coupled with the need for CO2 to convert ammonia into urea, ammonia processing is a viable option (NETL 2013). The capital equipment generally needed for CO2 capture and treatment at an ammonia plant can be limited to water knockout (no cooling) and compression, with additional water being removed between compression stages.

Figure 25-11 Ethanol Plants and CO_2 Pipelines

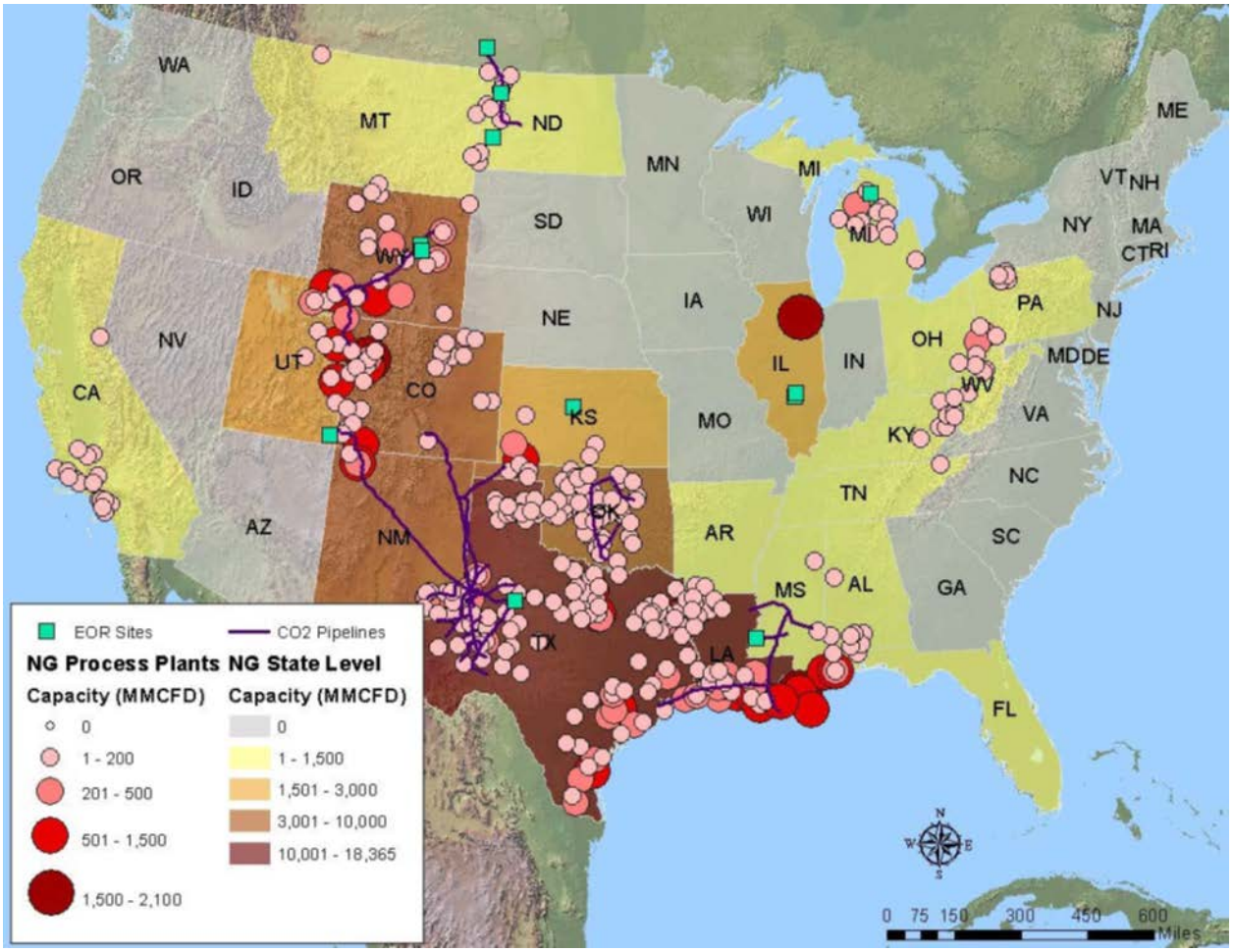


Source: NETL 2013

The CO2 emissions result from the fermentation process in ethanol plants. Ethanol plants are located primarily in areas of high corn production in the Midwest. Ethanol production generates a CO2 byproduct stream of pure CO2, except for small amounts of water. Therefore, the capital equipment needed for CO2 capture and treatment at an ethanol plant can be limited to cooling and compression, with water being removed between compression stages.

Currently DOE is partnering in one development phase ethanol-capture project. The Midwest Geological Sequestration Consortium's (MGSC) Illinois Basin-Decatur Project (IBDP) is a collaboration of DOE, the Illinois State Geological Society (ISGS), the Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and others. The IBDP is an integrated industrial carbon capture and storage system capturing CO2 from an ethanol source and storing it in a saline reservoir.

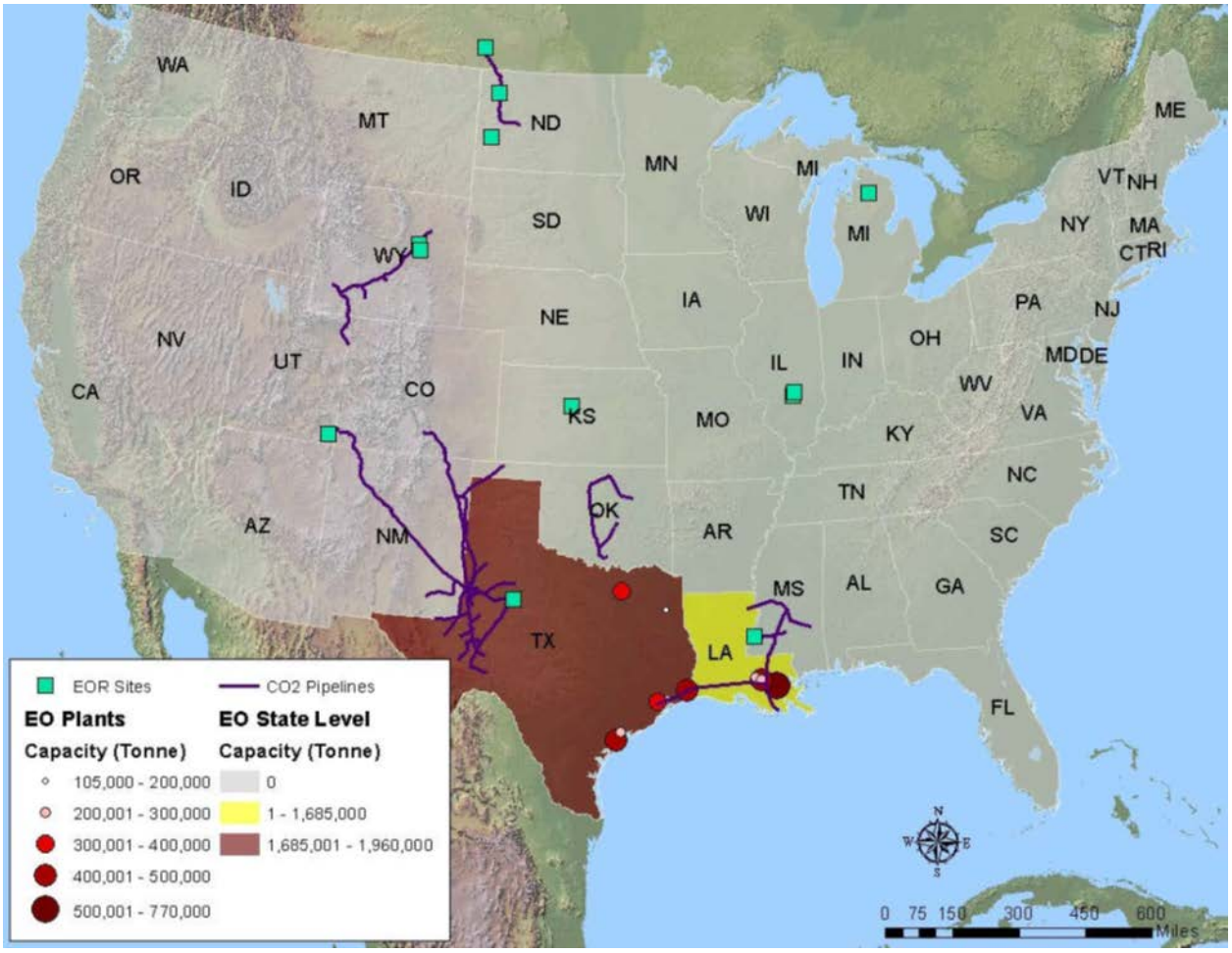
Figure 25-12 Natural Gas Processing Plants and CO_2 Pipelines



Source: NETL 2014

High purity CO2 (>95%) is a byproduct of acid gas removal. Removing CO2 from gas is necessary in most regions of the country. Techniques for removing CO2 from raw natural gas streams to meet sales gas requirements have been in use since the 1930s. The first commercial EOR project started in 1972, using a waste stream of by-product CO2 from several natural gas processing facilities in the Val Verde area of southern Texas. Instead of being vented, the CO2 that had already been separated from the natural gas stream in the Val Verde gas plants was compressed and transported through the first large scale CO2 pipeline to the SACROC 9 oilfield several hundred kilometers away (GCCSI 2016). The capital equipment generally needed for CO2 capture and treatment at a natural gas processing plant can be limited to water knockout (no cooling) and compression, with additional water being removed between compression stages.

Figure 25-13 Ethylene Oxide Plants and CO_2 Pipelines



Source: NETL 2013

Ethylene Oxide (EO) is produced by direct oxidation of ethylene in the presence of a silver catalyst. Seventy-three percent of North American EO production goes directly to synthesis of ethylene glycol, which is used in antifreeze, polyester, liquid solvents, and plastics production. EO is considered a high purity source. The process has a single CO_2 point source: the CO_2 removal system. The removal system may be one of several types—physical sorbents such as Rectisol or Selexol, chemical sorbents such as MEA, or cryogenic separation. CO_2 separation is an inherent part of base plant operations and, therefore, only compression and cooling are required (NETL 2013).

