Modeling CO_2 Sequestration in Saline Aquifer and Depleted Oil Reservoir to Evaluate Regional CO_2 Sequestration Potential of Ozark Plateau Aquifer System, South-Central Kansas

Wrap-up presentation

DOE-NETL, Pittsburgh, PA, February 12, 2015

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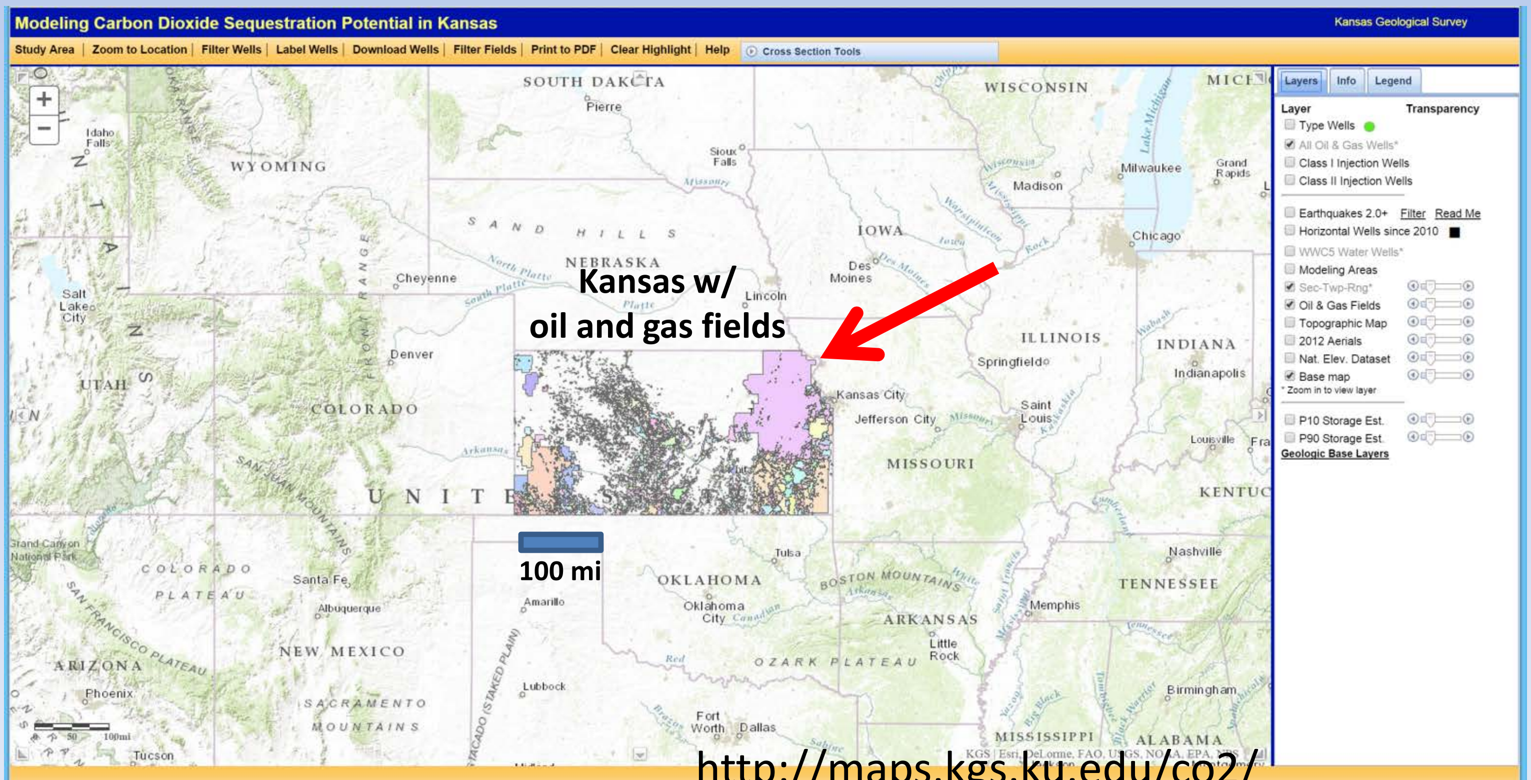
KANSAS GEOLOGICAL SURVEY
The University of Kansas

Award No. DE-FE0002056

KSCO2

Outline

- Overview/Statement of Work
- Experimental methods
- Results and discussion
- Lessons learned



Research collaboration in Kansas for CO_2-EOR and saline aquifer storage

SW Kansas CO_2-EOR Initiative

IHR Improved Hydrocarbon Recovery LLC
HEDKE-SAENGER GEOSCIENCE, LTD
SUNFLOWER ENERGY LLC
fairfieldnodal
CIMAREX
GloriOil
Anadarko Petroleum Corporation
Dawson-Markwell Exploration Co.
BEREXCO
Celebrating 20 Years, Merit Energy Company

Industrial and Electrical Power Sources of CO_2

Conestoga Energy Partners LLC
Sunflower Electric Power Corporation
Abengoa Bioenergy : The Global Ethanol Company

- Industry, academia, survey, state government
- Best practices, building on industry infrastructure and resources
- Industry -- Access to field and technical knowledge
- Donation of important 3D seismic data and field records
- Project supported Class VI application for CO_2 injection into Arbuckle at Wellington Field

Partners FE0002056

KU Kansas Geological Survey, The University of Kansas
NETL
U.S. Department of Energy
Department of Geology, Kansas State University
KU The University of Kansas, Department of Geology
fairfieldnodal
Wellington Field Operator BEREXCO
Paragon Geophysical Services, Inc
Echo Geophysical Corporation
Devilbiss Coring Service
Basic Energy Services
noble energy
Lockhart Geophysical
MUDCO
Weatherford Laboratories
Trilobite Testing, Inc
HALLIBURTON
HEDKE-SAENGER GEOSCIENCE, LTD
Bittersweet Energy Inc.
Charter Consulting, Integrated Geology & Geophysics
Petrotek
KOGER Remote Sensing
Lawrence Livermore National Laboratory, Science and Technology in the National Interest
Well Green Tech

DOE-NETL Contract #FE0006821

52,000 metric ton (small scale) CO_2 injection test at Wellington

433,000 bbls equivalent (620 bbsl/day)

KU Kansas Geological Survey, The University of Kansas
TBirdie Consulting, Inc
Tiraz Birdie
L. Watney (Joint PI), J. Rush (Joint PI), T. Bidgoli, J. Doveton, E. Holubnyak, M. Fazelalavi, R. Miller, D. Newell, J. Raney
NETL
Brian Dressel, P.M.
Berkeley Lab, Lawrence Berkeley National Laboratory
Tom Daley, Barry Freifeld
BEREXCO
Dana Wreath, Adam Beren
EPRI Electric Power Research Institute
Robert Trautz, PI FOA-0798
Department of Geology, Kansas State University
Saugata Datta
IRIS PASSCAL
KU The University of Kansas, Department of Geology
Mike Taylor, George Tsoflias, Jen Roberts, David Fowell
Sandia Technologies, LLC
Dan Collins, David Freeman

Statement of Objectives & Outline to Presentation

A. Characterize the Ozark Plateau & Western Interior Plains Aquifer and petroleum system

i. Encompassing *Mississippian age sandstones and carbonates and Cambro-Ordovician Arbuckle Group carbonate and minor basal sandstone*

B. Establish unified and integrated model of aquifer/petroleum system

i. Using geology, geophysics/potential fields, and remote sensing spanning *33 counties in south-central Kansas*

C. Model 5 oil fields for CO_2-EOR and use information to characterize and model CO_2 storage in the Arbuckle saline aquifer:

i. Wellington Field, Sumner Co., KS
ii. Cutter Field, Stevens Co., KS
iii. Pleasant Prairie SE Field, Haskell Co., KS
iv. Eubank Field, Haskell Co., KS
v. Shuck Field, Seward Co., KS

New well and seismic data from DOE/NETL support

D. Evaluate potential to employ large-scale commercial carbon storage in Kansas

via CCUS and developing ownership with regional petroleum industry

i. **Mississippian oil and gas reservoirs above and Arbuckle saline aquifer below** in existing fields and similar structures
ii. **Identified and modeled 10 sites for commercial scale CO_2** – analogous to calibration sites; suitable candidates for Class VI permit

A. Risk analysis toward establishing storage capacity

i. **Wellbore, injection, caprock, faults, and USDW/usable aquifers in Kansas**

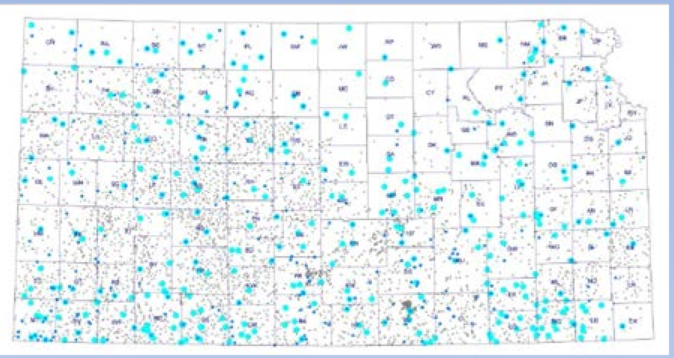
B. Address program goals

i. **Develop technologies that will support industries' ability to predict CO_2 storage capacity** in geologic formations to within ±30 percent.
ii. **Evaluate best practices to minimize risk and maximize CO_2 storage.**

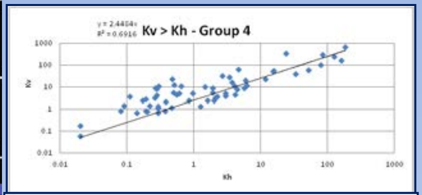
A. Characterize the Ozark Plateau/Western Interior Plains Aquifer and Petroleum System encompassing Mississippian sandstones and carbonates and Cambro-Ordovician Arbuckle Group carbonate and minor sandstone (Predict CO_2 storage within ±30 percent)

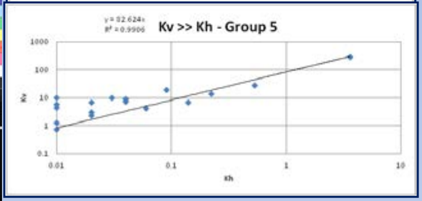
1. **Type wells – scan, digitize logs and samples descriptions, establish standardized correlations**
2. Created **structural and stratigraphic maps and cross sections** to evaluate storage and risk
3. Developed and use **Java tools and interactive map** to integrate data, make publicly accessible
4. **Develop regional Petrel project** to access, process, and display digital well logs, basic cross sections, stratigraphic, geophysical, and remotely-sensed lineaments
5. Process and interpret **regional gravity and magnetic data**
6. Interpret regional **remote sensing** information for lineaments and spatial anomalies
7. Analyze **regional fluid chemistry and establish hydrostratigraphic units** in Arbuckle Group saline aquifer
8. **Evaluate fracture and fault distribution, seal integrity, and reservoir characterization**
    1. Utilize donated 3D seismic (130 mi^2) and that acquired (~20 mi^2) at Wellington and Cutter fields
9. **Develop regional simulation, "Mega Model"**, estimating carbon storage based on injectivity
10. Evaluate **CO_2-EOR potential in Kansas and propose business model for use of anthropogenic CO_2** with industry partners, KS Department of Commerce, and Governor's office
11. Map major **sources and sinks for CO_2**
12. **Evaluate risk**

Workflow

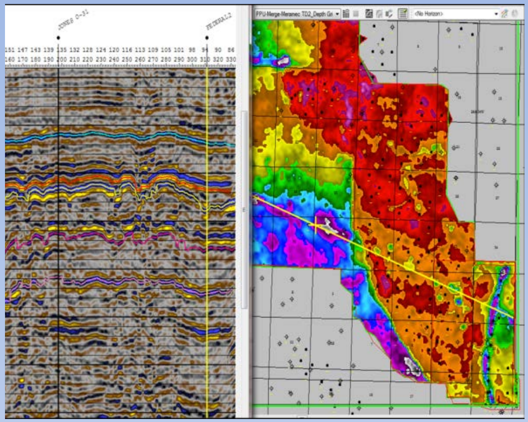


Select and digitize key wells

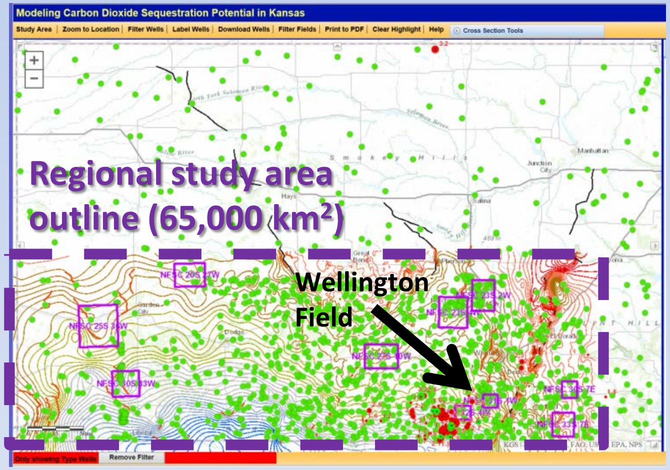




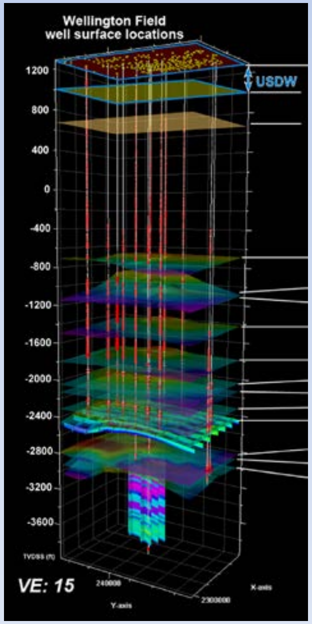
Core, log & well test analysis



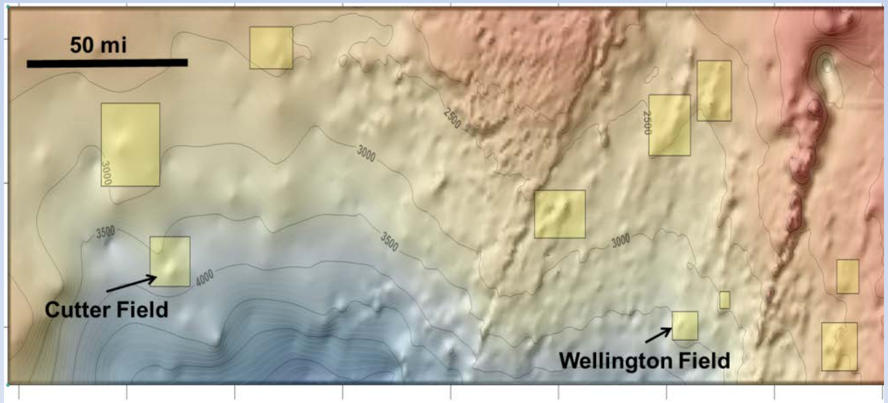
Seismic analysis



Mapper & Java tools



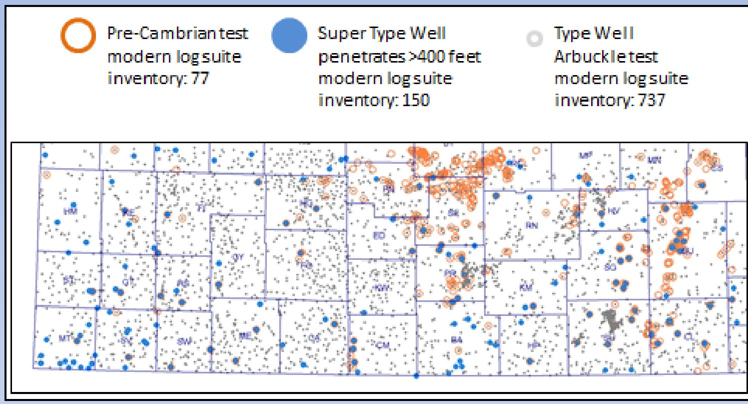
Geomodels



Regional "Mega Model" simulation

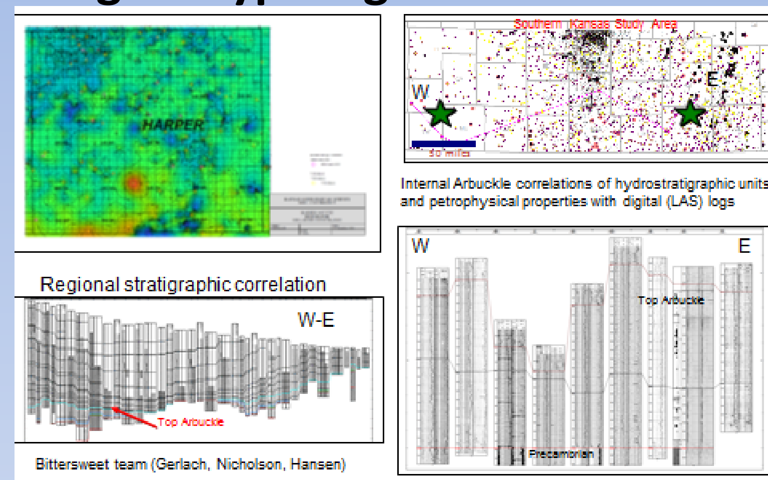
Maximize new information gained to quantify key variables in CO_2 injection and storage

CO_2 well inventory



+ scanned images of 90,000 shallower wells

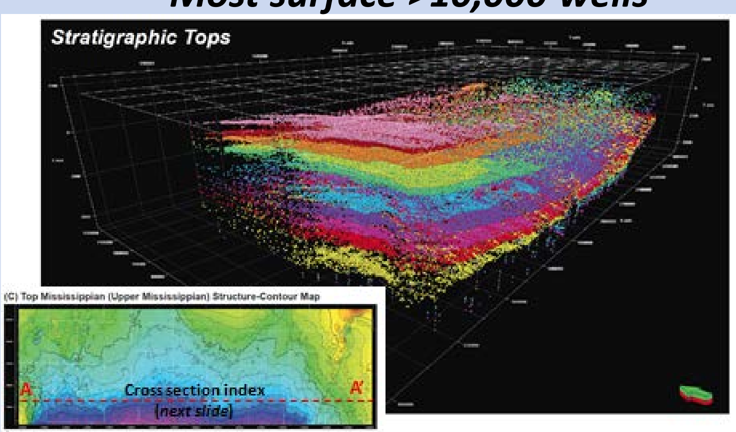
Digital Type logs and correlation



KGS & Bittersweet team

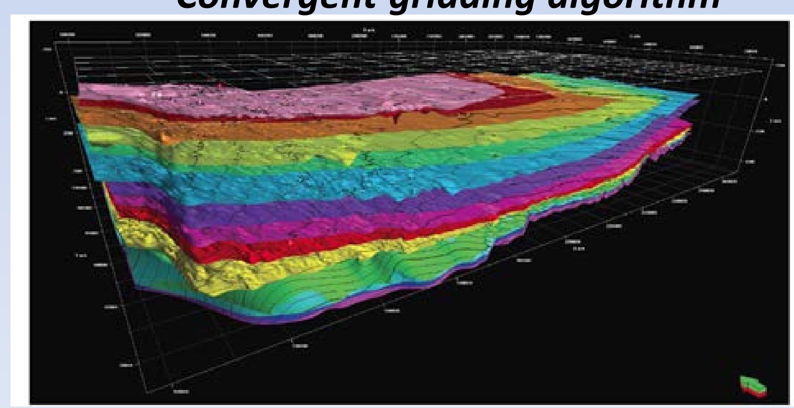
3D view of stratigraphic tops

- *Regional Petrel database*
- *Most surface >10,000 wells*



3D view of 18 structure surfaces

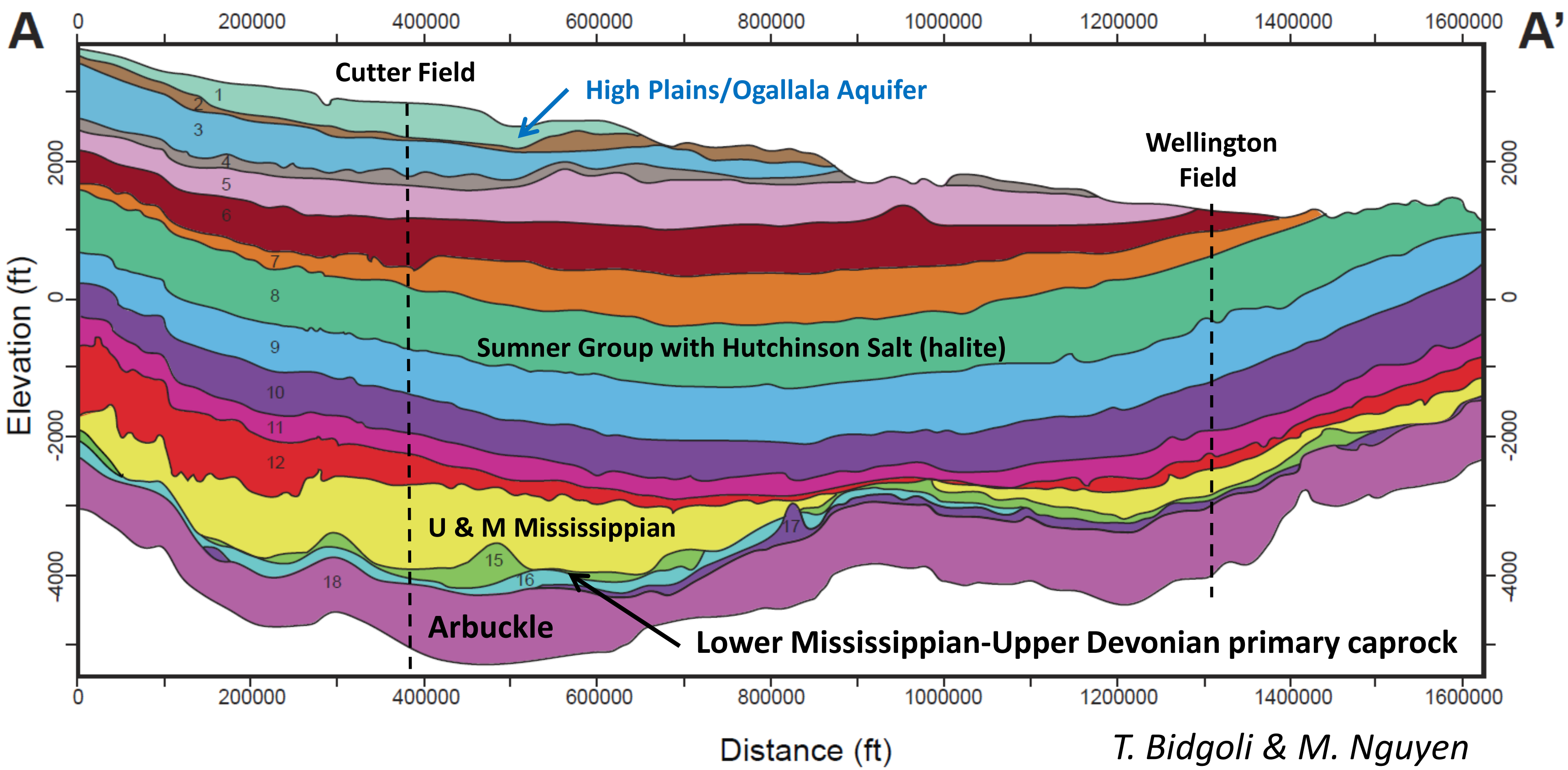
- *2500 x2500 ft grids*
- *Convergent gridding algorithm*



