DOE F 4600.2
(5/09)
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ATTACHMENT 3
U.S. Department of Energy
FEDERAL ASSISTANCE REPORTING CHECKLIST AND INSTRUCTIONS

1. Identification Number:	2. Program/Project Title:
DE-FE0002056	**Modeling CO2 Sequestration in Saline Aquifer and Depleted Oil Reservoir to Evaluate Regional CO2 Sequestration Potential of Ozark Plateau Aquifer System, South-Central Kansas**
3. Recipient: University of Kansas Center for Research	

4. Reporting Requirements:		Frequency	No. of Copies	Addresses
A. MANAGEMENT REPORTING				
☒ Progress Report		Q	Electronic Version to NETL>	FITS@NETL.DOE.GOV
☒ Special Status Report		A		
B. SCIENTIFIC/TECHNICAL REPORTING * (Reports/Products must be submitted with appropriate DOE F 241. The 241 forms are available at https://www.osti.gov/elink)				
Report/Product	Form			
☒ Final Scientific/Technical Report	DOE F 241.3	FG	Electronic Version to E-link>	http://www.osti.gov/elink-2413
☒ Conference papers/proceedings/etc.*	DOE F 241.3	A		http://www.osti.gov/elink-2413
☐ Software/Manual	DOE F 241.4			http://www.osti.gov/estsc/241-4pre.jsp
☒ Other (see special instructions)				
Topical	DOE F 241.3	A		
** Scientific/technical conferences only*				
C. FINANCIAL REPORTING				
☒ SF-425, Federal Financial Report		Q, FG	Electronic Version To NETL>	FITS@NETL.DOE.GOV
D. CLOSEOUT REPORTING				
☐ Patent Certification		FC	Electronic Version To NETL>	FITS@NETL.DOE.GOV
☐ Property Certificate		FC		
☐ Other				
E. OTHER REPORTING				
☒ Annual Indirect Cost Proposal		A	Electronic Version To NETL>	FITS@NETL.DOE.GOV
☒ Annual Inventory Report of Federally Owned Property, if any		A		
☐ Other				
F. AMERICAN RECOVERY AND REINVESTMENT ACT REPORTING				
☐ Reporting and Registration Requirements				http://www.federalreporting.gov

FREQUENCY CODES AND DUE DATES:

A - As required; see attached text for applicability.
FG - Final; within ninety (90) calendar days after the project period ends.
FC - Final - End of Effort.
Q - Quarterly; within thirty (30) calendar days after end of the calendar quarter or portion thereof.
S - Semiannually; within thirty (30) calendar days after end of project year and project half-year.
YF - Yearly; 90 calendar days after the end of project year.
YP - Yearly Property - due 15 days after period ending 9/30.

QUARTERY PROGRESS REPORT

Award Number: DE-FE0002056

Recipient: University of Kansas Center for Research &
Kansas Geological Survey
1930 Constant Avenue
Lawrence, KS 66047

"Modeling CO2 Sequestration in Saline Aquifer and Depleted Oil Reservoir To Evaluate Regional CO2 Sequestration Potential of Ozark Plateau Aquifer System, South-Central Kansas"

Project Director/Principal Investigator: W. Lynn Watney
Principal Investigator: Jason Rush

Thirteenth Quarter Progress Report

Date of Report: 1-30-13

Period Covered by the Report: October 1, 2012 through December 31, 2012

Contributors to this Report: Robin Barker, Saugata Datta, John Doveton, Martin Dubois, Mina Fazelalavi, David Fowle, Paul Gerlach, Tom Hansen, Dennis Hedke, Eugene Holubnayak, Christa Jackson, Randi Lee, Larry Nicholson, Derek Ohl, Abdelmoneam Raef, Jennifer Raney, Jennifer Roberts, Jason Rush, Ayrat Sirazhiev, George Tsoflias, Ray Sorenson, John Victorine, Lynn Watney, John Youle, Dana Wreath

EXECUTIVE SUMMARY

The project "Modeling CO2 Sequestration in Saline Aquifer and Depleted Oil Reservoir to Evaluate Regional CO2 Sequestration Potential of Ozark Plateau Aquifer System, South-Central Kansas" is focused on the Paleozoic-age Ozark Plateau Aquifer System (OPAS) in southern Kansas. OPAS is comprised of the thick and deeply buried Arbuckle Group saline aquifer and the overlying Mississippian carbonates that contain large oil and gas reservoirs. The study is collaboration between the KGS, Geology Departments at Kansas State University and The University of Kansas, BEREXCO, INC., Bittersweet Energy, Inc. Hedke-Saenger Geoscience, Ltd., Improved Hydrocarbon Recovery (IHR), Anadarko, Cimarex, Merit Energy, GloriOil, and Cisco.

The project has three areas of focus, 1) a field-scale study at Wellington Field, Sumner County, Kansas, 2) 25,000 square mile regional study of a 33-county area in southern Kansas, and 3) selection and modeling of a depleting oil field in the Chester/Morrow sandstone play in southwest Kansas to evaluate feasibility for CO2-EOR and sequestration capacity in the underlying Arbuckle saline aquifer. Activities at Wellington Field are carried out through BEREXCO, a subcontractor on the project who is assisting in acquiring seismic, geologic, and engineering data for analysis. Evaluation of Wellington Field will assess miscible CO2-EOR potential in the Mississippian tripolitic chert reservoir and CO2 sequestration potential in the underlying Arbuckle Group saline aquifer. Activities in the regional study are carried out through Bittersweet Energy. They are characterizing the Arbuckle Group (saline) aquifer in southern Kansas to estimate regional CO2 sequestration capacity. Supplemental funding has expanded the project area to all of southwest Kansas referred to as the Western Annex. IHR is managing the Chester/Morrow play for CO2-EOR in the western Annex while Bittersweet will use new core and log data from basement test and over 200 mi2 of donated 3D seismic. IHR is managing the industrial partnership including Anadarko Petroleum Corporation, Cimarex Energy Company, Cisco Energy LLC, Glori Oil Ltd., and Merit Energy Company. Project is also supported by Sunflower Electric Power Corporation.

PROJECT STATUS

Task Name	Planned Start Date	Actual Start Date	Planned Finish Date	Actual Finish Date	% Complete
1.0 Project Management & Planning	12/8/2009	12/08/09	12/7/2012		55%
2.0 Characterize the OPAS (Ozark Plateau Aquifer System)	1/1/2010	01/01/10	6/30/2012		70%
3.0 Initial geomodel of Mississippian Chat & Arbuckle Group - Wellington field	1/1/2010	01/01/10	9/30/2010	09/30/10	100%
4.0 Preparation, Drilling, Data Collection, and Analysis - Well #1	9/15/2010	12/15/10	3/31/2011	08/30/11	100%
5.0 Preparation, Drilling, Data Collection and Analysis - Well #2	1/1/2011	02/20/11	6/30/2011	08/30/11	100%
6.0 Update Geomodels	5/1/2011	05/01/11	9/30/2011	10/31/12	100%
7.0 Evaluate CO2 Sequestration Potential in Arbuckle Group Saline Aquifer	8/1/2011	08/01/11	12/31/2011	10/31/12	100%
8.0 Evaluate CO2 Sequestration Potential in Depleted Wellington field	10/15/2011	10/15/11	3/31/2012	+++	85%
9.0 Characterize leakage pathways - risk assessment area	1/1/2010	01/01/10	6/30/2012	10/31/12	100%
10.0 Risk Assessment related to CO2-EOR and CO2 Sequestration in saline aquifer	6/1/2012	06/01/12	9/30/2012	**	80%
11.0 Produced water and wellbore management plans - Risk assessment area	1/1/2012	01/01/12	10/31/2012		90%
12.0 Regional CO2 sequestration potential in OPAS	8/1/2012		12/7/2012		70%
13.0 Regional source sink relationship	1/1/2010	1/1//2010	12/7/2012		70%
14.0 Technology Transfer	1/1/2010	01/01/10	12/7/2012		75%

Milestone	Planned Completion Date	Actual Completion Date	Validation
HQ Milestone: Kick-off Meeting Held	3/31/2010	03/31/10	Completed
HQ Milestone: Begin collection of formation information from geologic surveys and private vendors	6/30/2010	01/01/10	Completed
HQ Milestone: Semi-Annual Progress Report on data availability and field contractors	9/30/2010	07/30/10	Submitted to Project manager
HQ Milestone: Establish database links to NATCARB and Regional Partnerships	12/31/2010	12/31/10	Completed
HQ Milestone: Annual Review Meeting attended	3/31/2011	10/05/10	Completed
HQ Milestone: Complete major field activities, such as drilling or seismic surveys at several characterization sites	6/30/2011	Note: This milestone was met collectively by all projects. No one project was held accountable to the milestone.	Completed
HQ Milestone: Semi-Annual Progress Report (i.e. Quarterly Report ending June 30, 2011)	9/30/2011	09/30/11	Completed
HQ Milestone: Yearly Review Meeting of all recipients; opportunities for information exchange and collaboration	12/31/2011	11/15/11	Attended meeting
HQ Milestone: Complete at least one major field activity such as well drilling, 2-D or 3-D seismic survey, or well logging	3/31/2012	08/15/12	Completed 3D seismic Cutter competed
HQ Milestone: Complete at least one major field activity such as well drilling, 2-D or 3-D seismic survey, or well logging	6/30/2012	10/09/12	Completed cutter well reach TD
HQ Milestone: Semi-annual report (i.e. Quarterly Report ending June 30, 2012) on project activities summarizing major milestones and costs for the project 9/30/2012	9/30/2012	09/30/12	Completed
FOA Milestone: Updated Project Management Plan	3/31/2010	03/31/10	
FOA Milestone: Submit Site Characterization Plan	5/28/2010		Completed
FOA Milestone: Notification to Project Manager that reservoir data collection has been initiated	9/15/2010	01/01/10	Completed
FOA Milestone: Notification to Project Manager that subcontractors have been identified for drilling/field service operations	7/30/2010	01/01/10	Completed
FOA Milestone: Notification to Project Manager that field service operations have begun at the project site	7/1/2010	01/01/10	Completed
FOA Milestone: Notification to Project Manager that characterization wells have been drilled	6/3/2011	03/09/11	Completed
FOA Milestone: Notification to Project Manager that well logging has been completed	6/3/2011	03/09/11	Completed
FOA Milestone: Notification to Project Manager that actvities on the lessons learned document on site characterization have been initiated	7/15/2012		Completed
FOA Milestone: Notification to Project Manager that activities to populate database with geologic characterization data has begun	12/31/2010	12/31/10	Completed, email summary
KGS Milestone 1.1: Hire geology consultants for OPAS modeling	3/31/2010	03/31/10	92% Completed*
KGS Milestone 1.2: Acquire/analyze seismic, geologic and engineering data - Wellington field	6/30/2010	06/30/10	Completed, quarterly rpt
KGS Milestone 1.3: Develop initial geomodel for Wellington field	9/30/2010	09/30/10	Completed, email summary
KGS Milestone 1.4: Locate and initiate drilling of Well #1 at Wellington field	12/31/2010	12/25/10	Completed, email summary
KGS Milestone 2.1: Complete Well#1 at Wellington - DST, core, log, case, perforate, test zones	3/31/2011	08/30/11	Completed, email summary
KGS Milestone 2.2: Complete Well#2 at Wellington - Drill, DST, log, case, perforate, test zones	6/30/2011	08/30/11	Completed, email summary
KGS Milestone 2.3: Update Wellington geomodels - Arbuckle & Mississippian	9/30/2011	10/31/12	completed
KGS Milestone 2.4: Evaluate CO2 Sequestration Potential of Arbuckle Group Saline Aquifer - Wellington field	12/31/2011	10/31/12	Completed
KGS Milestone 3.1: CO2 sequestration & EOR potential - Wellington field	3/31/2012		85% complete'++
KGS Milestone 3.2: Characterize leakage pathways - Risk assessment area	6/30/2012	10/31/12	Completed
KGS Milestone 3.3: Risk assessment related to CO2-EOR and CO2-sequestration	9/30/2012		90% complete++++
KGS Milestone 3.4: Regional CO2 Sequestration Potential in OPAS - 17 Counties	12/7/2012		70% complete

SUBTASKS COMPLETED WITHIN THE CURRENT QUARTER

Task 7. Evaluation of sequestration potential in Arbuckle Group saline aquifer at [Wellington Field] through refined geomodel and employing initial simulations of small and larger scale CO2 injection.

Static and dynamic modeling has been completed for the Arbuckle at Wellington Field for use in the Class VI injection application to establish maximum plume extent, plume stabilization time, maximum pressure response, maximum pressure boundary extent, and CO2 trapping. Additional modeling will continue, but a baseline case has been developed that is believed will provide predictable results. Updates to the modeling will be provided to stakeholders as they become available.

Static model of the Arbuckle saline aquifer at Wellington Field

Petrel geo-model is used for input of porosity and permeability in a geocellular framework using well data that is conditioned with the 3D seismic volume. The general model input to the static model is provided in **Figure 1**.

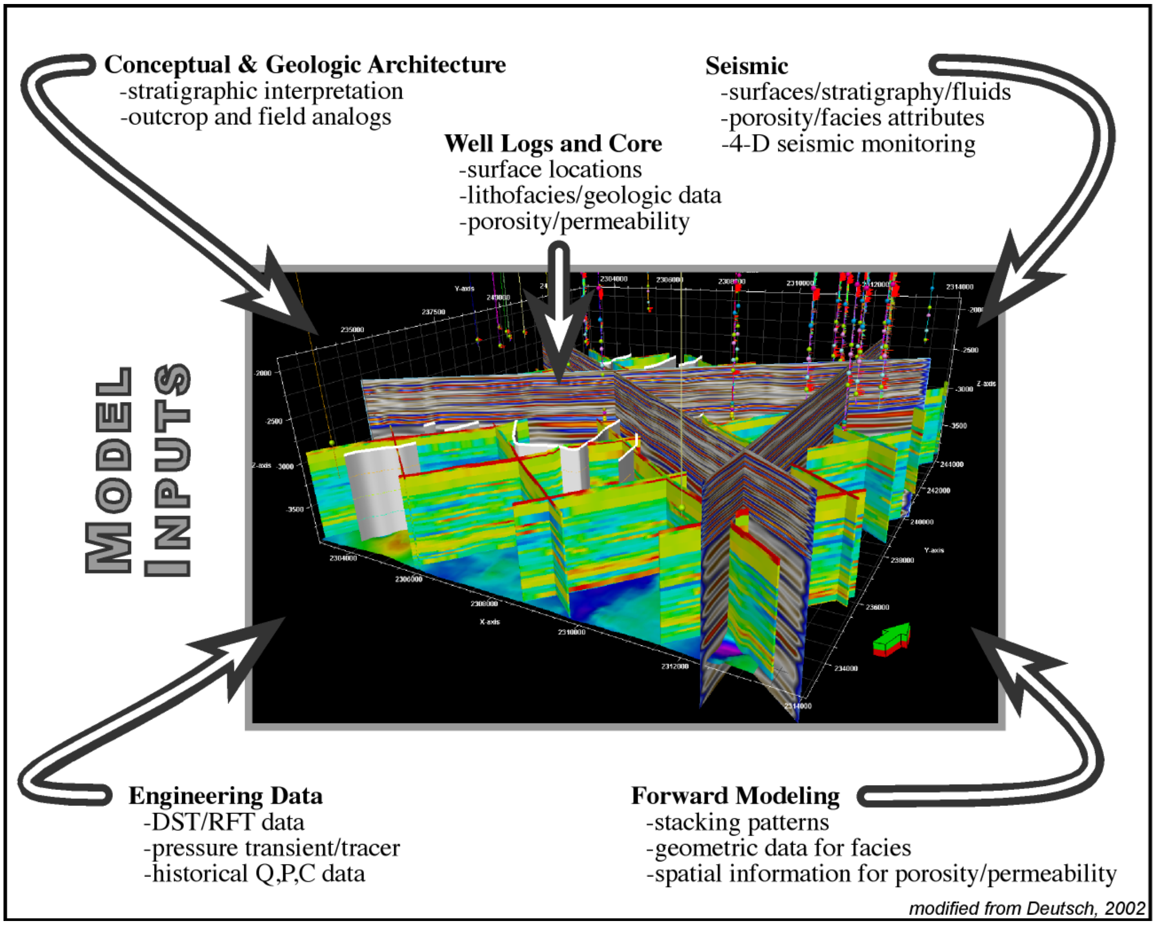


Figure 1. Typical model inputs used in developing a static geo-model of a reservoir.

The porosity model is derived from a genetic inversion from the PSDM seismic volume that is then conditioned to porosity logs Figure 2. Neural network processing was used to perform the inversion.

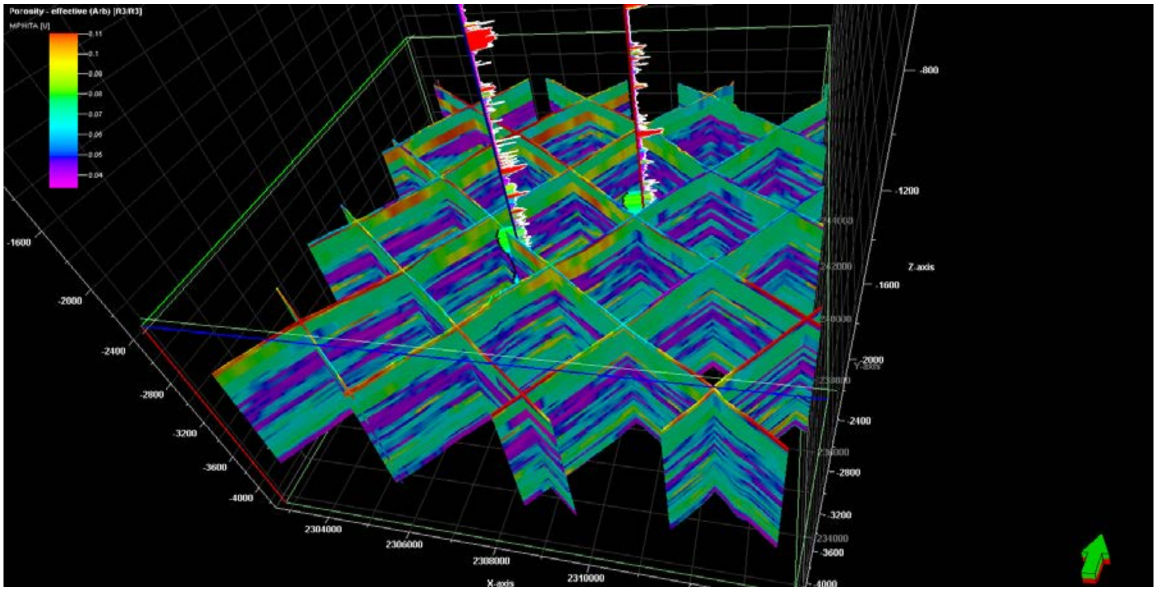


Figure 2. Geo-model of porosity in the Arbuckle saline aquifer at Wellington Field in the vicinity of the Wellington KGS #1-32 (left) and #1-28 (right) as noted above.

The permeability model used is a standard petroleum industry distribution derived from upscaled logs ranging from 0.13 to 242 mD (**Figure 3**). The permeability was co-located and co-Kriged to the porosity model.

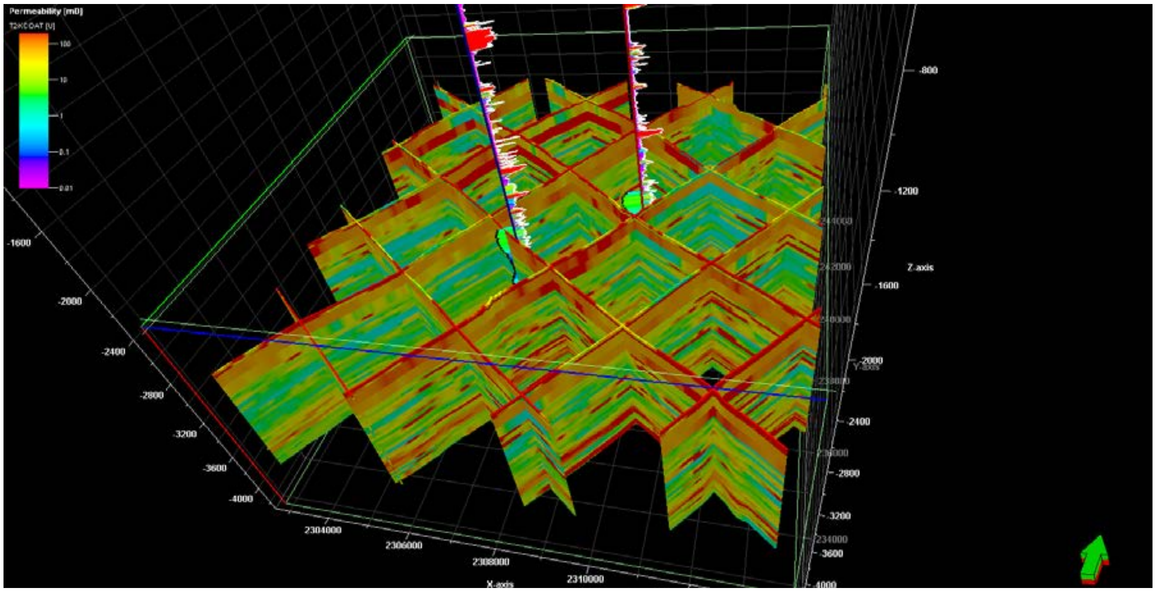


Figure 3. Geo-model of permeability in the Arbuckle saline aquifer in Wellington Field in the vicinity of the Wellington KGS #1-32 (left) and #1-28 (right) as noted above. Permeability is in excess of 100 mD in red areas while permeability in blue colored areas is under 1 mD.

Uncertainty is accounted for in the static model. There are inconsistencies (factor of 5 to 10) between permeability measurements derived from wireline logs, whole core, and step-rate tests. Three permeability models were created:

Low Perm – base case permeability model
Mid Perm – base case multiplied by factor of 5
High Perm – base case multiplied by factor of 10

To investigate the effect of porosity on the plume extent, three porosity models were developed:

Low Porosity – base case multiplied by factor of 0.8
Mid Porosity – base case porosity model
High Porosity – base case multiplied by factor of 1.2

A total of 9 static models were created for use in dynamic simulations.

Simulation of the CO2 injection into the Arbuckle saline aquifer at Wellington Field

The simulation injected 40,000 tonnes of CO2 into Lower Arbuckle. The model used open boundaries (Carter-Tracy aquifer with no-leakage). Only matrix porosity and permeability were used with multipliers applied to estimate effects of fractures. Later simulation will use a dual-porosity model after a discrete fracture network is developed for the Arbuckle. Two scenarios were run that include the mid Arbuckle is an impermeable boundary and another where it has low permeability as measured from core and well logs. The permeability multipliers are used to define best and worst case outcomes. CO2 solubility in water is included in calculations, but other reactions with rock and brine has yet to be modeled so as to include in the simulations as reaction kinetics.

Temperature	**60 °C**
Temperature Gradient	0.008 °C/ft
Pressure	2093 psi
Pressure Gradient	0.42 psi/ft
Perforation Zone	4763 – 5110 ft
Perforation Length	300 ft
Injection Period	9 months
Injection Rate	2.65x10^6 ft^3/day
Total CO2 injected	40,000 mt

A results table of the modeling scenarios with 40,000 tonnes of CO2 injected using the above porosity and permeability are summarized in **Figure 4**. The maximum extent of the plume ranges from 1598 ft to 2484 ft. The maximum bottom-hole pressure ranges from 2124 psi to 2269 psi. The maximum differential bottom-hole pressure (BHP) ranges from 31 psi to 176 psi.

Modeling Case	CO2 Maximum Diameter of Aerial Extent	Maximum Bottom-Hole Pressure, psi	Max Delta Bottom-Hole Pressure, psi
Low Permeability, Low Porosity	2008 ft., 612 m	2269	176
Medium Permeability, Low Porosity	2208 ft., 673 m	2199	106
High Permeability, Low Porosity	2484 ft., 757 m	2128	35
Low Permeability, Medium Porosity	1824 ft., 556 m	2266	173
Medium Permeability, Medium Porosity	2133 ft., 650 m	2194	101
High Permeability, Medium Porosity	2372 ft., 743 m	2126	33
Low Permeability, High Porosity	1598 ft., 487 m	2264	171
Medium Permeability, High Porosity	2096 ft., 639 m	2189	96
High Permeability, High Porosity	2034 ft., 620 m	2124	31

Figure 4. Results table for modeling scenarios.

The BHP is at the maximum after 3 months of injection (**Figure 5**). There is a slow decrease in BHP after the 3rd month to the 9th month. An abrupt pressure drop occurs to near the initial BHP conditions after the well is shut-in. The BHP and reservoir pressure is controlled by the permeability. The highest pressure pulse is observed in the Low Permeability case and the lowest pressure pulse is the High Permeability case. The pressure pulse is below that allowed by the EPA guidelines.

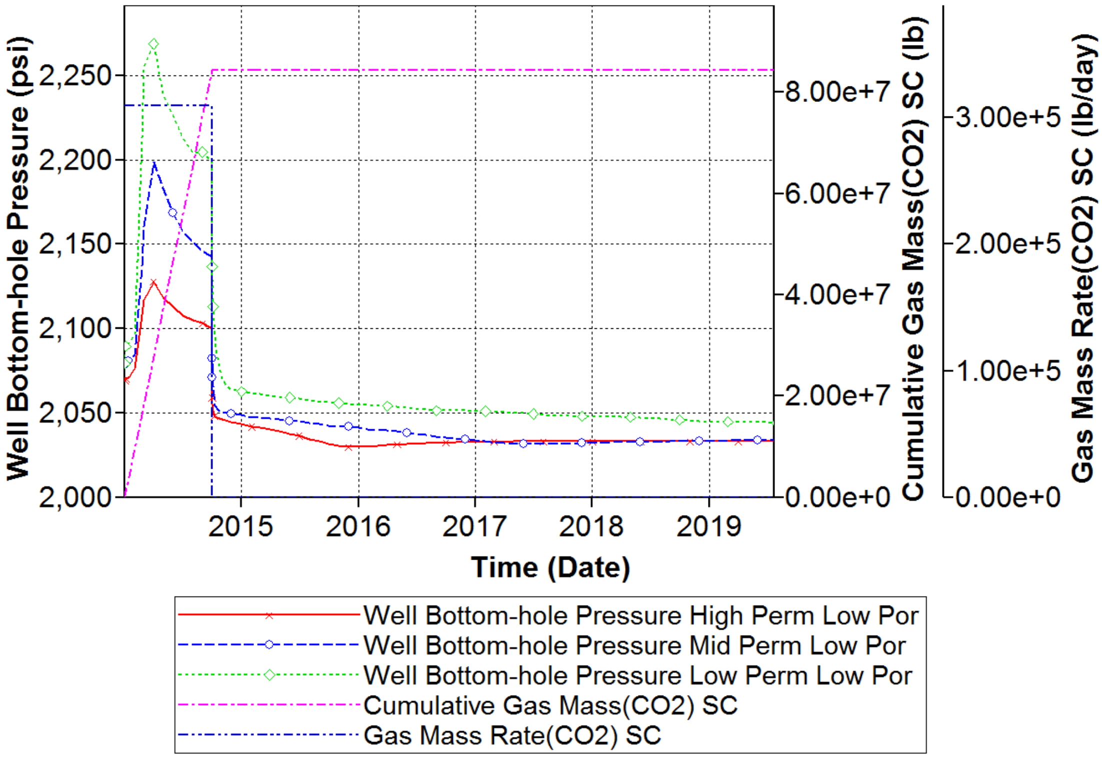


Figure 5. Plot of the bottom-hole pressure vs. cumulative gas (CO2) rate vs. gas (CO2) mass rate for 3 different scenarios.

As mentioned above, the maximum extent of the plume ranges from 1598 ft to 2484 ft, the maximum extent associated with the Low Permeability-Low Porosity case. An aerial view of the pressure boundary for the worst case scenario is shown in **Figure 6**. Pressure boundary expands beyond the model boundaries. Pressure is returned to the near original reservoir conditions after 2 years post-injection. Pressure boundaries expand non-uniformly and propagate more towards North-North-East direction. Pressure pulse in surrounding wells (e.g. KGS 1-32) is expected to reach 2-10 psi.

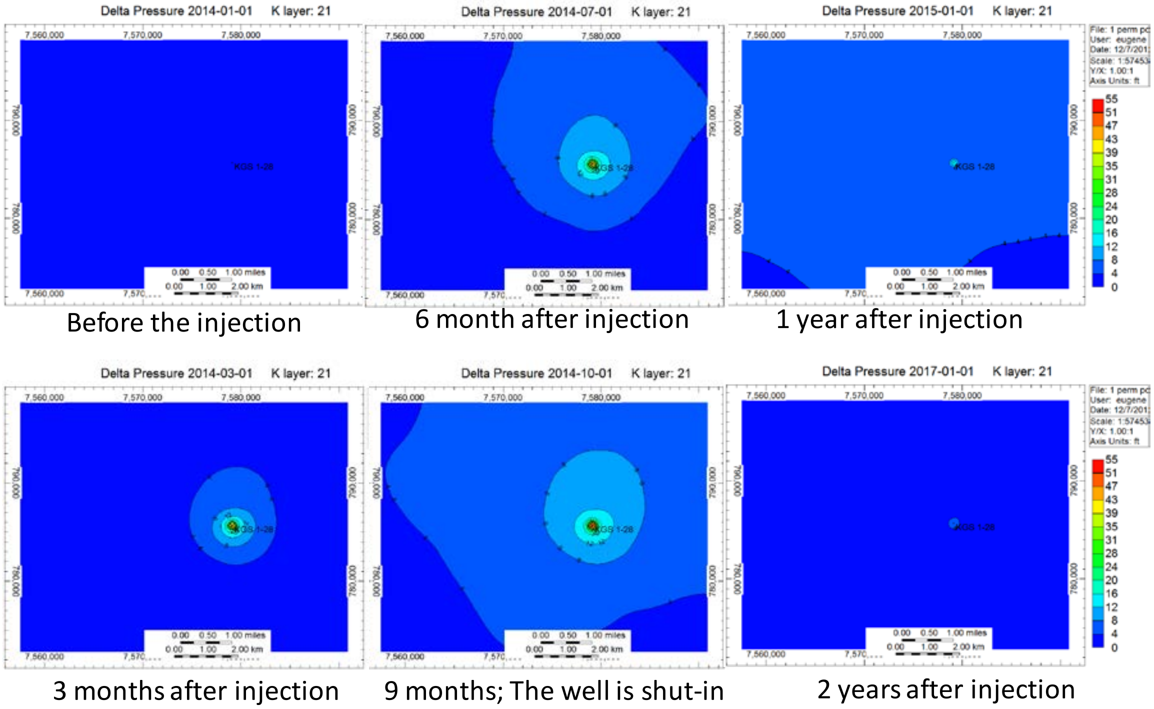


Figure 6. Aerial view of the pressure boundary extent for the Low Permeability, Lowe Porosity case.

The vertical pressure distribution in the case of the confinement by the mid-Arbuckle tight interval under conditions of Low Permeability and Low Porosity is illustrated in **Figure 7**. The pressure albeit low quickly reaches the top of the Arbuckle after 3 months of injection. The higher pressure is limited to the lower Arbuckle in this scenario with a low permeably middle Arbuckle. Once the C02 injection ceases the pressure quickly dissipates.

The vertical CO2

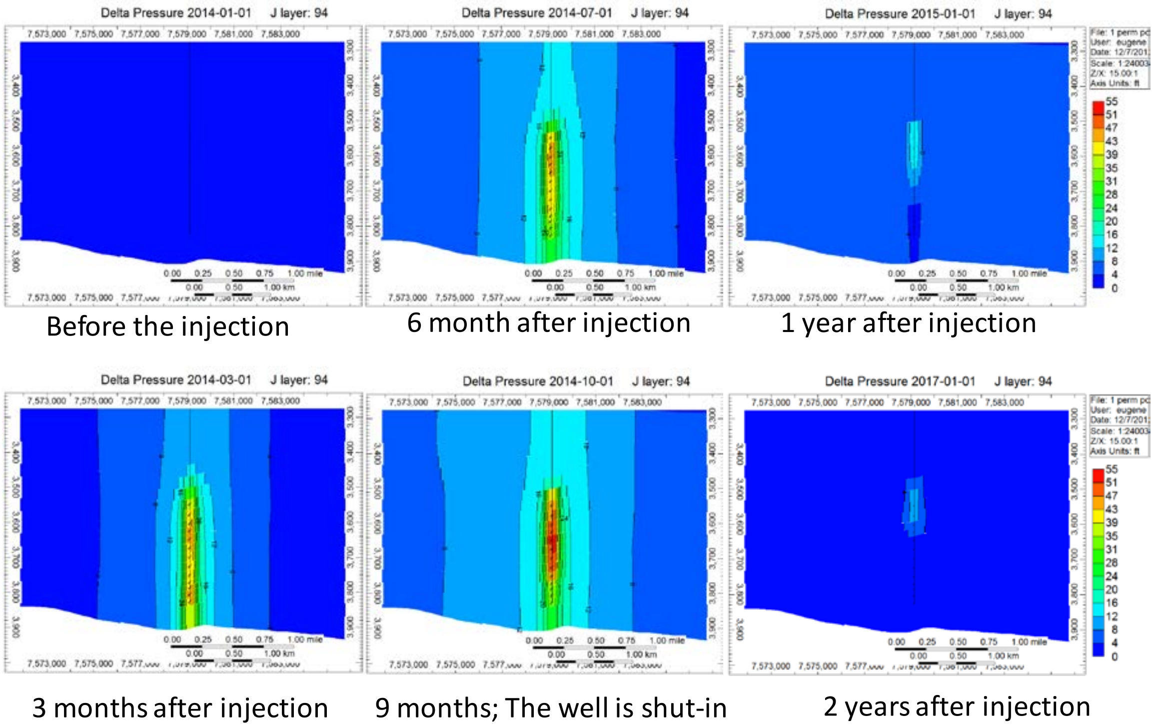


Figure 7. Vertical pressure boundary for Low Permeability-Low Pressure case. Vertical exaggeration is 15:1.

The aerial CO2 plume extent after 40,000 tonnes of CO2 injection quickly builds to its maximum diameter after 6 months under a Low Permeability-Low Porosity scenario (**Figure 8**). The vertical CO2 plume extent under the Low Permeability-Low Porosity scenario does not each the top of the Arbuckle until 2 years after injection. The pressure under which the CO2 reaches the top of the Arbuckle is low.

The vertical extent of the CO2 plume under a Low Permeability-Low Porosity case also does not reach the top of the Arbuckle until 2 years after injection. The plume continues to be stable beyond the 2 years shown in these models.

Summary of the dynamic modeling -- The CO2 plume extent is controlled by both porosity and permeability. The maximum diameter of aerial plume extent is registered in High Permeability- Low Porosity case. The minimal diameter is registered in the Low Permeability-High Porosity case. The plume movement is primarily in vertical direction. The horizontal plume movement is limited and is stabilized after 3-5 years post-injection. The CO2 is getting trapped by lower permeability layers interbedded with high permeability zones. More than 85% of CO2 is projected to be trapped via brine solubility (**Figure 9**). This is a significant finding. Capillary and mineral trapping will further add to stabilizing the plume and dissipating the pressures.

