Brookhaven Field: Conformance Challenges in an Active CO_2 Flood

Michael Cain
Denbury Resources, Inc.

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About Forward Looking Statements

The data contained in this presentation that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, net asset values, proved reserves, potential reserves and anticipated production growth rates in our CO2 models, 2010 and future production and expenditure estimates, availability and cost of equipment and services, and other enumerated reserve potential. These forward-looking statements are generally accompanied by words such as “estimated”, “projected”, “potential”, “anticipated”, “forecasted” or other words that convey the uncertainty of future events or outcomes. These statements are based on management’s current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent 10-K and 10-Q. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company

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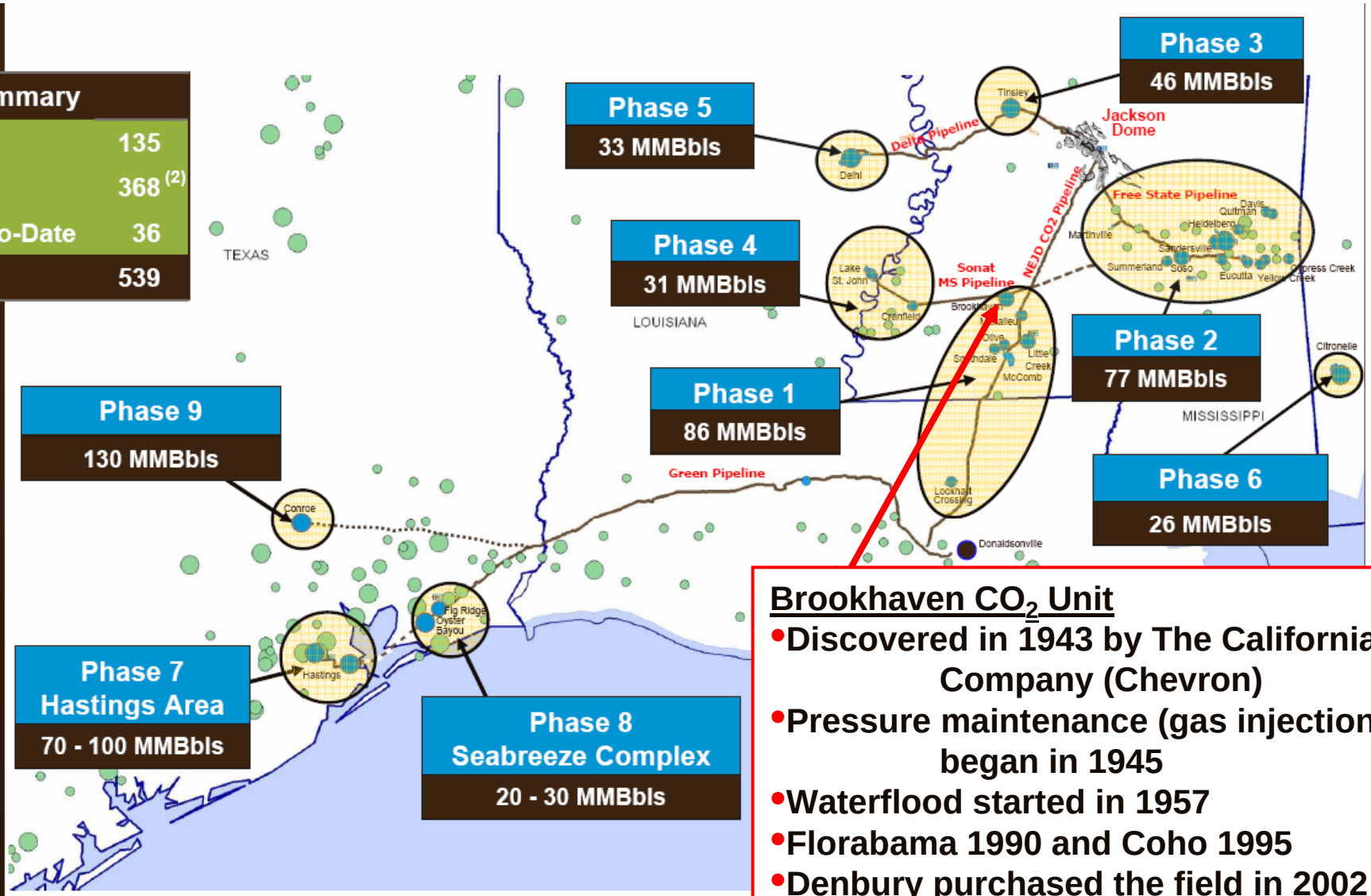
Cautionary Note to U.S. Investors – The SEC has recently modified its rules regarding oil and gas reserve information that may be included in filings with the SEC. The newly applicable rules allow oil and gas companies to disclose not only proved reserves, but also probable and possible reserves that meet the SEC’s definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury’s proved reserves as of December 31, 2009 were estimated by DeGolyer & MacNaughton and Miller & Lents, independent petroleum engineering firms. In this presentation, we make reference to probable and possible reserves, some of which have been prepared by our independent engineers and some of which have been prepared by Denbury’s internal staff of engineers. In this presentation, we also refer to estimates of resource “potential” or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible, include estimates of reserves that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Gulf Coast CO_2 Projects – Potential Tertiary Oil Reserves[1]

Summary	
Proved	135
Probable	368 [2]
Produced-to-Date	36
Total [2]	539

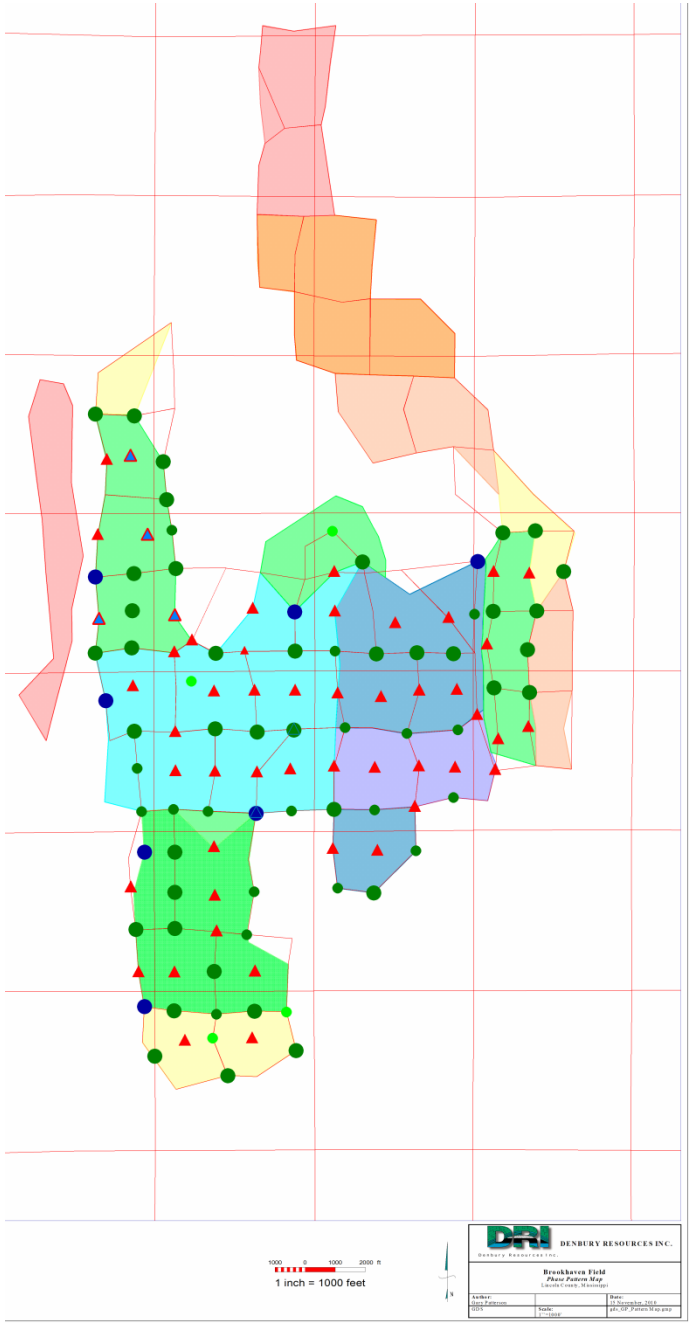


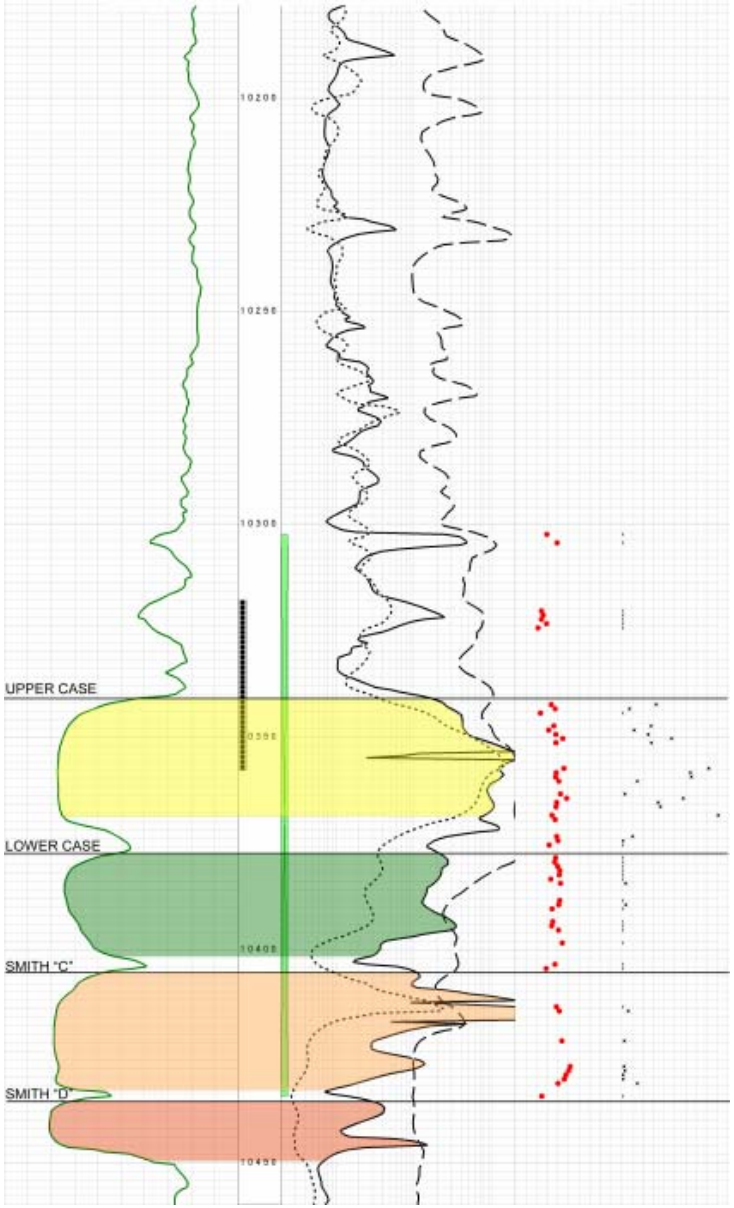
Brookhaven CO_2 Unit

- Discovered in 1943 by The California Company (Chevron)
- Pressure maintenance (gas injection) began in 1945
- Waterflood started in 1957
- Florabama 1990 and Coho 1995
- Denbury purchased the field in 2002
- CO_2 injection began in 2005

(1) Proved plus probable tertiary oil reserves as of 12/31/09, including past production, based on a range of recovery factors.
(2) Using mid-points of range.