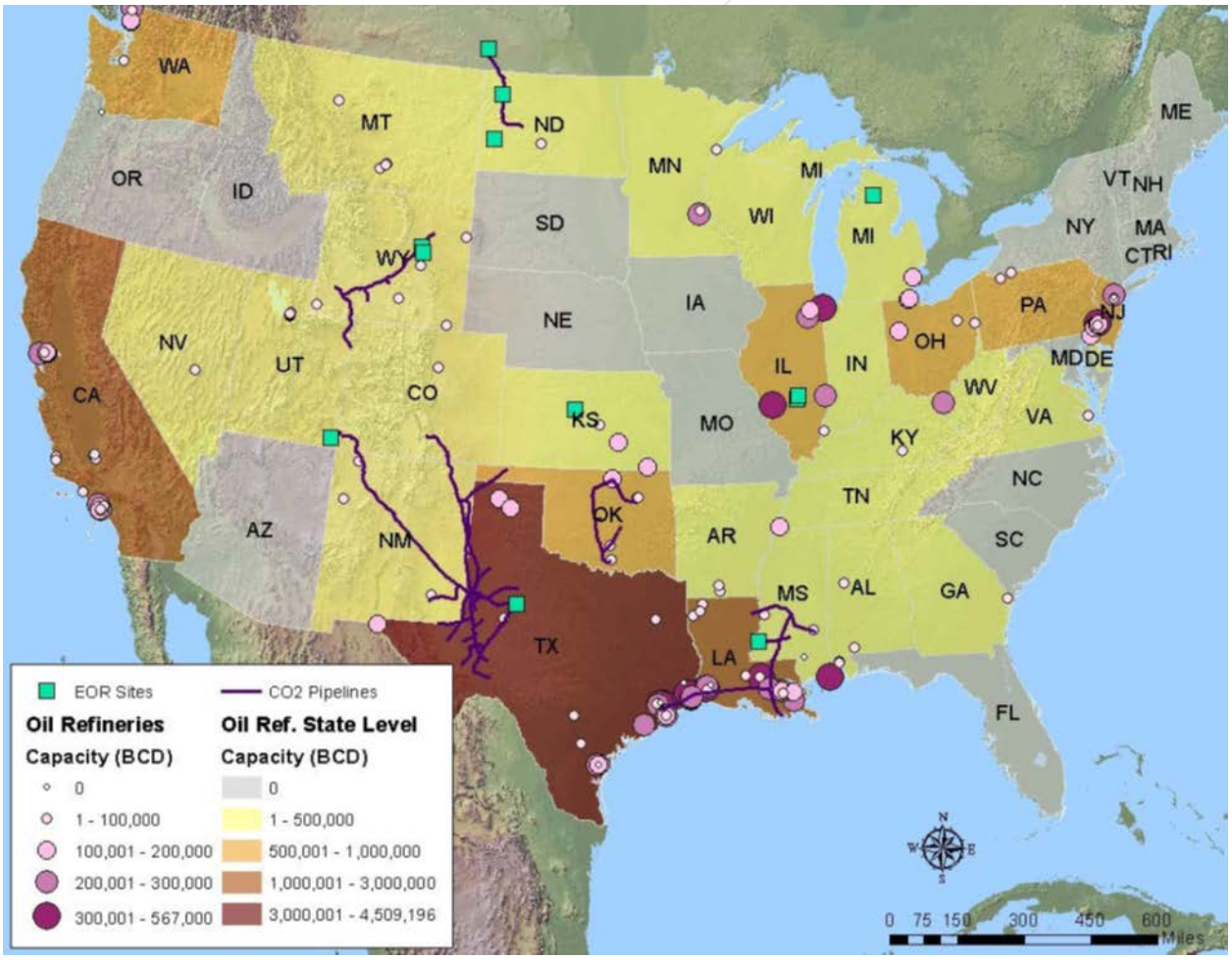
Low Purity / High Quantity Industrial CO_2

NETL also mapped locations for low purity sources (< 90 vol. %) of CO2 from refineries that produce hydrogen and emit CO2, cement plants, and steel plants (NETL 2013). While the emission streams are categorized as low purity for industrial sources, they still contain CO2 concentrations much higher than those found in flue gas from coal-fired power plants (CFPP, ~17 mol %). The refinery hydrogen, cement and steel facilities produce industrial CO2 at lower purity but often in large quantities.

Refinery hydrogen, steel and cement CO2 capture facilities all require separation and purification of CO2 prior to compression. Typically, MDEA acid gas removal (AGR) units are used for CO2 separation and purification. The AGR process can produce a CO2 stream that is >90% pure and suitable for truck and pipeline transportation. The MDEA solvent in the AGR contacts inlet acid gas and binds with CO2. Low pressure steam is needed to displace the CO2 and regenerate the solvent for reuse. Cooling of the product CO2 is required for all cases following compression to meet the pipeline temperature specification.

Oil refineries (see Figure 25-14 below) can have numerous small-quantity vented CO2 sources, but CO2 resulting from hydrogen production units are the most attractive source for capture and treatment. Fluid catalytic cracking (FCC) units also are potentially viable sources of CO2 at refineries.

Figure 25-14 Oil Refineries and CO_2 Pipelines



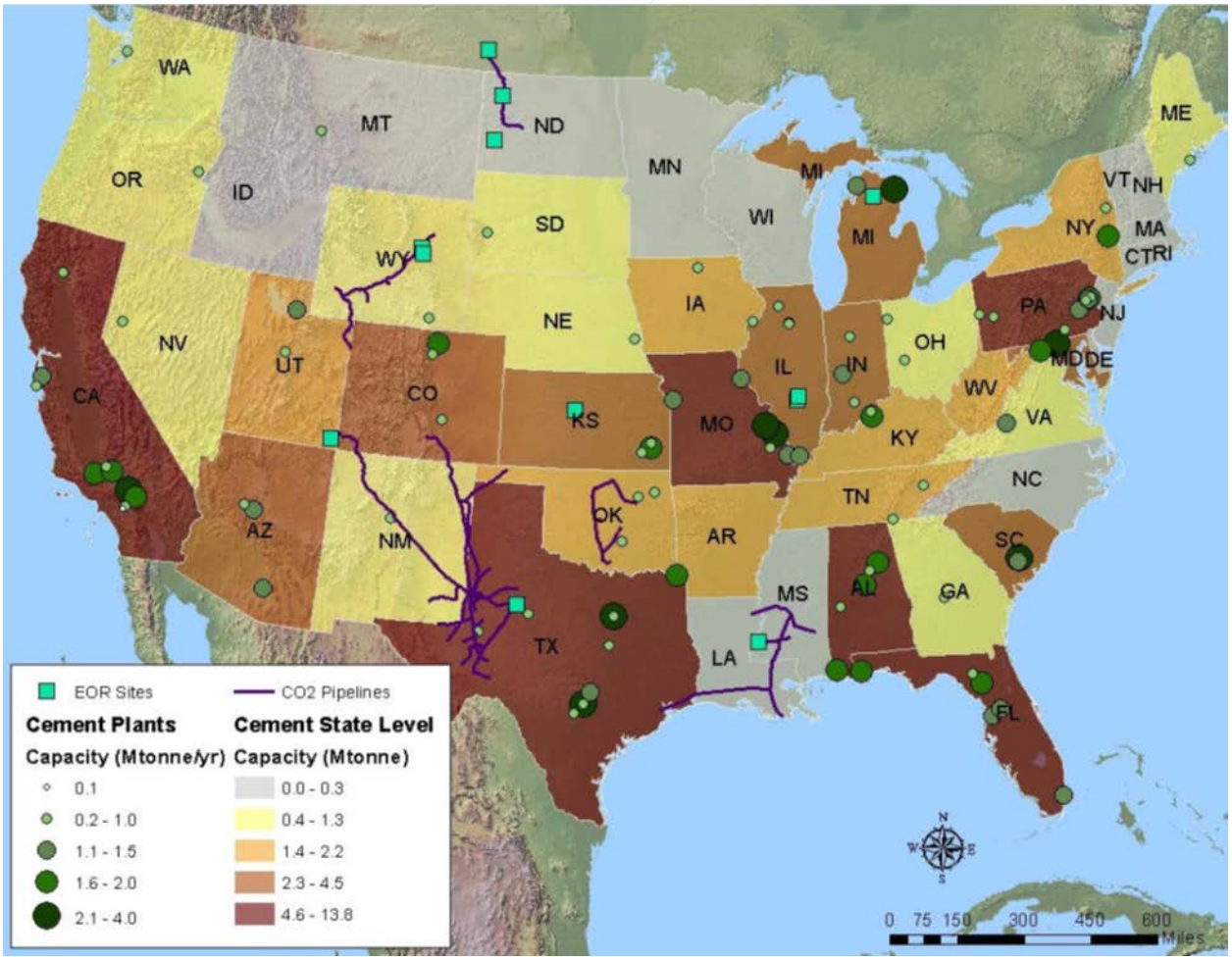
Source: NETL 2013

When producing hydrogen via steam reforming, there are three point sources in which CO2 can be collected or vented from the plant. Only one of these, the pressure swing absorption (PSA) tail gas, is a source with CO2 concentration elevated over that of a flue gas (NETL 2013). Since the PSA tail gas stream CO2 concentration is low (< 45 %), further purification is required. This is achieved using an MDEA. The MDEA solvent can be used to capture CO2. Low pressure steam is needed to displace the CO2 and regenerate the solvent for reuse. Cooling of the product CO2 is required for all cases following compression to meet the pipeline temperature specification.

DOE and Air Products and Chemicals Inc (AP&C) have a commercial scale project underway that is capturing CO2 from two steam methane reformer (SMR) hydrogen production units located within Valero Refinery's Port Arthur, Texas facility. The CO2 is transported via the existing Green Pipeline to Denbury's West Hastings oil field for use in CO2 EOR.

There are two types of Portland Cement (PC) processes (see Figure 25-15 below): wet kiln and dry kiln.

