SPE 201471
Report on the First Rich Gas EOR Cyclic Multi-well Huff 'n' Puff Pilot in the Bakken Tight Oil Play

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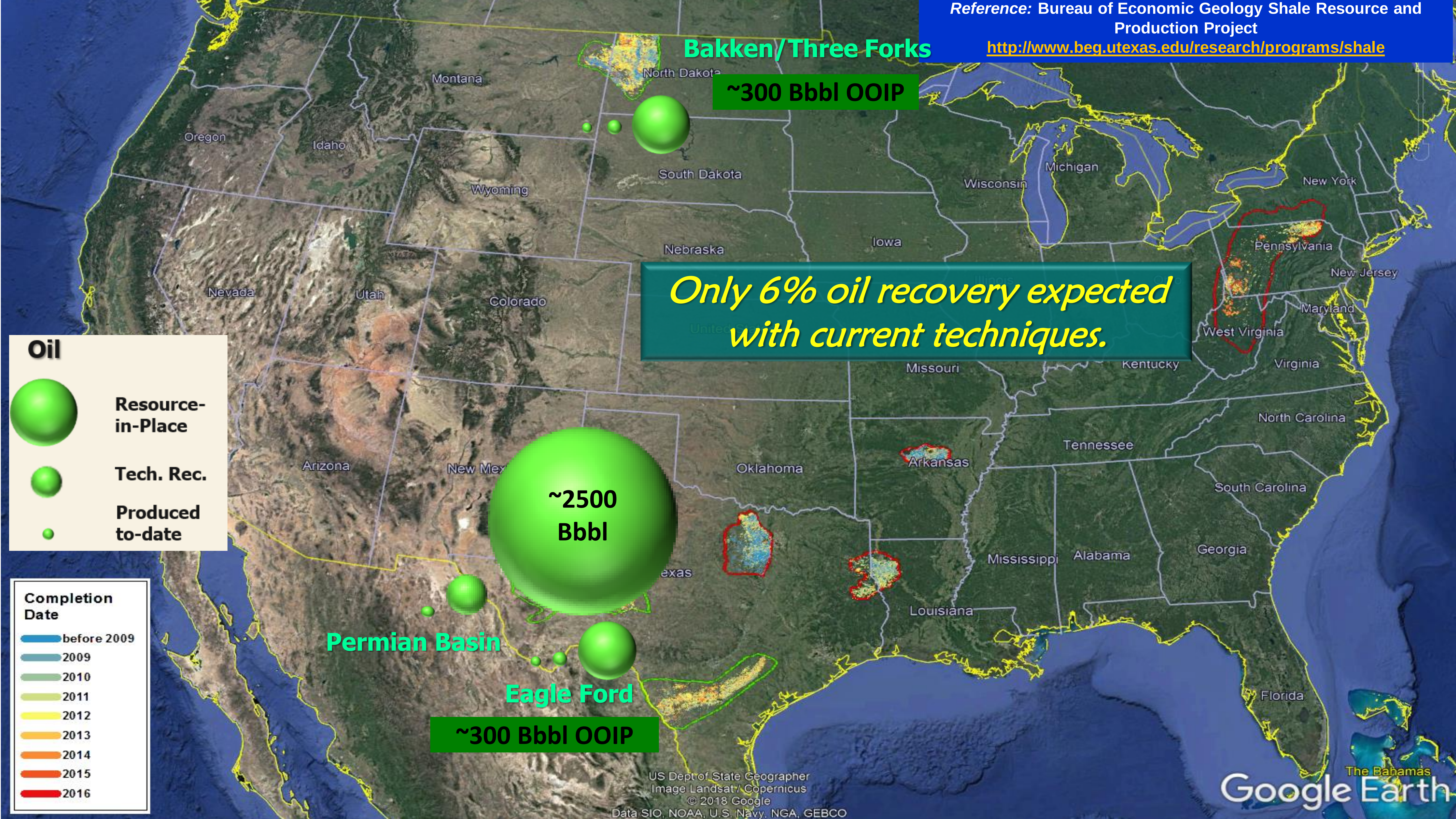
*Formerly with Liberty Resources LLC.