Brookhaven Map and Type Log





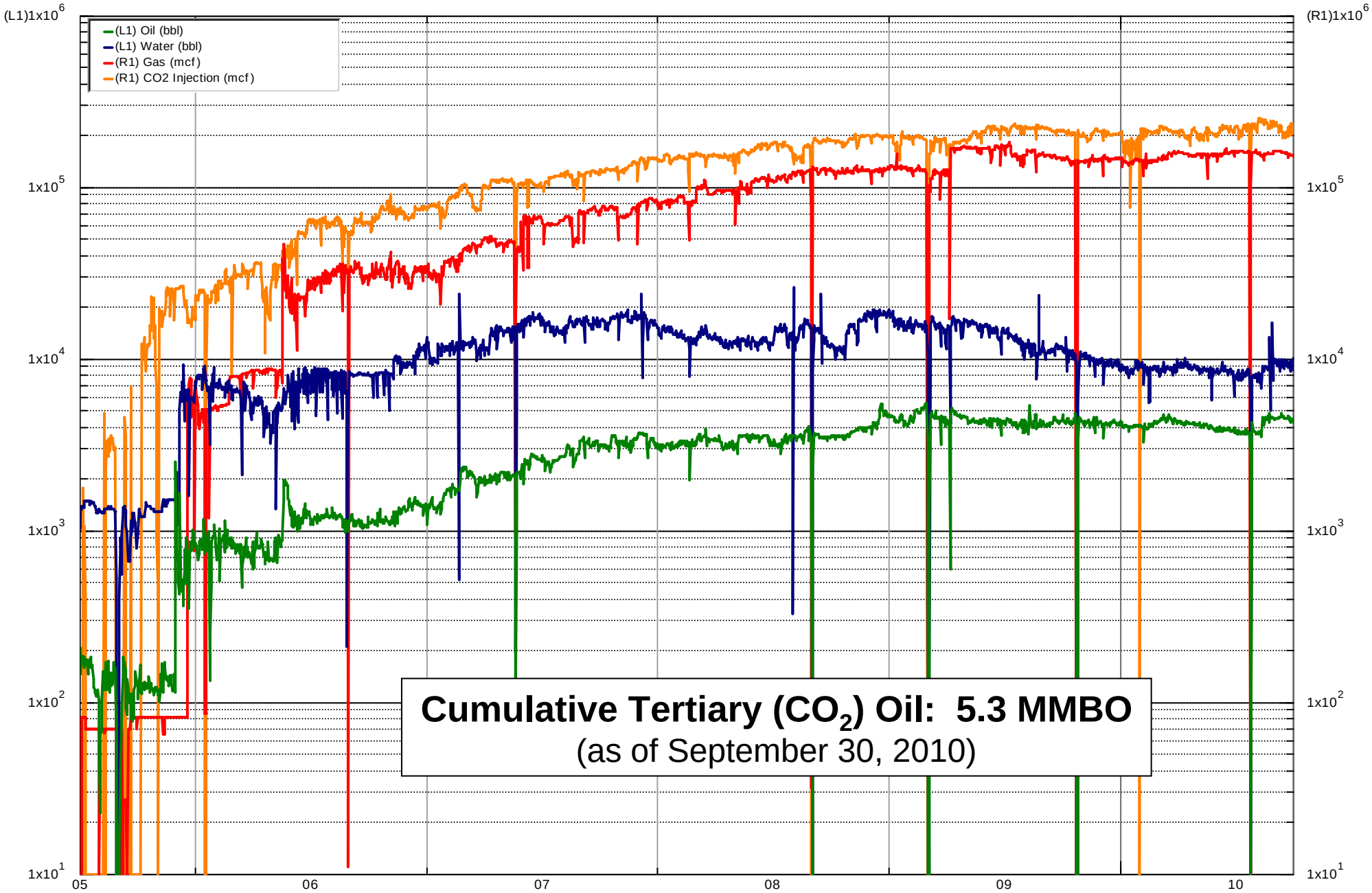
Brookhaven Geological Setting

- Located in the Mississippi Interior Salt Basin, a passive continental margin with extensional rift tectonics (normal faulting)
- Structure is a Salt Cored 4-way Anticline, producing from the Upper Cretaceous, Tuscaloosa formation
- Approximately 9200 acres of Closure
- Faulting Occasionally Affects Production, Faults tend to have small (100-200') vertical displacements and trend north-south
- Depositional Environment – Fluvial Sands with long, narrow meandering channel sands that tend to trend North-South
  - Thickness ranges from 1-2' up to 42' for individual sands, when sands coalesce together can reach 60-70'
  - Average ϕ; 22.2% (all sands) max ϕ; 42%
  - Average Permeability; 181.7 md (all sands) max k; 5830 md

Flooding Philosophy at Brookhaven

- Clean out or tie-back existing wellbores
  - 10,500’ Lower Tuscaloosa
  - 60+ years old wellbores
  - Less expensive than drilling
- Use existing perforation intervals
  - Typically 100% of the sands are shot
  - Regardless of porosity and permeability streaks
  - Both injectors and producers
- Enjoy flowing producing wells
  - Relatively low lifting costs
  - No artificial lift (pumping units, etc)
- Inhibited oil is circulated in producers to prevent corrosion
- Miscible flood

Brookhaven CO_2 Production



Cumulative Tertiary (CO_2) Oil: 5.3 MMBO
(as of September 30, 2010)

Brookhaven CO_2 Unit

- 69 Producers
  - 44 Active producers
  - 10 Waiting on response
  - 15 Shut-in due to high GOR

- 48 CO_2 Injection Wells
- 3 SWD Wells

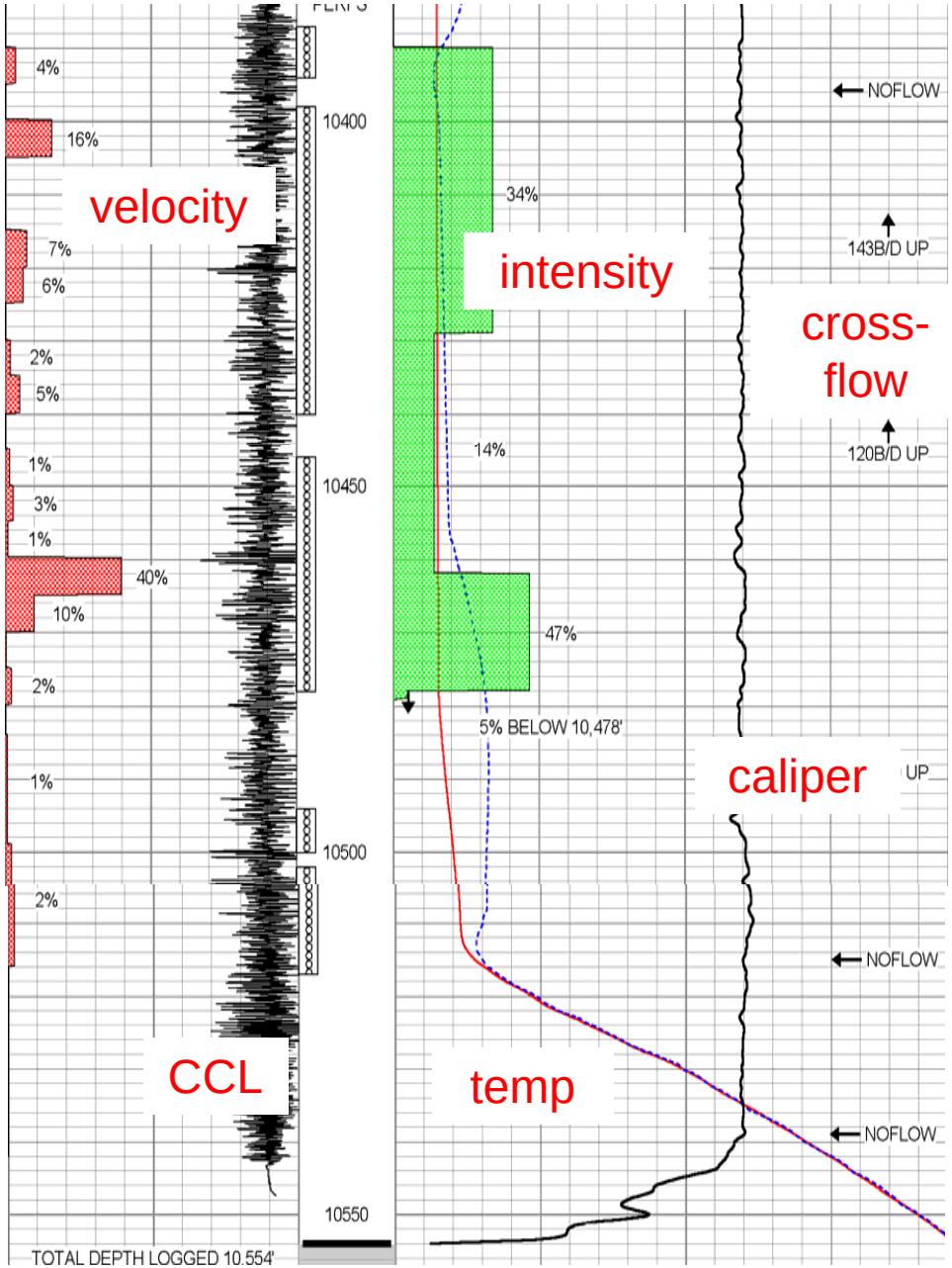
What is conformance and why is it important?

- Conformance is:
  - "The process of applying various methods and technologies to a reservoir or wellbore to reduce or control unwanted water or gas production so that recovery efforts are effectively enhanced and operator profitability improved"(1)
- In highly heterogeneous reservoirs, CO_2 tends to bypass lower permeability rock and travel primarily in high permeability streaks
  - Initially, high production rates can be realized
  - Ultimately, recovery factors may be reduced due to a significant volume of oil not being contacted by CO_2
- Techniques to identify and modify injection profiles is essential for effective management of a CO_2 flood

(1) "Conformance Technology", Halliburton Energy Services Publication, 1996.

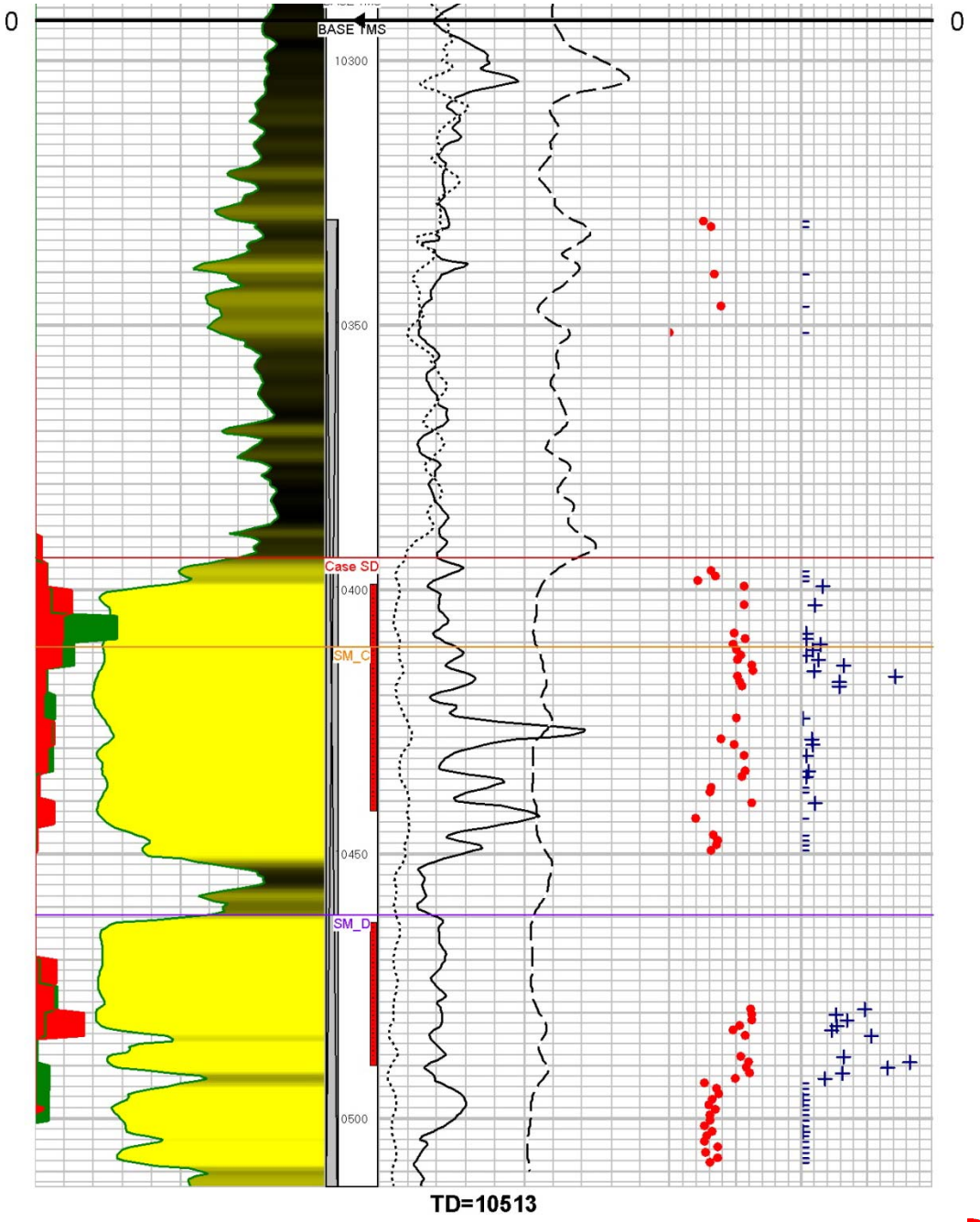
Injection Profiles

- Traces the path of injectant
  - Indicates % of CO_2 entering the reservoir by depth
  - Highly interpretive
  - Radioactive iodine, I-131
- Red bars indicates velocity, green is intensity
- Temperature indicates cooling
- Important tool for engineers
  - Helps identify injectors that may need profile modification work
  - Assists reservoir engineer in predicting future performance of offset wells