Figure 25-15 Cement Plants and CO_2 Pipelines

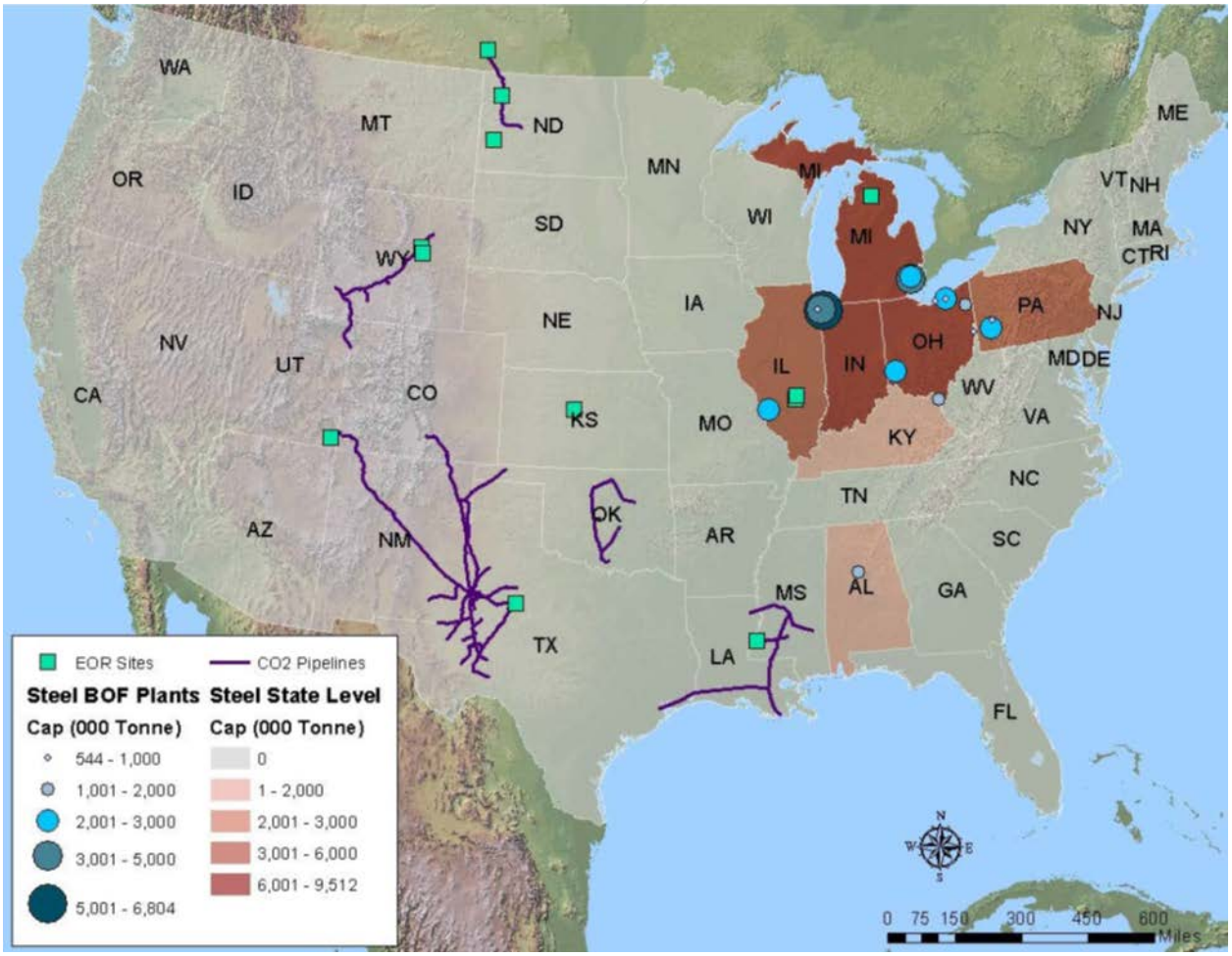


Source: NETL 2013

Both the dry and wet kiln processes utilize a multitude of different fuels to provide the heat necessary for drying, calcination, and sintering (Wiley 2011). Fuel burning to provide kiln heat is one of two CO2 emissions sources, with the second resulting from calcinations. The kiln off-gas stream concentrations are relatively low; however, it is above typical coal fired power plant flue gas concentrations and will require purification before compression. MDEA solvents can be used on cooled gas steams to capture CO2, followed by water knockout and compression.

According to a study published by the American Iron and Steel Institute (see Figure 25-16 below), there are 116 steel plants in the U.S., accounting for approximately 80 M tonnes of steel production in 2010 (AISI 2012). Of these 116 steel plants, 99 plants produce steel using an Electric Arc Furnace (EAF) and 17 plants produce steel using Basic Oxygen Furnace (BOF). Since the BOF process utilizes a larger amount of iron ore than the EAF process, the BOF process will produce more blast furnace CO2.

Figure 25-16 Steel Plants and CO_2 Pipelines



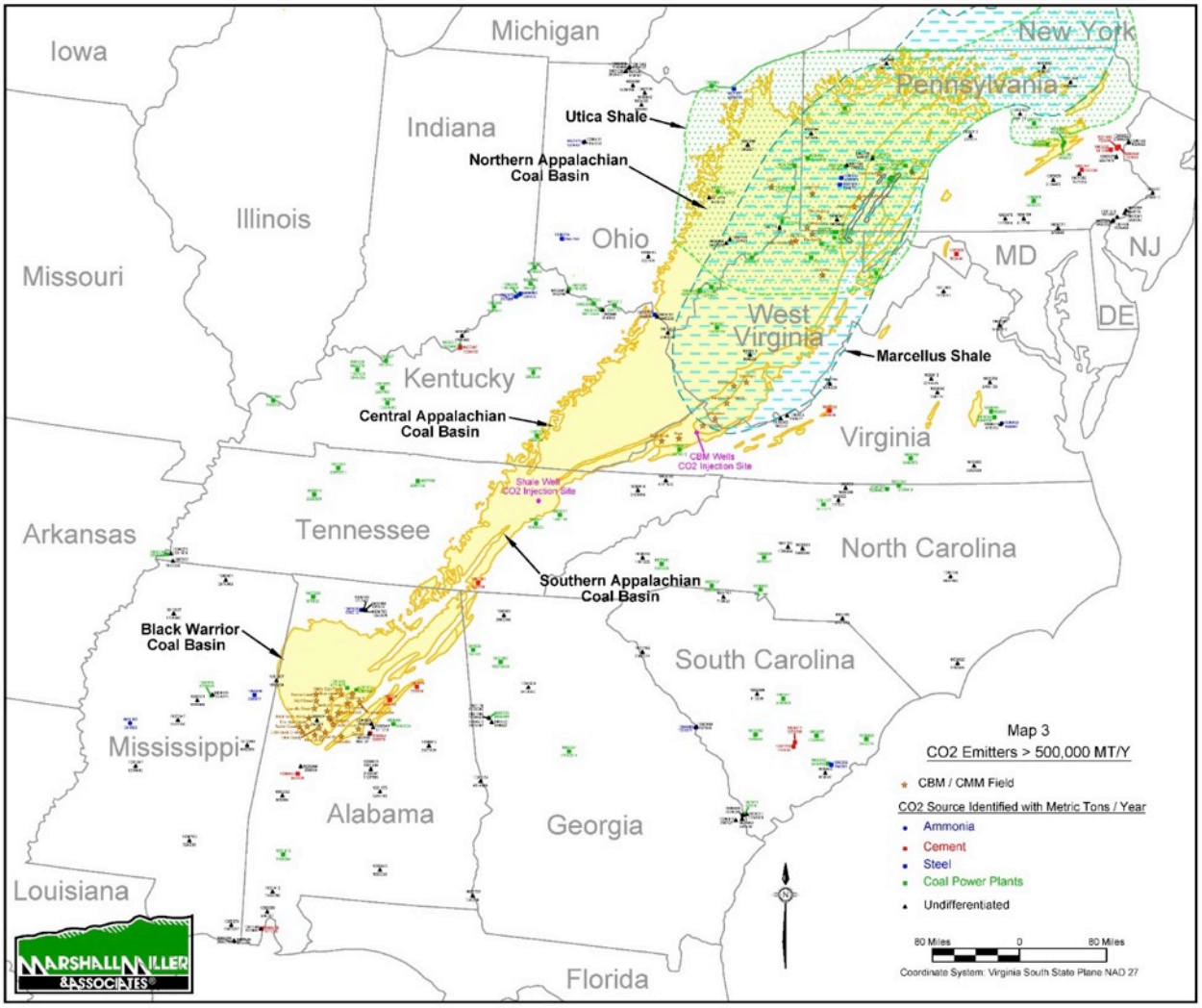
Source: NETL 2013

The Blast furnace gas (BFG), instead of being vented, is cleaned and used in the plant as low-grade fuel. Therefore, CO_2 is distributed throughout the plant as smaller CO_2 point sources. This will increase the cost of CO_2 capture in the steel plant. The three highest CO_2 concentrations of these point sources are the coke oven gas at 27 volume percent, the blast furnace stove at 21 volume percent, and the power plant stack at 23 volume percent (AISI 2012). In many applications, a MDEA solvent can be used to capture CO_2, in combination with cooling, compression and dehydration.

Low Cost Industrial Capture for the Appalachian Region

Within the industrial capture units identified, the Appalachia region has a number of significantly large emitters that could provide CO_2 for ECBM and ESGR. *Figure 25-17* identifies facilities with CO_2 emissions greater than 500,000 metric tons per year.

Figure 25-17 CO_2 emissions greater than 500,000 metric tons per year



Large or concentrated sources of industrial CO2 are the “low-hanging fruit” among CCUS project opportunities, because many industrial processes produce relatively pure streams of CO2. For example,

in many industrial processes (such as hydrogen production from steam methane reforming, ethanol production, and processing of natural gas, among others) the separation of CO2 is an inherent part of the fuel production process. These facilities represent a low-cost pathway for stimulating CCUS deployment, as capture from these high-purity sources is less capital intensive in comparison to capture from diffuse sources of CO2, such as power generation. [DOE 2016]

As illustrated in Table 25-1 and Figure 25-18 below, Ammonia, Ethanol and Natural Gas processing currently provide the lowest capture cost for CO2.

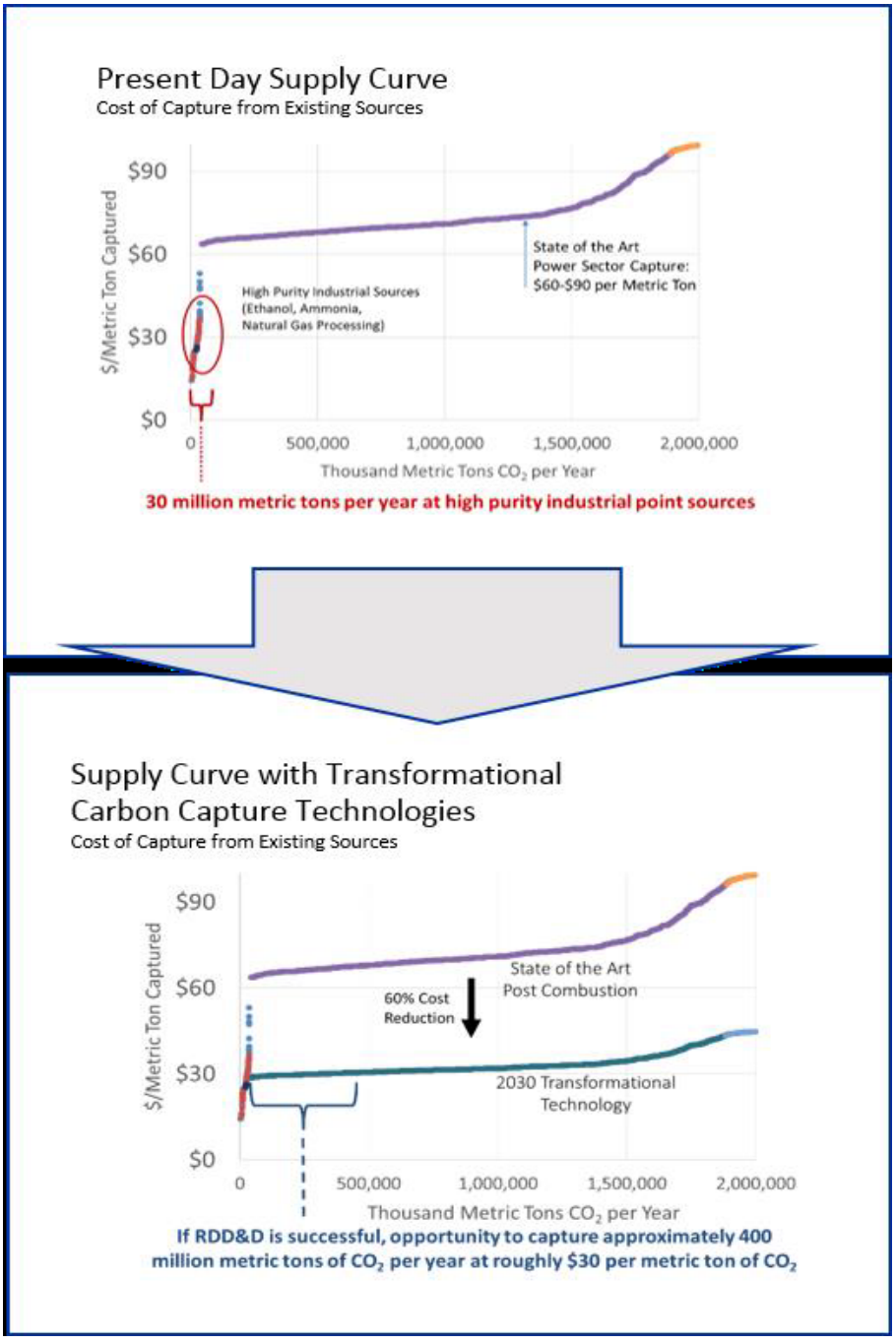
Table 25-1 NETL breakeven cost for CO_2 capture for Ammonia, Ethanol and Natural Gas Processing

