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2021 Bakken EOR Topical Report
Findings and Conclusions Derived from Several Bakken Enhanced Oil Recovery Studies

Bakken Production Optimization Program

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Product of BPOP 3.0

Led by the Energy & Environmental Research Center (EERC), the highly successful Bakken Production Optimization Program (BPOP), funded by its partners and the North Dakota Industrial Commission through its Oil and Gas Research Program, conducts research to provide the state and industry with science-based insight to maintain the economic and environmental sustainability of the Bakken play in North Dakota. **BPOP 3.0 Members:**

ConocoPhillips, CMG Computer Modelling Group Ltd., devon, equinor, HESS, Liberty Resources, Marathon Oil, North Dakota oil & gas research program, Oasis Petroleum, Petro-Hunt L.L.C., WPX Energy, XTO Energy

For more information, please visit: https://undeerc.org/bakken/Optimization/

Abstract

This topical report summarizes findings and conclusions derived from several ongoing Bakken enhanced oil recovery studies conducted through the EERC-managed Bakken Production Optimization Program (BPOP). A survey of the nine known Bakken petroleum system enhanced oil recovery (EOR) injection tests and field pilots conducted in the North Dakota and Montana portions of the Williston Basin are discussed. Considerations for CO_2 and rich gas applicaion for Bakken EOR are provided, and the potential impact of CO_2 EOR on North Dakota Bakken oil production is explored for several potential development scenarios using spreadsheet forecasting. Several knowledge gaps and potential advancements are enumerated that could improve the design, implementation, deployment, and forecasting of Bakken EOR. Results of several reservoir simulation case studies are used to explore methods for detecting and characterizing short circuiting of injected gas between horizontal wells and other conformance issues associated with multiwell cyclic huff 'n' puff.

CHAPTER 1:
Summary of EOR Pilot Tests in the Bakken

Goals and Objectives

- **Review and summarize the approaches and results of past EOR field pilot tests in the Bakken play prior to 2018.**
  - **Seven North Dakota Bakken injection tests**
  - **Elm Coulee Bakken injection test**

- **Provide high level summary of Liberty Resources' multiwell cyclic huff 'n puff tests at their Stomping Horse complex in 2018-2019.**

- **Offer interpretation and insight regarding lessons learned and the value and applicability of these tests to future EOR efforts.**

www.bakkendispatch.com

Injection Tests Conducted Prior to 2018

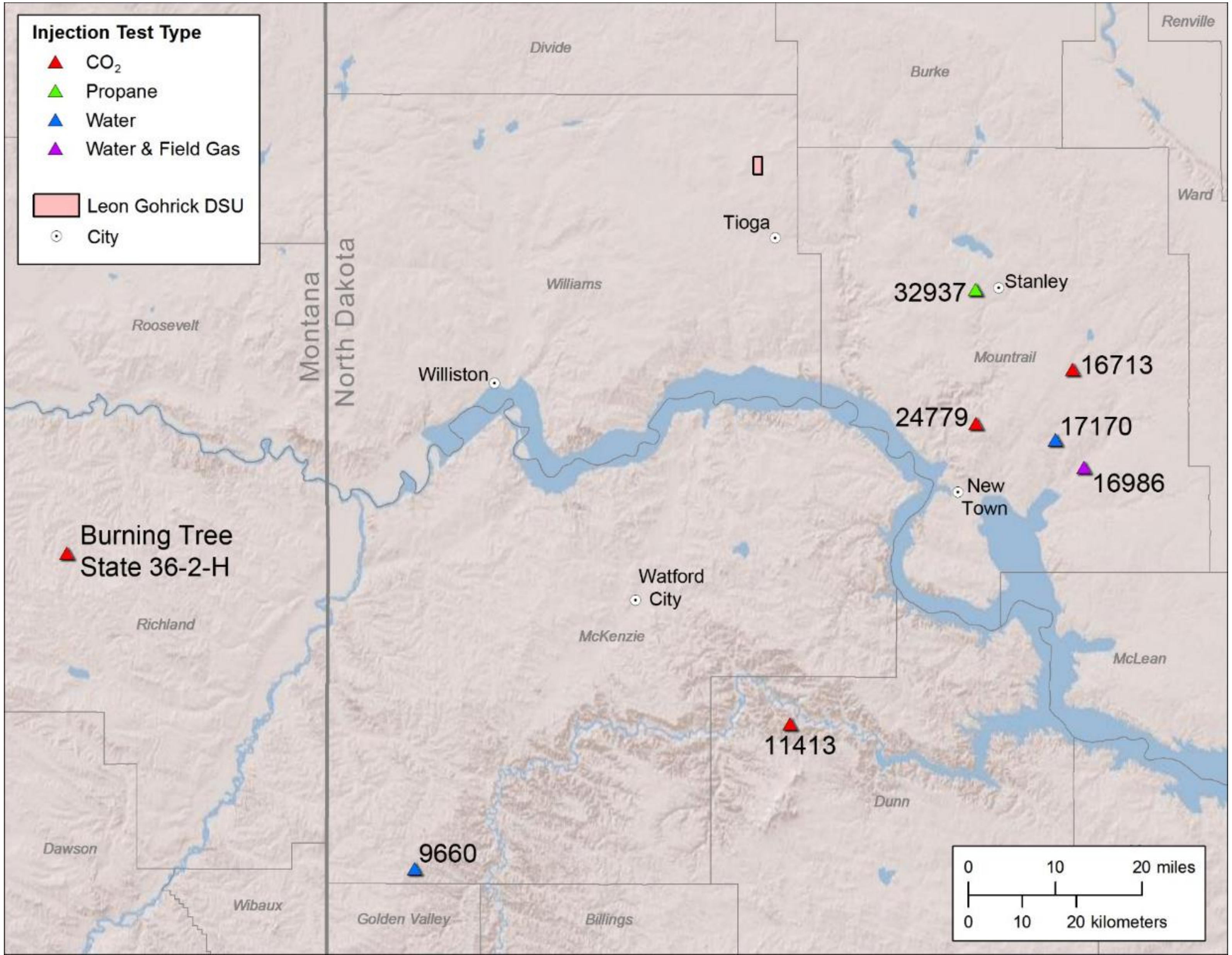
Seven North Dakota Bakken injection tests (NDIC Well #):

1. **#9660:** Water, Meridian tested March–April 1994 (50 days)
2. **#16713:** CO_2, EOG tested September–October 2008 (29 days)
3. **#17170:** Water, EOG tested April–May 2012 (30 days?)
4. **#16986:** Waterflood followed by field gas injection, EOG
   – Waterflood, tested April 2012–February 2014 (672 days)
   – Field gas, tested June–August 2014 (54 days)
5. **#24779:** Vertical CO_2, Whiting tested February 2014 (4 days)
6. **#32937:** Vertical propane, Hess tested May – July 2017 (at least 90 days)
7. **#11413:** Vertical CO_2, XTO Energy tested June 2017 (5 days)

One Montana Bakken injection test:

1. **Burning Tree State-36-2-H:** CO_2, Enerplus/Continental/XTO tested January–February 2009 (45 days)

Location of Bakken EOR Tests (Pre-2018)



Summary of Test Statistics

Well	Operator	Test Year	Max. Inj. Rate	Max. Pres., psi	Avg. Inj. Rate	Avg. Pres., psi	Zone	Cumulative injected
#9660	Meridian	1994	500 bpd	5000 bhp	200 bpd	3000 bhp	UB	13,082 bbl water
#16713	EOG	2008	700 bpd	1500 sdp	580 bpd	1000 sdp 6950 bhp	MB	30.7 MMscf CO_2
#17170	EOG	2012	3000 bpd	4000 bhp	1500 bpd	1000 bhp	MB	38,177 bbl water[a]
#16986	EOG	2014	1500 Mscfd	5000 bhp	1500 Mscfd	4500 bhp	MB	88.7 MMscf field gas
#24779[b]	Whiting	2014	31 gpm	3500 bhp	10.5 gpm	3500 bhp	MB	3.4 MMscf CO_2
#32937[b]	Hess	2017	227 Mscfd	5500 sdp	105 Mscfd	4000 sdp	MB	9.5 MMscf C_3H_8
#11413[b]	XTO	2017	12 gpm	9480 bhp	9 gpm	9400 bhp	MB	1.7 MMscf CO_2
Burning Tree	Enerplus	2009	3000 Mscfd	1848 bhp	1000 Mscfd	NA	MB	45 MMscf CO_2

[a] Includes values reported prior to reported test start.
[c] Vertical well.

bhp = bottomhole pressure
sdp = surface discharge pressure
gpm = gallons per minute

Lessons Learned from Pre-2018 Bakken Injection Tests

- Seven Bakken injection tests have been performed in North Dakota and one in Montana, but ***test details are limited and inconclusive*.**
  - Two water injection tests (one produced water).
  - Four CO_2 injection tests.
  - One propane injection test.
  - One unique case of waterflood pilot followed by field gas injection.
- Previous tests seemed to indicate injectivity into the stimulated Middle Bakken is not a problem; but ***injection conformance is a significant challenge.***
  - Test objectives are often unclear and difficult to independently evaluate.
  - Robust geologic data were limited.
  - Operators' notes/activity logs were limited to nonexistent.
  - Information on natural and induced fracture networks present at test locations is limited to nonexistent.
- ***Future tests need to have clear objectives and include robust data collection before, during, and after the test in injectors and offset wells.***

Lessons Learned from Pre-2018 Bakken Injection Tests

- ***Information on injection design, design rates, volumes, durations, soak times, challenges, results, and all other data were not reported to the Department of Mineral Resources – Oil and Gas Division, and such data are essentially unknown for the horizontal tests in the North Dakota wells.***
  - This limits development of lessons learned from these tests and applicability of results to future tests.
  - ***The CO_2 test in Montana and the rich gas test conducted by EOG were both in wells that appear to have been a single-stage frac; therefore, those tests have little applicability to wells with more sophisticated, multistage completions.***
- Tests in vertical wells provide valuable information about injectivity into the matrix and the potential effectiveness of hydrocarbon gas but offer little insight regarding conformance in long, multistage hydraulically fractured wells.

Shortcomings of Pre-2018 Bakken Injection Tests in Horizontal Wells

Tests in horizontal wells…

- Applied less sophisticated completions, tend to be older wells with few frac stages.

- Geology in Parshall and Sanish Fields (EOG and Whiting tests) and Elm Coulee (Montana) is substantially different from most of the other Bakken production areas.
  - More natural fractures in Parshall and Sanish area.
  - More dolomitic and higher-porosity Middle Bakken in Elm Coulee.

- There are sparse detailed operational data, and some of the available data are contradictory, making it impossible to draw conclusions.

Shortcomings of Pre-2018 Bakken Injection Tests in Horizontal Wells

The tests in horizontal wells…

- Applied conventional approaches to designing and operating EOR tests (e.g., "standard" HnP or injector–producer pair schemes), which do not account for the unique properties of unconventional tight plays (low-perm matrix, fracture-dominated flow pathways, complex pore pressure distribution in the reservoir, etc.).

- None of the tests appear to make attempts at conformance control (at least nothing reported).

- Lack of robust pretest baseline and posttest monitoring data in injectors and offset wells.

- Only one test used field gas, with unknown gas compositions, into a single-stage completion.

Shortcomings of Pre-2018 Bakken Injection Tests in Vertical Wells

The tests in vertical wells…

- Do not provide guidance with respect to conformance.
- Do not account for the complexity that will be encountered in a long horizontal well.
- Were not conducted at a scale that provides insight on the economics of EOR in the Bakken.
- None of these tests used rich gas.

Bakken Injection Test Summaries

Approaches and Results

- Seven North Dakota Bakken injection tests
  - EOG, Whiting, Hess, Meridian test information based on NDIC well files
  - XTO test information based on EERC Bakken CO_2 Storage and EOR Project
- Elm Coulee Bakken injection test
  - Test information provided by Continental Resources, with permission of XTO and Enerplus, as part of EERC Bakken CO_2 Storage and EOR Project

NDIC Well #9660 – Meridian Water Injection Test

Meridian Oil Company

- Converted existing horizontal well.
- ***Freshwater injection into Upper Bakken Shale.***
- Injection began March 8, 1994 : Shut in April 27, 1994 (50 days).
  - "*shut in for approximately 1–2 months to evaluate its performance.*"
- Request to put back on pump July 19, 1994.
  - "*test was found to be unsuccessful.*"

Injected water volumes

- March 1994: 7616 bbl (avg. 1389 psi BHP).
- April 1994: 5644 bbl (avg. 1096 psi BHP).

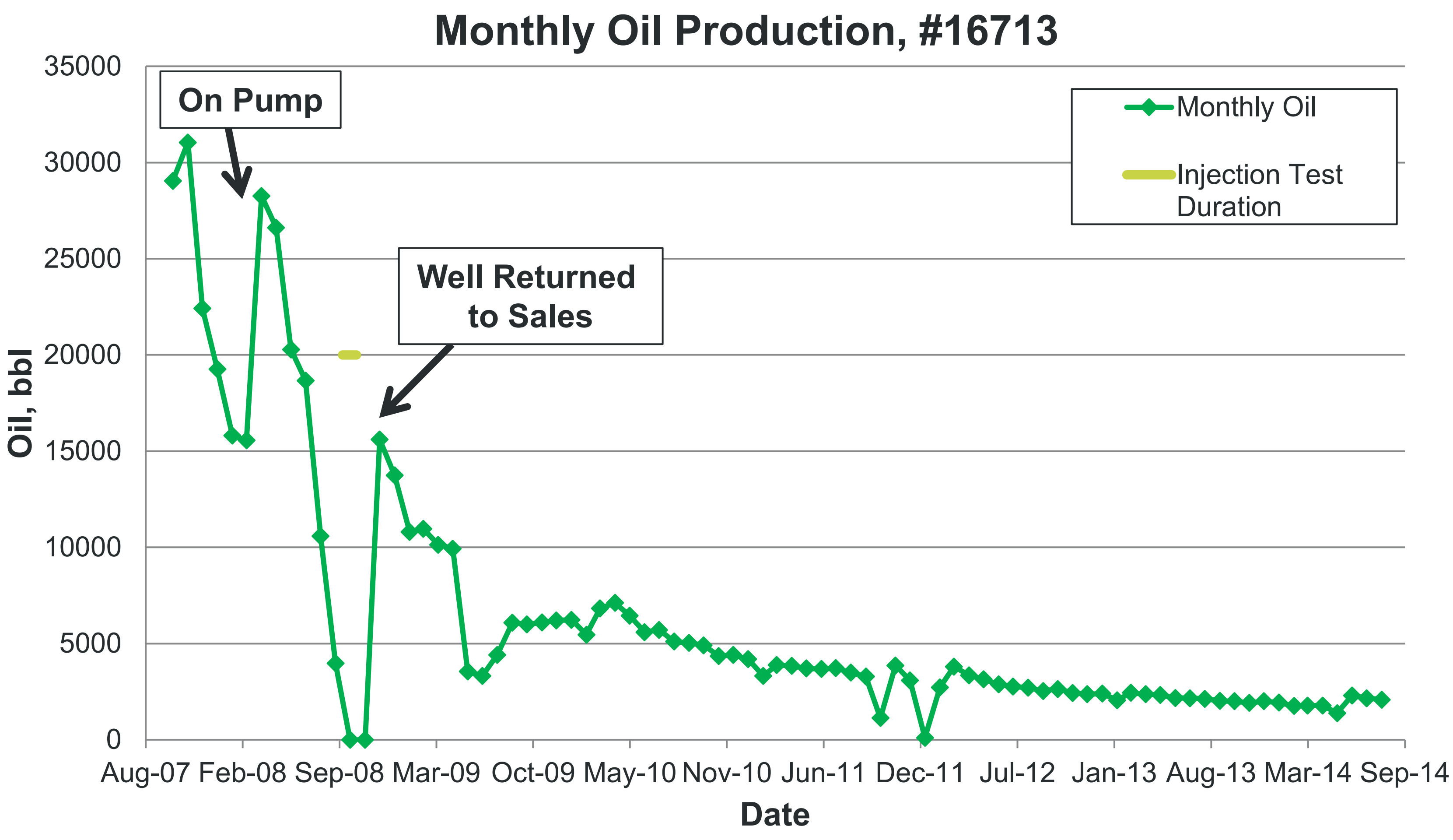
NDIC Well #16713 – EOG CO_2 Injection Test

- EOG Resources, Inc.
- Fractured (April 2008) with sand and gel, ***no report of multistages***; however, well diagram shows six packers in production zone.
- Permit includes a detailed injection plan.
  - Planned 60-day soak time with return to production; later altered to 30 days.
  - Food-grade CO_2 from Praxair.
- Injection began September 15, 2008: CO_2 injection completed on October 14, 2008 (29 days).
- ***After 11-day injection, breakthrough occurred 1 mile away in an offset well.***

- **Injected CO_2 volumes:**
  - "September 2008: 5010 bbl" = 15.6 MMscf
  - "October 2008: 4862 bbl" = 15.1 MMscf

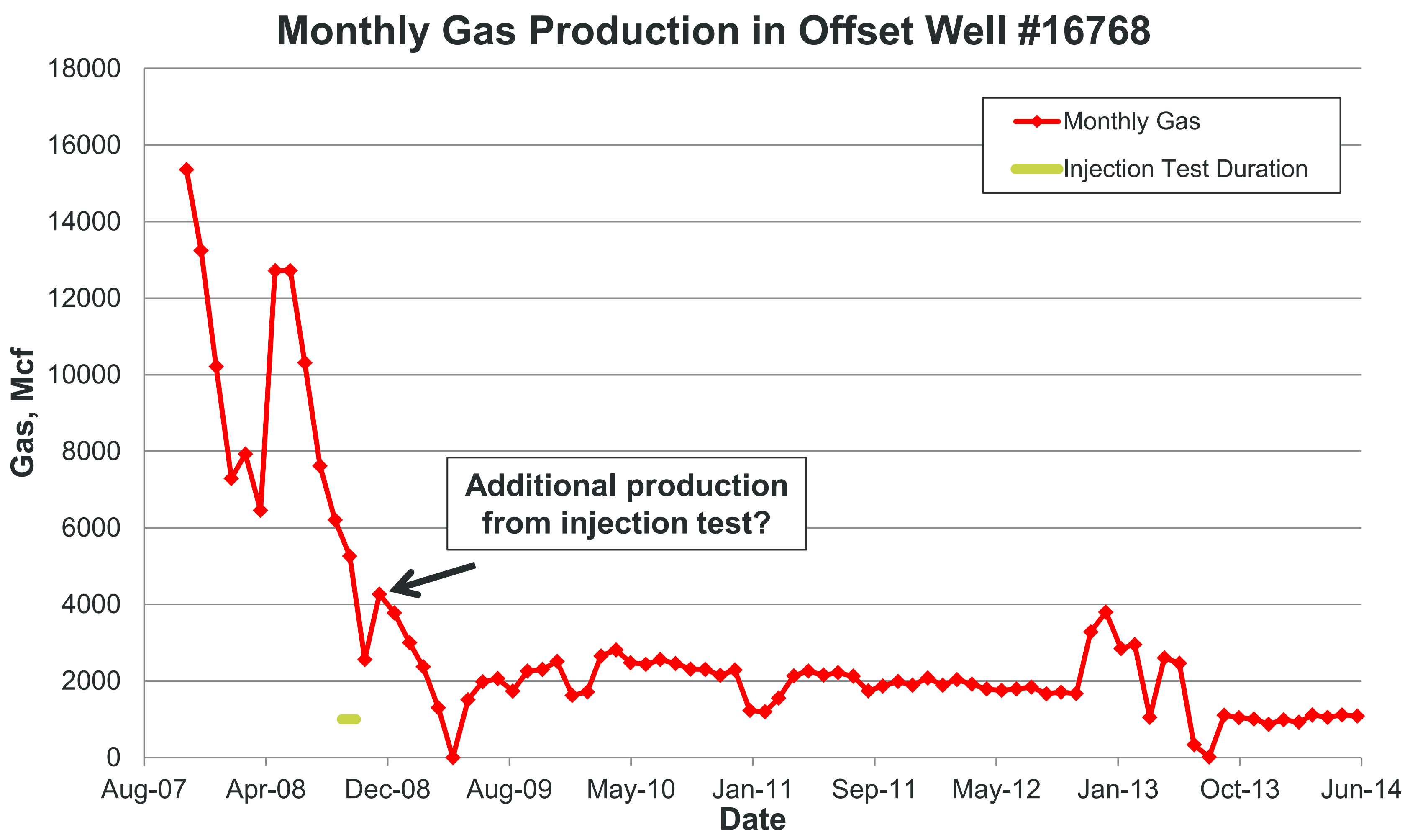
- ***No posttest results; no records of any kind after March 2010.***

NDIC Well #16713 – EOG CO_2 Injection Test



#16713 EOG CO_2 Injection Test: Offset Wells

#16713 CO_2 Injection Test: Gas Production in Offset Well #16768



Quotes from the NDIC Files:
NDIC Well #16713 – EOG CO_2 Injection Test

"After injecting CO_2 for 11 days into the Austin 1-02H (#16713), **we have begun to see breakthrough from Austin 1-02H (#16713) to the Austin 2-03H(#16768), over a mile away**. The other offset wells we are monitoring, the Austin 9-11H **(#17075)** and the Bruhn 1-12H **(#17475), have yet to show an increase in CO_2 concentrations.**

The **concentration observed** in the Austin 1-02H (#16713) **have increased from a background reading of 5,000 ppm** the week before injection began and during the first days of the injection **to approximately 25,000 ppm**. Based on our calculations **this translates to approximately 4 Mcfd of the approximately 1000 Mcfd we are injecting into #16713.**"

NDIC Well #17170 – EOG Water Injection Test

- EOG Resources, Inc.
- Fractured (August 2008) with sand and gel, ***no report of multistage***; however, seven packers are illustrated in the well diagram.
- Taken off production April 22, 2012.
- Produced water injection test.
  - "Huff 'n puff."
- Injection test began May 3, 2012: ***No available notes on completion of test.***
  - Contradictory injection dates listed on state website.
- Planned 30-day injection with 10-day soak.
  - Cycle to repeat until deemed uneconomical; returned to production.
- August 20, 2012, additional reserve pits were installed to collect fracture sand
- Requested "low-pressure injection through artificial lift" on October 12, 2012 (sundry notice), i.e., artificial lift was initiated.
- No newer records.