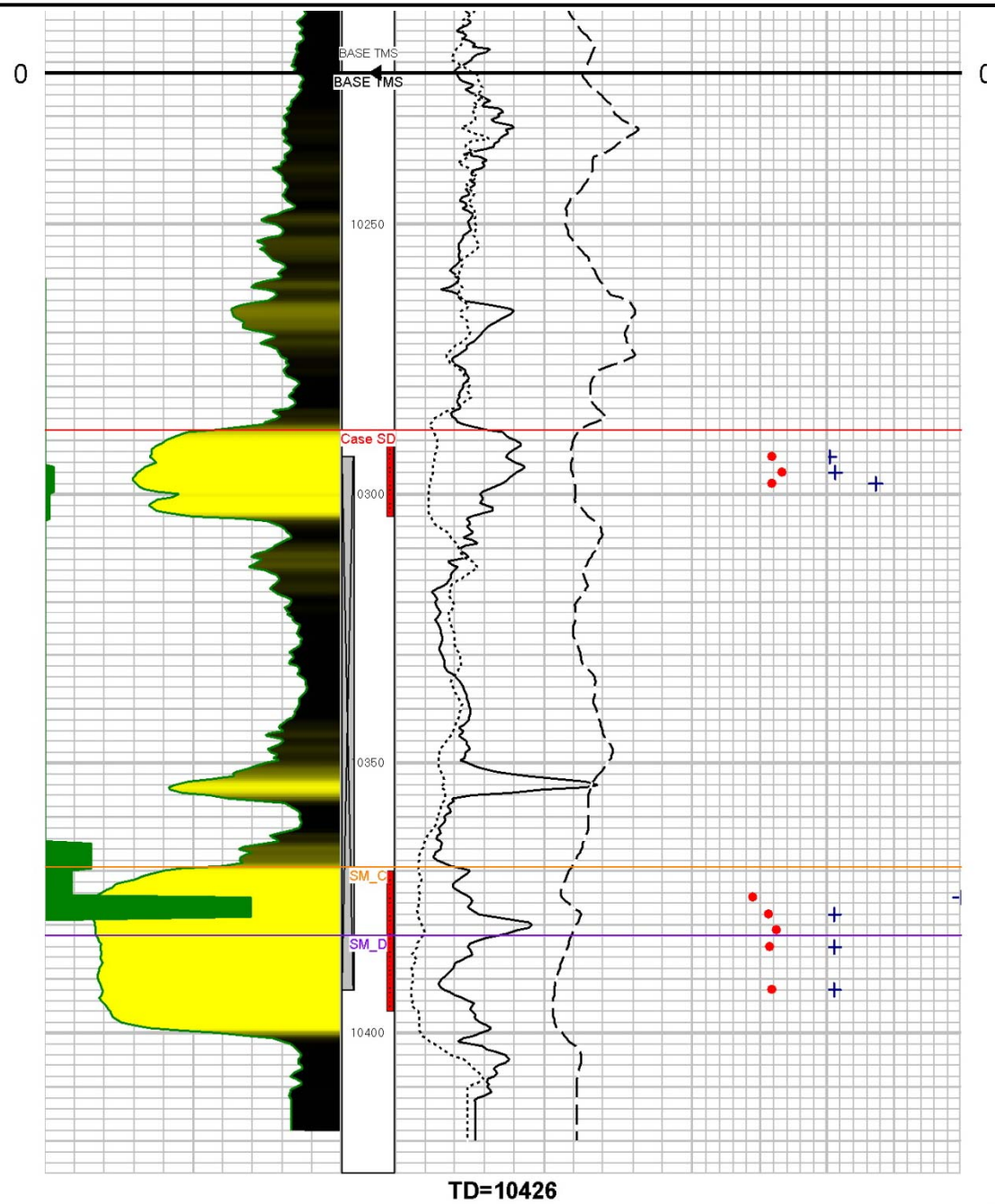
Good Injection Profile

- Good vertical distribution – especially in the top sand
- CO_2 is being injected in all three sands
- Should result in higher sweep efficiency for the pattern



Poor Injection Profile

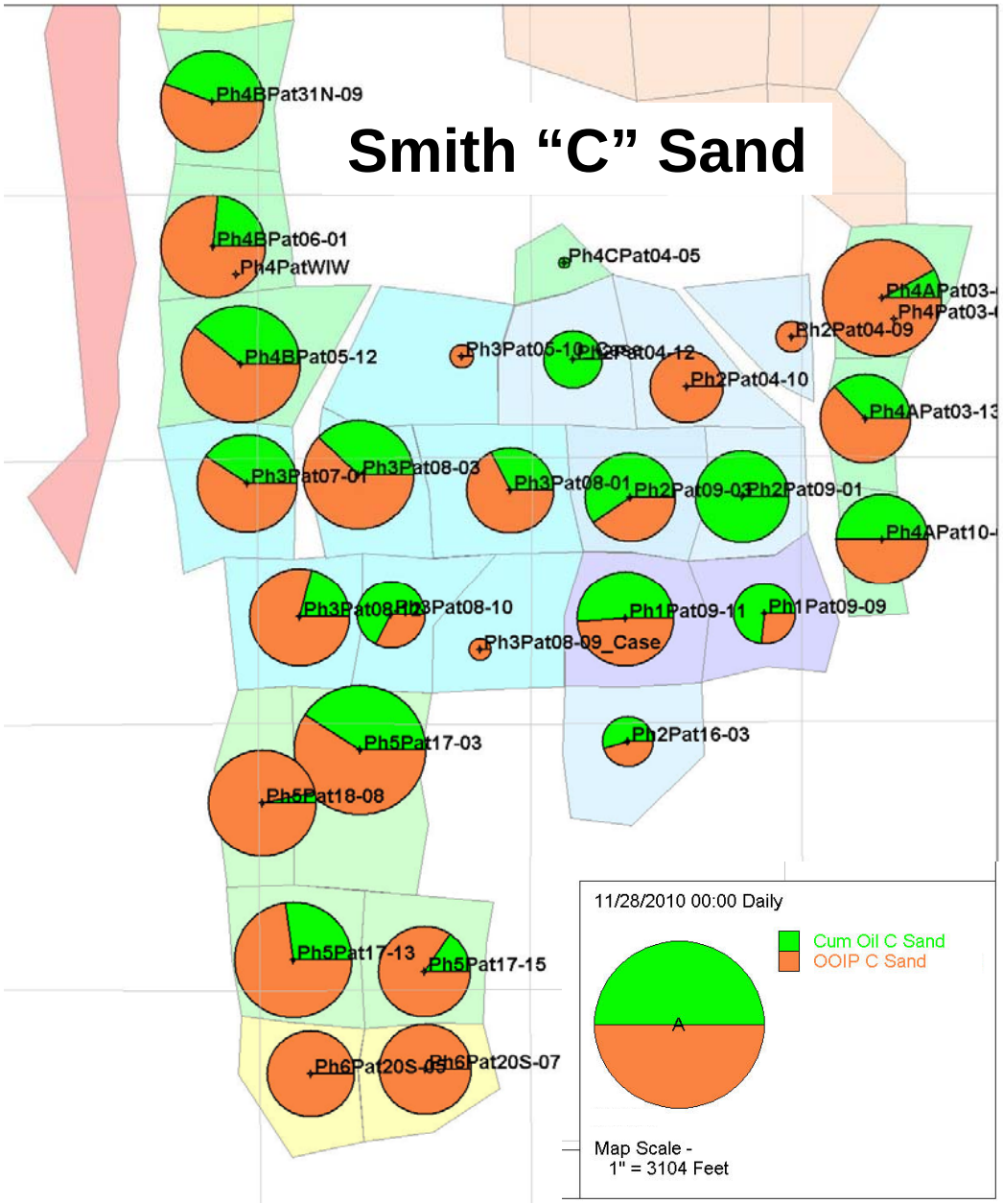
- Only one sand, Smith "C", is taking most of the CO_2
- Poor conformance results in less oil being contacted by CO_2 and early gas breakthrough at producers

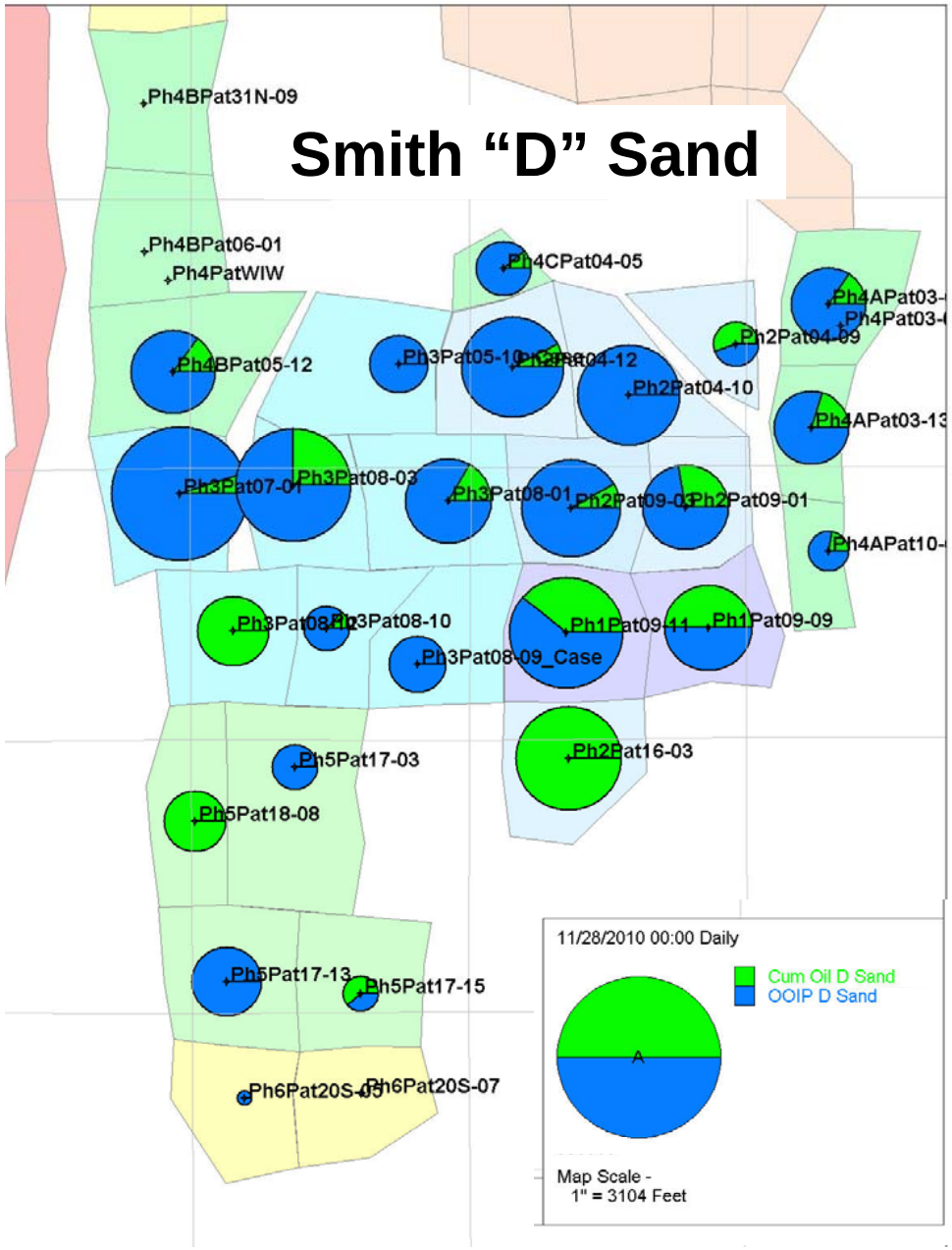


Identifying Areas of Unswept Oil

- Review of injection profiles suggests a significant portion of the reservoir was not being swept
- Developed a methodology for determining areas of unswept oil
  - Pattern production and injection for individual sand units is allocated based on injection profiles and pattern allocations
- Assumptions
  - Geometric pattern allocations
  - CO_2 stays in same sand as injected into
  - Injection and pattern allocations are constant over a period of time
- Bubble maps are generated to help identify areas of interest
- Identifies areas for “targeted” injection