Source	Green Field $/tonne	Retrofit $/tonne
Ammonia	$26.26	$26.52
Ethanol	$30.15	$30.46
Natural Gas Processing	$17.38	$17.56

Source: (NETL 2013)

The low cost of CO2 capture for these industrial process is a result of the relatively pure streams of CO2 associated with these industrial processes. In time, and with continued research on transformational technologies, post combustion capture of CO2 from fossil fuel facilities could provide additional CO2 sources for Appalachia and other regions. Given the significant economic impact coal production has in the region, advance in post-combustion capture technologies could have multiple positive impacts of the region in the form of continued or increased coal production as well as providing capture options for regional coal plants to increase the available supply of CO2 for additional use in CBM and Shale operations.

Figure 25-18 CO_2 Capture Cost – Existing and Possible Future costs with Transformational capture Technologies

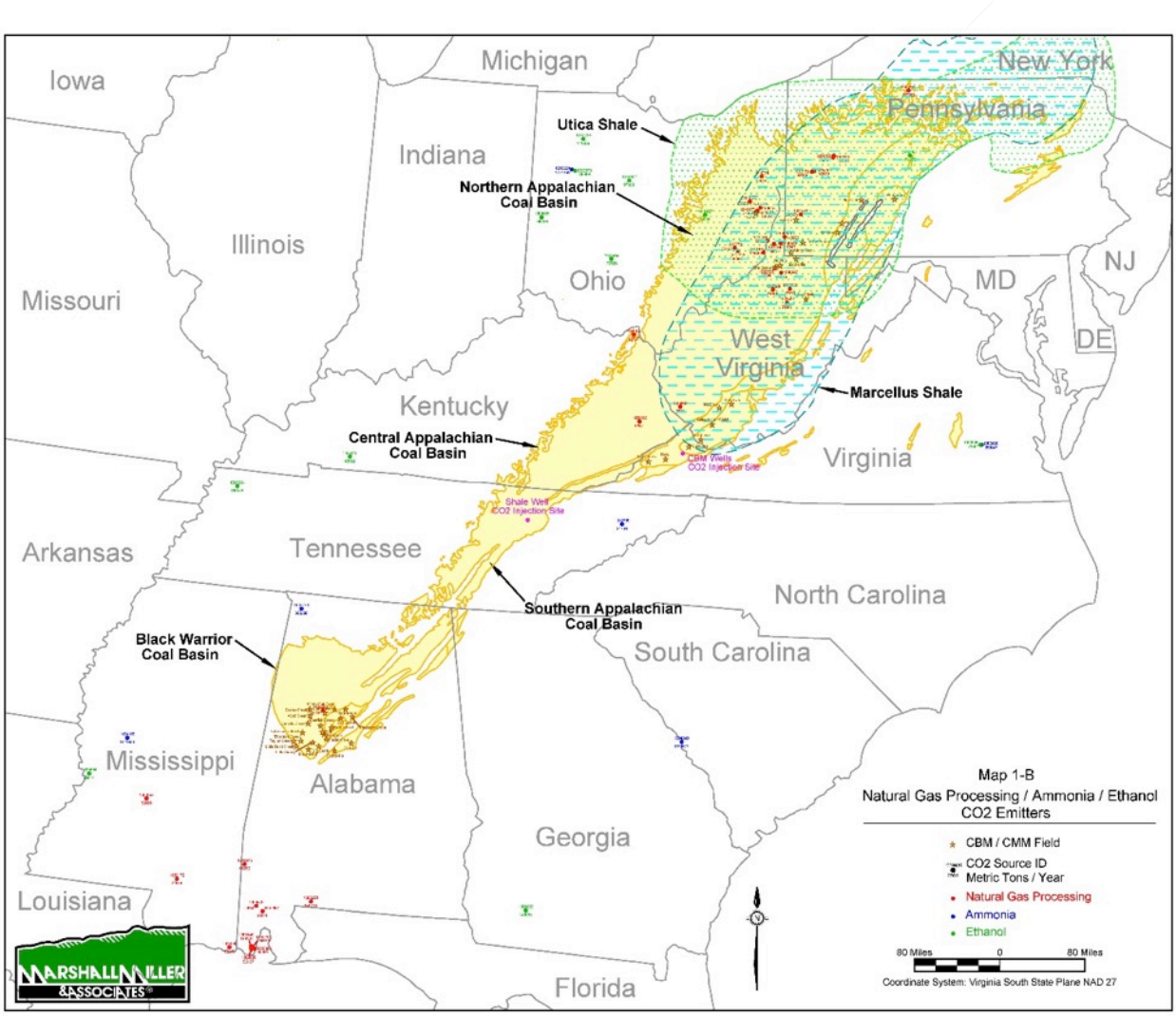


Source: DOE 2016

As shown in Figure 25-18, even with transformative capture technologies, post combustion capture of CO2 will remain more expensive than industrial sources. Significant reductions in cost for post combustion capture will provide future CO2 sources but current costs for post combustion CO2 remain significantly higher than CO2 from industrial sources. A focused effort to identify and use the lowest cost CO2 will greatly enhance the chances for the successful operation of an integrated Industrial

Carbon Capture and Storage facility. The Appalachian Region is fortunate to have potential CO2 sources from Ammonia, Ethanol and Natural Gas Processing. Figure 25-19 identifies some of the low cost industrial sources of CO2 in the Appalachian Region. All CO2 emission data was obtained from the Environmental Protection Agency Facility Level Information on Green House Gases Tool (FLIGHT).

Figure 25-19 Low Cost Industrial CO_2 Emitters



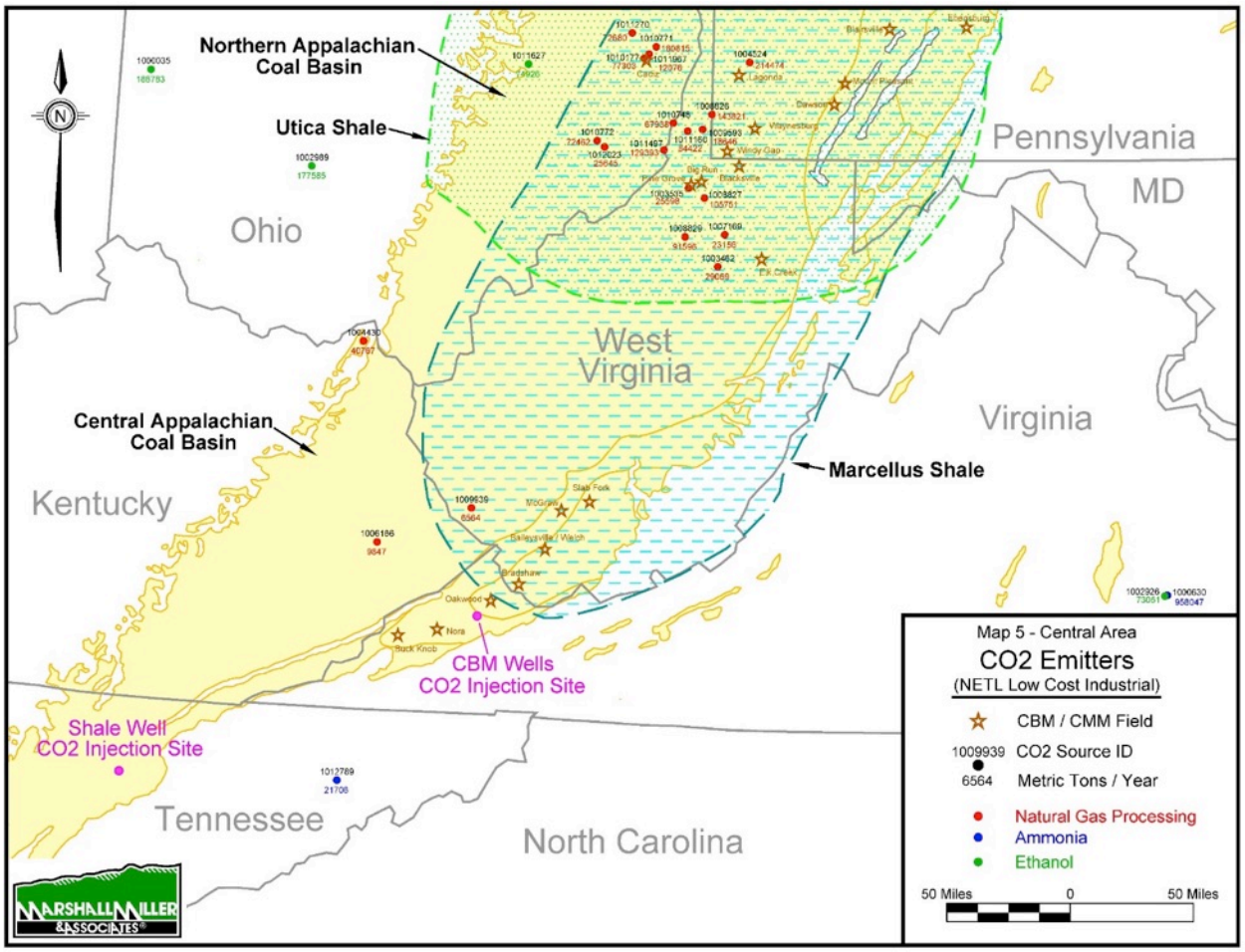
CO_2 From Regional Ammonia Production

Within Appalachia, there are multiple ammonia production facilities that could be initial sources of CO2 for commercial ECBM or ESGR. The use of ammonia as a point source for CO2 would provide significant cost reductions in the purchase price of CO2 ($26 vs. $89/ton delivered in the current CBM study).