Presentation Outline

- Introduction & Background – "The Prize"
- Pilot Design Basis
- Fluid & Laboratory Studies
- Reservoir Description & Modeling
- Huff "n" Puff Pilot Operations
- Results & Observations
- Key Lessons & Recommendations
- Acknowledgments



Reference: Bureau of Economic Geology Shale Resource and Production Project
http://www.beg.utexas.edu/research/programs/shale
Bakken/Three Forks
~300 Bbbl OOIP
Only 6% oil recovery expected with current techniques.
~2500 Bbbl
Permian Basin
Eagle Ford
~300 Bbbl OOIP
Oil
Resource-in-Place
Tech. Rec.
Produced to-date
Completion Date
before 2009
2009
2010
2011
2012
2013
2014
2015
2016
Montana
North Dakota
Oregon
Idaho
South Dakota
Wyoming
Nebraska
Iowa
Wisconsin
Michigan
New York
Pennsylvania
New Jersey
Maryland
West Virginia
Virginia
Kentucky
Missouri
Nevada
Utah
Colorado
Arizona
New Mex
Oklahoma
Arkansas
Tennessee
North Carolina
South Carolina
exas
Mississippi
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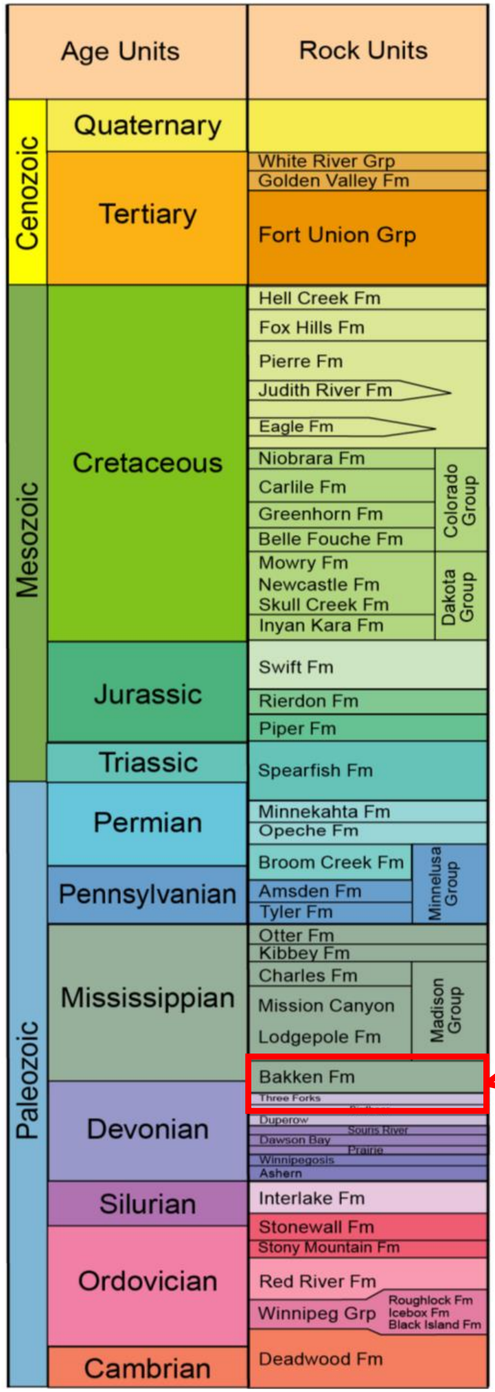
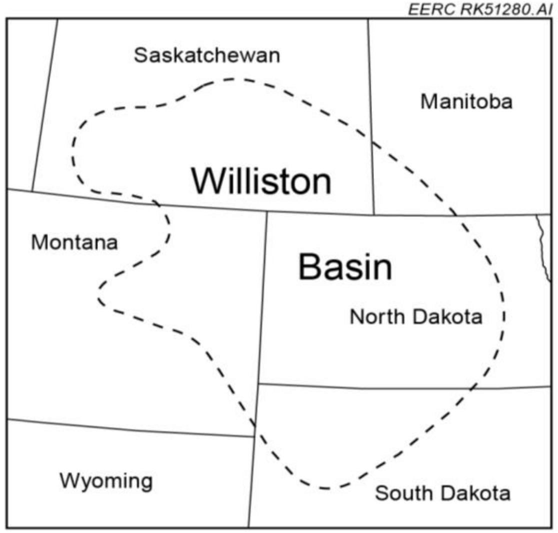
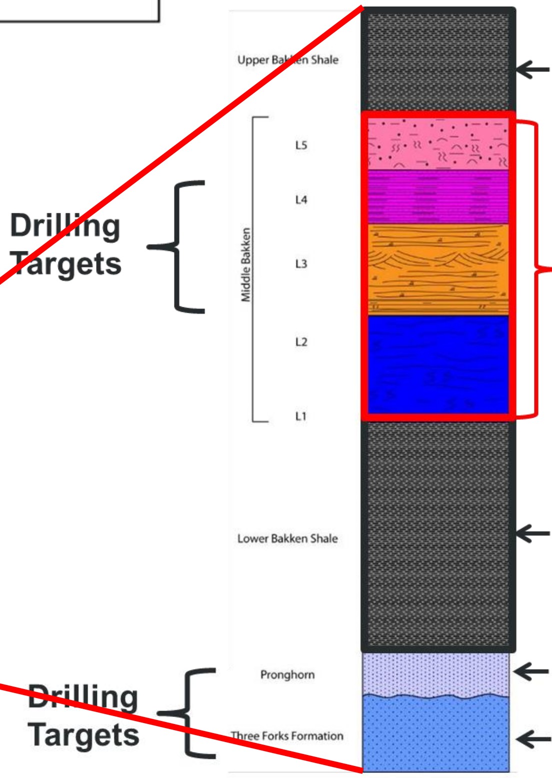
Bakken Petroleum System