Allocated Production By Sand





Difficulties with Selective Perforations

- Targeted sands tend to be lower permeability
  - Injectors: Lower injection rates result in delayed production response
  - Producers: Tighter sands usually result in lower production rates
- Squeezing off intervals can be problematic
  - CO_2 will find the weak spots and migrate through cement
- Near wellbore effect only
  - Need shale break to effectively isolate CO_2 injection

Additional Techniques to Address High GOR

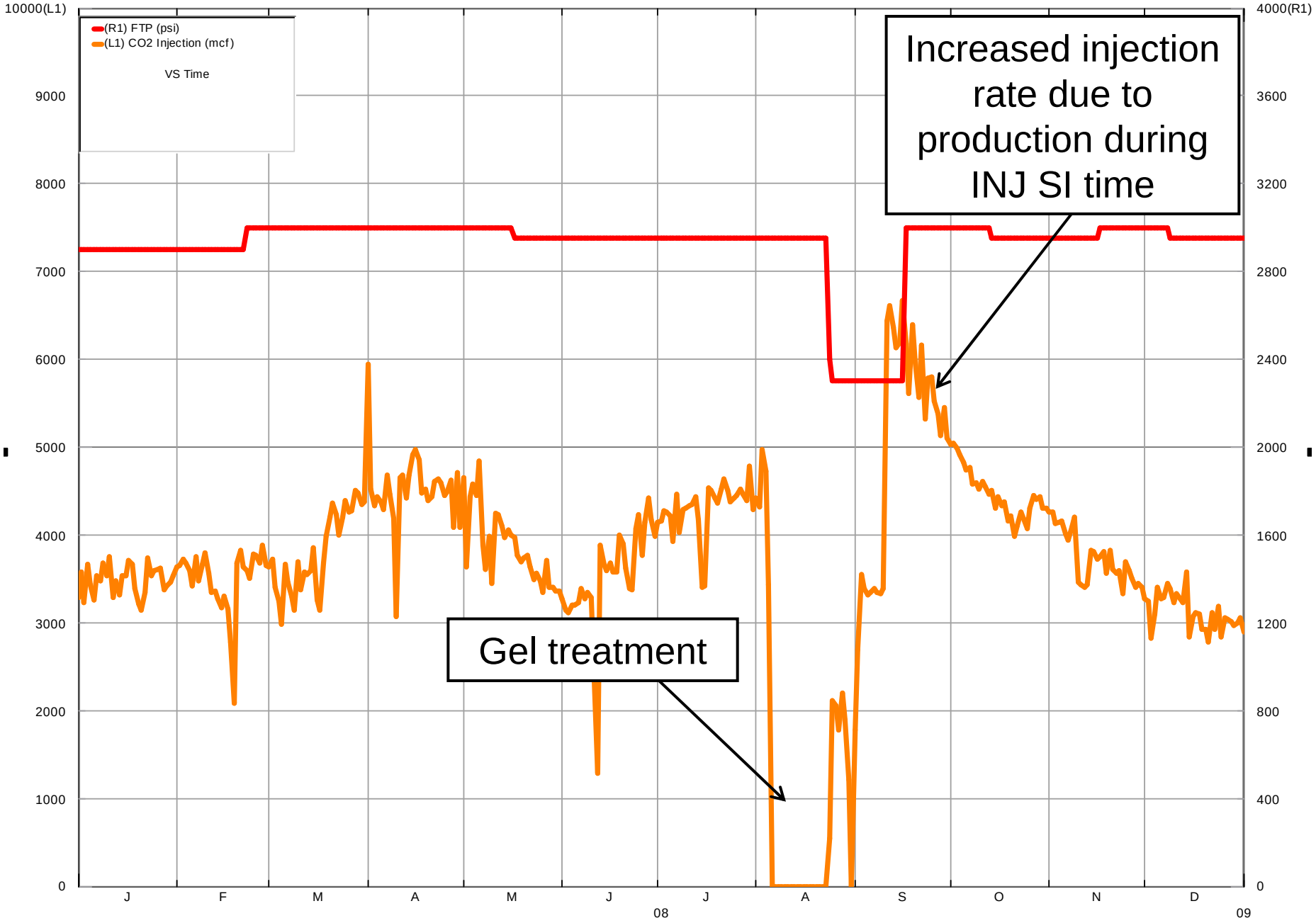
- Conversion of Producer to Injector (CTI)
  - Utilizes an idle wellbore
  - Must consider other factors such as IWR and available CO_2
  - Likely to have conformance issues; possibly accelerating GOR increase in offset producers
  - Does not solve conformance/sweep problem

- Gel Treatments
  - Idea is to introduce a significant volume of permanent gel in swept, high permeability rock to force CO_2 to take an alternate path
    - Gel is pushed into the reservoir away from wellbore
  - Brookhaven team has conducted 5 gel treatments in the field
    - Four ~5,000 bbl gel treatments on four injectors
    - One 1,500 bbl gel treatment on a producer

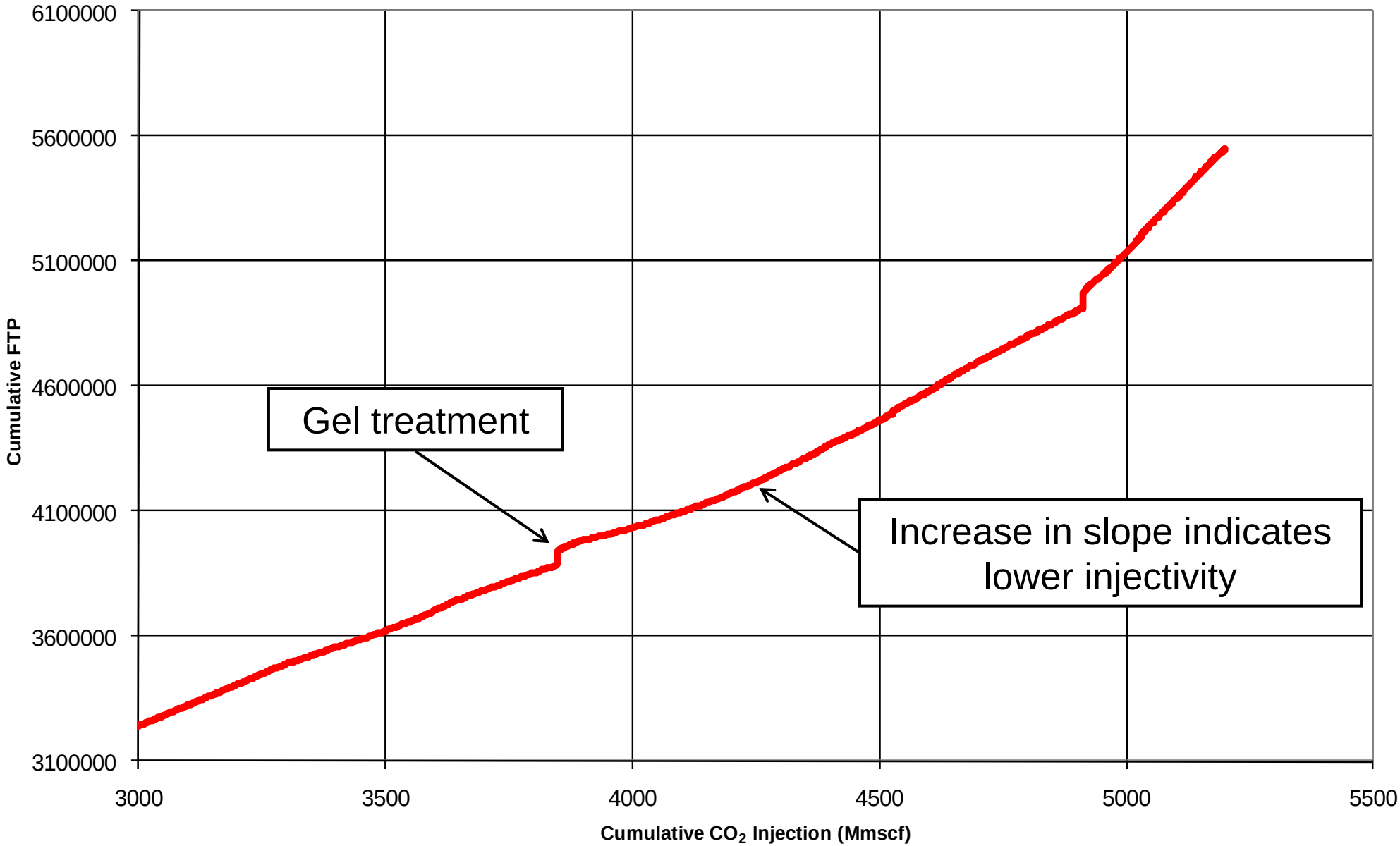
Gel Treatments

- Polyacrylamide polymer with organic cross-linker
  - Concentrations of 3,000 to 9,000 ppm
  - Rates of 0.75 to 1.0 bbl per minute over several days
  - Shut-in to allow strengthening of the gel
- First gel treatments – August 2008
  - INJ #1: 3,900 bbl
  - INJ #2: 6,900 bbl
  - Offset production continued during treatment and shut-in period
- Second gel treatments – January 2009
  - INJ #3: 5,500 bbl
  - INJ #4: 5,500 bbl
  - Offset production shut-in after treatment to reduce withdrawals and minimize reservoir pressure reduction
- Producer gel treatment – July 2009
  - PRD #1: 1,500 bbl