T. Bidgoli and M. Nguyen, KGS

Regional stratigraphic database archived in dedicated Petrel workstation to facilitate continued analysis

W-E Cross section across southern Kansas illustrating surface in Petrel database of Phanerozoic stratigraphy
10x vertical exaggeration



T. Bidgoli & M. Nguyen

1. Present-day surface
2. High Plains base (Neogene)
3. Top Dakota (Cretaceous)
4. Base Dakota (Cretaceous)
5. Blaine Formation (Permian)
6. Cedar Hills Formations (Permian)
7. Top Stone Corral Formation (Permian)
8. Hutchinson Salt (Permian)
9. Top Chase Group (Permian)
10. Root Shale (Upper Pennsylvanian)
11. Heebner Shale (Upper Pennsylvanian)
12. Stark Shale (Upper Pennsylvanian)
13. Top Cherokee Group (Mid. Pennsylvanian)
14. Top Mississippian (Upper Mississippian)
15. Top Pierson Formation (Mid. Mississippian)
16. Top Viola Limestone (Middle Ordovician)
17. Top Simpson Group (Middle Ordovician)
18. Top Arbuckle (Lower Ordovician)

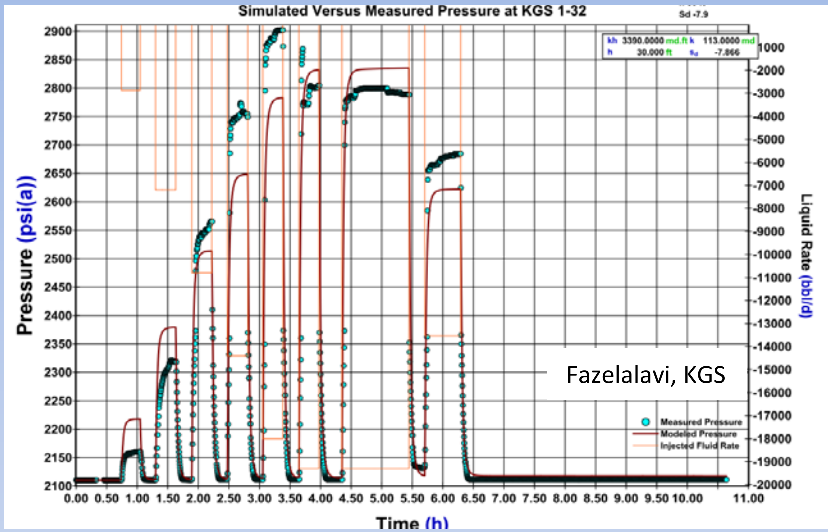
B. Model carbon dioxide injection in Arbuckle Group saline aquifer and the overlying Mississippian reservoir at Wellington Field (Sumner County, Kansas)

(*Eastern Calibration site*)

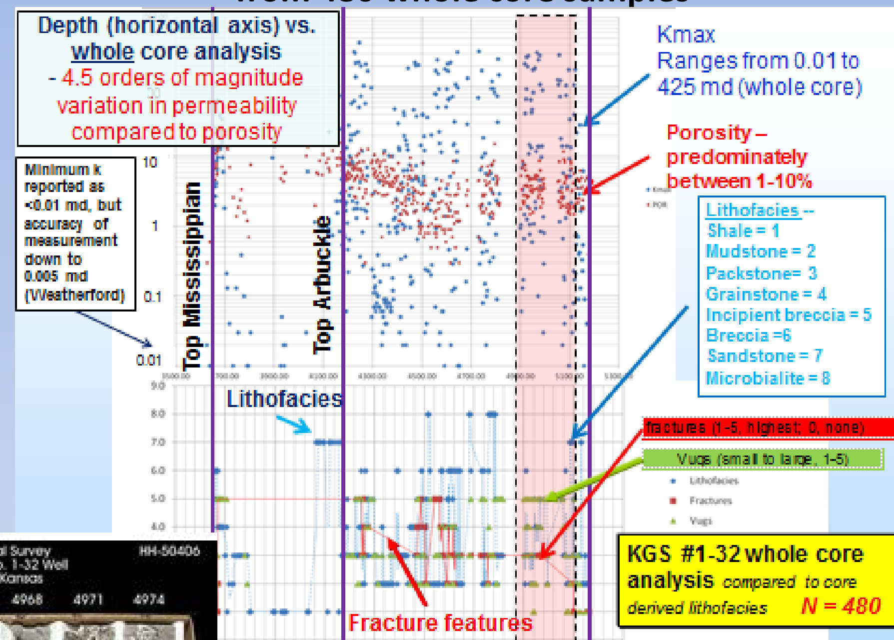
1. *Drill, core (1528 ft), test #1-32 and drill and test #1-28, both ~5200' basement tests; including step-rate test between wells in proposed Arbuckle injection zone*
2. *Acquire, process, interpret 12 mi^2 of multicomponent 3D seismic to interpolate Φ-k distribution, resolve structure, and evaluate seals*
3. *Obtain geochemical, isotopic, and microbial analysis of brines and rock to characterize hydrostratigraphy and evaluate and model reactions with CO_2*
4. *Establish diagenetic history/paragenesis of the regional aquifer/petroleum system using petrography, geochemical, and fluid inclusions*
5. *Use Petrel and CMG to build integrated depth-migrated and well based geo-engineering models*
6. *Evaluate at risk wells and estimate CO_2 leakage and effects*

Extensive, integrated characterization of the Arbuckle saline aquifer at eastern calibration site (Wellington field)

Step-rate test pressure-time plot, #1-32 & #2-18

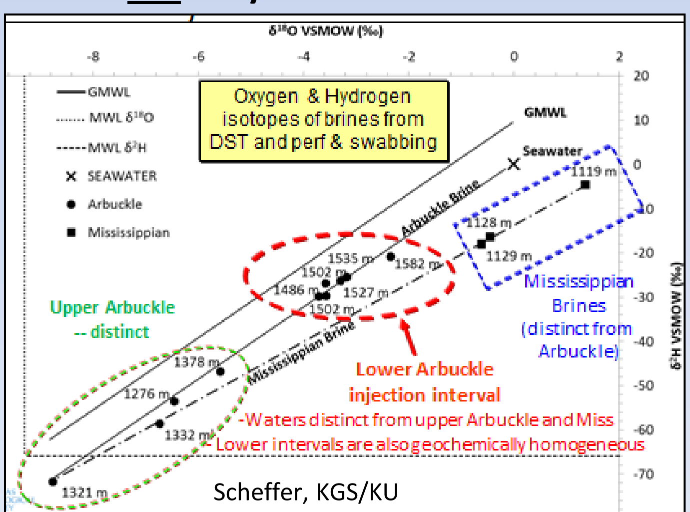


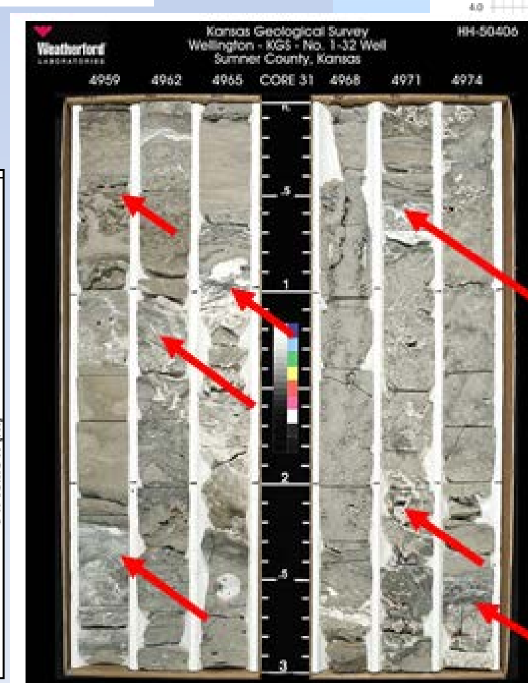
Depth vs. Φ & k, fracture features plot from 480 whole core samples



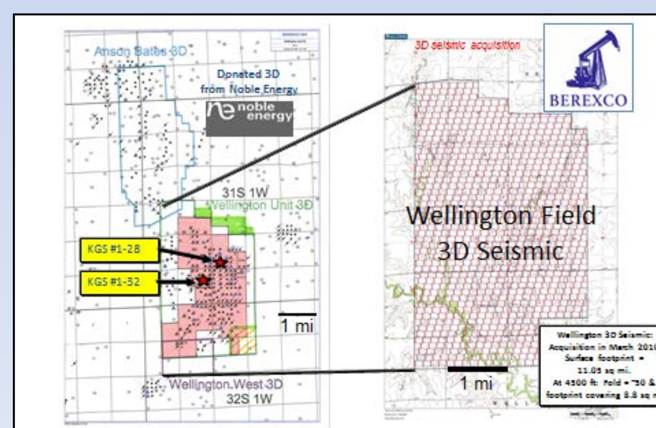
Weatherford

Oxygen and hydrogen isotopes → Lower and Upper Arbuckle at Wellington are not in hydraulic communication

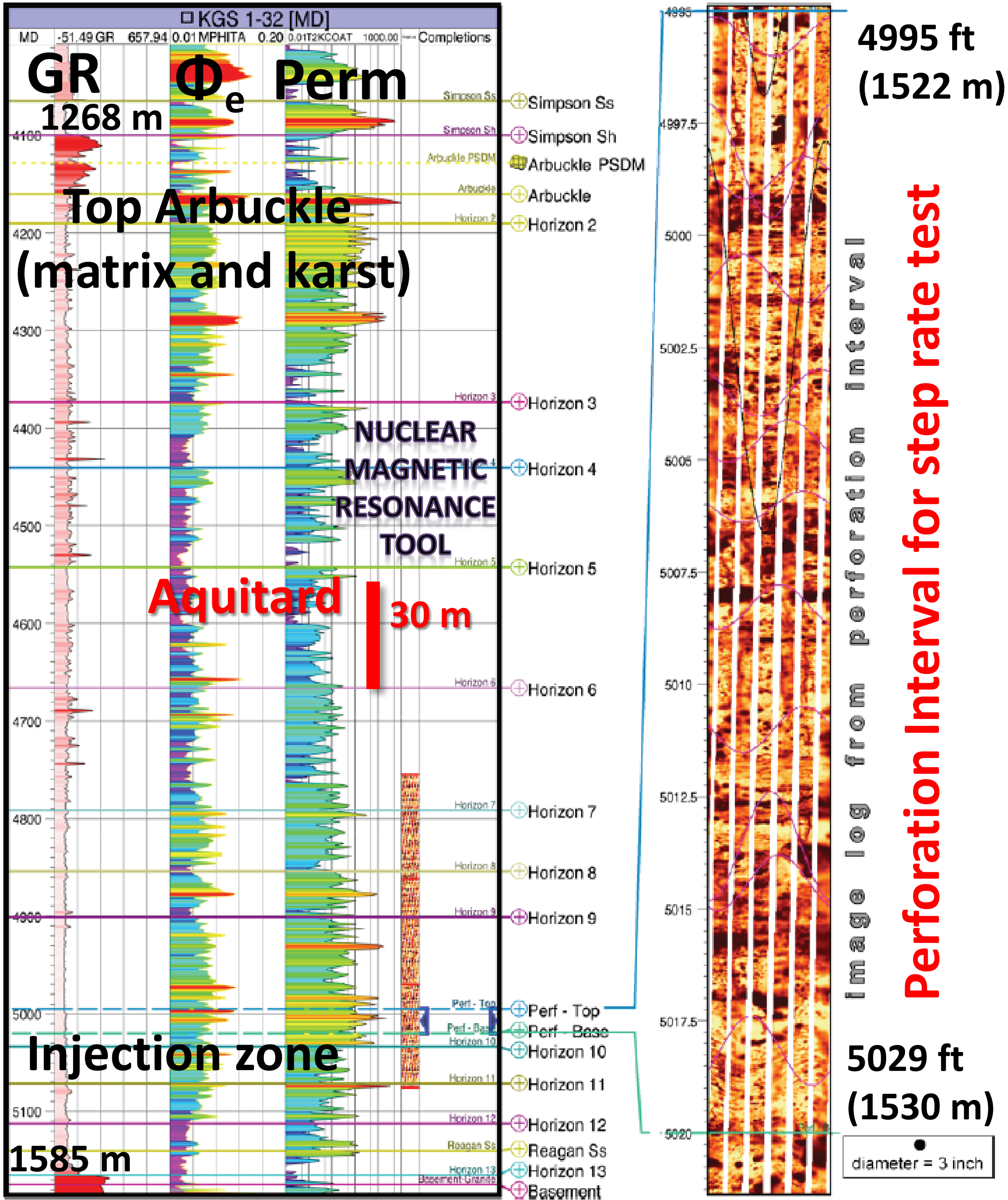




12 mi² Wellington multi-component 3D



Paragon Geophysical, Wichita



Porous crackle breccia common in injection zone (*dissolved evaporites*)

- Gamma ray
- Halliburton derived effective porosity from Nuclear Magnetic Resonance (NMR)
- Coates Permeability from NMR tool
- Microresistivity imaging log (MRIL)

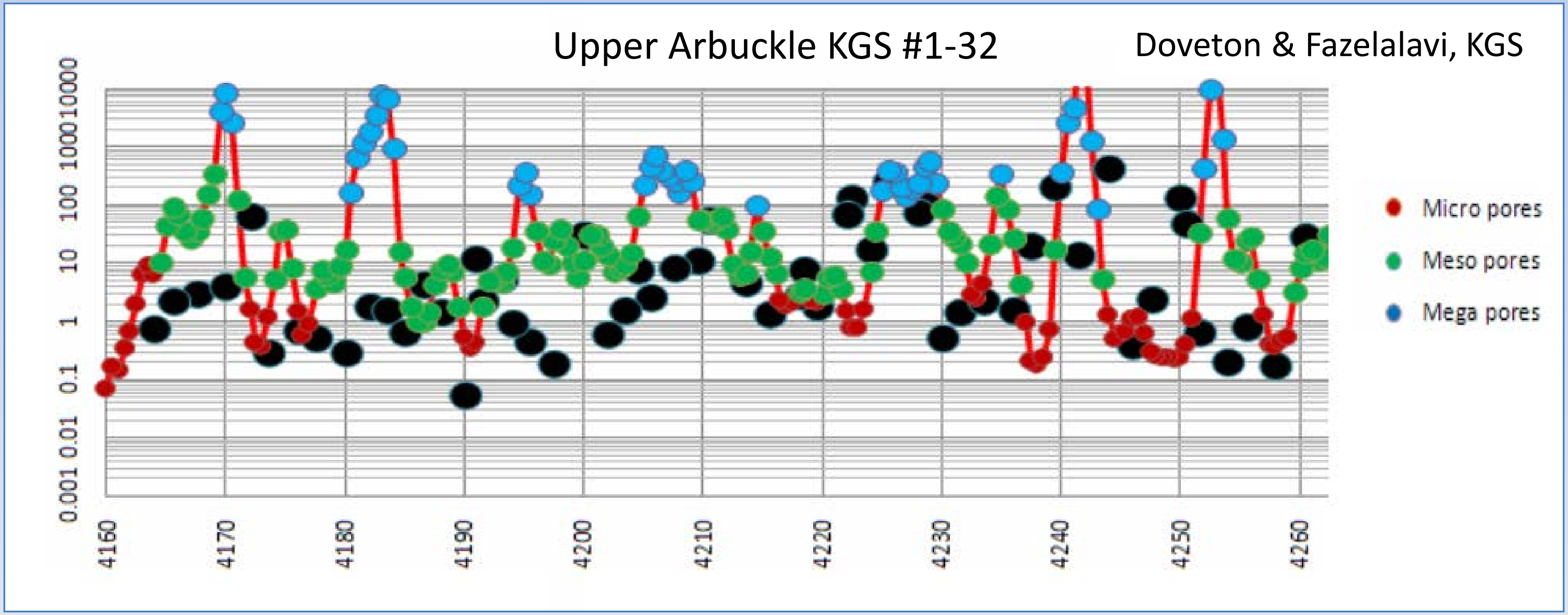
J. Rush, KGS

HALLIBURTON

Schlumberger Petrel

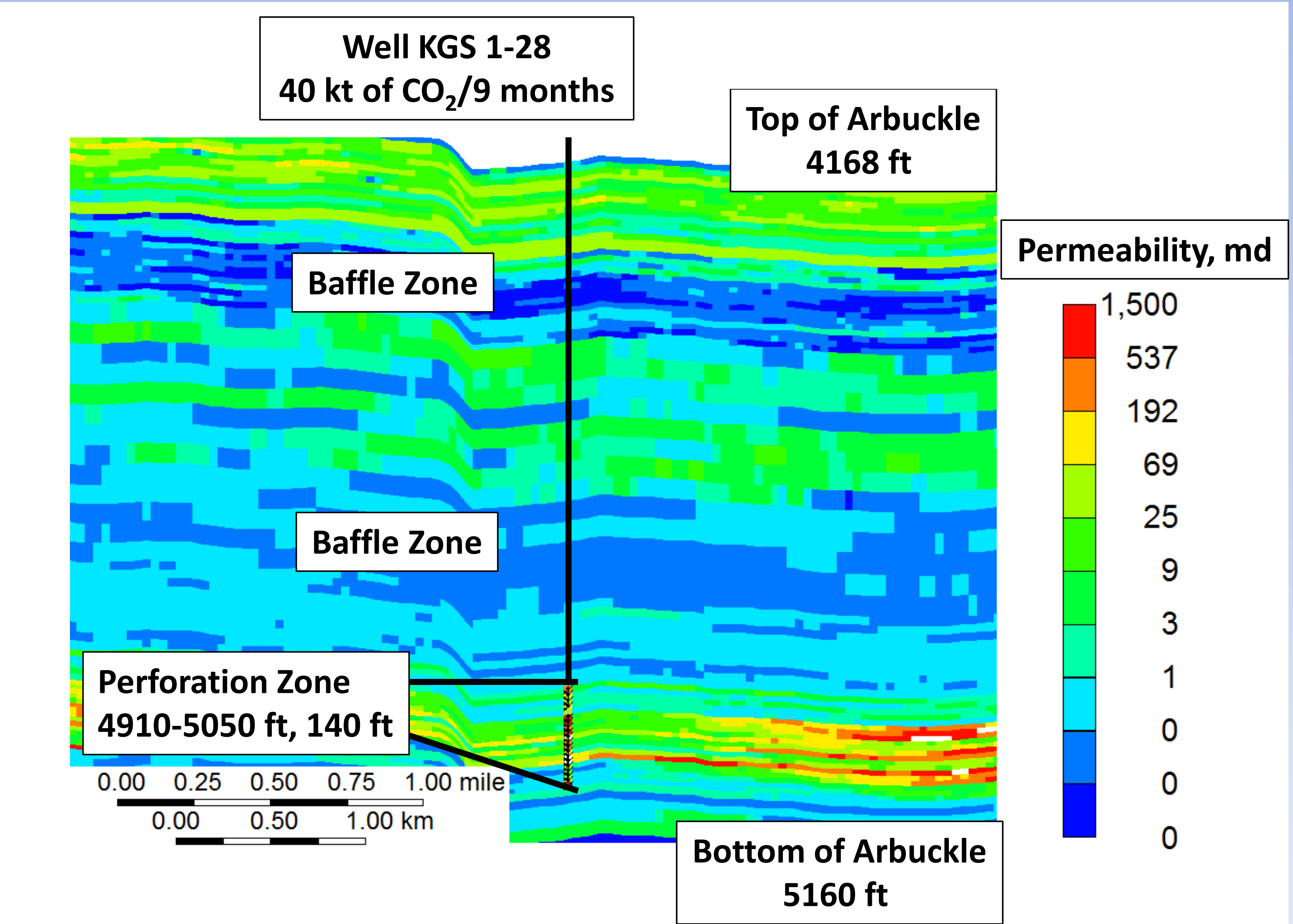
Improved permeability estimation in Wellington KGS #1-32 and correlation to Wellington KGS #1-28

- Micro, meso, and mega groups defined from core & log analyses
- Derived FZI (*flow zone indicator*) from core and irreducible water saturation from NMR log
- Permeability computed from FZI value (Fazelalavi method)