Bakken Petroleum System Lithology



Upper Bakken Shale: Brown to black, organic-rich.
- **Bakken source rock**

Middle Bakken: Variable lithology (up to 9 lithofacies), ranging from silty sands to siltstones and tight carbonates
- **Bakken tight reservoir rock (horizontal drilling target)**

Lower Bakken Shale: Brown to black, organic-rich
- **Bakken source rock**

Pronghorn Member: Mixed sandstone, siltstone, dolomite, and shale.

Three Forks Formation: Interbedded dolostone/limestone, siltstone/mudstone, shale, evaporites.

Bakken vs. Eagle Ford Reservoir Properties

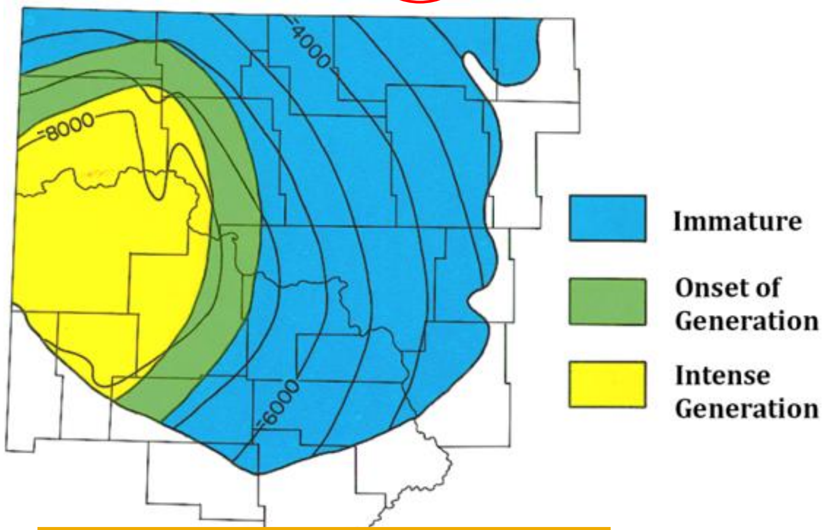
Table 1. Summary of Bakken and Eagle Ford Reservoir Properties*

	Max. Thickness, ft	Depth, ft	Temp., °F	Pressure Gradient, psi/ft	Lithology	Porosity, %	Permeability**	API Gravity	C2–C5 in Liquid, vol%
Bakken	160	9600–10,400	240	0.6–0.73	Organic rich shale, shaly siltstone, limestone, dolomite	1–15	0.01–20 mD (MB/TF) 100–20,000 nD (UB/LB)	40–43	7.2
Eagle Ford	300	1500–12,000	270	0.5–0.8	Marlstone, limestone, shaly siltstone	4–12	50–1500 nD	47–59	8.3

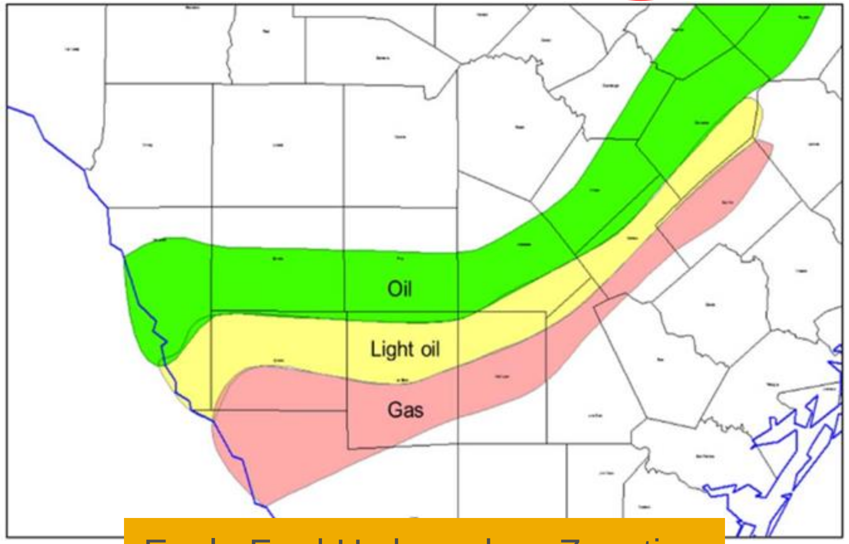
*High-level comparison of the Bakken and Eagle Ford reservoir properties.