The large operational ammonia plants are located outside of the regional shale and coal basins and the associated shale and CBM wells. The US Nitrogen LLC ammonia plant located in Midway, TN (see Figure 25-20 below) is currently operational but has had difficulty with operations. Other ammonia plants in

or near the Appalachian region could provide significant volumes of CO2 for regional commercialization efforts.

Figure 25-20 Low Cost CO_2 Emitters in Central Appalachia



With fully operational plants in Alabama, Mississippi, Georgia, Virginia and Ohio, ammonia production could become a high-volume source of CO2. An ammonia production plant in Hopewell, VA is the closest facility to any large concentration of CMB or Shale wells in Central Appalachia. The Hopewell plant is approximately 250 miles from these wells.

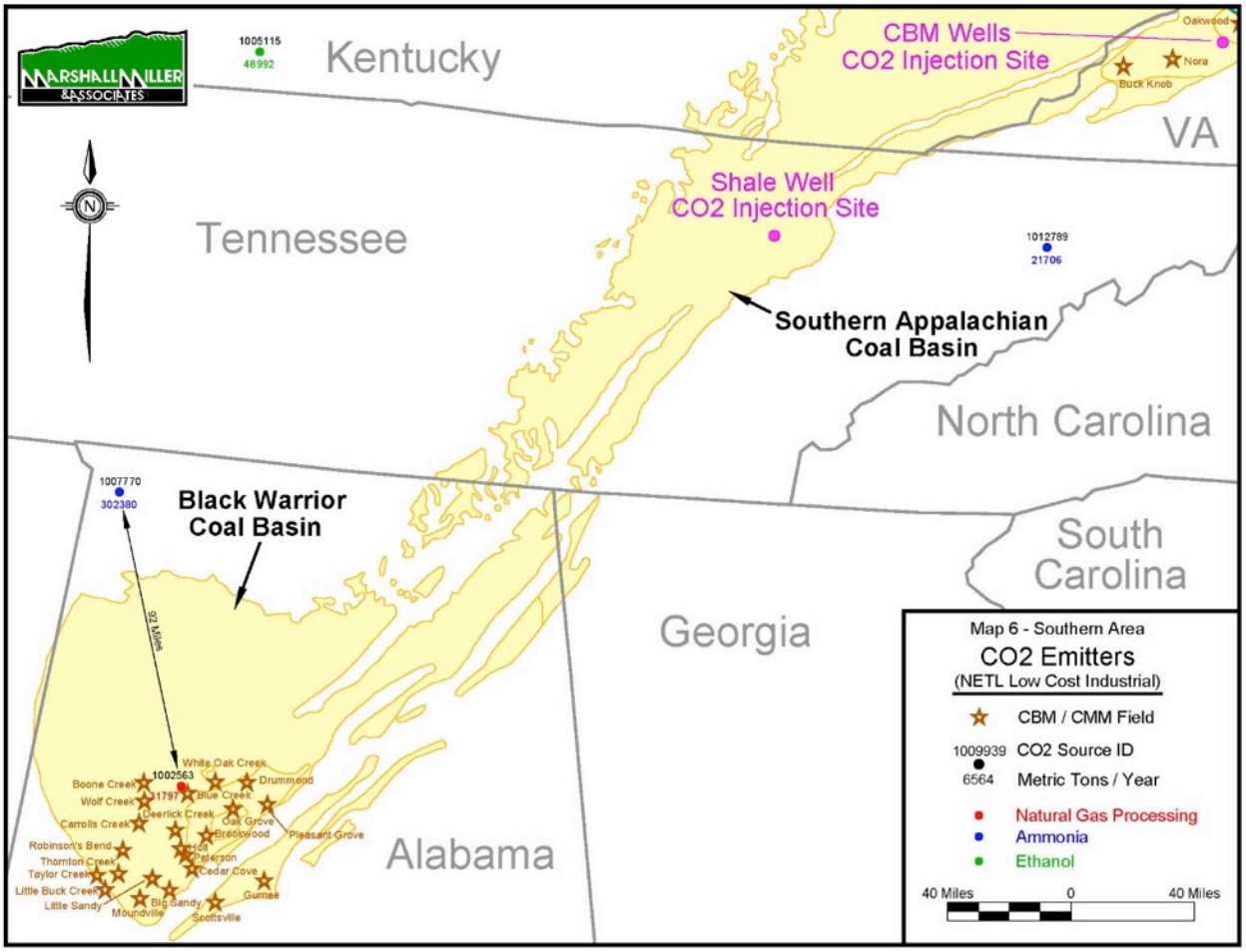
There are two ammonia plants in Southern Appalachia that are located near the Black Warrior Coal Basin (see Figure 25-21 below). One is located in Yazoo City, Mississippi, and the other is located 92 miles north of the Black Warrior Coal Basin in Alabama. Figure 25-21 shows the location of the Cherokee Plant in Colbert County, Alabama, in relation to the Black Warrior Basin CBM fields.

Given the large distance from source to sink the use of trucks for final delivery will need to be augmented with a CO2 pipeline. A dedicated CO2 pipeline will need to be used to move CO2 from an

ammonia plant to one or more centralized distribution hubs that can be serviced by 20-ton semi-trucks. The semi-trucks will provide final delivery of the CO2 to the wells.

Construction of a dedicated pipeline will be expensive and time consuming. Industry rule of thumb for commercial CO2 pipeline construction is approximately $1 million per mile. This initial expense to build a pipeline to service CBM or Shale gas fields on a large scale will require a very large operator or group of operators willing to form a joint venture or special purpose vehicle to provide the financial backing to construct the pipeline.

Figure 25-21 Ammonia Production Near Black Warrior Basin



An initial pipeline would likely run from the ammonia plant to one or more central distribution centers located close to large concentrations of wells that could accommodate the initial CO2 volumes. The Terrell gas processing facility is one of the smallest commercial operations in the US and moves approximately 500,000 tons of CO2 annually. That would likely be the lowest amount of CO2 that would need to be contemplated to begin operation of a pipeline of any distance. The financial impact on the project and delivered cost of CO2 will be greatly influenced by the length of the pipeline and the volume

of CO2 delivered by the pipeline. The greater the volume the lower the overall cost of CO2, as the cost of constructing the pipeline can be allocated to a greater volume of CO2.

This initial pipeline could eventually become the basis for a regional CO2 pipeline infrastructure with additional sources of CO2 flowing into the system and multiple distribution hubs serving to wells across the region. This framework has occurred in the Permian Basin of Texas with a network of CO2 pipelines serving multiple oil fields.

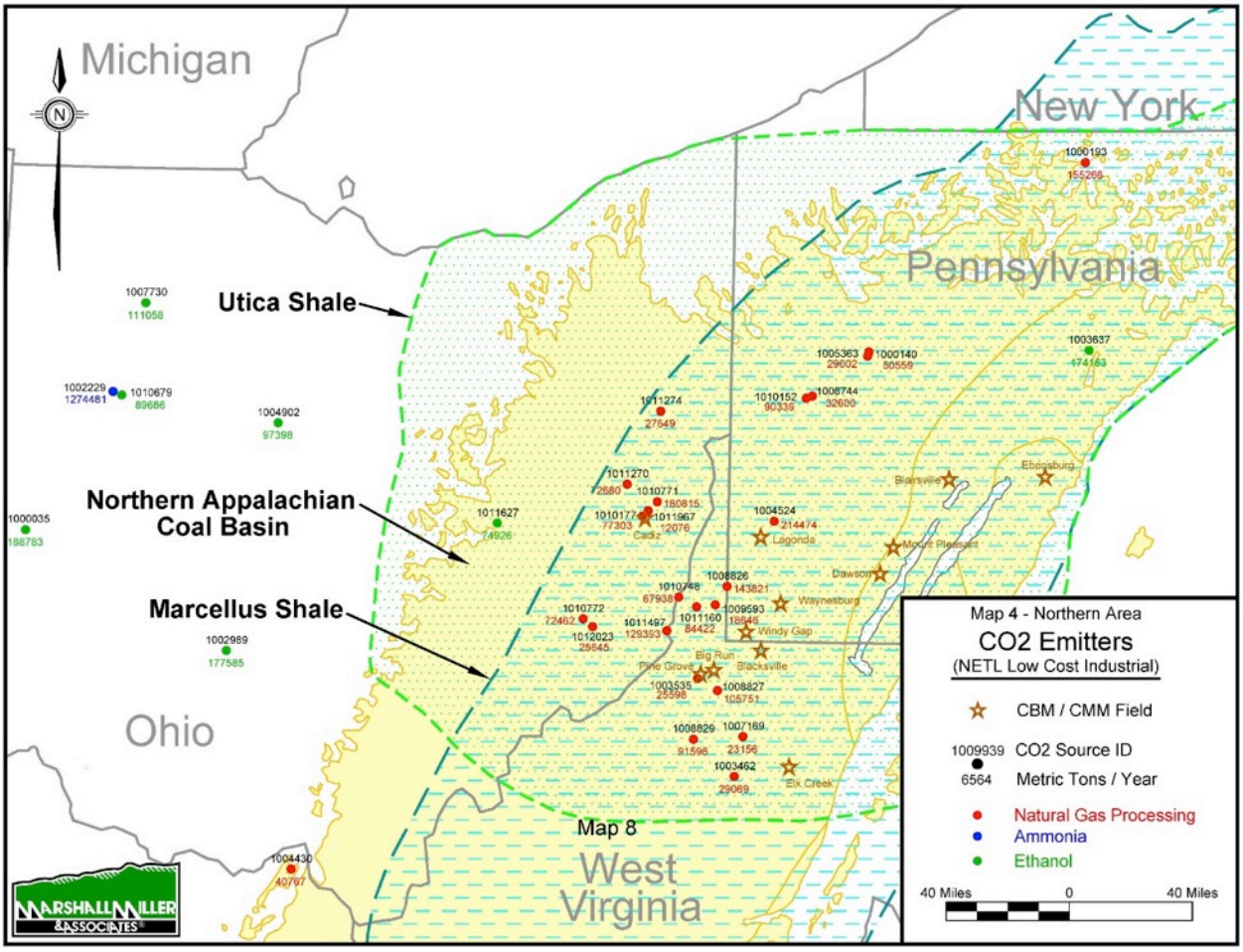
In an initial startup commercial operation both parties will have risks that must be mitigated and/or accounted for during the negotiating process. With the large operational ammonia plants located about 250 miles from CBM and Shale fields any commercialization plan will need to contemplate the construction of a dedicated CO2 pipeline. The addition of a pipeline adds significant cost and complexity when compared to sourcing CO2 from NGP or ethanol production. This additional cost and complexity can be overcome but companies will need greater certainty that investment dollars can be recovered through additional methane production before investing in large scale CO2 pipeline infrastructure.