Injected Produced Water Volumes

- April 2012: 10,380 bbl.
- May 2012: 28,797 bbl.

NDIC Well #16986 – EOG Water and Field Gas Injection Tests

- EOG – Middle Bakken horizontal.
  - Well currently listed as **“Inactive gas injector.”**
- Timeline:
  - Spudded January 28, 2008.
  - Began producing in April 2008.
  - Fractured June 2008 (sand and gel, ***no note of multistage OR presence of production packers***).
  - On pump late July 2008.
  - December 2011, request for conversion to EOR injection well (produced water injection, “waterflood pilot”); approved February 2012.
  - Water injection began April 16, 2012.
    - ♦ Periodic injection until February 2014.
    - ♦ No additional details in well file.
  - Returned to production in March 2014.

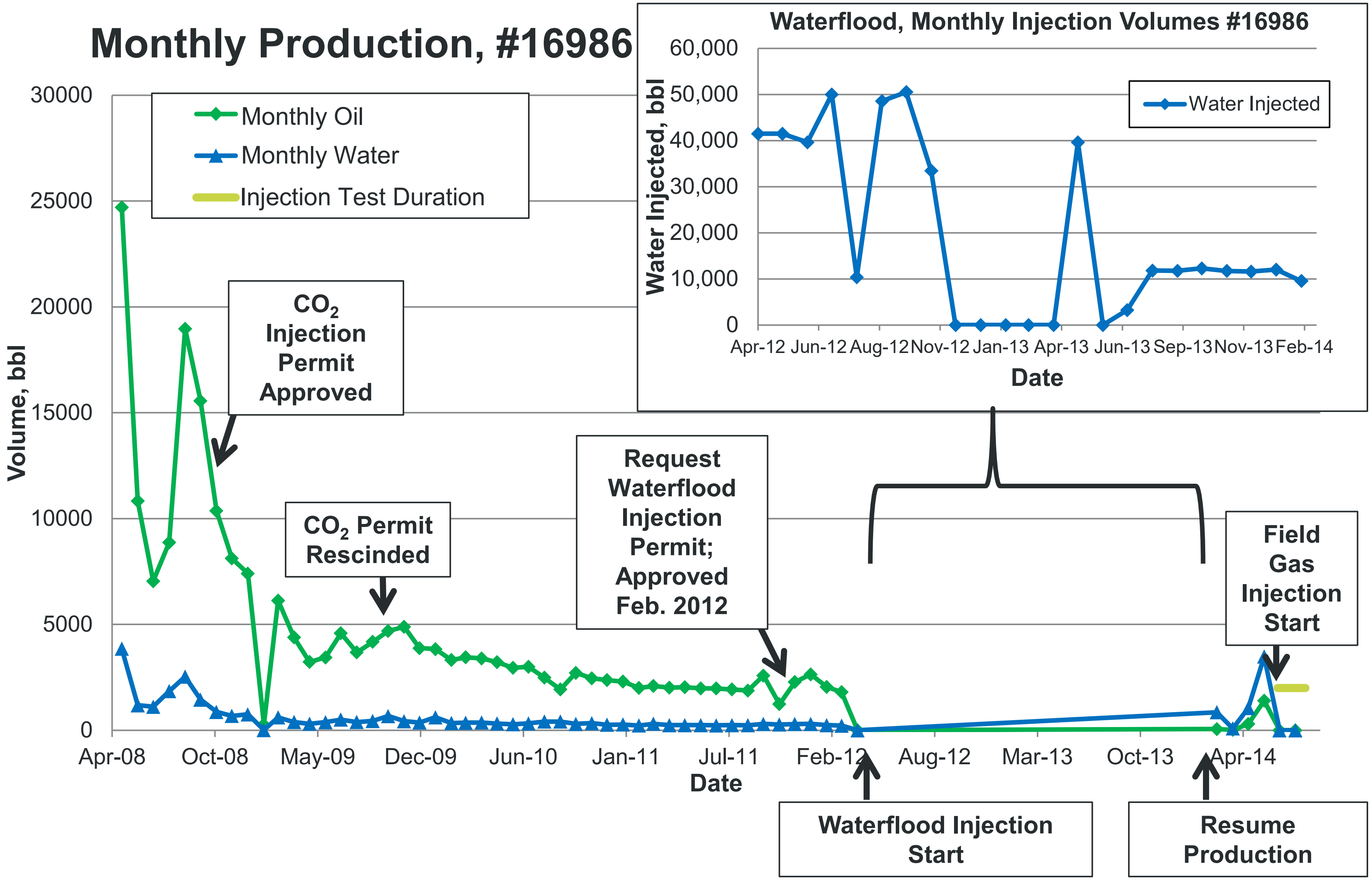
Cumulative Injected Produced Water Volumes (NDIC)

- ♦ 438,969 bbl.

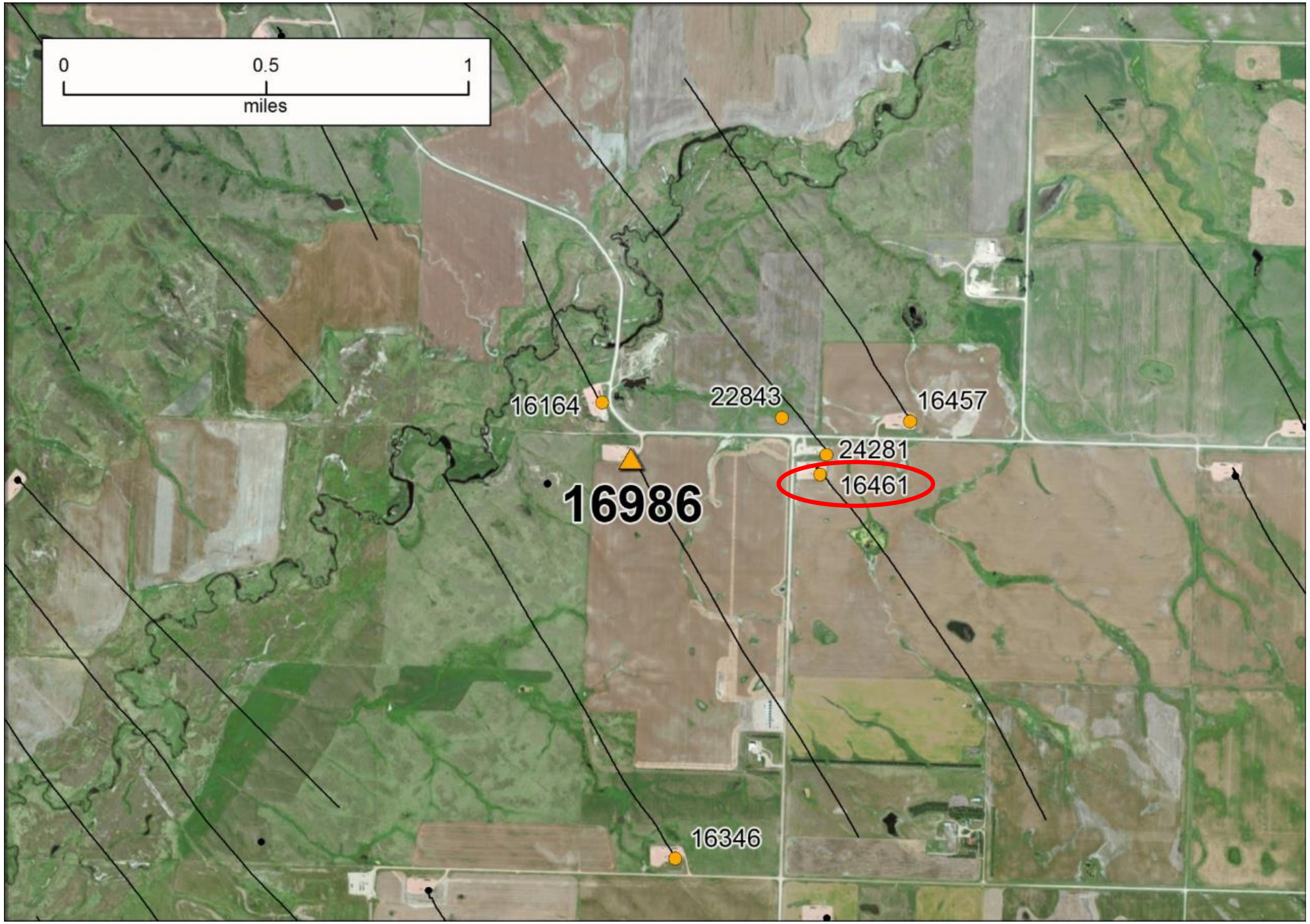
NDIC Well #16986 – EOG Field Gas Injection Test, continued

- Timeline, continued:
  - June 2014 requested change to gas injection.
  - Test consisted of injection of **field gas** with some produced water injection.
  - Water used to “manage effects of gas mobility in the fracture system” or, if needed, “build system pressure with less gas volume.”
  - Goal “evaluate and test the technical feasibility and production performance results of injecting produced gas into the Bakken formation for the purposes of secondary recovery.”
  - Injection began June 27, 2014.
  - Appeared to have communication with the production well.
  - Injection ended August 16, 2014.
  - **Injected field gas volumes:**
    - ♦ June 2014: 4598 Mscf.
    - ♦ July 2014: 50,871 Mscf.
    - ♦ August 1–20, 2014: 33,260 Mscf.
    - ♦ *Cumulative total: 88,729 Mscf.*
  - No posttest production data available.

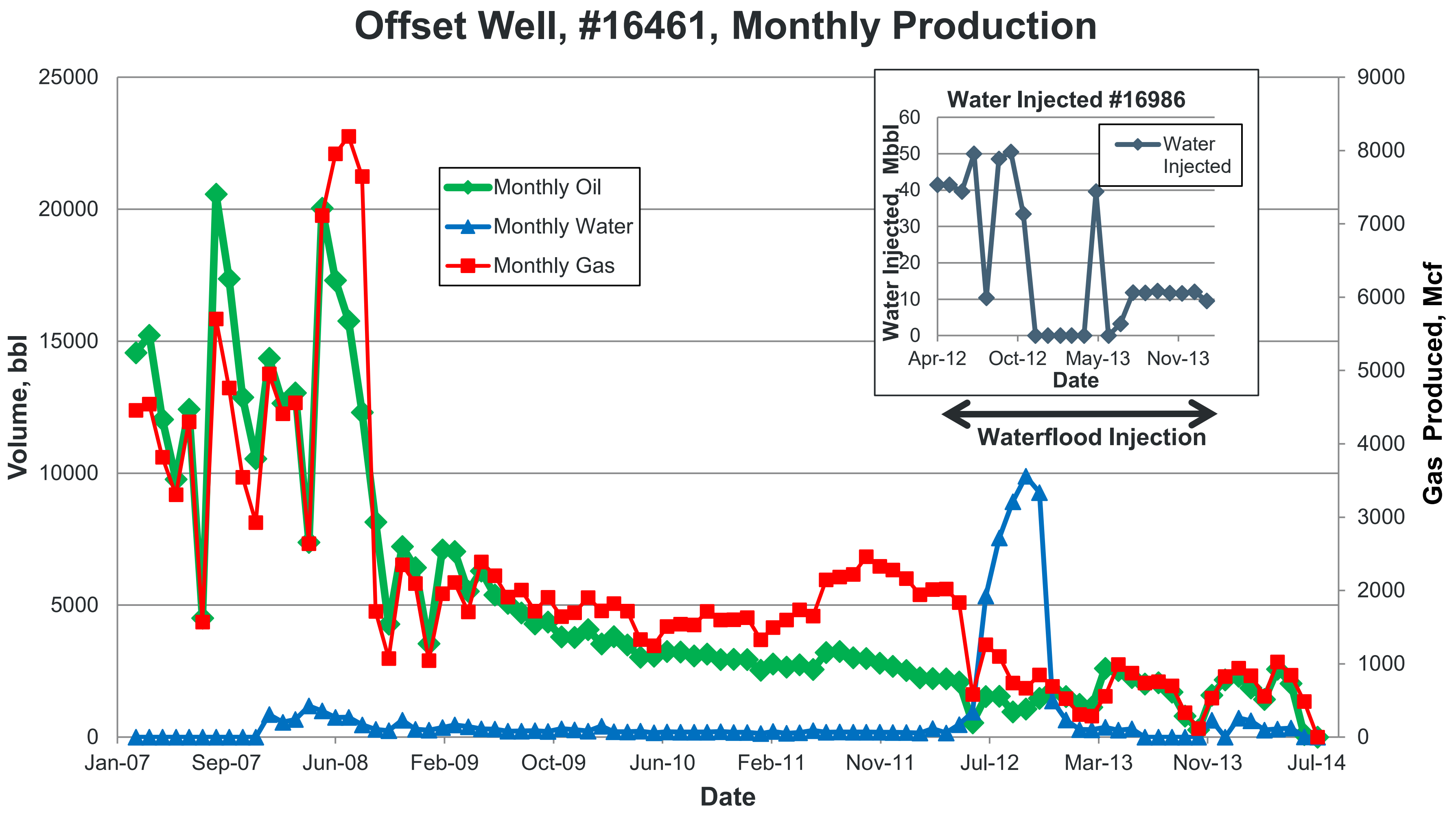
NDIC #16986 – EOG Water and Field Gas Injection Tests



NDIC #16986 – EOG Water and Field Gas Injection Tests: Offset Wells



NDIC #16986 – EOG Waterflood: Production from Offset Well NDIC #16461



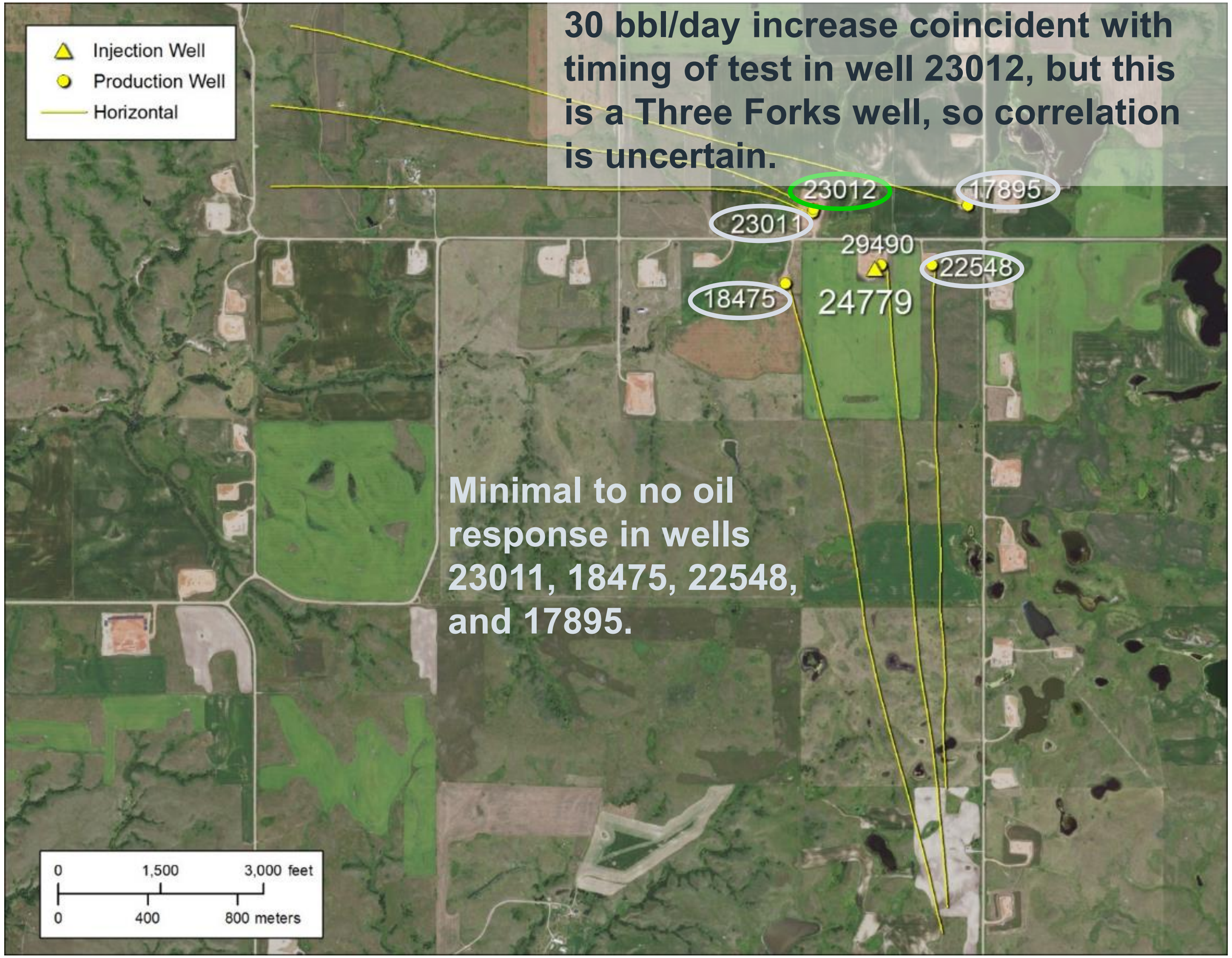
Quotes from the NDIC Files: NDIC #16986 – EOG Water and Field Gas Injection Tests

"Gas injection operations began on the **Parshall 20-03H *(#16986)*** on **June 27, 2014**, which represented the first day where we had consistent gas injection rate. On **July 2, 2014, the Patten 1-02H *(#16461)***, which is 1of 3 wells on the 1280 EOR pilot area, had gas production of 177 MCF and oil production of 33 BBLS. Pre-injection GOR for this well was approximately 400 scf/bbl; therefore, **we would estimate that of the 177 MCF produced on this day, 164 MCF was incremental as a result of gas injection operations**. T**o mitigate the volume of gas channeling through to the Patten 1-02H *(#16461)***, our first operational course of action was to reduce the VFD speed of the pump to help build bottom hole pressure in this well. **On 7 /3 we continued to observe instantaneous gas rates on the Patten 1-02H *(#16461)* and these rates were showing an escalation from the previous day. We decided to stop the pump on the Patten 1-02H *(#16461)* and operate this well on an as needed basis**. We feel this will help mitigate the volume of gas that it being cycled from injection to surface and help build BHP in the injection well."