**The Bakken includes two tight units (Middle Member Bakken Fm and Three Forks Fm) and Bakken shale units (Upper Bakken Shale and Lower Bakken Shale).

The Bakken and Eagle Ford systems have analogous properties within the light oil window.

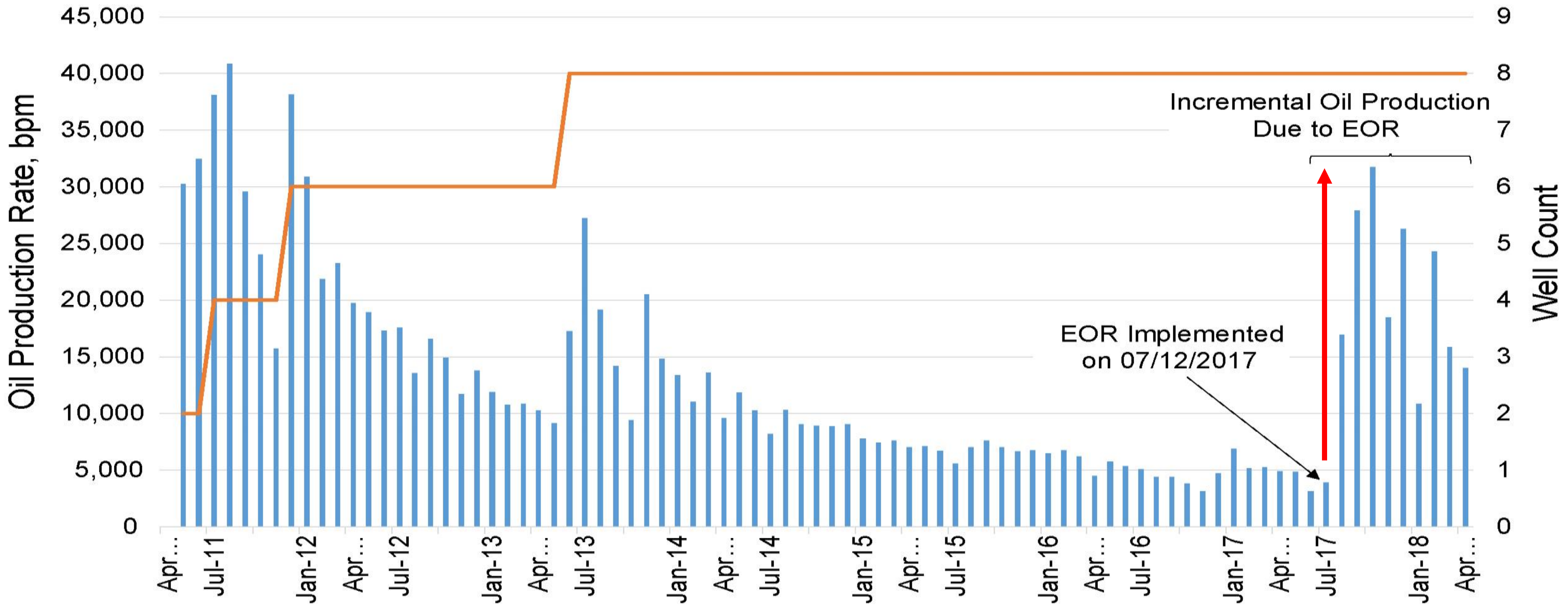


Bakken Source Rock Zonation



Eagle Ford Hydrocarbon Zonation

Eagle Ford – Vincent Unit - Huff 'n' Puff Results



Reported Data:

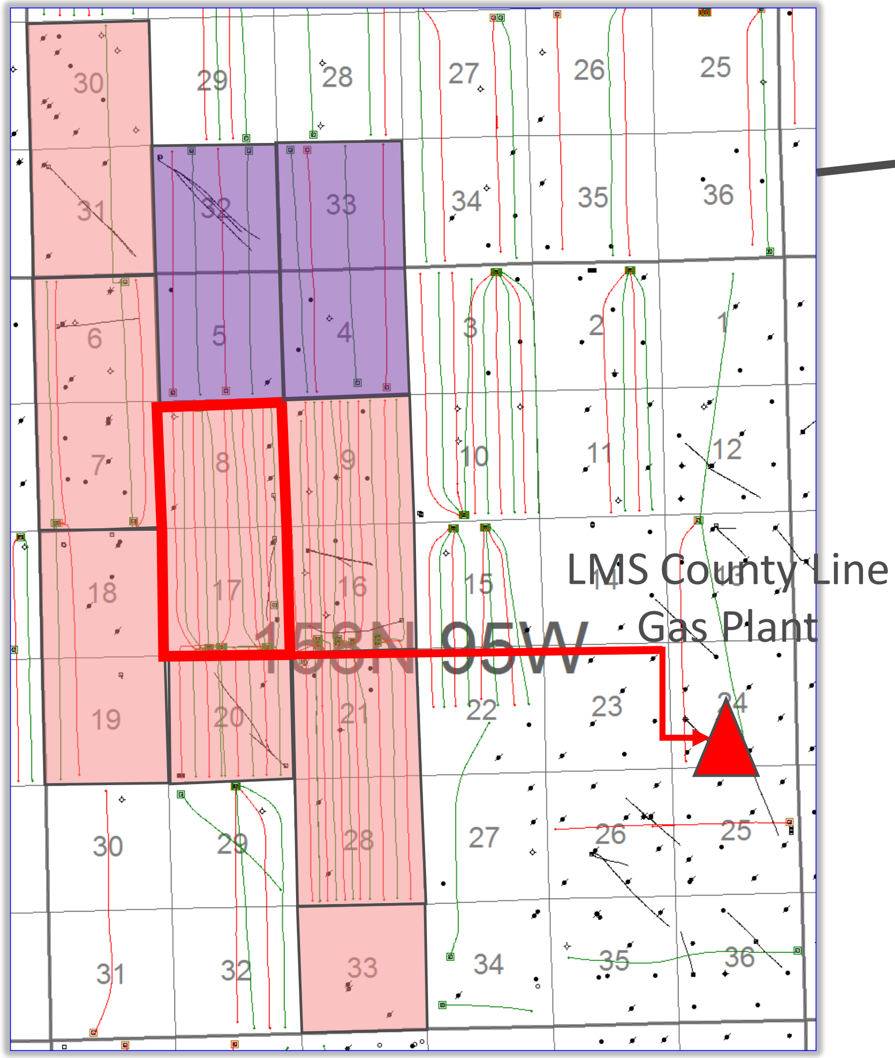
- Wells in Unit – Eight; EOR Oil Per Well – 132.5 mbo
- Gas Inj. Rate Ave. – 14 mmcfd; Peak Rate – 25 mmcfd
- Value of EOR oil - $42.2 mm; Total Project Cost - $5.5 mm

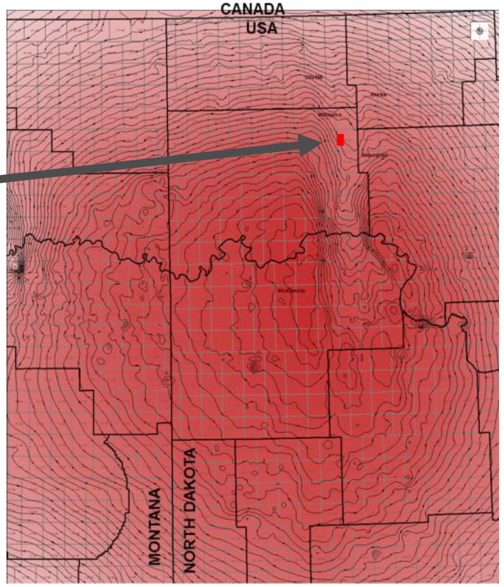
Observations:

- Rapid oil rate increase
- High gas injection rates
- High ratio of HNP Prod./Inj. time

Bakken Huff 'n' Puff Pilot Design Considerations

- Cost effective opportunity to test multi-well HnP gas injection EOR in the Bakken and Three Forks.
- Fully developed DSU with eleven horizontal wells.
- Access to produced gas.
- Operated most of the offset DSUs.
- Well & completion design provided for higher conformance.
- Predominantly cemented liners with Plug & Perf completions.
- Jet pump operations eased well conversions.





- **Bakken Region ND**
  - Williams County
  - 1280 Acre DSU
  - Centralized Pad
  - <450' well spacing

Pilot Goals and Design Summary

Pilot Goals

- To execute the pilot without causing harm to either people or the environment.
- To determine the technical feasibility of EOR from the Bakken pool by using produced gas as a miscible injectant.
- To utilize a fully developed Bakken pool DSU to evaluate and optimize injection methods for EOR.
- To evaluate the effectiveness of various rich gas mixtures to mobilize oil in the BPS.