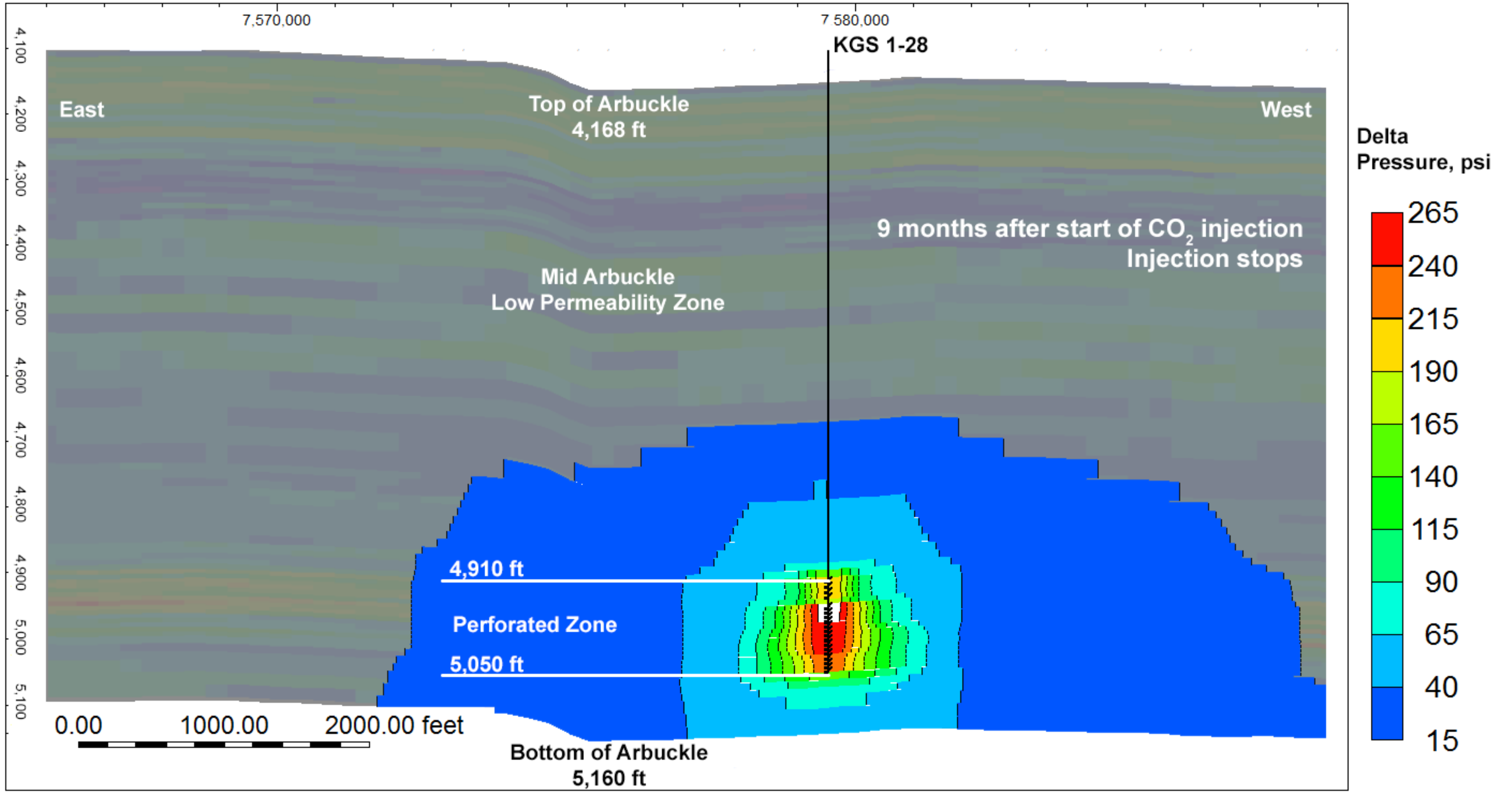


Black points = core measured permeability

Simulations of CO_2 injection at Wellington Field into high permeability hydrostratigraphic unit in lower Arbuckle



Vertical pressure distribution at maximum stress (just before the small scale 40k tonne injection stops)



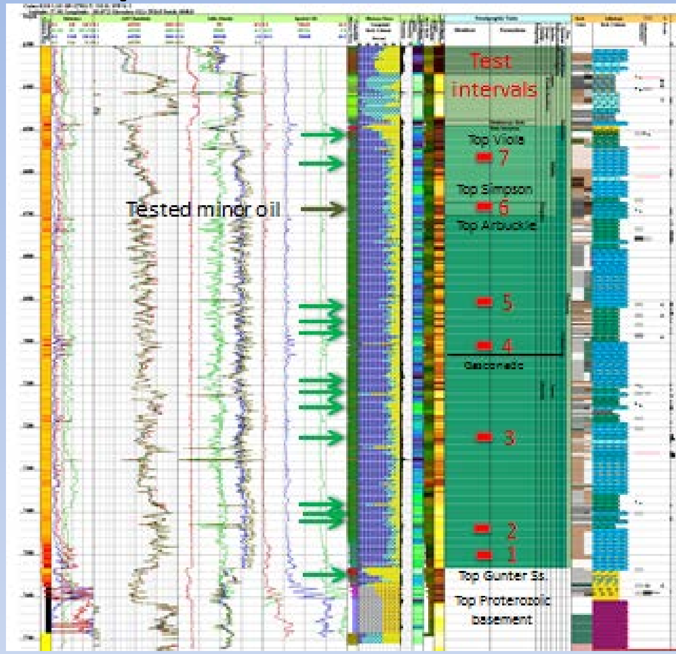
C. Evaluate CO_2 sequestration potential in oil four fields in southwestern Kansas

(Western *calibration site*)

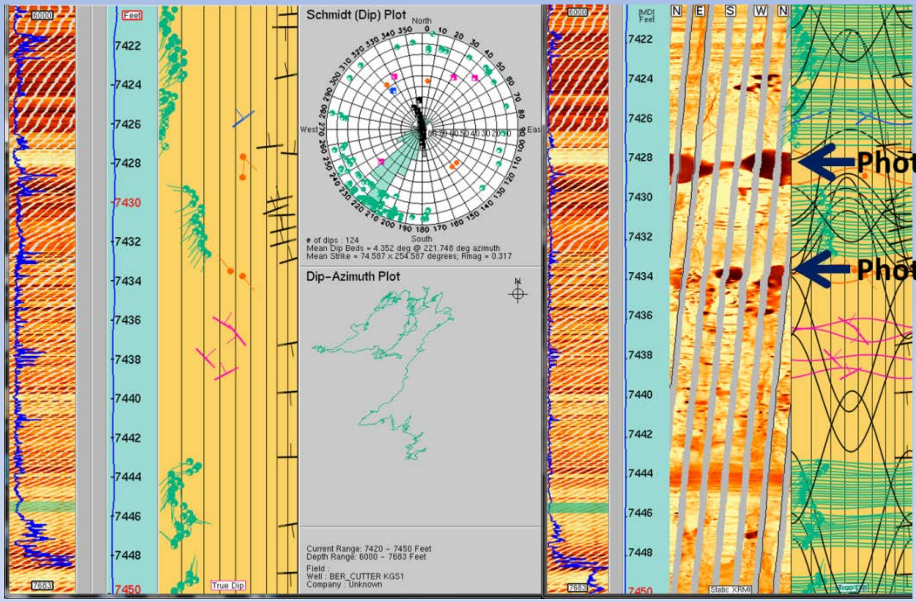
1. *Drill and complete 7500 ft basement test in Cutter Field, Stevens Co., KS using bid process and regional service companies*
    - *Core (**1216 ft net**) from base Pennsylvanian to basement*
    - *Run multiple interval well tests including perf and swab*
    - *Acquire, process, and interpret 10 mi^2 of multicomponent 3D seismic*
2. *Obtain, reprocess, and interpret 130 mi^2 of 3D seismic through industry consortium – SW Kansas CO_2 Initiative*
3. *Analyze fluids and rock from Cutter KGS #1*
4. *Simulate CO_2-EOR @ 4 fields*
    - *Cutter, South Pleasant Prairie, Eubanks North, and Shuck fields*
    - *Optimize CO2 storage*

Cutter Field core was cored, logged, and tested in manner analogous to Wellington Field

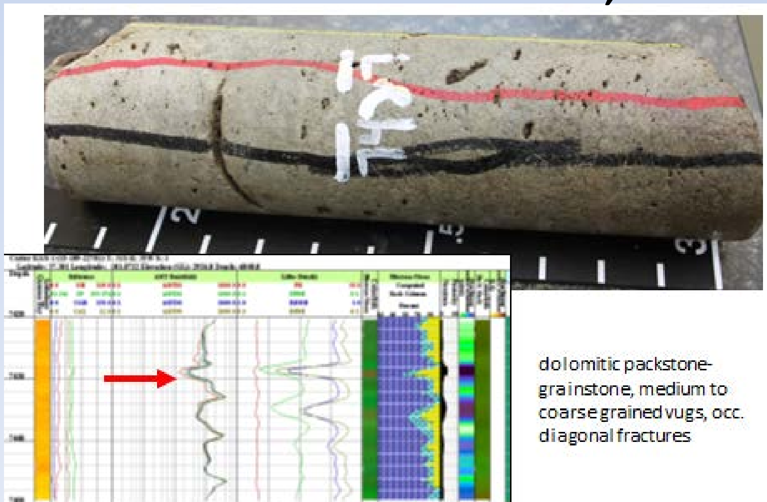
Multiple oil shows in Arbuckle core



Lower Gasconade Dolomite 7420-50 ft
Vuggy pores from image log

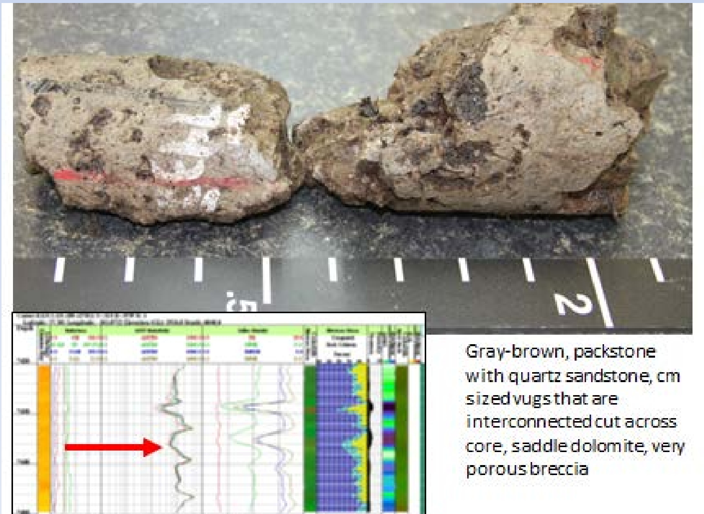


Lower Gasconade Dolomite, 7427 ft



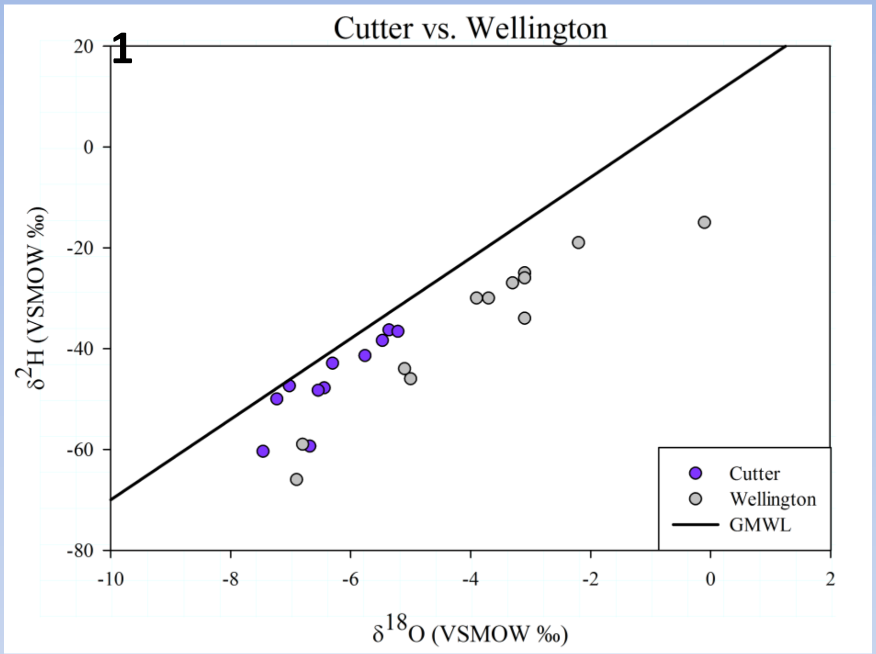
dolomitic packstone-grainstone, medium to coarse grained vugs, occ. diagonal fractures

Lower Gasconade Dolomite, 74233 ft



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

Arbuckle in the Cutter vs. Wellington: Isotope and hydrochemical comparison

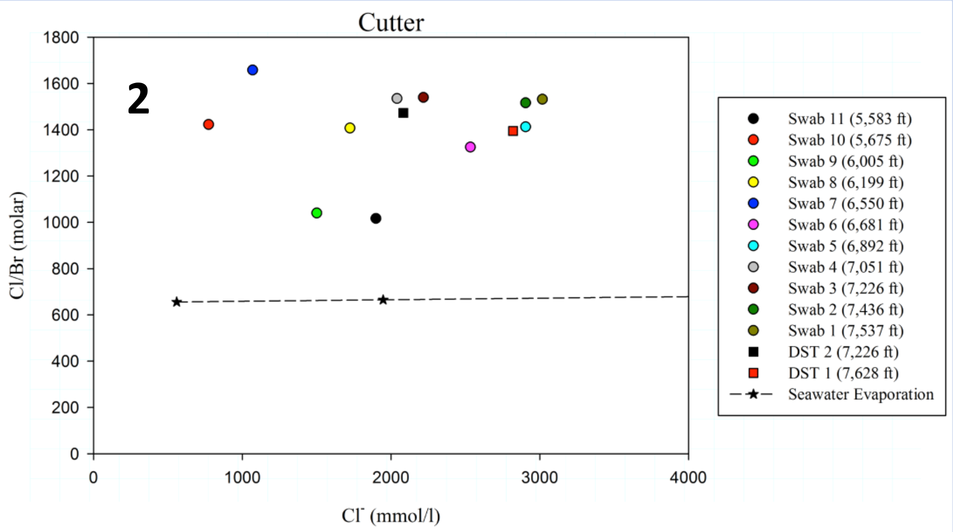


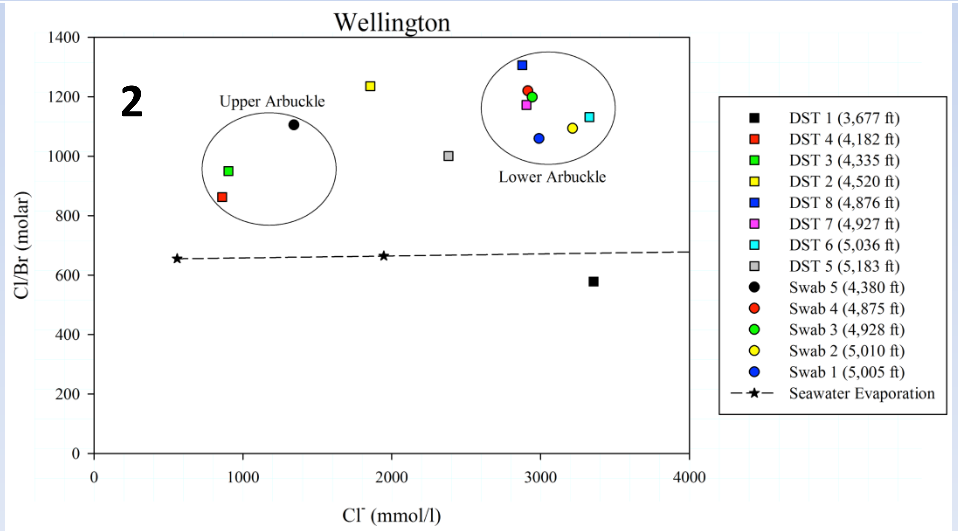
1. **Cutter brines appear to be mixed**.

2. **Wellington shows distinct groups in upper and lower Arbuckle**. Cutter waters are closer to the GMWL, and indicates more evaporation.

3. **Cl/Br ratios (below) show no vertically separated units within Cutter**, which is in contrast with Wellington.

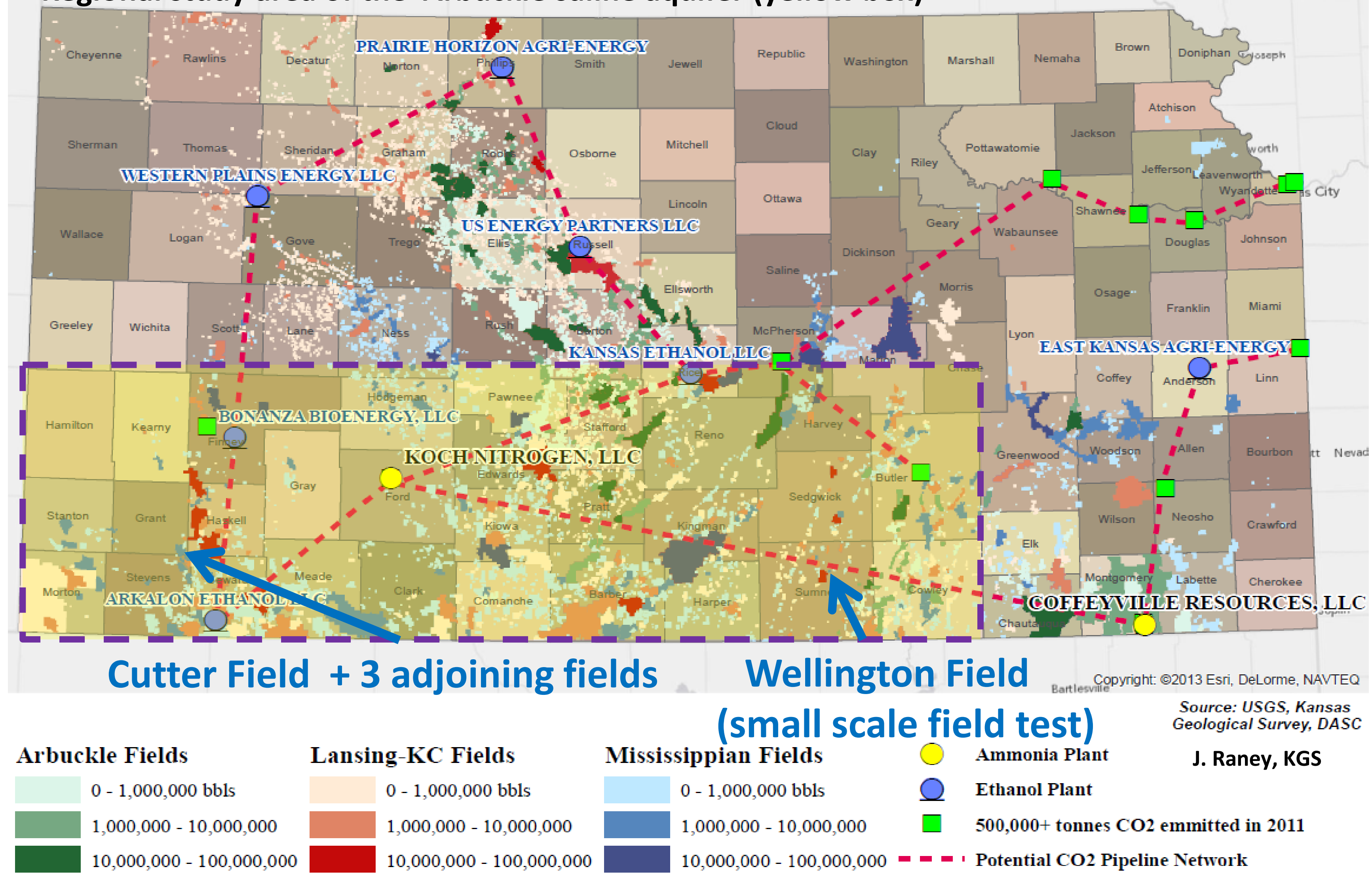
Campbell and Datta, KSU



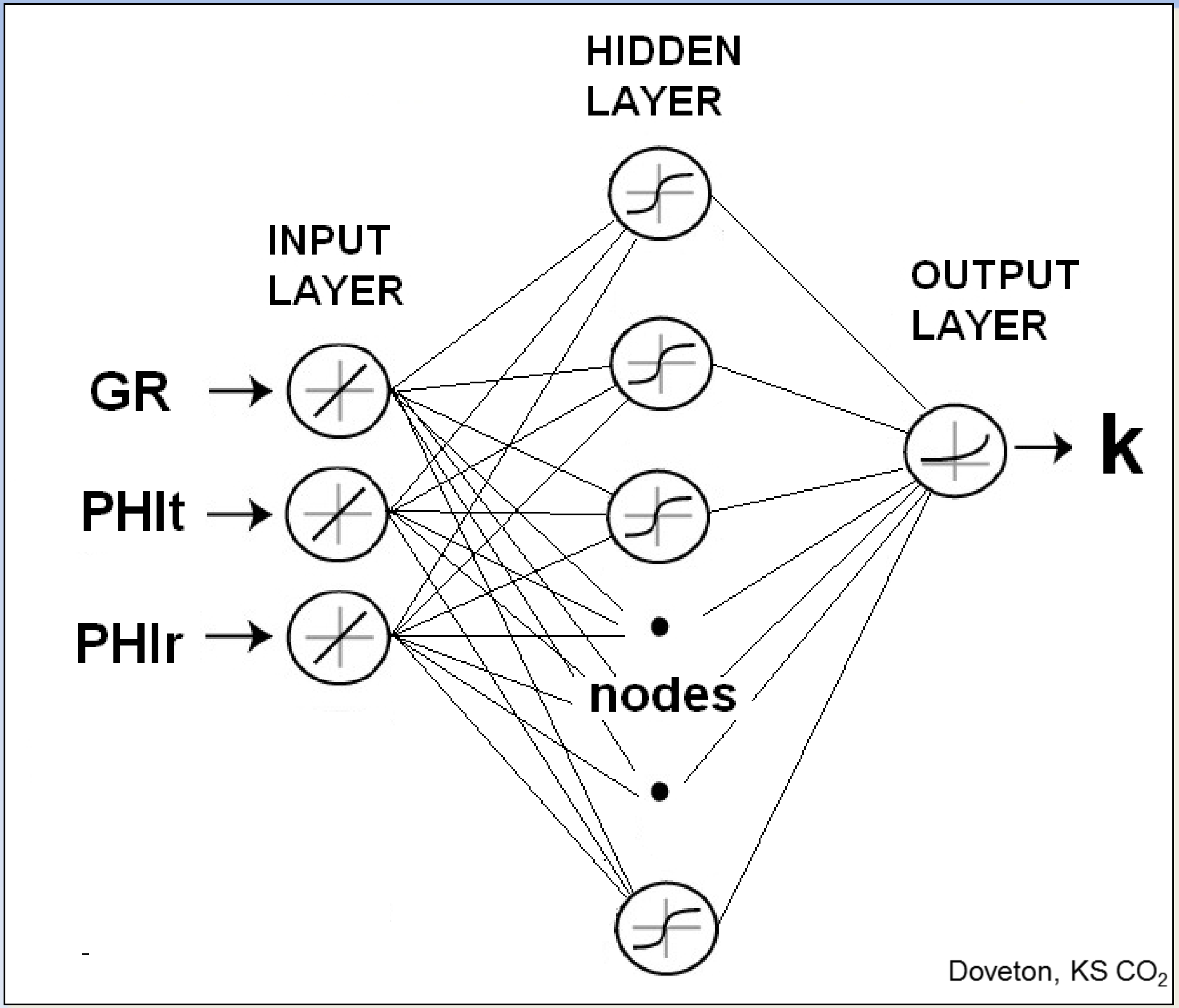


D. Evaluate potential to employ large-scale commercial carbon storage

- Major oil and gas reservoirs as candidates
  for CO_2-EOR & existing CO_2 sources in Kansas
- Regional study area of the Arbuckle saline aquifer (yellow box)