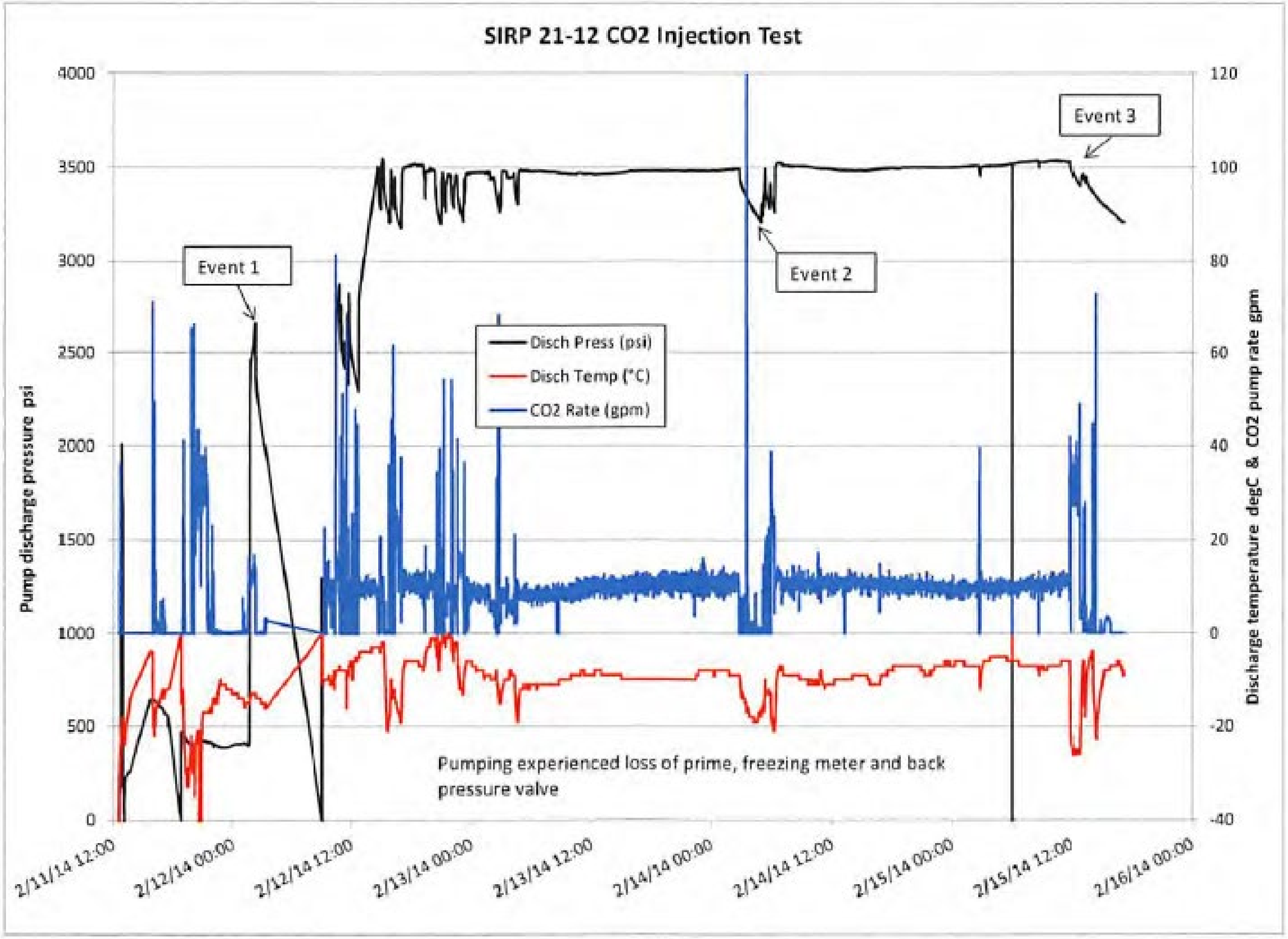
NDIC Well #24779 – Whiting CO_2 Injection Test

- Whiting Oil & Gas Corp.
- ***Vertical well, completed in the Middle Bakken, was not hydraulically fractured.***
- Initially drilled as a stratigraphic test well.
  - Collected 366' of core.
  - No production.
- ***Test designed to see if the unstimulated formation can accept CO_2 gas.***
- Planned for 20-day test, but only injected over 4 days in February 2014.
  - Packers isolated the Middle Bakken zone.
  - Planned injection of 10 MMscf of CO_2.
  - Total injected was 3.4 MMscf.
  - Test ceased after CO_2 breakthrough in offset well.
  - Oil production rate increase of approx. 30 bbl/day observed in a Three Forks offset well. Correlation of oil rate increase to CO_2 injection is questionable due to the small amount of CO_2 injected and lack of frac job on injection well, but nothing in the well file explains the increase.
  - No substantial influence on Bakken offset wells observed in the available data.
- ***"Whiting considered the test to be less than optimal…"***

NDIC Well #24779 – Whiting CO_2 Injection Test

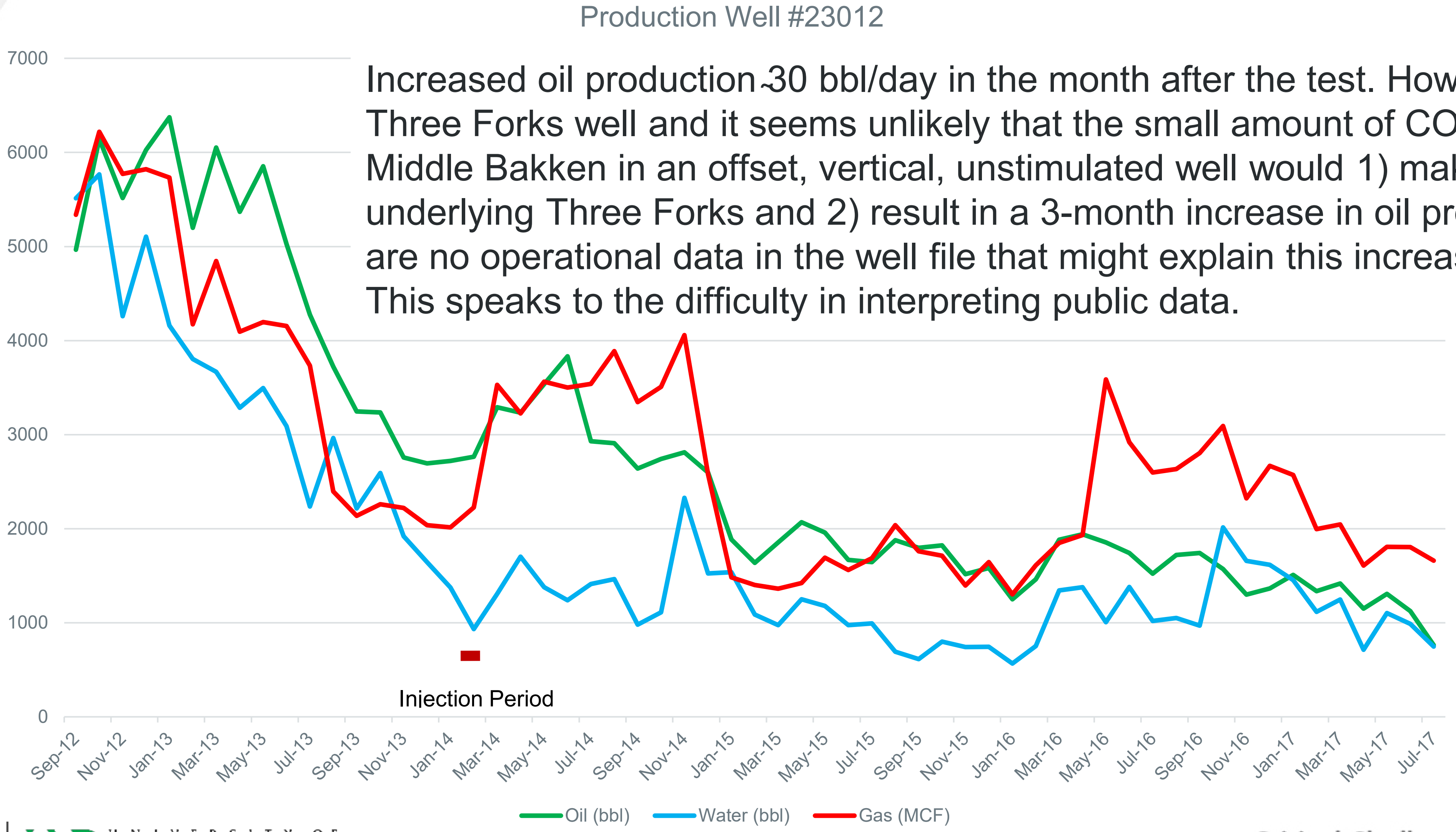


NDIC Well #24779 – Whiting CO_2 Injection Test

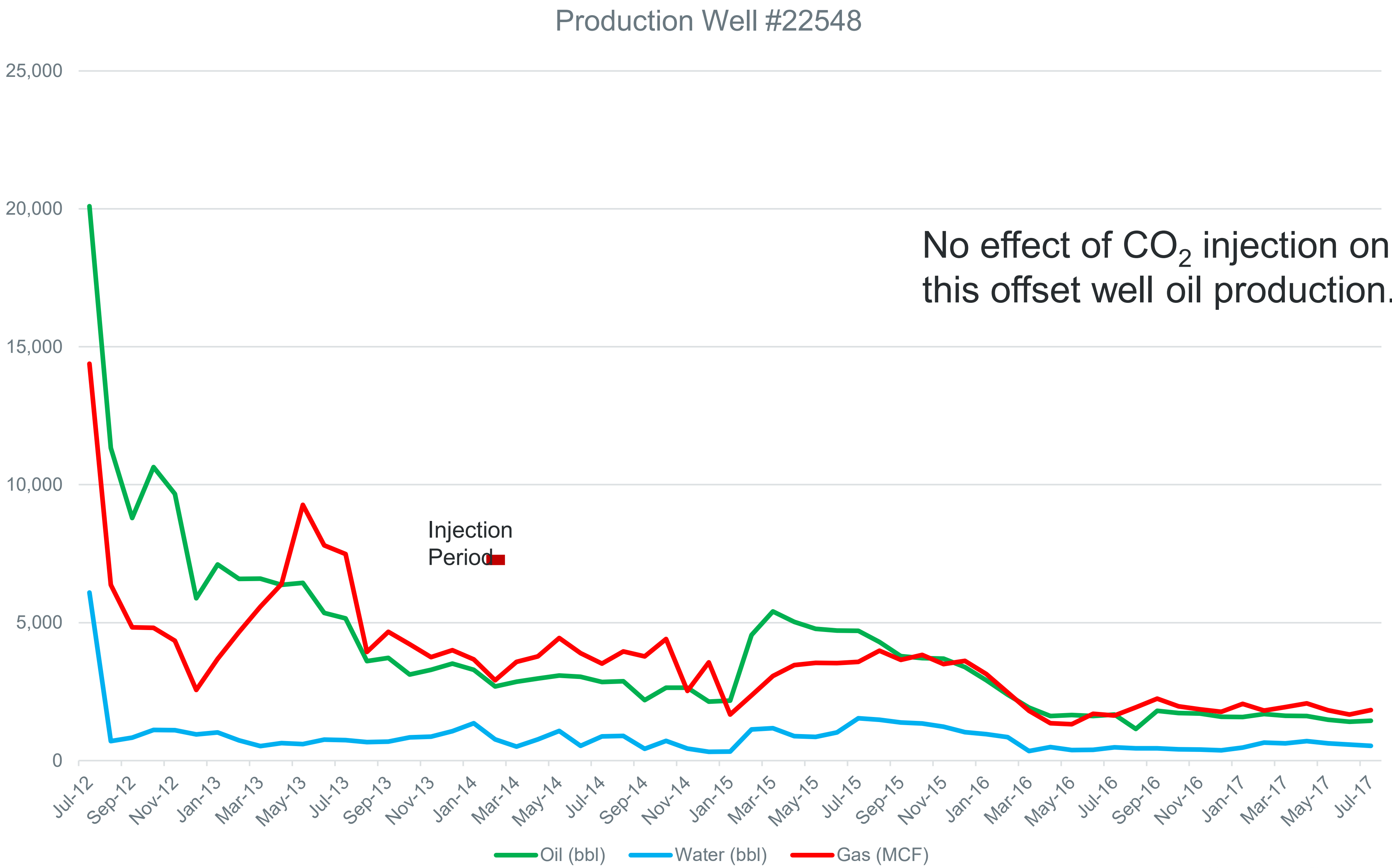


2014 Whiting CO_2 Test – Offset Three Forks Production Well NDIC Well #23012

Increased oil production ~30 bbl/day in the month after the test. However, this is a Three Forks well and it seems unlikely that the small amount of CO_2 injected in the Middle Bakken in an offset, vertical, unstimulated well would 1) make its way to the underlying Three Forks and 2) result in a 3-month increase in oil production. There are no operational data in the well file that might explain this increase in production. This speaks to the difficulty in interpreting public data.

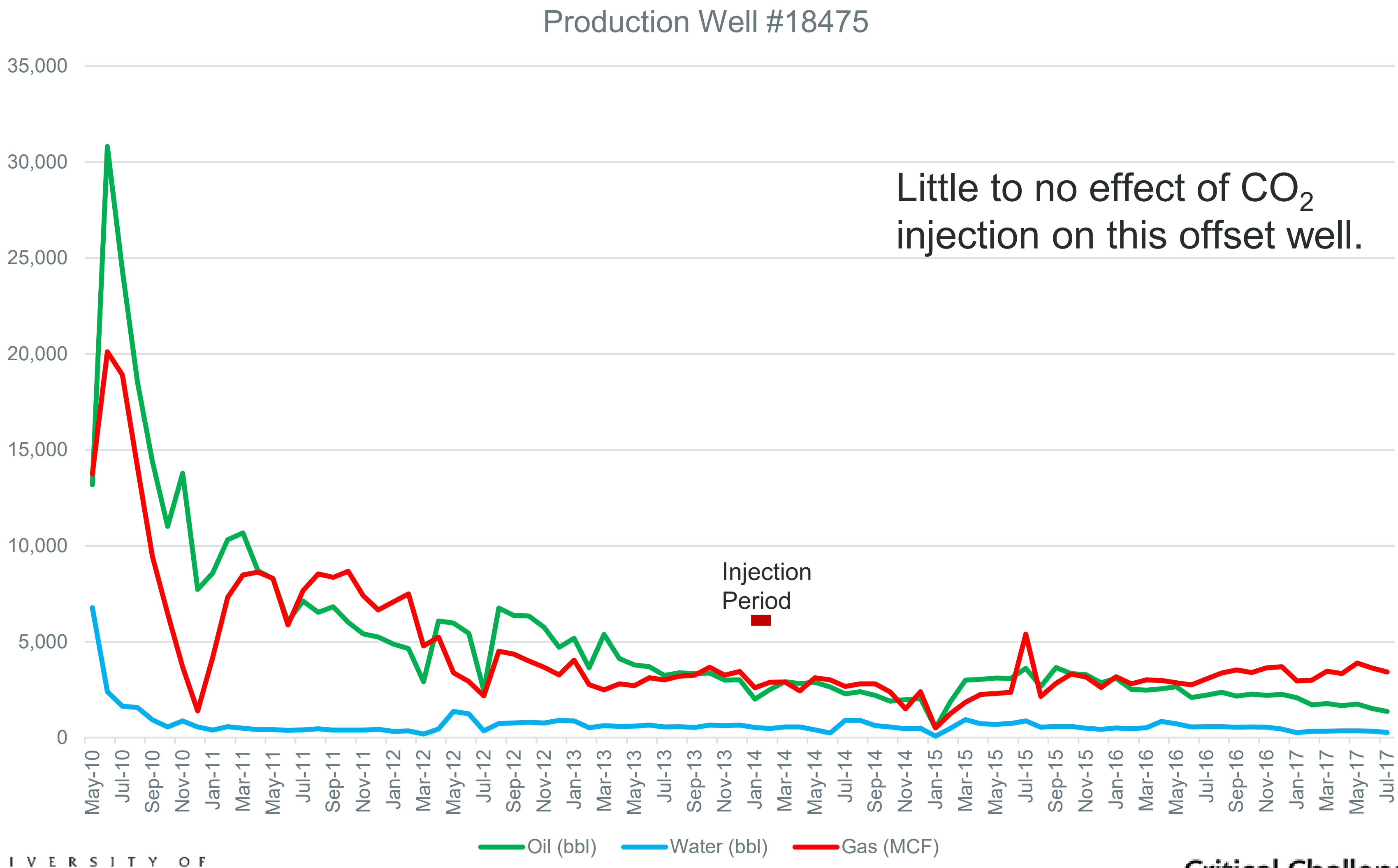


2014 Whiting CO_2 Test – Offset Bakken Production Well NDIC Well #22548



No effect of CO_2 injection on this offset well oil production.

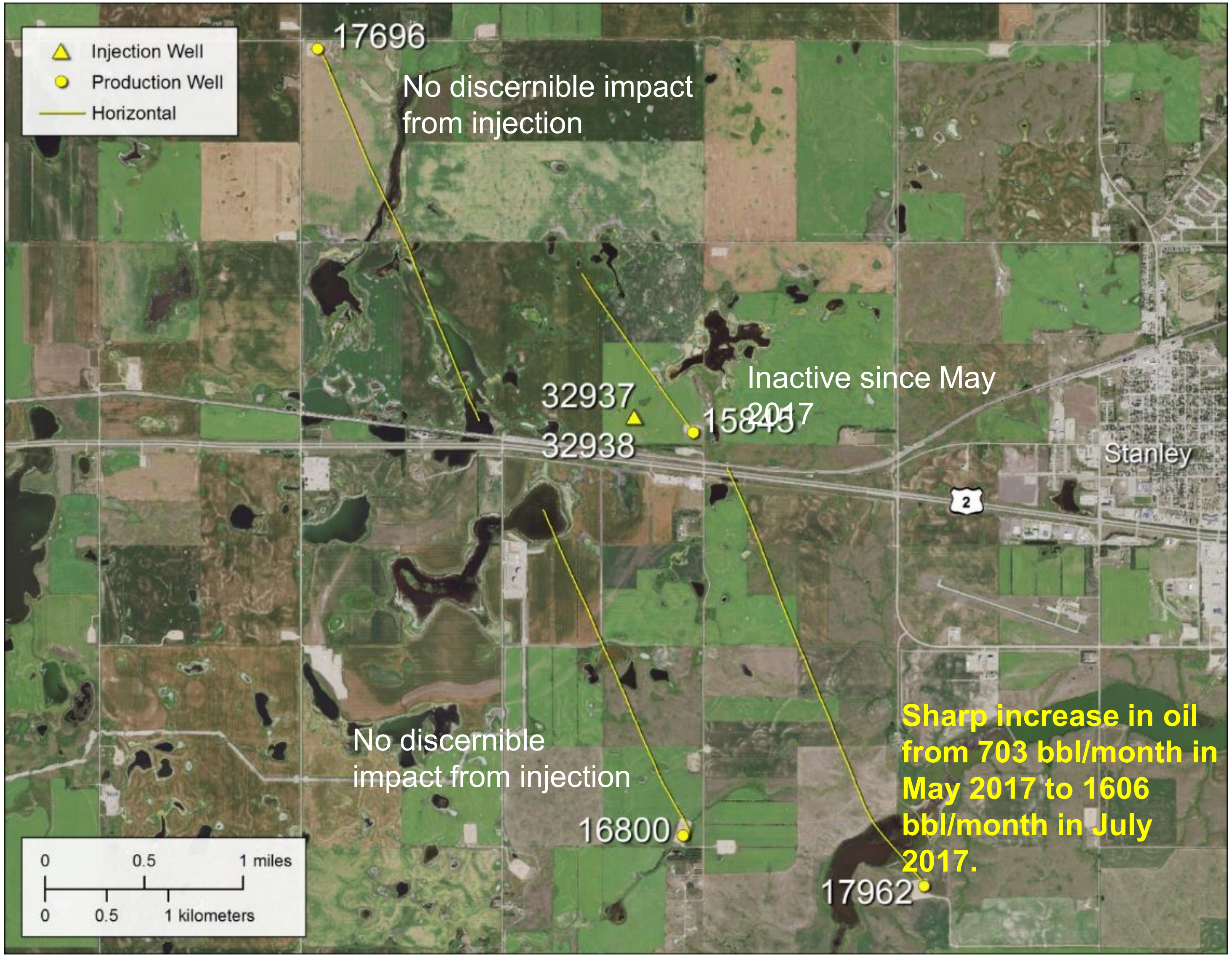
2014 Whiting CO_2 Test – Offset Bakken Production Well NDIC Well #18475



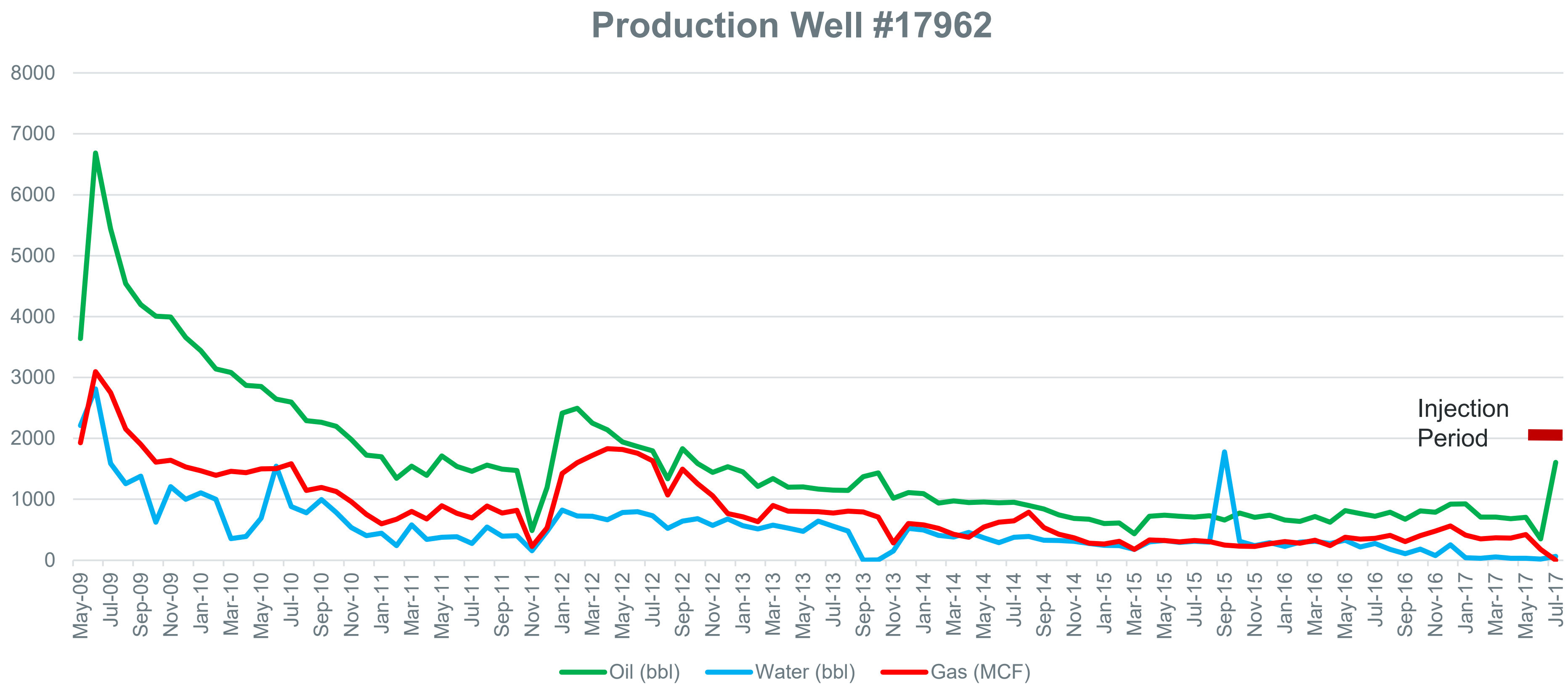
NDIC Well #32937 – Hess Propane Injection Test

- Hess Bakken Investments.
- ***Vertical well drilled and hydraulically fractured in late 2016.***
- No record of production prior to injection.
- Data available for injection conducted during May, June, and July 2017.
- Offset wells monitored for changes in pressure, gas composition, and oil production.
- ***Purpose of the test is to see if injection of propane into a fracked vertical well can result in incremental recovery from nearby producing wells.***
- Plans provided in the well file state the test will be a “cyclic production/injection test” but do not state how many cycles will be conducted or how long the testing will last.
  - Permitted to inject at surface pressures up to 5500 psi.
  - Packers isolated the Middle Bakken zone with 20 ft of perfs.
  - Total injected over 3 months is 9.5 MMscf.
  - Reported plan in the well file calls for 1.5 to 2 years of injection.
  - ***Offset well #17962 shows sharp increase in production 2 months after initiation of injection.***

Hess Propane Injection Test –
NDIC Well #32937 Is the injector, with Four Offset Wells



2017 Hess Propane Test – Offset Production Well NDIC Well #17962



NDIC Well #11413 – XTO CO_2 Injection Test

- XTO Energy operated the test, which was designed jointly by XTO and the EERC.
- Vertical well drilled and completed in the Duperow Formation in 1985.
- Reentered and completed (no stimulation) in the Middle Bakken in March 2017.
- ***Purpose of the test was to determine injectivity of CO_2 into an unstimulated vertical well and examine the ability of CO_2 to permeate matrix and mobilize hydrocarbons through compositional changes in the oil (pretest compared to posttest oil analyses).***
- No Bakken production prior to injection, but oil samples were obtained from swabbing.
- Injection conducted June 24–28, 2017.
- ***There were no completed offset wells in the predicted area of influence of the test, so no offset data were collected.***
  - Maximum BHP was 9480 psi.
  - Packers isolated the Middle Bakken zone with 16 ft of zero-degree perfs.
  - Total injected over 4 days was 1.7 MMscf.
  - After 15-day soak period, the well flowed 9 bbl of oil over 45 minutes, then stopped.
  - Changes in hydrocarbon composition suggest that CO_2 did penetrate matrix and mobilize oil.