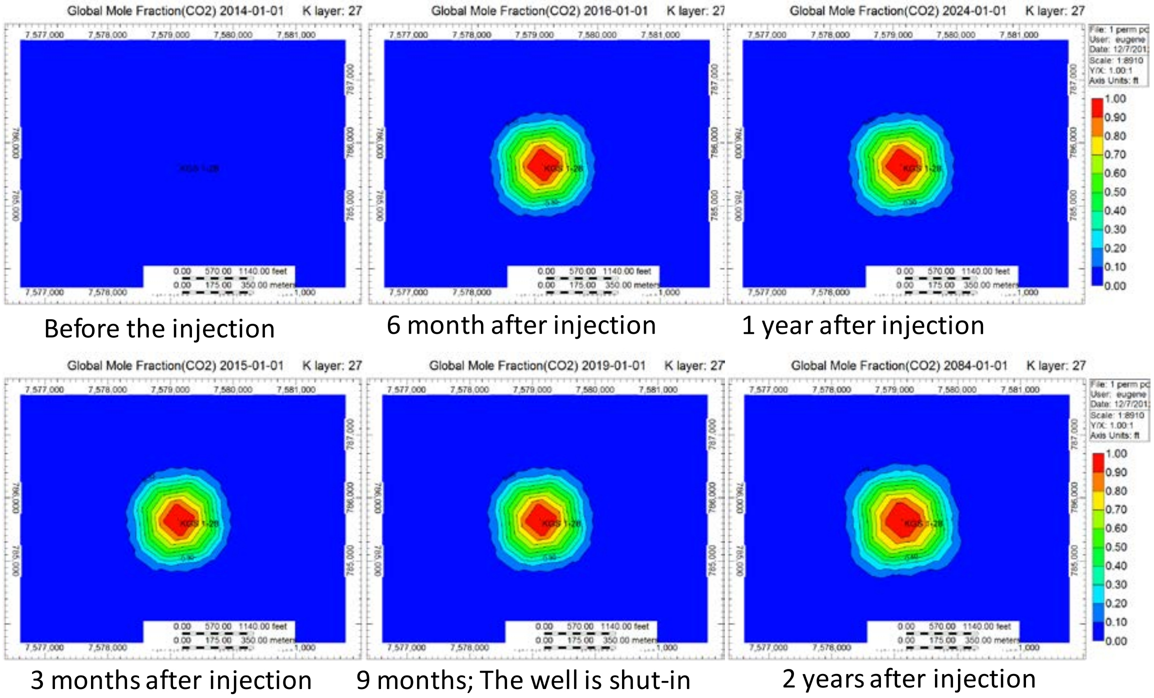


Figure 8. The aerial distribution of the CO2 plume under conditions of Low Permeability-Low Porosity.

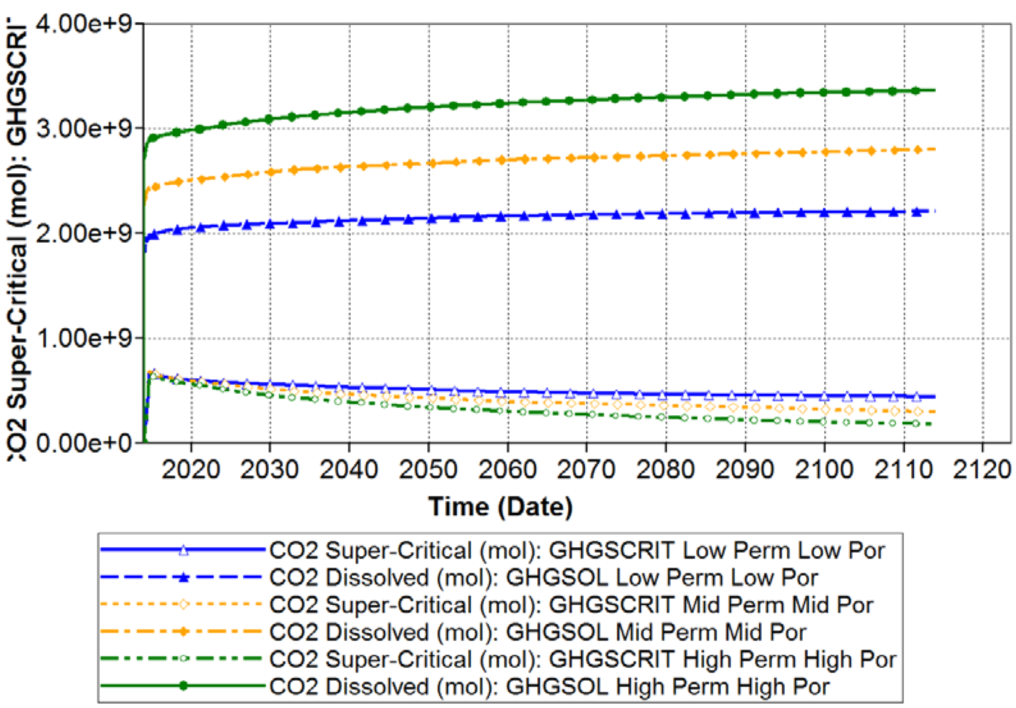


Figure 9. CO2 solubility comparing supercritical vs dissolved CO2.

The larger scale view of the simulated aerial extent of the CO2 plume and pressure front for 40,000 tonnes injection is compared with that of 16 million tonne injection of CO2 (**Figure 10**). The CO2 plume grows a maximum of 3 miles in length and the pressure front increases to ~4 miles. Size of the larger scale injection is within the confines of Wellington Field and structure.

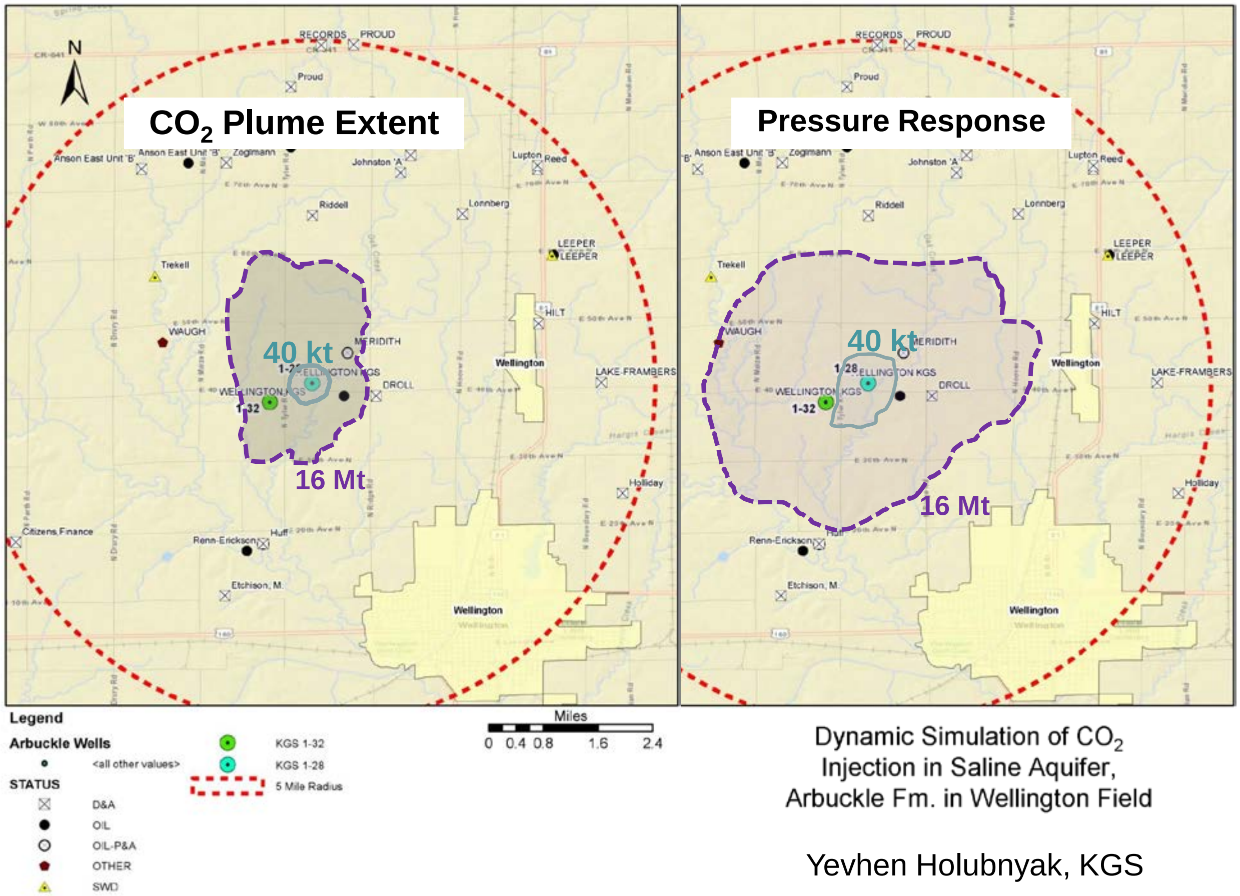


Figure 10. Comparison of the simulated size of a CO2 plumes and pressure fronts for small scale 40,000 tonne CO2 injection and a larger commercial scale CO2 injection of 16 million tonnes.

ONGOING ACTIVITIES - REGIONAL STUDY INCLUDING SOUTHWEST KANSAS)

Task 17: Acquire (New) Data at a Select Chester/Morrow Field to Model CO2 sequestration Potential in the Western Annex

Subtask 17.3. Collect new multicomponent 3D seismic survey

The seismic data has been collected and the post-stack, first PSTM, and final PSTM volumes for Cutter p-wave have been completed. Preliminary horizon maps have been prepared prior to final processing. An example is the top of the Viola Limestone, a horizon that lies immediately above the Arbuckle Group, our deep saline aquifer beneath Cutter Field (**Figure 11**). Shorter travel times inferred to be shallower are in red and green and longer times are in dark blue and purple. The Cutter KGS #1 was drilled in the northeast corner of Section 1, which is on the northeastern flank of a shorter isotime.

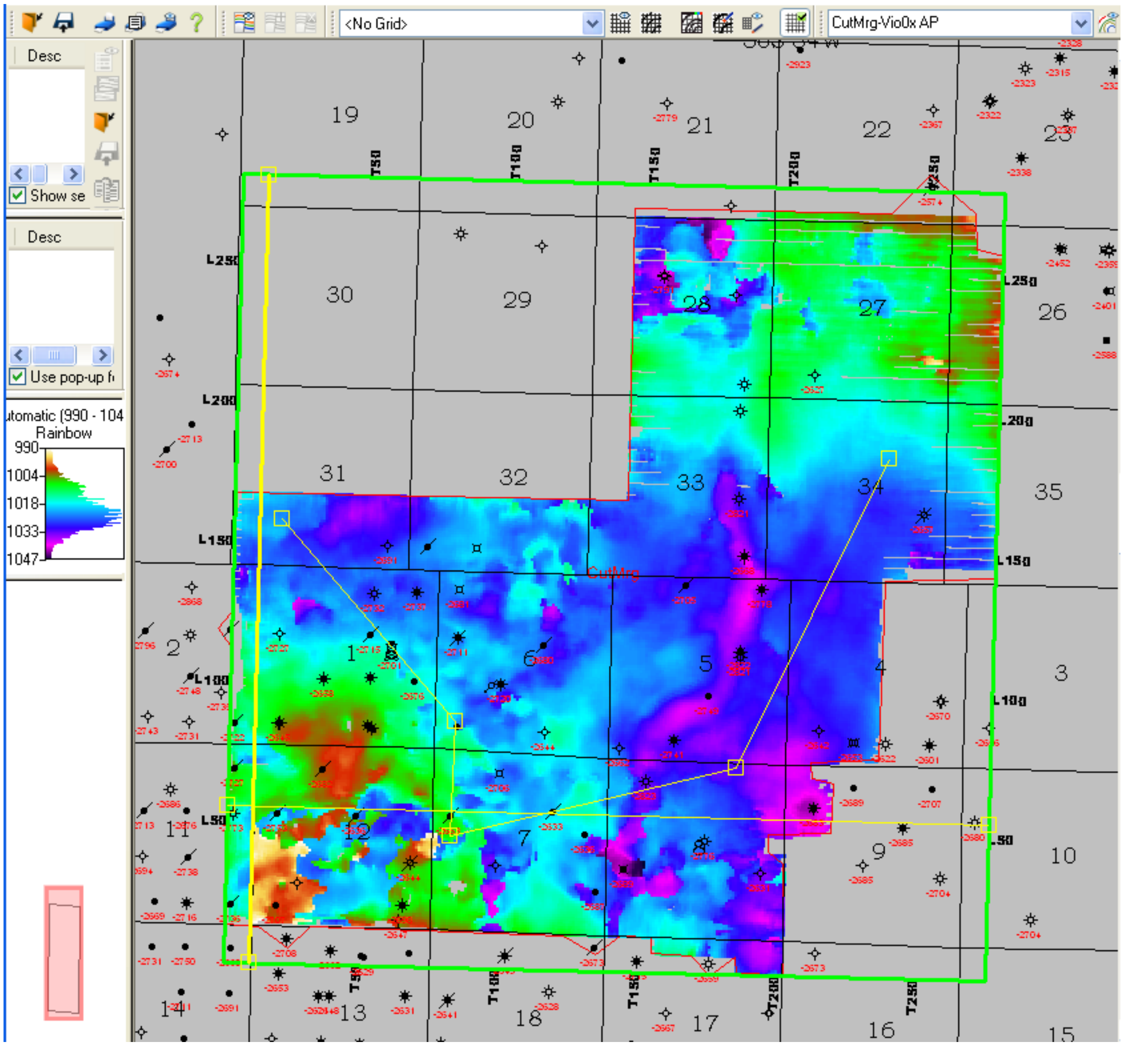


Figure 11. Preliminary isotime map of the top Viola Limestone for the new seismic volume that was collected at Cutter Field and adjoining area.

Subtask 17.8. Drill, retrieve core, log, and run DST – Test Borehole #3, Berexco Cutter KGS #1

Cutter KGS #1 has been drilled and core transported to Weatherford Labs in Houston. Well as logged with Halliburton tools and data continues to be analyzed and integrated with the initial core description done during visit to Houston on November 12-14. Core analysis has begun and procedures are being established to obtain brine samples and pressure testing of the cased and cemented well. A summary of the well is provided in **Figure 12** and a base map of southern Kansas study area showing the location of Cutter Field is provided in **Figure 13**.

Summary: Berexco's Cutter KGS-1 Cored Upper Morrow and Chester

- Berexco Cutter KGS #1 was spudded on 8-1-12 and reached TD of 7735 ft on 09/28/12.
- Twenty-seven core runs provided 1042 ft of core from the
  - Lowest Atokan, upper Morrow, all the Chester to the St. Louis "C".
  - Coring also included lower Osage, Kinderhook, Chatanooga Shale, Viola, Simpson
  - Much of the Arbuckle down into the Gunter Sandstone that lies on weathered granite.
  - Core has been described in Houston on Nov. 11-13 as the sampling procedure was established.
- The preliminary description of the core from the short visit is captured in the composite log (low-res included in this report)
- Core sampling work underway by Weatherford.
  - Maximize whole core analysis vs. plugs and are doing oil extraction and saturation runs on reservoirs and other intervals with HC shows

Figure 12. Snapshot of the drilling, coring, and analysis of the Cutter KGS #1.

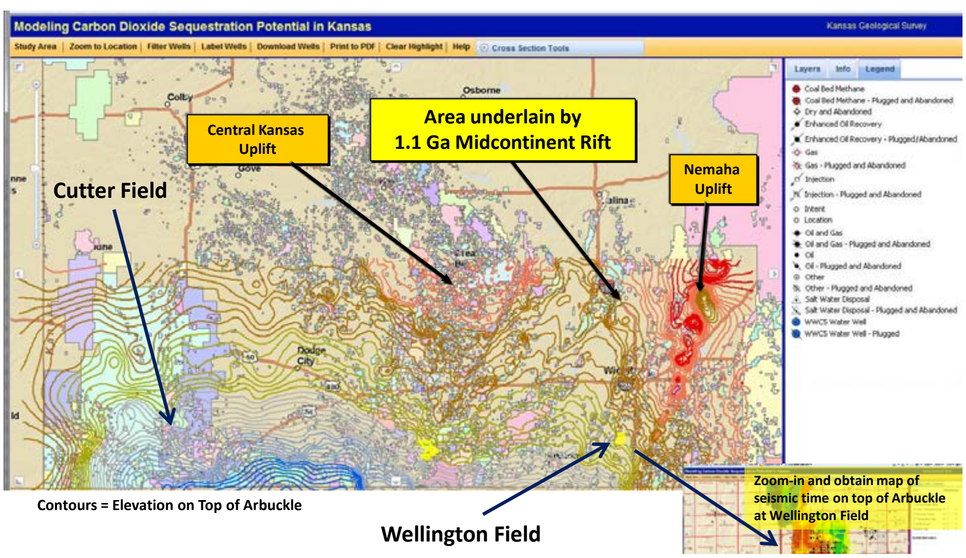


Figure 13. Study areas of southern Kansas showing location of Cutter Field.

The visit to Weatherford included Watney, Holubnyak, and Datta. The entire 2042 ft of core was laid out and described and sample locations chosen (**Figure 14**). An example of the data sampling request is shown in **Figure 15**.

Weatherford Labs, Houston

describe & ID sampling on 1042 ft of core, Nov. 11-13, 2012

Figure 14. Selecting and marking sampling intervals at Weatherford Labs in Houston.

November 13 2012
Cutter Core
With Lynn and Eugene
Core Sections and Core Plugs
Berexco KGS - No. 1
- Cutter
Cutter KGS #1 (15-189-22781)
T: 312 R: 35WS:1

sample #	Core Plug (Saugata)[1]	Whole core or Core Plug (Eugene)[2]	Whole Core Section[3]	Core Section[3a]	Extraction and HC saturations[4]		Sample for Total Organic Carbon Analysis	
1	7588	if can not obtain whole core	7587 - 7588	-		Possibly run saturation on plug ????		
2	7585		7585 - 7586	-				
3	7584		-	-				
	7582.5		-	-				
4	7580		7580 - 7581	-				
5	7577		7577 - 7578	-				
6	7574.5		-	-				
	7575.7		-	-				
7	7572		7572 - 7573	-				
8	7570.5		7569,5 - 7570,5	-				
	7569			-				
9	7566.4		7566,5 - 7567,5	-				
10	7562		7561 - 7562	-		x		
11	7558.7		7559 - 7560	-		x		
12	7555.3		-	-				
13	7553.5		7552 - 7553	-		x		
14	7549.4		-	-				
15	7548.6		7547,6 - 7548,6	-		x	5237.4	TOC
16	7545.2		7543,8 - 7548,8	-		x	5233.4	TOC
17	7538.2		7539 - 7540	-		x	5233.7	TOC
	7540.2			-			5240.4	TOC
18	7536.6		7535,4 - 7536,4	-		x	5244.1	TOC
19	7534.1		7533 - 7534	-		x	6486.4	TOC
20	7531.7		-	-			6486.7	TOC
21	7529.6		7528,5 - 7529,5	-			5535.5	TOC
22	7527.7		7526,6 - 7527,6	-			5589.5	TOC
23	7422.5		-	-			5414.4	TOC
24	7419		7418 - 7419	-		x		

KEY
- Core Plug (Saugata)1
- Whole core or Core Plug (Eugene)2
- Whole Core Section3
- Whole Core Section3a
- Extraction and HC saturations4
- Possibly run saturation on plug

Figure 15. Sample summary sheet for plugs and whole core developed from the Weatherford trip.

Subtask 17.11. Analyze wireline log - Test Borehole #3

Initial analyses of the well logs from Cutter KGS #1 were made after examining the core. The initial results are reported below in **Figure 16** through **58**. The description and discussions are contained within the figure captions.

UV Fluorescence Shows in Cutter KGS #1

5401-5403 light show
5420-5424light show
5476-5480mid show
5530-5532heavy show
5533-5543heavy show
5557-5562light show
5592-5596light show
5600-5619heavy show
5611-5636heavy show
5638-5642light show
5664-5668light show
6515-6725light show
6515-6518light show
6524-6526light show
6690-6697light show
6708-6711light show
6741-6753light show
6907-6909very light show
6915-6921very light irregular show
6928-6932light show
6937-6940light show
6953-6959light show
6967-6971light show
6975-6977light show
6978-6982light show
7090-7095light show
7099-7101light show
7112-7106light show
7158-7160light show
7222-7224light show
7381-7388light show
7420-7420light show
7402-7412light show
7550-7589light show

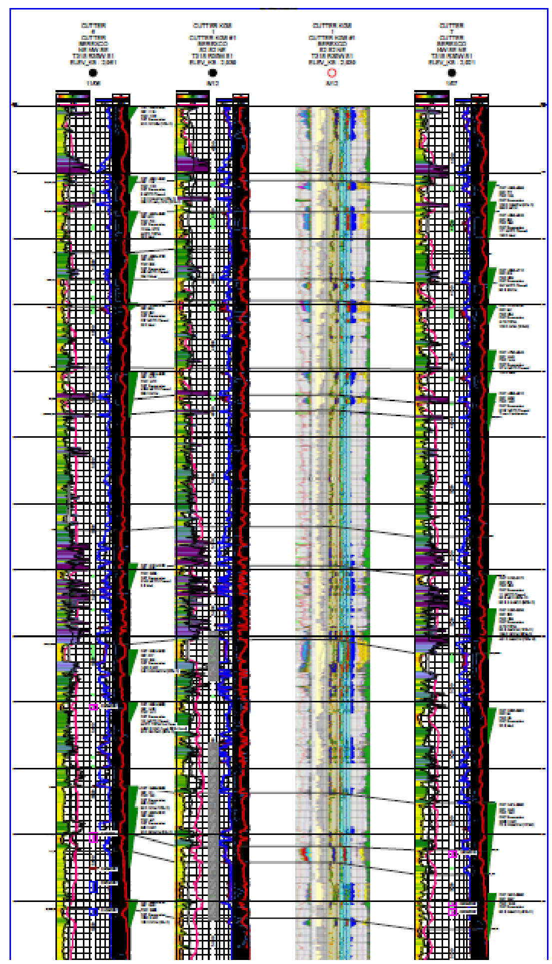


Figure 16. List of intervals with ultraviolet fluorescence of core and plastic covering of core as observed in examining core in October 2012. The intervals span the Pennsylvanian Morrowan sandstone, the main reservoir of Cutter Field to the mid Arbuckle, our deep saline aquifer. A structural cross section is shown on the right including the Cutter KGS #1 NMR log located 2nd from right. The oil shows in the Morrow are not unexpected since the

well is drilled high on the structure. Deep oil shows in the Viola, Simpson, and Arbuckle were possible, but not expected since these lower intervals are not productive the region. This suggests a possible modification of our understanding of the hydrocarbon system. The impact on CO2 storage in the saline aquifer has yet to be determined through additional testing of the well to more fully understand the economic value.

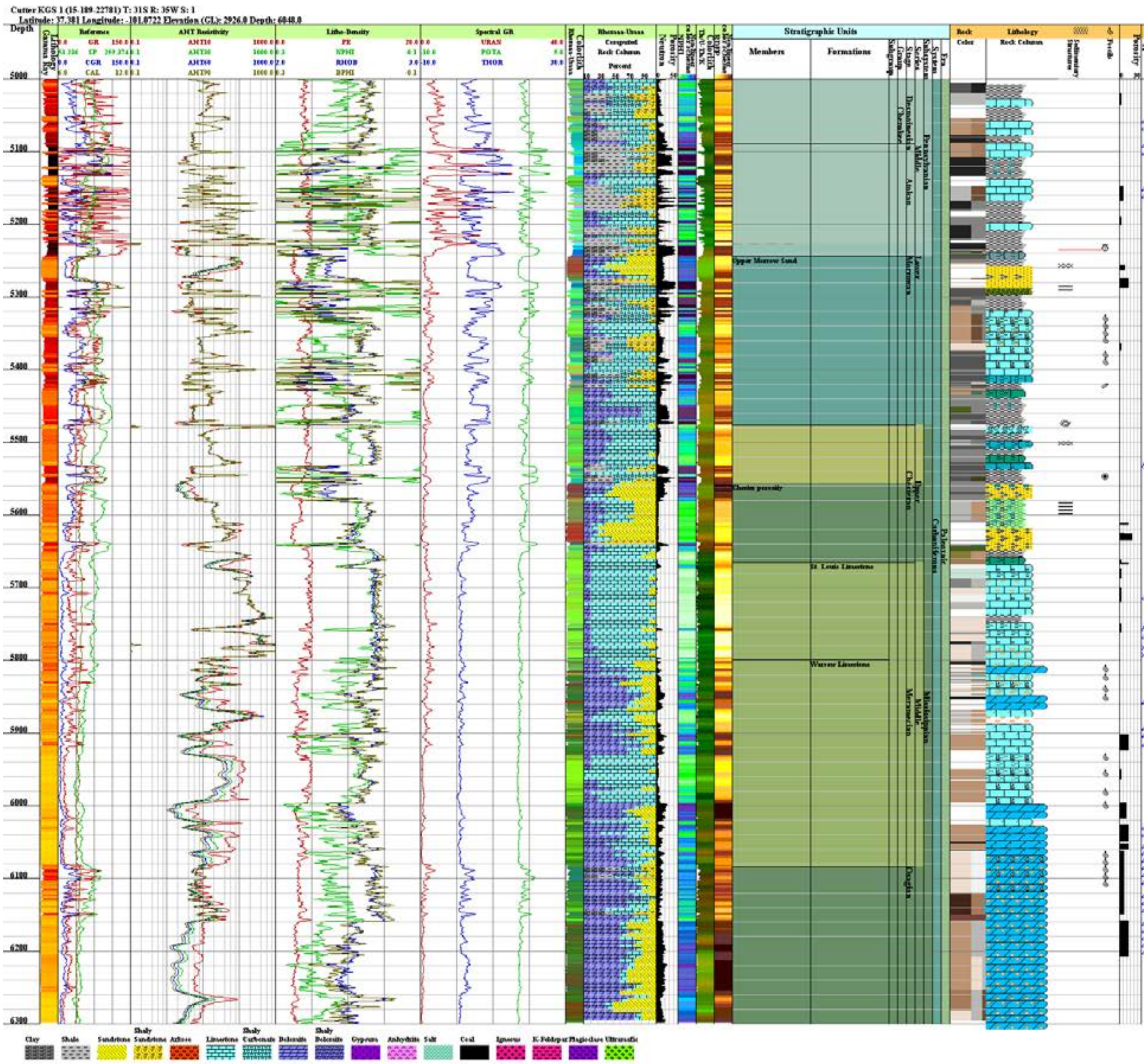


Figure 17. Graphic well log (left), color log imaging with lithology (center), stratigraphic intervals (green and blue columns), and combined cuttings and initial core description (right). The upper Morrow sandstone near the top is where coring began and above that is the 120 ft thick Atokan, consisting of organic rich shales and thin limestones. The section extends down through the Chester, Ste. Genevieve, St. Louis, and into the upper Osage Mississippian strata, primarily carbonates as noted by the lithologic curves.

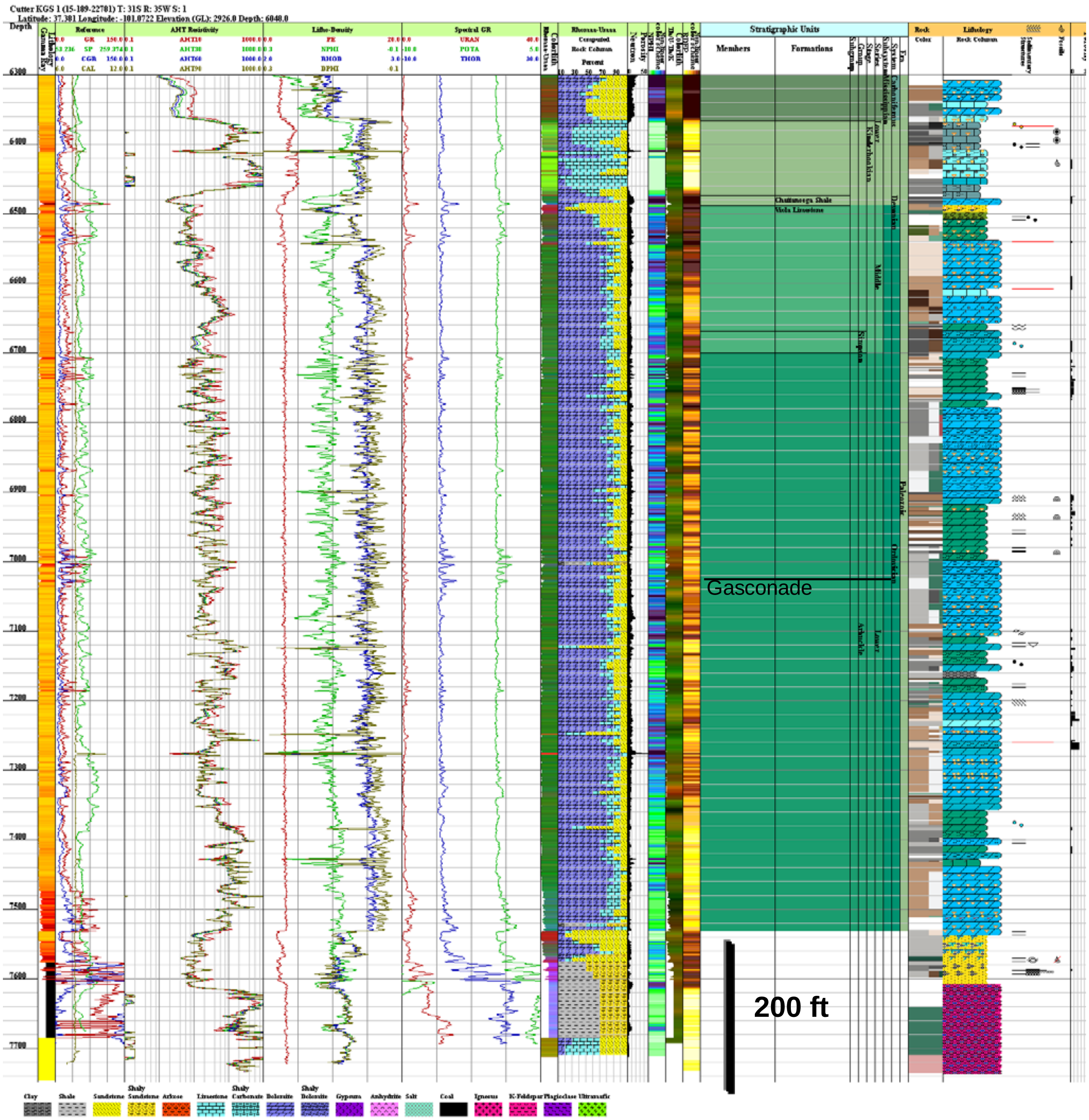


Figure 18. The lower half of the cored interval is shown in graphic combined log, interpreted lithology, and graphic core description (right). The top of the graphic is the base of the Osage Mississippian starting from the base of Figure 17. The Kinderhook Mississippian beneath that is distinguished by a shaly carbonate that overlies the Chattanooga Shale. The nearly 200 ft thick Viola Limestone becomes shalier with depth and the Simpson Group continues to have a shaly carbonate lithology. These rock units

overlie the ~850 ft thick Arbuckle Group. The entire Ordovician strata (Viola through the Arbuckle) are cherty dolomite with thin intervals of shaly carbonate. The regionally correlated top of the Gasconade Dolomite is labeled in the mid-Arbuckle interval. The Gunter Sandstone lies on weathered granite. The cored intervals will be highlighted in the following Figures.

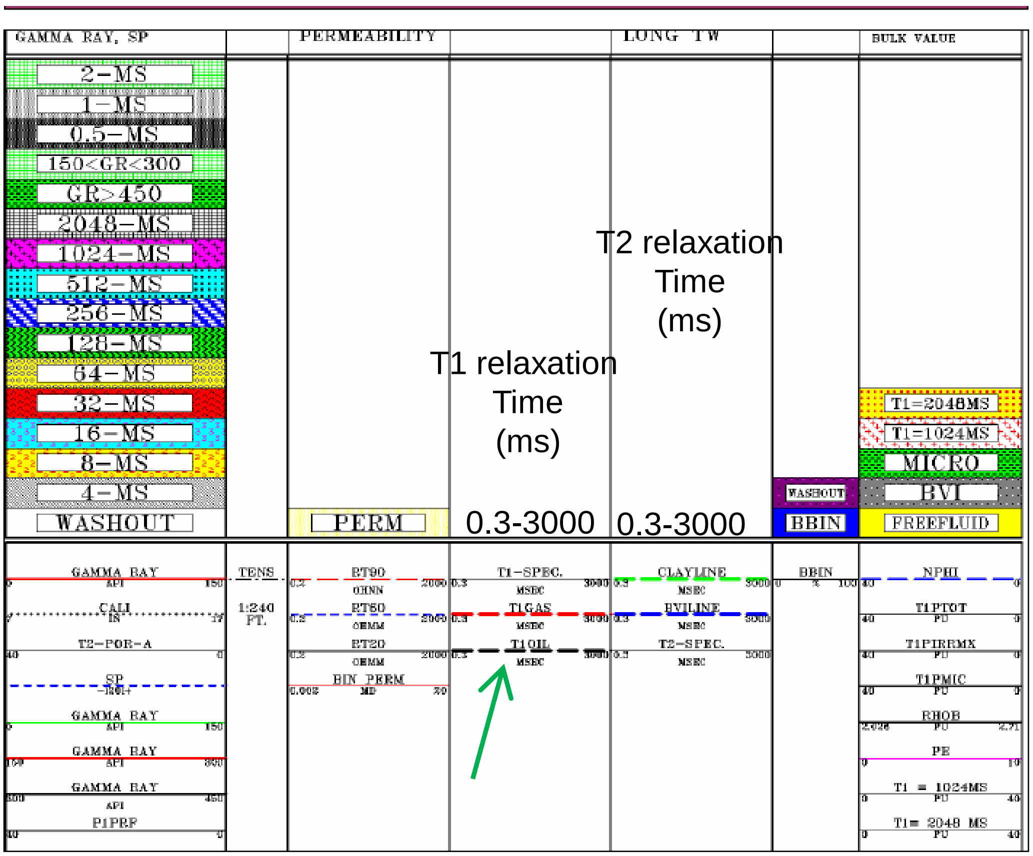


Figure 19. The MRIL logging tool is used in subsequent figures to convey the pore size and distribution and provide an estimate of permeability prior to obtaining core analyses. The T2 relaxation time is proportional to pore size so the larger pores have high T2 values. The log also provides a means to evaluate hydrocarbon saturation with threshold values of the T1 relaxation time (in milliseconds). Higher T1 indicates oil or gas. Location of tracks for T1 and T2 curves is provided in this figure in the presentation format of Halliburton.