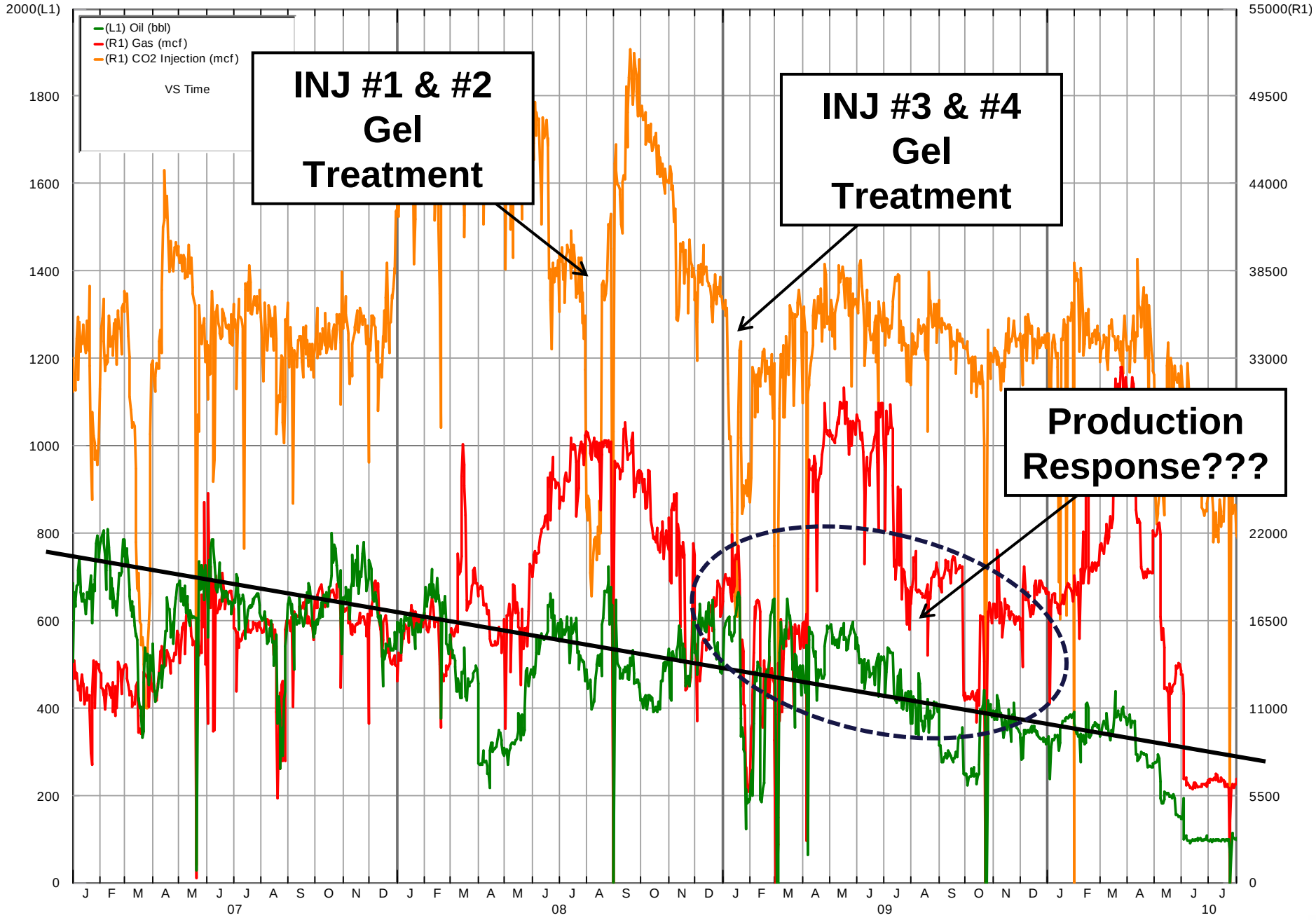
INJ #2 Gel Treatment Example



INJ #2 Hall Plot



Gel Treatment Production Effect

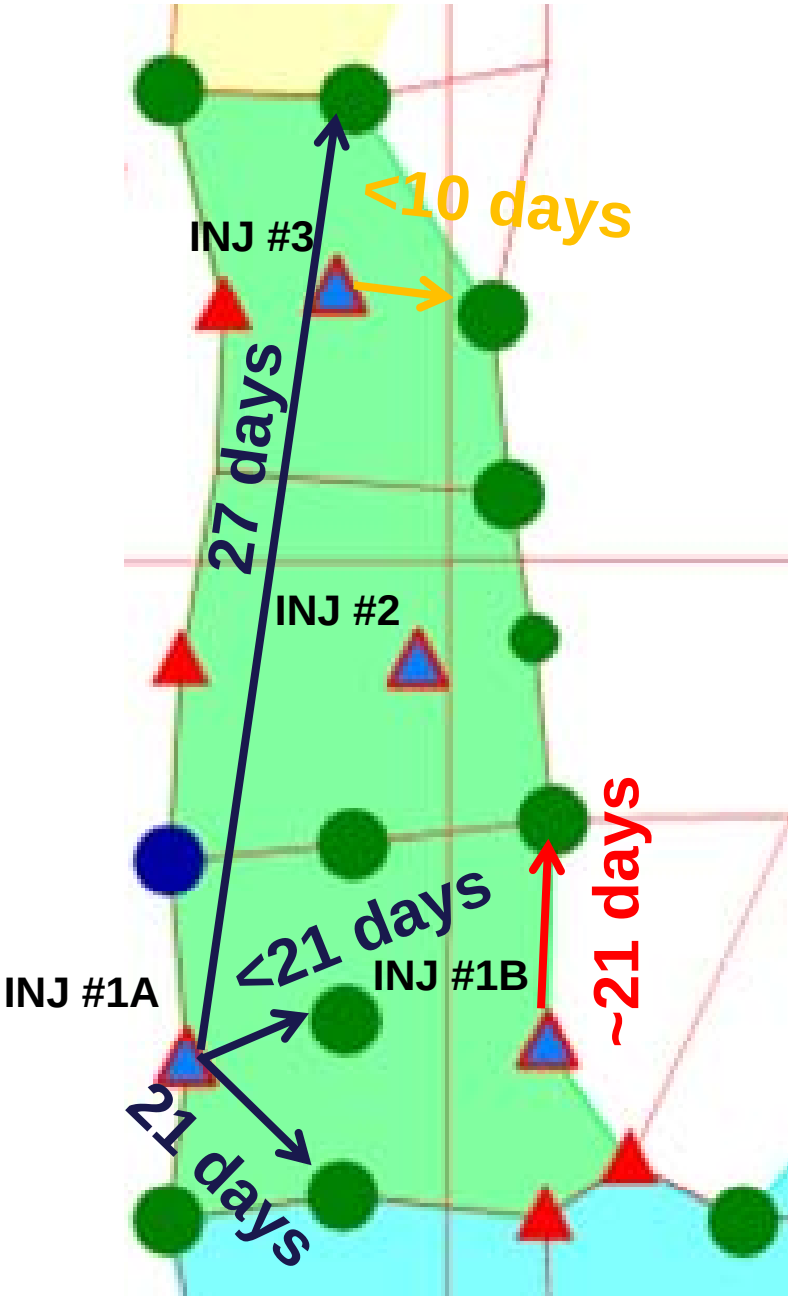


Gel Treatment Conclusions

- Injectivity decreased in 3 of 4 injectors
- Production impacts are very difficult to quantify
  - Too many variables to measure gains and losses
- Gel treatments may have slightly modified injection profiles
  - Near well effects may be minimal because gel is pushed deep into the reservoir before it sets up
- Considering significantly larger treatments in the future
  - Attempt to plug off a more substantial portion of the high permeability streak

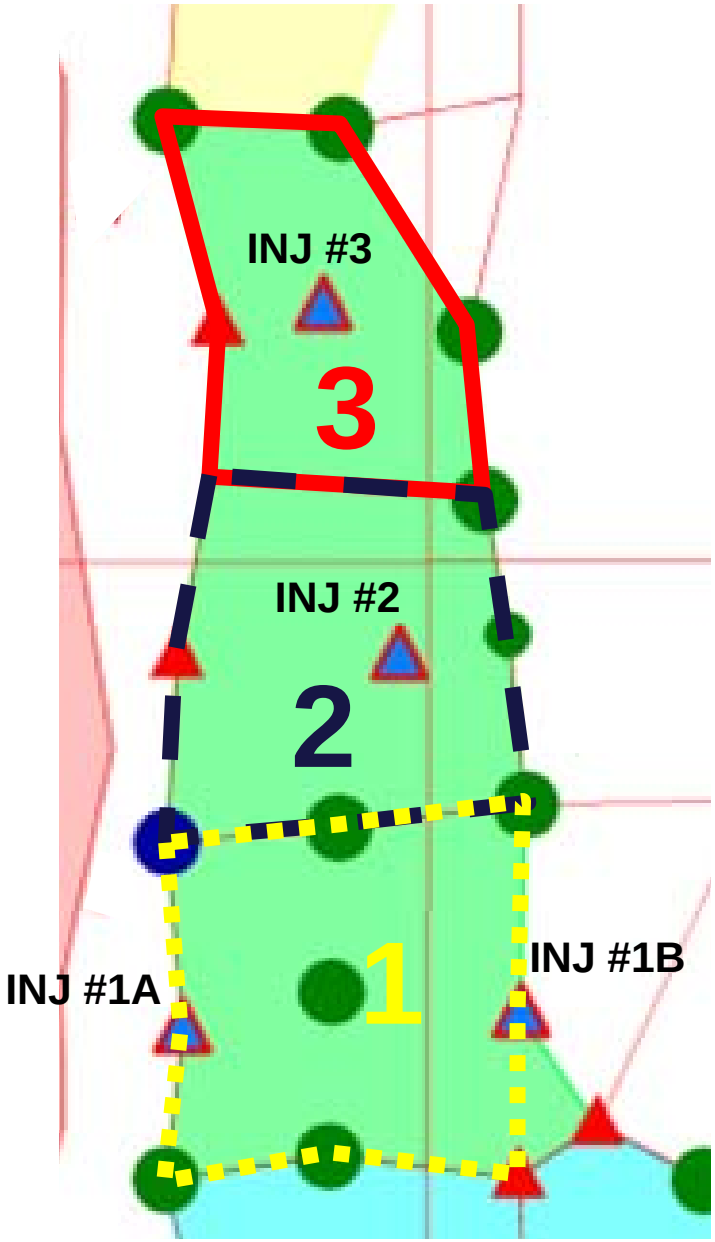
Phase 1 of Tracer Study - Breakthrough Times

- Unique, CO_2 soluble chemical tracers were injected in 4 CO_2 injectors
- Breakthrough times of highest tracer concentrations shown at right
- Tracers from INJ 1A have been detected in almost every well in the area
- Study has confirmed a north-south preferential flow direction



Water-Alternating Gas (WAG)

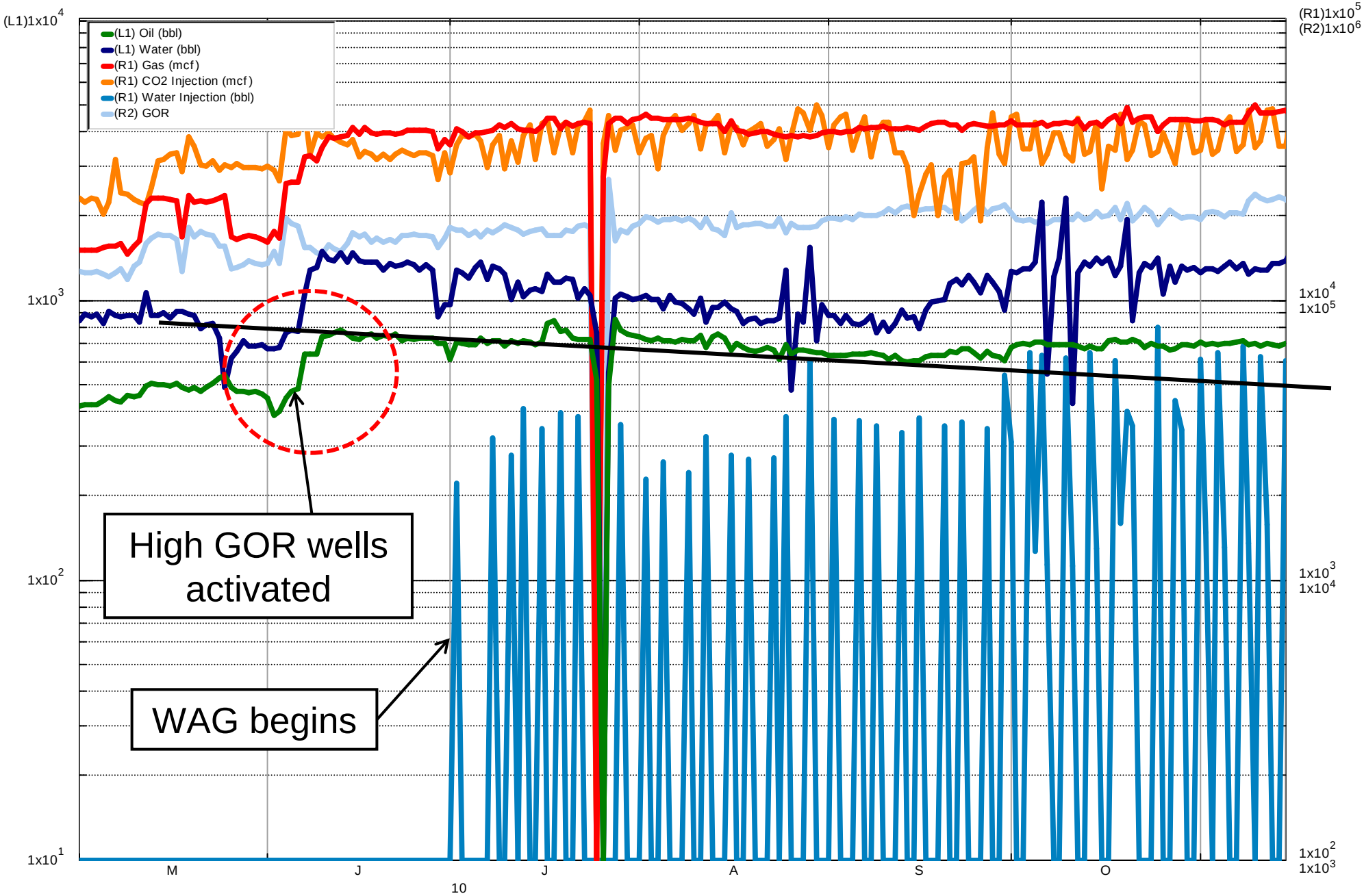
- As of May 2010, 7 of 11 active producers were shut-in due to high GOR
- Convert four continuous CO_2 injectors to WAG injectors
  - Use slugs of produced water to divert CO_2 into unswept regions
  - Try to avoid artificial lift with small water slug sizes
- Chemical tracer survey conducted by ProTechnics
  - Two phase program
    - 1st Phase: Continuous CO_2 study (completed)
    - 2nd Phase: WAG (water and CO_2) study (ongoing)