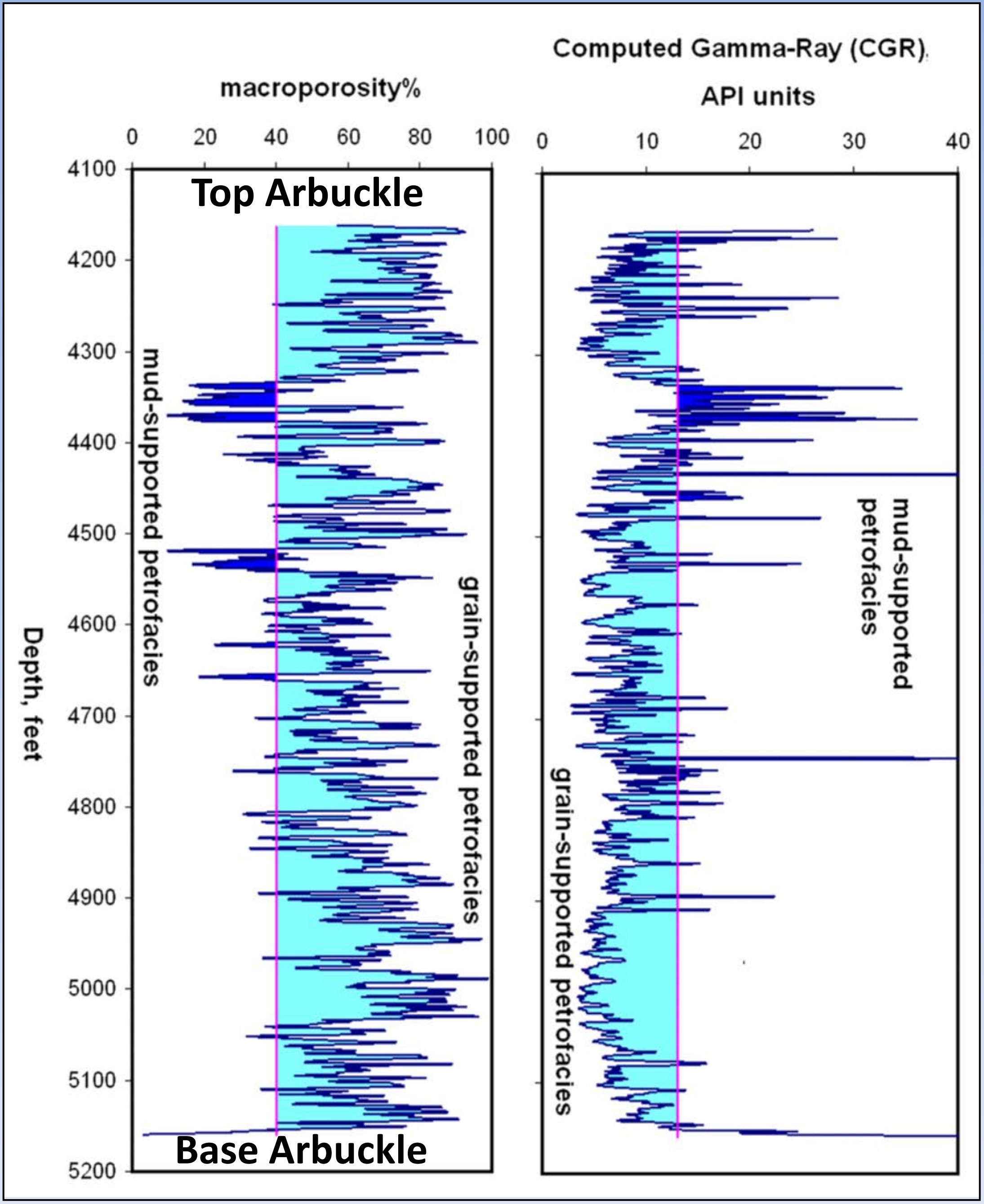
Neural network (NN) prediction of Arbuckle permeability from logs



1. GR (Gamma-ray, API units)

The CGR (K+Th) shows good distinction between more permeable grainstones and less permeable mudstones.

Complication: Standard gamma-ray logs include uranium, which may bias grainstones towards mudstones

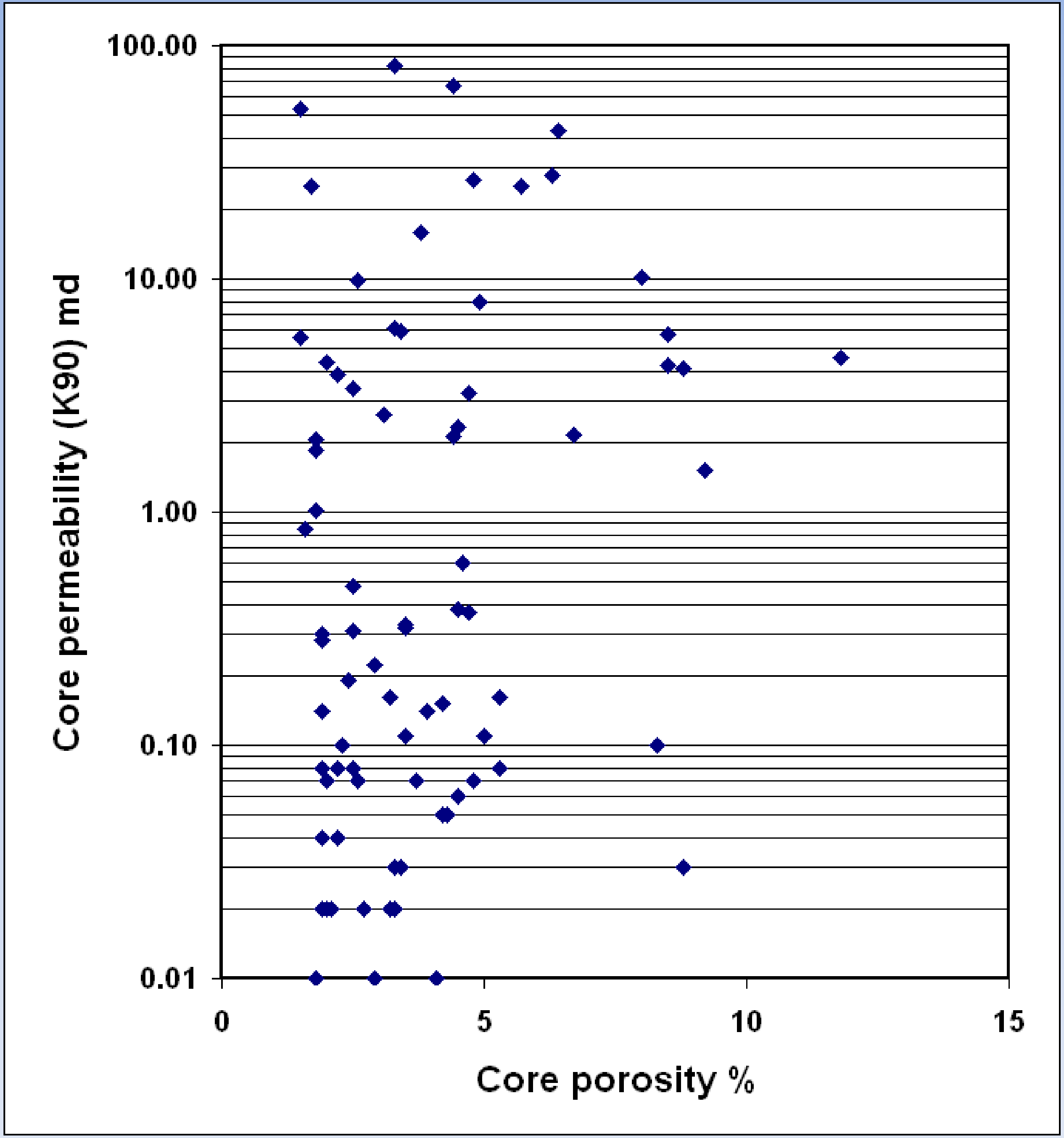


Doveton, KGS

2. PHIt (volumetric porosity% from density & neutron logs)

There must be some relationship between porosity and permeability

…Surely?



Doveton, KGS

3. PHIr (connected porosity estimated from resistivity log %)

From the first Archie equation for carbonates:

$$F = \frac{R_o}{R_w} = \frac{1}{\Phi_R^2}$$

where Φ_R is the electrically connected porosity.

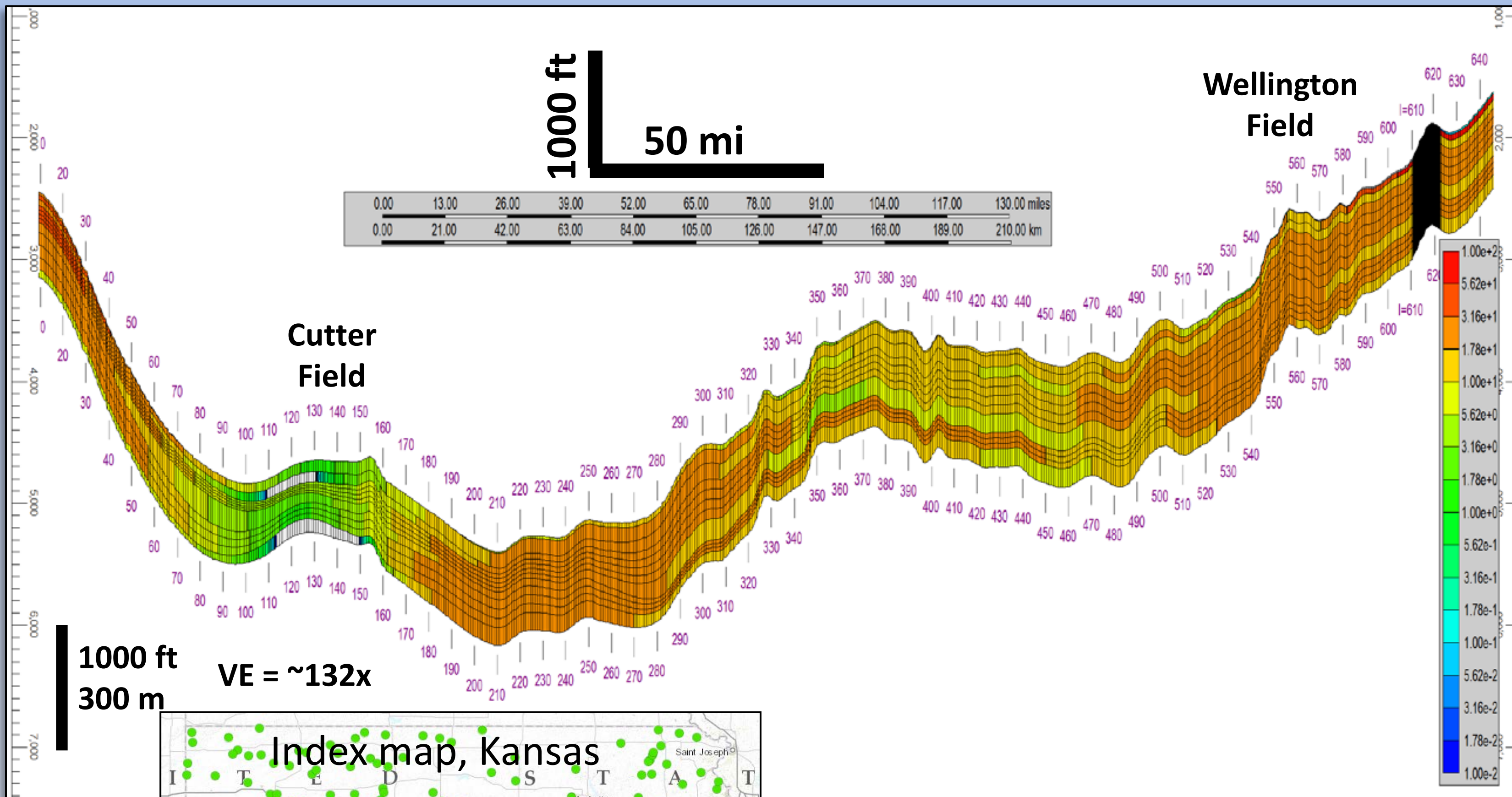
So,

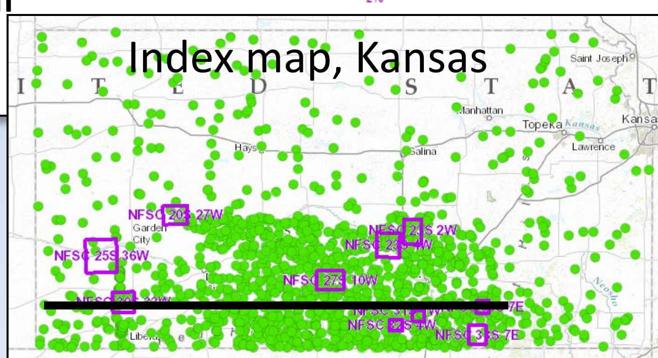
$$\Phi_R = \sqrt{\frac{R_w}{R_o}}$$

Complication: Rw is significantly higher in the top of the Arbuckle than in the middle and this variability needs to be accommodated in the calculation of PHIr

Doveton, KGS

West-East structural cross section showing permeability distribution in 16 Arbuckle flow units, southern Kansas on regional 2500 x 2500 ft grid





Realizations of Horizontal Permeability, md
Based on neural net
Wellington and Cutter Fields

Williams, Gerlach, Fazelalavi, Holubnayk, Doveton, KS CO_2

Regional Sequestration Numerical Models

- **Max injection rate per well** = 5,900 tonnes/day
- **Limiting Injection Pressure** = 150 % of ambient pressure at site
- **CO_2 Trapping Processes Simulated**:

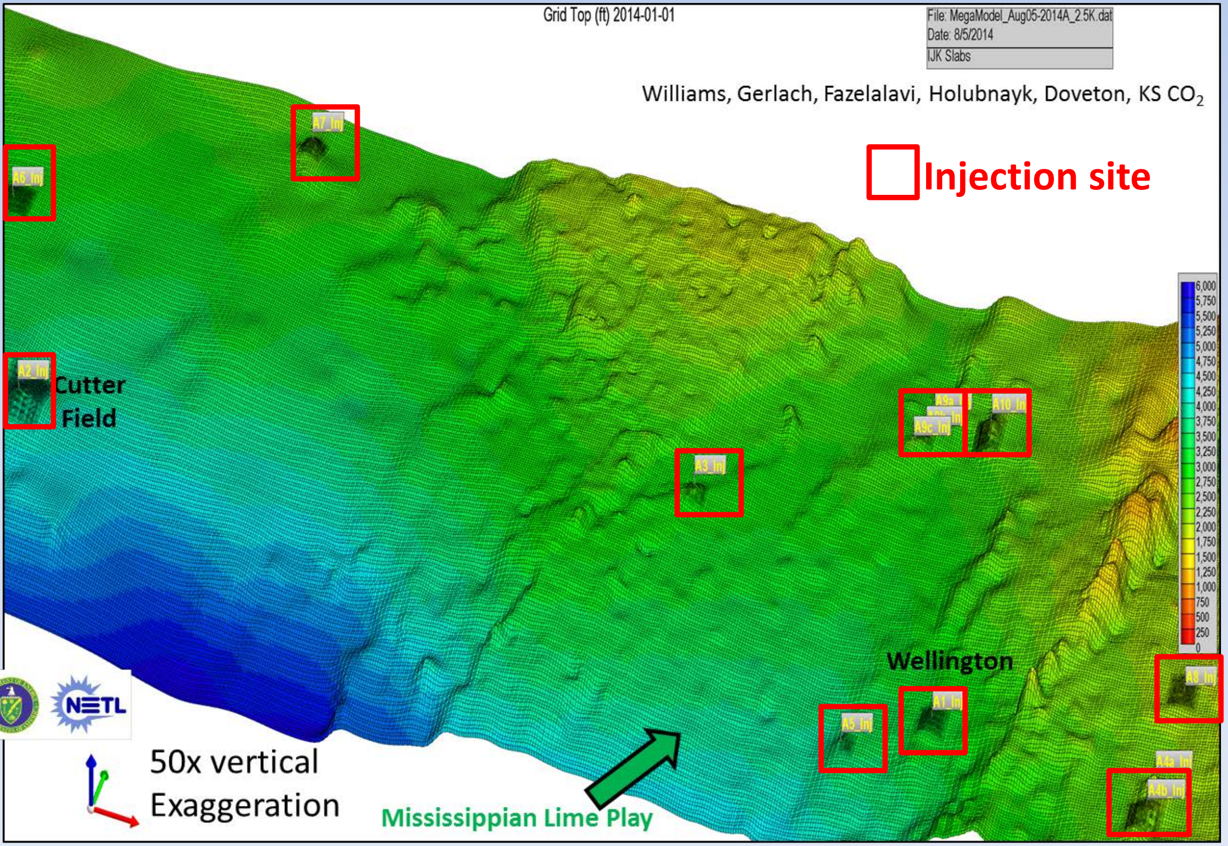
  Structural, Hydrodynamic, Solubility, Residual, Mineral
- **Conservatively simulated as a closed system**

Mega Model 1

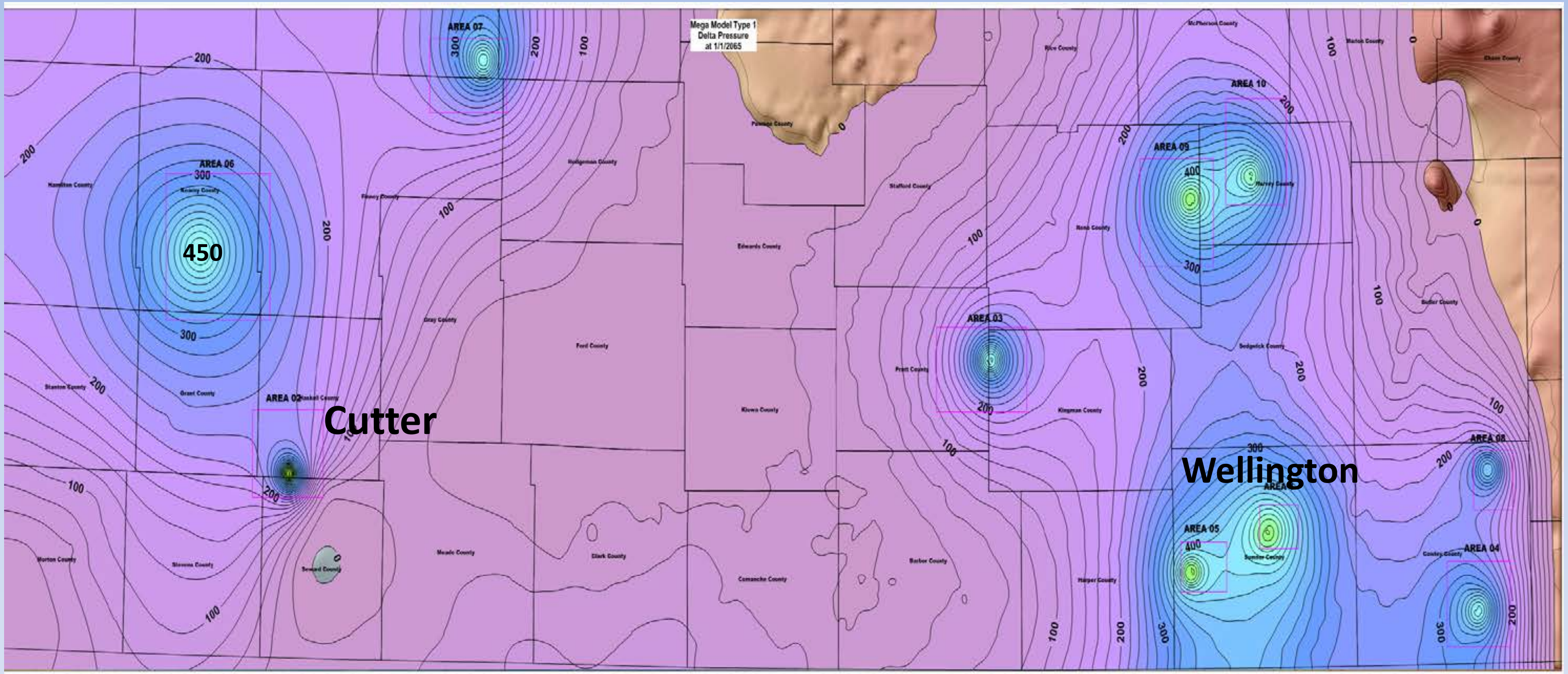
- 10 injection sites
- 50 years to 2065

Mega Model 2

- 10 injection sites of Mega Model 1 plus 103 uniformly distributed wells
- 150 years to 2165