Source of Injection Gas

Lease gas sourced from wells co-located on the multi-well drill site.

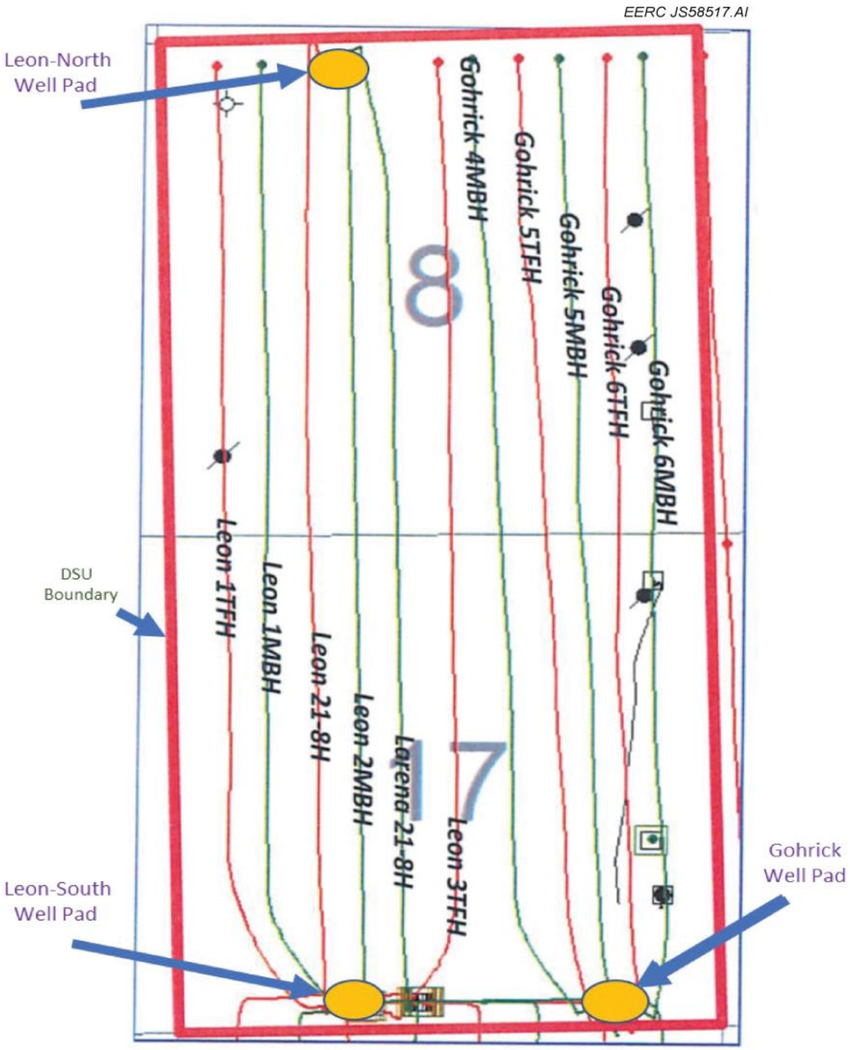
Anticipated Injection Rates

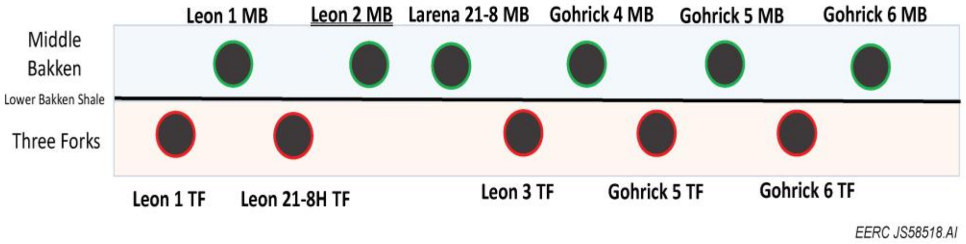
Approximately 3 million standard cubic feet per day (MMscfd), injected into either one or more than one well simultaneously.

Maximum Allowable Surface Injection Pressure

5000 psi as constrained by wellhead and flowline maximum allowable operating pressure and to stay well within geologic boundary layer pressures.

Drill Spacing Unit (DSU) – Well Spacing





Leon–Gohrick DSU East–West Cross Section:

- Average distance between adjacent wells is ~400’.
- Average distance between wells in the same formation is ~800’.
- Vertical offset between Middle Bakken and Three Forks ~60’.

Leon–Gohrick DSU Map View:

- North – south oriented laterals ~10,000’ in length
- Middle Bakken wells shown in green; Three Forks wells in red.