NDIC Well #11413 – XTO CO_2 Injection Test Statistics

- Initial BHP ~7500 psi.
- Stable injection rates between 6 and 12 gpm.
- Maximum BHP ~9480 psi.
- BHP during continuous injection ~9400 psi to ~9470 psi.
- Temperature ranged from 251° to 257°F.
- ~ 1.7 million cubic feet of gas injected.

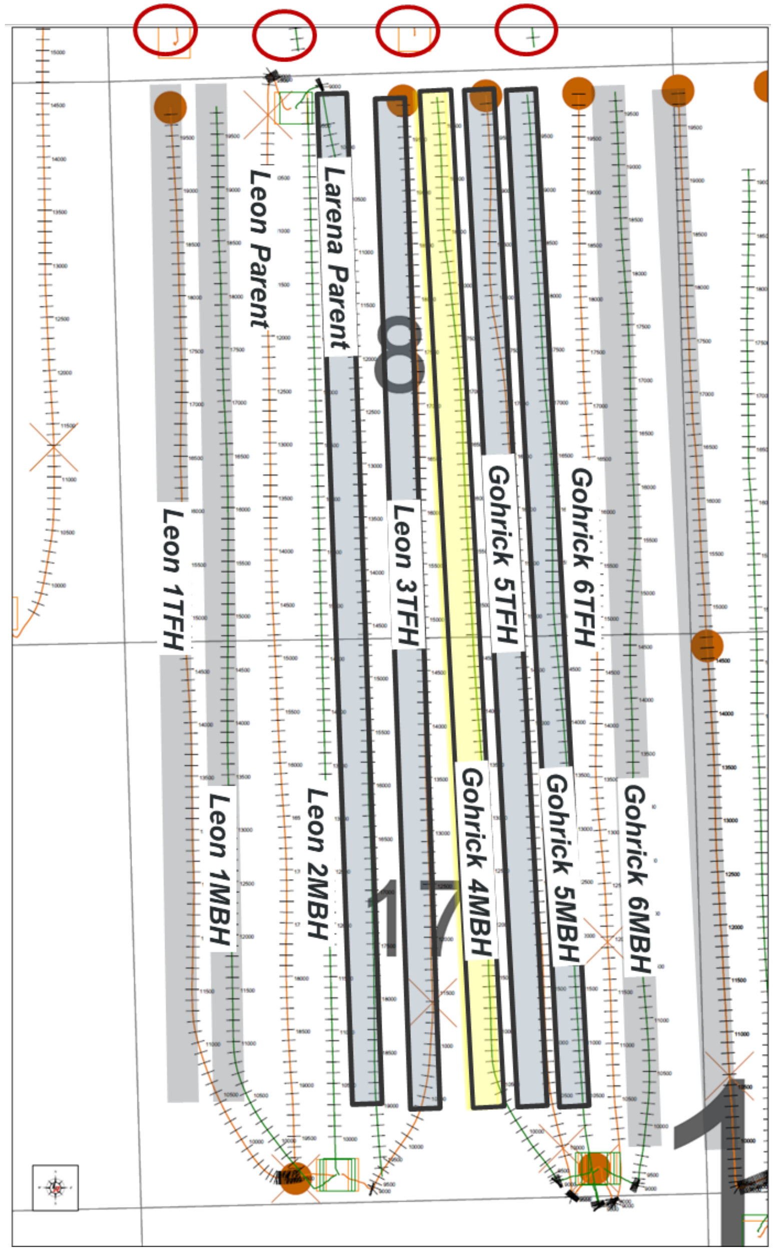
Day	Date	Total Cum [gal]	Cum Mass [tons]	Period
1	24-Jun	2236.7	10.4	Filling
1	24-Jun	50.8	0.2	BHP from 8200 to 8600
1	24-Jun	207	1.0	Cyclic inj- Part 1
2	25-Jun	1160.5	5.4	Cyclic inj- Part 1
2	25-Jun	904.5	4.2	Cyclic inj- Part 2
2	26-Jun	1009.4	4.7	Cyclic inj- Part 2
3	26-Jun	1752.6	8.1	Cont. Inj
4	27-Jun	11131	51.8	Cont. Inj
5	28-Jun	2806.2	13.0	Cont. Inj
		TOTAL	**98.9 tons of CO_2 injected**	

Burning Tree-State 36-2-H (Elm Coulee, Montana) – Continental/Enerplus/XTO CO_2 Injection Test

- Enerplus operated the HnP test, which was designed jointly by Enerplus, Continental Resources, and XTO Energy.
- ***Single-stage horizontal well drilled and completed in the Middle Bakken in 2000.***
- Injection conducted over a 45-day period in January and February 2009, with a 64-day soak period.
  - Maximum bottomhole injection pressure was 1848 psi.
  - Total injected over 45 days was 45 MMscf.
  - Average daily injection rate was approx. 1000 Mcf/day, but injection was intermittent over the 45 days, ranging from 0 to 3000 Mcf/day.
- Daily oil, water, and gas production data and occasional compositional data were collected from May 3 to October 19, 2009, at which point the test monitoring period was considered to be complete.
- No incremental oil production was observed in the test well during the monitoring period.
- ***There is no record of offset wells being systematically monitored as part of this test. Publicly available offset well production data are inconclusive with respect to potential effects of the injection.***
- ***Available data did not allow for determining a mass balance of CO_2 injected vs. CO_2 produced.***

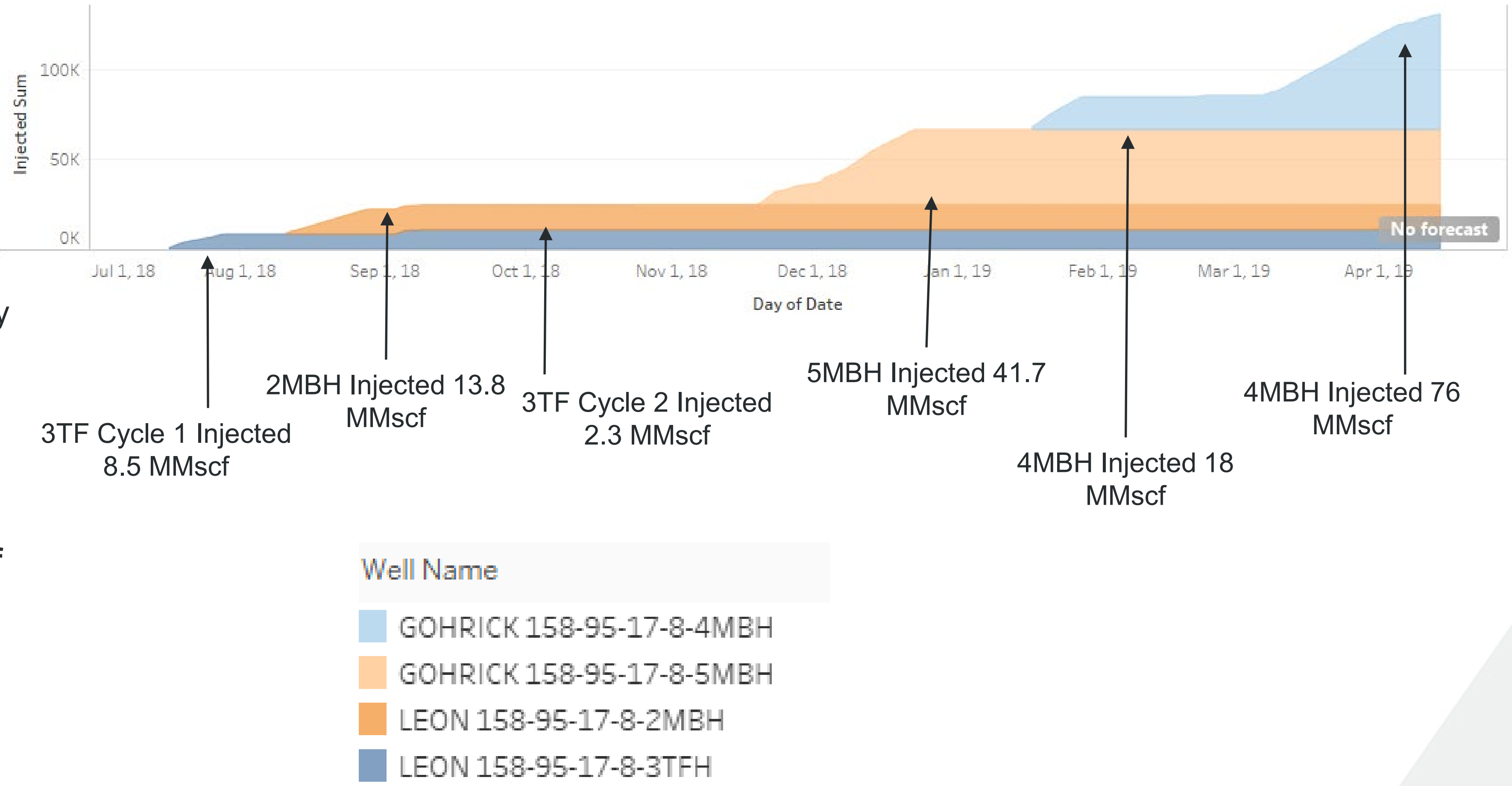
Liberty's Stomping Horse EOR Pilot

- In 2018-2019 Liberty Resources (LR) conducted a cyclic multiwell huff 'n puff at their Stomping Horse complex, a complex of multiple LR operated DSUs, gas plant, and infrastructure located north of Tioga, North Dakota.
- DOE National Energy Technology Lab and the NDIC Oil & Gas Research Program (through BPOP) provided funding to the EERC to conduct laboratory and modeling efforts in support of the Liberty EOR pilot tests.

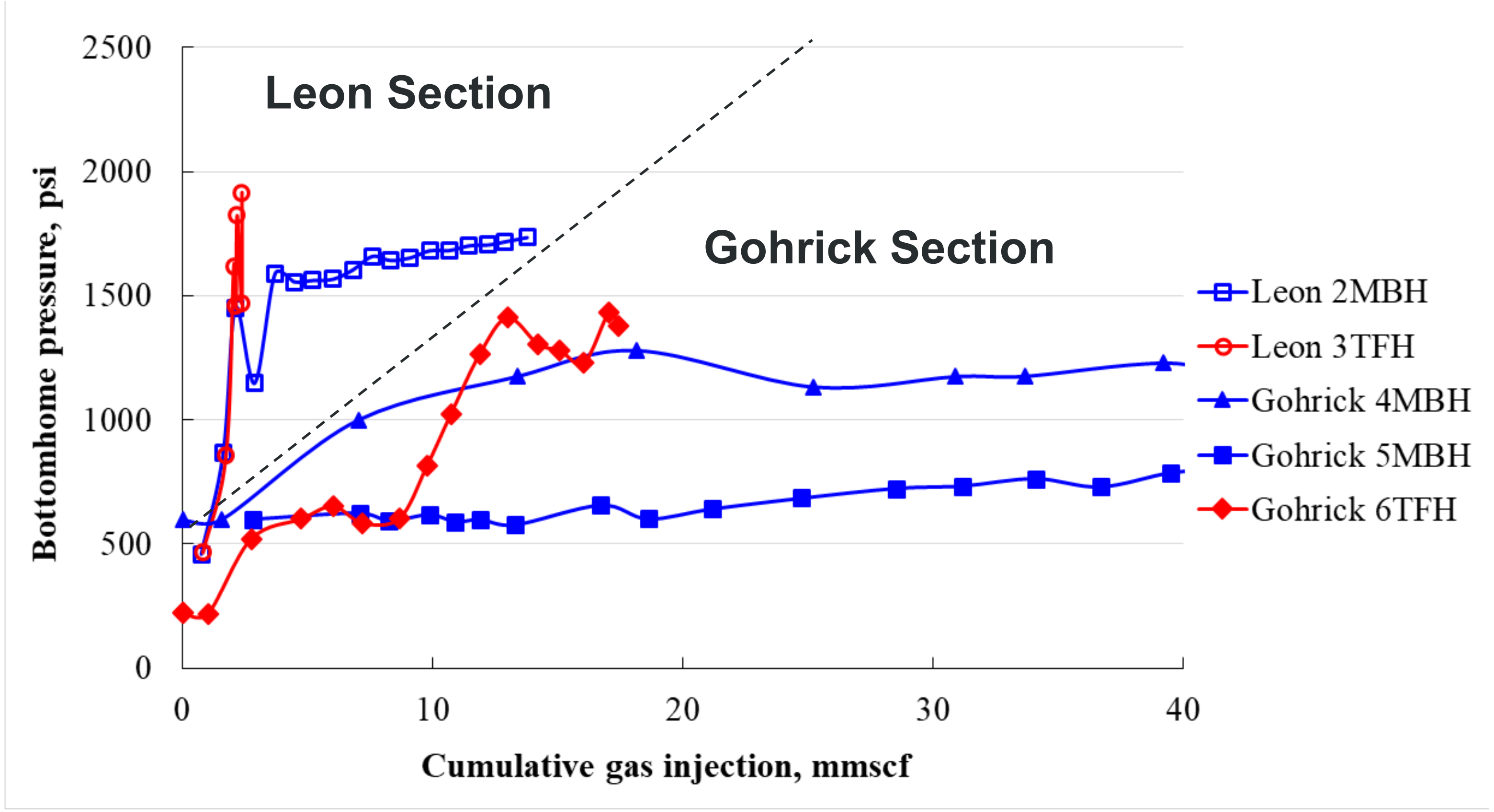


LR Stomping Horse Pilot Test

- Pilot goals were to determine injectivity, build pressure, and manage conformance using multiwell cyclic HnP approach using rich gas as the working fluid.
- Rich gas composition was approximately 70% methane, 20% ethane, 10% propane.
- The permit allowed for only the use of associated gas produced from the Leon-Gohrick DSU.
- Initial small-scale tests in Leon wells largely to investigate injectivity.
- Larger-scale injection in Gohrick wells to investigate pressure buildup and conformance.
- **By end of May 2019, total of ~160 MMscf gas was injected in five wells during six different injection periods.**
- **More details are available in BPOP final report on the Stomping Horse pilot released to members in 2020.**



Reservoir Response to Gas Injection in the LR Wells



- Leon wells were easier to pressure up than the Gohrick wells.
- Three Forks wells were easier to pressure up than the Middle Bakken wells.
- Two stages of pressure lifting: fracture filling and produced volume filling with different slopes.

Lessons From the Stomping Horse Pilot EOR Tests

- Injectivity is readily established and has not been a constraint on operations.

- Reservoir surveillance demonstrates the injected gas can be controlled and has been contained within the DSU.

- Pressure buildup can be achieved.

- Adequate supply of working fluid is essential to build and maintain reservoir.

Take-Home Message from Past Bakken Pilot EOR Tests

- Most previous tests had flaws in design, execution, monitoring, reporting, or some combination thereof.
- While each previous test offers some valuable learnings, none of them individually or as a whole should be considered to be representative of future Bakken EOR operations.
- Design and execution of next generation of Bakken pilots are building off of lessons learned from these early pilots.
- This next phase of Bakken pilots will be key to unlock and demonstrate commercial viability of Bakken EOR.

CHAPTER 2:

Bakken EOR Potential, Deployment Scenarios, and Knowledge Gaps

Bakken CO_2 EOR Potential

- Why CO_2 instead of rich lease gas?
- The Eagle Ford experience
- Forecasting potential impact of CO_2 EOR on Bakken production
- Knowledge gaps

Why CO_2 Instead of Rich Gas for Bakken EOR?

- Rich gas EOR deployment may be imminent in the Bakken to reduce flaring; however, rich gas supply has limitations. Assuming 2.6 Bcfd of rich gas supply (typical daily associated gas production in North Dakota in 2019) and 30 MMcfpd/DSU for EOR (as used in EOG Eagle Ford EOR), then there is only enough rich gas to supply EOR to 86 DSUs (out of >1000 Bakken DSUs in North Dakota). Capture of CO_2 from North Dakota power plants can fill the gap.

- CO_2 capture is being driven by environmental, social, and governance (ESG) directives, and financial incentives for carbon capture and storage may result in better availability and more stable economics for large-scale deployment of Bakken EOR.

- CO_2 needs to be tested on a larger scale because of the logistics of gathering and handling it, both from sourcing and transportation aspects but also within oilfield EOR operations. Migration of CO_2 outside of a DSU would impact offset production, requiring additional diligence in operations and EOR design potentially favoring larger EOR units.

Considerations for Use of CO_2 vs. Rich Gas for Pilot- and Field/Basin-Scale Bakken EOR Deployment

Item	Lease gas (CGEOR)	CO_2 (CCO_2 EOR)
Injectant cost (pilot scale)	Market value of gas plus cost of local gathering lines.	Some sort of temporary on-site generation or long-distance transport – likely to be expensive.
Injectant availability (pilot scale)	Gas easily available.	Some sort of on-site generation – likely too small and short-lived to justify pipeline from known source; other forms of sourcing and transportation are challenged.
Injectant cost (field/basin scale)	Market value of gas plus cost of local gathering lines.	Still unclear but likely to be less expensive option at scale as more regional CO_2 supply becomes available.
Injectant availability (field/ basin scale)	Would require extensive gathering system to aggregate significant volume.	Likelihood of much higher volumes becoming available in time.
Interaction with oil	Some studies show higher recoveries likely; still unknown.	Some studies show lower recoveries likely; still unknown.
Gas Processing	Simple recompression.	Could be simple recompression; possibly some separation to enhance or maintain mobilization of oil.
Potential for natural gas liquids (NGL) spiking	Likely to be similar; further study needed.	
Effect on wellbores	Minimal generally but would expose it to higher pressures than during primary depletion.	Introducing corrosive CO_2 will degrade casing and require mitigation measures to protect tubing, packer, and wellhead.
Effect on surface facilities	Higher pressures will be encountered.	High pressures encountered but not as high as with lease gas; corrosion mitigation required throughout production system.
End of life	Pressure depletion after final cycle could recover some gas.	Additional volumes could be sequestered after end of last cycle.