Mega Model 1 delta pressure (PSI) at 50 yrs injection

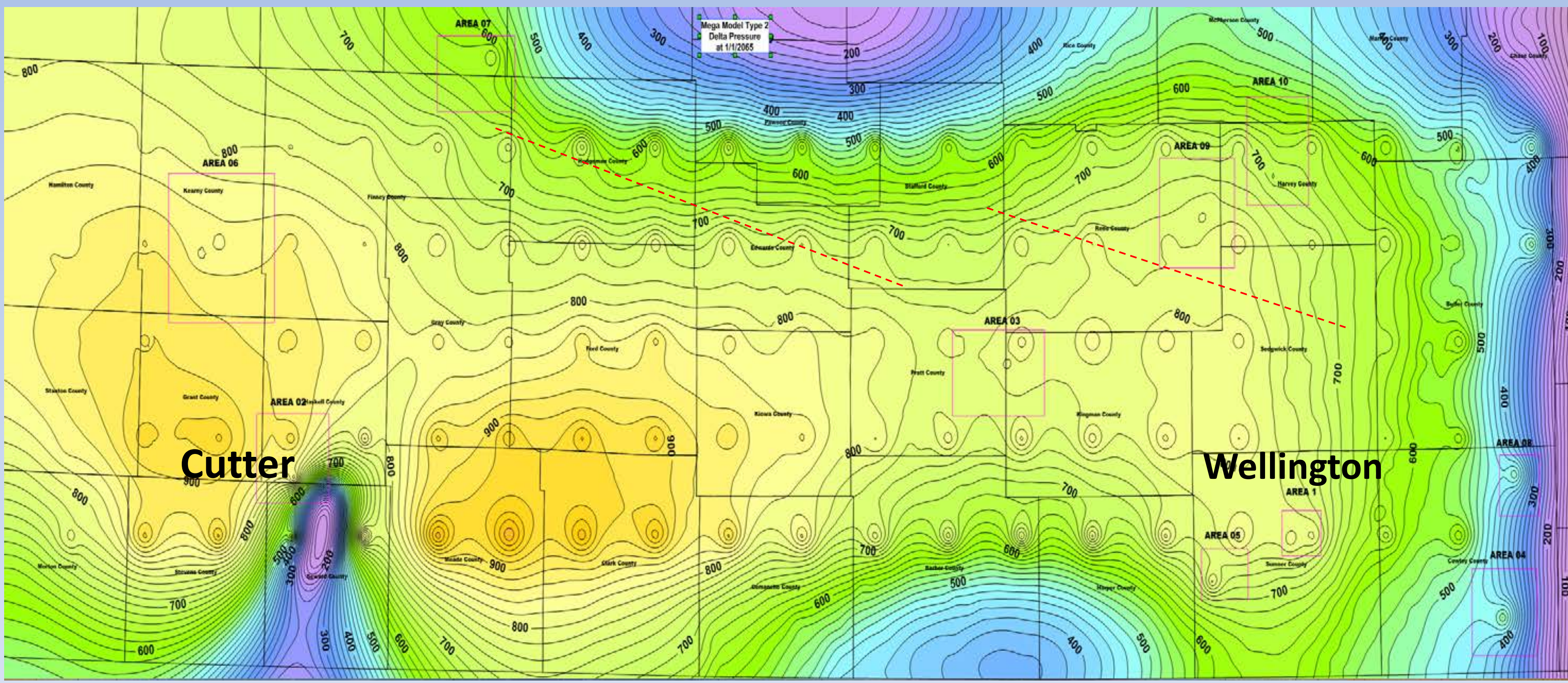


10 injection wells
Maximum local pressure 450 psi

Contour interval = 25 psi

Williams, Gerlach, Fazelalavi, Holubnayk, Doveton, KS CO_2

Mega Model 2 delta pressure (psi) at 50 years injection

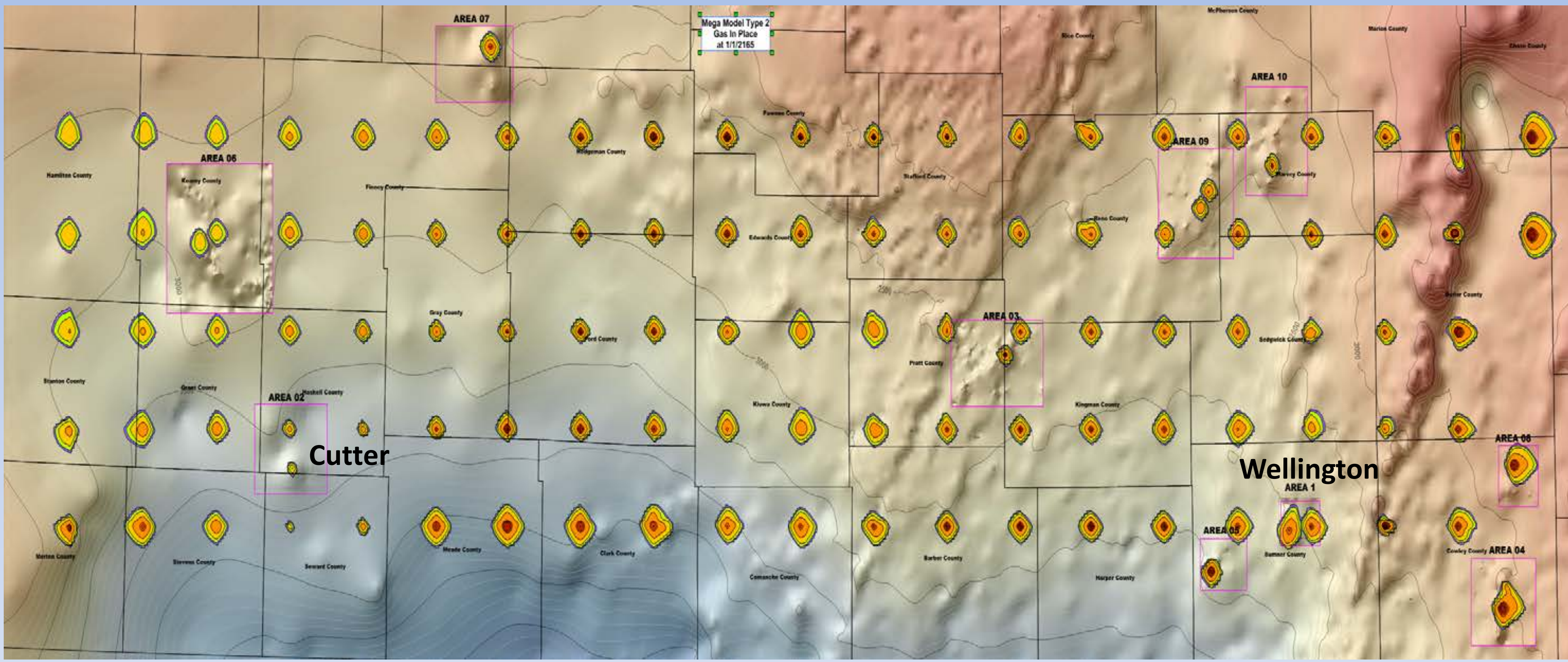


- 103 injection wells
- Max pressure ~1025 psi

Contour Interval: 25 psi

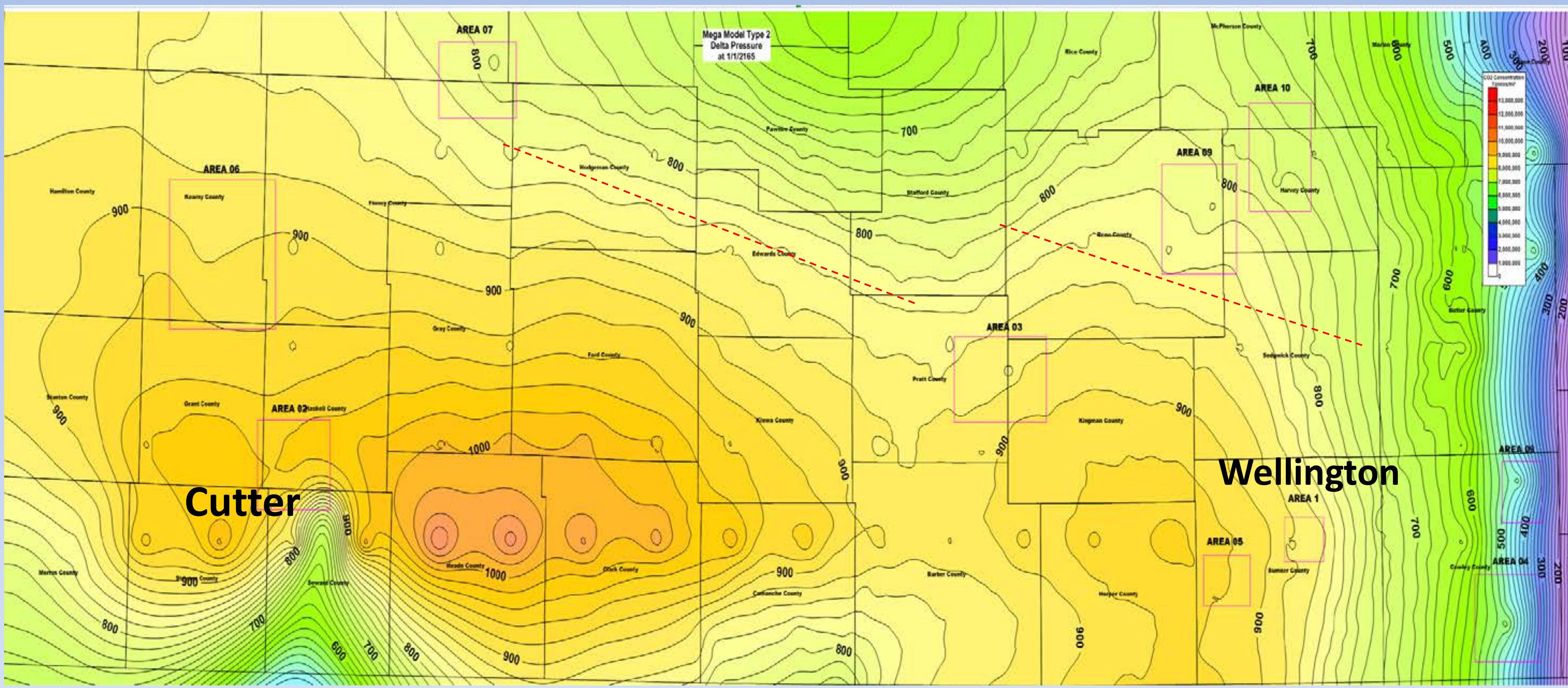
Williams, Gerlach, Fazelalavi, Holubnayk, Doveton, KS CO_2

Model 2
CO_2 as super critical gas in place after 150 yrs of injection



103 injection wells
4 billion tonnes injected in 150 years

Mega Model 2 delta pressure at 150 years injection



103 injection wells

Maximum delta pressure ~1075 psi

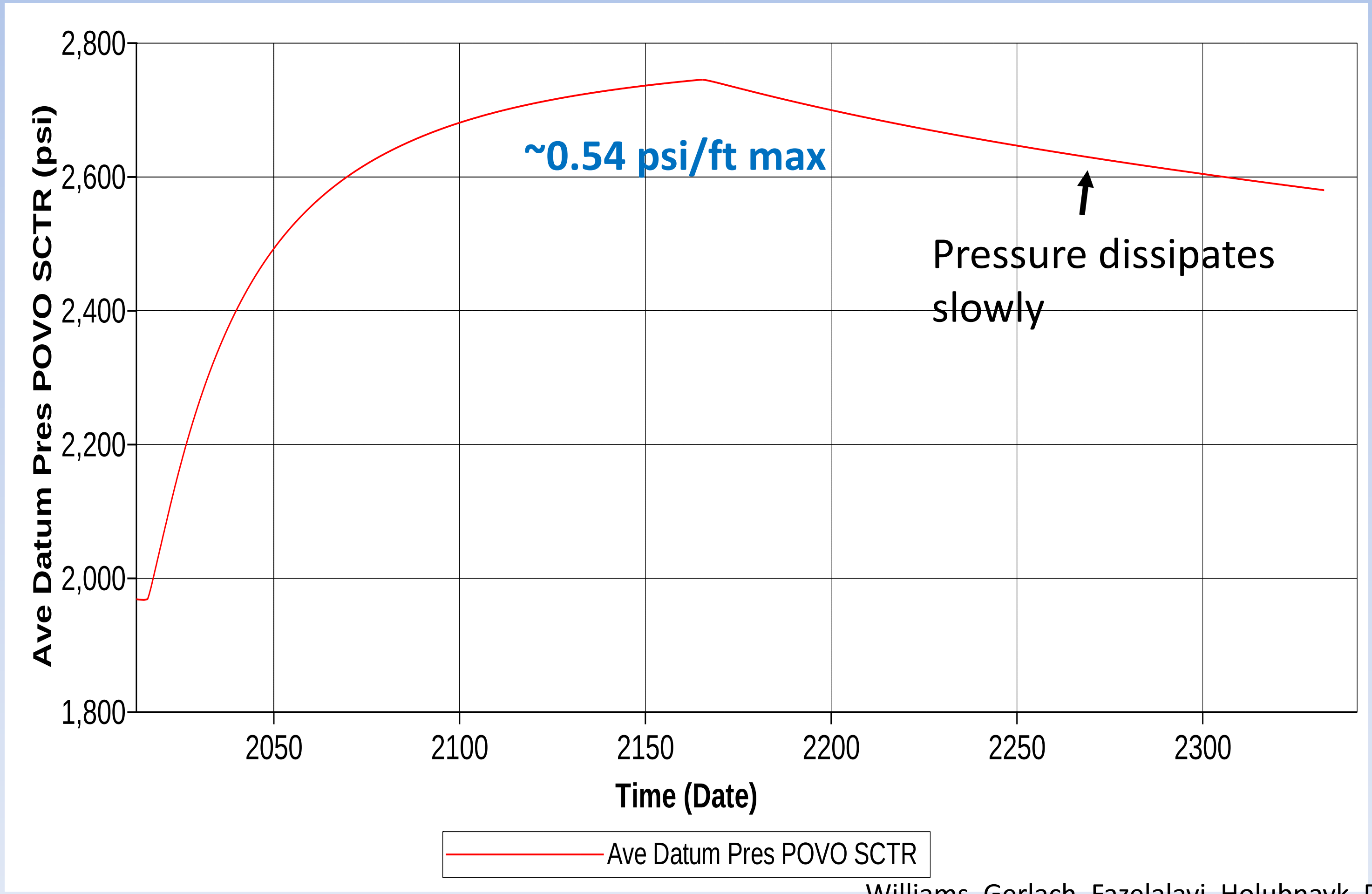
-- simulation with a closed system

Contour Interval: 25 psi

Williams, Gerlach, Fazelalavi, Holubnayk, Doveton, KS CO_2

Mega Model 2 aquifer pressure

- Average aquifer pressure at datum depth of 5000 ft builds from 1968 psi to 2745 psi (Δ P = 777 psi)
- 39.5% increase in pressure
- Conservatively simulated as a closed system

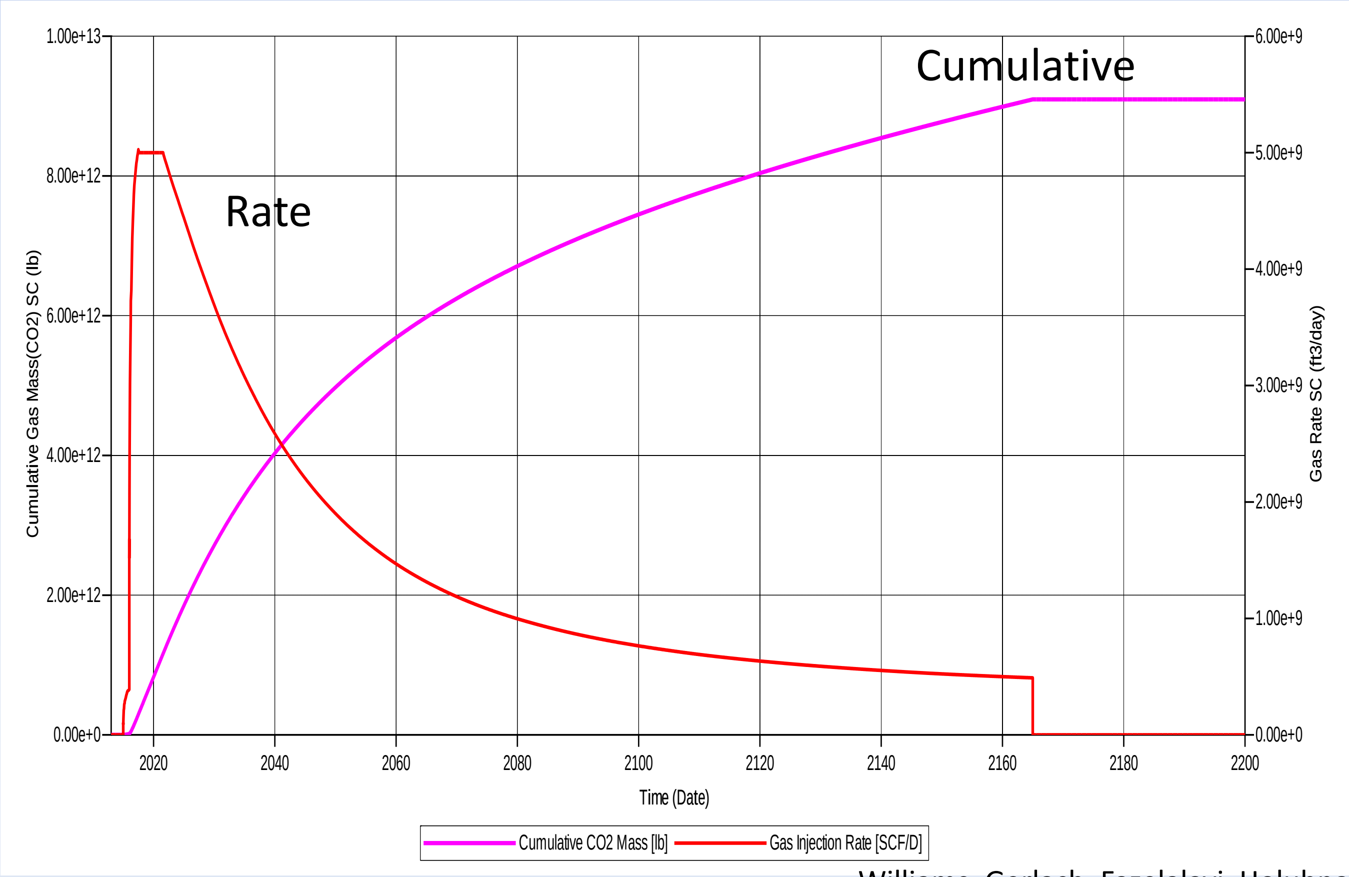


Williams, Gerlach, Fazelalavi, Holubnayk, Doveton, KS CO_2

Mega Model 2 CO_2 injection

- CO_2 is injected for 150 years, 103 wells
- Conservatively simulated as a closed system
- CO_2 injection capability diminishes as aquifer pressure increases

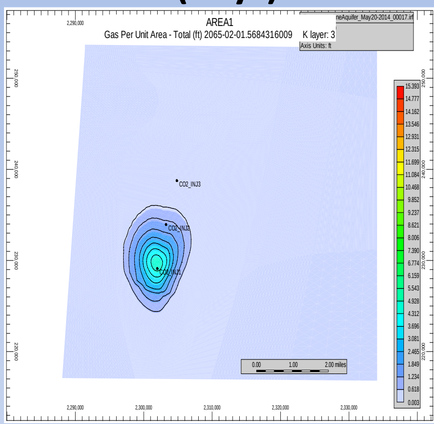
  (5.2**9 SCFD CO_2 (*306 MMT*) down to 0.5**9 SCFD CO_2 [*29 MMT*])
- Total CO_2 injected $9x10^{12}$ lbs → <u>4.02 billion tonnes</u>



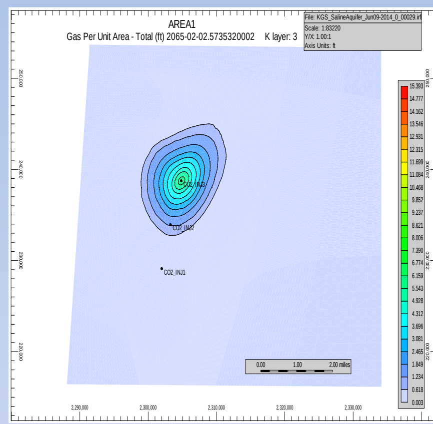
Williams, Gerlach, Fazelalavi, Holubnayk, Doveton, KS CO_2