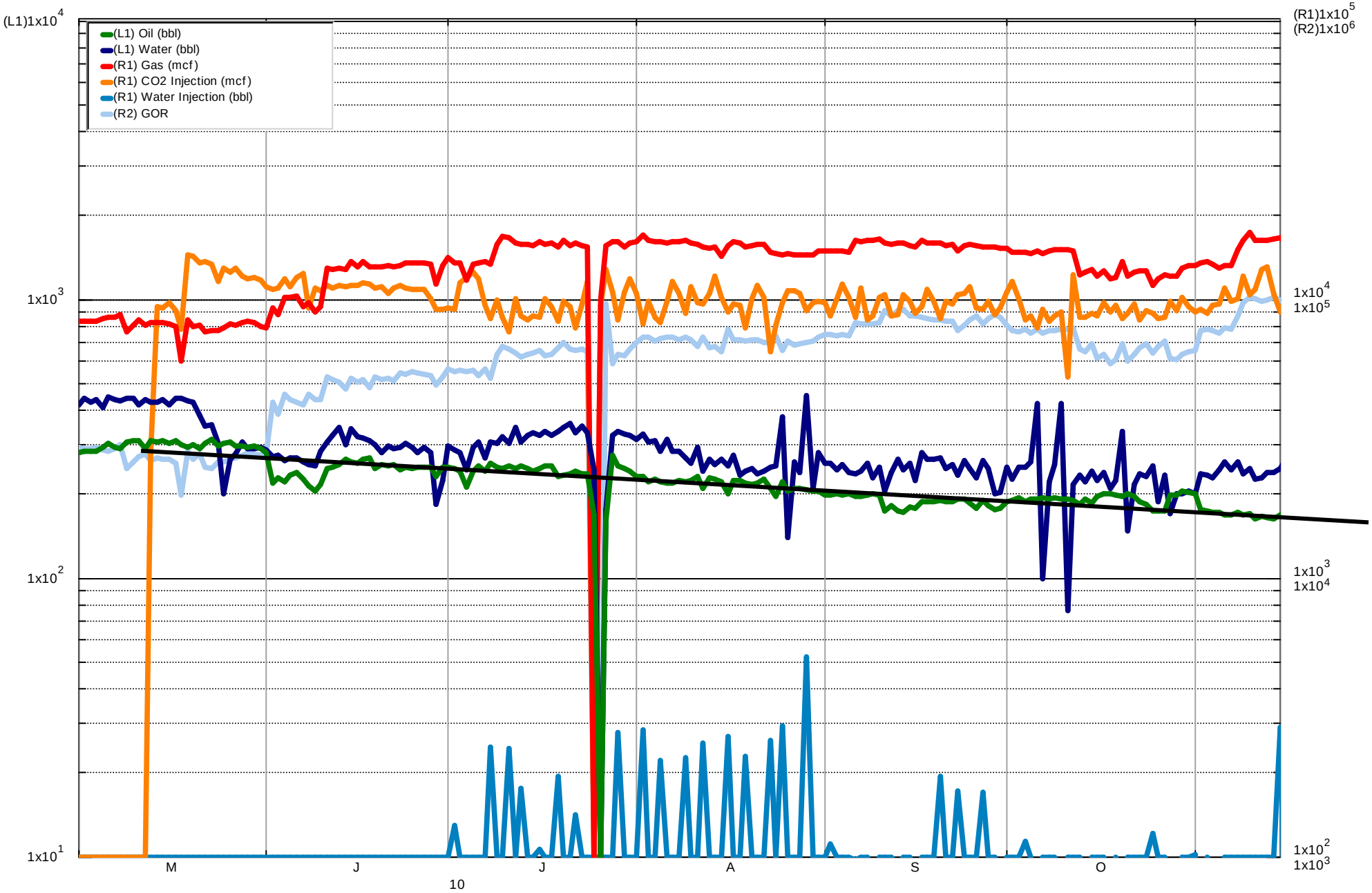
Three Pattern WAG Injection Protocol

- WAG cycles began on 6/29/2010
- Target was ~1000 bbl of water, twice a week
  - Approximate amount of water injected per injection cycle:
    - WAG INJ #1A: ~1100 bbl
    - WAG INJ #1B: ~1250 bbl
    - WAG INJ #2: ~1100 bbl
    - WAG INJ #3: ~200 bbl
- WAG INJ #2 was down due to MIT failure for the month of August
- WAG cycles altered on 10/1/2010
  - Approximate amount of water injected per injection cycle:
    - WAG INJ #1A: ~2100 bbl
    - WAG INJ #1B: ~2700 bbl
    - WAG INJ #2: ~2200 bbl
    - WAG INJ #3: ~100 bbl

WAG Area


(L1)1x10^4
1x10^3
1x10^2
1x10^1
(R1)1x10^5
(R2)1x10^6
1x10^4
1x10^5
1x10^3
1x10^4
1x10^2
1x10^3
(L1) Oil (bbl)
(L1) Water (bbl)
(R1) Gas (mcf)
(R1) CO2 Injection (mcf)
(R1) Water Injection (bbl)
(R2) GOR
High GOR wells activated
WAG begins
M
J
J
A
S
O
10