CO_2 From Regional Ethanol Production

Within the Appalachian Region there are several ethanol production facilities that could be an initial source of CO2 for a commercial ECBM or Shale gas operation. The use of ethanol as a point source for CO2 would provide significant cost reductions in the purchase price of CO2 ($30 vs. $89/ton delivered in current CBM study).

The Greatest concentration of Ethanol production facilities is in Northern Appalachia (see Figure 25-22 below).

Figure 25-22 Low cost Emitters in Northern Appalachia



Using ethanol production facilities to source CO2 for use in ECBM and ESGR well stimulation provides several benefits that could allow commercial operations to ramp up over time. The CO2 captured at the plant could be compressed and stored in large onsite facilities. These storage facilities could serve as a centralized source of CO2 for nearby wells and could be serviced by 20-ton semi-trucks for delivery. The trucks could transport CO2 captured at the ethanol facility to nearby wells based on the schedule and needs of the individual operator(s). This flexibility will be necessary as initial commercialization efforts may be small and widely distributed geographically. This model allows the ethanol production plant to set the initial CO2 capture rate to match CO2 needs, and the amount of CO2 captured can be scaled up quickly with additional compression and storage capacity. The scalability and ability to start small and grow quickly will help reduce the initial upfront costs and allow for future growth.

The use of onsite storage and trucks for transportation eliminates the need to build an expensive pipeline infrastructure. The initial contracts for CO2 purchase could be sized and structured to allow for the needs of a small or large start-up commercial operation.

In an initial startup both parties to the commercial operation will have risks that must be mitigated and/or accounted for during the negotiating process. The ethanol producer will need to spend money to install compression and storage facilities and is at risk if the purchaser of the CO2 defaults during the contracted period. Likewise, the CBM or Shale gas operator will be spending money to prepare wells for CO2 stimulation and will be at risk if the ethanol plant is unable to supply CO2. Both parties are subject to various market risks, which could cause either operation to fail.

Ethanol production is highly dependent on the availability and pricing of corn as well as the ability to sell the resulting ethanol for fuel blending. If one or more market factors change the ethanol plant may not be a profitable enterprise and may cease to operate. Severe drought could cause a reduction in availability in corn or there could be legislative changes that decrease the demand for ethanol blending in gasoline. In this situation, the CBM or Shale gas operator may lose access to CO2 if plant operations are stopped or reduced and may not be able to locate an alternative source of CO2.

CBM and Shale gas production is dependent on the price of natural gas and if prices for natural gas become too low well stimulation may prove uneconomical. In this situation, the CBM or Shale operator may stop well stimulation and their future need for CO2 would be zero. The ethanol plant would need to find a new purchaser for the CO2 but may not be able to find a replacement purchaser.

Contractual arrangements between the two parties will need to contemplate a wide range of possible business interruptions and remedies prior to beginning any commercial operations.

CO_2 From Regional Natural Gas Processing

Within Southern, Central, and Northern Appalachia there are several Natural Gas Processing (NGP) facilities that could be initial sources of CO2 for commercial ECBM or ESGR operations. The use of NGP as a point source for CO2 would provide significant cost reductions in the purchase price of CO2 ($17 vs. $89/ton delivered in current CBM study). Figures 25-23 and 25-24 below identify NGP facilities in Central and Northern Appalachia as well as some specific areas of interest for additional research.

Figure 25-23 NGP Facilities in Northern Appalachia in Relation to CBM / CMM Fields

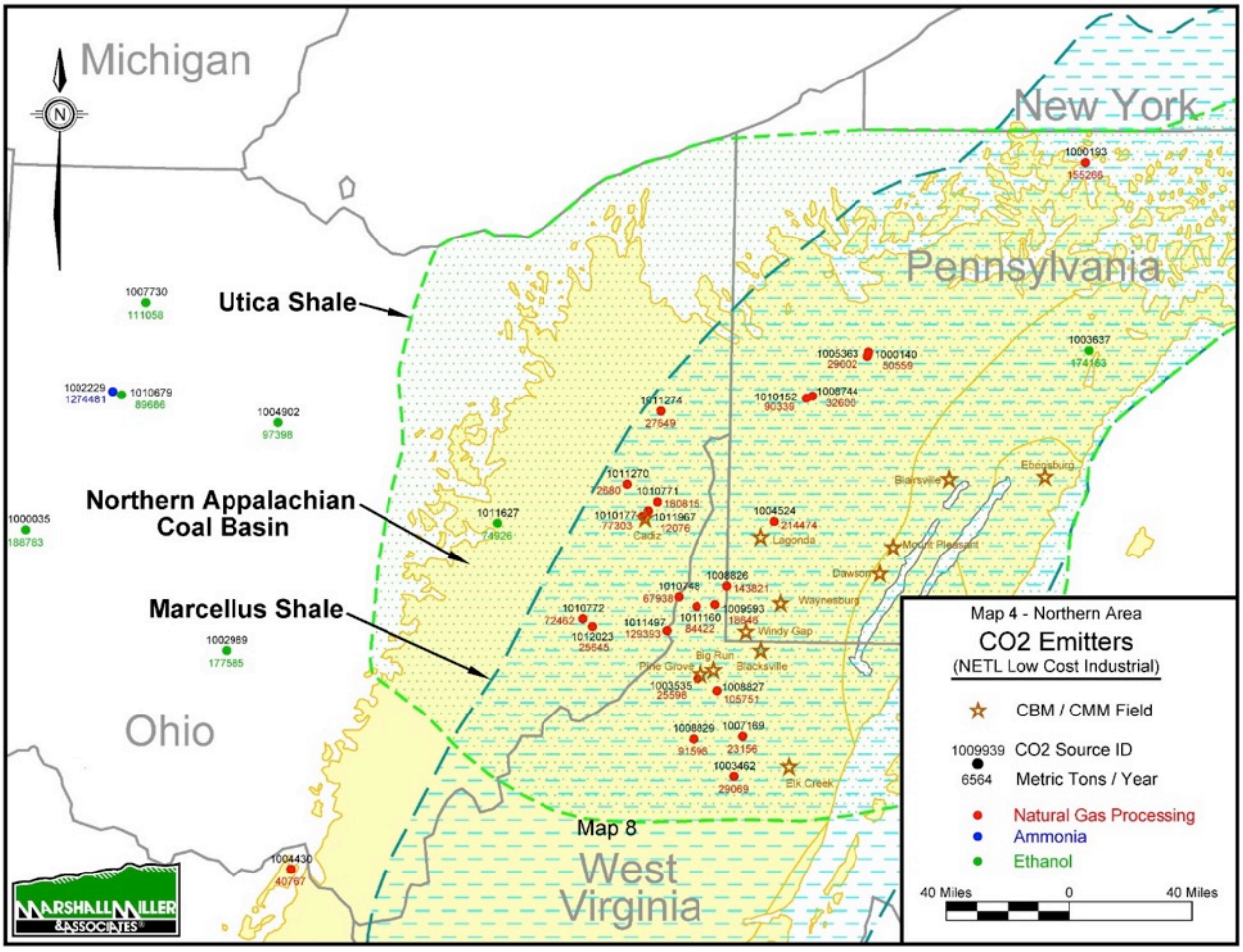
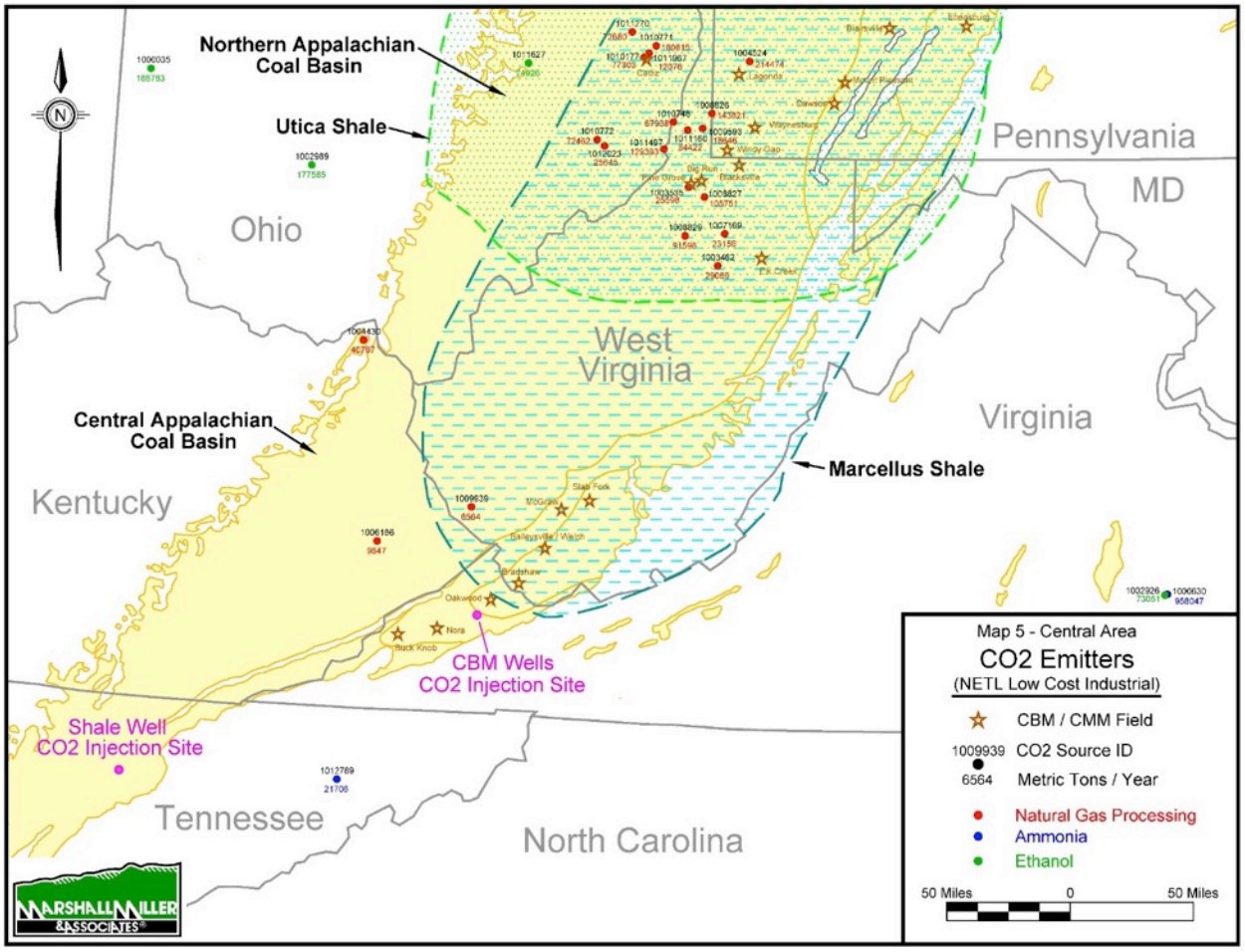


Figure 25-24 NGP Facilities in Central Appalachia in Relation to CBM / CMM Fields



Using NGP facilities to source CO2 for use in ECBM and ESGR well stimulation provides several benefits that could allow commercial operation to ramp up over time. The CO2 must be removed from the gas prior to sale, so additional capital to prepare the CO2 for use in CBM or Shale fields is limited to compression and some water removal. Captured CO2 could be stored on site and serve as a centralized source of CO2 for nearby wells. This centralized storage facility could be serviced by 20-ton semi-trucks. The trucks could transport CO2 captured at the NGP facility to nearby wells based on the schedule and needs of the individual operators. This flexibility will be necessary as initial commercialization efforts may be small and widely distributed geographically. Many NGP facilities have smaller CO2 emissions but the smaller size may complement smaller initial commercialization investments and could be scaled up though additional storage or inclusion of multiple NGP facilities to meet larger regional demand as CO2 well stimulation commercialization efforts continue in Appalachia.