Comparison of gas distribution at various volumes (Area 1 – Wellington Field)

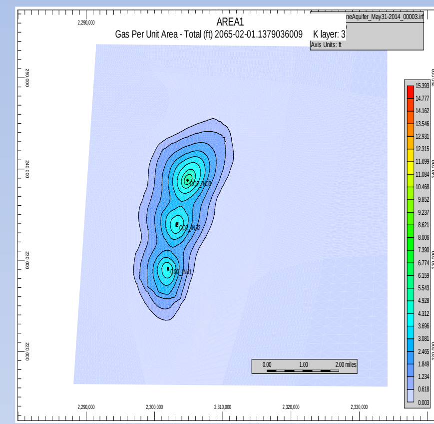
Injection Total 5.68 MM Ton (50yr)



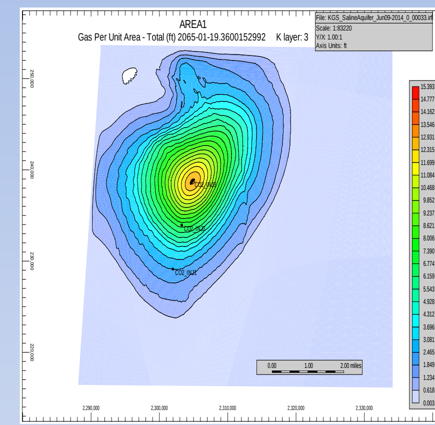
Injection Total 7.6 MM Ton (50yr)



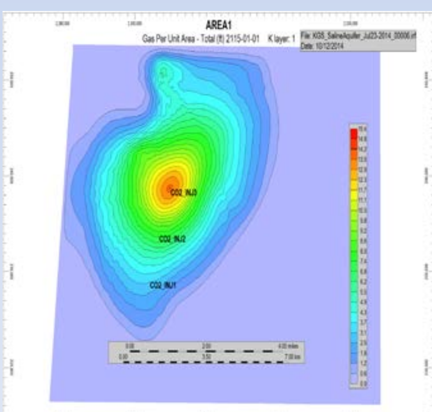
Injection Total 13.4 MM Ton (50yr)



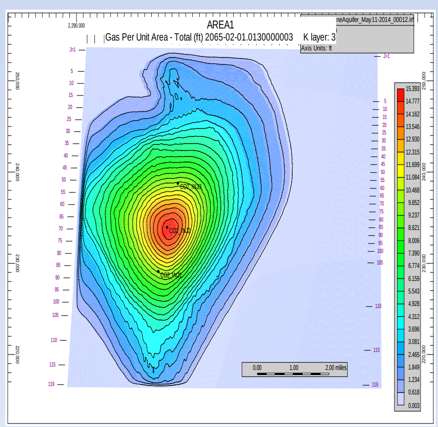
Injection Total 71.1 MM Ton (50yr)



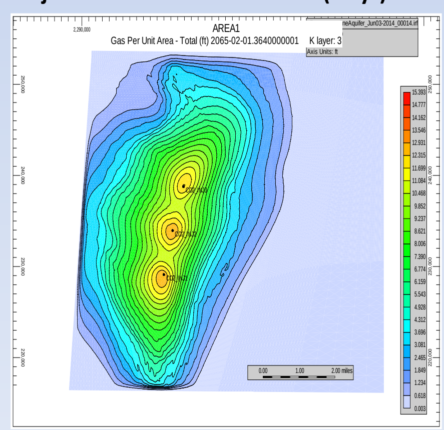
Injection Total 79.2 MM Ton (100yr)



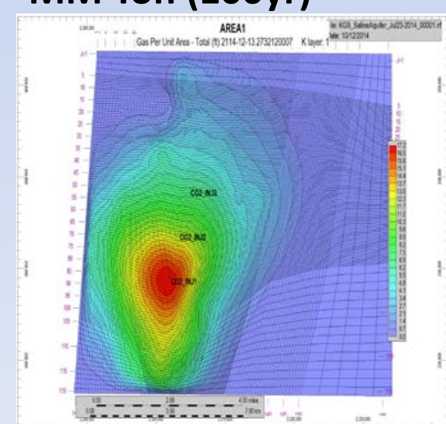
Injection Total 144.5 MM Ton (50yr)



Injection Total 165.4 MM Ton (50 yr)

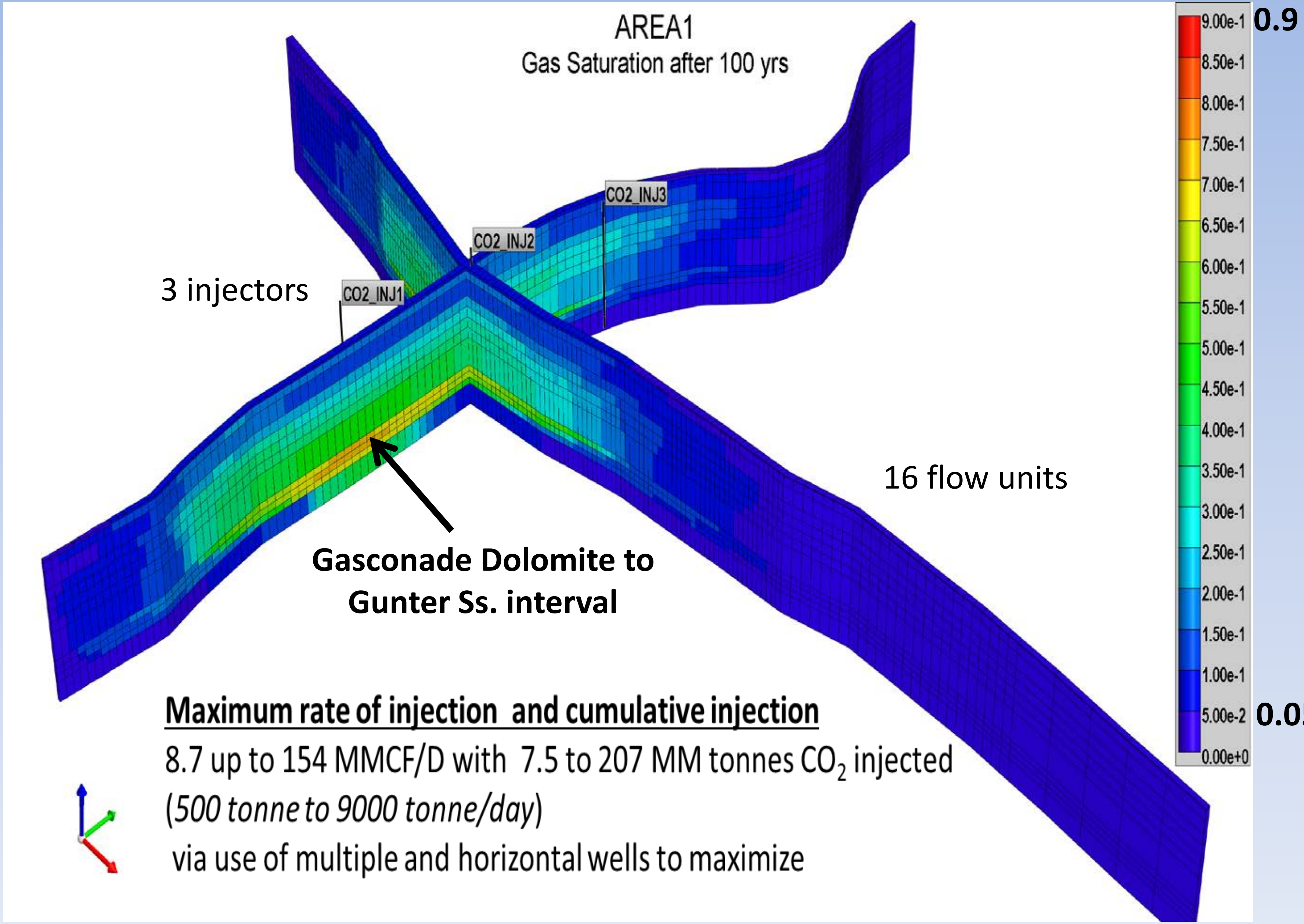


Injection Total 207.3 MM Ton (100yr)



$4 billion at $20/tonne

Area 1 (Wellington Field) – CO_2 gas saturation after 100 yrs



Maximum rate of injection and cumulative injection

8.7 up to 154 MMCF/D with 7.5 to 207 MM tonnes CO_2 injected (*500 tonne to 9000 tonne/day*)

via use of multiple and horizontal wells to maximize

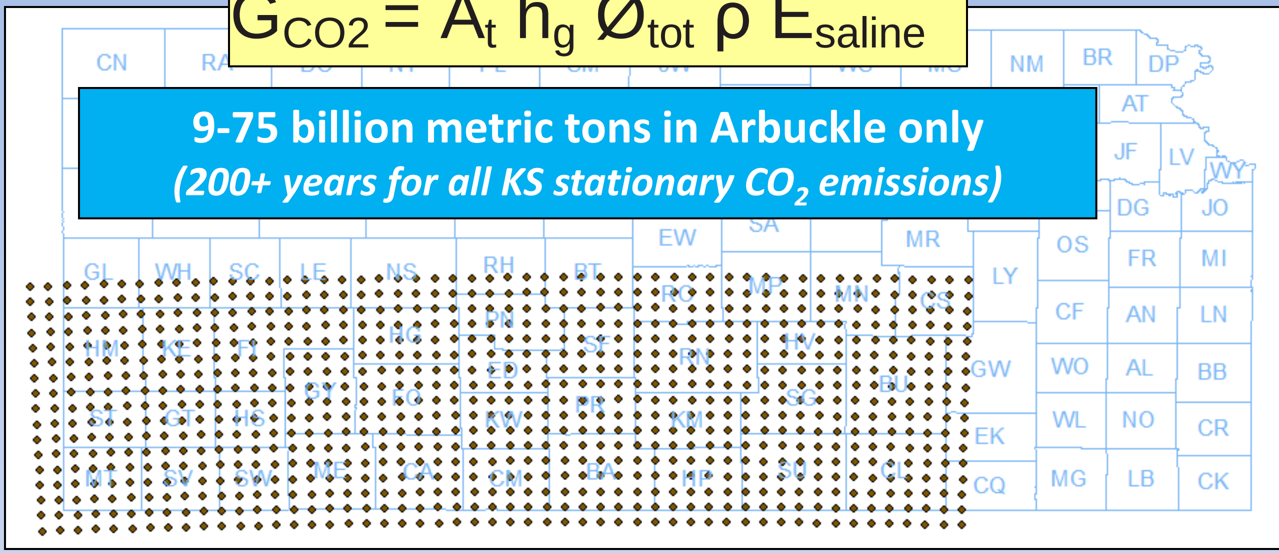
CO_2 storage capacity estimate via DOE methodology

Deep Arbuckle Saline Formation (reported for NATCARB)

$$G_{CO2} = A_t\, h_g\, Ø_{tot}\, \rho\, E_{saline}$$

9-75 billion metric tons in Arbuckle only

(200+ years for all KS stationary CO_2 emissions)



Metric tons CO_2 per Grid Cell

10 km^2

(3.8 mi^2)

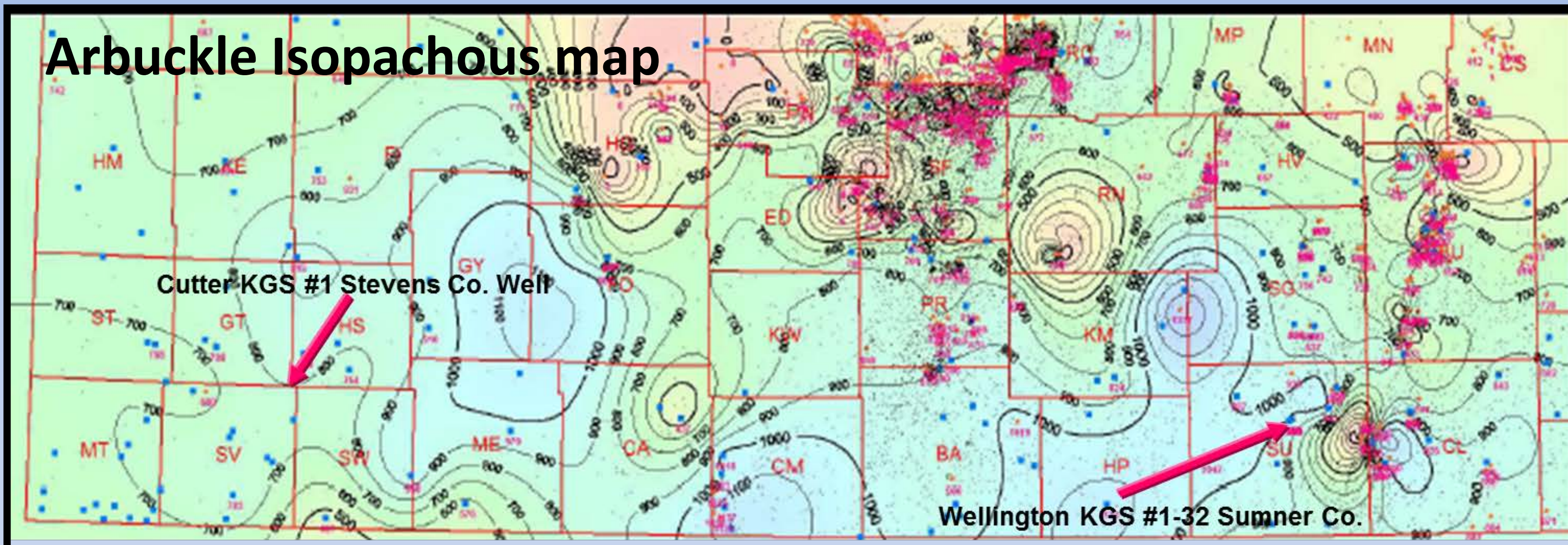
Each grid cell is 10K (+/-)

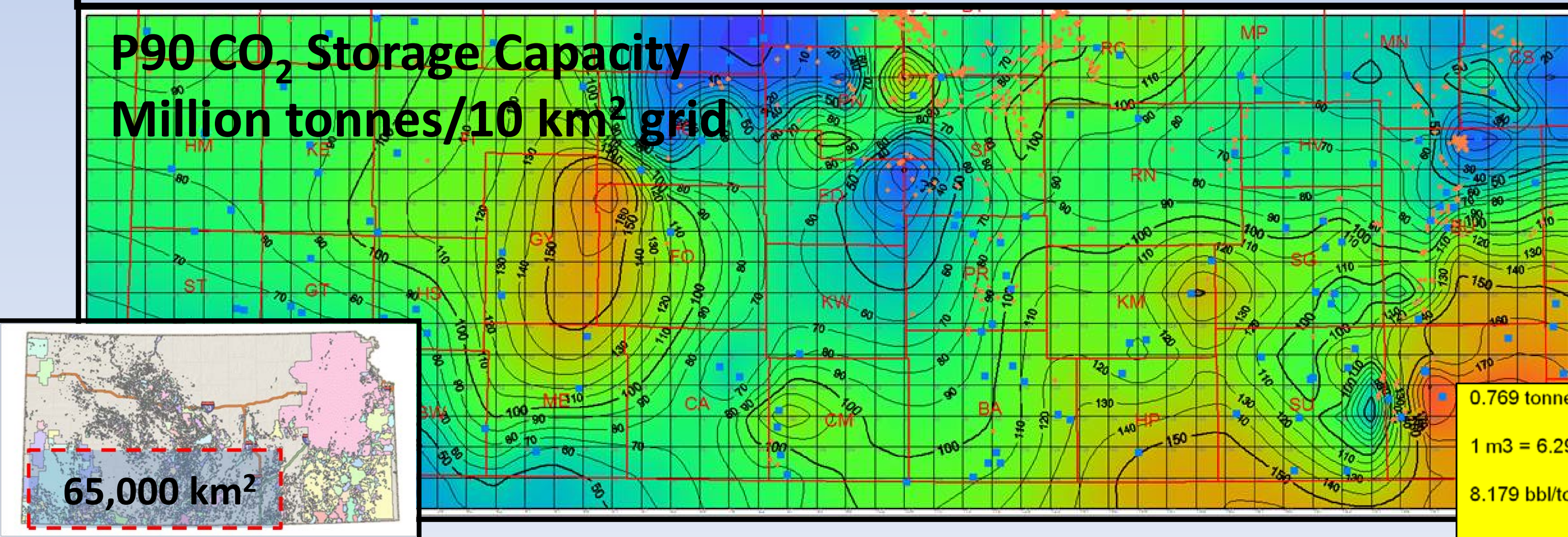
P10	
8,781,380,535	Total All Cells
22,214,247	High Cell
10,287,863	Median Cell
10,554,544	Mean Cell

P90	
75,464,988,970	Total All Cells
190,903,682	High Cell
88,411,323	Median Cell
90,703,112	Mean Cell

Gerlach and Bittersweet team

Thickness (ft) (top) & (P90) estimate of CO_2 storage (millions tonnes/10 km^2 cell) (bottom) in southern Kansas





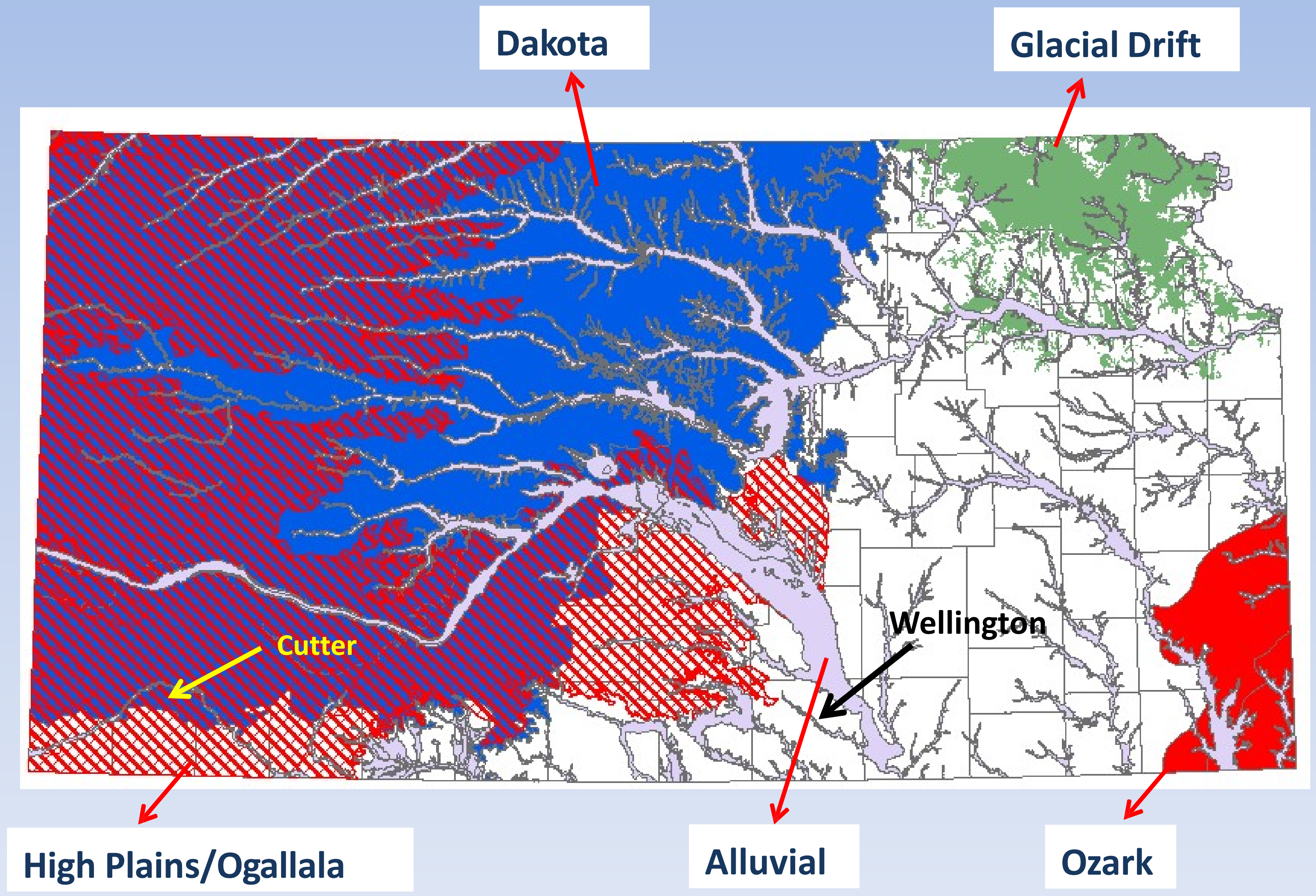
0.769 tonne/m3

1 m3 = 6.29 bbls

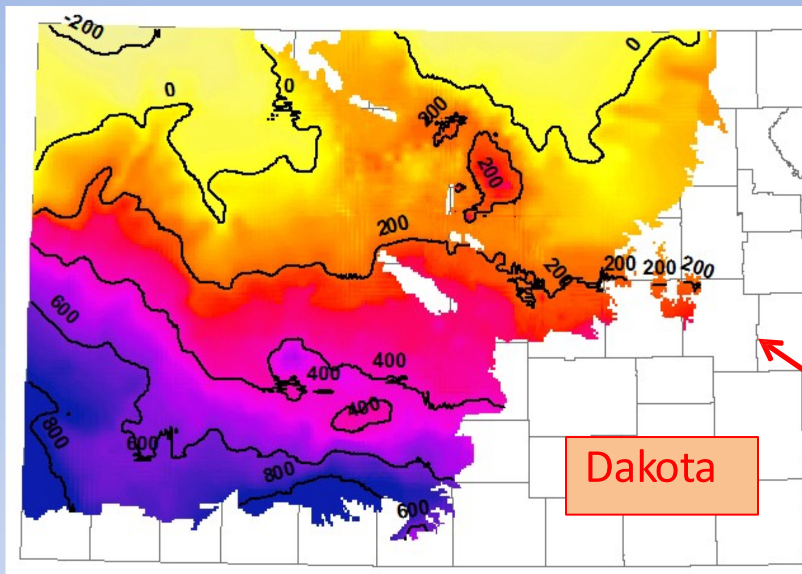
8.179 bbl/tonne CO2

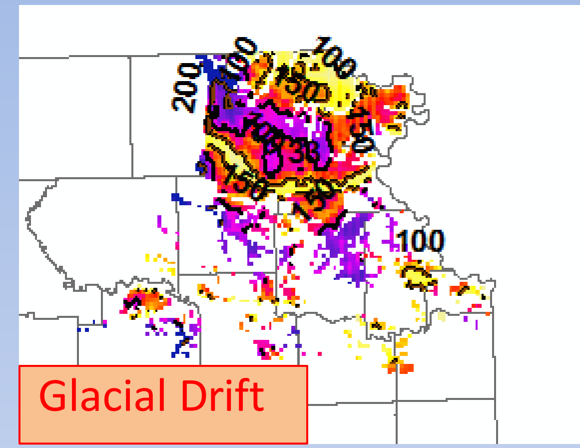
E. Risk assessment

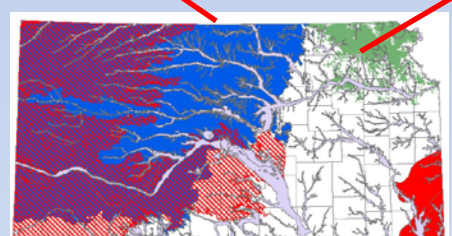
Freshwater aquifers in Kansas

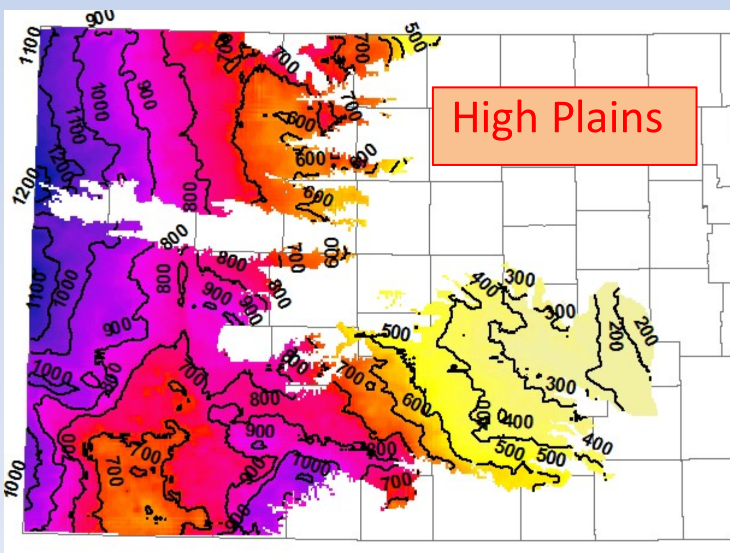


Required increase in pore pressure (*psi*) for migration of brines from Arbuckle into freshwater aquifers