Pattern 3


(L1)1x10^4
(R1)1x10^5
(R2)1x10^6
(L1) Oil (bbl)
(L1) Water (bbl)
(R1) Gas (mcf)
(R1) CO2 Injection (mcf)
(R1) Water Injection (bbl)
(R2) GOR
1x10^3
1x10^2
1x10^1
1x10^4
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1x10^3
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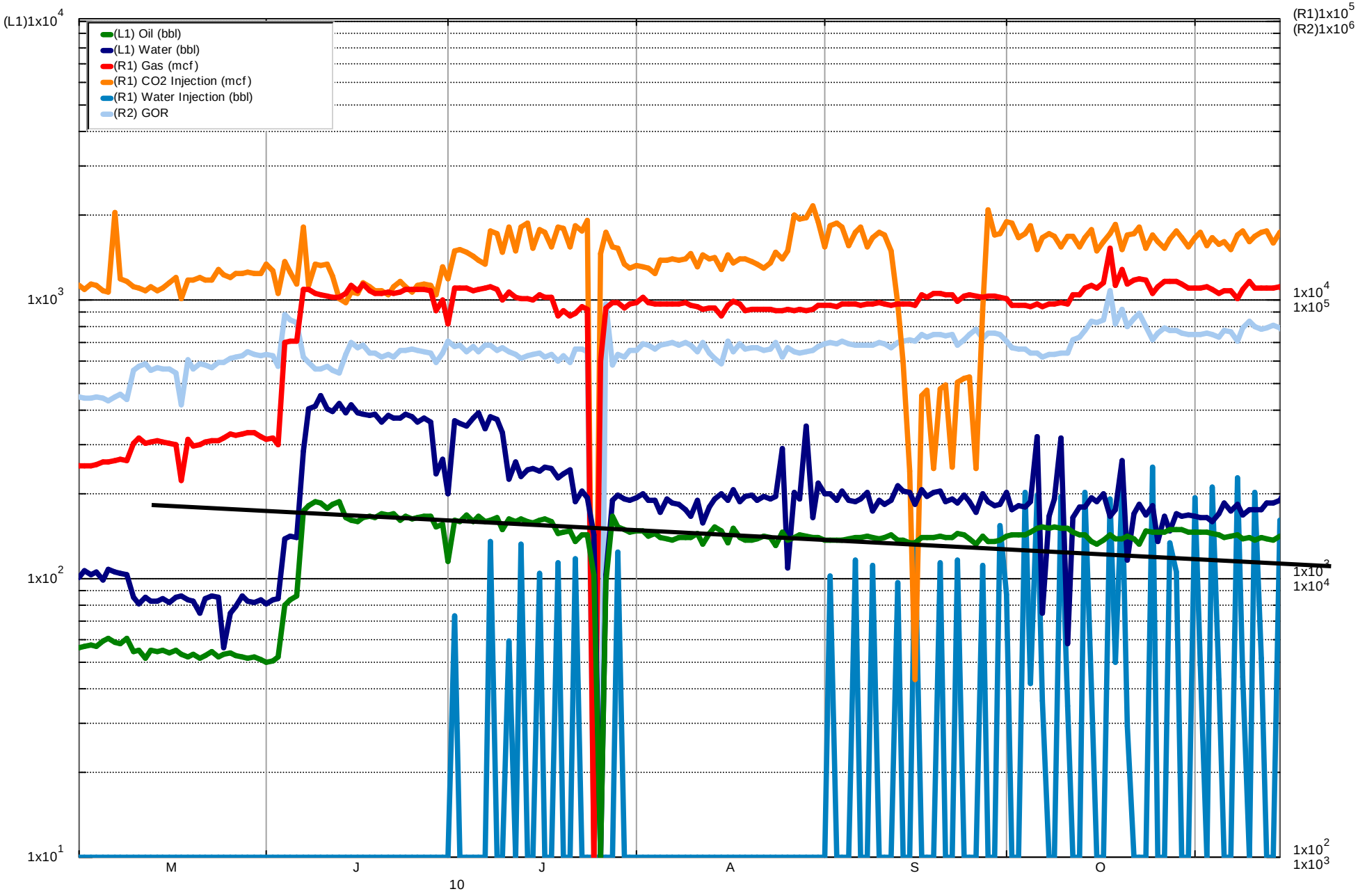
Pattern 2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(R1)1x10^5
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(L1) Oil (bbl)
(L1) Water (bbl)
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(R1) CO2 Injection (mcf)
(R1) Water Injection (bbl)
(R2) GOR
1x10^3
1x10^2
1x10^1
1x10^4
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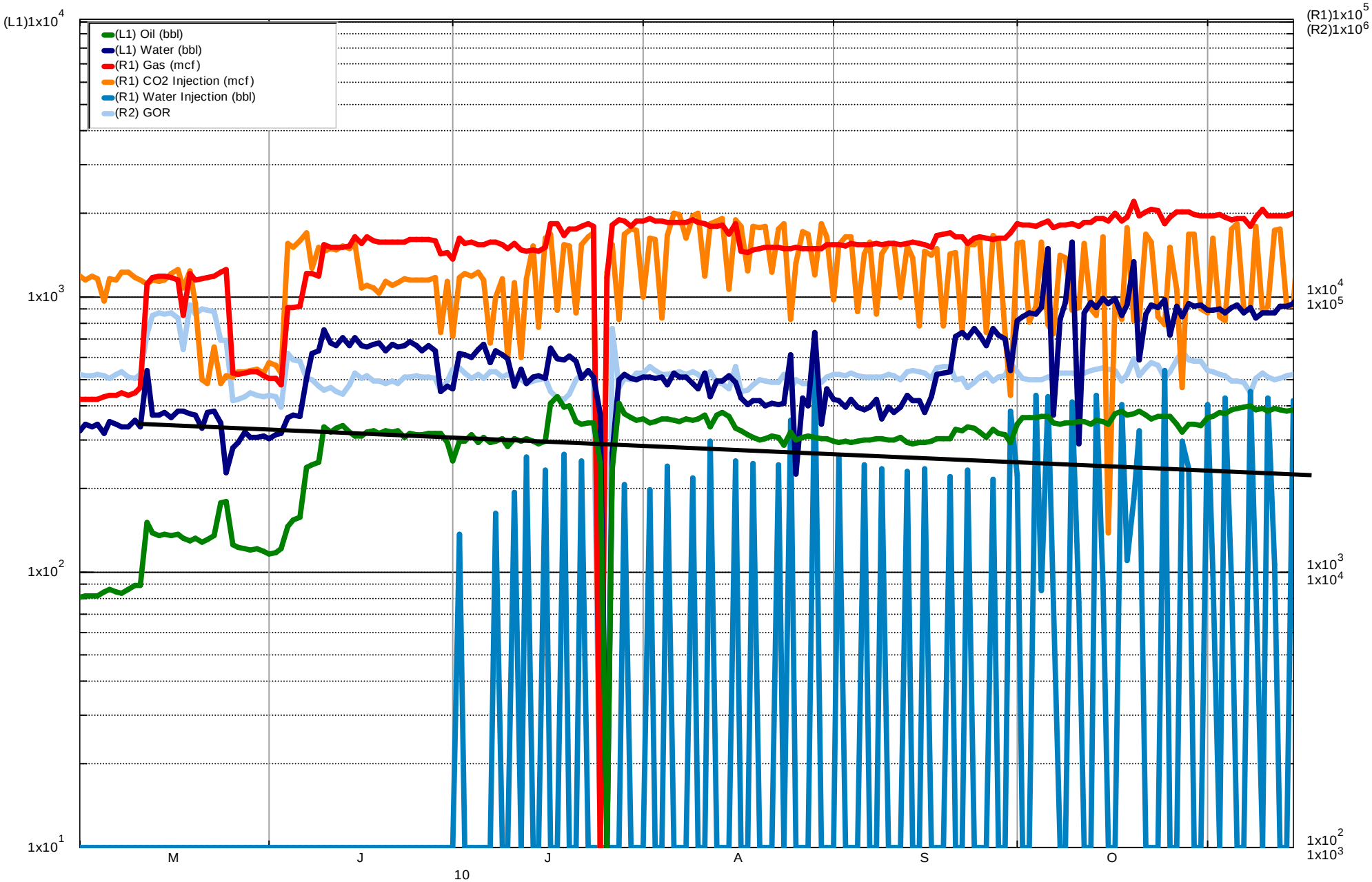
Pattern 1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(R1)1x10^5
(R2)1x10^6
(L1) Oil (bbl)
(L1) Water (bbl)
(R1) Gas (mcf)
(R1) CO2 Injection (mcf)
(R1) Water Injection (bbl)
(R2) GOR
1x10^3
1x10^2
1x10^1
1x10^4
1x10^5
1x10^3
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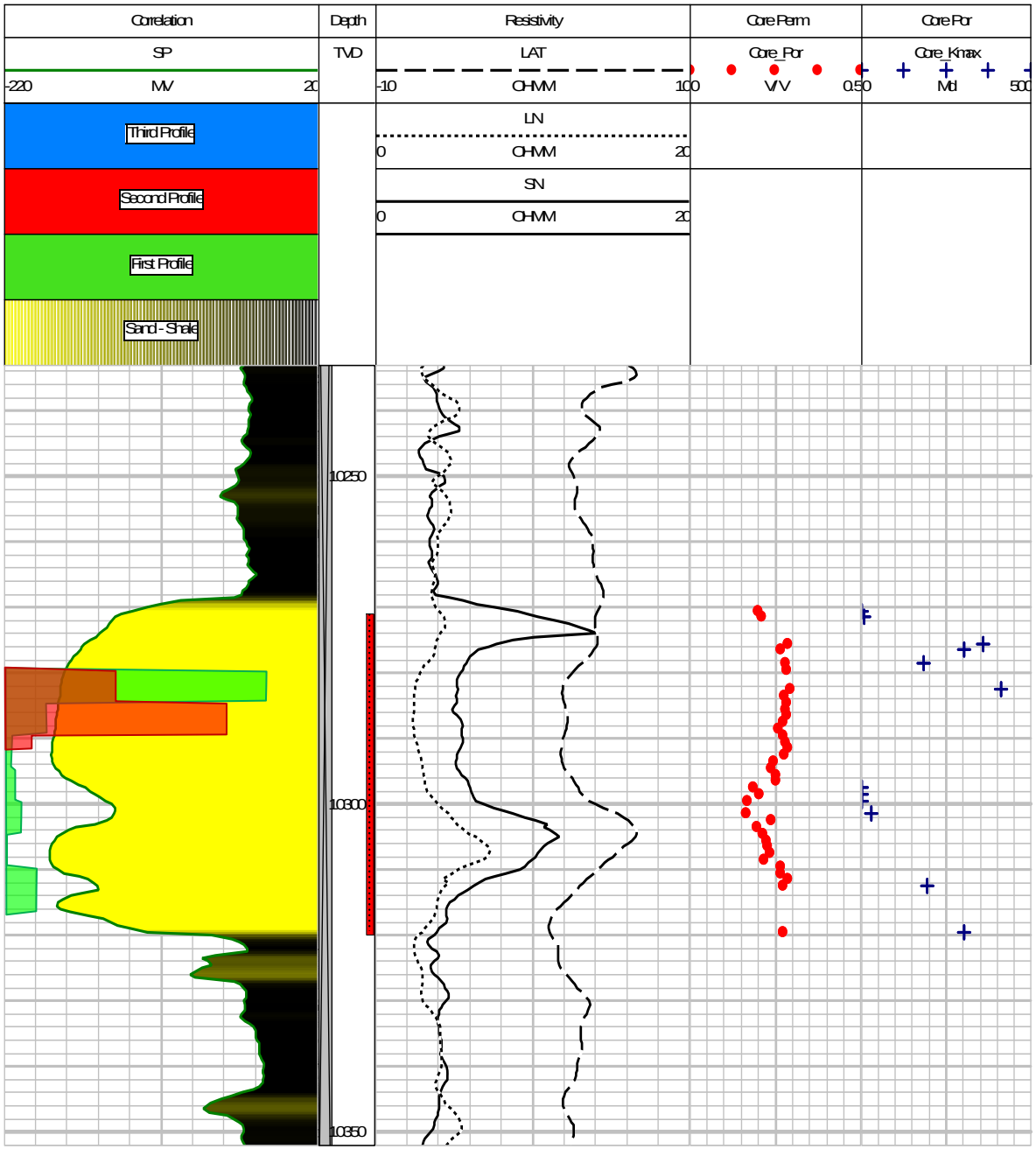
CO_2 Injection Profile Modification – INJ #1B



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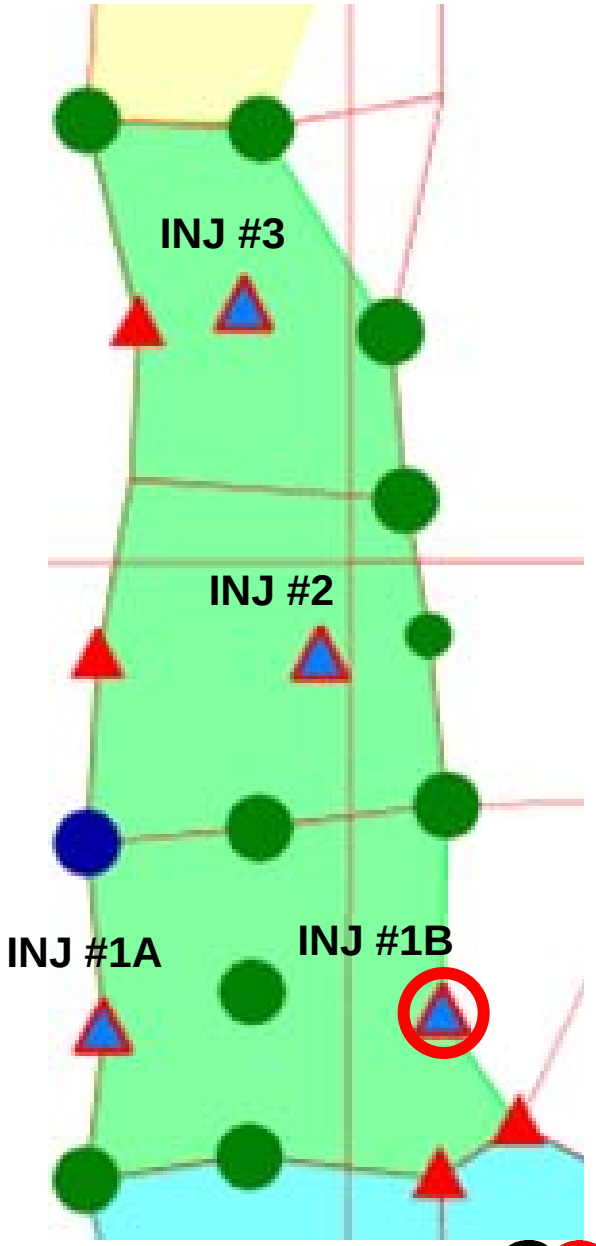
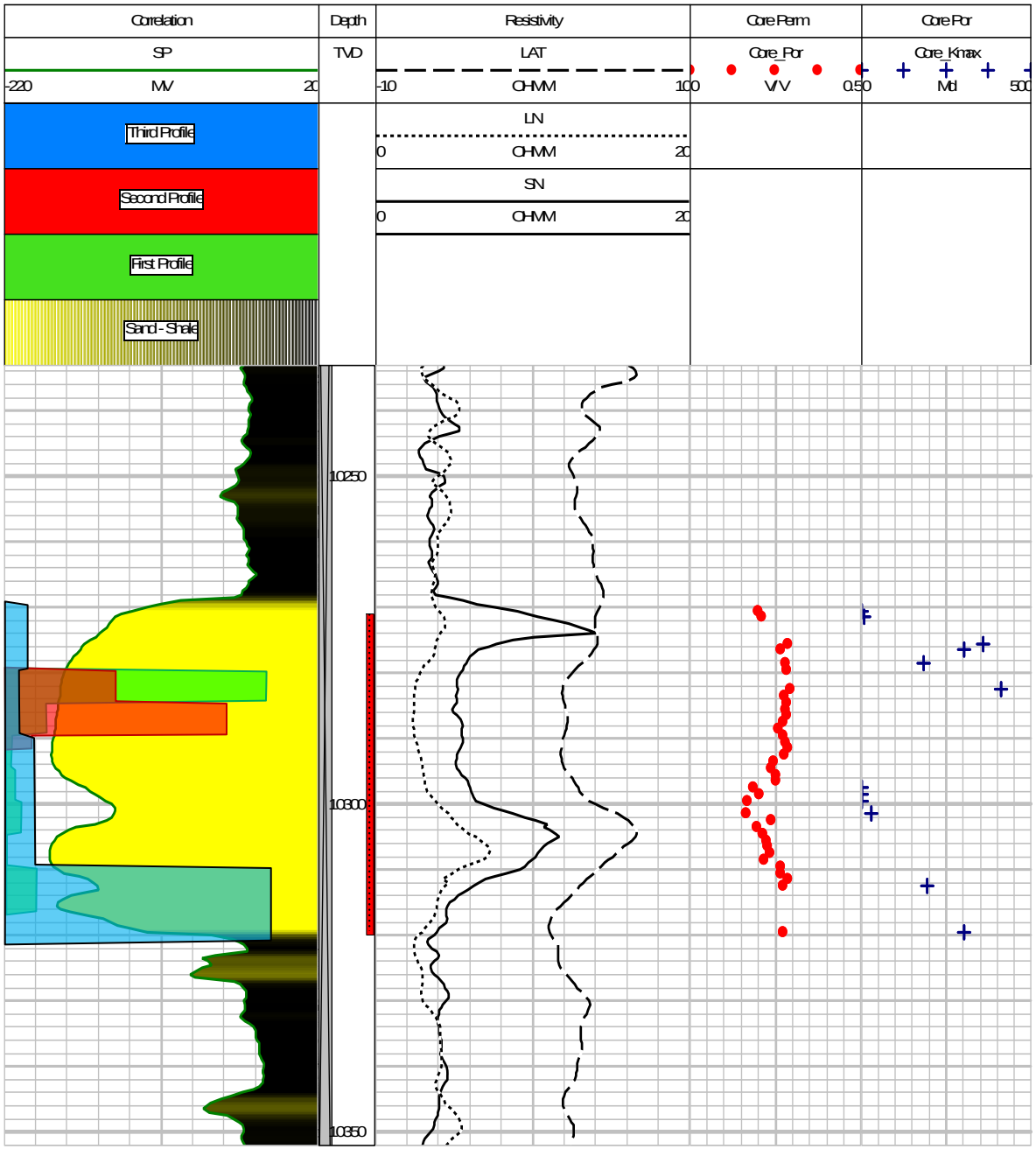