EOG Eagle Ford IOR Ratios Independently Verified

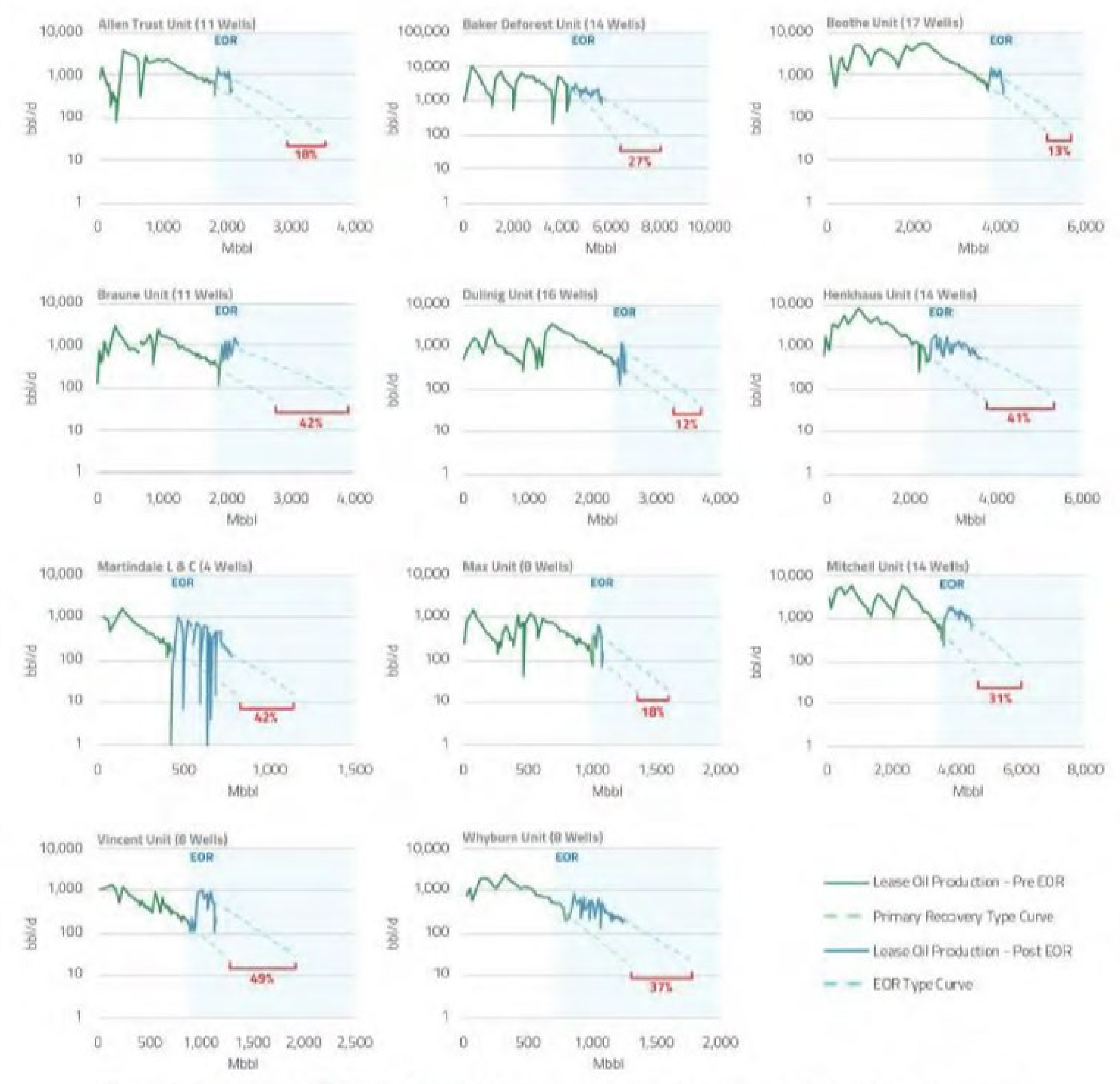


Figure 4. Analysis of EOR uplift for all 11 leases in the play. Data sourced from RS Energy Group.

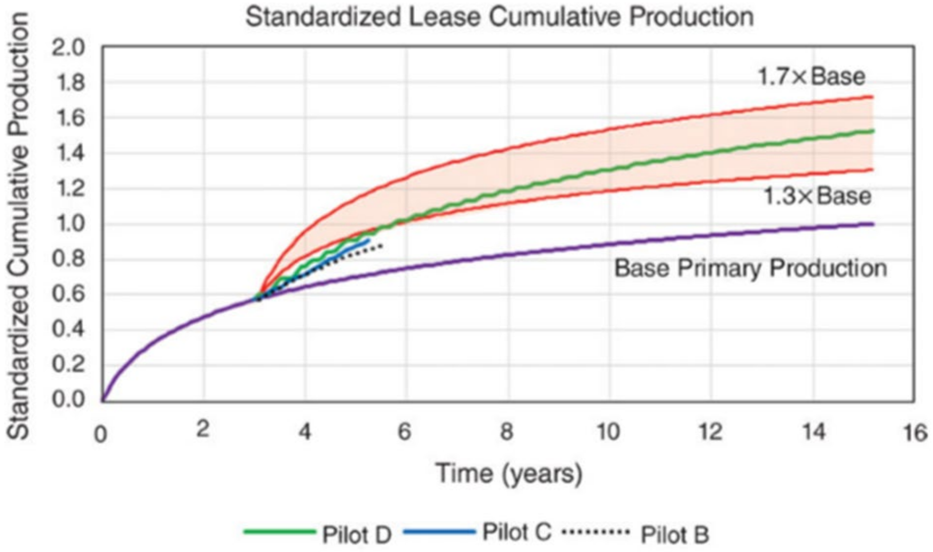
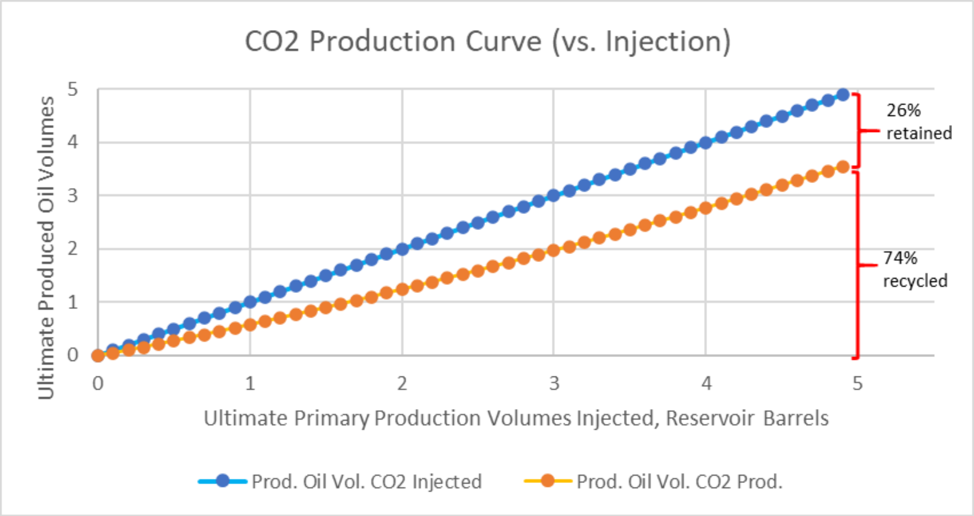


Fig. 1—Comparison of measured production from three leases with reported estimated recovery.

After response data became available, EOG's projections were verified by Whitson Consultants (left) and by Todd Hoffman (above)

Forecasting Methodology: General Assumptions

- CO_2 retention estimated to be ~25% based on internal discussions, and conventional EOR experience.
- CO_2 recycle modeled using quadratic equation; retained CO_2 volume is difference between produced and injected volumes.
- Retention assumed to decrease over time as it does in conventional EOR.
- CO_2 injected and CO_2 produced were made a function of the reservoir volume occupied by ultimate primary oil production (proxy for hydrocarbon pore volume, HCPV).
- Resulting relationship is for 26% retention at 5 produced oil volumes, as shown.
- Higher CO_2 retention results in less CO_2 being available to begin EOR in future wells/DSUs; therefore, it retards overall production response given a fixed supply of CO_2.

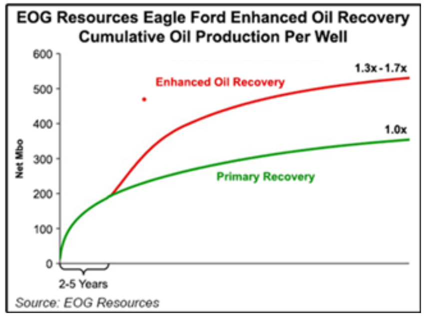


Forecasting Methodology: General Assumptions

- IOR (improved oil recovery) ratio is ratio of total oil recovery after cyclic CO_2 EOR to total oil recovery from primary depletion alone.
- An IOR ratio of 1.3 is used for the base case forecast.
- Full cycles assumed to have length of 24 weeks.
  - 4–7 weeks injecting
  - 1 week soak
  - 16–19 weeks on production
- Injection rates average 14 MMcf of CO_2 per day with sufficient compression to generate high pressures.
- CO_2 retention estimated to be 25%.

Forecasting Methodology: Support for IOR Ratio

- EOG (2016) predicted range of 1.3–1.7 (Eagle Ford, lease gas)



- Hoffman (2018) predicted range of 1.3–1.5 (Eagle Ford, lease gas)

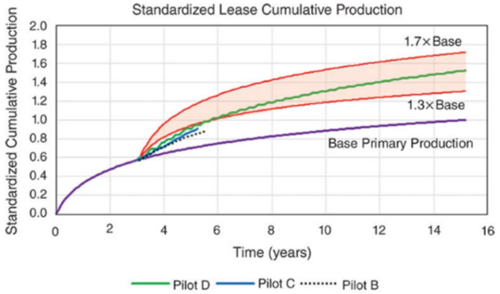


Fig. 1—Comparison of measured production from three leases with reported estimated recovery.

- Lashgari et al (2019) predicted range of 1.30–1.47 (numerical modeling, CO_2)

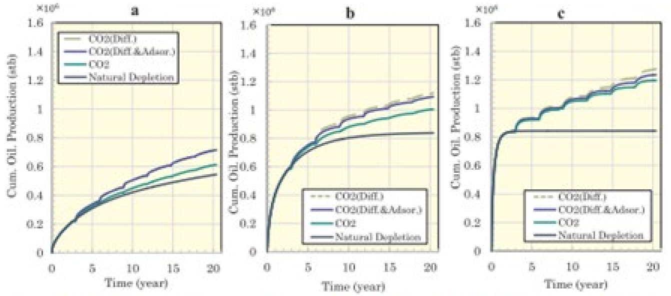
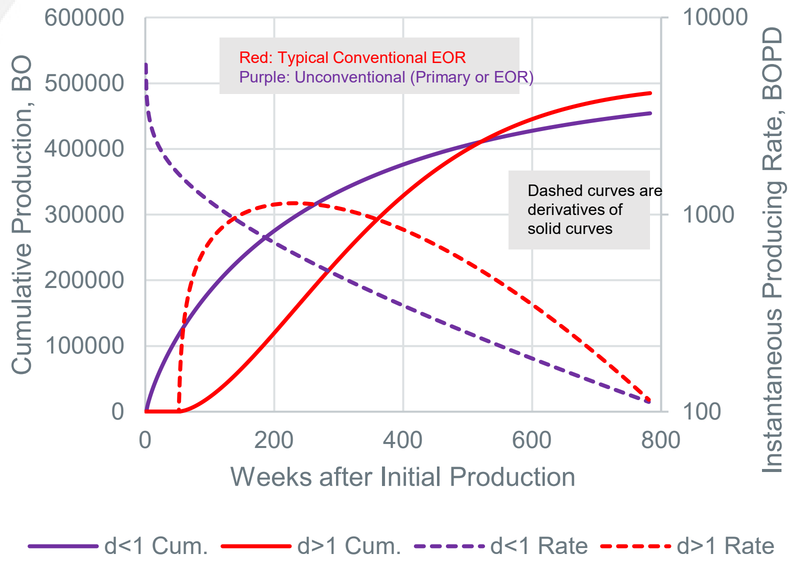


Fig. 9. Comparison of oil recovery factor between different miscible gas injection scenarios at (a) 1 μD, (b) 10 μD, and (c) 100 μD matrix permeability cases during 20 years of injection and production using the Huff-n-Puff process.

- Bakken EOR pilots less conclusive:
  - Operating pressures too low
  - Small volumes injected
  - No injection over multiple cycles
  - Data hard to obtain and/or analyze
  - More pilot data needed

Forecasting Methodology: “Banker’s Curve”



This curve is widely used to mathematically model production response from conventional EOR projects, in which case dimensionless volumes of HCPVs injected and produced are plotted.

To use this curve to model unconventional EOR, we are not using the true dimensionless curve, but instead use the shape to represent production versus time – applying the same equation to get the desired curve shape.

- **y = a*(1 - exp(-(b(x-c))^d))**

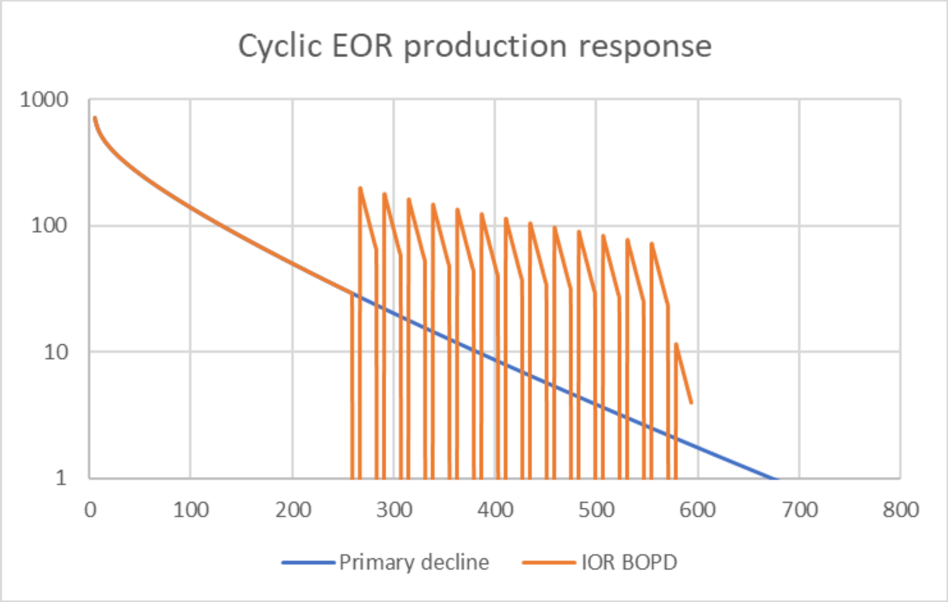
where:

- a = the horizontal asymptote representing the maximum theoretical oil recovery.
- b = shape coefficient that controls initial upward slope.
- c = initial time lag/x-intercept of curve (first response).
- d = shape coefficient controlling character of curve where value greater than one produces an s-shaped curve as observed in conventional EOR projects, a value of one indicates an immediate exponential decline, and a value less than one produces an early-peak, immediately hyperbolic decline as observed in an unconventional well.
- x = independent variable (time function).
- y = oil recovery function, in this case cumulative barrels.

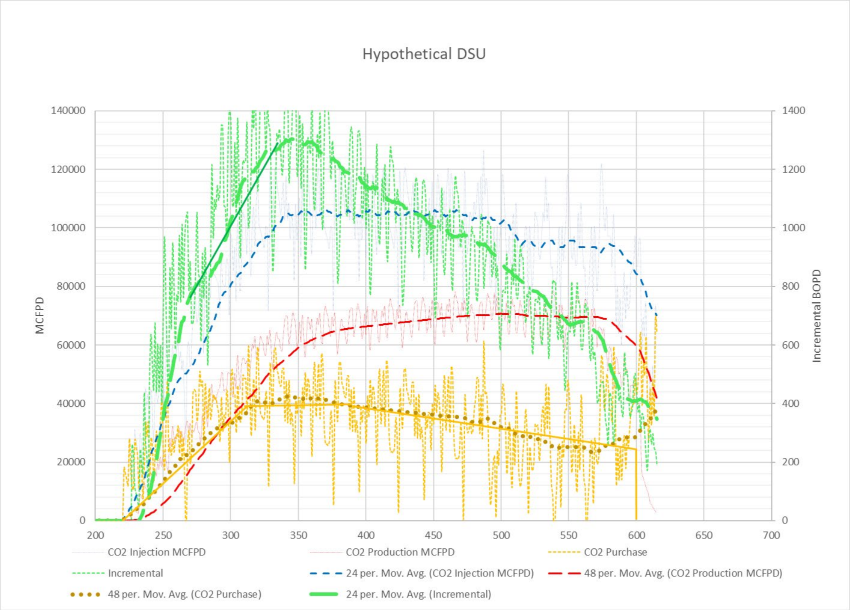
Forecasting Methodology: Single-Well Profile

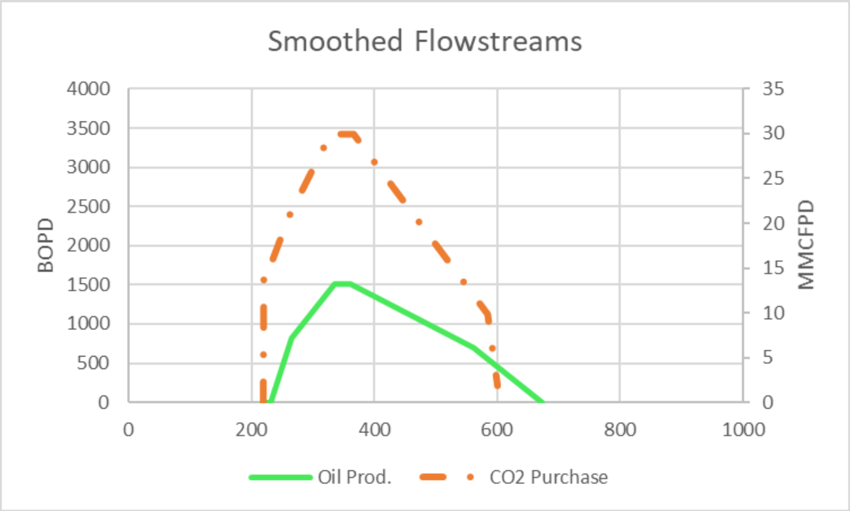
- A group of 30 single-well production response curves was generated using the banker's curve and assumptions for cycle length, injection rate, and production decline rate within cycles.

- These curves were scheduled based on utilization of a specific constant CO_2 volume and available recycle gas, and their results were aggregated to generate a production response for the DSU.



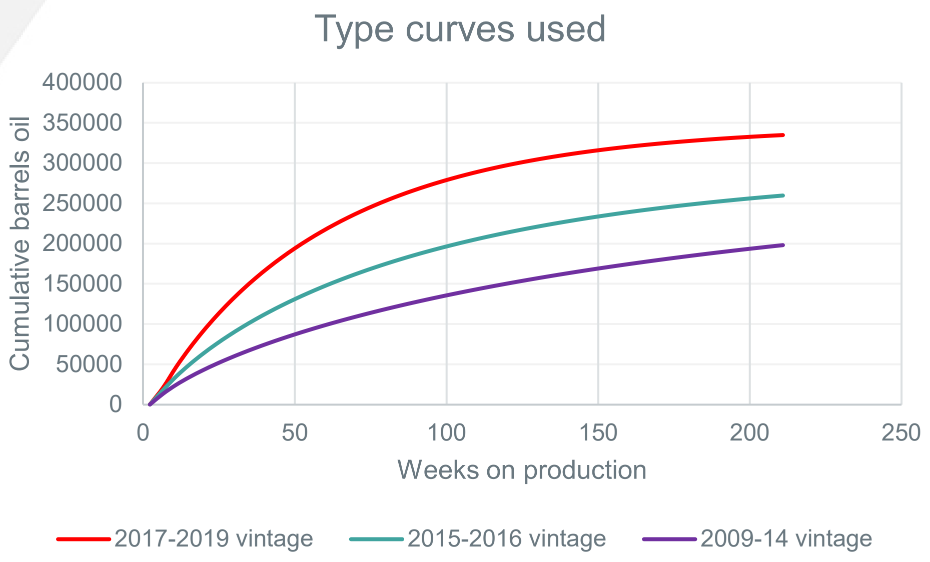
Scale-Up Methodology and Assumptions



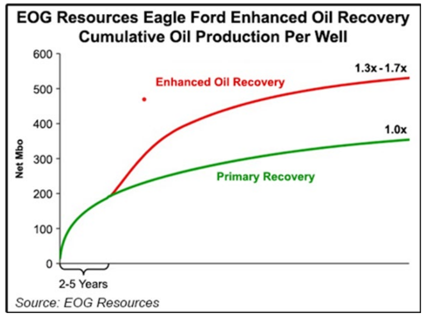


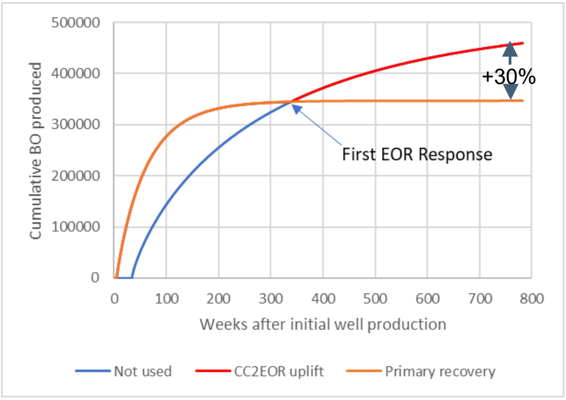
- A single case was built for a 30-well "hypothetical DSU" or comparable grouping of 30 wells that are in sufficient proximity to each other as to be able to share production-gathering facilities and the same CO_2 supply.
- Output had large amount of scatter, not representative of an actual operation with fixed incoming CO_2 volumes and more stable oil production.
- Smoothed curves for CO_2 purchases and oil production were created using moving averages of the forecast output to create a generic curve that would be used to represent the appropriate flowstreams to be aggregated. with start-ups occurring at various points in time.