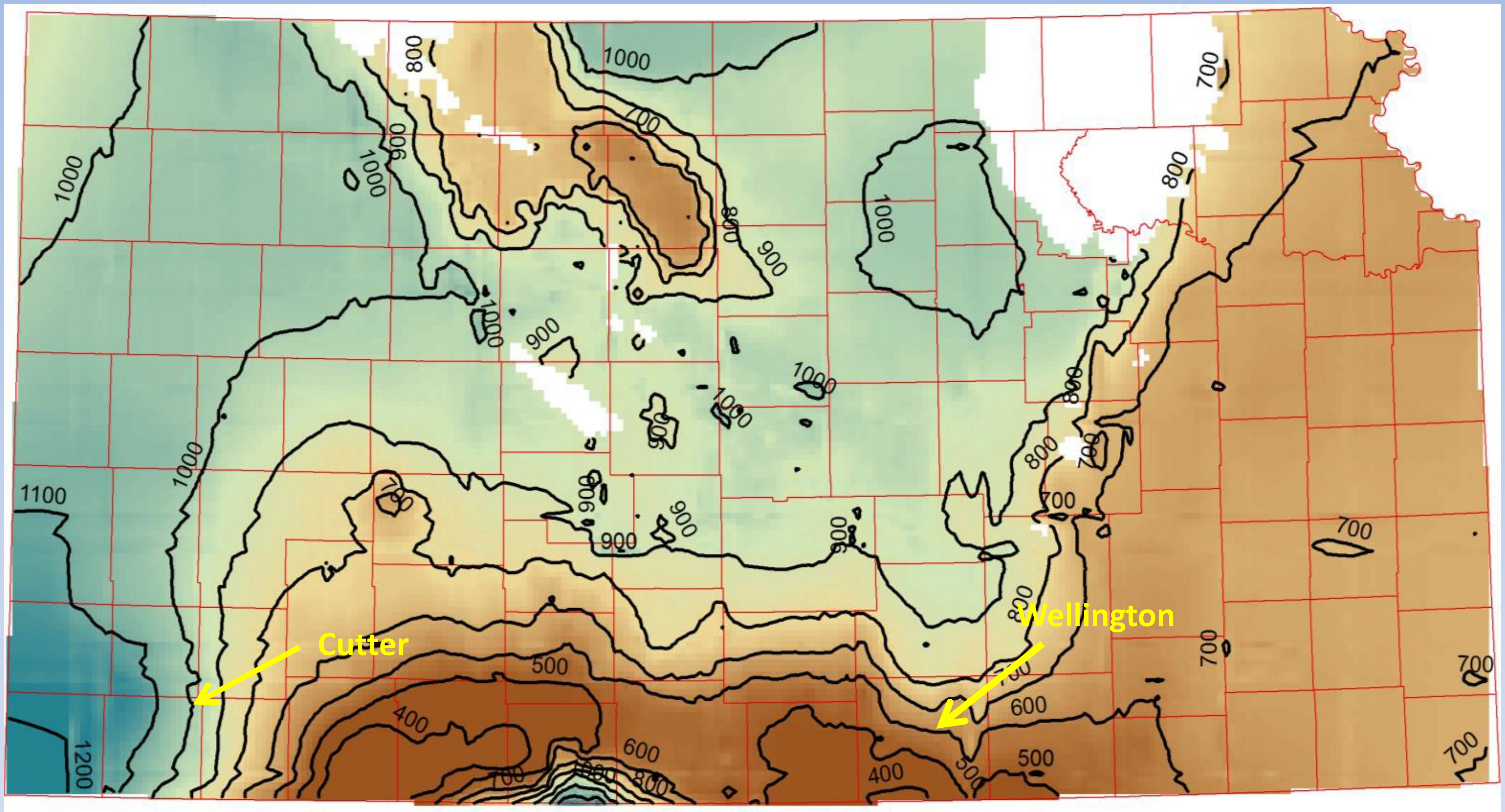






- **Need to ensure these pressures are not exceeded if improperly abandoned wells or communicative faults are present within zone of influence**

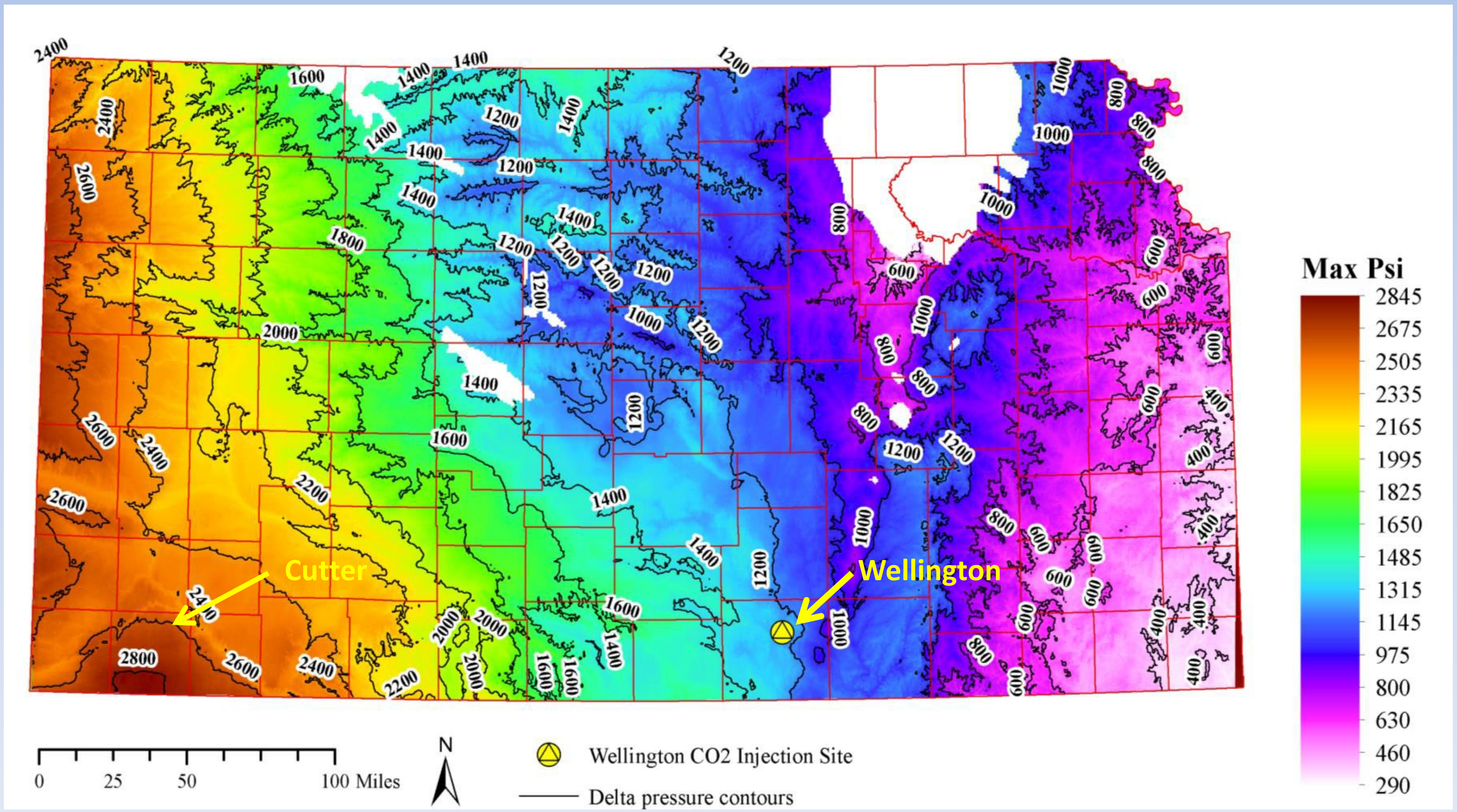
Depth to fluid level in Arbuckle (ft, msl)



- In-situ water levels lower by about 600 ft in SW Kansas due to heavier brines in the Arbuckle
- Low relief of fluid level compared to surface elevation → "underpressured"

Maximum allowable fracture-based increase in pore pressure

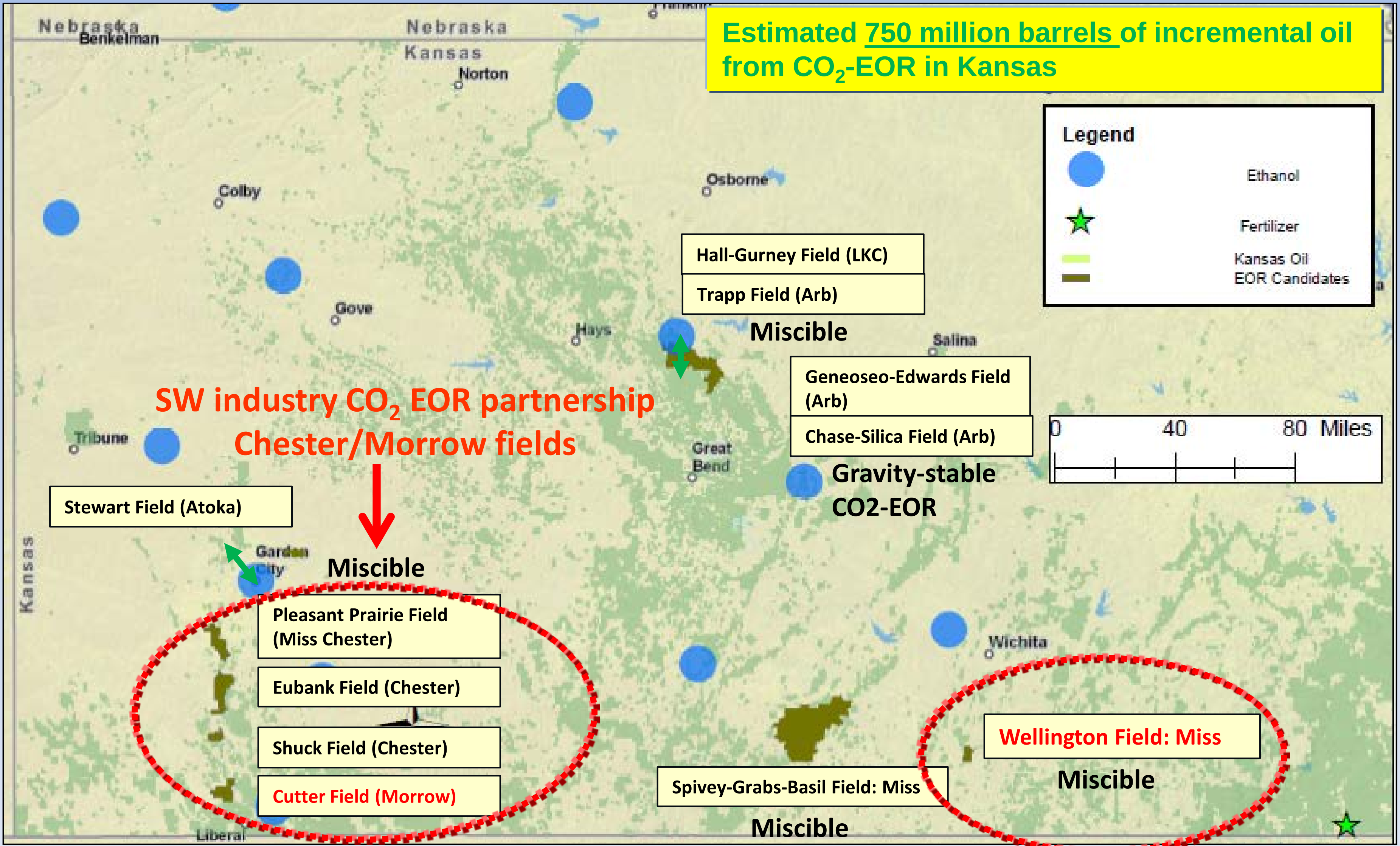
- Induced pore pressures should not exceed 90% of the “Fracture Gradient” in Kansas of ~ 0.75 psi/ft [EPA Class VI injection well requirement]
- Maximum pressure of Mega Model = 1075 psi after 150 years (0.61 psi/ft at 5000 ft)



F. Address program goals

- Develop technologies to support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent.
  - Commercialization of CCUS
  - Web tools and interactive mapper to facilitate initial steps of commercial development
  - Keep database "evergreen" for use in refining models, problem solving, and collaboration with industry in keeping with mission of the KGS
  - Acknowledge DOE/NETL

Current Anthropogenic CO_2 sources and selected oil fields to initiate CO_2-EOR in Kansas



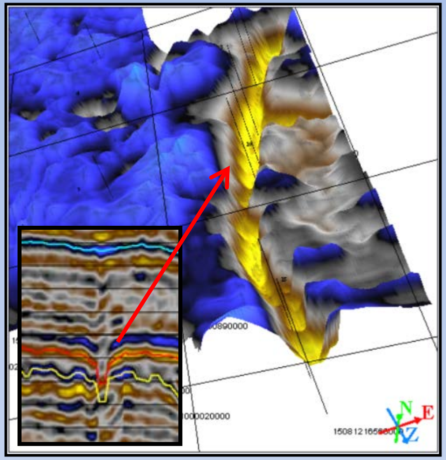
Also in collaboration with Midwest Governor's Association & Clinton Foundation Climate Initiative

Southwest Kansas CO_2-EOR Initiative

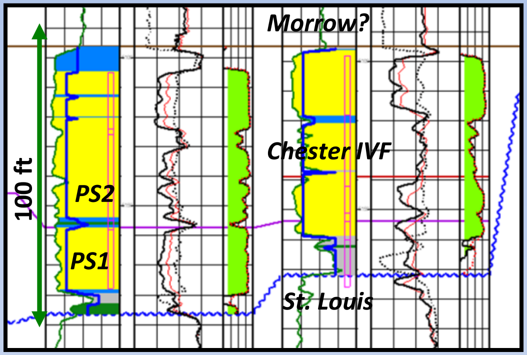
Integrated Multi-Discipline Project for CO_2-EOR Evaluation

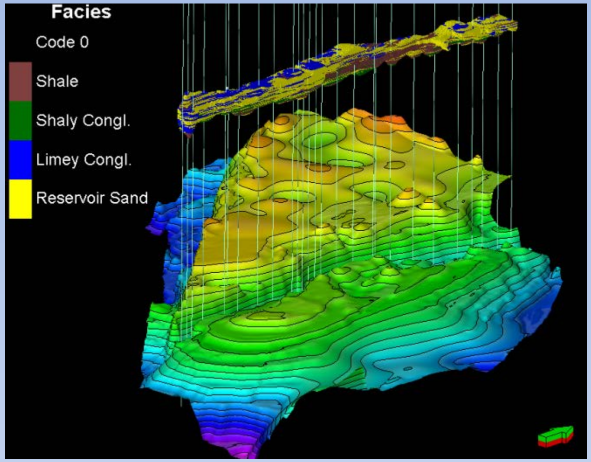
Static Model

Geophysics:
structure, attributes, faults

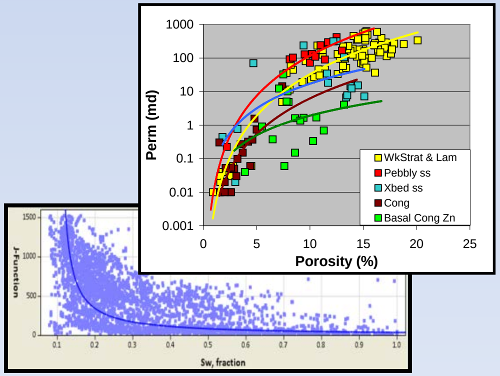


Geology:
Formation tops, sequence stratigraphy, core lithofacies, lithofacies prediction (NNet)



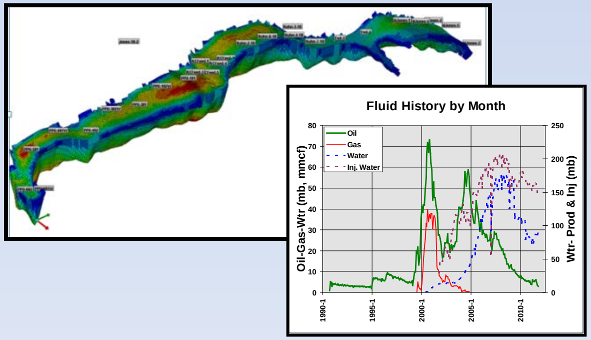


Petrophysics:
Core K-Phi, corrected porosity, free water level, J-function



Engineering:
PVT and fluid analysis, recurrent histories, dynamic modeling

Dynamic Model

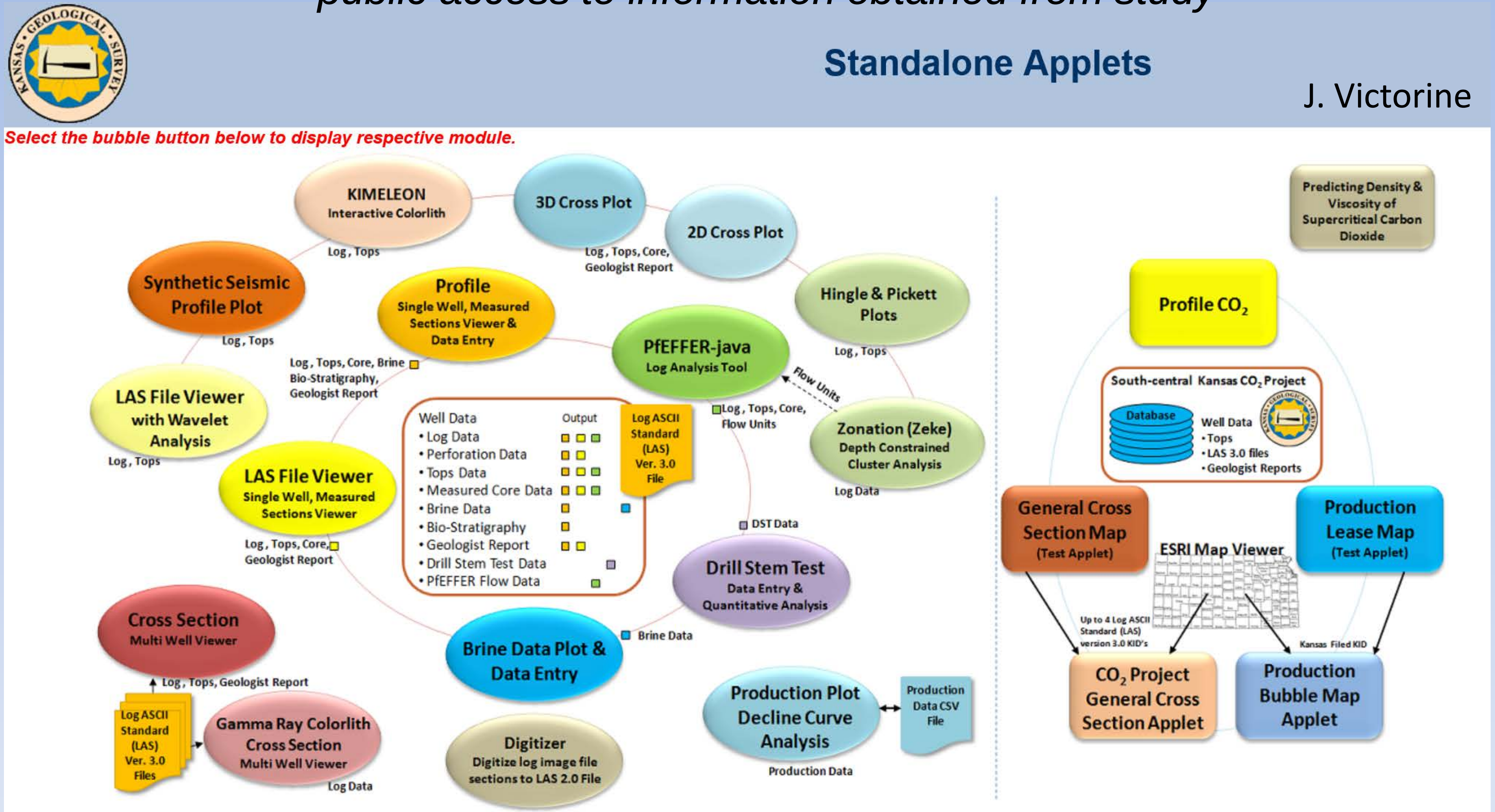


Dubois

Java Applets (*available for standalone distribution*)