MRIL log and Main pay of Field -- Upper Morrow Sandstone

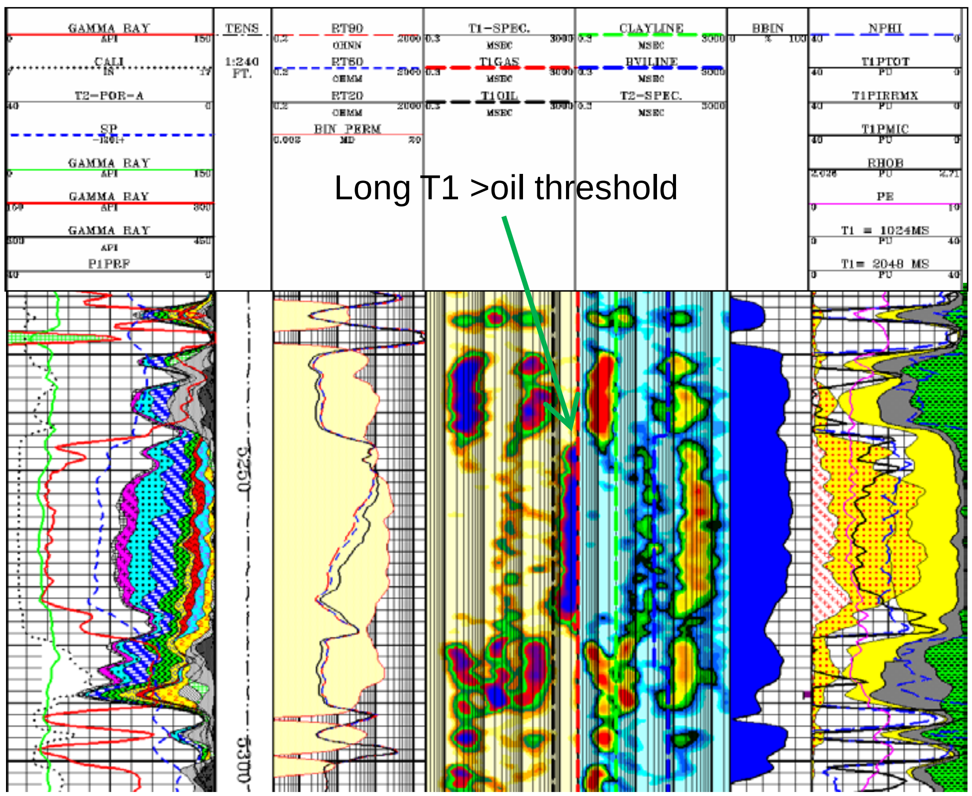
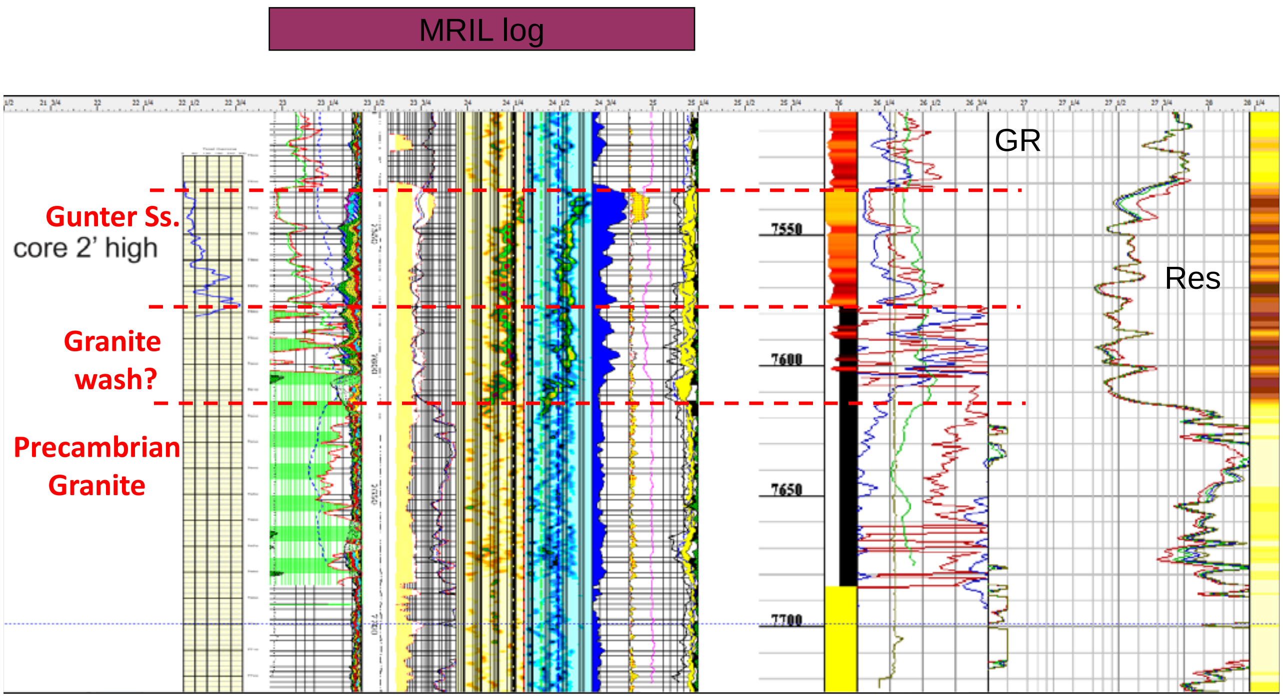


Figure 20. The MRIL log is shown over the main oil producing reservoir of Cutter Field. The T1 curve is highlighted showing a high T1 value. The black dashed line just left of the green arrow tip is the threshold value for oil, clearly indicating an oil bearing horizon. The T2 curve is in track to right of T1 and indicates uniformly large pores that comprise the sandstone reservoir. The permeability track is the 2nd from left. The area in light yellow bounded by the red dashed line on its right indicates high permeability.

Base Gasconade Dolomite, Gunter Sandstone, granite wash, Precambrian granite



7550-7589 UV fluorescence, light show

Figure 21. This and following figures begin at the base of the well and move upward to share information about key intervals, focused on the Arbuckle Group saline aquifer. This figure illustrates the basal Gunter Sandstone resting on the Precambrian granite. An MRIL tool (described in Figure 20) on the left and the standard log suite on the right including gamma ray and induction resistivity clearly define sandstone from granite wash (weathered granite), and the solid granite at the base. Pore size is moderate as is permeability estimate. The T1 curve does not exceed the oil threshold except or the topmost 15 ft.

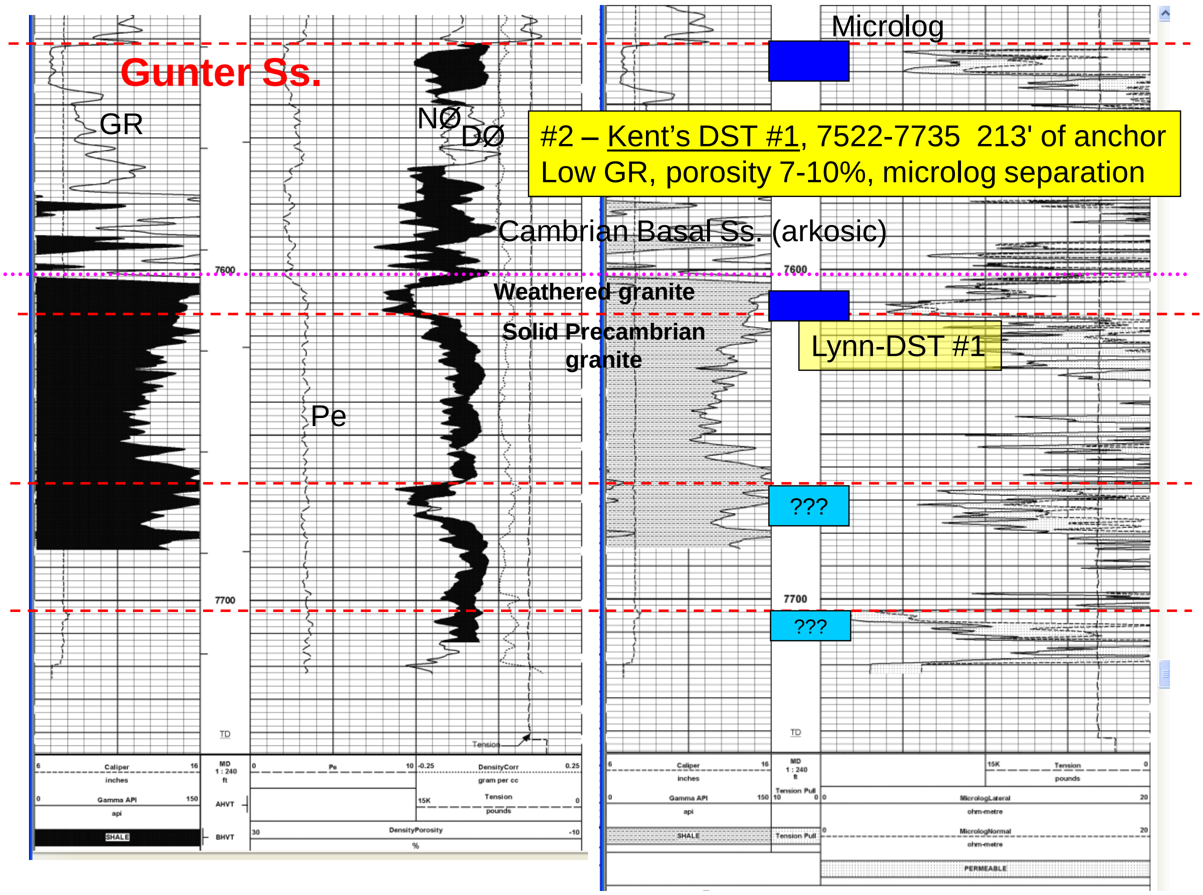


Figure 22. The Neutron-density porosity log for the same Gunter to basement interval as shown in Figure 21. Note that the topmost Gunter with apparent oil show has porosity up to ~6-8% and there is microlog separation an indirect means of indicating permeability. To establish the nature of the hydrocarbon show a test is warranted. It appears that the granite is layered. These may be dikes/fractured that are weathered and porous.

Gunter Sandstone,7579 ft
(core depth 2 ft high to logs)

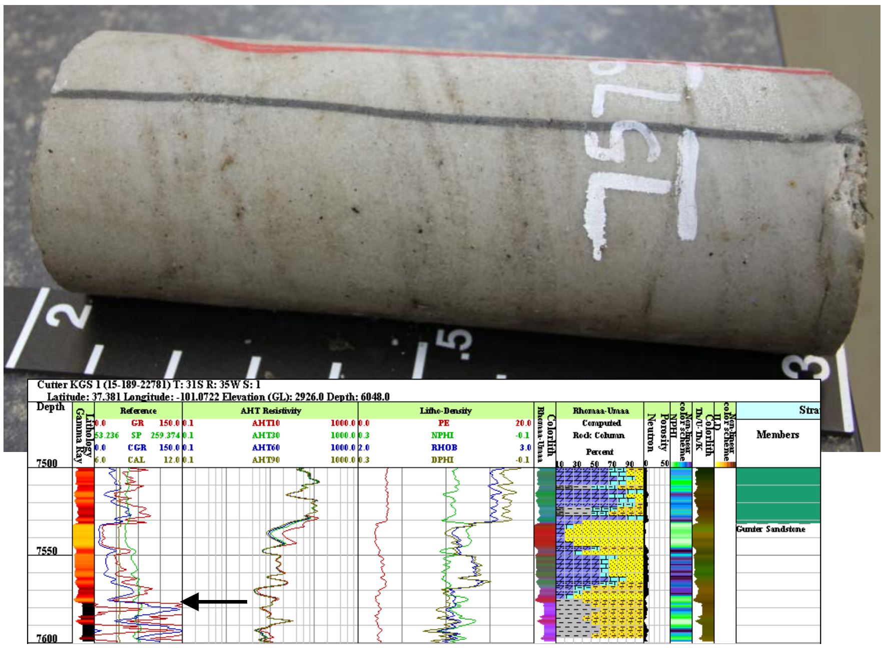


Figure 23. The lower Gunter sandstone at the base of the core is cross stratified, moderately clean, but is cemented with silica cement.

Gunter Sandstone
(core depth 2 ft high to logs)

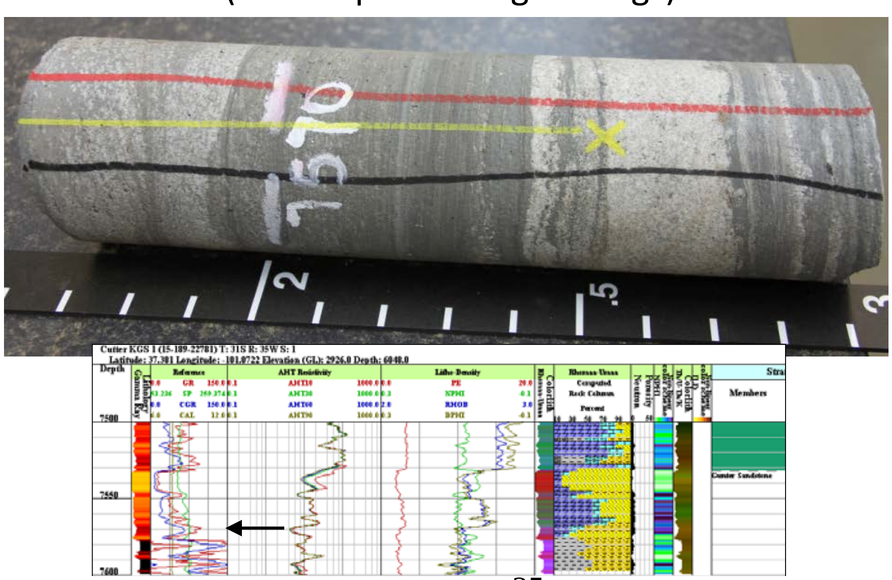


Figure 24. Slightly higher than Figure 23, this interval of Gunter sandstone has shaly siltstone beds with horizontal bedding and abrupt reactivation surfaces.

Gunter Sandstone, 7532 ft
(core depth 2 ft high to logs)

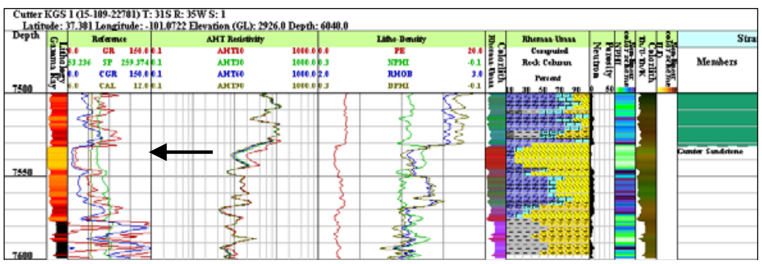


Figure 24. The uppermost clean sandstone bed of the Gunter Sandstone is faintly laminated with low dipping, near horizontal bedding and more massive sandstone. The 8% porosity remains from both silica and dolomite cement. An oil show indicated by MRIL is not visually substantiated.

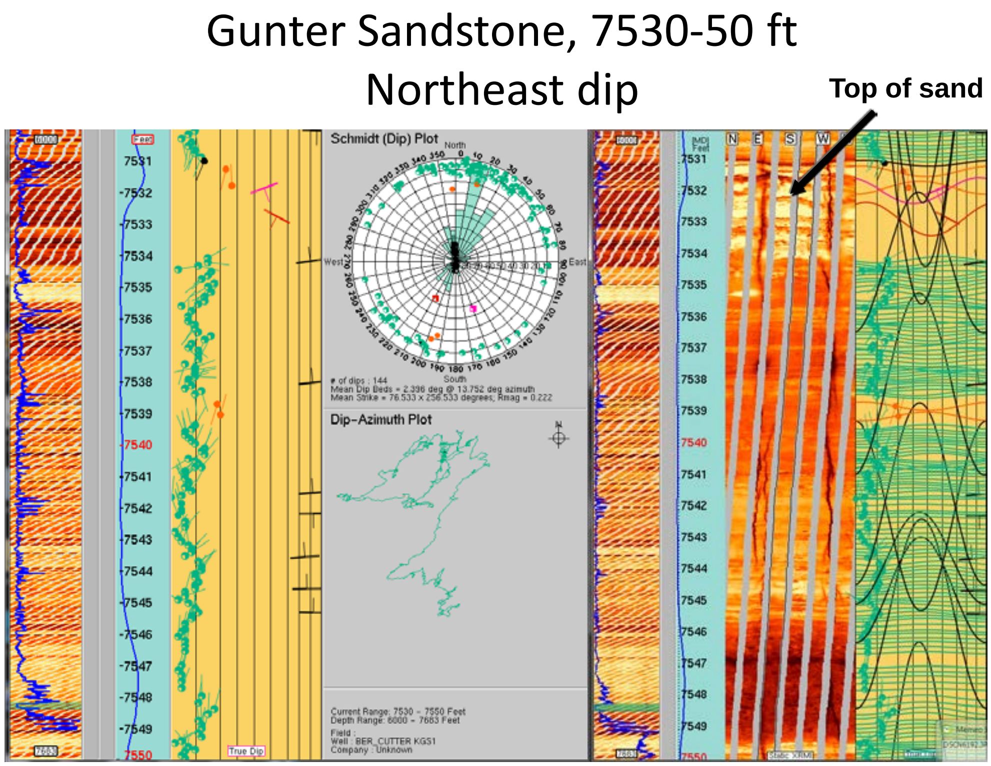


Figure 25. The Gunter Sandstone interval is shown on an interpreted microresisitivity imaging log of Halliburton. The arrow identifies the top of the clean Gunter Sandstone

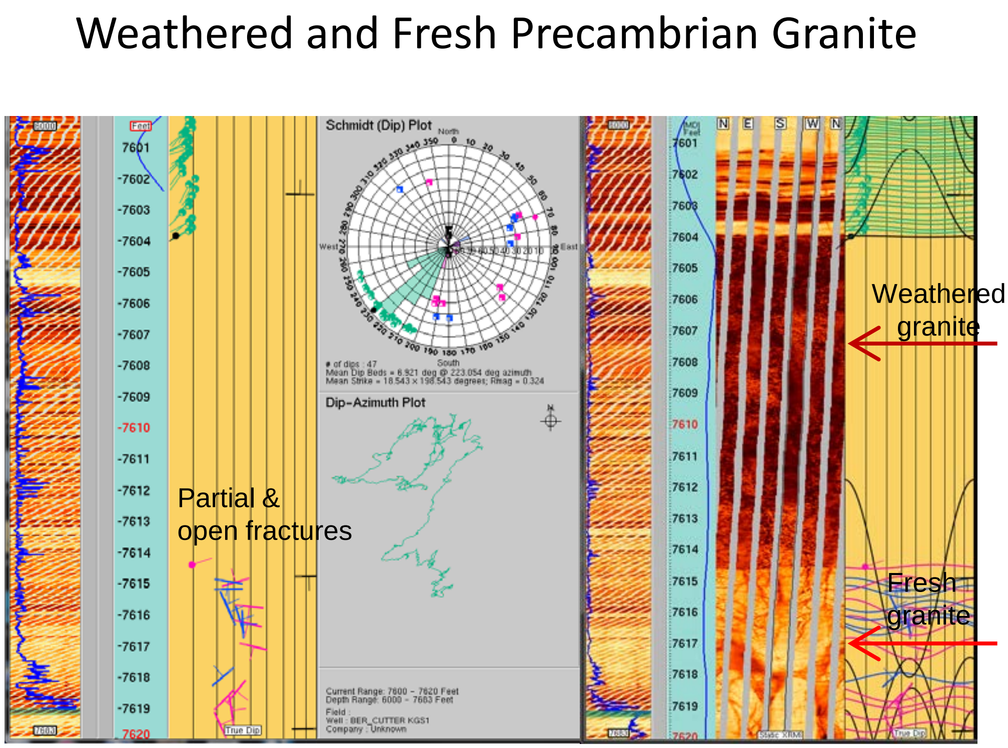


Figure 26. Interpreted microresistivity imaging log of the base of the Gunter Sandstone to into the weathered and fresh granite at the base of the well. Fresh granite is fractured.

Lower interval of the Gunter Sandstone has southwest dip while the upper Gunter (Figure 25) has northeast dip. Basal shaly sandstone may conform to structural dip on the top of the granite while the upper Gunter reflects possible depositional dip in the sandstone itself. Sandstone may be marine strandline strata deposited in the lower shoreface (long angle bedding) to massive sandstone at top characteristic of a coarsening upward shoreline deposit.

Lower Gasconade Dolomite (7280-7500 ft)

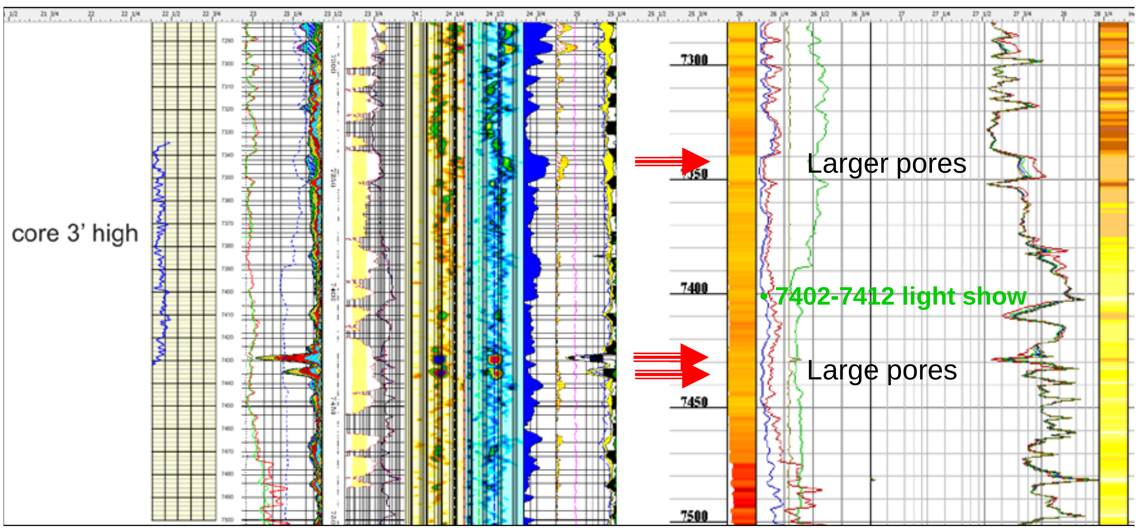


Figure 27. The Lower Gasconade Dolomite overlies the Gunter Sandstone shown in previous figures. The coring was done on interval due to rig time and cost factors (see cored drill time as blue line in first track of this figure. When the core would jam, the coring would be stopped to drill ahead several 10's of feet. The factor for jamming is fractures and it was determined through experience in the Arbuckle that drilling ahead rather than going back to coring was most prudent in order to exit the fractured interval.

The lower Gasconade in the cored interval has several zones of larger pores as indicated by the MRIL log, particularly noted by red arrows above. These porous intervals are the focus of subsequent figures. In addition UV fluorescence indication of an oil show is noted in this interval.

Lower Gasconade Dolomite, 7420-50 ft

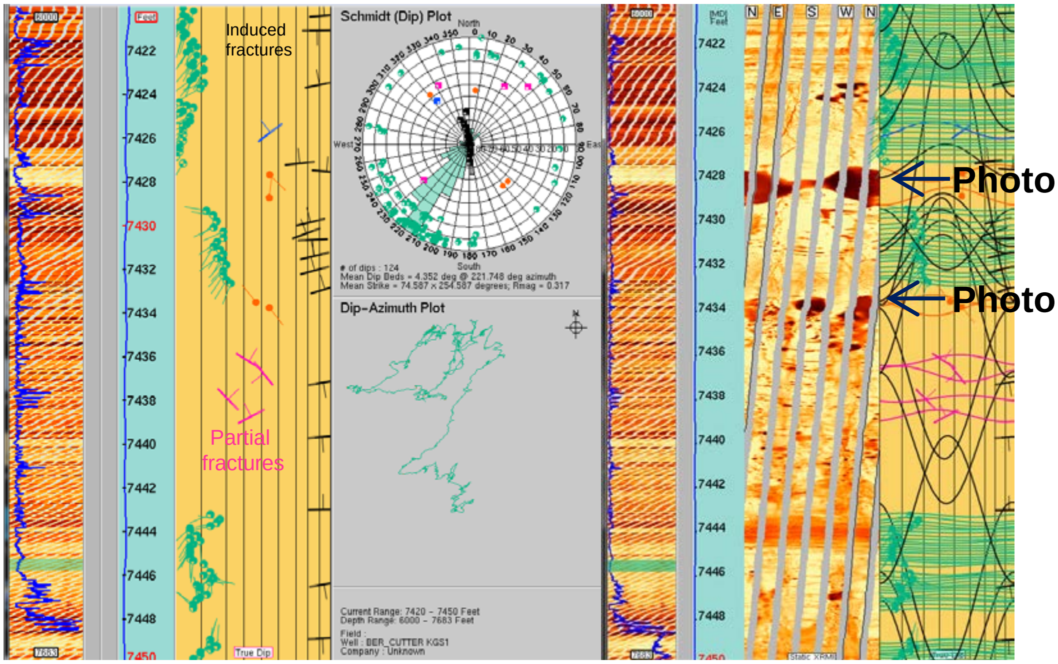
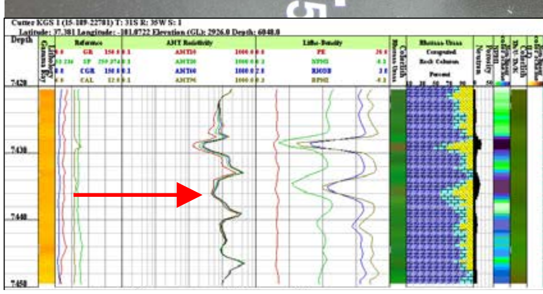


Figure 28. The microresistivity imaging log of two intervals of porosity in the lower Gasconade Dolomite clearly delimits their locations indicating larger pores on the order of one foot. Also, note that the dip (green curves on 2nd track from left) are dipping again to the southwest at the basement.

Lower Gasconade, 7433 ft

(core depth 3 ft high to log)



Gray-brown, packstone with quartz sandstone, cm sized vugs that are interconnected cut across core, saddle dolomite, very porous breccia

Figure 29. A photo of the lowest interval in Figure 28 highlighted with abundant vuggy porosity. Core description is dolomitic packstone, gray-brown, with quartz sandstone, cm sized vugs, interconnected and cut across core, pores partly lined with saddle dolomite; locally also brecciated.

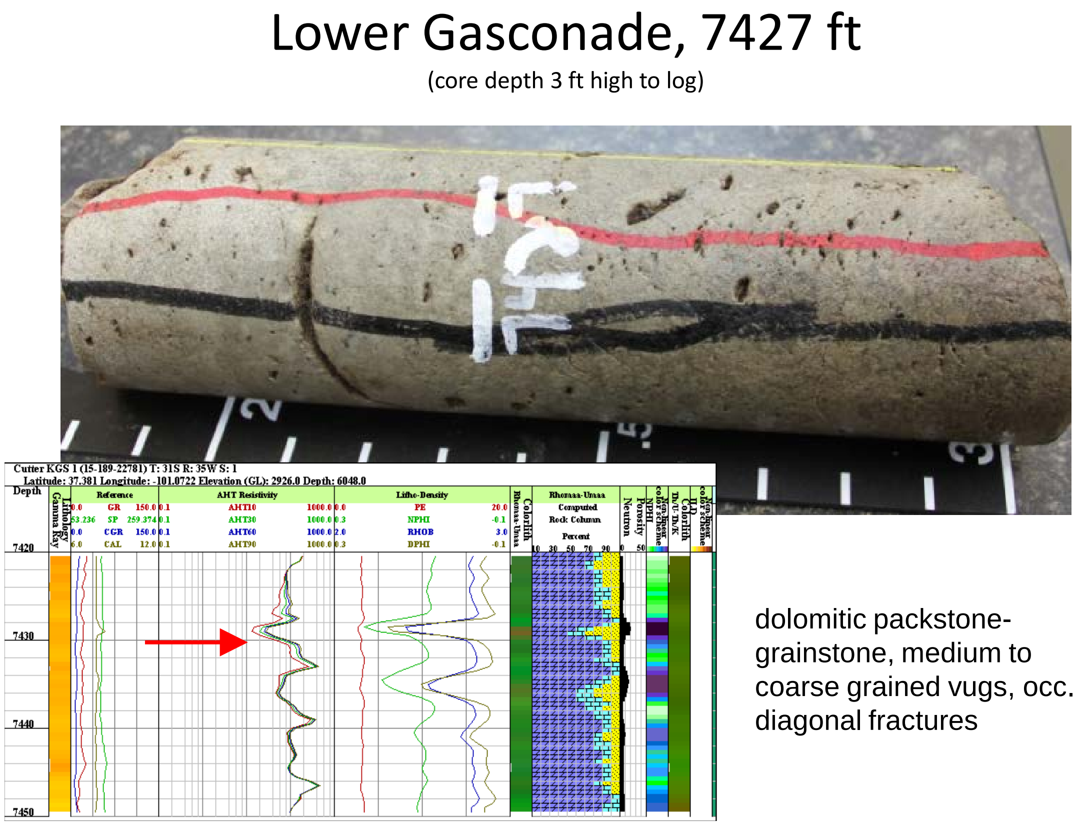


Figure 30. The uppermost interval with apparently vuggy porosity identified from the image log shown in Figure 28 is confirmed with this core photo. The vugs are mid sized as also indicated by the MRIL tool. Core description of interval is dolomitic packstone-grainstone, medium to coarse grained vugs, occasional diagonal fracture.

Lower Gasconade to Gunter Ss.

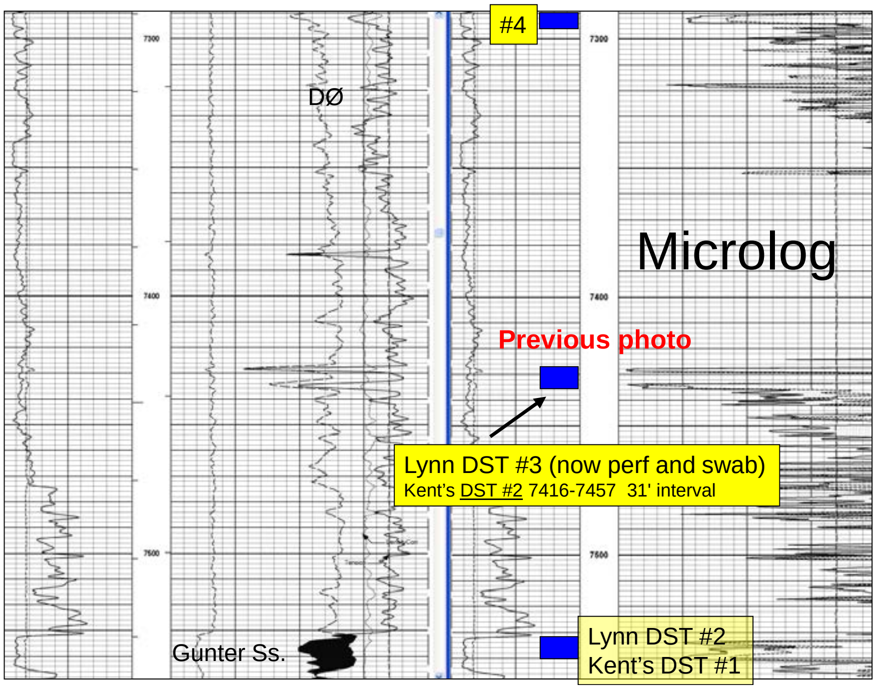
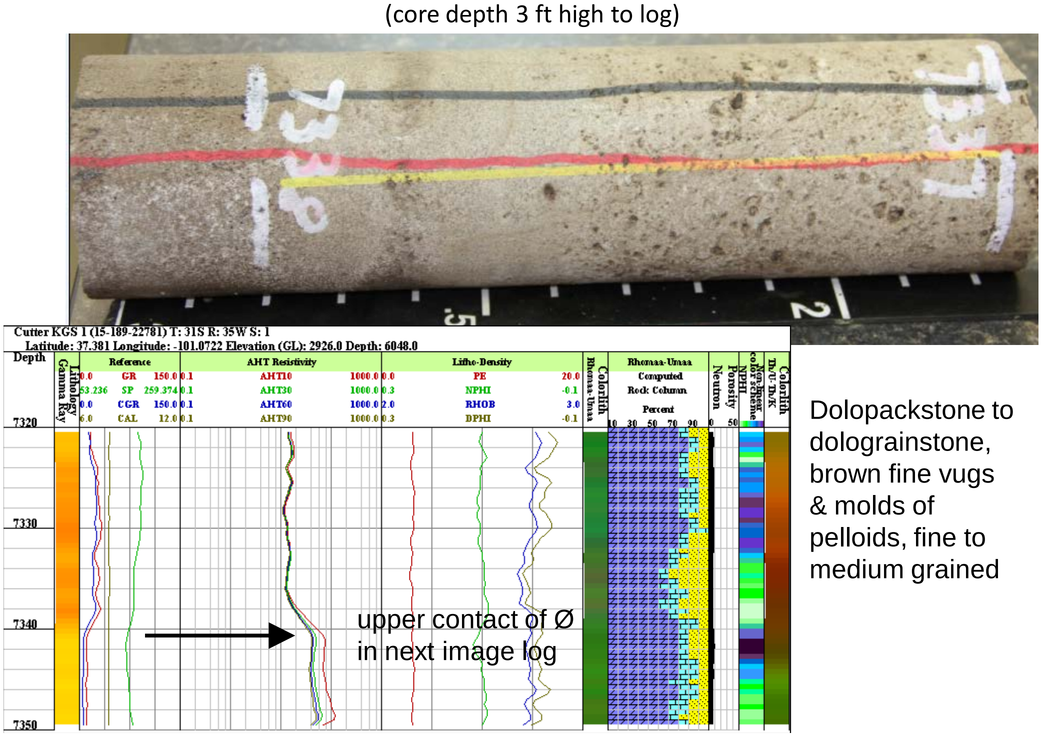


Figure 31. Finally to complete the series of figures above is the depiction of the porosity that is being illustrated using the neutron-density porosity log on the left and the microlog on the right. Both clearly show porosity and microlog is indicative of permeability. The notations on these logs indicate the selection of the interval for further testing.

Lower Gasconade, 7337-38 ft

(core depth 3 ft high to log)



Dolopackstone to dolograinstone, brown fine vugs & molds of pelloids, fine to medium grained

Figure 32. Again the lower Gasconade is illustrated, but upsection from the previous examples. The interval in focus is another porous interval at the upper contact of a clean dolomite as illustrated by this gamma ray-resistivity-neutron & density porosity log suite.

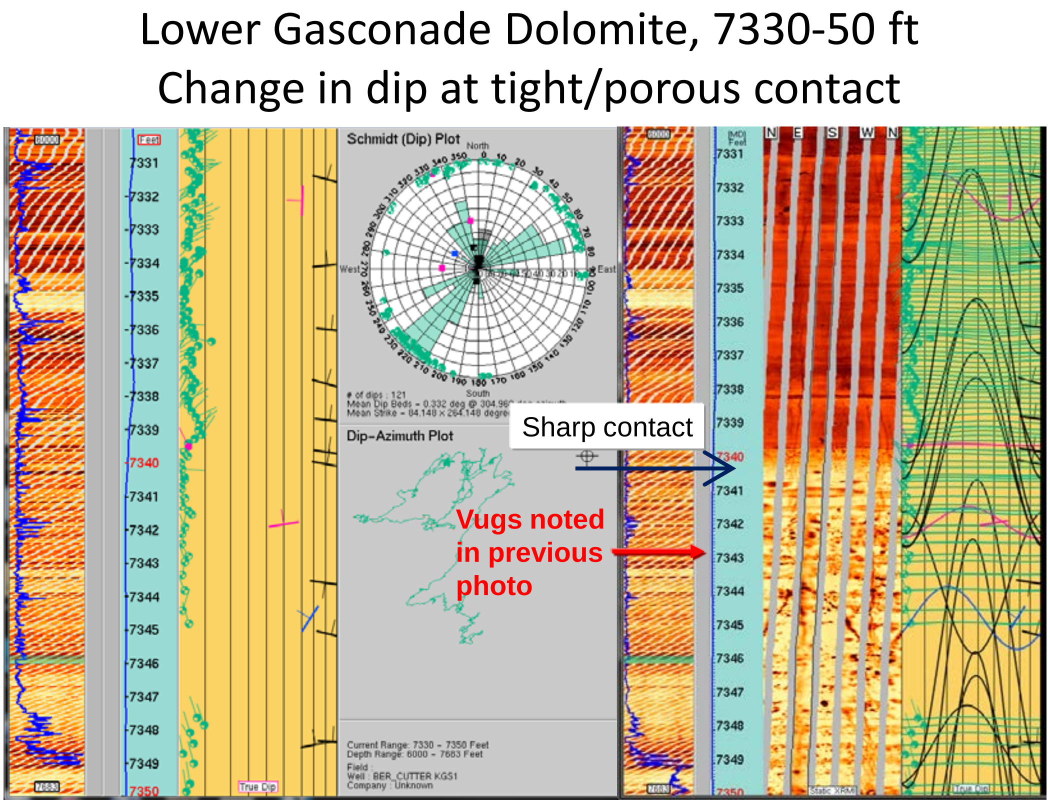
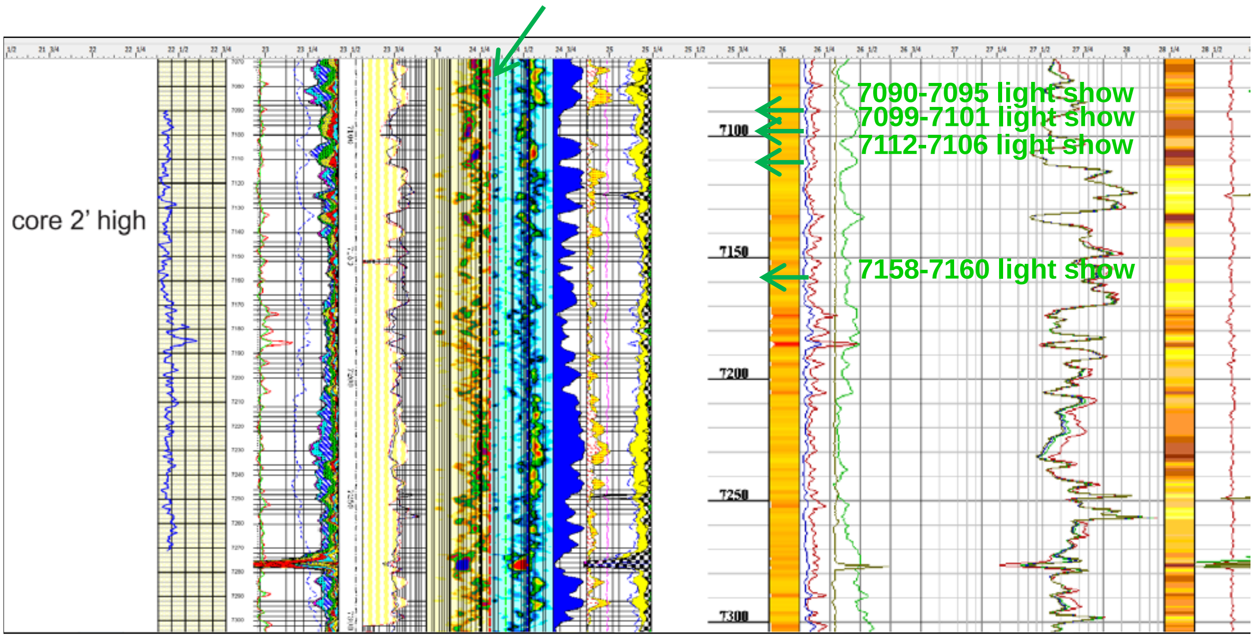


Figure 33. The microresistivity imaging log spanning the same depth interval as Figure 32 shows the sharp contact at the top of a vuggy porous interval of cleaner dolomite. It shows the same vugs viewed in the core shown in previous figure.