Scale-Up Methodology and Assumptions



- “Banker’s curve” equations were derived for three vintages of wells with similar production trends, and a representative mix of these vintages was used to project continued primary production.



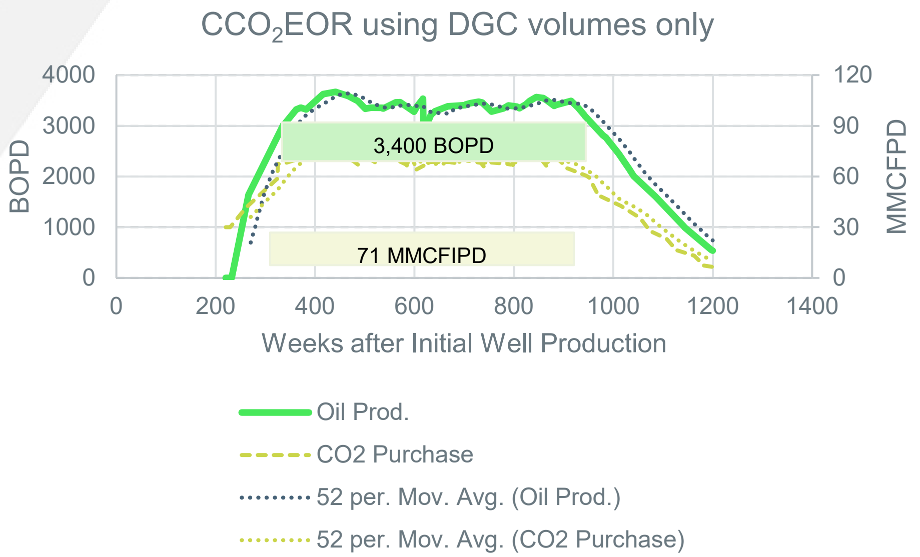


- Banker’s curve equation was also derived for oil rate versus time functions for both primary production and CCO_2 EOR.

Scale-Up Methodology and Assumptions

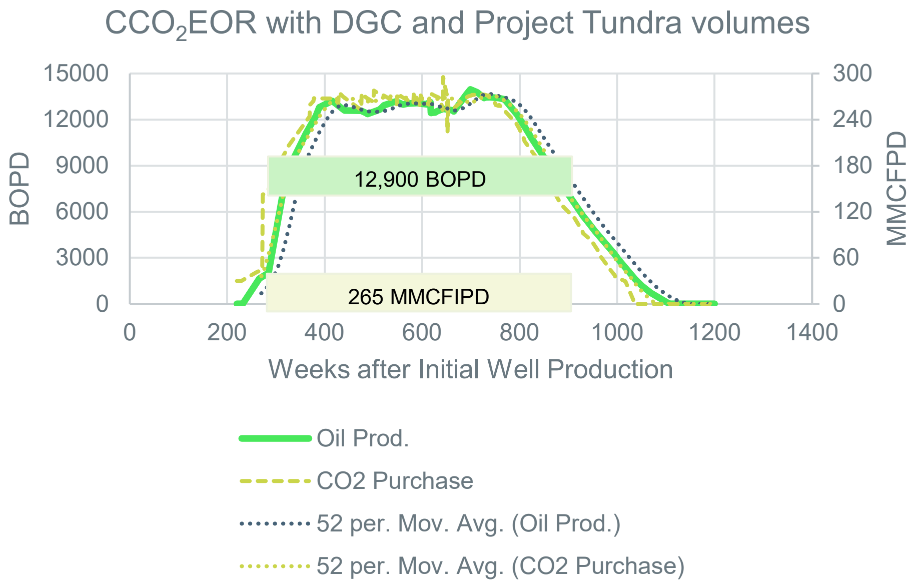
- A scheduling tool was built in Excel to schedule multiple “hypothetical DSU” cases coming online at various times.
- Projects were scheduled in a manner that would evenflow CO_2 injection (as much as practical) to match need to sequester CO_2 dependably and consistently.
- Oil production from all cases was aggregated to determine expected oil production rate “plateau.”

Low Case and Medium Case Supply Scenarios



Low Case Scenario Description

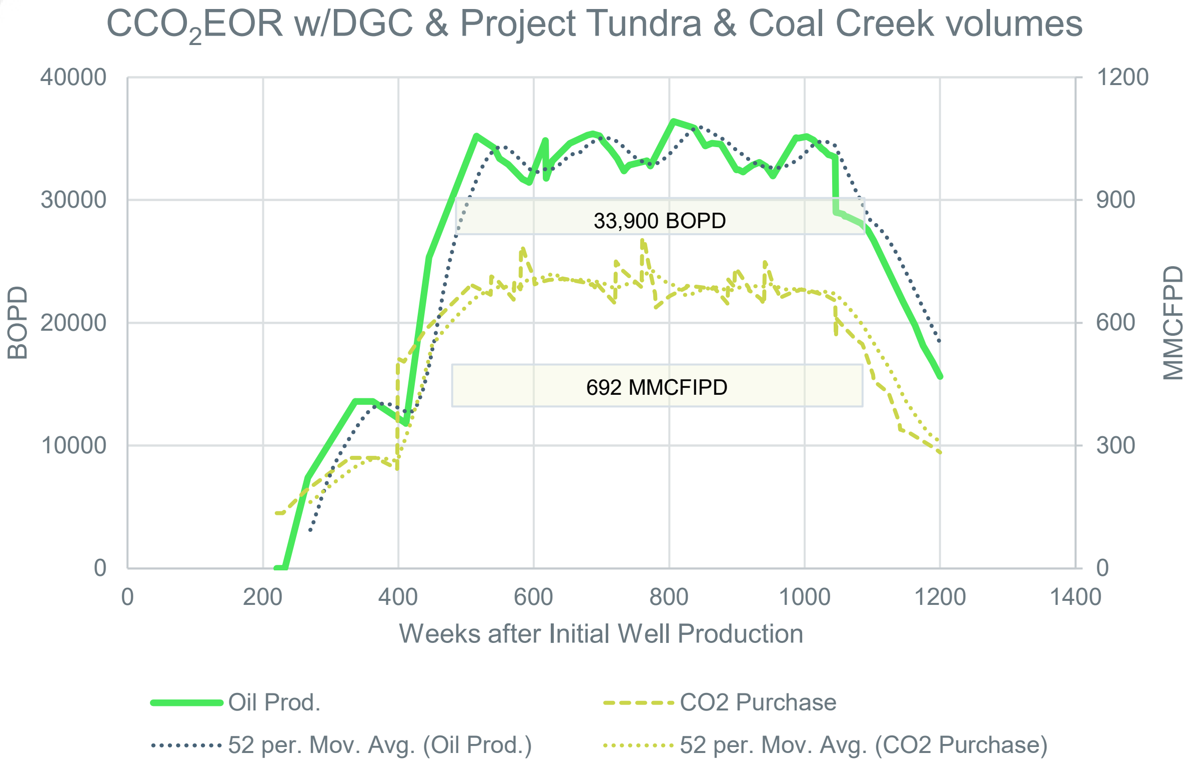
- 71 MMcfpd (1.3 million tpy) from Dakota Gasification Company (DGC) is used in this study as the low case.
- Scenario assumes CO_2 supply is available 2021.
- 3400 BOPD oil production plateau.
- Seven DSUs developed.



Medium Case Scenario Description

- 71 MMcfpd (1.3 million tpy) from DGC assumed to be available 2021.
- 194 MMcfpd (~4 million tpy) additional CO_2 assumed to be available in 2025 from Project Tundra.
- Total available CO_2 volume = 265 MMcfpd.
- 12,900 BOPD oil production plateau.
- 24 DSUs developed.

High Supply Scenario: DGC, Project Tundra, Coal Creek



- 265 MMcfpd (5.3 MMtpy) as described in prior scenario:
  - 71 MMcfpd (1.3 million tpy) from DGCV assumed to be available 2021.
  - 194 MMcfpd (~4 million tpy) additional CO_2 assumed to be available in 2025 from Project Tundra.
- Additional 427 MMcfpd (8 MMtpy) available from Coal Creek assumed to be available in 2027.
- Total available CO_2 volume 692 MMcfpd (13.3 MMtpy).
- 34,000 BOPD oil production plateau.
- 70 DSUs developed (2100 wells).

For each of these cases, the following rules of thumb can be used for quick reference:

1 MMcfpd of CO_2 sequestered will generate ~50 BOPD of sustained oil production, OR

1 tonne per day of CO_2 sequestered will generate ~1 BOPD of sustained oil production.

Sensitivities

To CO_2 supply volume

CO_2 Supply Scenario	CO_2 Supply Rate MMcfpd	BOPD Rate	No. wells to reach plateau	No. wells for 10-year plateau
Low	71	3,400	75	210
Medium	265	12,900	285	720
High	692	33,900	810	2100

To CO_2 retention

CO_2 Retention Scenario	CO_2 Supply Rate MMcfpd	BOPD Rate
0.21	692	46,300
0.26 (Base)	692	33,900
0.31	692	29,100

To IOR ratio (no change in shape of recovery curve)

IOR Ratio	CO_2 Supply Rate MMcfpd	BOPD Rate
0.4	692	45,200
0.3 (Base)	692	33,900
0.2	692	22,600

IOR ratio for Bakken EOR is not well understood. Well-designed and executed field pilots are necessary to improve our understanding of IOR ratio.

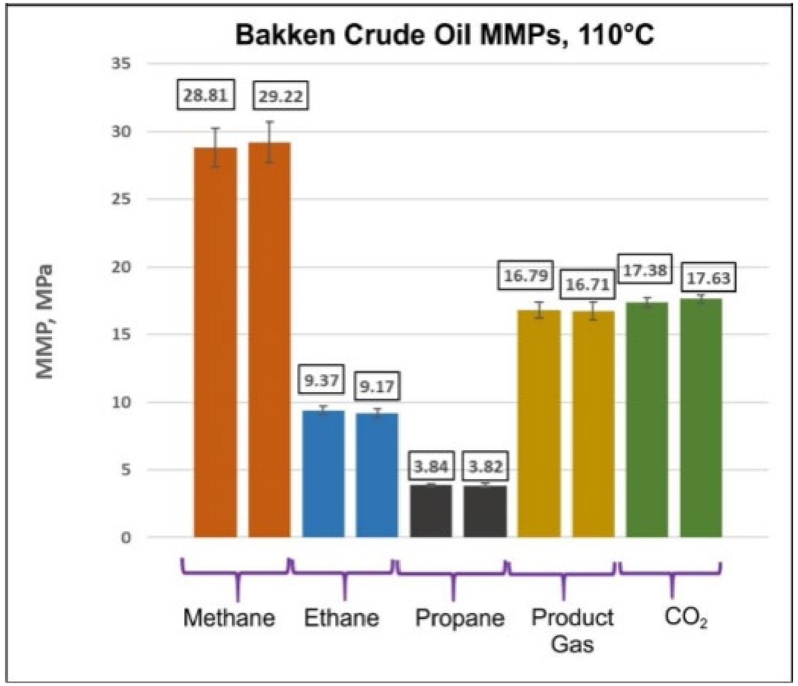
Knowledge Gaps

- Performance related to obtainable operating pressures
  - Effect on fluid interactions
  - Containment
  - Costs: equipment ratings and capacities
- Conformance
- Interwell communication
- Completion technology
- Gas handling and processing
- Land issues
- Advanced/Innovative development

Hypothetical relationships between these issues – addressing one item influences others.

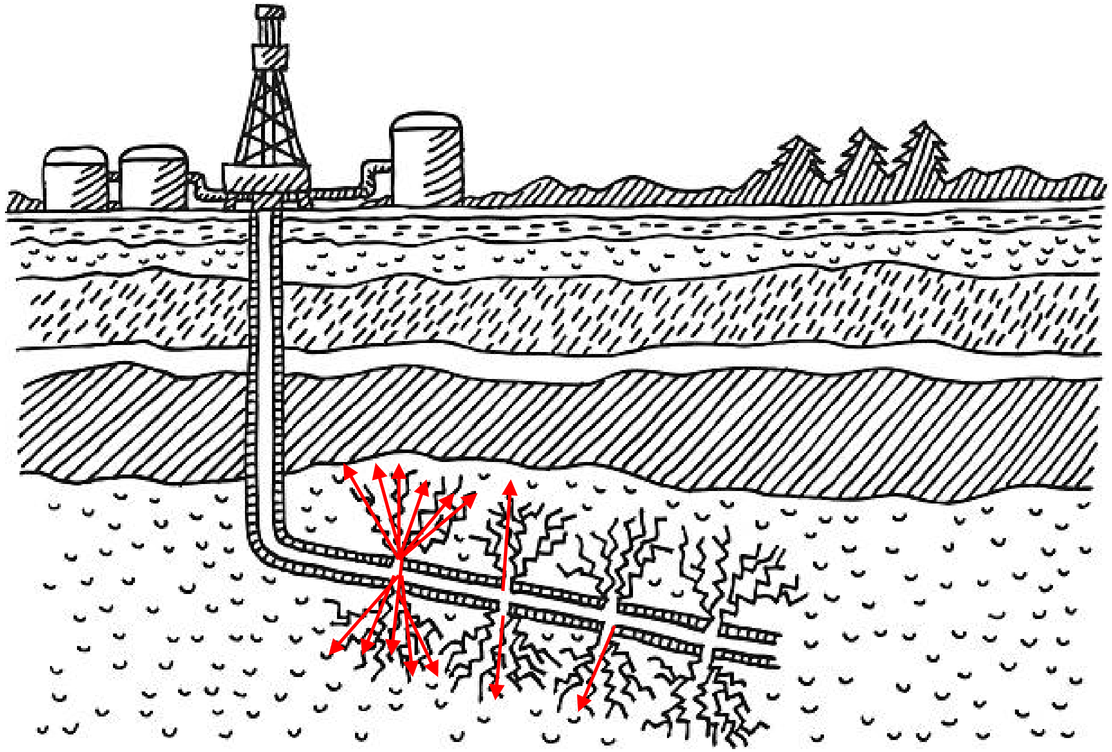
On: \ Influence of:	1) Operating Pressure	2) Conformance	3) Well-to-well communication	4) Mixing behavior	5) Completion Technology	6) Gas processing	7) Land Issues	8) Reliability as carbon sink	9) Economics
1) Operating Pressure		3	4	1	0	3	0	3	0
2) Conformance	3		4	1	3	0	0	0	1
3) Well-to-well communication	3	3		0	4	0	0	1	0
4) Mixing behavior	5	0	1		0	2	0	2	0
5) Completion Technology	1	1	1	0		0	0	1	2
6) Gas processing	3	1	0	3	1		2	1	2
7) Land Issues	0	2	4	0	0	1		3	2
8) Reliability as carbon sink	2	1	3	1	1	0	1		3
9) Economics	4	4	4	5	3	3	2	2	

The Importance of Higher Pressure



- Benefits of higher pressure:
  - More CO_2 going into solution in hydrocarbon phase – higher recovery.
  - Whitson et al. has theorized that first-contact miscibility needs to be attained, not multicontact as graphed here.
  - Greater lateral conformance.
- Determining highest pressure needed to optimize recovery is important as field facility costs increase with pressure.
- Possible drawback: increased likelihood of lateral and vertical containment issues.
- Bakken CO_2 pilots have not yet tested the concept at sufficiently high pressures.

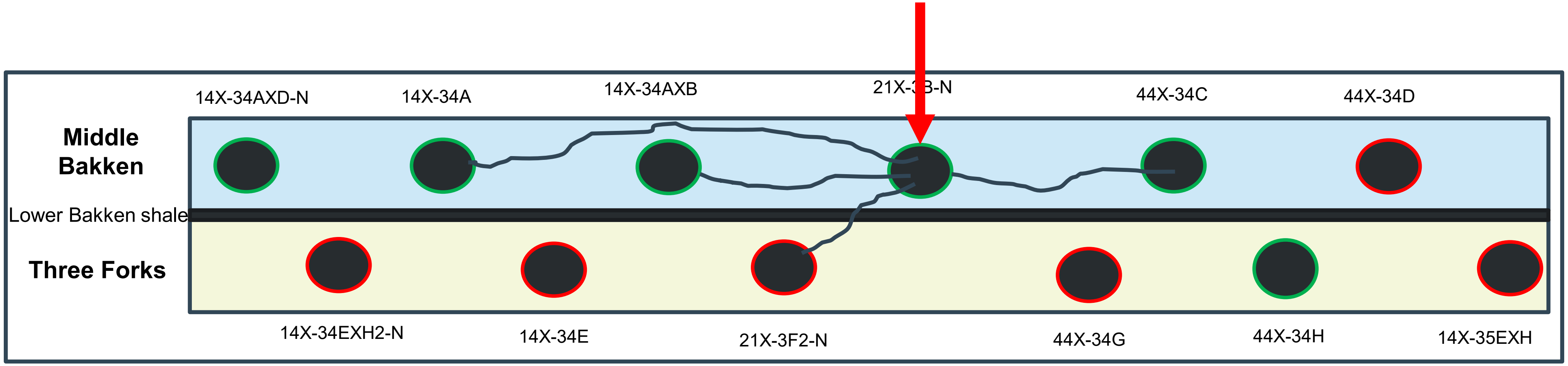
Conformance



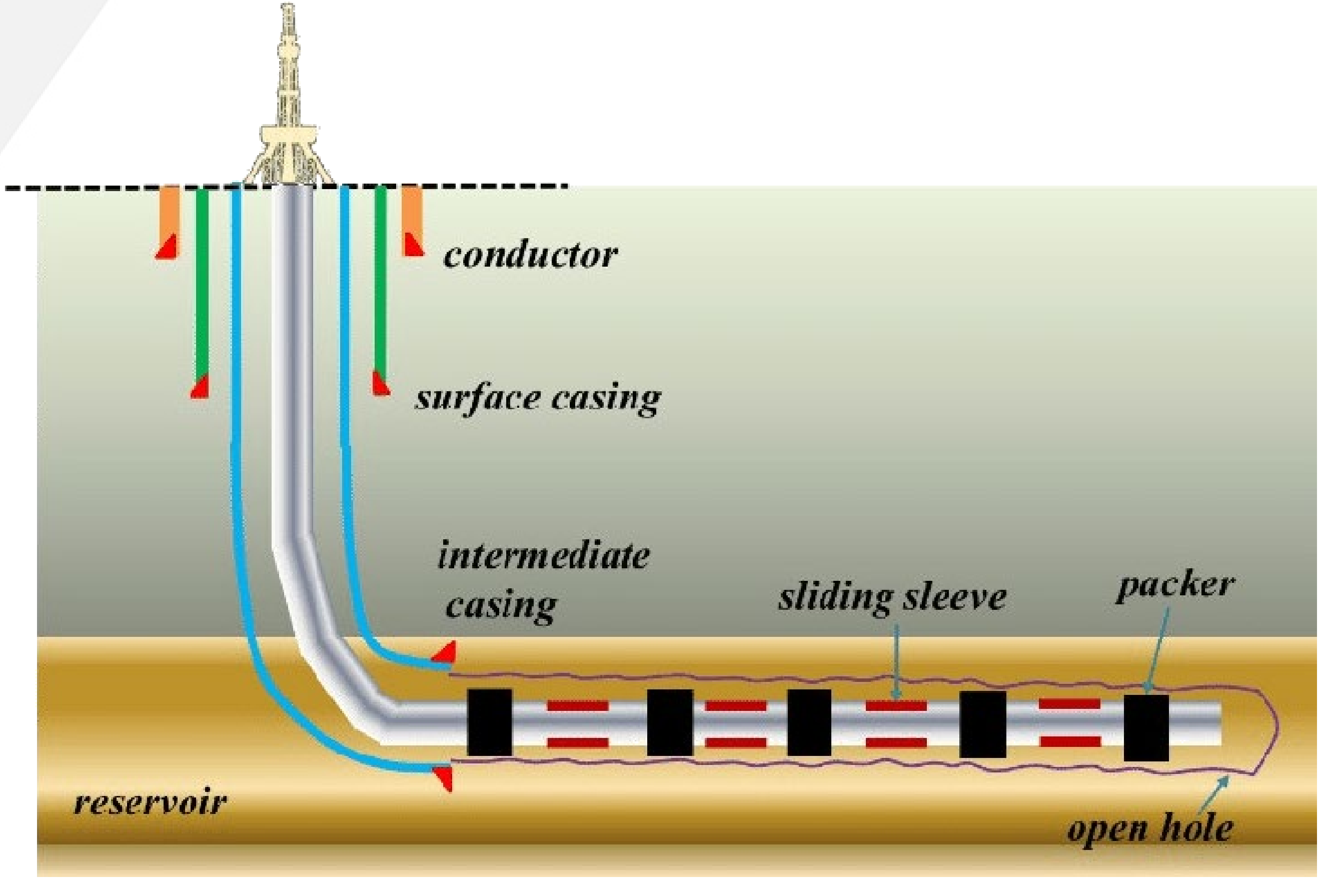
- Suppose nearly all the CO_2 exits the first set of perfs…
  - During the pilot phase, we need to know this for evaluation purposes.
  - During further development, it becomes no less important.
- Higher pressure will increase likelihood of adequate injected volumes reaching the toe.
- How will we measure this?
  - Logging
  - Installed fiber-optic cable
  - Microseismic
- What countermeasures will be deployed?
  - Mechanical isolation (permanent or for well treatments)
  - Polymers

Interwell Communication

- Communication has been commonly observed in cyclic EOR pilots.
- What is the best operational strategy?
  - Shutting in affected wells
  - Continuing to produce
  - Controlling by addressing individual fractures
  - Injecting into affected wells or injecting into large groups of wells
- How are these options influenced by the reservoir pressure target and vice-versa?
- How does this strategy affect facility design and management?
- Will it make sense for some wells to become permanent injectors or producers after a few cycles?