-- primarily focused on archiving, analysis, and integrated display of digital well information; fluid production, well test analysis

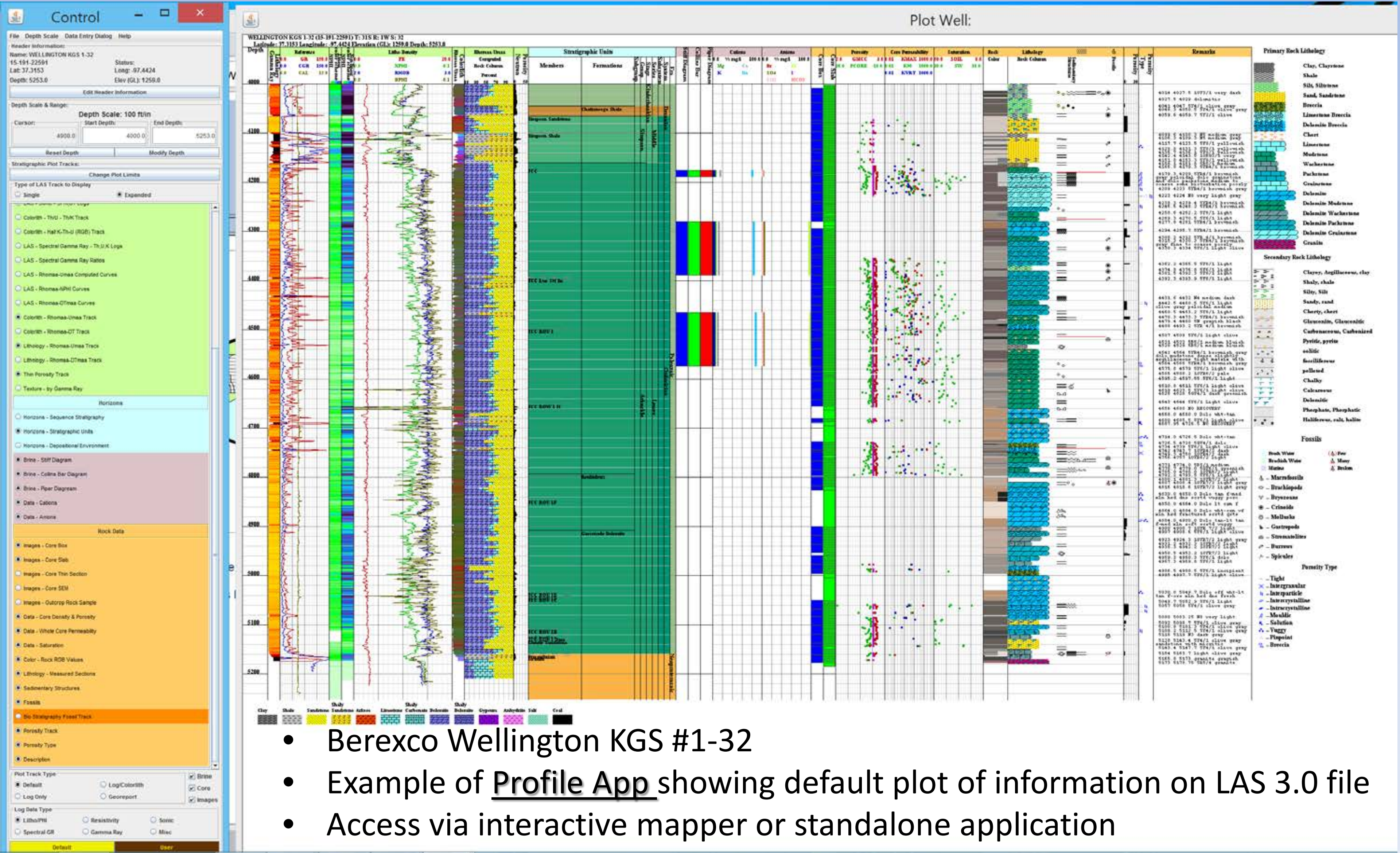
-- *public access to information obtained from study*



http://www.kgs.ku.edu/Gemini/Tools/Tools.html

Next generation development of GEMINI (GeoEngineering Modeling through INternet Informatics)

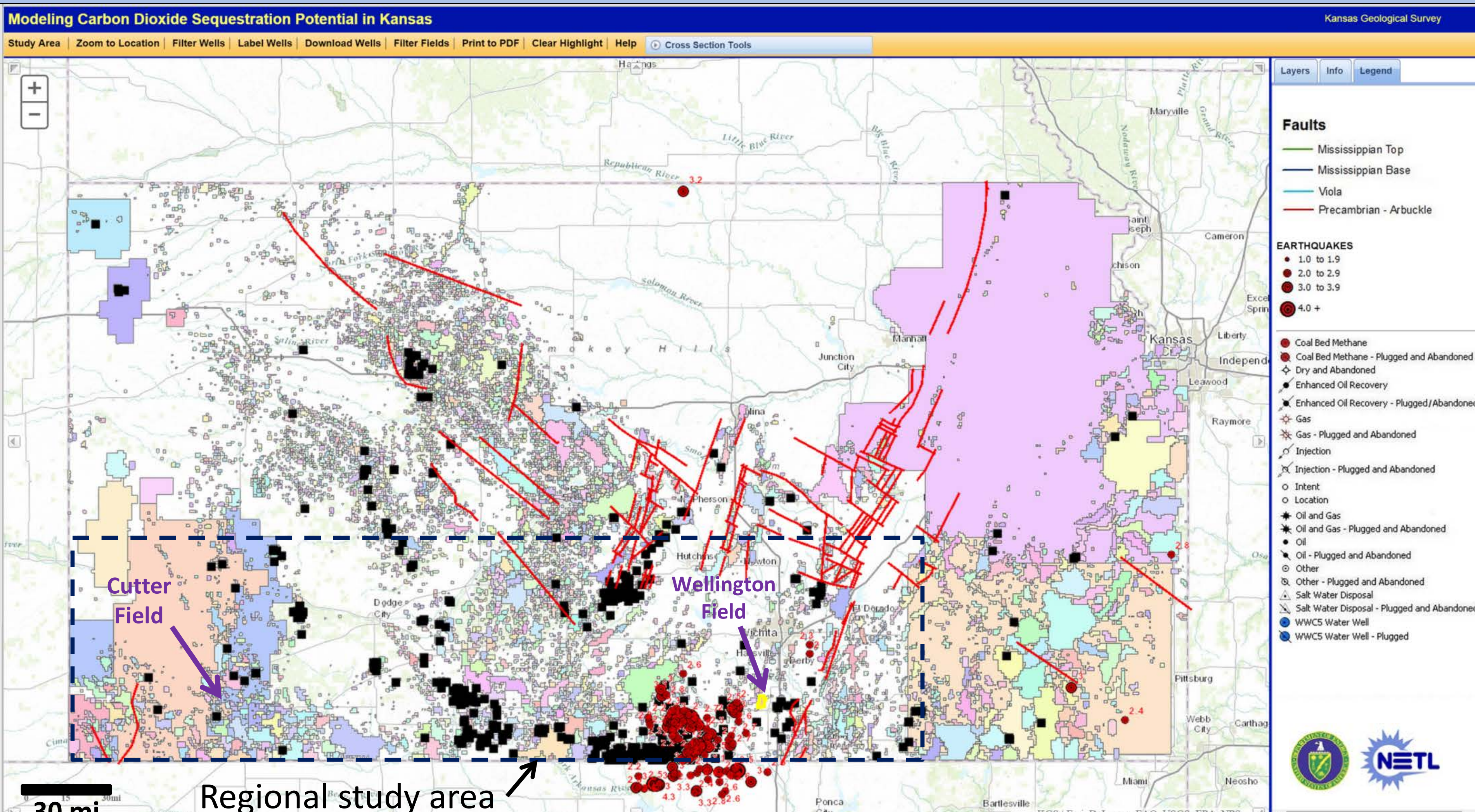
Digital type logs *archived* as LAS 3.0 (ascii format) bundling digital wireline logs, samples, core, test data *accessed and analyzed with Java apps*



- Berexco Wellington KGS #1-32
- Example of Profile App showing default plot of information on LAS 3.0 file
- Access via interactive mapper or standalone application

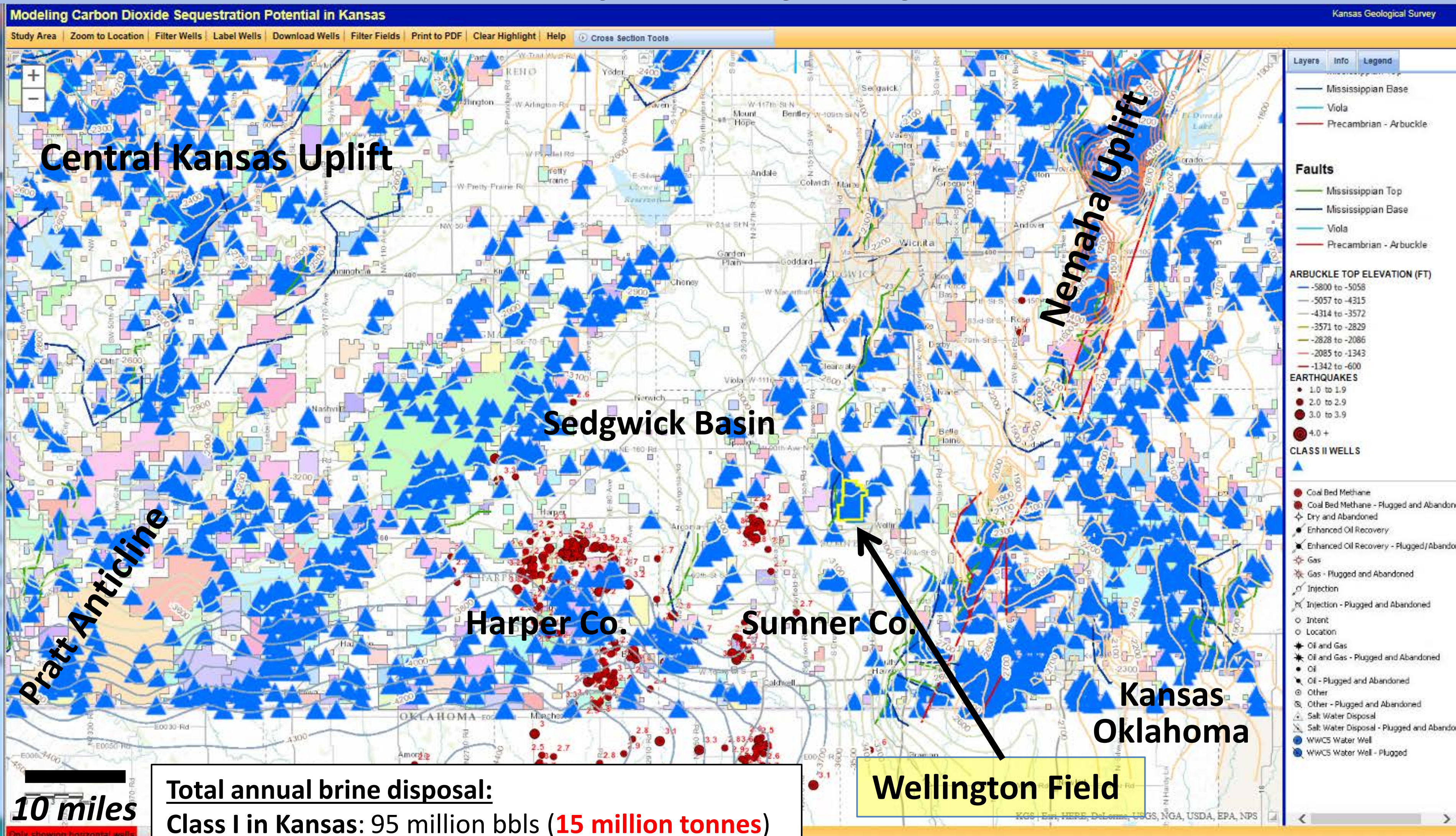
Managing fluid disposal in a complex Midcontinent structural setting

-- access to regional results via project's interactive mapper



http://maps.kgs.ku.edu/co2/

Top Arbuckle structure with overlays –
Class II disposal wells, oil fields, mapped faults, earthquakes, *eastern portion of study area*



Total annual brine disposal:

Class I in Kansas: 95 million bbls (**15 million tonnes**)

Class II: 52 million bbls in Harper and Sumner County (**8.3 million tonnes**)

http://maps.kgs.ku.edu/co2/

Statement of Results -- Why they are important

a) CO_2 P10 & P90 storage using DOE recommended methodology provided 8.8 and 75.5 MMM tonnes capacity. First generation simulation of 150 yrs of CO2 injection = ~4 MMM tonnes
b) Conservatively simulated in this initial regional model as a closed system
c) Wellington Field commercial scale CO2 disposal 5.68 to 207.1 MM tonnes for 50 and 100 yr injection
d) Cores, logs, seismic, DST, geochemical and microbial analysis, and step-rate test at Wellington Field indicates that lower Arbuckle is a *primary injection interval* (~300 ft thick) overlain by widespread thick (400 ft) baffles/barriers in mid Arbuckle.
e) Thick (~120 ft) primary caprock in lower Mississippian augments the Chattanooga Shale in south-central Kansas.
f) Arbuckle saline aquifer is an open system in geologic time, but initially, conservatively modeled for storage as a closed system
g) Local and regional permeability barriers within internal flow units limit actual feasible injectivity and related storage during term of anticipated injection (100s of years).
h) Injection pressure of any fluid should be below parting pressure of rock, generally between hydrostatic and fracture gradient
i) Detection and delineation of faults is hampered by lack of extensive 3D seismic, decreasing throw of faults or drape over faults at shallow depths, few basement penetrations.
j) Fault properties include geometry, length, stress distribution, vulnerability to changes in pore pressure in contact with injected fluid or stress from weight transfer/stress without contact with faults
k) Inherited faults affecting Arbuckle and Mississippian include oblique-strike slip motion with diagnostic features noted across south-central Kansas.

Developing better ways to characterize sites and basins

- Outside of Class I UIC wells, information on Arbuckle disposal wells is limited to monthly injection information in paper format, limiting use in validation of models
- **Seismic processing and interpretation** needs good velocity control for depth migration
- **Essential parameters** -- coring of entire target zones to calibrate a comprehensive well log suite for pore network, minerals, stratigraphic analysis
- **Inherit heterogeneity in carbonate aquifers requires characterization from pore to basin scale** -- establish net effective aquifer based on injectivity and mapping no flow zones (flow units)
- **Maximize use of key common logs --** triple combo, microresistivity imaging log, dipole sonic for pore fabric, fracture network, and geomechanical properties; NMR if budget allows
- **Extensive well testing integrated with other data**-- individual well tests - DST, perforation and swab and pressure buildup, cross well - step rate, interference tests
- **Step rate test and interference tests** -- inexpensive and effective to obtain macroscale/interwell estimates of basic injectivity and lateral connectivity

Developing better ways to characterize sites and basins

- **Water analyses -- DST's and perf and swab to verify distinct hydrostratigraphic units**
  - Vertical and lateral connectivity of the hydrostratigraphic units -- O, H isotopes, redox elements, and anions (Br, Cl, I ratios)
  - Phosphate and other nutrients respond to microbial population
- **Begin with characterization of pores -- core/log calibration; whole core analysis in carbonates**
  - Capillary pressure and NMR pore size distribution (ran NMR to 5 seconds to encompass larger vugs expected in the Arbuckle saline aquifer)
  - Use of common well logs suites to indicate pore type -- examine conductivity/low resistivity as indications of large connected pores and proxy for elevated (*supercharged*) permeability
- **Sample logs – important to use a reliable set of cuttings descriptions to validate pore type, also use drill time and lost circulation to augment other analyses**
- **Use of integrative web apps to bring core-logs-water and core analyses**
  - Well suited for collaborative sharing without special high end software
  - Display images of processed logs to emphasize differences
  - Solve for lithology and graphic displays on-the-fly
  - Annotate with consistent set of stratigraphic nomenclature

What made accurate characterization difficult?

- Commonly dispose of brine in the top of the Arbuckle along "Karst“ so information not representative of the entire Arbuckle
- Old logs appeared to be an issue, but even cable tool sample logs proved to be useful to establish pore type and help calibrate nearby wireline log data; issue was much less control due to shallow depth of penetration of Arbuckle wells
- Lack of available regional seismic
- Lack of stress mapping and geomechanical information
- Lack of a clear structural model (kinematics) and appreciation for the effects of neotectonics
- Not routine to handle large regional simulations to determine storativity using flow unit approach

Where are the technological gaps that hindered characterization efforts? Are these gaps that have potential solutions through R&D efforts?

- **More efficient means to manage large regional datasets –**
  - Processing of well logs and sample data to build model comprised of hydrostratigraphic units;
  - Realizations of permeability and porosity applied to them and measures of goodness of fit;
  - Examining outliers of high and low permeability
- **Establishing a fracture/fault hierarchy and accompanying structures in 3D for the entire basin**
  - Discern timing and kinematics
  - Evaluate faults for leakage or barriers to flow
  - Establish local understanding of fault lengths/damage
  - Integrate earthquake mechanisms to further characterize fault behavior, critical stress, geomechanics, role of weight and pore pressure on potential fault movement
- **More extensive modeling of regional brine disposal data**
  - Mapping stress, understanding parting pressure, and fracture gradients in “underpressured” reservoir systems such as the Arbuckle in western Kansas
- **Basement analysis** – integration of extensive work on geochronology of basement terranes and integrating with gravity mag analysis and Phanerozoic history

Were there technologies/methodologies that were modified to fit their specific location?

- How were they modified – slow run of NMR to capture larger pores; non-trivial log analysis in recognition of range of pore types; characterization of microbes in dense brines complimented H/O stable isotopes to fingerprint brine systems; able to run many DST and perforation/swabbing runs to refine brine system; developed extensive web applications and interactive mapping system facilitated access and analysis of the project dataset; developed digital type-log system including means to modify and refine stratigraphic nomenclature
- What were the specific location conditions that were addressed through this/these modification(s)? Used an integrated approach to verify and quantify properties of vuggy, brecciated, and fractured carbonate intervals
- Are those modifications able to be applied to other locations with similar conditions? YES!
- Please explain – Carbonates are complex reservoirs and CO_2-EOR needs to move to the next generation to increase effectiveness of CO_2 (DOE-NETL initiative)

Would anything be done differently if could or if had no limits on time/funding?

- Incorporate all brine disposal data to help evaluate model parameters (*used only Class I well tests in the study to compare to injectivity estimated for nearby type wells*)
- Keep static and dynamic models "evergreen"
- Develop a more comprehensive digital surface to subsurface information system focused on stratigraphic, sedimentologic, petrophysical, geophysical, and engineering properties suited for use in static and dynamic models

- Would additional investigation in other areas of the storage area/basin have the potential to significantly change the findings?
  - Helpful to evaluate and validate methodologies
  - Realizations of permeability need more calibration and testing
- Does the heterogeneous nature of the subsurface require more extensive characterization to achieve accurate results?
  - Yes, make more use of existing brine disposal data from Class I and Class II wells
  - Collaborate on larger basis with industry to examine 3D seismic to verify faults, karst, etc. while keeping data confidential (e.g., for examination of basement faults, slice out basement data)
  - Incorporate historical knowledge of basement maps, e.g., geochronologists, and integrate with mapping – *NSF Earthscope, USGS (e.g. Resource assessment studies (Higley et al. for Anadarko Basin as collaborated with in this investigation)*
  - Incorporate existing well data on fracture orientation and earthquake solutions to reveal more about local and subregional stress variations to evaluate critical stress of faults, establish patterns to stress – neotectonics and kinematics
- If so, could that be performed in a cost effective manner?
  - Yes

Best practices and lessons learned

- Outline Best Practices and well recompletion plans for at-risk wells
  - Utilize services of consultants who work with Class I permitting to sift through data to suite EPA
  - Predict to understand pressure history through simulation and stay below the critical pressures to part existing fractures and to prevent flow of brine into USDW
- Outline Best practices and well completion plans for new CO_2 injector wells
  - High quality casing to suite EPA, use CO_2 resistant cement, cement in multiple stages, run radial cement bond log, run MIT
  - as carried out with Wellington KGS #1-32 & #1-28, and Cutter KGS #1
  - Regional petroleum industry service companies can provide!