Upper Gasconade Dolomite
-- UV fluorescence, light oil show



Base Gasconade 7532 ft.

Figure 34. A long section of core was taken from the upper portion of the Gasconade Dolomite (see long blue drill time during coring on left track). This section has similar intervals of vuggy porosity as indicated by the T2 curve of the MRIL tool. The T1 curve also indicates possible hydrocarbon where measured values exceed the T1 threshold (black dashed curve identified with the green arrow). Moreover, the UV fluorescence of the core similarly suggest hydrocarbon as noted by green annotated text.

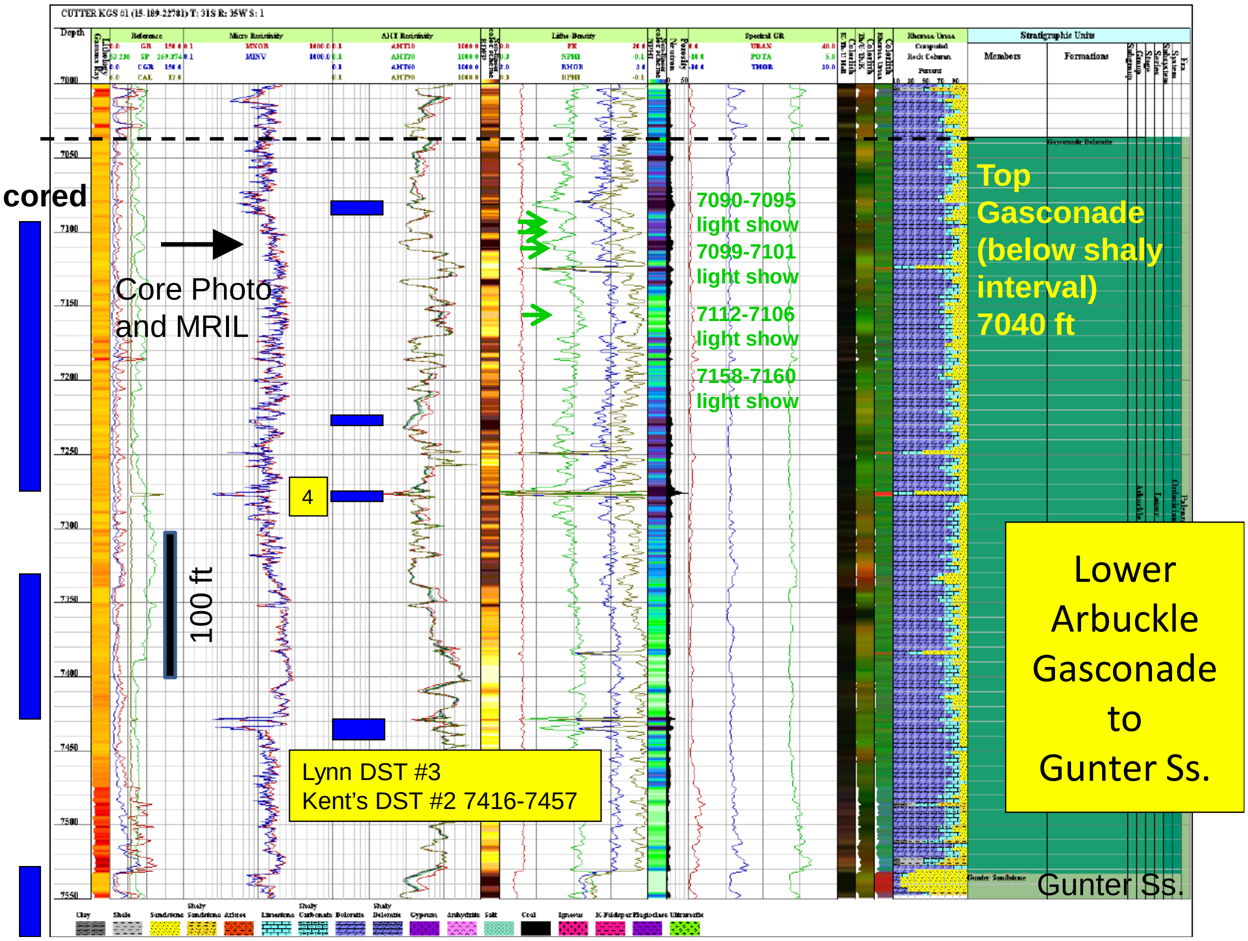


Figure 35. A look at conventional logs for the entire Gasconade Dolomite using original curves, images, and lithologic solution shown toward the right side of the figure. The key porous intervals are shown in short blue bars and the cored intervals are shown in blue bars along the left margin. A core photo of the interval with hydrocarbon shows is provided in the next figure.

Upper Gasconade, 7100 ft

(core 2 ft high to log)

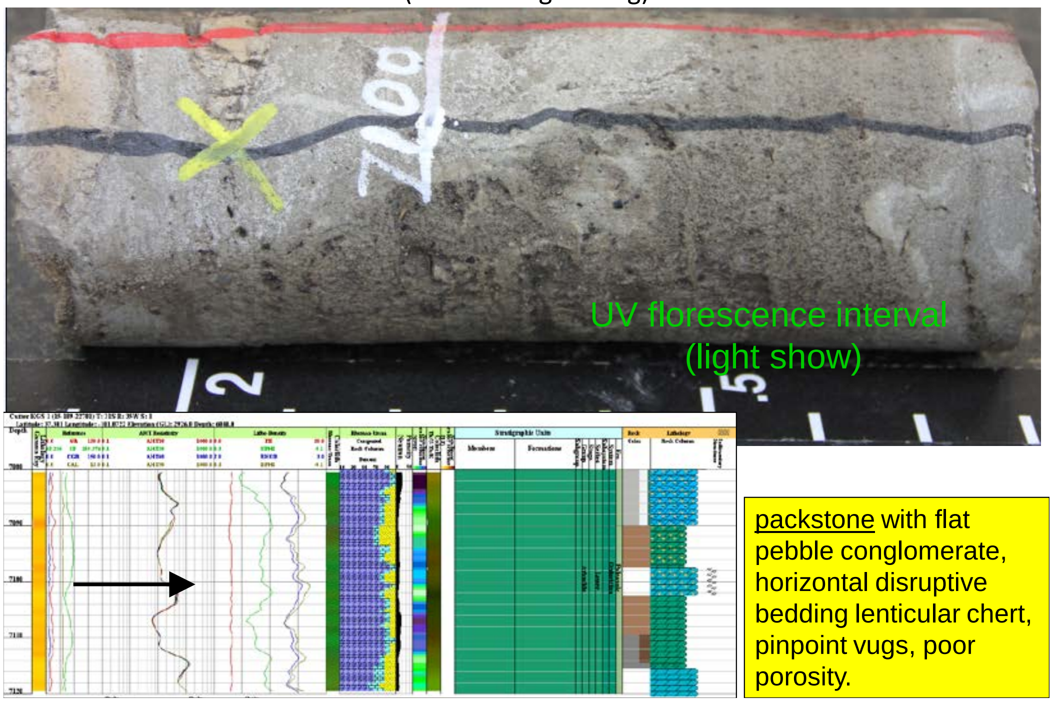


Figure 36. Photo of a core interval from the upper Gasconade Dolomite containing hydrocarbon show. Porous interval is a dolomitic packstone, gray, with incipient and minor autoclastic breccia, with bedded intervals containing scattered open vugs and moderate pinpoint porosity.

Upper Gasconade Dolomite, 7100-7120 ft
Interbedded tight and porous

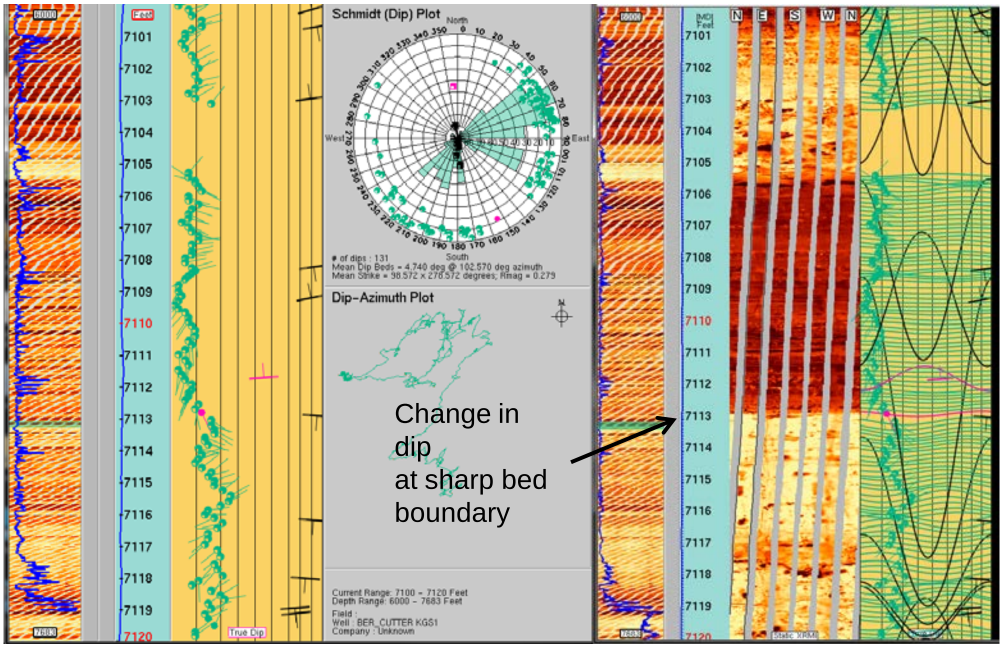


Figure 37. Upper Gasconade shaly and clean dolomite bedding with sharp contacts. Note dramatic change in dip direction across the sharp boundary. Also note the changing direction in dip within the clean dolomite. Core indicates clean dolomite as mudstone – packstone texture, gray - brown, with scattered fine pinpoint vugs, poor porosity.

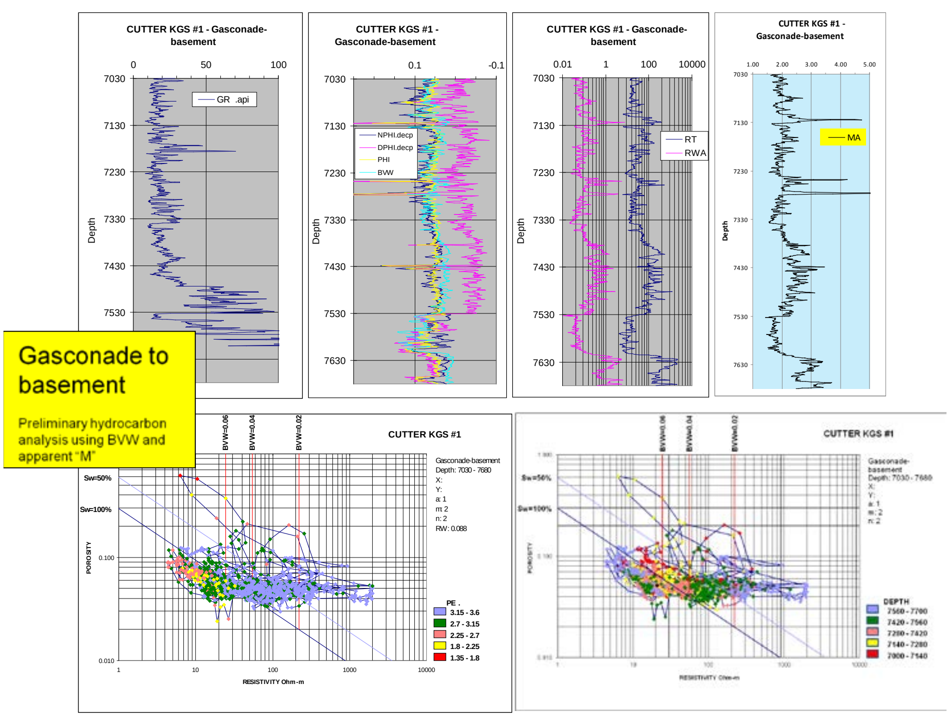


Figure 38. Suite of logs for the Gasconade Dolomite to basement interval with porosity and resistivity cross plots are used to shown overall stratigraphic patterns. Apparent "m", Archie cementation exponent, is shown in right track in light blue background. The m hovers around a value of 2, but intervals are noted with higher values (excursions to the right) that suggest vuggy porosity in agreement with the previous descriptions of the interval.

Contact between Jeff-City Cotter and Gasconade Dolomite, 7020-7040 ft

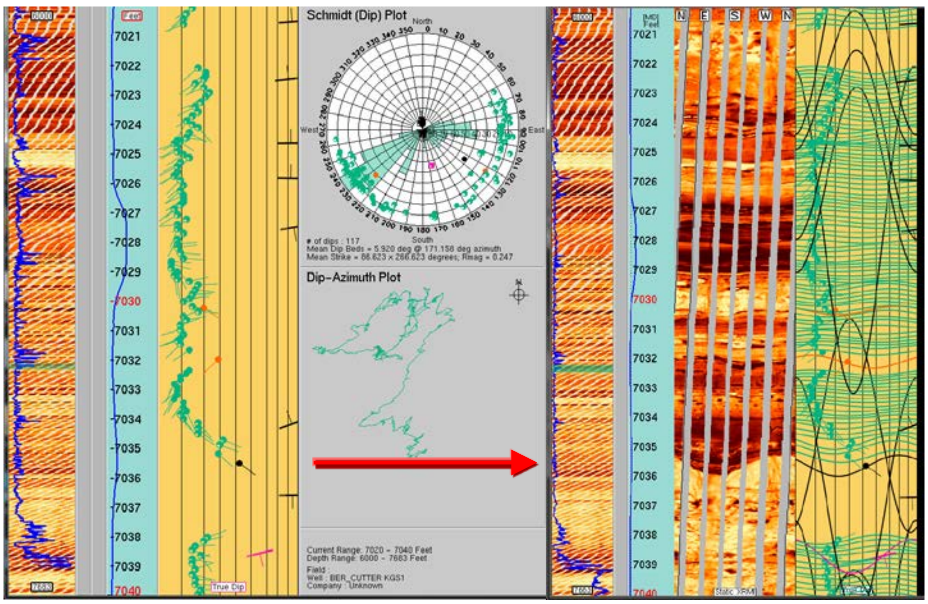


Figure 39. The key regional contact that has been mapped in southern Kansas within the study area is the top of the Gasconade Dolomite. The contact with the base of the overlying Jefferson-City Cotter Dolomite is sharp and irregular. Note that dips increase up to contact and also decrease above from the contact suggesting tilted beds. Breccia clasts are evident from the imaging portion and together this suggests a notable unconformity surface. This interval was not cored, but this log data is quite revealing of what the nature of the contact is.

Lower Jefferson City-Cotter Fm.
More hydrocarbons shows and oil indications on MRIL

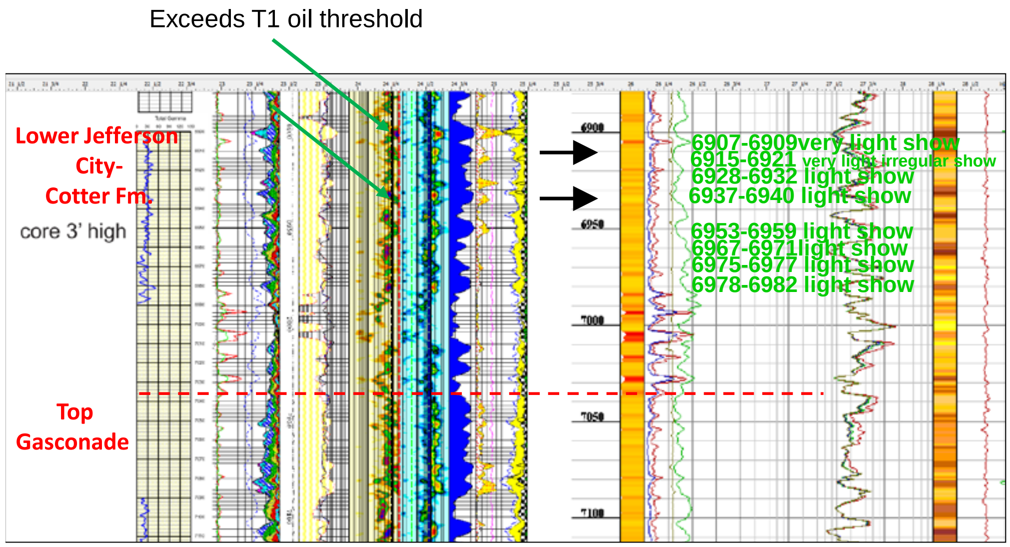


Figure 40. The MRIL log at the contact between the Jefferson-City and Gasconade shows larger pores at the top of the Gasconade as suggested from Figure 39. The cored section above the contact has ~75 ft of UV hydrocarbon shows that correspond with T1 values that exceed those indicating an oil bearing section. This interval will be tested.

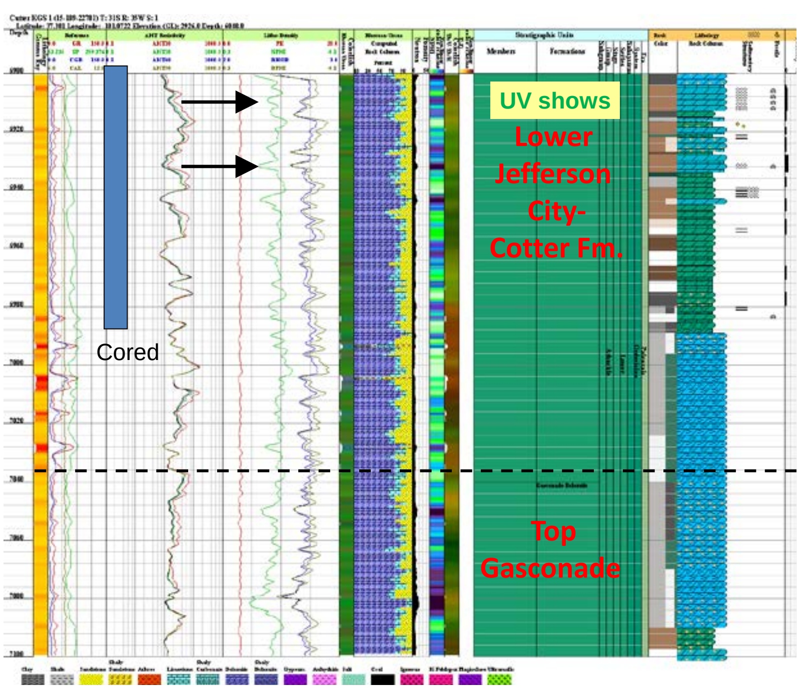


Figure 41. Standard log suite showing the lower Jefferson City-Cotter dolomite interval.

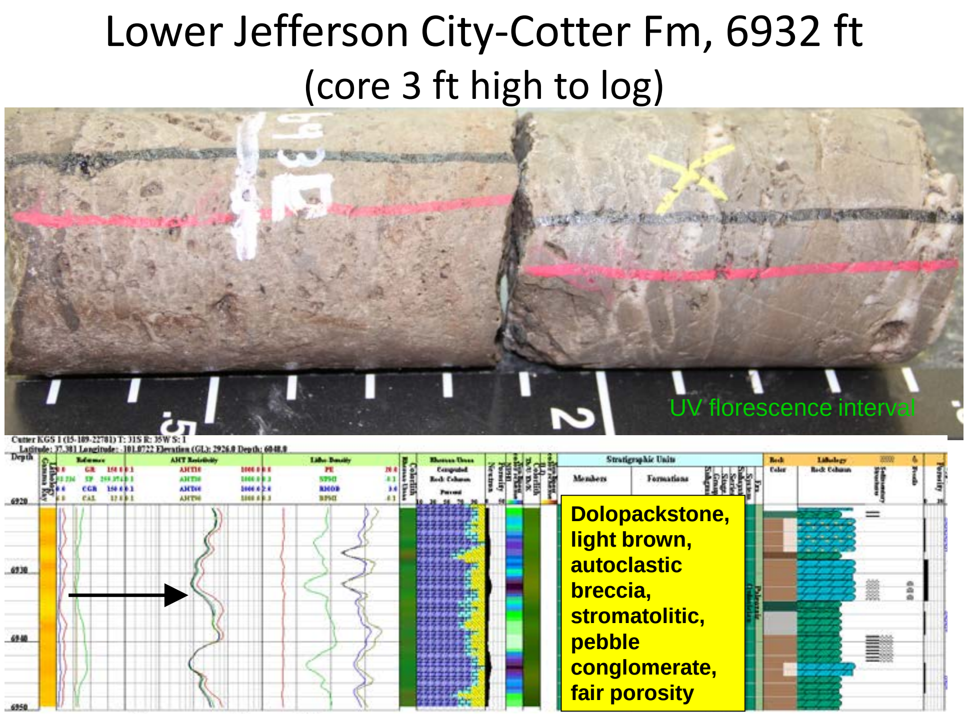


Figure 42. Porous core interval consisting of an autoclastic, stromatolitic, and conglomeratic.

Figure 43. Close-up of a thin flat pebble conglomerate interval in the lower Jefferson City-Cotter interval. Clasts are rounded and are attributed to a rapid current action that ripped up the partially consolidated muddy carbonate without considerable transport.

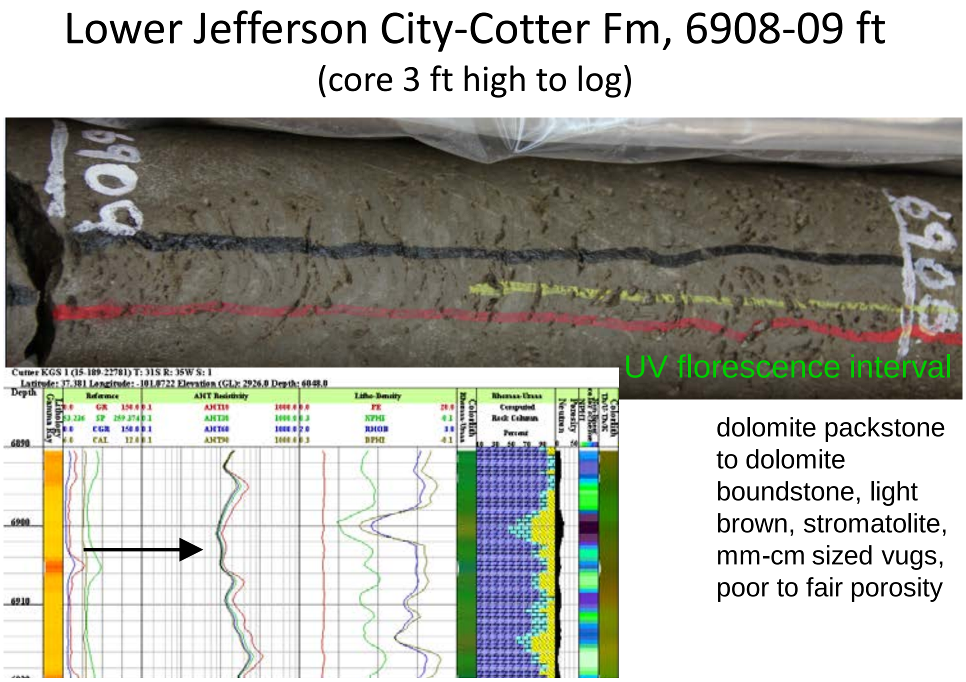


Figure 43. Stromatolitic boundstone and packstone showing vuggy pores in shelter pore space within the stromatolitic framework.

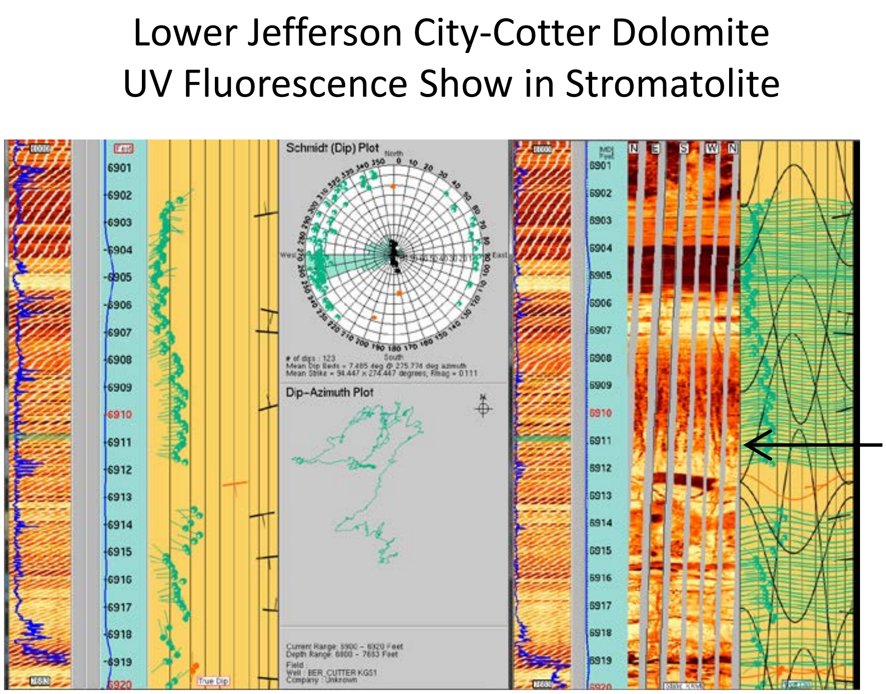


Figure 44. Image log at the location of the stromatolite. Vertically oriented vugs are dominate this interval, underlain by a dolomite mudstone, dark gray, autoclastic breccia with poor porosity and overlain by laminated shaly sediment (latter not cored).

Base Viola Ls., Simpson Gp.,
and upper Arbuckle Gp.

-- More light oil shows

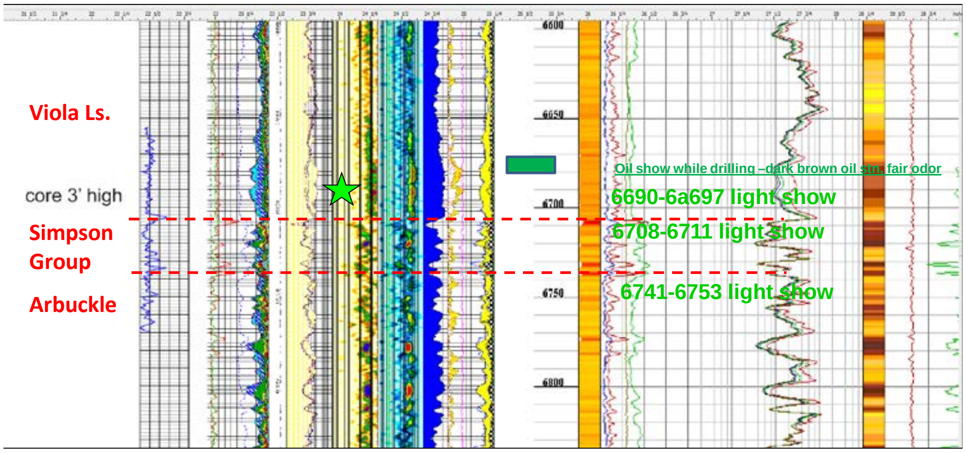


Figure 45. Contacts between top of Arbuckle, Simpson Group, and Viola Limestone illustrated by the MRIL and resistivity tools. Cored interval highlighted with blue drill time curve in left track. Simpson Group has slightly smaller pores and includes thin sandstone, dark gray, quartz - coarse grained, with phosphatic shale clasts. Top of Arbuckle is brecciated and reworked into base of Simpson Group. Note the UV hydrocarbon shows.

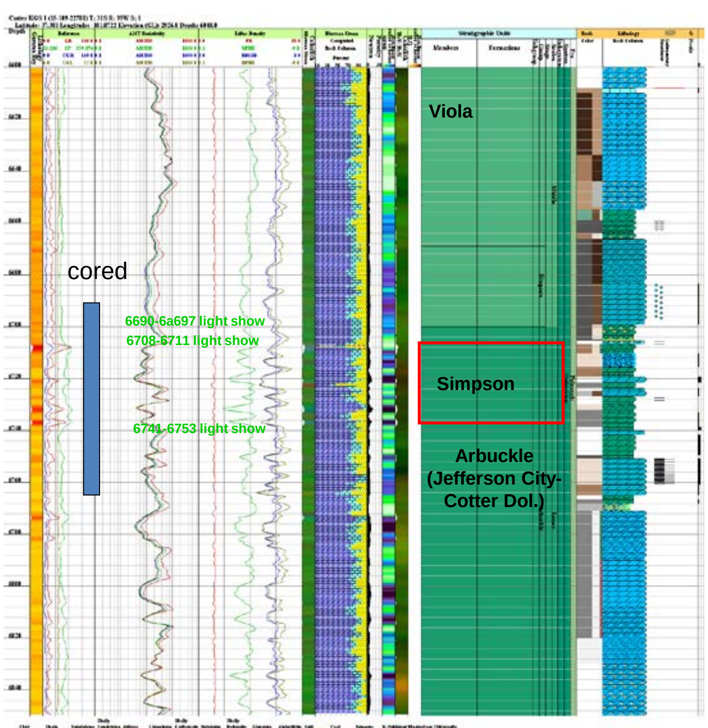


Figure 46. Same interval as in Figure 45 showing more argillaceous Simpson Group.

Simpson Group

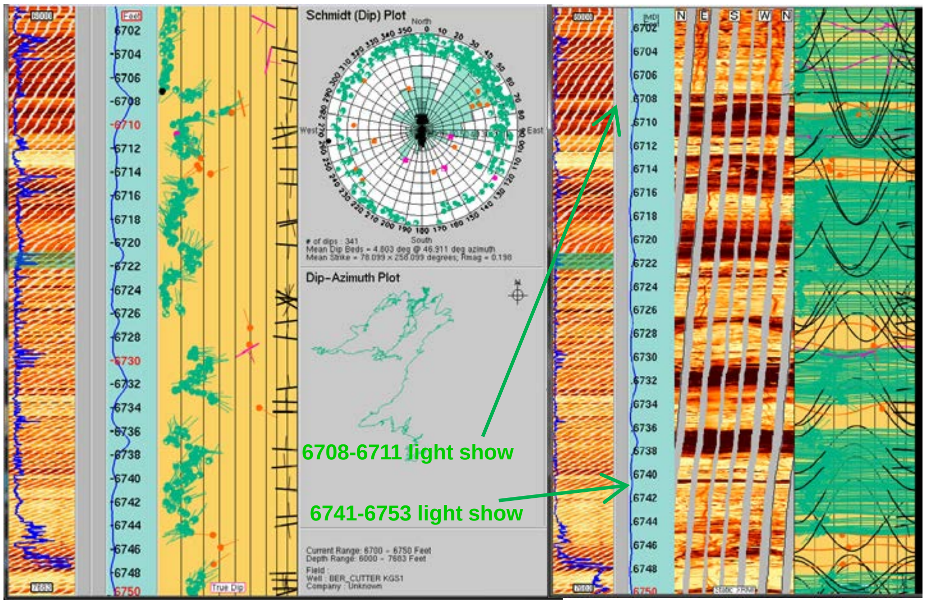


Figure 47. Image log with Simpson Group showing the intervals with hydrocarbon shows, thin interbedded sandy dolomite and shale.

Lower Osage, Northview Sh.,
Compton Ls., Chattanooga Sh.,
and upper Viola Ls.

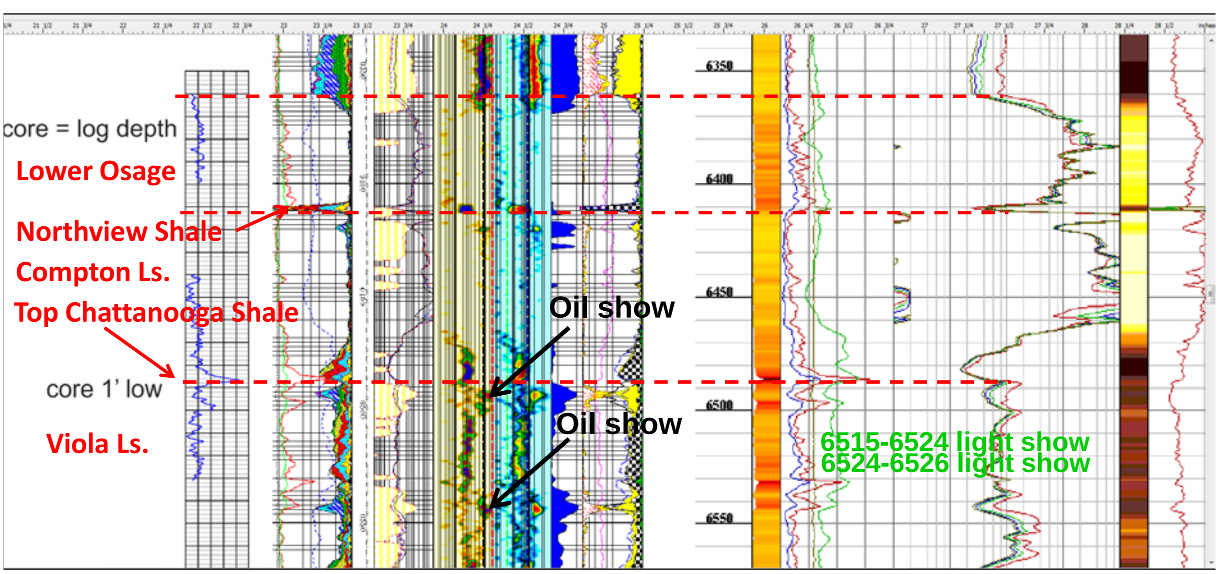


Figure 48. MRIL of the upper Viola Limestone to lower Osage Mississippian. Interval is very tight as indicated by the T2 curve and permeability estimate from the MRIL. This is considered the primary caprock above the Arbuckle saline aquifer. Not that oil shows occurred during drilling in the uppermost Viola, suggesting sealing nature of the overlying interval. UV shows are noted in the core.