This model allows the NGP facility to set the initial CO2 capture and storage needs to match the initial volume of CO2 needed for the field operator. The amount of CO2 captured and stored can be scaled up

quickly with the addition of more compression and storage capacity. The scalability and ability to start small and grow quickly will help reduce the initial upfront costs but not hamper future growth.

The use of onsite storage and trucks for transportation eliminates the need to build an expensive pipeline infrastructure. The NGP facilities tend to be located close to the CBM and Shale fields and this proximity will help to further reduce transportation costs. The initial contracts for CO2 purchase could be sized and structured to allow for the individual needs of a small or large start-up commercial operation.

In an initial startup commercial operation both parties will have risks that must be mitigated and/or accounted for during the negotiating process. The NGP facility will need to spend money to install compression and storage facilities and is at risk if the purchaser of the CO2 defaults during the contracted period to supply CO2. Likewise, the CBM or Shale gas operator will be spending money to prepare the wells for CO2 stimulation and will be at risk if the NGP plant is unable to supply CO2. Both parties are subject to various market risks, which may cause either operation to fail.

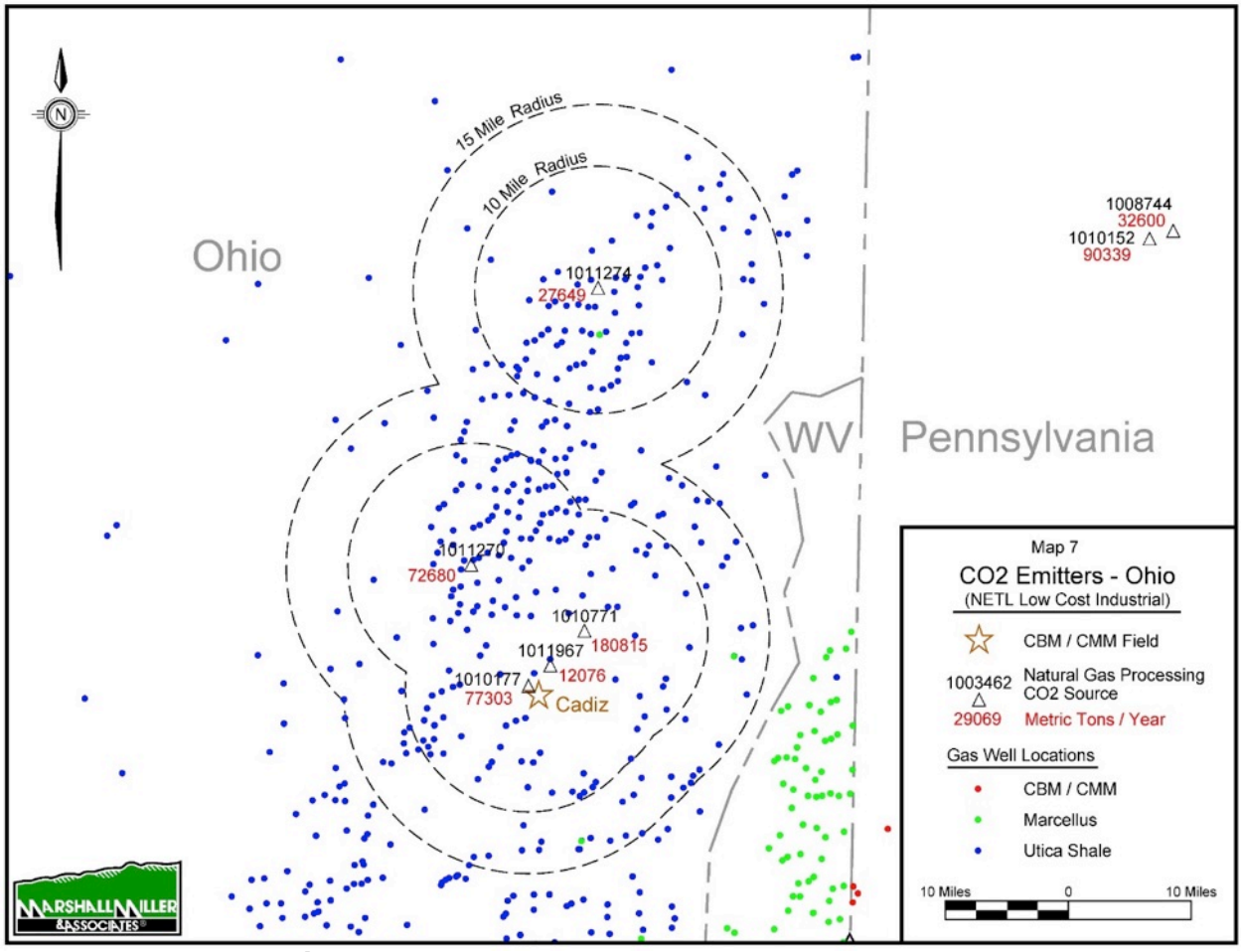
Both NGP and CBM and Shale Gas are dependent on the market price of natural gas. ECBM and ESGR will have a slightly higher cost structure when compared to a traditional natural gas well as the ECBM and ESGR have the added cost of purchased CO2. This will make ECBM and ESGR less profitable relative to traditional natural gas. During an extended period of declining prices, it is possible that future ECBM and ESGR well stimulation would stop, given the higher cost structure to produce ECBM and ESGR. If ECBM and ESGR stimulation ceases, the NGP facility will not have a buyer for the captured CO2.

Contractual arrangements between the two parties will need to contemplate a wide range of possible business interruptions and remedies prior to beginning any commercial operations.

In some instances, the location of the gas processing plant may be in an area that has existing wells that could be stimulated with CO2 or the operator of the NGP plant also has CBM or shale wells nearby that are amenable to CO2 stimulation. In this case, many of the contractual concerns will not be applicable because the operator of the NGP plant and the wells will be the same.

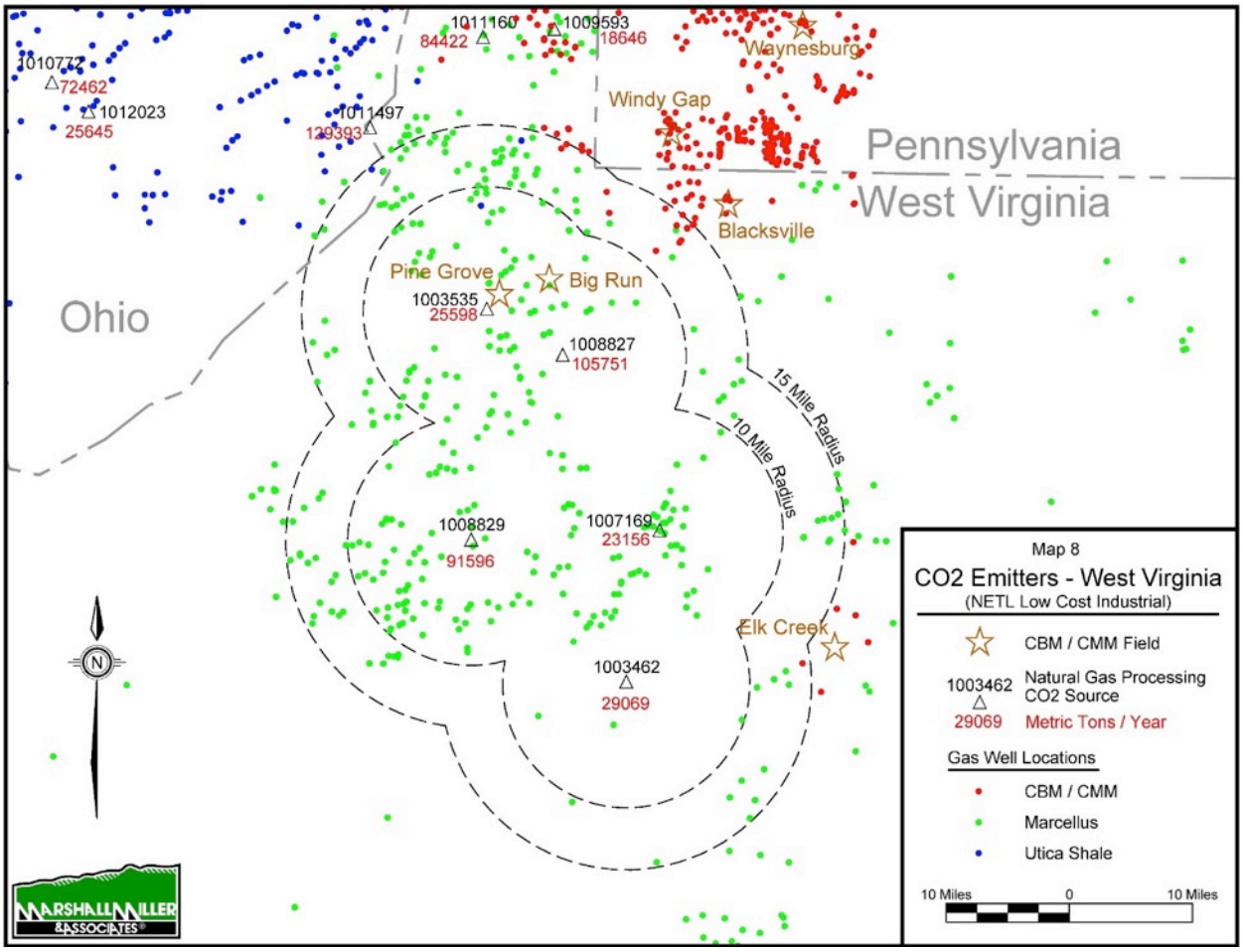
Potential locations for sub-regional pilot projects exist and will require research in order to match CO2 sources with users. The initial pilot projects could be expanded into a commercial operations using CO2 sourced from several surrounding NGP facilities. Multiple opportunities exist, as is highlighted in Figures 25-25 and 25-26.