Completion Technology



- Some kind of conformance technique(s) will have to be utilized to improve overall conformance and address interwell communication.
  - Free pipe in lateral with ports/mandrels
  - Packers and sliding sleeves (as shown)
  - Plugging agents injected into selected perfs using temporary isolation
  - Plugging agents bullheaded with no isolation
- What will be the service life of permanent installations? How will they hold up in a CO_2-rich corrosive environment?
- What contingencies will there be for equipment failures?
- Will the desire to “keep it simple” call for fewer, longer isolation intervals?
- Refracking – Should wells (especially older-vintage wells with fewer stages) be refracked prior to cyclic EOR (possibly with CO_2 as frac fluid)?

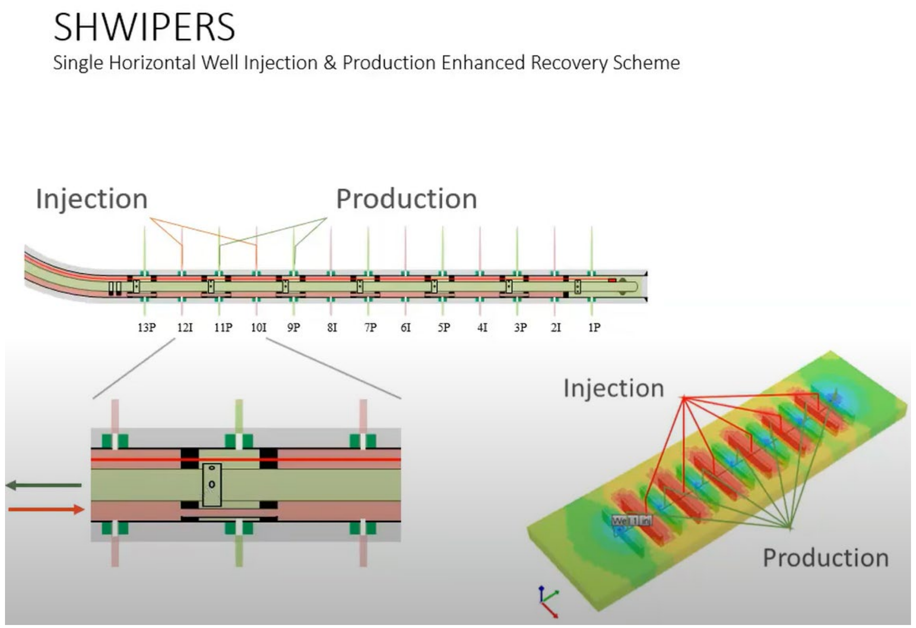
Gas Handling and Processing

- Cyclic CO_2 EOR presents gas-handling challenges beyond those imposed by cyclic rich gas EOR.
  - Rich gas can be injected in another well or sold into a pipeline.
  - But CO_2 cannot be sold; if it is reinjected, it will have been contaminated with hydrocarbon gases from the reservoir.
  - How will this contamination increase over time and affect interaction with the crude (for which minimum miscibility pressure [MMP] is a proxy) during successive cycles?
  - Can this gas be enriched with imported mix of C_2–C_4 components to lower MMP?
  - Is methane removal from gas stream feasible?
    - ♦ Potential cryogenic process or other method to remove methane and nitrogen from produced gas stream and cool remaining stream prior to compression (potential horsepower savings).
    - ♦ Methane is detrimental to EOR process whereas ethane-plus fraction is beneficial (but how much when combined with CO_2?).
    - ♦ North Dakota gas mix could use more dry methane.

Future Advanced/Innovative Development Scenarios

Cyclic processes will still recover only a small fraction of the oil. Well-to-well displacement processes hold hope to greatly increase that recovery. The cyclic EOR process is a necessary first step to learn about recovery processes in the shale but will generate learnings that will allow for innovation. These scenarios could be a follow-up to cyclic EOR or could eventually be installed as grassroots projects made possible by these learnings.

“We usually find **oil** in a **new place** with **old** ideas. Sometimes, we find **oil** in an **old place** with a **new** idea, but we seldom find much **oil** in an **old place** with an **old** idea.” ---- **Parke Dickey**



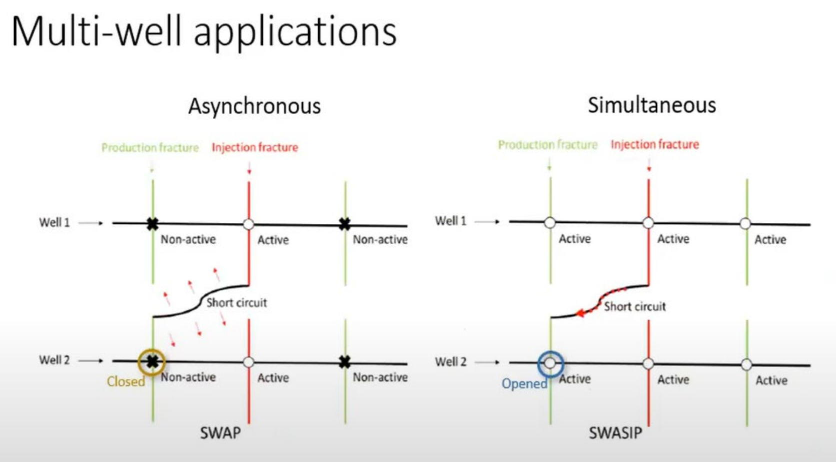


Figure 25: Comparison of SWAP and SWASIP operation with multiple wells. For SWAP, the production fracture is non-active in the injection mode, so the injection fluid in the short circuit between wells is pushed into the reservoir when the pressure in the short circuit is higher than the reservoir. For SWASIP, all injection and production fractures are active in both wells, so the short circuit between wells acts like a fluid conduit which attracts the injection fluid from well 1 to production fractures in well 2 without displacement of oil in the reservoir.

Source: Warren McPhail, through Whitson with consent of Devon Energy.

CHAPTER 3:
Modeling Investigation of Gas Breakthrough and Conformance Control for Bakken EOR Multiwell Huff ‘n’ Puff Applications - Summary of Case Study Results and Findings

Modeling Investigation of Gas Breakthrough and Conformance Control

Problem Description:

- Breakthrough time and conformance have been identified as plausible causes contributing to a lack of incremental oil production from the first generation of the Bakken injection pilot tests.

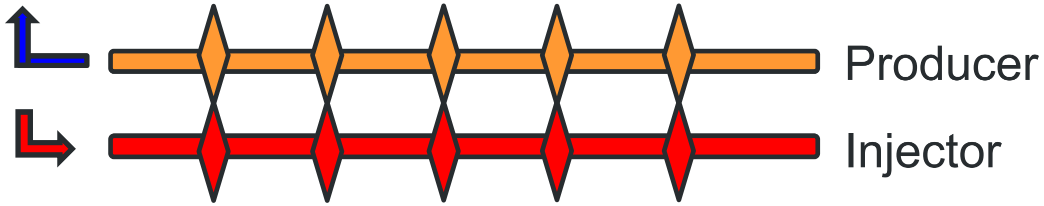
Tasks:

- Use modeling to analyze premature gas breakthrough in the previous gas injection enhanced oil recovery (EOR) pilots in the Bakken.
- Develop a multiple-well, multiple-fracture model to simulate well interference in the gas injection EOR process.
- Diagnose premature gas breakthrough in the gas injection EOR process.
- Apply conformance treatments specifically designed for hydraulically fractured wells.

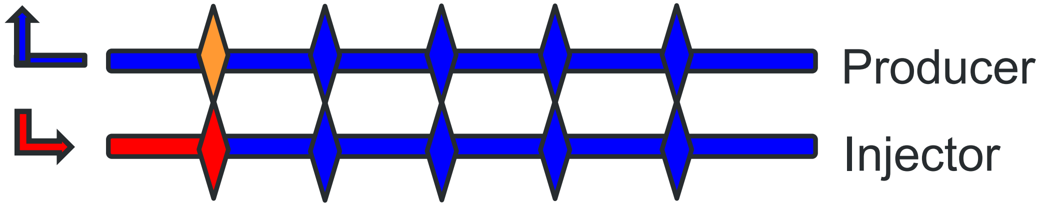
Premature Gas Breakthrough

- Assumptions
  - Injected gas preferentially flows through the fractures before entering the tight matrix.
  - Two possible scenarios for gas breakthrough:

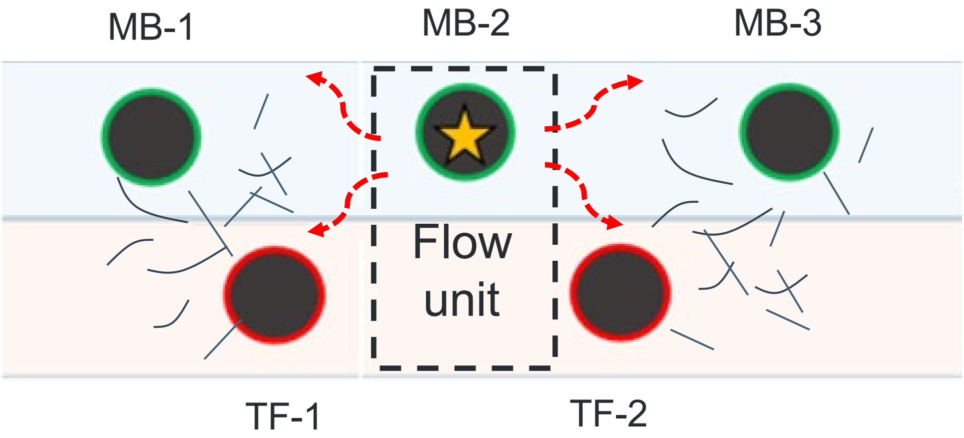
Scenario 1: fully fill the injector before breakthrough



Scenario 2: partially fill a stage before breakthrough occurs



Fracture filled with reservoir fluids | Fracture filled with injection gas | Fracture filled with reservoir fluids and injection gas



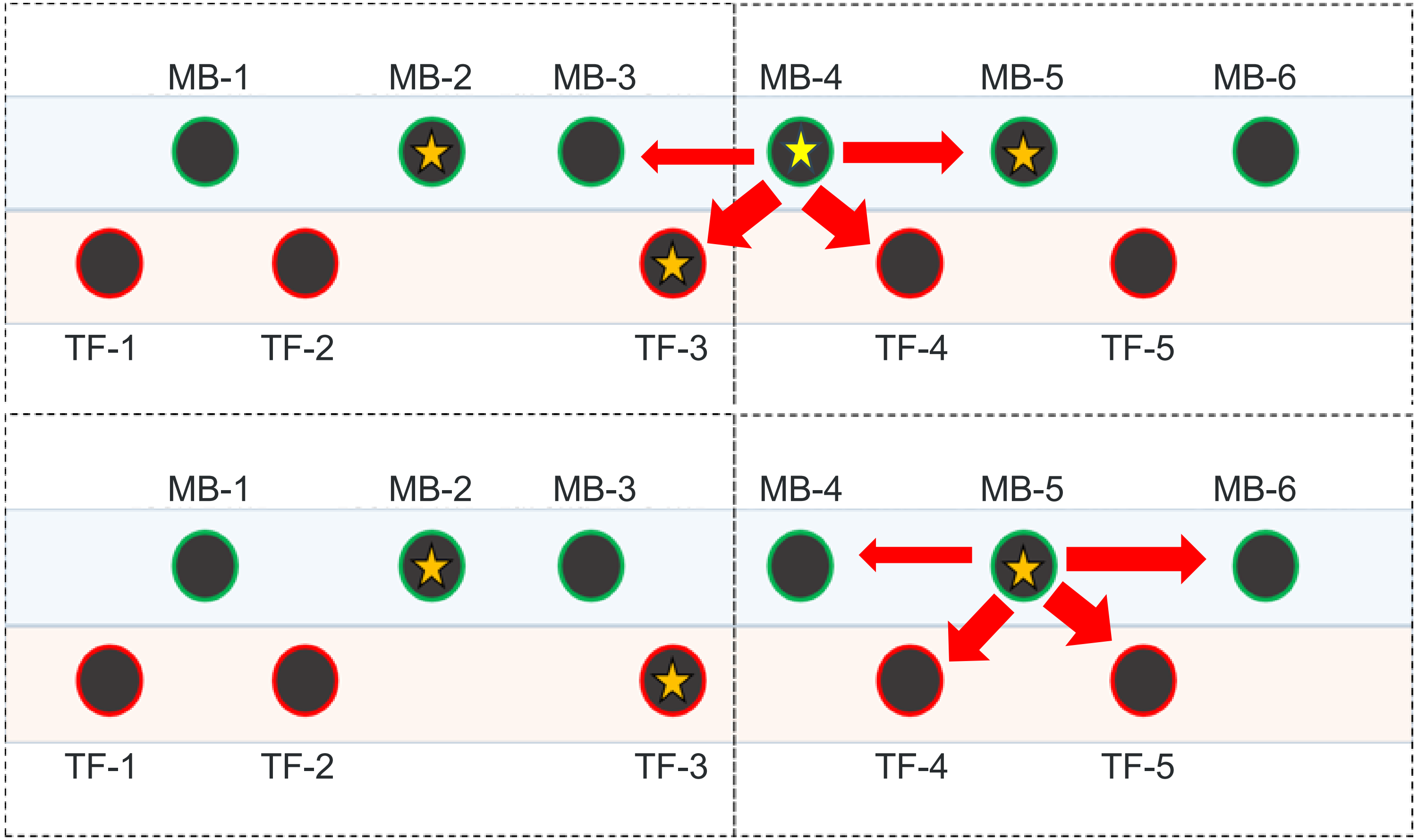
- A multiple-well, multiple-fracture model is needed for gas breakthrough and conformance control simulation.

Premature Gas Breakthrough

Modeled Gas Breakthrough Compared to Bakken EOR Pilot Results

Tracer results from a Bakken EOR pilot indicated that the huff 'n' puff (HnP) injectors often have fluid communication with their neighboring producers. Gas breakthrough happens quickly after injection begins (Pospisil et al., 2020).

Well	Modeled Gas Breakthrough Time Compared to Field Test Tracer Breakthrough, hours		
	Scenario 1, 100% fill w/ initial injection rate	Scenario 2, 5% fill w/ initial injection rate	Tracer breakthrough (field test data)
MB-2	616	31	N/A
TF-3	418	21	N/A
MB-4	519	26	~26 hours
MB-5	726	36	~72 hours

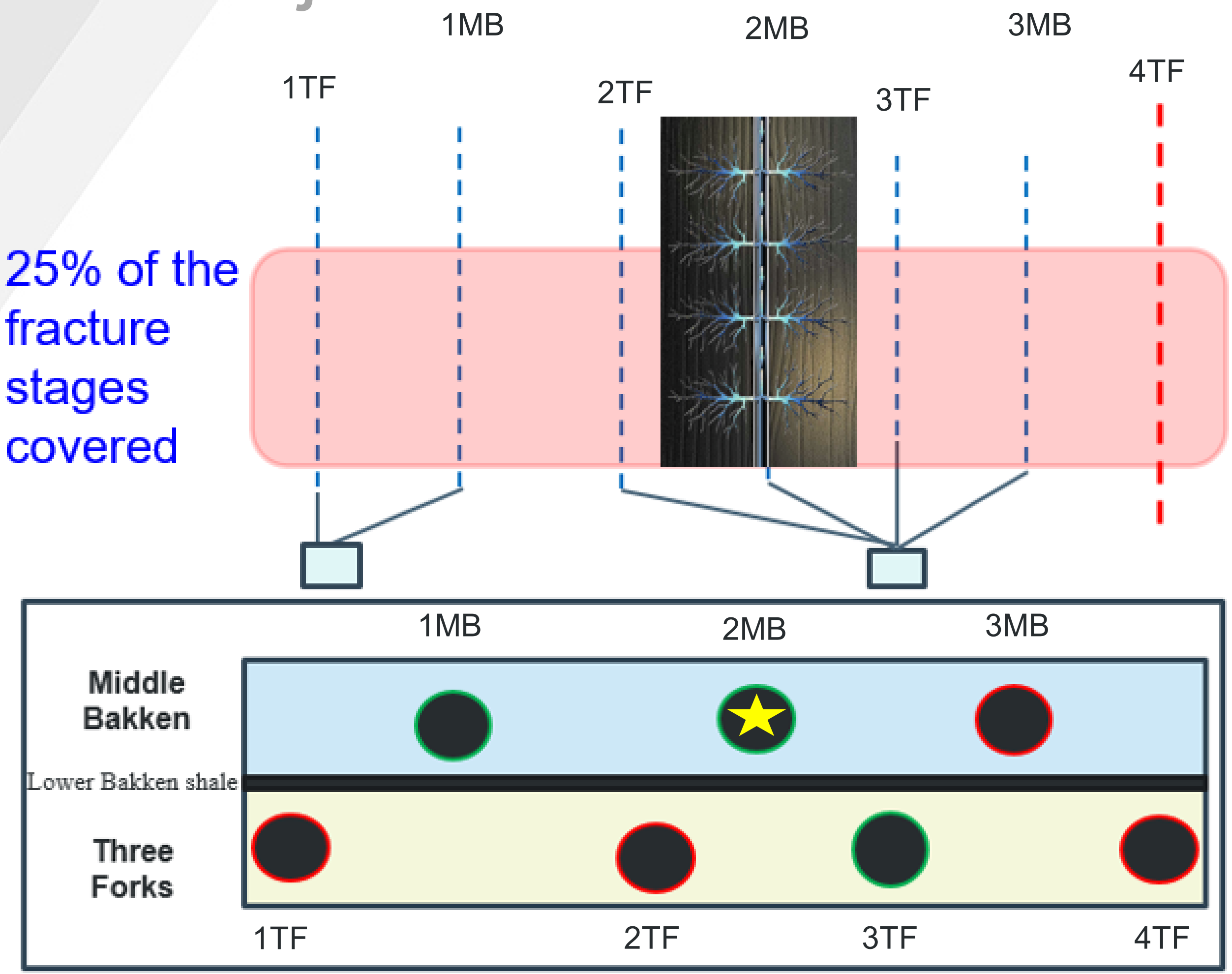


Potential engineering concepts to address short circuiting:

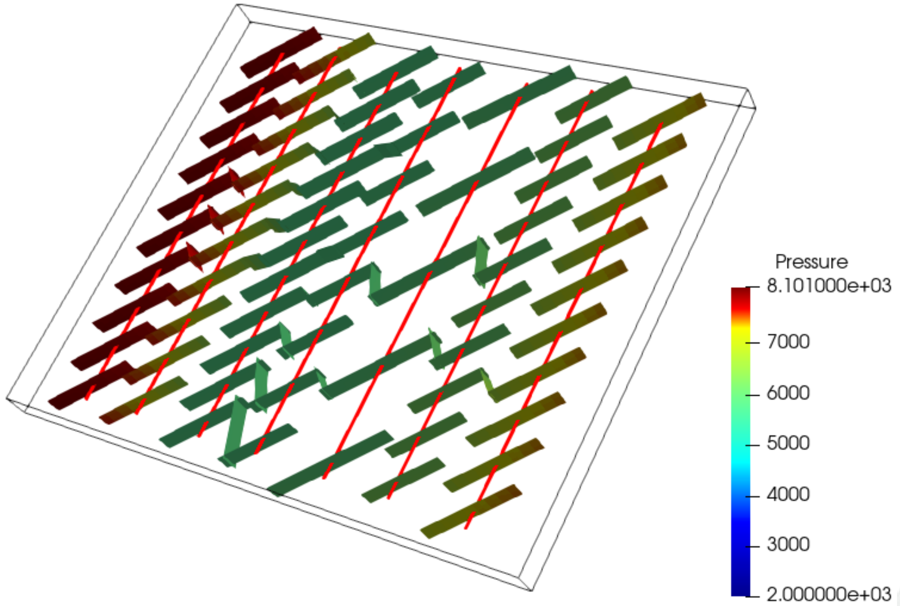
- Advanced well completion?
- Controllable completions?
- Higher injection rate?