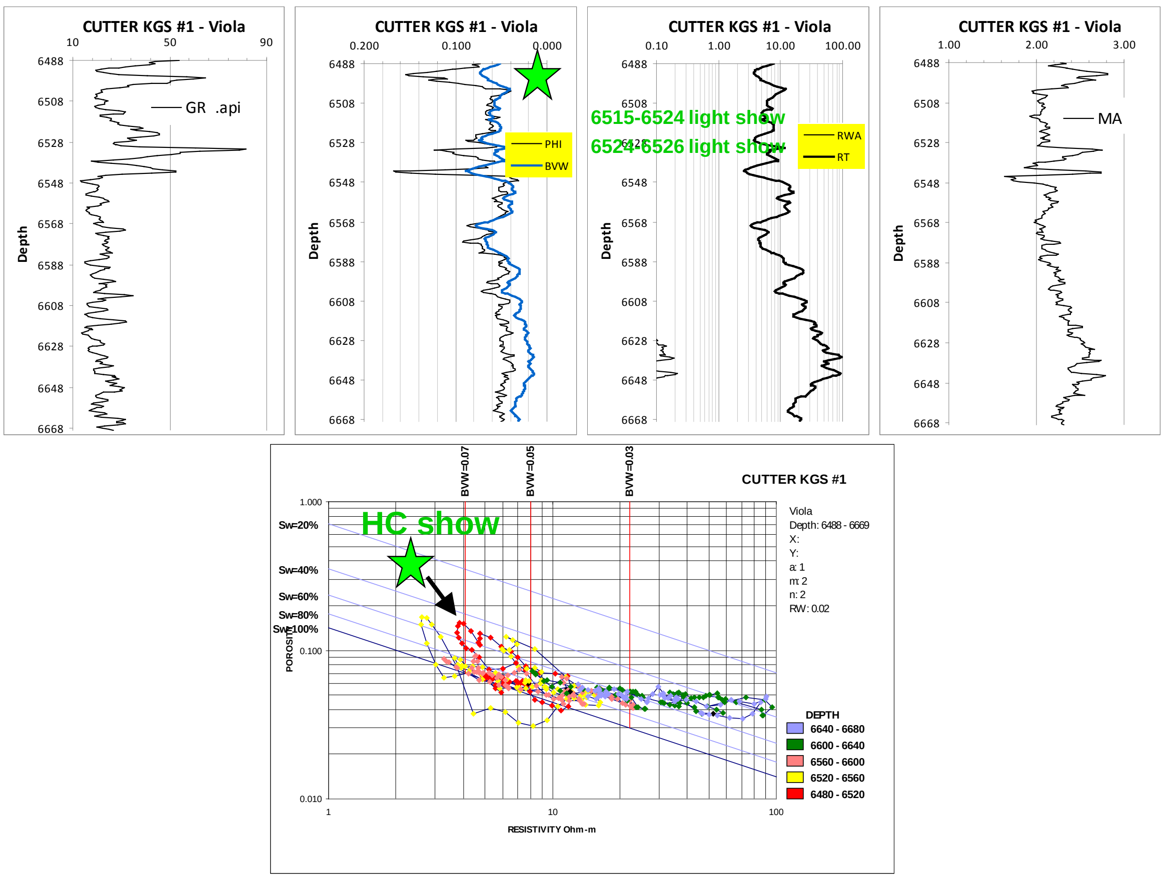


Figure 49. An examination of the standard log suite of the upper Viola Limestone in the interval of oil shows also confirm the hydrocarbon show with bulk volume water (BVW) less than porosity and water saturation calculation that indicates approximately 50%. This interval will be tested.

Chattanooga Shale-Viola Ls. Contact

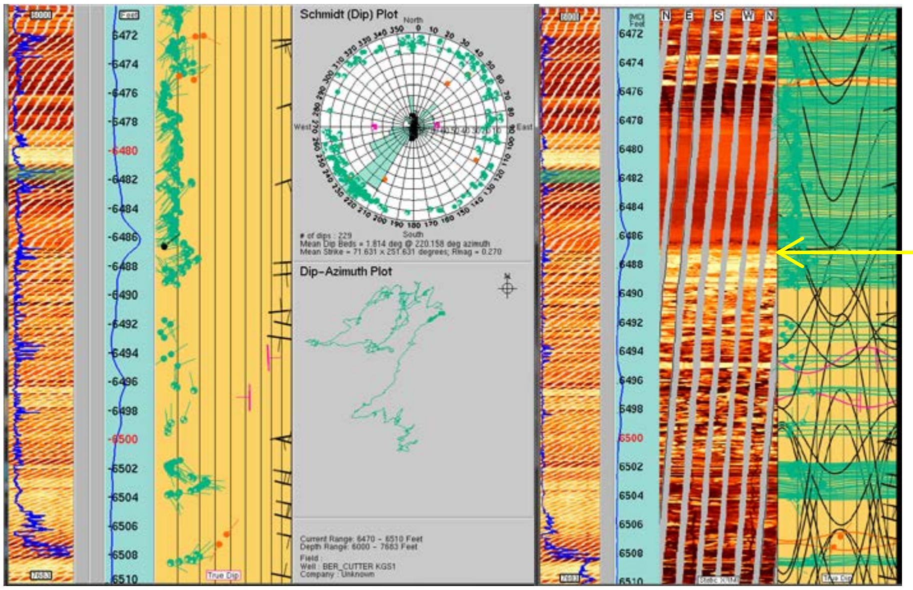


Figure 50. The Viola-Chattanooga Shale contact as viewed by the microresistivity imaging log. The basal Chattanooga Shale interval is argillaceous dolomitic mudstone, dark gray, abundant quartz silt, tight. The top of the Viola is chert conglomerate and breccia, tan, quartz sand matrix (well rounded, coarse sand) and clay, tight and hard. This is underlain by weathered breccia chert in green waxy shale, with broken pieces throughout the core box, abundant clay matrix, tight.

Lower Ste. Genevieve Ls. and upper St. Louis Ls.

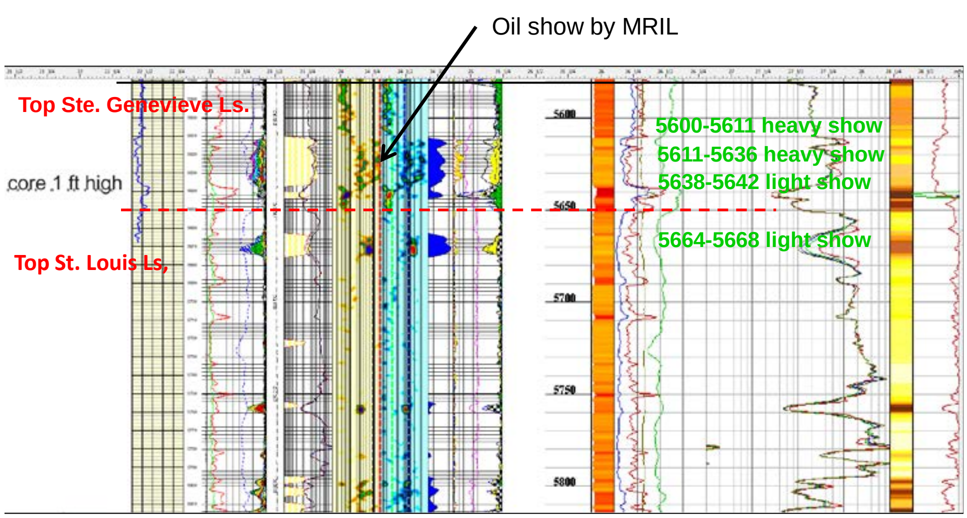


Figure 51. Coring at the base of the Ste. Genevieve and upper St. Louis Limestone included two porous intervals each with indications of hydrocarbon content.

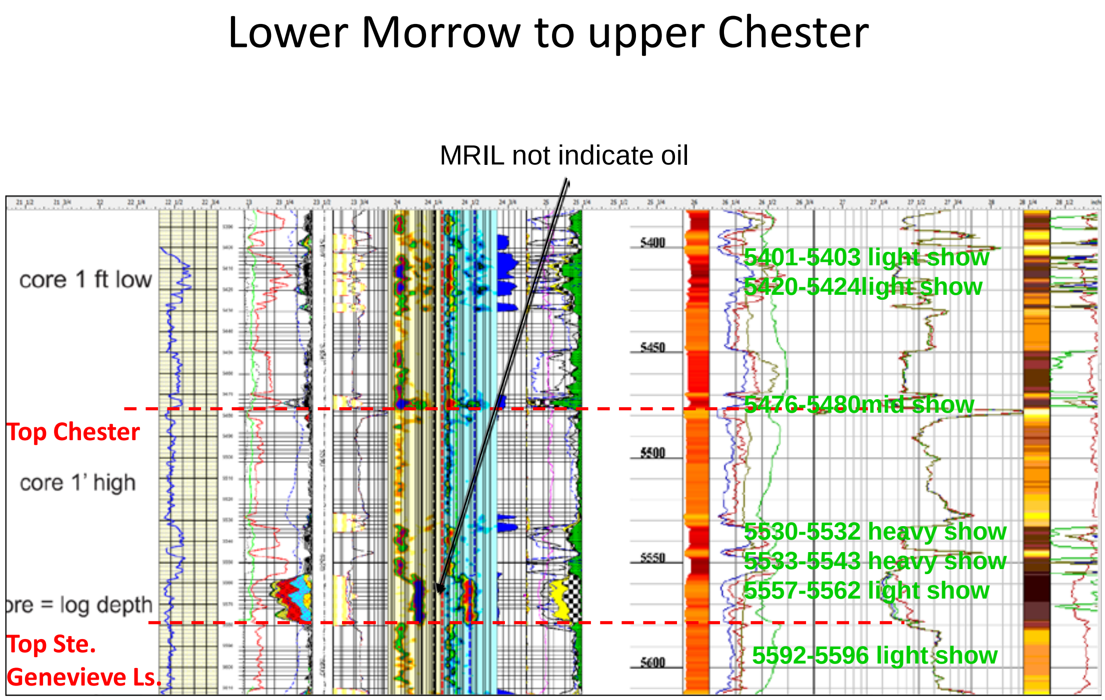


Figure 52. Additional hydrocarbon shows in the lower Morrow and Upper Chester also have hydrocarbon shows.

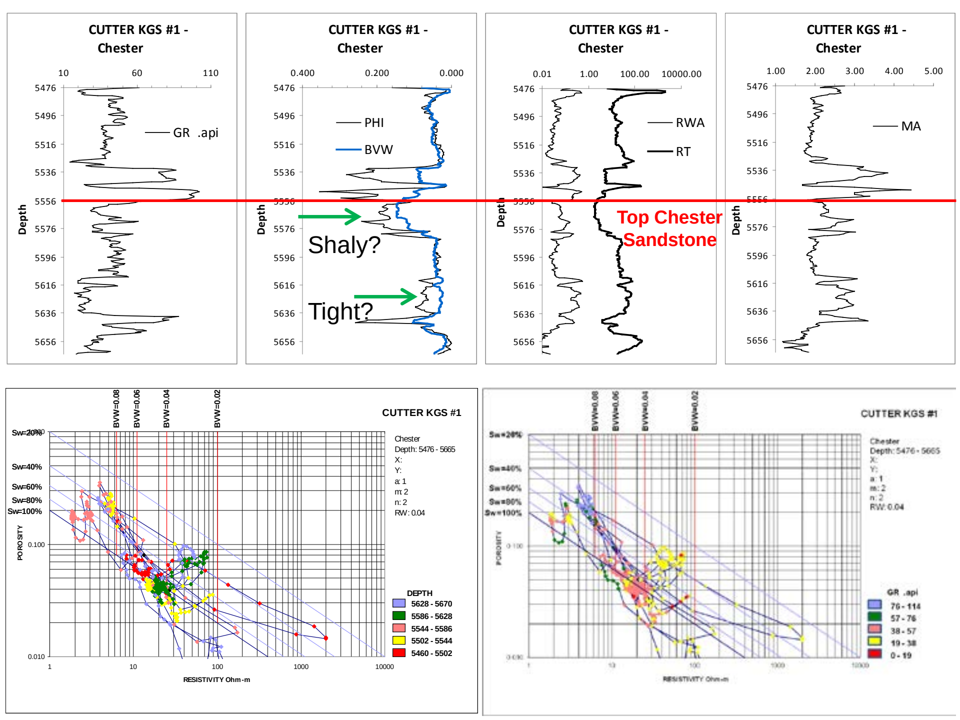


Figure 53. Standard logs and analyses indicate favorable oil reservoir in upper Chester sandstone.

Lower Morrow to St. Genevieve Ls.

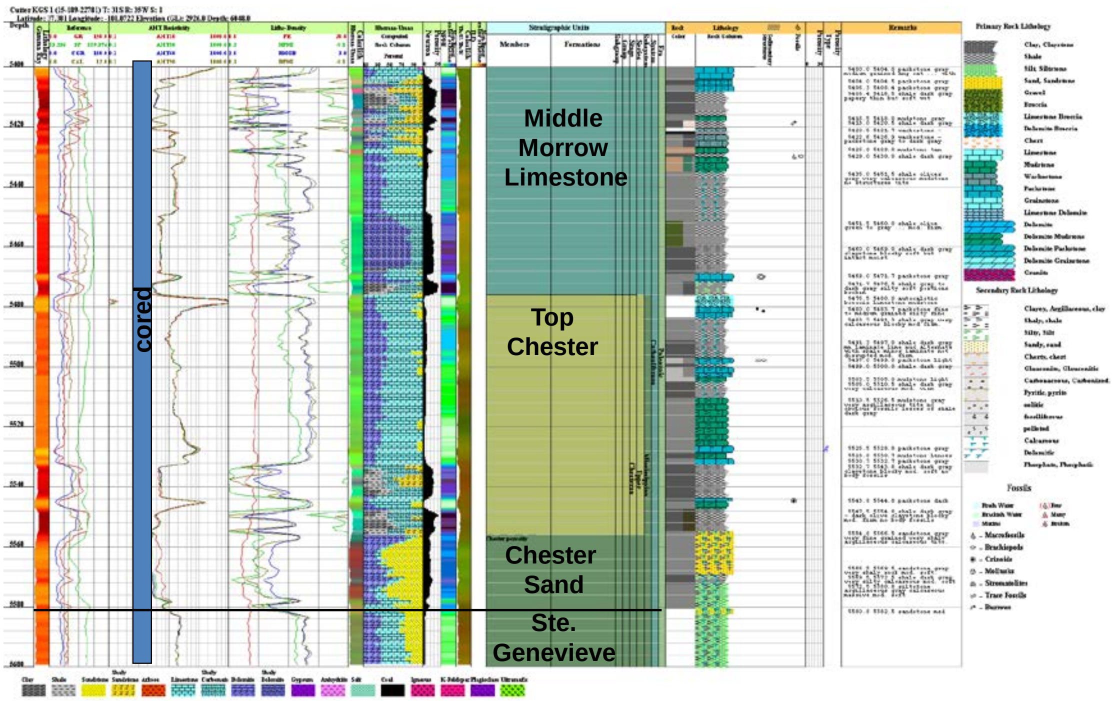


Figure 54. Examination of longer interval from Ste. Genevieve to Middle Morrow Limestone including complete Chester section. Entire interval was cored.

Upper Morrow Sandstone
-- Pay zone for Cutter Field

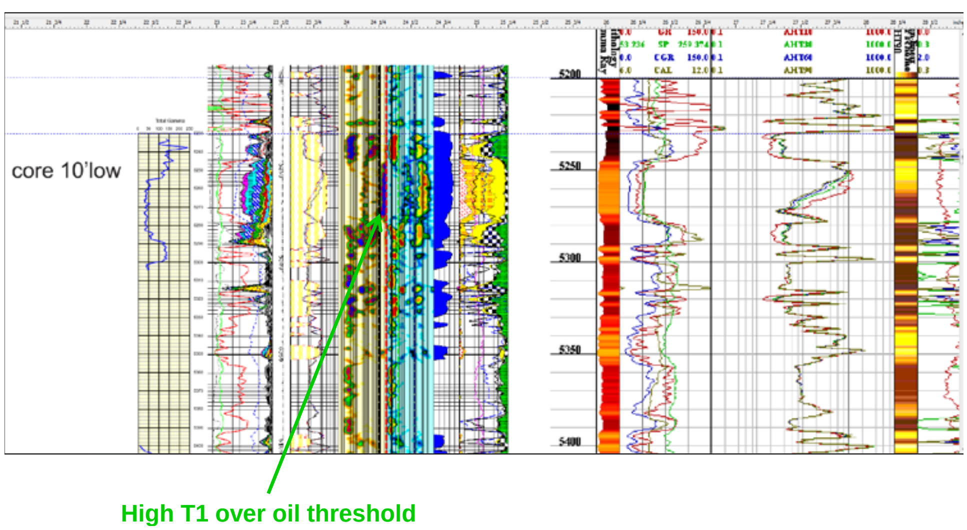


Figure 55. MRIL log of the Upper Morrow sandstone, the primary reservoir in Cutter Field.

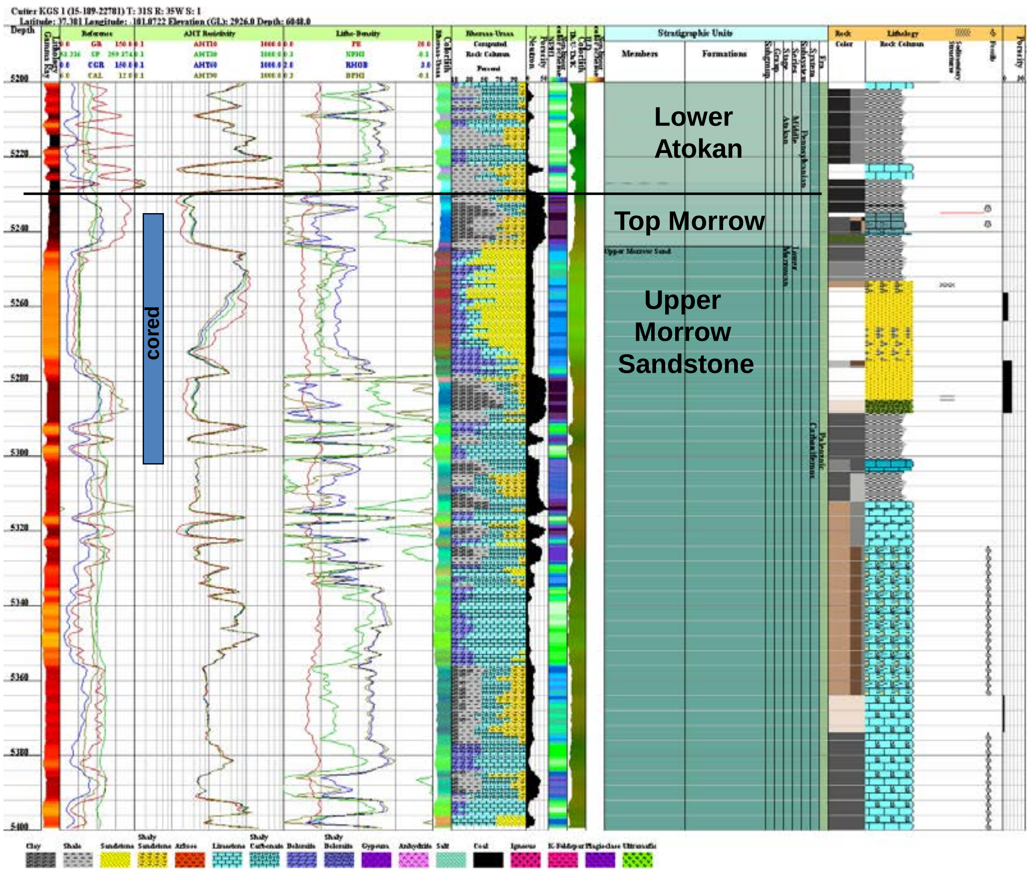


Figure 56. Longer section showing uppermost core interval that includes the Upper Morrow Sandstone reservoir.

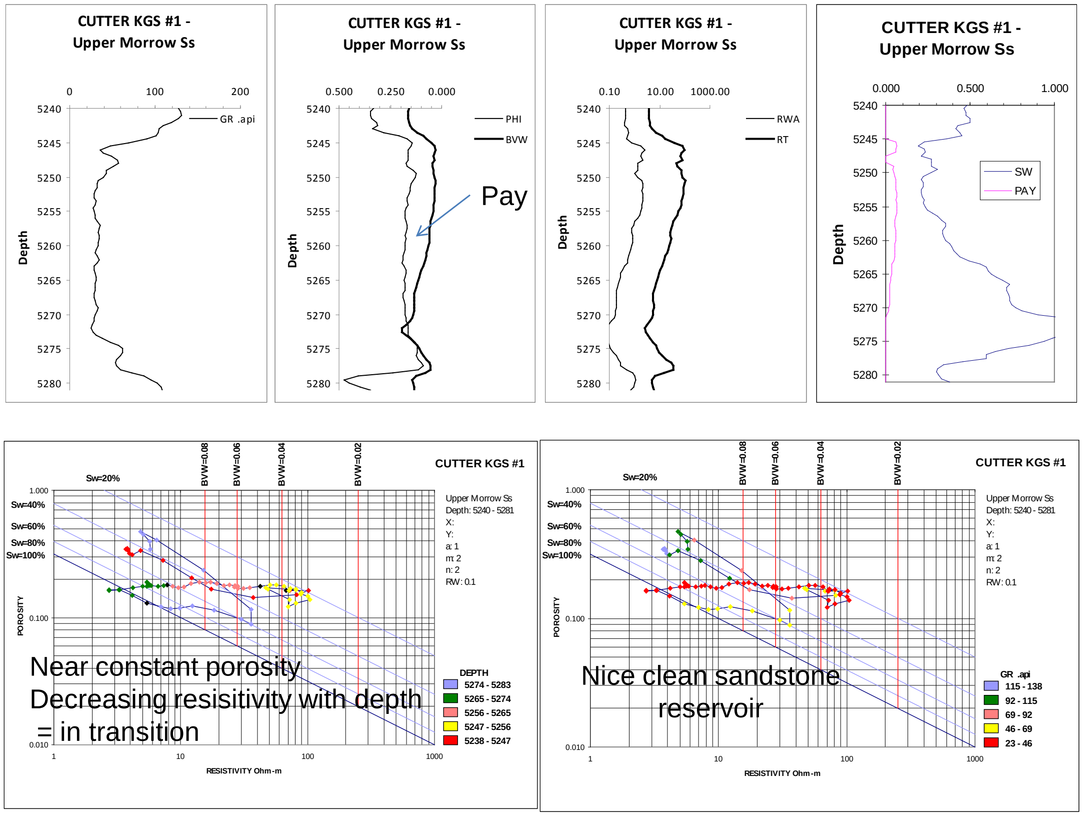


Figure 57. The analysis of the upper Morrow sandstone reservoir clearly indicates a long pay interval.

Future Studies
Key Findings, Significance

- **Core analysis;** core-log correlation
- **Perf and Swab**; fluid sampling and pressure buildup; pressure monitoring in nearby wells
- **Interpret 3D seismic** and integrate in reservoir model of Upper Morrow Sandstone
- **Simulation** CO2-EOR (U. Morrow) and CO2 sequestration (Arb.)
- **Arbuckle is complex stack of meter-scale peritidal cycles**, porous and non-porous
- **Oil shows need to be validated** – hot wire, UV, core analysis/saturations, oil typing
- **Potentially significant implications for petroleum system**

Figure 58. Summary of the initial description of the core and well logs.

Task 9: Characterization of Potential Leakage Pathways in Risk Assessment Area

Analysis of structure continues to understand timing and systematics of active tectonics and passive, subtle, gradual deformation.

Task 10: Risk Assessment Related to CO_2-EOR in Mississippian Chat Reservoir and CO_2 Sequestration in Arbuckle Aquifers

Study continues using well through mapping and cross sections, potential fields, seismic, and remote sensing data in southern Kansas to evaluate risk.

Task 12: Regional CO_2 Sequestration Potential in the OPAS in approximately 17 Counties in South-Central Kansas

Digitization, verification, addition of header information, and uploading of LAS files of type wells is nearly complete. The data will be used to refine the evaluation of carbon storage in southern Kansas.

The correlation of digital type logs is being assisted by volunteers who are experts who are validating and adding additional correlations. This process is enabled by the use of online software developed to expedite this review and editing process. Additions to stratigraphic correlations are limited to those vetted by the team. The outcome will be a more rigorous interpretation of lithofacies to evaluate caprocks, seals, reservoir, and variations within the saline aquifer as well as to document subtle changes due to structural activity. The results are being shared on the project’s interactive mapper as baseline data to backup the evaluation of CO2 storage and risk variables.

The online Java application used to evaluate, modify, and add to the stratigraphic correlations is illustrated in the following figures.

Login to Enable Map

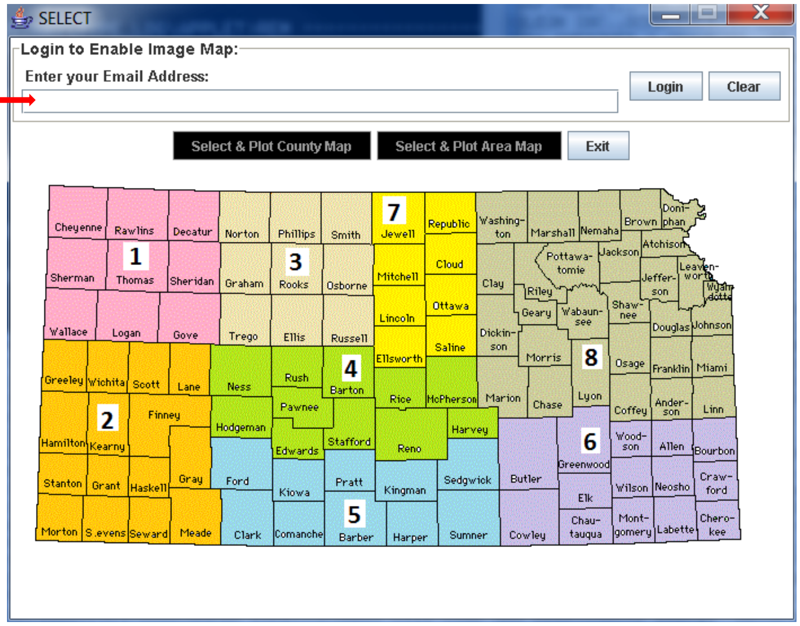


Figure 59. The state is divided into provinces that reflect the divisions of geology and expertise. User enters site via password.

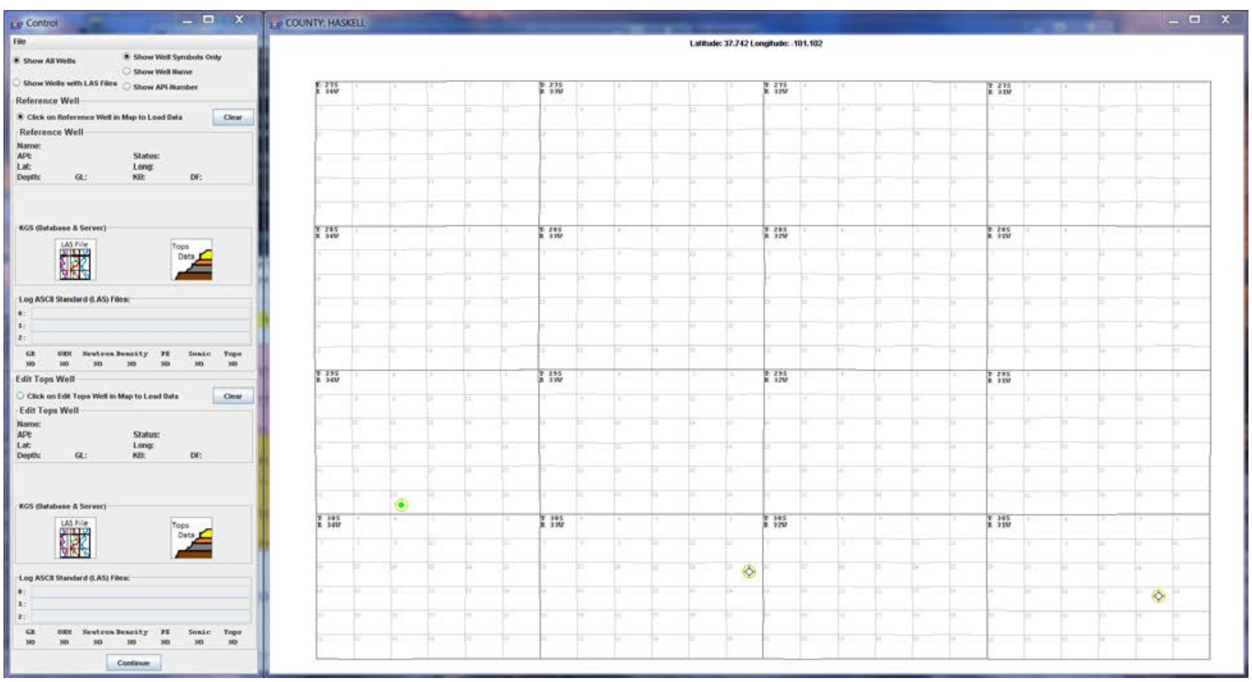


Figure 60. A region of the state is selected and wells are shown. Bold blocks are townships, 6 miles on a side.

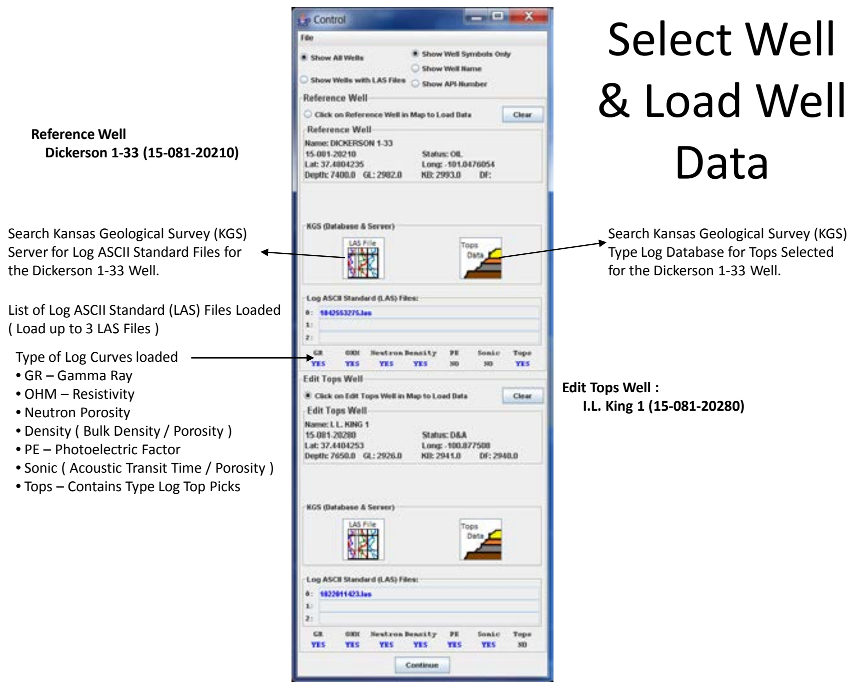


Figure 61. Interface to select wells and formation tops and view log curves that are available.

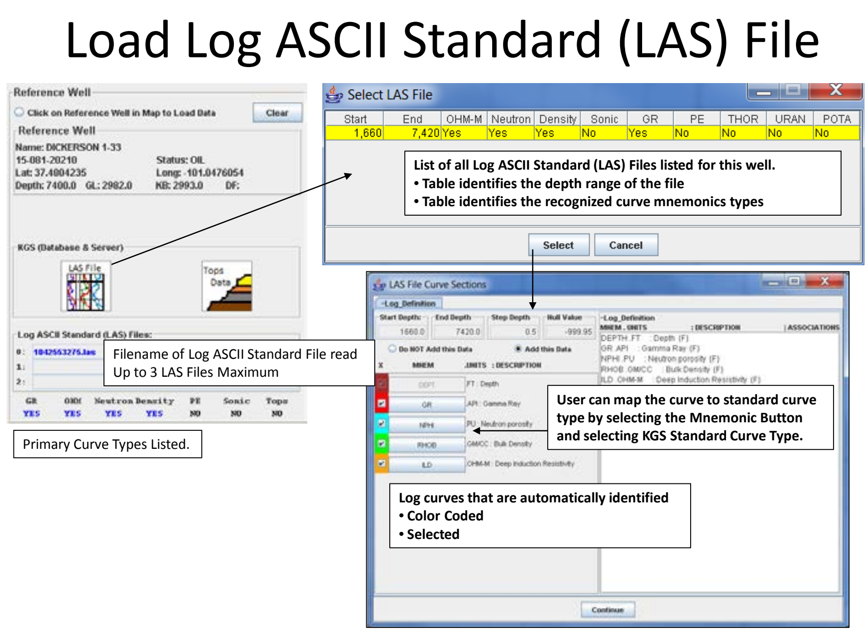


Figure 62. Popup dialogs show details of LAS file that are available and dialog that allows user to choose curves to show and depth intervals.

Load Type Log Selected Tops

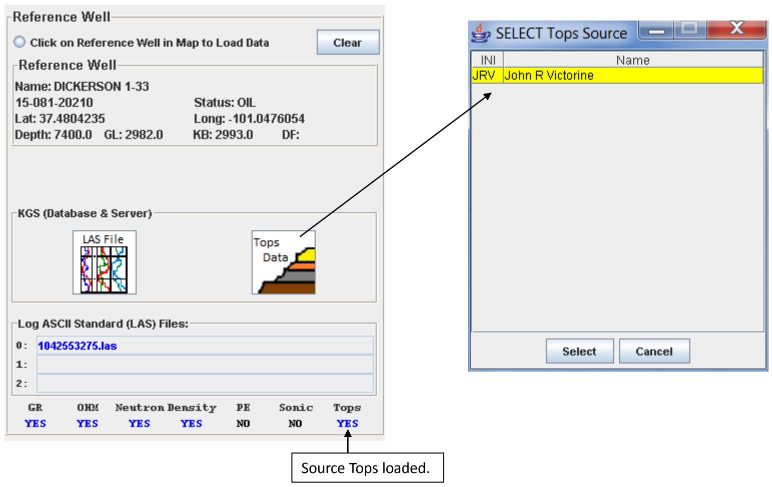


Figure 63. Loading of existing stratigraphic tops to be evaluated are identified by person who correlated the top.

Well Map Displays selected Wells

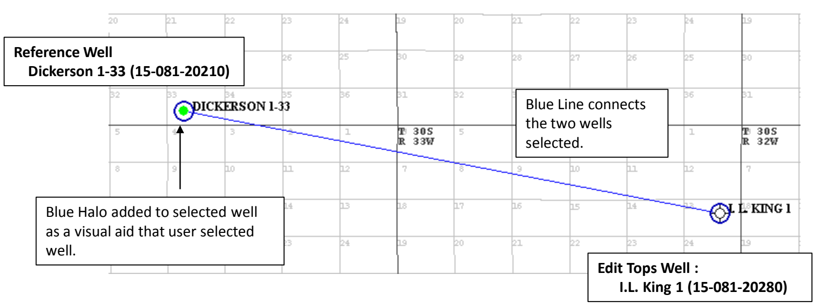


Figure 64. Portion of the map that is subsequently shown with the identification of the reference well and well to be edited. Also index line of the cross section is shown that is subsequently displayed.

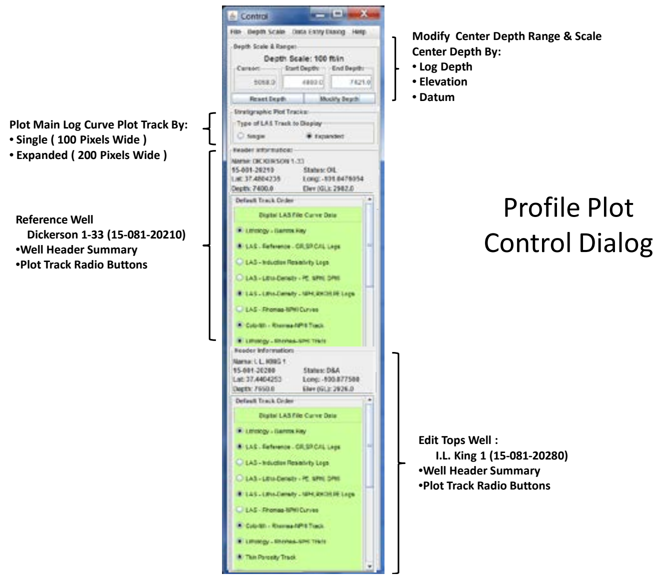


Figure 65. Along with the cross section, another dialog box is shown that permits the user to change how the cross section is displayed, including logs, interval, and scale.