Figure 25-25 Northern Appalachia area of focus in Eastern Ohio



As seen on Figure 25-25 above, a total of 775 shale wells are located within 10 miles of an NGP facility. The total number increases to 1,067 wells within a 15-mile radius from the highlighted NGP sources. In this preliminary report the total count for CBM / CMM (coal mine methane) wells has not been included, as some of the identified wells, including CMM, are not likely candidates for CO2 injection. Further research is required to support commercialization assessments.

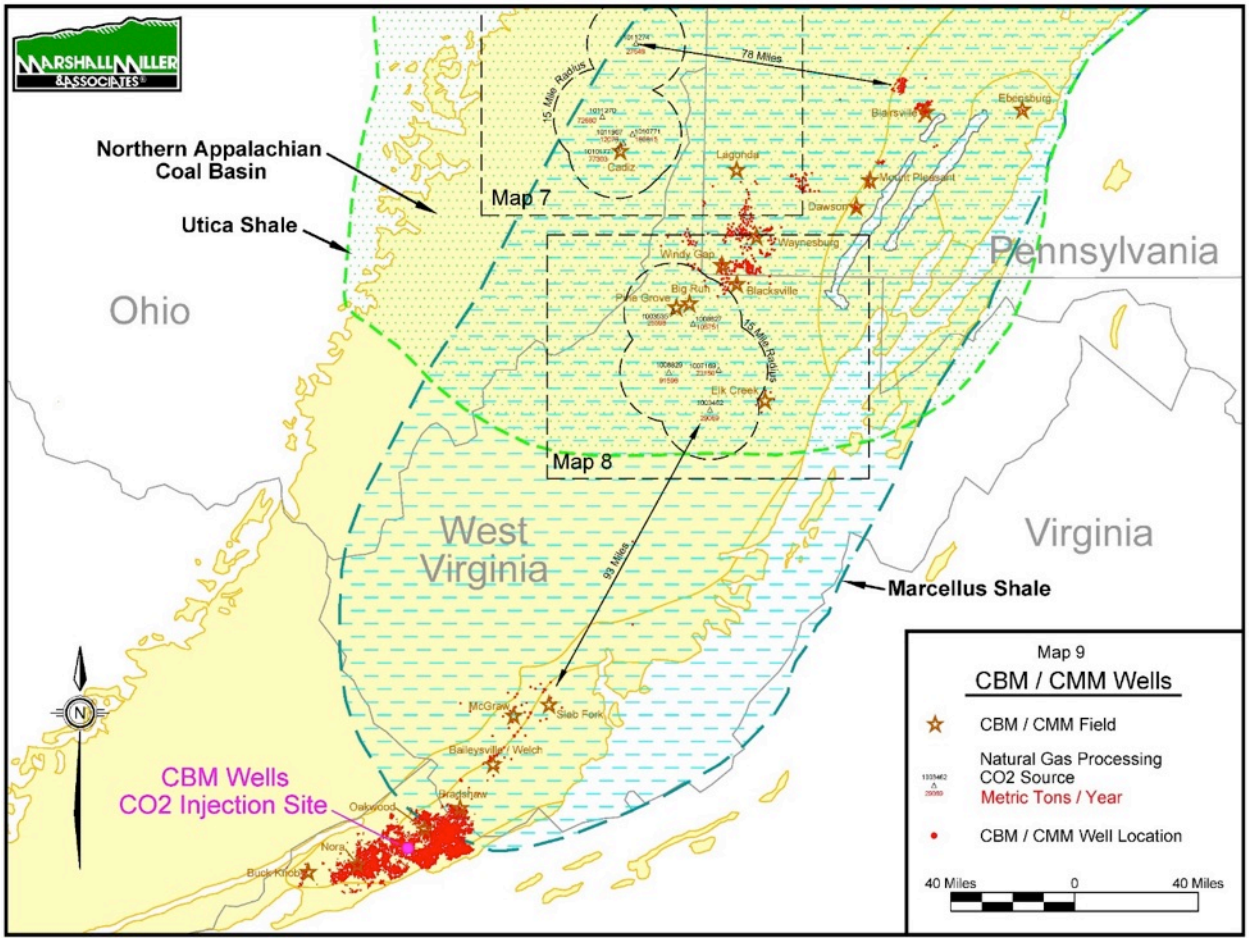
Figure 25-26 Northern Appalachia area of focus in West Virginia



As seen on Figure 25-26 above, a total of 903 shale wells are located within 10 miles of an NGP facility. The total number increases to 1,326 wells within a 15-mile radius from the highlighted NGP sources. Total count for CBM / CMM wells has not been included, as some of the identified wells would be less likely candidates for CO2 injection.

Figure 25-27 identifies the distances to some additional CBM / CMM fields that could be serviced from the proposed NGP facilities.

Figure 25-27 Locations of CBM / CMM Fields in Northern and Central Appalachians



These two areas provide very compelling characteristics that could provide a good opportunity for pilot projects on ECBM and ESGR. Both areas have large numbers of wells in close proximity to multiple NGP facilities. These NGP facilities could serve as a source of CO2 for a scalable pilot project. Dedicated local sources of CO2 could demonstrate ways to reduce the cost of CO2 and increase the reliability of the CO2 flow to the project.

25.6 Roadmap Implementation

A next step project is to develop a roadmap to identify and implement a public-private stakeholder engagement plan that is focused on addressing research gaps discussed in Objective 2 that are limiting the commercial adoption of enhanced coal bed methane (ECBM) recovery and/or enhanced shale gas recovery (ESGR) technology. This proposed roadmap will be a two-phased project. Phase I will focus on stakeholder engagement, knowledge sharing and capacity building to identify one or more locations

suitable for a ECBM recovery and/or ESGR field demonstration project. Phase II will be a larger scale CBM or shale gas well stimulation focused on gathering data to address the research gaps identified in Objective 2. Reducing existing information gaps is a key step to getting closer to the commercial scale adoption of ECBM/ESGR well stimulation.

An important component of the proposed roadmap will be the integration of real time production data collected from the current Buchanan County, VA CBM study throughout 2018 and 2019. Production data will not begin on the existing wells until 2018 but will be available to inform the stakeholder group as it works through Phase I and will be a key component of the final decision to move forward with Phase II.

25.6.1 Commercialization Pathway – ECBM/ESGR Phase I (Budget Year 1)

Element #1.

Establish stakeholder and advocacy "Commercial ECBM/ESGR Working Groups" across the public-private sectors, with participants from Southern, Central and Northern Appalachia. The Working Groups will include Federal and State partners, industry representatives, as well as subject matter experts and NGOs. The VCCER project team will:

Tasks

a. Develop a list of subject matter experts, industry experts, and state and federal participants for an initial stakeholder meeting.
b. Pre-brief a few stakeholders that we expect to be strong advocates for ECBM/ESGR and have them ready to support ECBM/ESGR during the initial stakeholder meeting.
c. Work with DOE, industry and academia to identify areas of interest within Southern, Central and Northern Appalachia.
d. Develop a framework to identify and evaluate possible locations for the Phase II studies.

Element #2.

Data collection and interpretation throughout Phase I will be critical to the working groups as they move towards possible Phase II field site locations. The VCCER project team will:

Tasks

a. Monitor and collect data at the three existing CBM wells in Buchanan County, VA.
b. Update working groups on production data, CO2 retention, and any other relevant news or studies on ECBM/ESGR.

Element #3.

Development of technical information in support of location recommendations that can be passed along to decision makers. The focus will be on technical support for potential Federal, State, and local policy makers, as well as informational outreach strategies to potential financial supporters. The VCCER project team will:

Tasks

a. Collaborate with DOE, academia, CBM and Shale gas operators, land owners, and other subject matter experts, to identify industry-wide categories of CO_2 emission sources (vents) and respective categories of CO_2 capture/treatment technologies that could be applied to the CO_2 vent categories.

b. Work with DOE and subject matter experts to perform an initial cost analysis for CO_2 capture from representative facilities in or near Appalachia.

c. Coordinate with DOE and subject matter experts to review and assemble existing information of market factors related to the use of CO_2 for ECBM/ESGR.

d. Prepare preliminary reports, power point presentations, financial analysis and other materials that can support the development of a commercial ECBM/ESGR project with associated CO_2 storage.

Element #4.

Identify sub-regional sources of CO_2 and ECBM/ESGR locations for larger-scale well stimulation pilot projects. The VCCER project team will:

Tasks

a. Review production data from Buchanan County, VA CBM test to determine CO_2 retention and the increase in methane production due to CO_2 stimulation.

b. Estimate additional future methane production based on pre-stimulation production decline curves and post stimulation production decline curves.

c. Identify potential ECBM/ESGR sites for larger-scale well stimulation.

d. Identify potential sources of CO_2 for proposed field test sites.

e. Provide final recommendation for Phase II large-scale ECBM/ESGR CO_2 well stimulation – Go/No Go decision point for Phase II.

25.6.2 Commercialization Pathway - ECBM/ESGR Phase II (Budget Years 2-??)

Element #1.

TRL 2-5 Site Characterization and Design of wells and CO_2 infrastructure for regional CO_2 capture for larger-scale well stimulation and CO_2 storage demonstration projects. The VCCER project team will:

Tasks

a. Complete Site characterization to include drilling characterization wells, analysis of core samples, modeling and establishing base lines for monitoring.
b. Design CO_2 injection, delivery and storage facilities.
c. Finalize CO_2 sourcing contracts and construction of pilot capture system.
d. Design and locate monitoring wells and geophysical wells.
e. Acquire all necessary well permits.

Element #2.

Site Preparation and Monitoring. The VCCER project team will:

Tasks

a. Convert existing production wells to allow for CO_2 stimulation, drilling monitoring wells and the installation of any additional monitoring stations.
b. Inject CO_2 in converted wells.
c. Monitor atmosphere, surface, reservoir and ground water to document and assess long-term storage of CO_2.

Element #3.

Post-stimulation Assessment. The VCCER project team will:

Tasks

a. Convert injection wells to production wells and monitoring wells.
b. Restore site to original.
c. Analyze and interpret data.
d. Continue post-injection monitoring to document and assess long-term storage of CO_2.
e. Model reservoir.

Element #4.

TRL 6-9 Commercial readiness assessment for CO_2 capture and ECBM/ESGR well stimulation. The VCCER project team will:

Tasks

a. Conduct commercialization assessment of pilot project scaling for CO2 capture with ECBM/ESGR well stimulation and associated CO_2 storage.

b. Identify and discuss lessons learned for CO_2 capture and ECBM/ESGR well stimulation and CO_2 retention.