Bakken & Three Forks Interval MMP Values

- The vanishing interfacial tension (VIT) technique was applied to measure minimum miscibility pressure (MMP) for crudes collected from the Middle Bakken and Three Forks wells.

- Rich gas mixtures (ca. 70/20/10 methane/ethane/ propane) produced from the BPS can achieve MMP at relatively low pressures, similarly to the pressures required by CO_2.

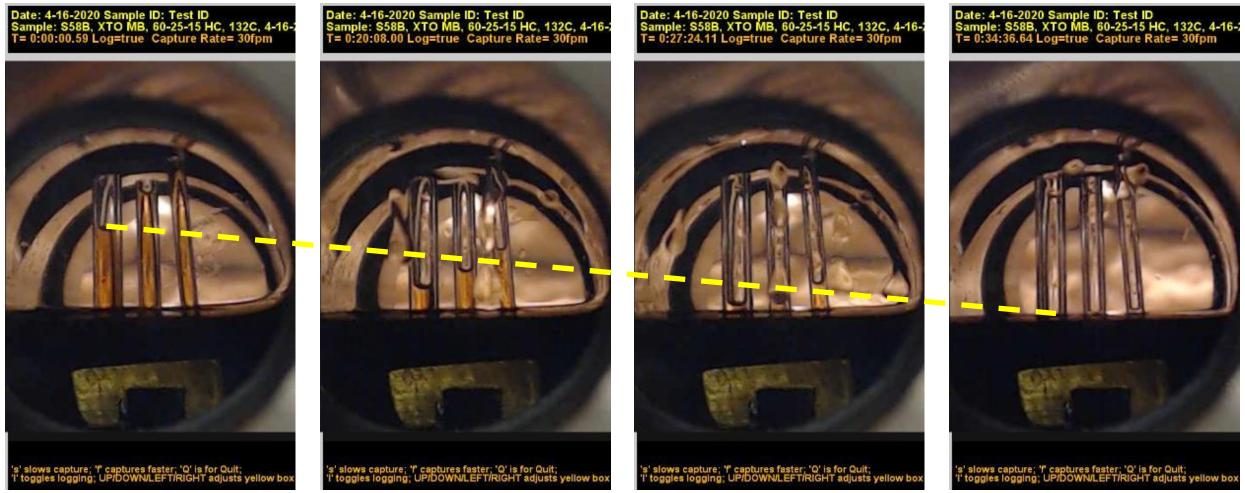


Figure 1. Capillary-rise vanishing interfacial tension (VIT) method.