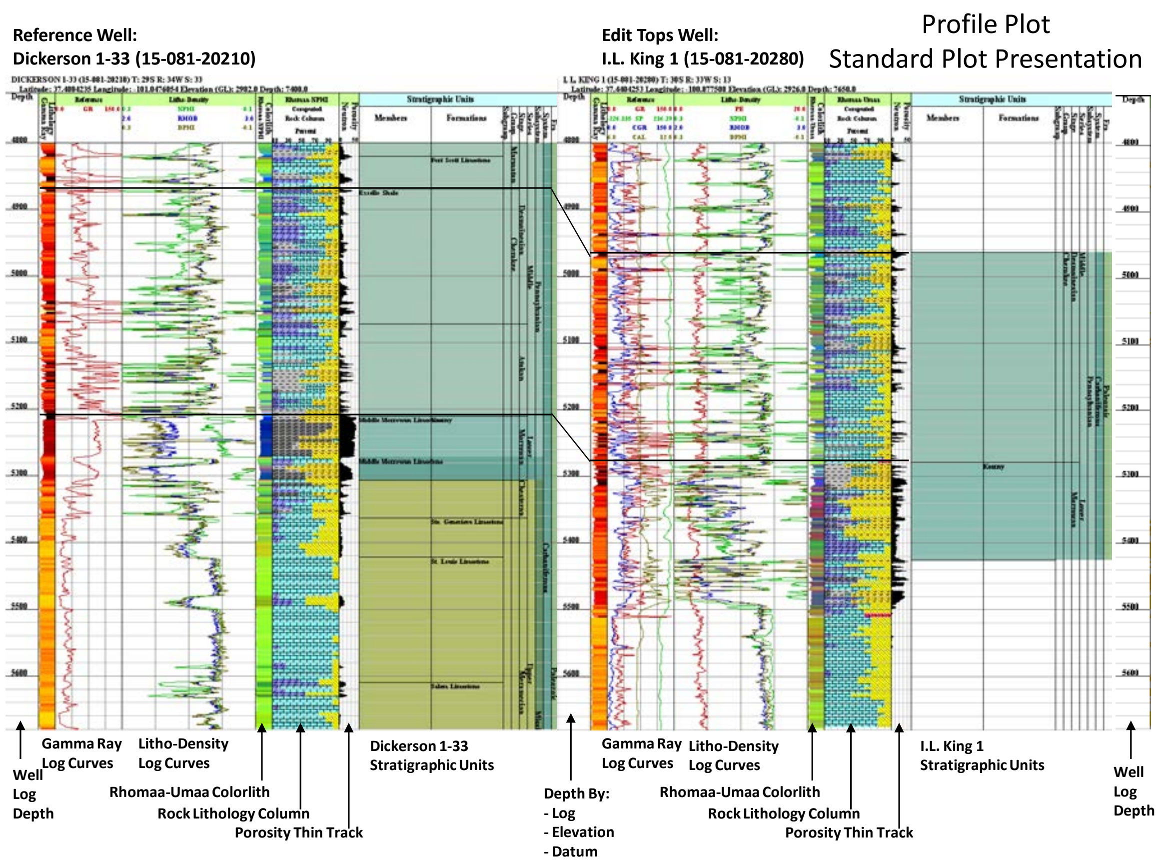


Figure 66. Example cross section showing log curves, log images, and stratigraphic correlations based on the digital data – LAS files, tops, etc.

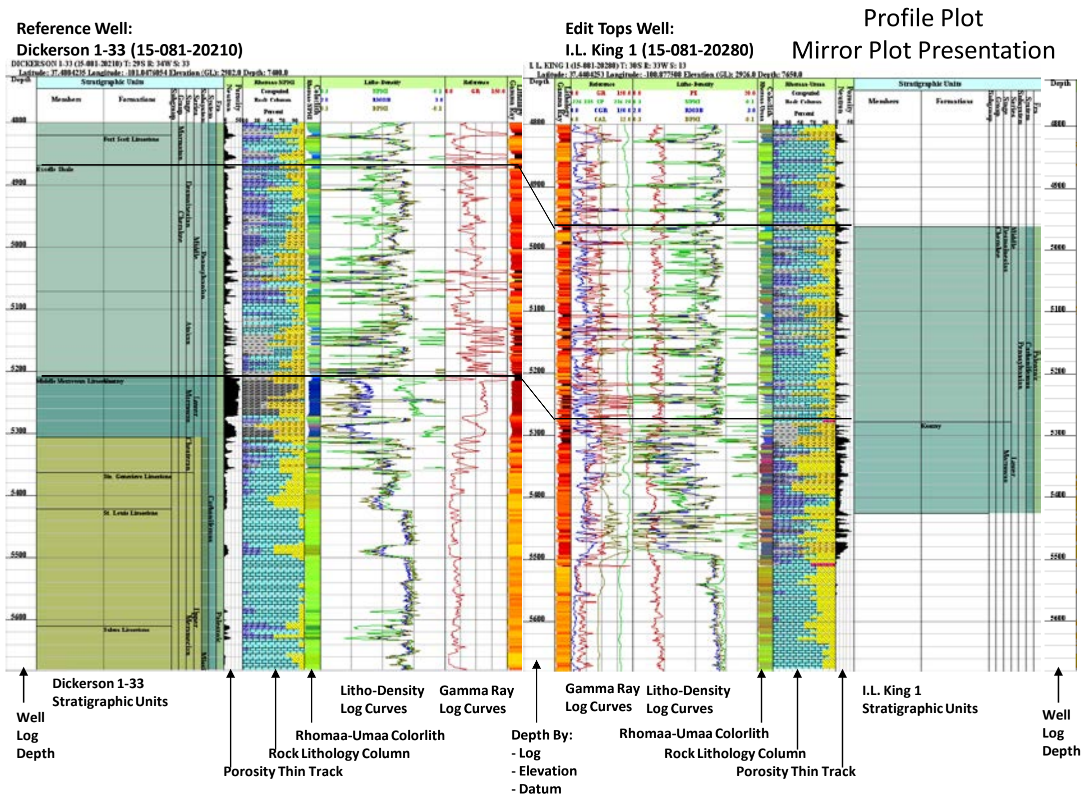


Figure 67. Cross section with reference well on left and edit tops well on right. This new cross section routine will be expanded to four wells maximum (due to video memory limitations experienced by most users) to use to interrogate the LAS database.

Adding and Evaluating Well Tops

Reference Well

- Copy Tops from Reference Well and Paste in Edit Well
- Tops are fixed and can not be edited as reference well

Edit Tops Well

- Copy Tops from Reference Well and Paste in Edit Well
- Only Tops Source can modify depth or name
- User adding a new top is source.
- User not source may only evaluate
  - by clicking thumbs up or thumbs down
  - and setting their depth
- As mouse floats over tops position
  - Displays the name, depth range, status (Gold, Silver,…)
- Left Click on mouse to Edit or Evaluate Top

Figure 68. Activities to edit and add stratigraphic tops.

Subtask 17.4. Process multi-component 3D seismic survey (Cutter Field)
*The Recipient shall process the newly acquired multi-component 3D seismic data. Analysis of the data shall include, but not be limited to, Kircoff pre-stack time migration, frequency enhancement, and relative seismic inversion. The newly acquired multi-component 3D seismic data will enhance characterization of both the Chester/Morrow sandstone reservoir and the Arbuckle Group saline aquifer by: a) detecting and characterizing important fracture/faults in the study area, b) helping resolve azimuth and frequency of fracture using seismic anisotropy, and c) determining if faults/fractures are open or closed, and d) resolving other rock proper*ties.

Cutter Field seismic data has been processed for P-wave data.

Task 19: Integrate Results with Larger 17+ County Regional Project in South-central Kansas

Integration and analysis of well and seismic data continue along with finalizing of digital log data.

Subtask 18.1. Update geomodels of the Chester/Morrow sands and Arbuckle Group saline aquifer in selected fields

The Recipient shall integrate multicomponent 3D seismic with core, wireline logs, and well test data to characterize and develop fine scale geomodels for both the Chester/Morrow sandstone reservoir and the Arbuckle Group saline aquifer along with respective caprocks. Pressure tests carried out across select perforations will also aid in understanding zonal (flow unit) communication across aquitards within the Arbuckle Group.

The following figures provide an update of the team working on the characterization and modeling of Pleasant Prairie South, Eubanks North, Cutter, and Schuck Fields. Text is limited to the figure captions since information in figures is extensive.

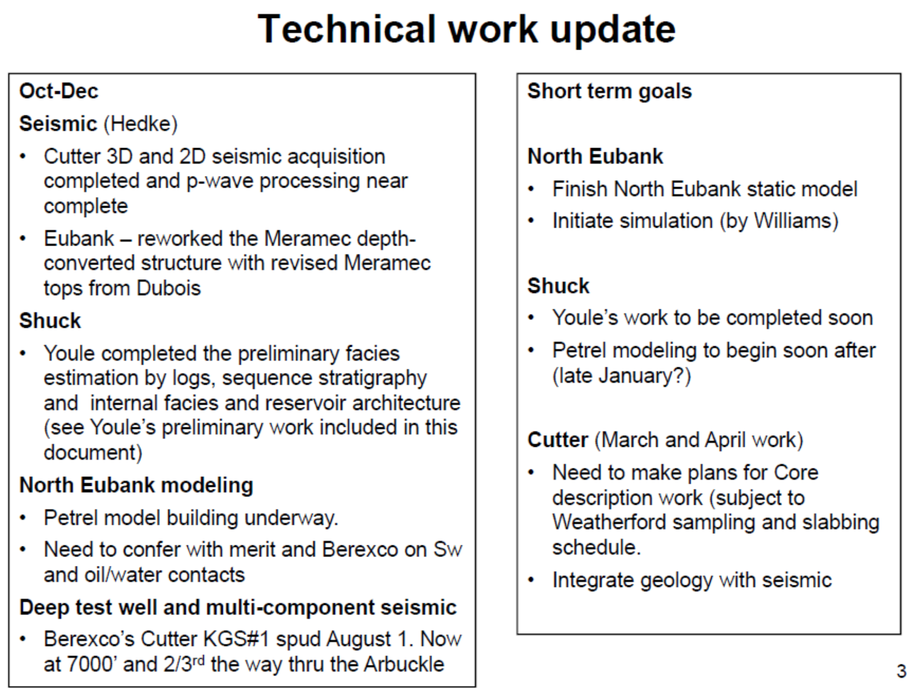


Figure 69. Status of the Southwest Kansas CO2 Initiative.

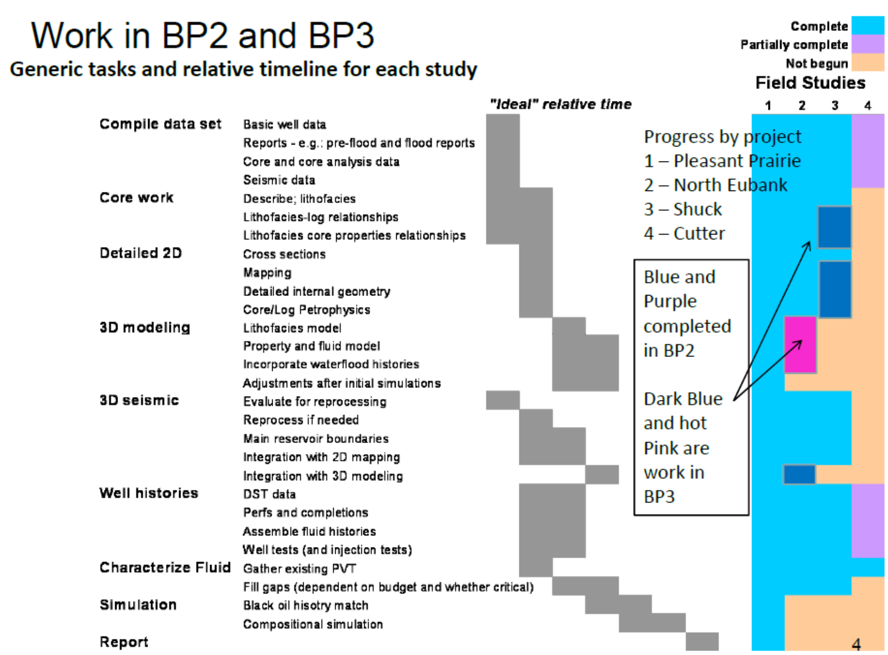


Figure 70. Timeline of the Southwest Kansas CO2 Initiative

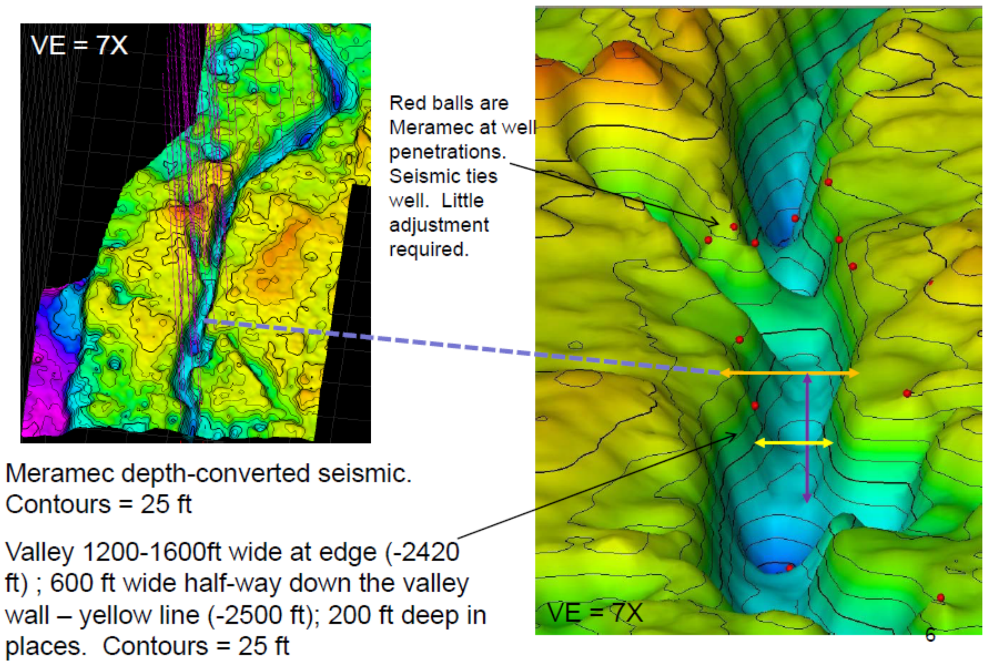


Figure 72. Eubank merged seismic showing Meramec depth structure.

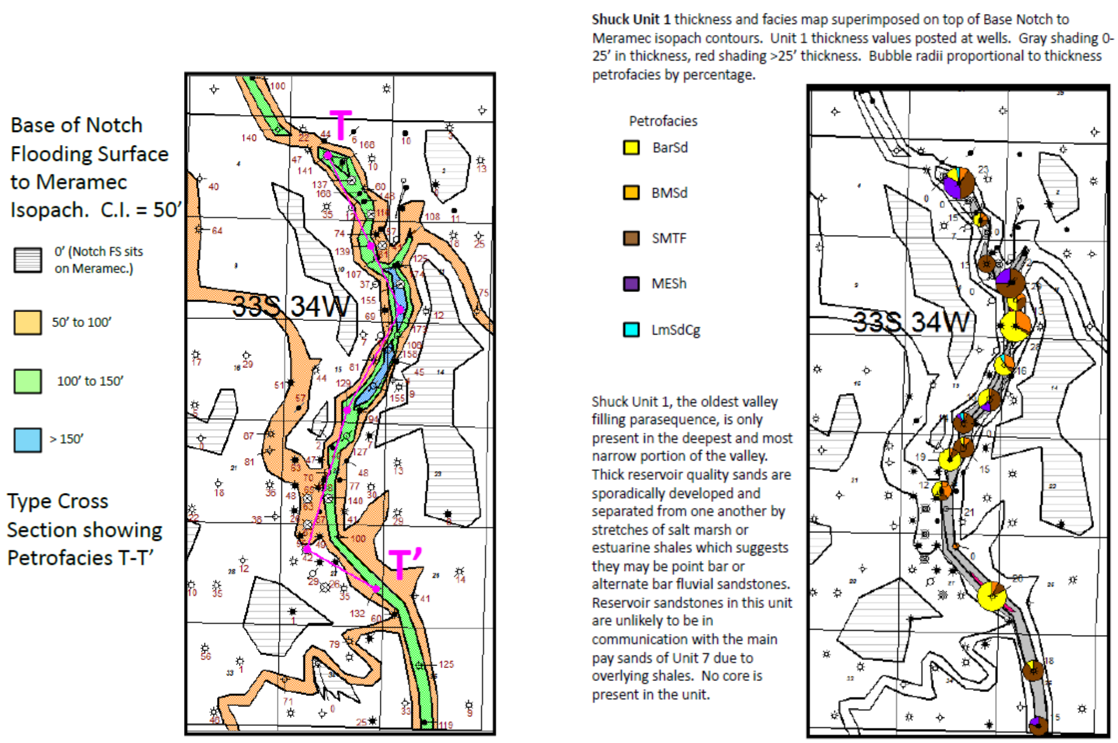


Figure 73. Interpretive maps of Chester incised valley fill in Eubank Field by Youle.

Shuck Unit 2 thickness and facies map superimposed on top of Base Notch to Meramec isopach contours. Unit 2 thickness values posted at wells. Gray shading 0-25' in thickness, red shading >25' thickness. Bubble radii proportional to thickness petrofacies by percentage.

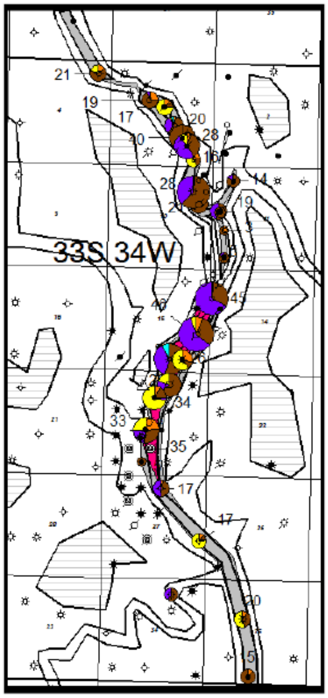
Petrofacies

BarSd SMTF

BMSd MESh

LmSdCg

Shuck Unit 2, the 2nd oldest valley filling parasequence, has a similar distribution to Unit 1 except it is more extensive throughout the valley and is much thicker in places. Where the unit thins to near zero at the base of the valley in the SW4 of section 11 it has been removed by Unit 7 incision. Unit 2 largely is composed of shales and sandy shales which should provide a top seal separating underlying Unit 1 fluvial sands from overlying estuarine valley fill reservoir sands. Local Unit 2 reservoir sandstones in section 22 are also unlikely to be plumbed into the overlying main pay sands as they are overlain by Unit 3 top sealing shales. Similar to Unit 1 sands, Unit 2 sands are probably local fluvially deposited lateral accretions bar sandstones; however, no core is present in the unit.



Shuck Unit 3 thickness and facies map superimposed on top of Base Notch to Meramec isopach contours. Unit 3 thickness values posted at wells. Gray shading 0-25' in thickness, red shading >25' thickness. Bubble radii proportional to thickness petrofacies by percentage.

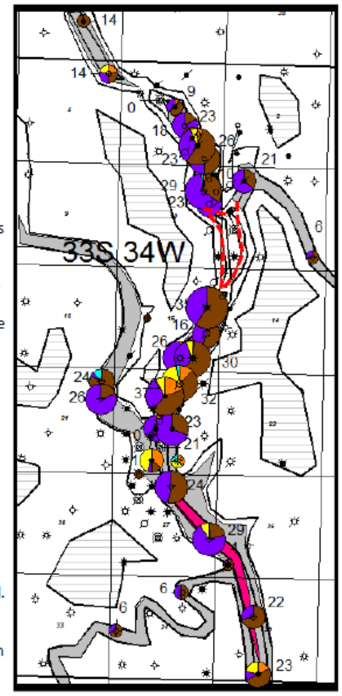
Petrofacies

BarSd SMTF

BMSd MESh

LmSdCg

Shuck Unit 3, is present over a broader area of the valley than older parasequences and appears to overstep them as it onlaps onto valley walls. Unit 3 is also the first parasequence to to have been deposited in tributary channels suggesting a progressive rise in base level from deposition of Unit 1 through Unit 3. Where the unit thins to zero at the base of the valley in the SW4 of section 11 (within red dashed outline) Unit 3 rocks have been removed by Unit 7 incision. Unit 7 valley incision reaches a maximum depth just below the confluence of the main valley with the large tributary running through section 11, and where the valley impinges against the nearly vertical eastern valley wall. Similar to Unit 2, Unit 3 is mostly composed of shales and sandy shales characteristic of salt marsh and subtidal central-basin estuarine deposits.



Shuck Unit 4 thickness and facies map superimposed on top of Base Notch to Meramec isopach contours. Unit 4 thickness values posted at wells. Gray shading 0-25' in thickness, red shading >25' thickness. Bubble radii proportional to thickness petrofacies by percentage.

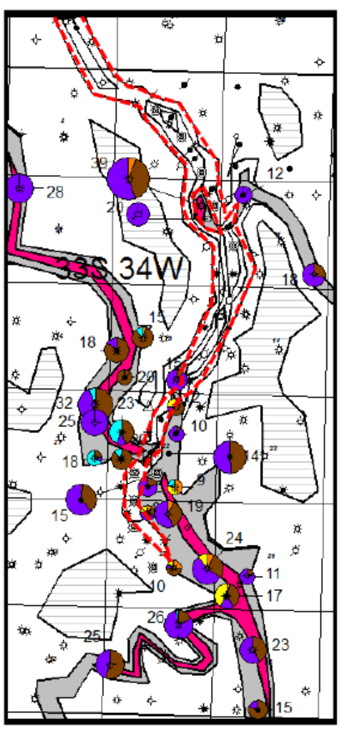
Petrofacies

BarSd SMTF

BMSd MESh

LmSdCg

Shuck Unit 4, is present over a broader area of the valley than older parasequences and appears to overstep them as it onlaps onto valley walls. Unit 4 overlaps Unit 3 rocks in tributaries suggesting a progressive rise in base level from deposition of Unit 3 through Unit 4. Unit 4 rocks are interpreted to have been completely removed by erosion associated with the final episode of channeling within the main incised valley within area of red dashed lines. Similar to Units 2 and 3, Unit 4 consists is mostly of non-reservoir shales and sandy shales characteristic of salt marsh and subtidal central-basin estuarine deposits. A thin (up to 6' thick) sandbar is present at the base of Unit 4 in the sw4 of section 26 but is unlikely to be physical contact with the main reservoir pay sand for the field.



Shuck Unit 5 thickness and facies map superimposed on top of Base Notch to Meramec isopach contours. Unit 5 thickness values posted at wells. Gray shading 0-25' in thickness, red shading >25' thickness. Bubble radii proportional to thickness petrofacies by percentage.

Petrofacies

BarSd SMTF

BMSd MESh

LmSdCg

Shuck Unit 5 is thinner than underlying Unit 4, but also oversteps Unit 4 beyond valley walls as it onlaps paleoghighs. This relationship again suggests a progressive rise in base level through deposition of Unit 5. Unit 5 rocks are interpreted to have been completely removed by erosion associated with the final episode of channeling within the main incised valley within area of red dashed lines. Similar to older units, Unit 5 consists is mostly of non-reservoir shales and sandy shales characteristic of salt marsh, subtidal central-basin estuarine deposits, and probably some paleosols along the margins of paleohighs.

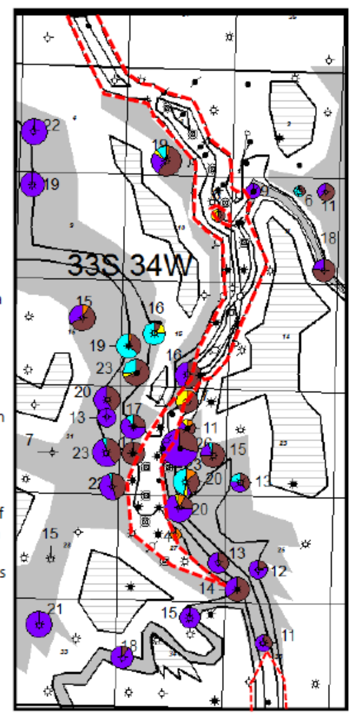


Figure 74. Interpretive maps of Chester incised valley fill in Eubank Field by Youle

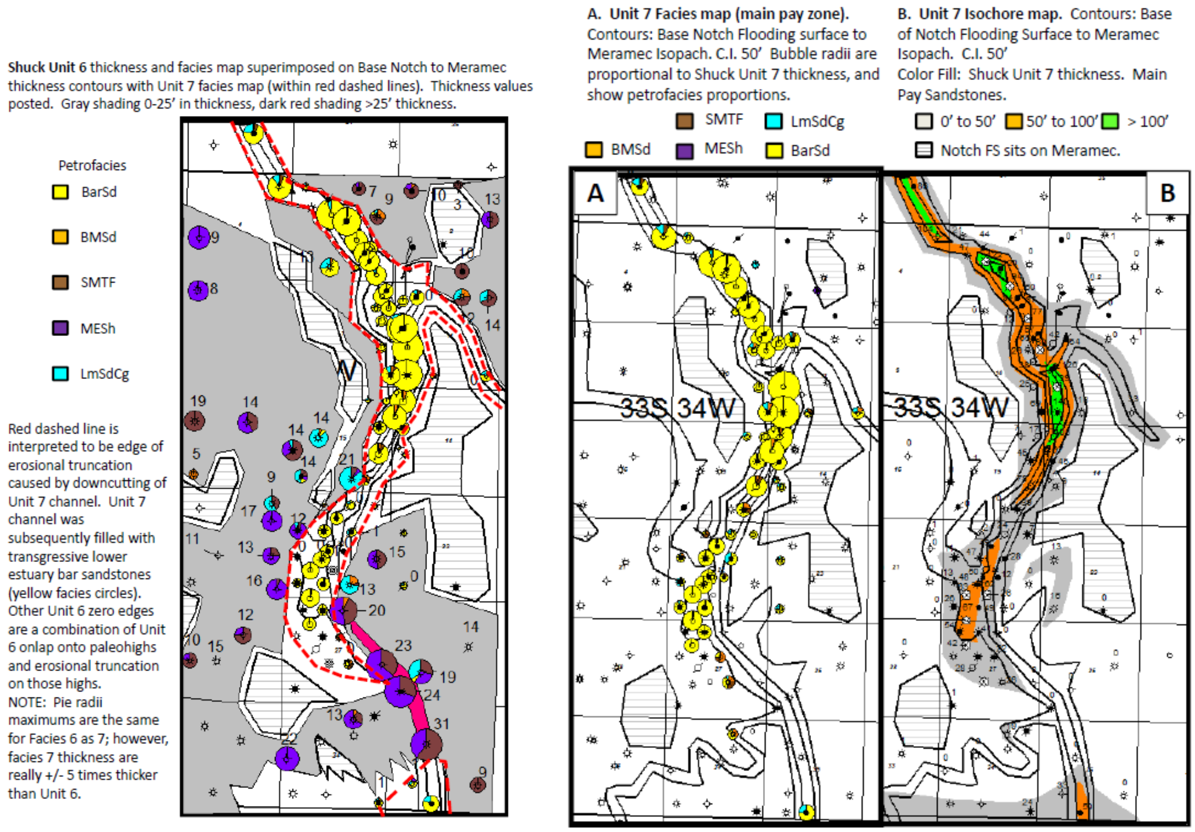


Figure 75. Interpretive maps of Chester incised valley fill in Eubank Field by Youle

ONGOING ACTIVITIES - WELLINGTON FIELD –

Subtask 6.5. Update geomodels of the Mississippian and Arbuckle at Wellington Field.

WELLINGTON FIELD MISSISSIPPIAN FORMATION
Preliminary Reservoir Description of the Mississippian by Mina FazelAlavi

Based on core data, conventional log analysis results, NMR analysis results and generalized Pc curves in the Wellington field, permeability in wells was estimated, capillary pressure curves and relative permeability curves were proposed for different rocks in the Mississippian reservoir. Well 1-32 has the most complete set of data and it was used as the key well. Routine core data of this well was analysed by FZI method and FZI was correlated with log derived porosity and water saturation of this well (NMR irreducible water saturation). FZI from cores was statistically related to the irreducible water saturation and porosity from log data. The following correlation was derived and permeability in well 1-32 was estimated in Chat conglomerate and Carbonate zones:

$$K = 1014\left[\frac{a}{S_{wir}\phi_e} + b\right]^2 \frac{\phi_e^3}{(1-\phi_e)^2}$$

The derived permeability was compared with core permeability and Coates permeability. The permeability from the correlation matches better with core permeability than NMR methods for permeability estimation. This correlation couldn't be applied to other wells to find permeability since initial water saturation was not available in them. Therefore, permeability of these wells was estimated by another technique. The reservoir was divided into six zones in 1-32 well based on log signatures and FZI and then equivalent FZI zones in other wells corresponding to well 1-32 were found and therefore permeability of each zone was estimated by the following equation:

$$K = 1014[FZI]^2 \frac{\phi_e^3}{(1-\phi_e)^2}$$

Dynamic modelling of Mississippian reservoir needs capillary pressure and relative permeability curves. The reservoir was divided into two zones (Chat conglomerate and carbonate) based on pore size distribution. Pc curves and relative permeability curves were derived for eight RQI ranges in Chat conglomerate and carbonate zones in the Mississippian. In the absence of special core analysis data, NMR data of Well 1-32 were used to drive capillary pressure curves for different RQI ranges of the reservoir. Pc curves in this report are based on generalized Pc curves, NMR irreducible water saturations and entry pressure from NMR. Both entry pressure and the irreducible water saturation can be defined as functions of RQI. The correlations between the end points and RQI and a single equation for the shape of generalized Pc curves were used to derive Pc curves for each RQI for each similar pore size distribution (single and bimodal). Both drainage and imbibition Pc curves were calculated for the reservoir. Depending on the path of oil migration into the Mississippian formation either drainage or imbibition Pc curves could be applied to the model and wells to represent initial condition of the reservoir. The Pc curves based on RQI provide initial water saturation for every depth in the reservoir. Initial water saturation calculated from the Pc curves based on RQI correlation matches with the initial water saturation from NMR in well 1-32.

SCAL Core relative permeability data were missing. Based on estimated end points from well 1-32 and generalized data from other fields, relative permeability curves were generated for all rock types. Since special core analyses is being performed in the lab on core samples of well 1-32, proposed capillary pressure curves and relative permeability curves in this report will be calibrated against lab data in future. Often the Grid of the dynamic or static model of the reservoir is divided in several Saturation Regions, each with a specific RQI. For each region a specific set of Pc curve and relative permeability tables is prepared to be assigned to the saturation regions during modeling. Detailed report of this work was prepared and is available.

Evaluation of lower Mississippian argillaceous, dolomitic siltstone as a part of the primary caprock at Wellington Field

The Chattanooga Shale is the primary caprock at Wellington Field and for the eastern half of the study area in south-central Kansas. However, locally this shale is missing in the field including at KGS Wellington #1-32. The lower Mississippian strata in and near Wellington Field contain another interval that is being evaluated for it serving as a primary caprock in addition to the Chattanooga Shale. It is being informally referred to as the Pierson formation in that it has properties that resemble the formation of the same name where it is exposed in the Ozark Uplift in southwest Missouri. This interval has been studies via the multidisciplinary team addressing the following:

Lithofacies – It was previously established that the Pierson formation is an argillaceous, dolomitic, siltstone containing varying amounts of organic matter imparting a dark gray to black color to the rock. Total organic carbon on three samples was under 2%. Spectral gamma ray log indicates that the interval is clearly defined by elevated uranium concentration (up to 6 ppm).

Porosity and permeability – The Pierson is firm and impervious with permeability measured as low as picodarcies by Scheffer at NETL lab in Pittsburgh. Porosity and permeability estimated by the nuclear magnetic resonance imaging log concur with the lab measurements on core and the pore size measured from the NMR log places the pore size just above the shales (**Figure 76**). Helical CT scans of the interval further attest to small pores and integrity of the Pierson formation.

Mechanical properties and fractures – The rock is moderately stiff, but fracture density is less than in other intervals as previously noted based on core description, dipole sonic, microresistivity imaging log, and helical CT scans of the rock.

Performance of caprock/seal properties of Pierson formation – A porous interval below the Pierson formation has a notable oil show (show of oil during drilling, oil staining of the core, oil saturation calculations from well logs) in Wellington KGS #1-32 indicating the Pierson is sealing at this location (**Figure 77**).

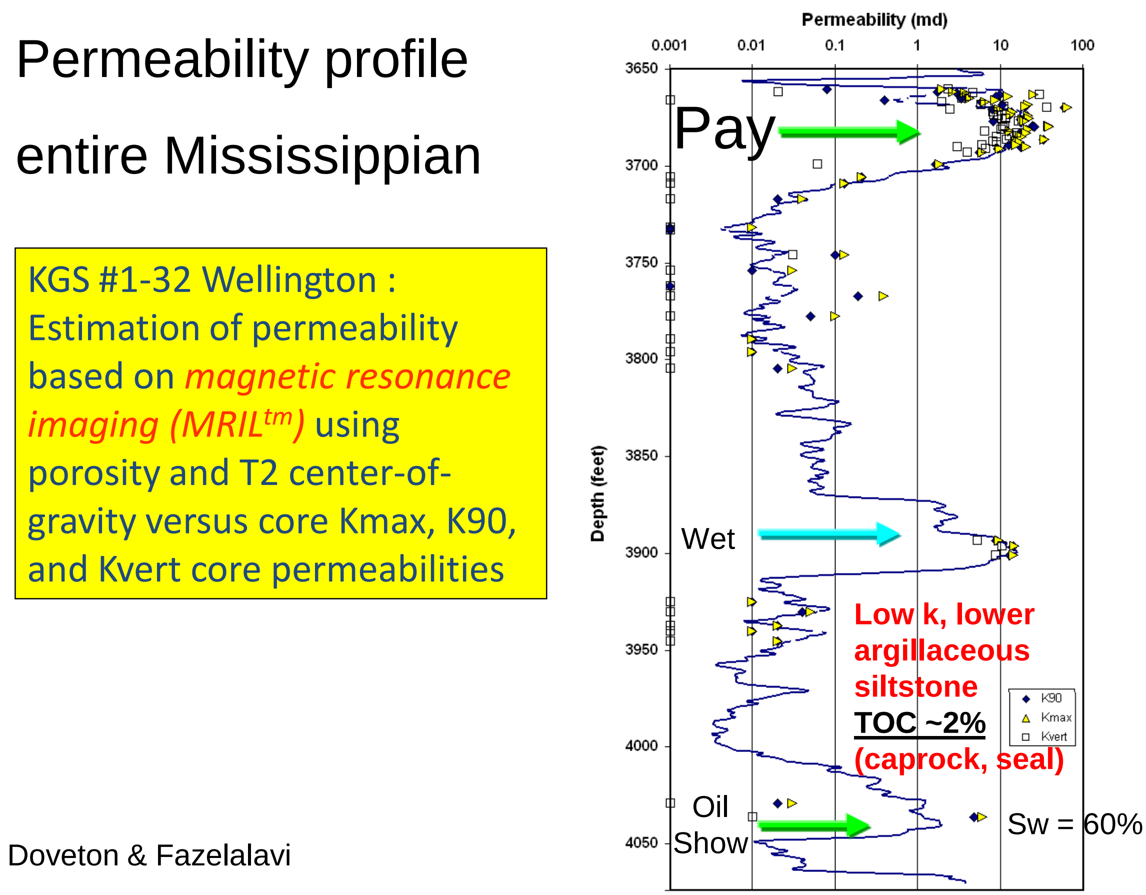


Figure 76. Permeability profile of the Mississippian from MRIL (NMR) log compared to core analyses (points). Lower Mississippian argillaceous siltstone has low permeability.