CO_2 Injection Profile Modification – INJ #1B



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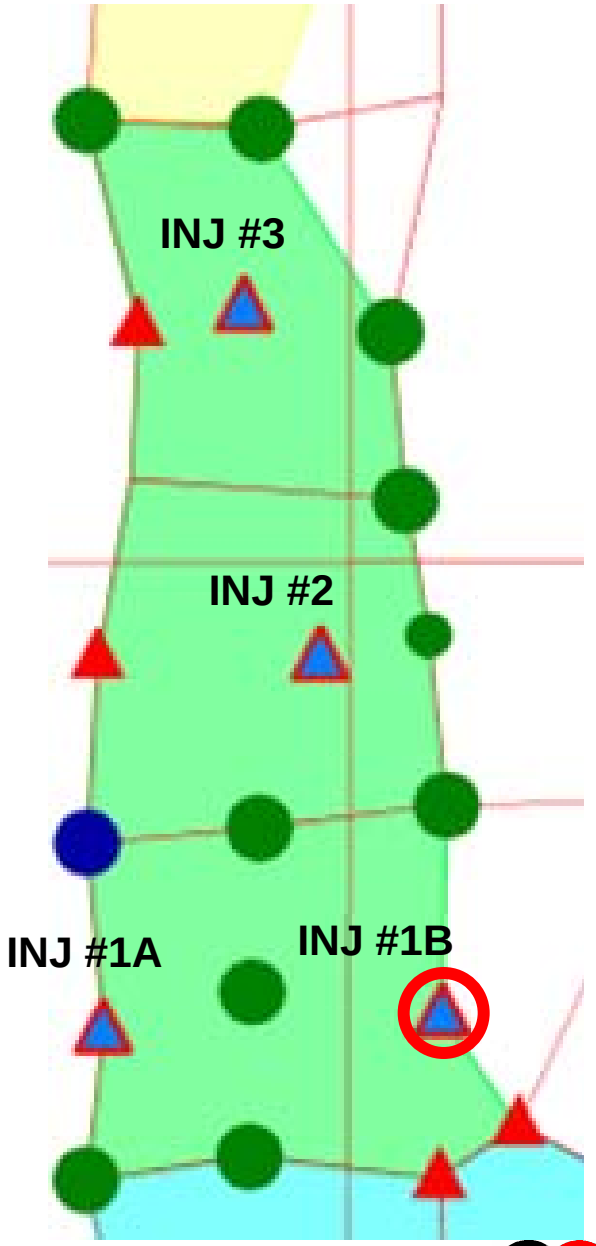

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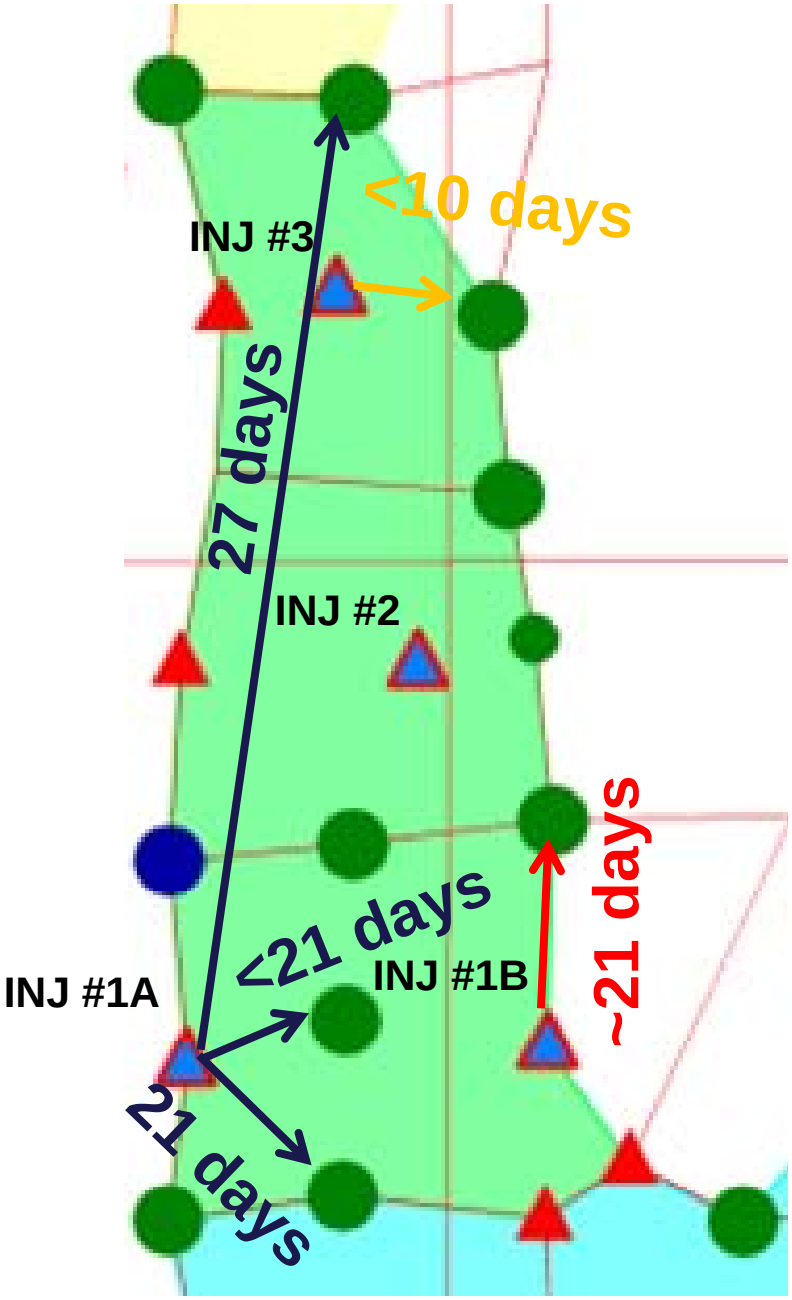
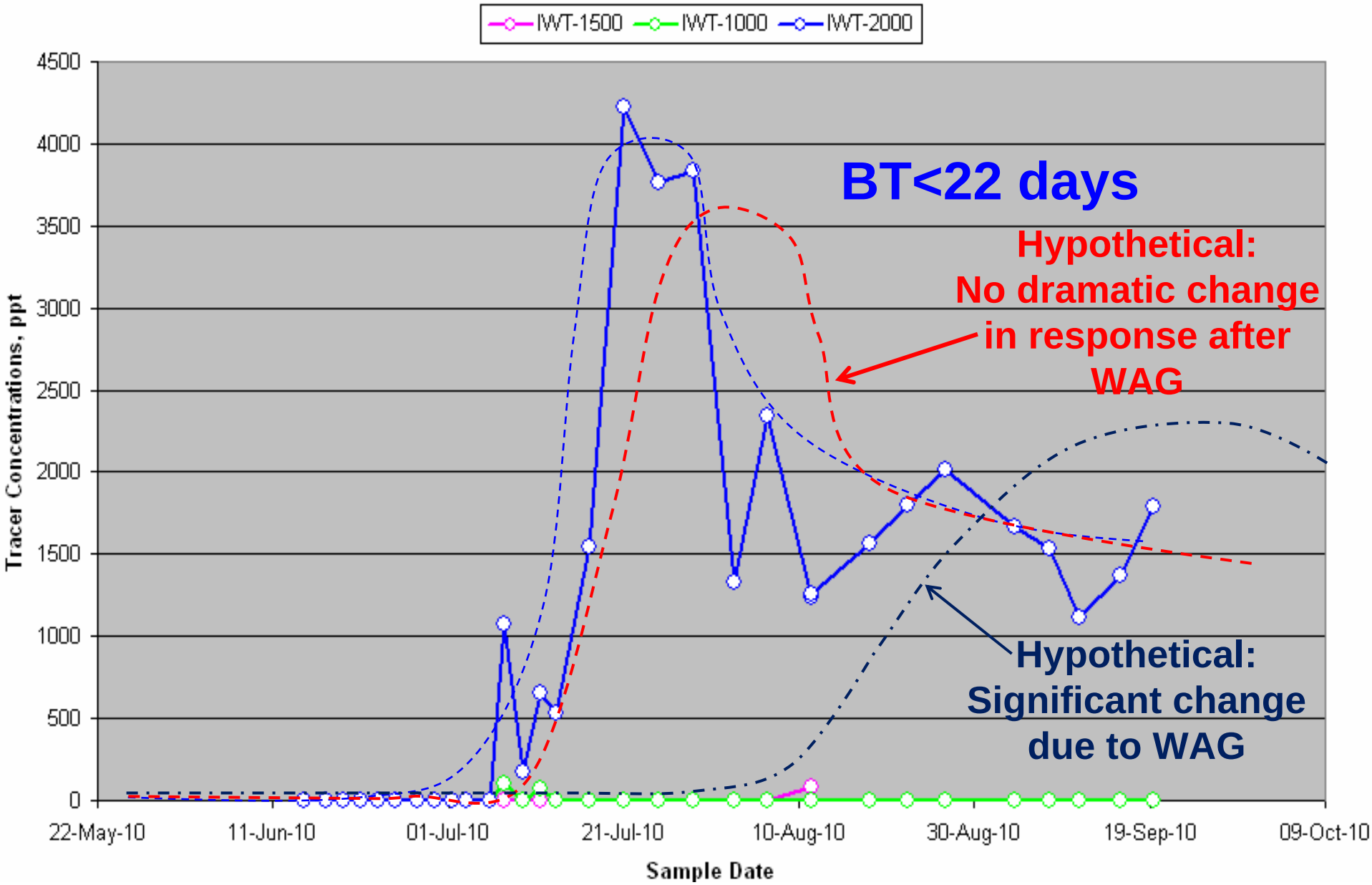


Tracer Elution Curve for WAG Producer



WAG Results to Date

- Have seen production improvements on the pattern level
  - Most improvement has been seen in Pattern 1
  - Approximately 200 BOPD incremental gain has been observed in the WAG area
  - No reduction in CO2 production has been observed yet
  - Water production has started to trend up in the past 2 months – unknown if this is injected water or formation water
- Successful in modifying injection profiles
- Tracer results to date are consistent with observed field behavior
  - Provided supporting information for modifying slug sizes
  - Began Phase 2 of tracer study 1st week of December

Future Conformance Work at Brookhaven

- Continue to selectively perforate wells when possible and target specific sands
- Gel treatments
  - Increase treatment size
  - Where implementing WAG may be expensive and/or difficult
  - Treat high GOR producing wells
- WAG plans
  - Modify slug sizes in Phase 4B
    - Need to determine optimal slug size for profile modification
  - Looking at expanding WAG in areas of the field where early CO_2 breakthrough is a problem
- Continue to look at new technologies
  - Foam
  - “Viscosify” water for WAG

Recognizing Personnel

- Field:
  - Billy Biggers, Kyle Burke, Chad Lofton, Don Herrington, Joey Williford and other BFU Operators, Lester Reed, Will Duncan, Betty Boothe, Lisa Ballard, Regina Compton, Denise Allen, Philip Hollimon, Matt O'Bryant and Arnold Jackson

SW Mississippi District Office dusted with snow

Recognizing Personnel

- Corporate Office
  - Management:
    - Barry Schneider, Bruce Augustine, Ken Cameron, Walt True, Dave Senor, Gordon Moore, West Richardson and Brenda Borden
  - Brookhaven Team:
    - Gary Patterson, Randy L. Charles, Kevin Skees, Ed Deslauriers, Jim Cobb, Jim Kean, Reuben Pratt, Lisa Nordstrom, Dylan Sheppard, Angie Cate, Karla Stines, Tammy Sims, and Naomi Johnson

Questions?