Using Modeling to Detect and Characterize Well Interference

Gas Injection EOR

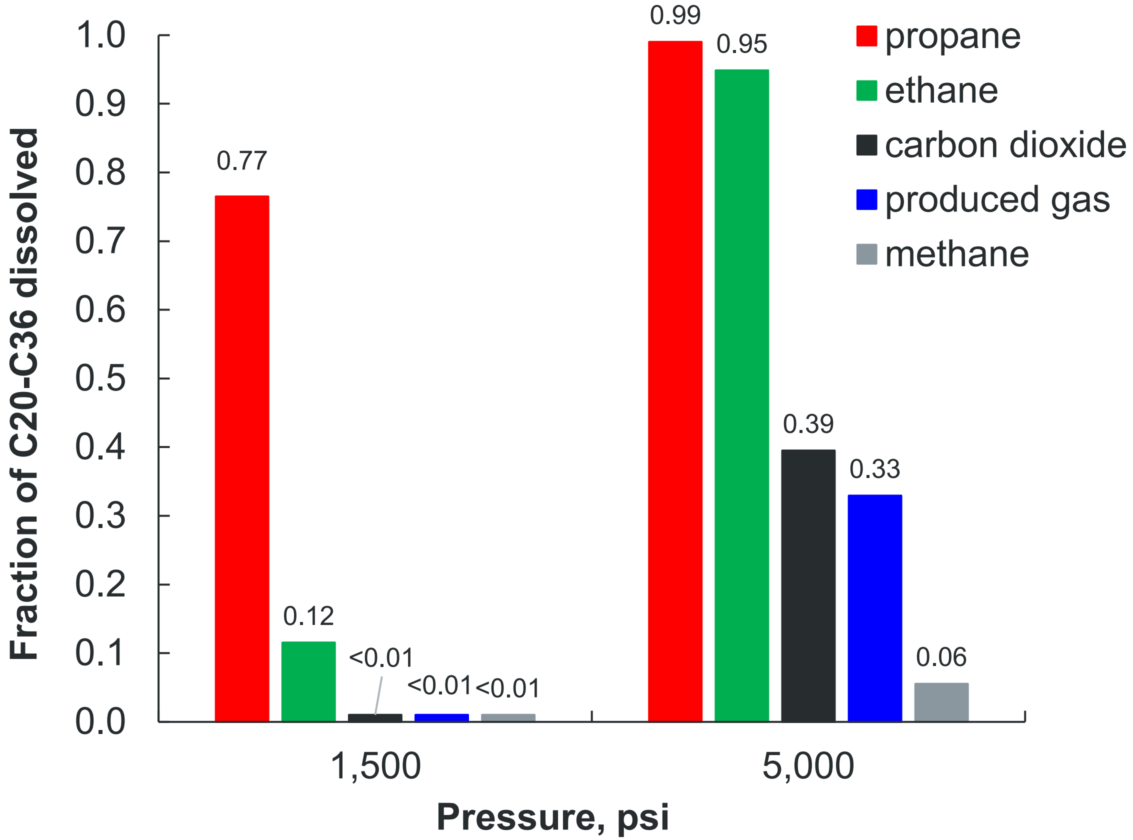


- Seven wells with 25% of the fracture stages were included in reservoir simulation model to consider well interference and conformance issues.
- An embedded discrete fracture model (EDFM) was applied to set up fractures and achieve better simulation performance.



Means of Characterizing Gas Breakthrough in the HnP Process

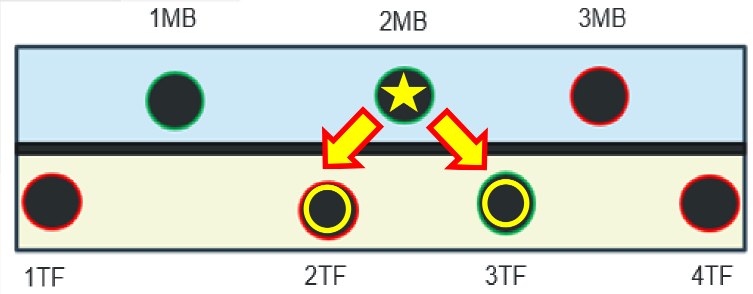
- Chemical tracer testing is effective in detecting well interference; however, it takes much time to collect, analyze, and interpret.
- Gas chromatography (GC) may be used to diagnose gas breakthrough by measuring the concentration change of a main component in the produced gas but must be performed frequently (e.g., daily), may not provide a unique solution, and can be expensive.
- Before large-scale injection, a pure rich gas (ethane, propane, etc.) may be used as a tracer to test the well connectivity. This method may be easier to operate, faster in analysis, and more effective for EOR.
- Pressure interference testing has been proposed and used in other bases.



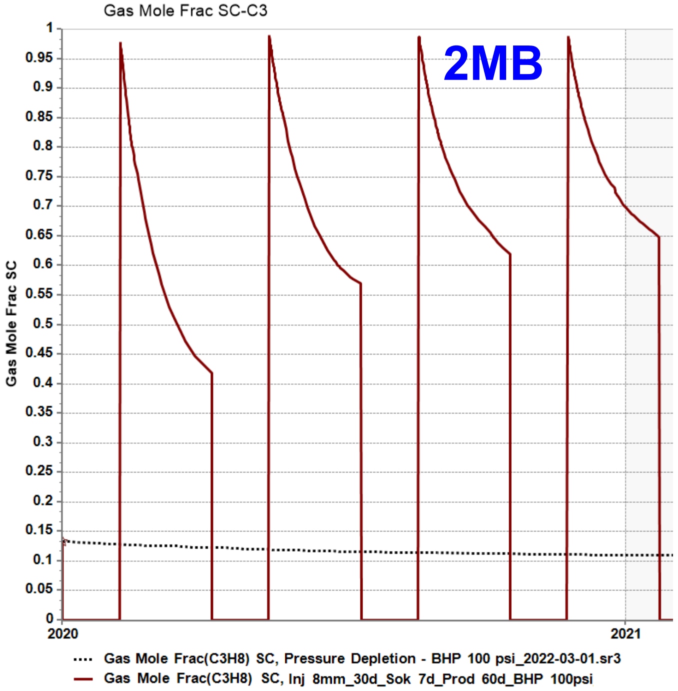
Fraction of C20–C36 dissolved in different gas under reservoir conditions (T = 230°F, P = 1500, 5000 psi)

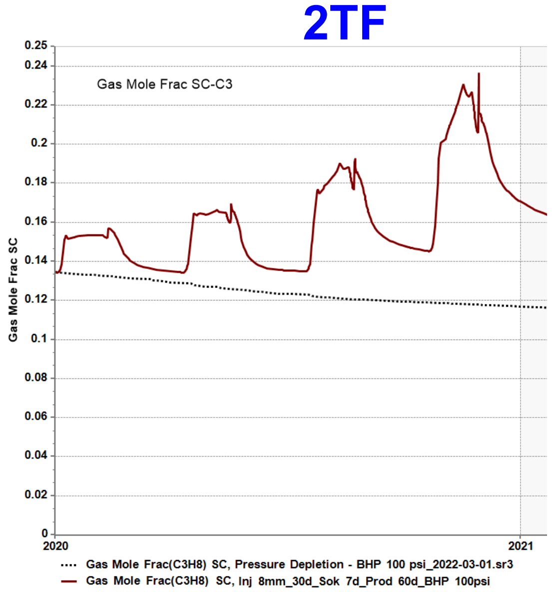
Hawthorne, S. B.; Miller, D. J. Comparison of CO_2 and Produced Gas Hydrocarbons to Dissolve and Mobilize Bakken Crude Oil at 10.3, 20.7, and 34.5 MPa and 110°C. *Energy Fuels* **2020**, *34*, 10882–10893.

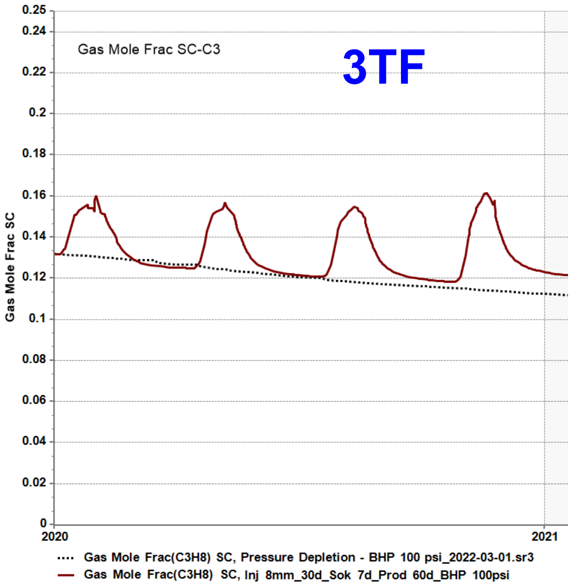
Modeling Gas Breakthrough in the HnP Process



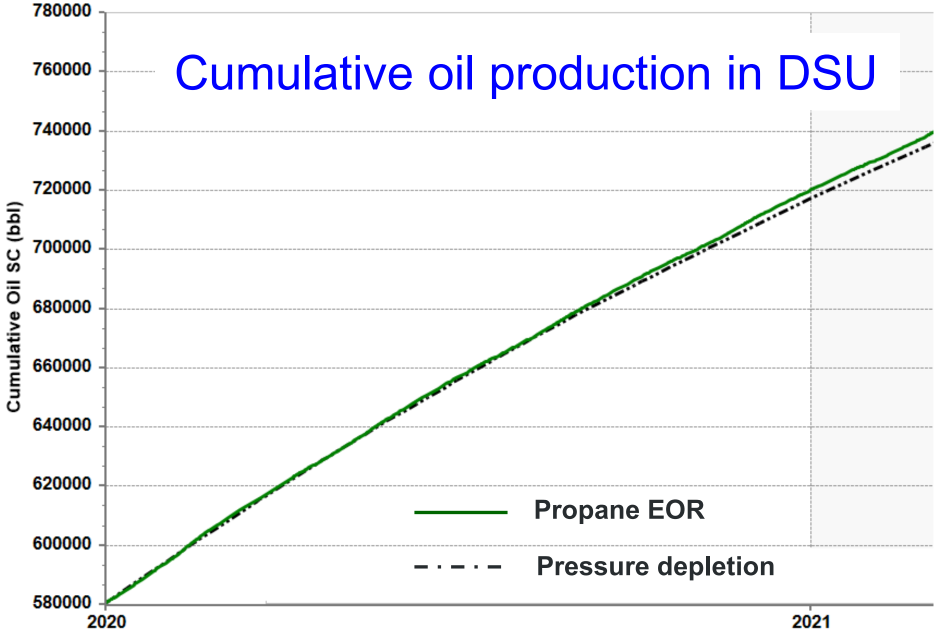
Mole fraction of C3 in the produced gas:





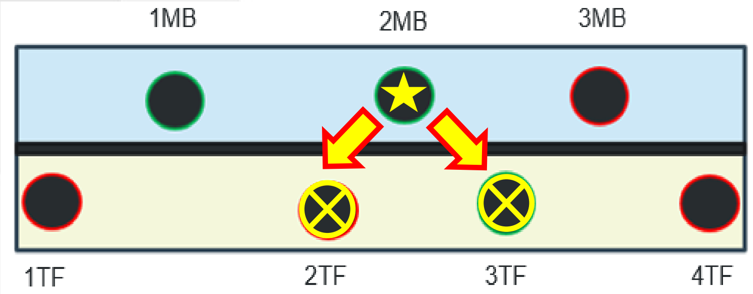


- Scenario 1 – neighboring wells remain producing in the EOR process: well interference can be detected quickly by measuring the produced gas composition in the neighboring wells when pure component (i.e., propane in this example) is injected for EOR.

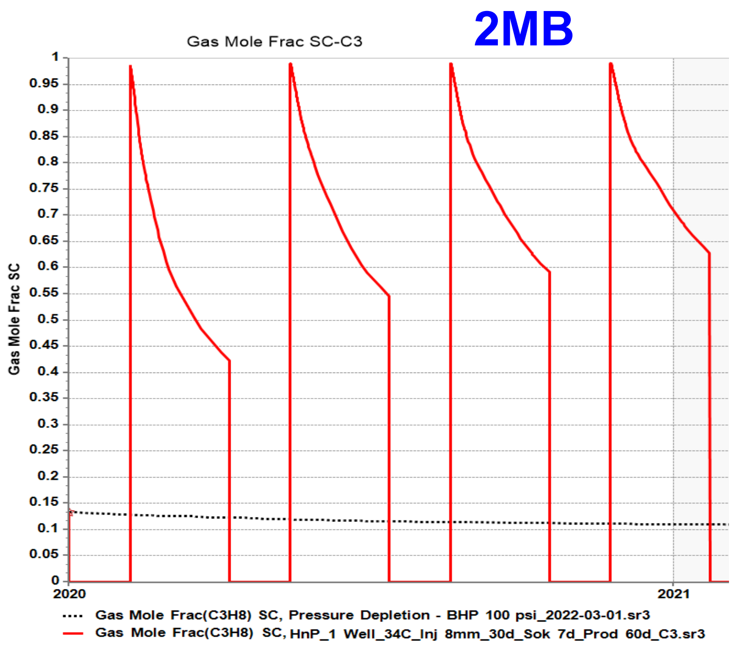


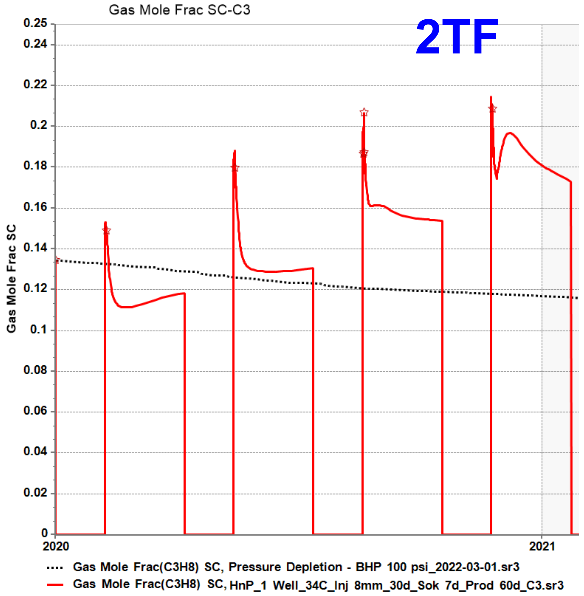
This scenario results in very little incremental oil production because the gas is short-circuiting to neighboring wells.

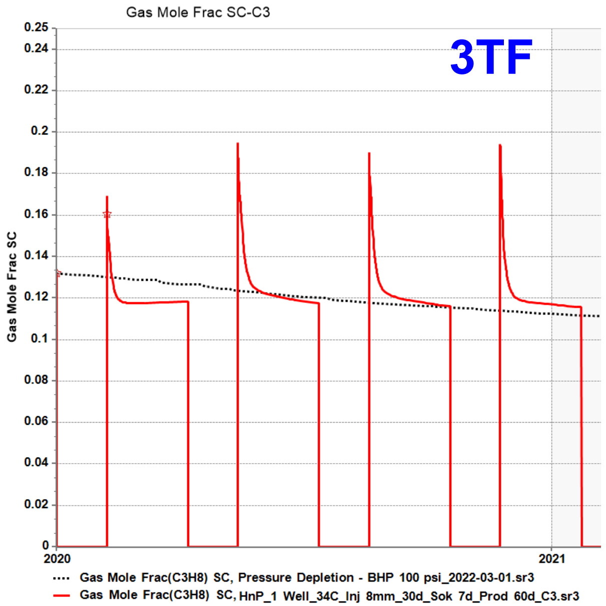
Modeling Gas Breakthrough in the HnP Process



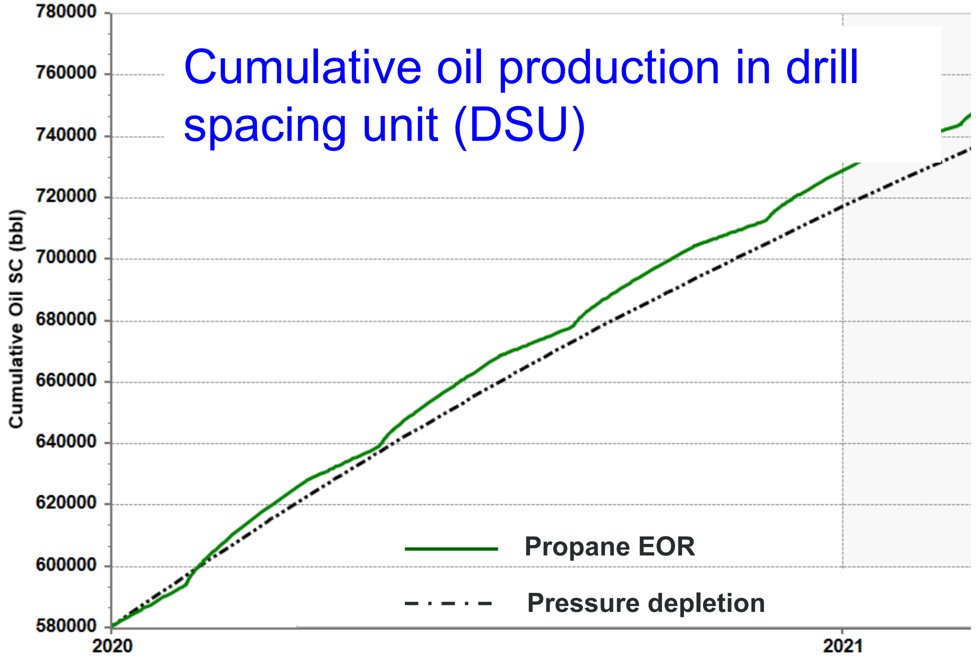
Mole fraction of C3 in the produced gas:







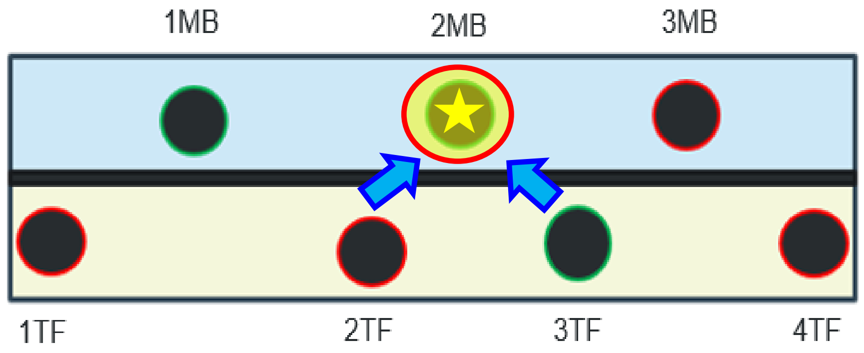
- Scenario 2 – neighboring wells follow the same HnP schedule: well interference can still be detected by measuring the produced gas composition in the neighboring wells.

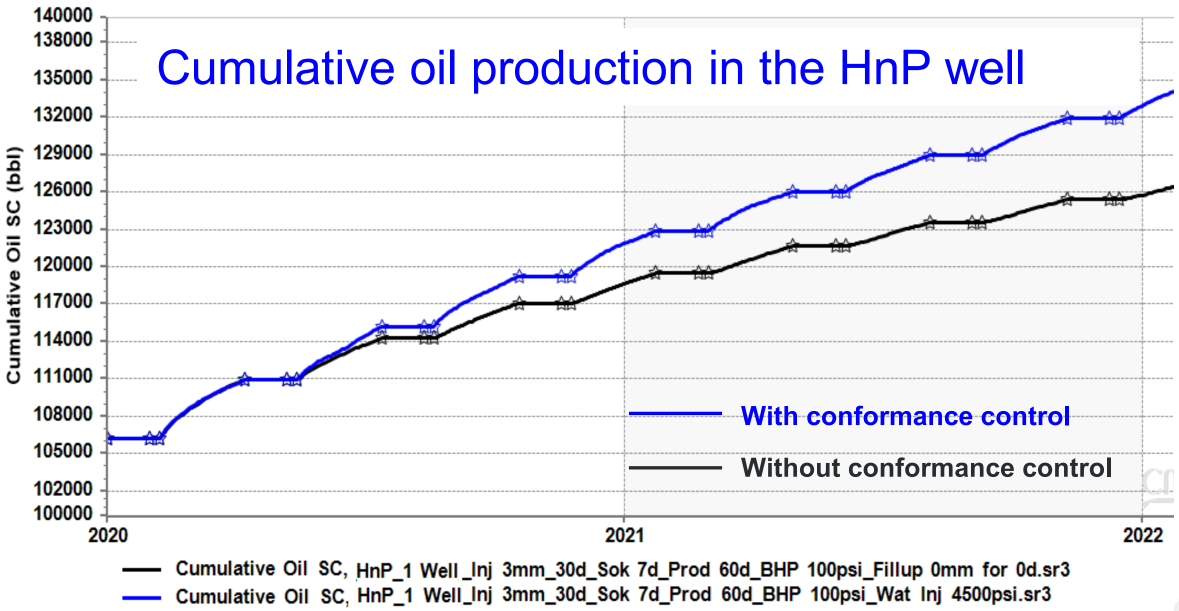


This scenario suggests applying the same HnP schedule to offset wells helps manage interference, resulting in incremental oil.

Water Injection as a Conformance Control Technique for Hydraulically Fractured Wells

- Conformance control becomes a key factor in the EOR process, especially when the gas injection rate is low.
- Reservoir pressure needs to be lifted for gas to penetrate and mix with oil in the matrix, so the injected gas should be confined in a certain volume around the injector to increase the pressure.
- Water can be injected into the wells connected to the HnP well to increase reservoir pressure and prevent the injected gas flowing to the neighboring wells.
- Modeling results indicate that water injection can improve oil production of a HnP injector but may not help oil production in the neighboring wells because of the high interfacial tension between oil and water – new EOR strategies will be needed to improve EOR over the full DSU.





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