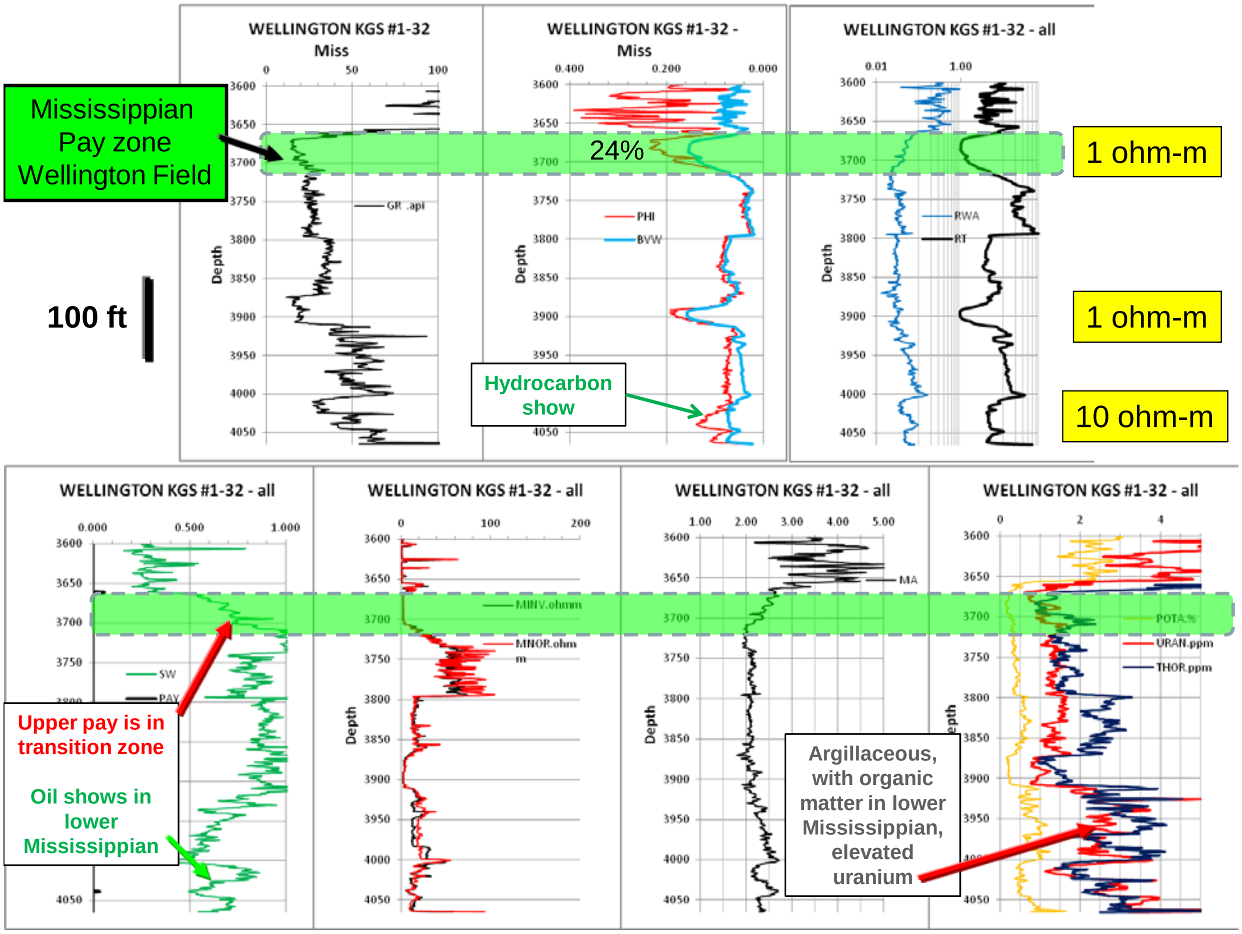


Figure 77. Series of petrophysical logs illustrating the stratigraphy of the Mississippian in Wellington KGS #1-32. The uppermost oil reservoir is highlighted in green. A second lower porosity zone is developed mid way into the Mississippian and a lower porosity zone is also present near the bottom of the Mississippian. The Pierson formation is present between 3910 and 4010 ft distinguished by higher gamma ray and low porosity.

Seismic properties – Seismic impedance (density x porosity) was previously shown to be lower in the Pierson formation. An impedance profile in **Figure 78** shows the Pierson as a navy blue colored horizon at 680 miliseconds within a window reaching up about 14 ms from the Kinderhook marker. The interval was correlated to seismic via the synthetic seismogram. An extracted slice of this interval is shown in **Figure 79** and demonstrates the variance in acoustic impedance. The map is derived from the Kinderhook time structure map, extrapolating into those areas where the Kinderhook either to be absent or very thin (Hedke, personal communication, 2012).

The seismic impedance map attests to the widespread extend and rather uniform properties of this tight argillaceous, ~100+ thick siltstone in Wellington Field. The areas where the Chattanooga Shale is missing and do have the Pierson based on seismic and log data. Properties of the Pierson formation are believed to be sufficient in its serving as a primary caprock.

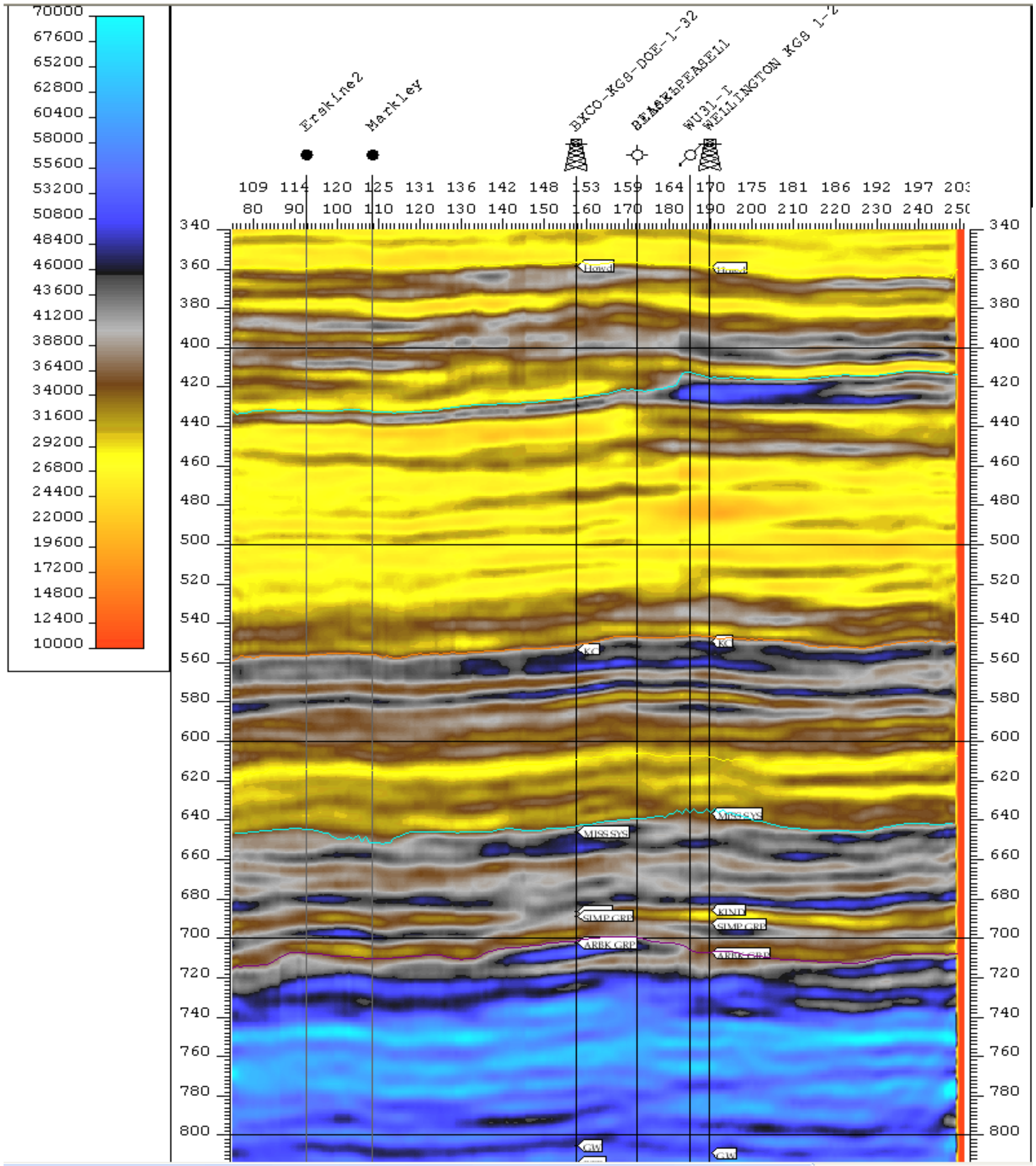


Figure 78. Arbitrary profile from acoustic impedance seismic volume including the two wells drilled in the project, Wellington KGS #1-32 and KGS #1-28. The Pierson formation is expressed as the navy blue horizon ~680 miliseconds. The Chattanooga Shale is the yellow layer immediately beneath the Pierson, locally missing at the location of #1-32. The overlying Pierson was cored and is described above and delimited on logs in Figure 77.

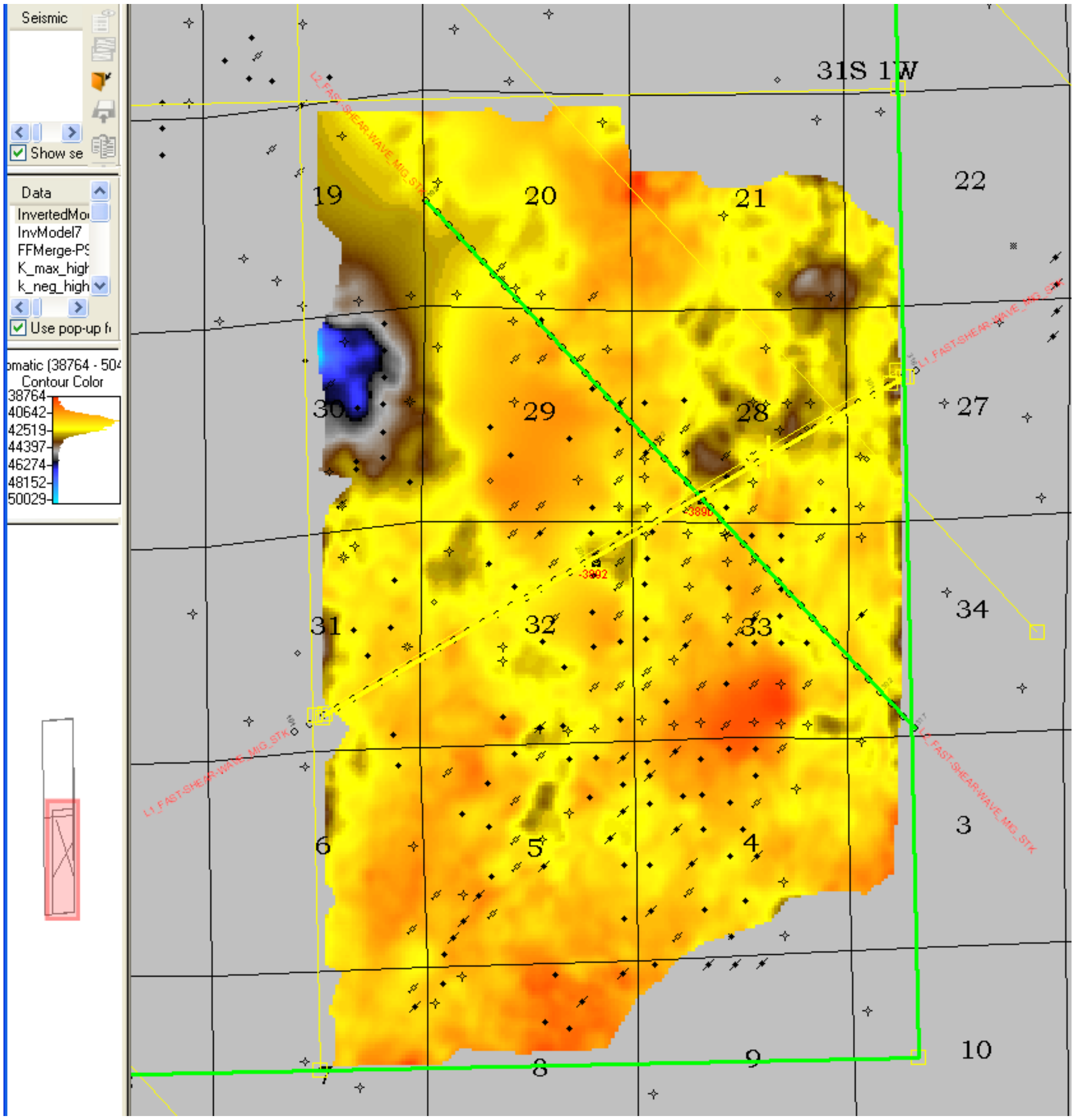


Figure 79. Impedance map of the lower Mississippian siltstone (Pierson formation). The more orange the color is lower impedance and the brown and blue colored areas have higher impedance. In general, the variation is tightly constrained around wells #1-32 and #1-28.

Sealing Integrity of Barriers above Arbuckle including lower Mississippian Pierson formation – prepared by Mina FazelAlavi

I - Introduction

It is planned to inject 40,000 tons of CO2 in Arbuckle formation and containment of injected CO2 in Arbuckle formation (DE-F0006821) is an issue. There are several vertical barriers above the Arbuckle formation which can prevent vertical movement of injected CO2 from Arbuckle to other formations or to the surface. Two of these main barriers are -- cap rock which is called Chattanooga Shale and the lower Mississippian Pierson formation from 3915 to 4005ft. CO2 entry pressure in each of these barriers is calculated, increase in Arbuckle pressure due to CO2 injection will be estimated and it will be shown that these barriers can prevent CO2 migration from Arbuckle to upper formations.

II – Chattanooga Shale Cap Rock

Chattanooga Shale lies above Arbuckle formation at it constitutes NMR Entry pressure in the Chattanooga Shale was calculated in well 1-32 and 1-28. Entry pressure is where capillary pressure at which the non-wetting phase enters the biggest pores, that is the pressure at which the wetting phases saturation is 85 % (Volokin et al., 2001). Techlog, Schlumberger log analysis software, converts pore size (T2 distribution) to pore throat radius using a proportionally constant Kappa (K) and similarly can be converted to capillary pressure. Capillary pressure and pore throat radius relationship can be expressed as:

$$P_c = \frac{2\sigma cos\theta}{r_{neck}}$$

Where,

P_c=Capillary pressure

$\boldsymbol{\sigma}$=Interfacial tension of Mercury-air

r_{neck}= pore radius

A Kappa value of 9 was used in the Chattanooga Shale and Kappa value of 15 was used in the tight carbonate zone (Pierson formation) in the lower Mississippian. Kappa value is usually 4 but can be ranged from 1 to 10 in sandstone for different core samples (Volokitin et al., 2001). In this article, Kappa value of 3 is the optimum scale that minimizes the error between NMR capillary pressure and core capillary pressure data. Kappa value of 4 was used at first but the results showed that NMR capillary pressure curves don’t match very well with the generalized Pc curves of chat conglomerate in Mississippian in the Spivey-Grab field (Watney et al., 2001). NMR capillary pressure curves matched better with Generalized Pc curves when Kappa value of 9 was used in sandstone. Kappa value in Carbonate reservoir is ranged from 10-20. NMR capillary pressure curves matched better with the generalized Pc curve in the Wellington West field (Bhattacharya et al., 2003) when Kappa value of 15 was used in the Carbonate zone. Kappa values can be adjusted when SCAL data become available.

According to NMR, mercury entry pressure for this shale interval is from 1 to 55 bars. Maximum entry pressure is about 55 bars in well 1-32 which is equivalent to 64 psi in CO2-brine system. Also based on Mercury injection, entry pressure in Chattanooga Shale in well 1-28 is from 0.5 to 250 bars. The maximum value is about 250 Bars which is equivalent to 293 psi in CO2-brine system. Entry pressure is higher in well 1-28 and this difference is due to the pore size distribution that exists in both well. This indicates pore sizes are smaller in 1-28 than 1-32 and therefore the entry pressure is higher. Entry pressure of cap rock is largely a function of its pore size and this can be variable laterally and vertically. Smaller pore size has a higher entry pressure. **Figure 80 and 81** are output of NMR entry pressure in Chattooga Shale in well 1-32 and 1-28, respectively.

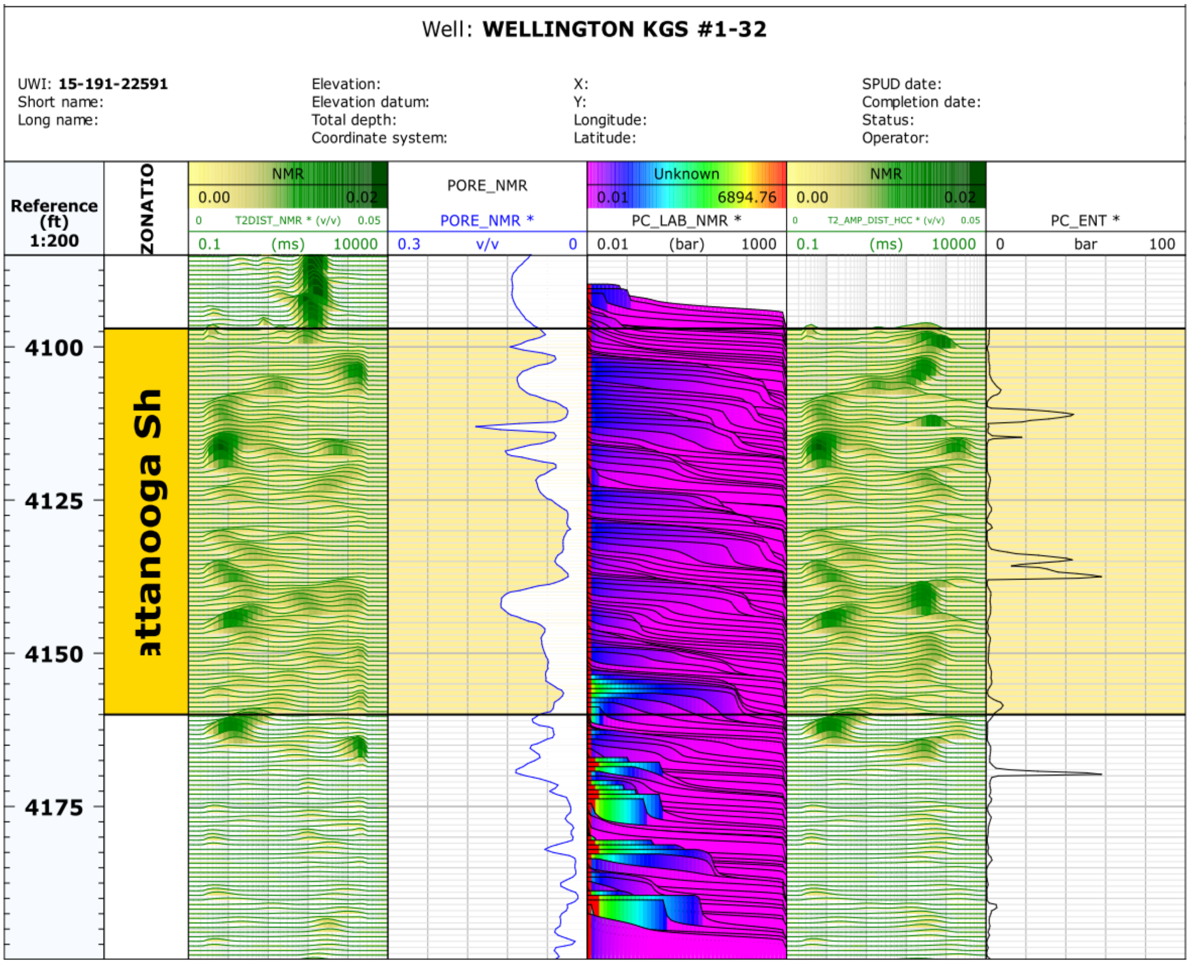


Figure 80. NMR entry pressure in Chattanooga caprock in well 1-32

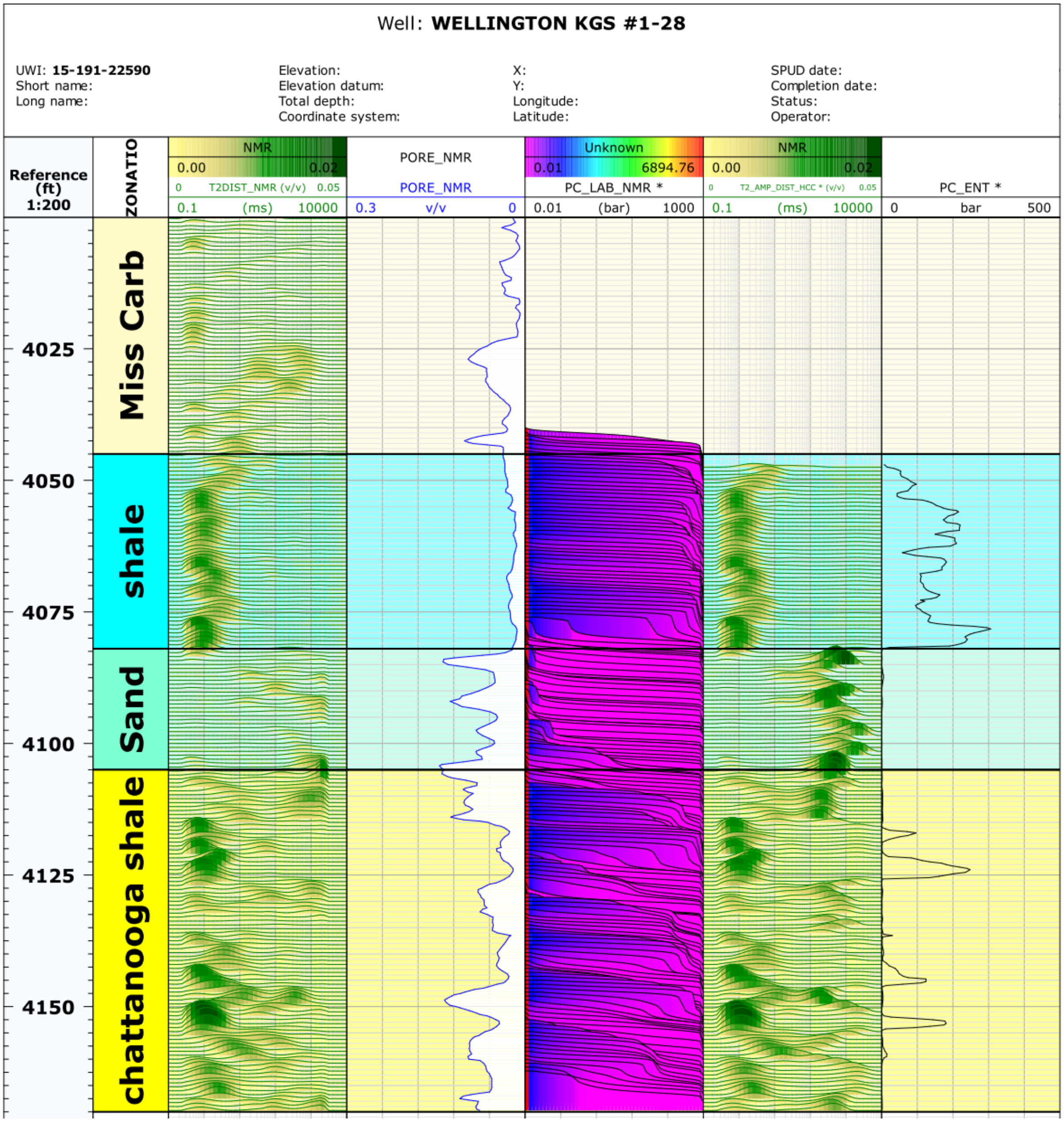


Figure 81. NMR entry pressure in Chattanooga caprock in well 1-28

The following equation was used to convert entry pressure from mercury-air system to CO2-brine system:

$$Pe_{CO2/brine} = P_{e-Hg/air}.\frac{\gamma_{CO_2/brine}.COS\theta_{CO_2/brine}}{\gamma_{Hg/air}.COS\theta_{Hg/air}} \qquad \text{(Equation 1)}$$

Where,

$Pe_{CO2/brine}$ is entry pressure in the reservoir system which in this case is $CO2/brine$
$Pe_{Hg/air}$ is entry pressure in mercury-air system
$\gamma_{CO2/brine}$ and $\gamma_{Hg/air}$ are interfacial tension of CO2/brine and Hg/air respectively
$COS\boldsymbol{\theta}_{CO2/brine}$ and $COS\boldsymbol{\theta}_{Hg/air}$ are contact angles of reservoir CO2/brie/solid and Hg/air/solid system

Interfacial tension of 30 dyne/cm and 485 dyne/cm were used for CO2-brine and Mercury air system respectively. Also, contact angle of 0 and 140 were used for CO2-brine and Mercury-air system respectively.

Average pressure increase of Arbuckle reservoir was estimated after injecting 40,000 tons of CO2. First, Arbuckle rock and water contraction per one psi pressure increase was estimated using the following equation:

$$(C_{f*}BV)*(1-\emptyset)+(C_w*BV*\emptyset) \qquad \text{(Equation 2)}$$

Where,

C_f is rock compressibility per psi
C_w is water compressibility per psi
BV is bulk volume
$\emptyset$ is Average porosity

The following parameters were used to estimate rock and water contraction per psi in Arbuckle:

C_f= 4E-6
$C_{w=}$ 3E-6
$\emptyset$=0.06
BV= 1.33E+12

The amount of contraction of Arbuckle rock and water is 5.24E+06 ft^3 /psi using equation 2. Volume of CO2 which will be injected was estimated using density of CO2 at reservoir condition, 0.58 g/cm^3. Volume of CO2 at reservoir condition is 2.44E+06 ft^3. Having the volume of CO2 at reservoir condition and rock and water contraction per psi, Average pressure increase in the reservoir after injection of CO2 was estimated. This value is 0.46 psi.

At the start of CO2 injection, Arbuckle and Chattanooga Shale pressure are in equilibrium at their initial pressure. After completion of CO2 injection, average pressure in Arbuckle will be higher than Chattanooga Shale pressure by 0.46 psi. During injection and immediately after injection, pressure at the depth and location of injection will be higher than the average pressure. But after few years pressure in Arbuckle area and depth will be equalized and pressure at every location will be close to the average which will be only 0.46 more than the initial pressure. Since entry pressure of Chattanooga Shale is 64 psi and exceeds average pressure increase in Arbuckle, CO2 cannot enter or pass Chattanooga Shale in the long term when injection pressure is equalized. Therefore few years after injection, escape of CO_2 from caprock would not be possible.

To investigate sealing integrity of Chattanooga Shale during injection, it is necessary to know pressure in Arbuckle reservoir immediately below Chattanooga Shale at the location of injection well during injection. If pressure in this location remains below initial pressure plus 64 psi which is the entry pressure, Chattanooga Shale will be sealing in this period.

However another mechanism which is important should also be considered when assessing sealing integrity of caprocks. Assume that pressure in Arbuckle immediately below caprock increases by 200 psi which is more than the entry pressure and CO_2 reaches just below cap rock. Even under this condition, CO_2 cannot enter caprock or pass through it. Since caprock is 100% saturated with water and CO_2 saturation in caprock is zero, only water phase in Arbuckle can flow into caprock and the flow of water will increase its pressure. Because increases in Arbuckle pressure will be gradual, caprock pressure will increase simultaneously. It can be said that pressure of shale layers immediately above Arbuckle will have the same increase in pressure that exists in Arbuckle just below these layers. If CO_2 phase pressure and water phase pressure in Arbuckle are equal, CO_2 cannot enter caprock because caprock pressure would be equalized with water phase pressure of Arbuckle. Only if CO_2 pressure is higher than water phase pressure in Arbuckle by entry pressure of caprock, CO_2 will be able to enter caprock. This condition cannot occur unless a large column of CO_2 is developed and accumulates below caprock.

Gravity difference between water and CO_2 at reservoir condition is 0.23 psi per ft of depth. Entry pressure of Chattanooga Shale is about 64 psi. If the column of CO_2 is small e.g. 10 ft, pressure difference between CO_2 and water phase will be small e.g. 2.3 psi which is less than entry pressure. In this condition CO_2 cannot enter or pass the cap rock. However if a CO_2 column with a thickness of 400 ft develops below caprock by injection of large masses of CO_2 (billion tons), CO_2 phase pressure will be 92 psi more than water phase pressure. At this condition CO_2 will enter Chattanooga Shale and pass through it to upper formations. Because volume of CO_2 injection in Arbuckle compared to the area of the reservoir is negligible, CO_2 column below caprock will be small and caprock integrity against migration of CO_2 remain theoretically guaranteed.

III – Second barrier (Tight Zones in Mississippian)

Another barrier exists in lower Mississippian formation. NMR module was run to get the entry pressure in the lower Mississippian. Entry pressure is from 33 to 150 bars from 3915 to 4005 ft according to mercury injection. Entry pressure is shown in **Figure 82**. Maximum entry pressure is about 150 bars which is equivalent to 176 psi in CO_2- brine system. This high entry pressure implies low permeability, small pore size and therefore small pore throat size exist in this interval. This barrier can prevent vertical movement of CO_2 by the same mechanism which was discussed before.

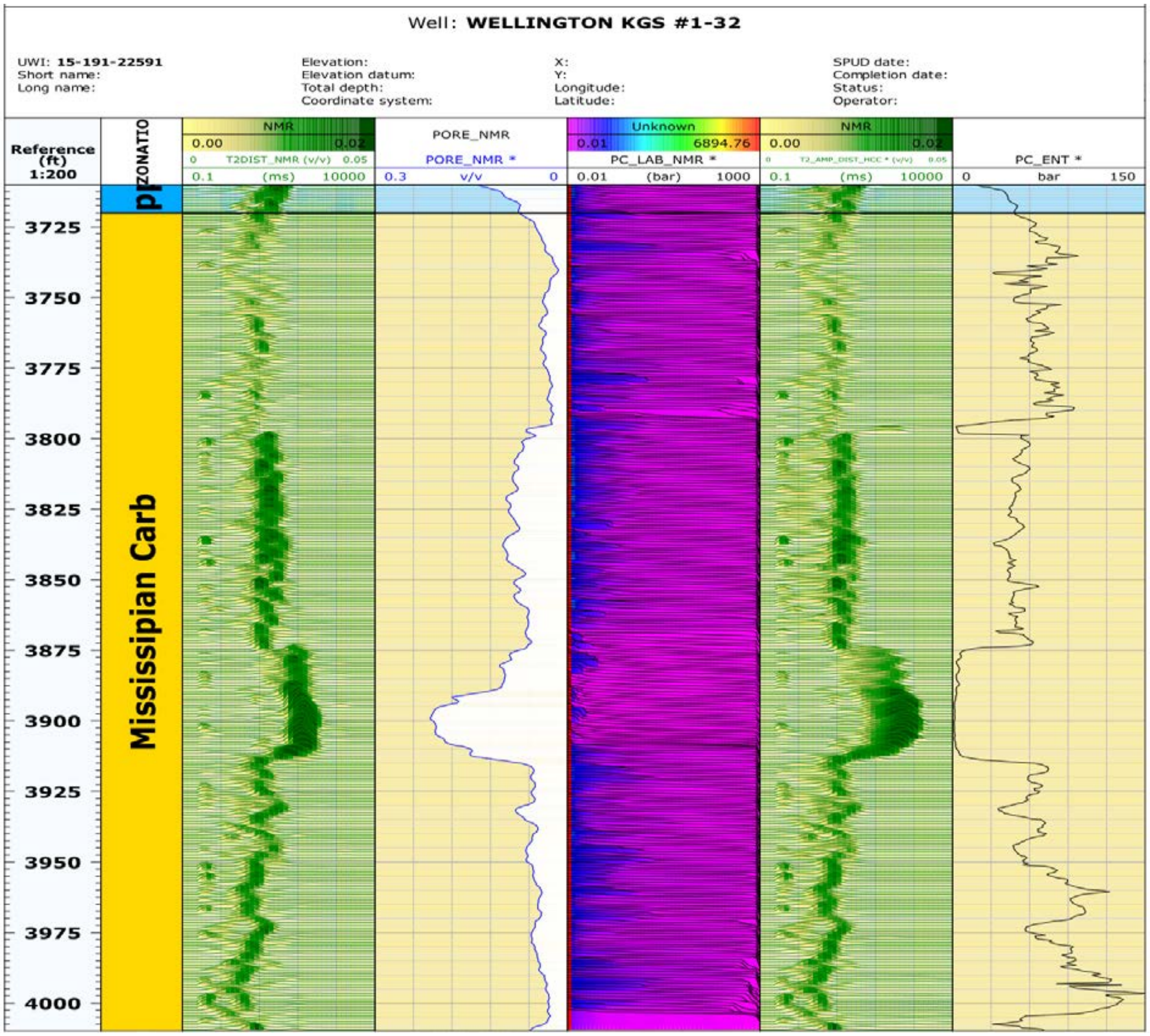


Figure 82. NMR entry pressure in tight Mississippian zone in well 1-32.

Continued characterization of the Arbuckle in Wellington Field

Continued investigation of the Arbuckle saline aquifer indicates that the lithologies and pore architectures are complex (**Figures 83 and 84**). Clear indications of shaly zones in the Arbuckle baffle zone are apparent from thin sections. The lower Arbuckle injection zone has pore type ranging from microporous chalcedony to vug and interparticle pore space in dolomite.

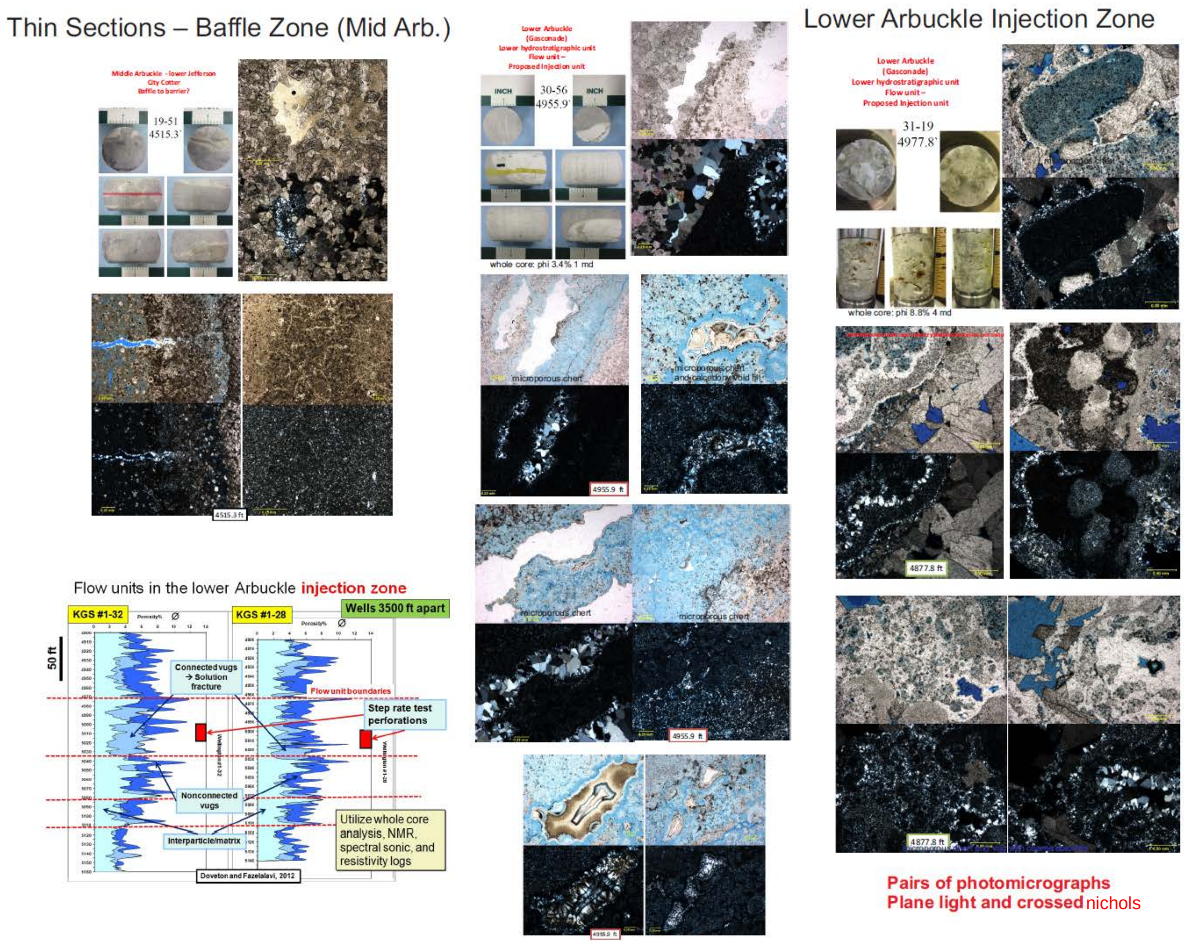


Figure 83. Thin sections of the mid Arbuckle baffle zone and the lower Arbuckle proposed injection zone. Scales are shown on each image.

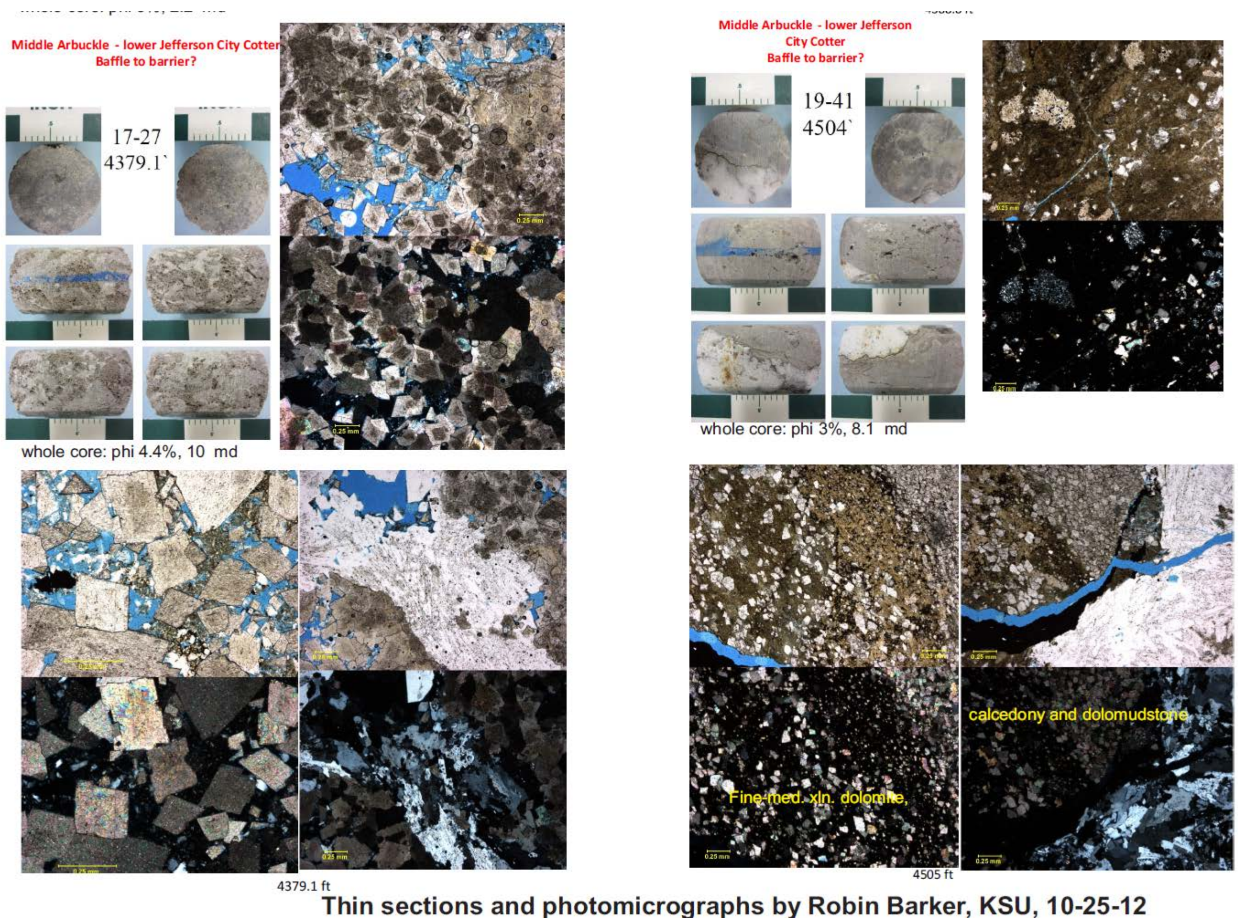


Figure 84. Thin sections of the mid Arbuckle baffle zone and the lower Arbuckle proposed injection zone. Scales are shown on each image.

Flow units have been defined in the lower Arbuckle based on core based definition of strata and lithofacies. This framework was extended to the interpretation of pore types based on log suites available at Wellington Field (**Figure 85**).

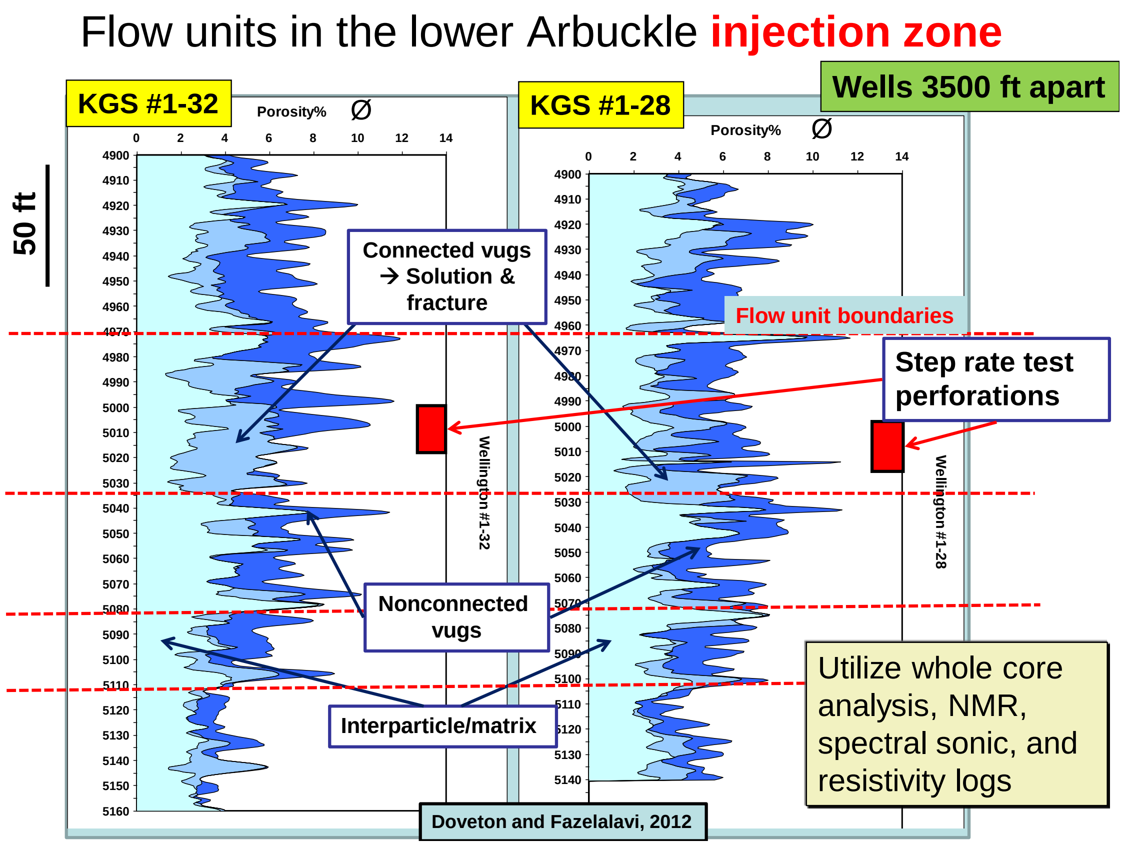


Figure 85. Flow unit interpretation based on succession of pore types that in turn are related to permeability. Flow unit definition and correlation are consistent between KGS #1-28 and #1-32. Smaller variations are noted reflecting the lateral changes in this peritidal dolomite.

The nature of the pore systems in the Arbuckle is often perplexing with basic log suites. With the availability of core, core analysis, and MRIL, some general observations can be made about locating intervals with vugs or fractures in the Arbuckle. The apparent "m", the cementation exponent in the Archie equation, will generally be higher than 2 with abundant vugs and values less than 1 are suggestive of fractured intervals (**Figure 86**). The analysis in a water wet interval facilitates this assessment.

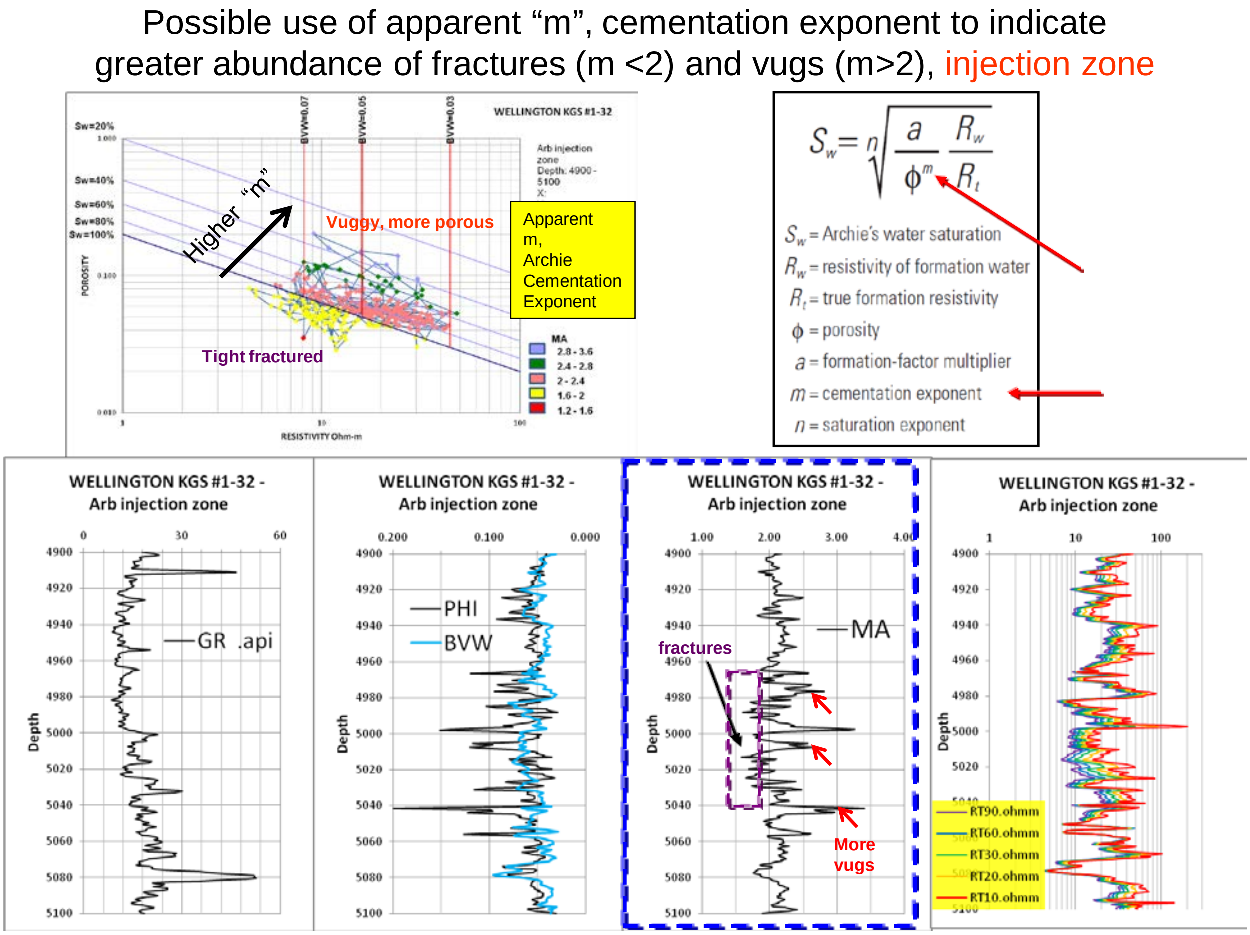


Figure 86. Calculation of apparent "m" is used to estimate vuggy vs. fractured intervals in the lower Arbuckle injection interval.

It is also useful to note that the Stoneley wave of the dipole sonic log can provide a rough estimate of permeability (**Figure 87**). This was applied to KGS #1-32 over the lower Arbuckle proposed injection interval. The results are similar to what core and MRIL log indicate.

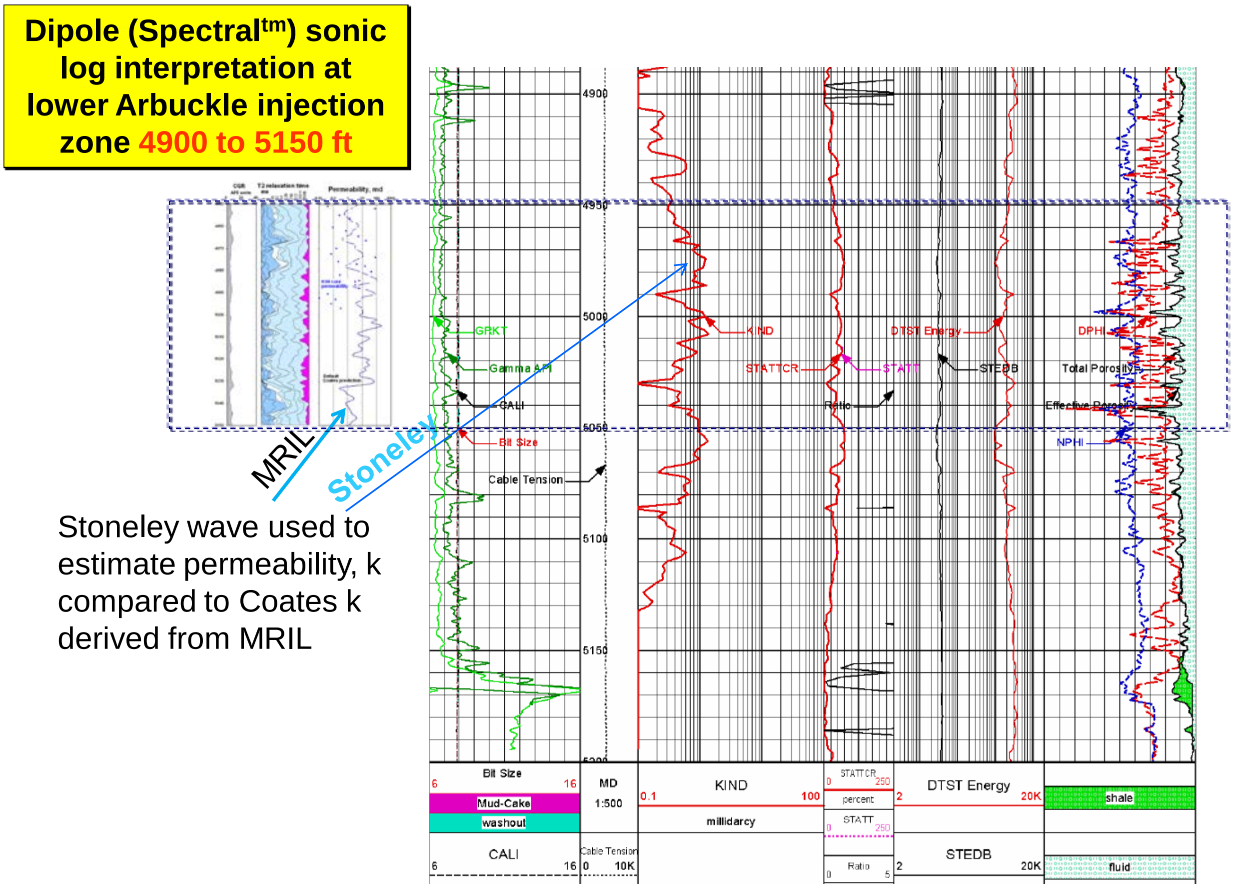


Figure 87. Use of Stoneley wave to estimate permeability in the lower Arbuckle in KGS #1-32. The interval of the proposed injection is outlined and the permeability estimate by MRIL is shown in the inset on the left side of the illustration. There is a resemblance between the two permeability curves.

PRESENTATIONS AND PUBLICATIONS

GSA annual meeting 2012, Charlotte, NC, November 4-7, 2013

GEOCHEMICAL AND MINERALOGICAL CHARACTERIZATION OF THE ARBUCKLE AQUIFER: STUDYING MINERAL REACTIONS AND ITS IMPLICATIONS FOR CO2 SEQUESTRATION

BARKER, Robinson1, WATNEY, W. Lynn2, SCHEFFER, Aimee3, FORD, Sophia1, and DATTA, Saugata1, (1) Department of Geology, Kansas State University, 108 Thompson Hall, Manhattan, KS 66506, rbarker@ksu.edu, (2) Kansas Geological Survey, Univ of Kansas, 1930 Constant Avenue, Lawrence, KS 66047, (3) Geology, University of Kansas, 1475 Jayhawk Blv. Room 120, Lawrence, KS 66045

GEOCHEMICAL AND MICROBIOLOGICAL INFLUENCES ON SEAL INTEGRITY DURING SC-CO2 EXPOSURE, ARBUCKLE AQUIFER, SE KANSAS
JACKSON, Christa1, SCHEFFER, Aimee2, FOWLE, David3, WATNEY, W. Lynn4, STRAZISAR, Brian5, and ROBERTS, Jennifer A.3, (1) Geology, University of Kansas, 1475 Jayhawk Blvd, Room 120, Lawrence, KS 66045, christa.jackson@ku.edu, (2) Geology, University of Kansas, 1475 Jayhawk Blv. Room 120, Lawrence, KS 66045, (3) Geology, University of Kansas, Multidisciplinary Research Building, 2030 Becker Dr, Lawrence, KS 66047, (4) Kansas Geological Survey, Univ of Kansas, 1930 Constant Avenue, Lawrence, KS 66047, (5) Geomechanics and Flow Laboratory, National Energy Technology Laboratory, 626 Cochrans Mill Road, PO Box 10940, Pittsburgh, PA 15236

GEOCHEMICAL, MICROBIOLOGICAL, AND PERMEABILITY CHARACTERISTICS INDICATING VERTICAL ZONATION OF THE ARBUCKLE SALINE AQUIFER, A POTENTIAL CO2 STORAGE RESERVOIR
SCHEFFER, Aimee1, STOTLER, Randy L.2, WATNEY, W. Lynn3, FOWLE, David4, DOVETON, John H.5, RUSH, Jason6, NEWELL, K. David7, FAZELALAVI, Mina3, WHITTEMORE, Donald O.8, and ROBERTS, Jennifer A.4, (1) Geology, University of Kansas, 1475 Jayhawk Blv. Room 120, Lawrence, KS 66045, ascheffer@ku.edu, (2) Department of Geology, University of Kansas, Lawrence, KS 66045, (3) Kansas Geological Survey, Univ of Kansas, 1930 Constant Avenue, Lawrence, KS 66047, (4) Geology, University of Kansas, Multidisciplinary Research Building, 2030 Becker Dr, Lawrence, KS 66047, (5) Kansas Geological Survey, Univ of Kansas, 1930 Constant Avenue, Campus West, Lawrence, KS 66047, (6) Kansas Geological Survey, The University of Kansas, 1930 Constant Avenue, Lawrence, KS 66047, (7) Kansas Geological Survey, University of Kansas, 1930 Constant Avenue, Lawrence, KS 66047-3726, (8) Kansas Geological Survey, University of Kansas, 1930 Constant Ave, Lawrence, KS 66047

M.S. Theses

Ayrat Sirazhiev, 2012, Seismic Attribute Analysis of the Mississippian Chert at the Wellington Field, south-central Kansas: M.S. Thesis, Department of Geology, The University of Kansas.

Ohl, Derek Robert, 2012, Rock formation characterization for carbon dioxide geosequestration: 3D seismic amplitude and coherency anomalies, and seismic petrophysical facies classification, Wellington and Anson-Bates fields, Sumner County, Kansas, USA, M.S. Thesis, Department of Geology, Kansas State University, 77 p.

Randi Jo Lee, 2012, Integration of in situ and laboratory velocity measurements: analysis and calibration for rock formation characterization Isham, M.S. Thesis, Department of Geology, Kansas State University.

Presentations

Geofest 2012, October 26th 2012, held in Lawrence, KS at Kansas Geological Survey, focused on a review of the DOE funded CCUS research in a morning seminar and a core workshop in the afternoon to examine the entire 1600 ft long core from Wellington KGS #1-32. Attendees included members of the Kansas Geological Society, Kansas Geological Survey, Departments of Geology at Kansas University and Wichita State University (**Figures 89-92**).

Figure 89. Banner for meeting.

Schedule

- 10:00 a.m. -- Bus arrives at Kansas Geological Survey
- 10:15-10:25 -- Welcome from Rex; Lynn -- overview; logistics
- 10:25 – 10:35 -- Message from KU Department of Geology
- 10:35 -12:15 -- Summary of long core and background information
- 10:35-10:55 -- Overview of Core – Lynn Watney and David Newell
- 10:55-11:15 -- Well logs and analyses of Arbuckle – John Doveton and Mina Fazelalavi
- 11:15-11:35 -- Geomodel development -- Jason Rush
- 11:35-11:55 -- Coupled geomechanical-fluid flow modeling -- Eugene Holubnyak
- 11:55-12:15 -- Class VI injection permit application – Tiraz Birdie
- 12:15-1:00 pm -- LUNCH catered by Biggs Barbecue
- 12:30 -1:30 -- Briefings, started during lunch, on KGS activities related to energy – Dana Adkins-Heljeson - survey website; Dave Newell – Mississippian drilling activity; Brownie Wilson – Kansas water resources
- 1:30-4:00 -- Examine Wellington #1-32 slabbed core (bring your hand lens) Discuss observations and findings, Q&A session
- 4:00-4:30 -- Summary, future plans, and invitation for continued dialog, group photo

Figure 90. Geofest meeting schedule.

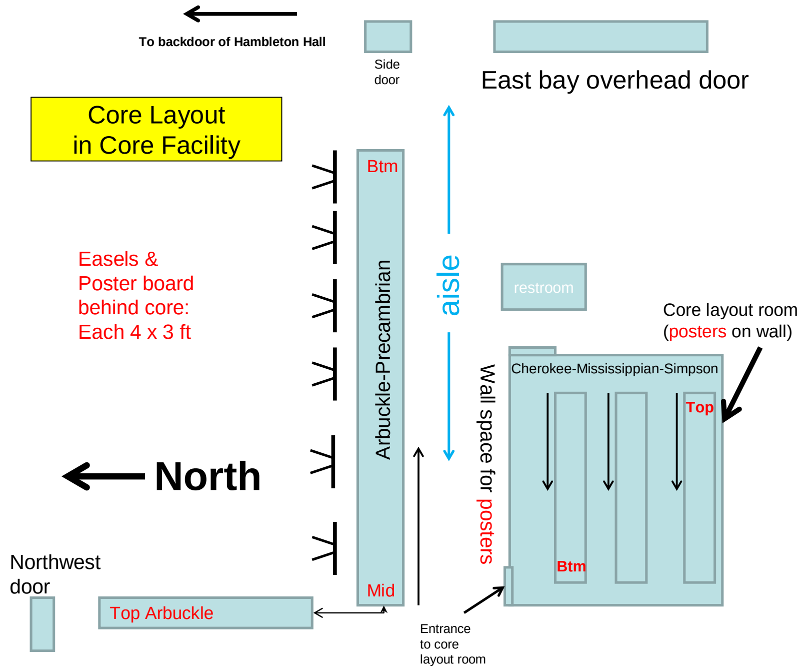
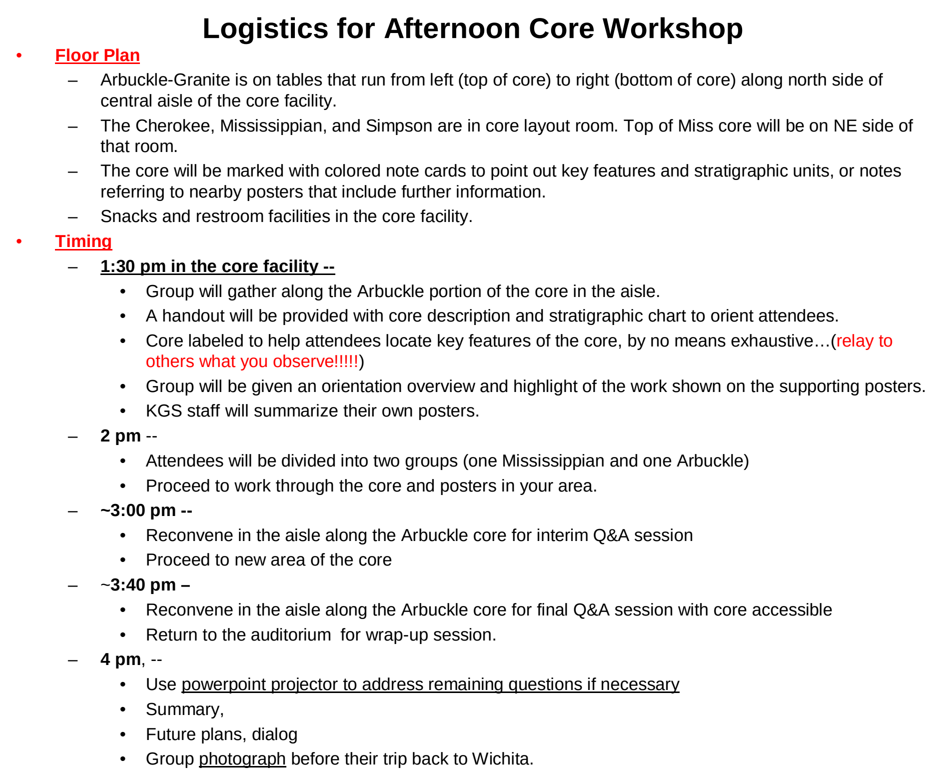


Figure 91. Core layout. Entire core facility used to display all of the core.



Logistics for Afternoon Core Workshop

- **Floor Plan**
  - Arbuckle-Granite is on tables that run from left (top of core) to right (bottom of core) along north side of central aisle of the core facility.
  - The Cherokee, Mississippian, and Simpson are in core layout room. Top of Miss core will be on NE side of that room.
  - The core will be marked with colored note cards to point out key features and stratigraphic units, or notes referring to nearby posters that include further information.
  - Snacks and restroom facilities in the core facility.
- **Timing**
  - **1:30 pm in the core facility --**
    - Group will gather along the Arbuckle portion of the core in the aisle.
    - A handout will be provided with core description and stratigraphic chart to orient attendees.
    - Core labeled to help attendees locate key features of the core, by no means exhaustive…(relay to others what you observe!!!!!)
    - Group will be given an orientation overview and highlight of the work shown on the supporting posters.
    - KGS staff will summarize their own posters.
  - **2 pm** --
    - Attendees will be divided into two groups (one Mississippian and one Arbuckle)
    - Proceed to work through the core and posters in your area.
  - **~3:00 pm --**
    - Reconvene in the aisle along the Arbuckle core for interim Q&A session
    - Proceed to new area of the core
  - ~**3:40 pm –**
    - Reconvene in the aisle along the Arbuckle core for final Q&A session with core accessible
    - Return to the auditorium for wrap-up session.
  - **4 pm**, --
    - Use powerpoint projector to address remaining questions if necessary
    - Summary,
    - Future plans, dialog
    - Group photograph before their trip back to Wichita.

Figure 92. Geofest meeting logistics.

A tech seminar was presented to the Kansas Geological Society on 12-18-12 to update them on the status of the FE-0002056 and a brief review of FE-0006821 (**Figure 93**).

Another presentation was made earlier in December focused on disposal in general in the Arbuckle saline aquifer (**Figure 94**).

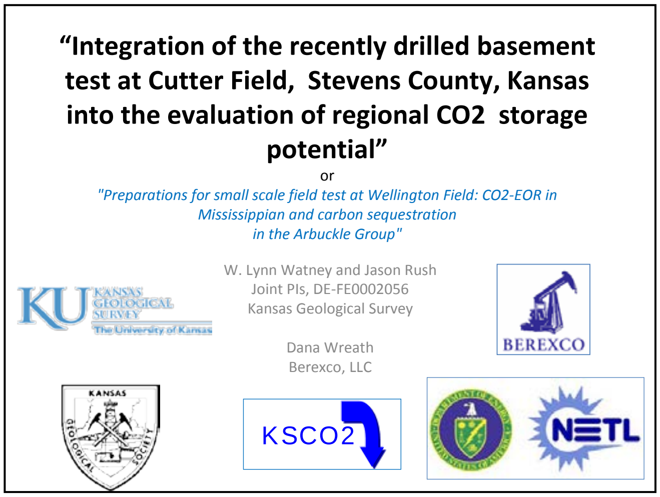


Figure 93. Head slide of the December 18 presentation.

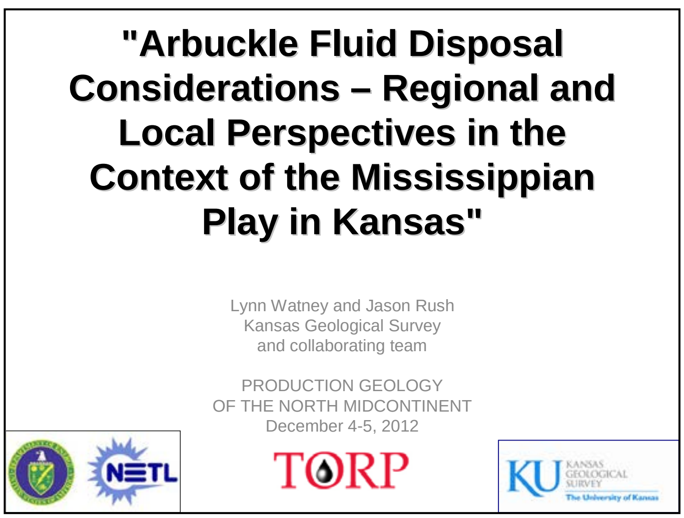


Figure 94. Head slide of 12-5-12 presentation.

KEY FINDINGS

1. Size of 40,000 tonnes CO_2 plume at Wellington is modeled to be within 2500 ft of injection well. Differential pressure is simulated as under 200 psi.
2. Initial processing of seismic at Cutter Field reveals a good quality acquisition.
3. Initial examination of 1042 ft of core shows excellent condition of core suited for considerable analysis. Key stratigraphic intervals are included in the core that was cut.
4. Arbuckle has many porous and permeable intervals based on core and log data, including estimates of permeability from MRIL logging tool.
5. Oil show are noted from the Arbuckle on up the stratigraphic column evaluated with core and detailed logging. Notable oil shows in the Viola below the tighter Chattanooga Shale and Kinderhook shaly carbonate suggest favorable sealing properties.
6. Regional stratigraphic correlations within the Arbuckle Group appear to be validated with core and log data.
7. Arbuckle stratigraphy and pore types at Cutter Field closely resemble that of Wellington Field.
8. Southwest Kansas CO_2-EOR Initiative is completing second geomodels, Eubank Field, and will submit for simulation.
9. Regional sequence stratigraphy of the Chester Stage including incised valley fill deposits is mature and founded on considerable data.
10. Characterization of the Wellington Field oil reservoir has addressed key parameters needed for simulation of CO_2-EOR, the next stage of the project.
11. The robust, detailed correlation of the digital well logs will be used to create a highly resolved 3D model of the geology in southern Kansas to aid in assessing CO_2 storage and seals, and assist in the evaluation of potential risks and opportunities.

PLANS

1. Complete processing of Cutter seismic.
2. Complete core analysis of core from Cutter KGS #1
3. Complete detailed stratigraphic correlations of type wells.
4. Conduct well tests at Cutter KGS #1.
5. Complete reservoir simulation at Eubank Field to evaluate CO_2-EOR.
6. Continue studies of CO_2 reactions via biological mediation and physical processes in order to obtain reaction kinetics.

SPENDING PLAN

	COST PLAN/STATUS												
	BP 1 Starts: 12/8/09	Ends: 2/7/11				BP2 Starts 2/8/11	Ends 8/7/12					BP3 Starts 8/8/12	Ends 2/7/14
	12/8/09-12/31/09	1/1/10-3/31/10	4/1/10-6/30/10	7/1/10-9/30/10	10/1 - 12/31/10	1/1/11 - 3/31/11	4/1/11 - 6/30/11	7/1/11-9/30/11	10/1/11 - 12/31/11	1/1/12 - 3/31/12	4/1/12 - 6/30/12	7/1/12 - 9/30/12	10/1/12 - 12/31/12
Baseline Reporting Quarter	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12	Q13
Baseline Cost Plan (from SF-424A)	(from 424A, Sec. D)												
Federal Share	$1,007,622.75	$1,007,622.75	$1,007,622.75	$1,007,622.75	$0.00	$0.00	$0.00	$1,169,543.00	$1,169,543.00	$1,169,543.00	$1,169,543.00	$316,409.00	$316,409.00
Non-Federal Share	$277,260.75	$277,260.75	$277,260.75	$277,260.75	$0.00	$0.00	$0.00	$303,182.75	$303,182.75	$303,182.75	$303,182.75	$81,854.50	$81,854.50
Total Planned (Federal and Non-Federal)	$1,284,883.50	$1,284,883.50	$1,284,883.50	$1,284,883.50	$0.00	$0.00	$0.00	$1,472,725.75	$1,472,725.75	$1,472,725.75	$1,472,725.75	$398,263.50	$398,263.50
Cumulative Baseline Cost	$1,284,883.50	$2,569,767.00	$3,854,650.50	$5,139,534.00	$5,139,534.00	$5,139,534.00	$5,139,534.00	$6,612,259.75	$8,084,985.50	$9,557,711.25	$11,030,437.00	$11,428,700.50	$11,826,964.00
Actual Incurred Costs													
Federal Share	$4,019.93	$84,603.97	$494,428.37	$111,405.52	$238,675.97	$1,902,936.55	$625,853.17	$275,754.50	$523,196.12	$453,026.11	$238,793.52	$1,282,545.00	$1,314,156.54
Non-Federal Share	$0.00	$43,980.04	$40,584.78	$13,195.88	$526,210.30	$35,887.34	$414,511.02	$20,247.24	$16,687.00	$61,683.20	$150,646.51	$221,053.41	$119,685.90
Total Incurred Costs-Quarterly (Federal and Non-Federal)	$4,019.93	$84,603.97	$535,013.15	$124,601.40	$764,886.27	$1,938,823.89	$1,040,364.19	$296,001.74	$539,883.12	$514,709.31	$389,440.03	$1,503,598.41	$1,433,842.44
Cumulative Incurred Costs	$4,019.93	$88,623.90	$623,637.05	$748,238.45	$1,513,124.72	$3,451,948.61	$4,492,312.80	$4,788,314.54	$5,328,197.66	$5,842,906.97	$6,232,347.00	$7,735,945.41	$9,169,787.85
Variance													
Federal Share	$1,003,602.82	$923,018.78	$513,194.38	$896,217.23	-$238,675.97	-$1,902,936.55	-$625,853.17	$893,788.50	$646,346.88	$716,516.89	$930,749.48	-$966,136.00	-$997,747.54
Non-Federal Share	$277,260.75	$233,280.71	$236,675.97	$264,064.87	-$526,210.30	-$35,887.34	-$414,511.02	$282,935.51	$286,495.75	$241,499.55	$152,536.24	-$139,198.91	-$37,831.40
Total Variance-Quarterly Federal and Non-Federal)	$1,280,863.57	$1,156,299.49	$749,870.35	$1,160,282.10	-$764,886.27	-$1,938,823.89	-$1,040,364.19	$1,176,724.01	$932,842.63	$958,016.44	$1,083,285.72	-$1,105,334.91	-$1,035,578.94
Cumulative Variance	**$1,280,863.57**	**$2,437,163.06**	**$3,187,033.41**	**$4,347,315.51**	**$3,582,429.24**	**$1,643,605.35**	**$603,241.16**	**$1,779,965.17**	**$2,712,807.80**	**$3,670,824.24**	**$4,754,109.96**	**$3,648,775.05**	**$2,613,196.11**