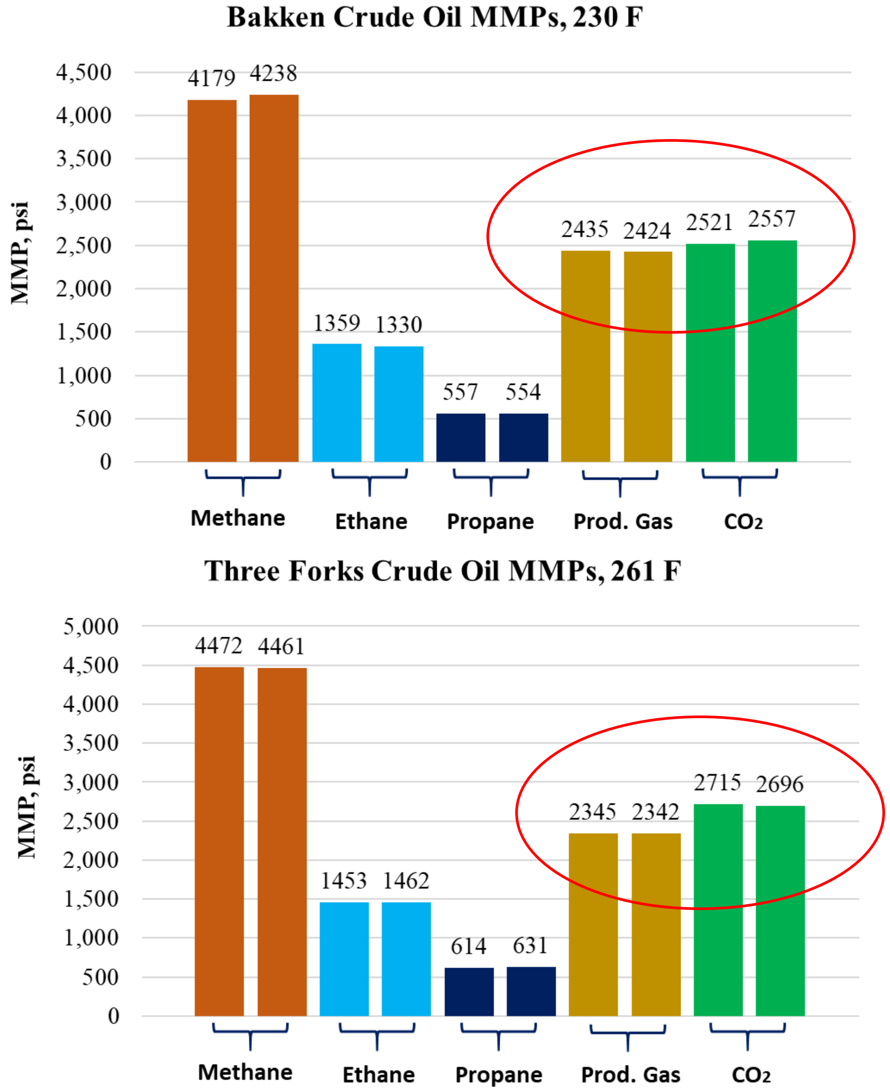
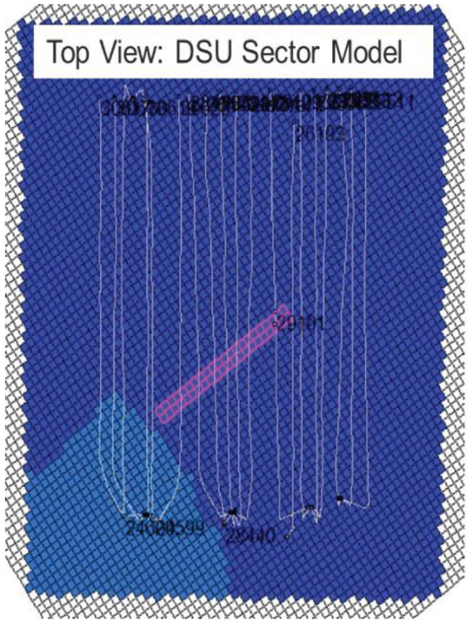
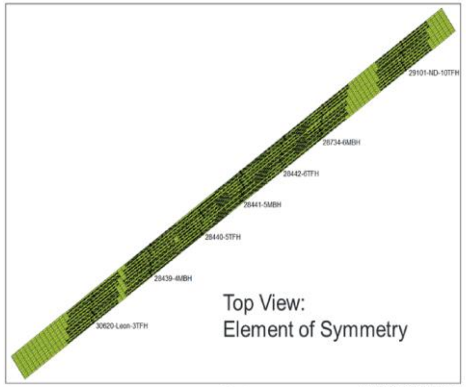


Figure 2. MMPs for MB and TF crudes with different gases.

Simulation Modeling Approach



(a)

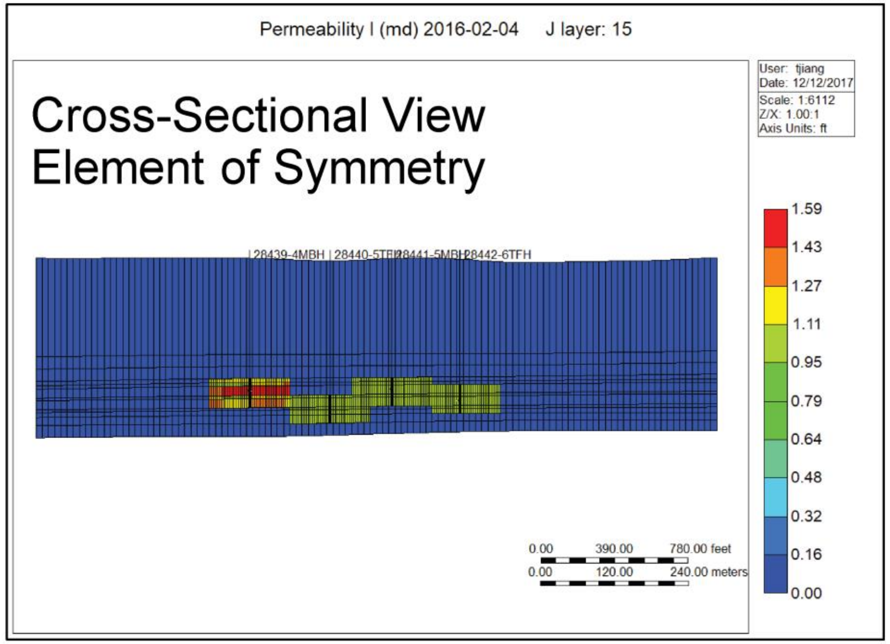


(b) EERC JS58510.AI

Illustrations of single-stage simulation model:

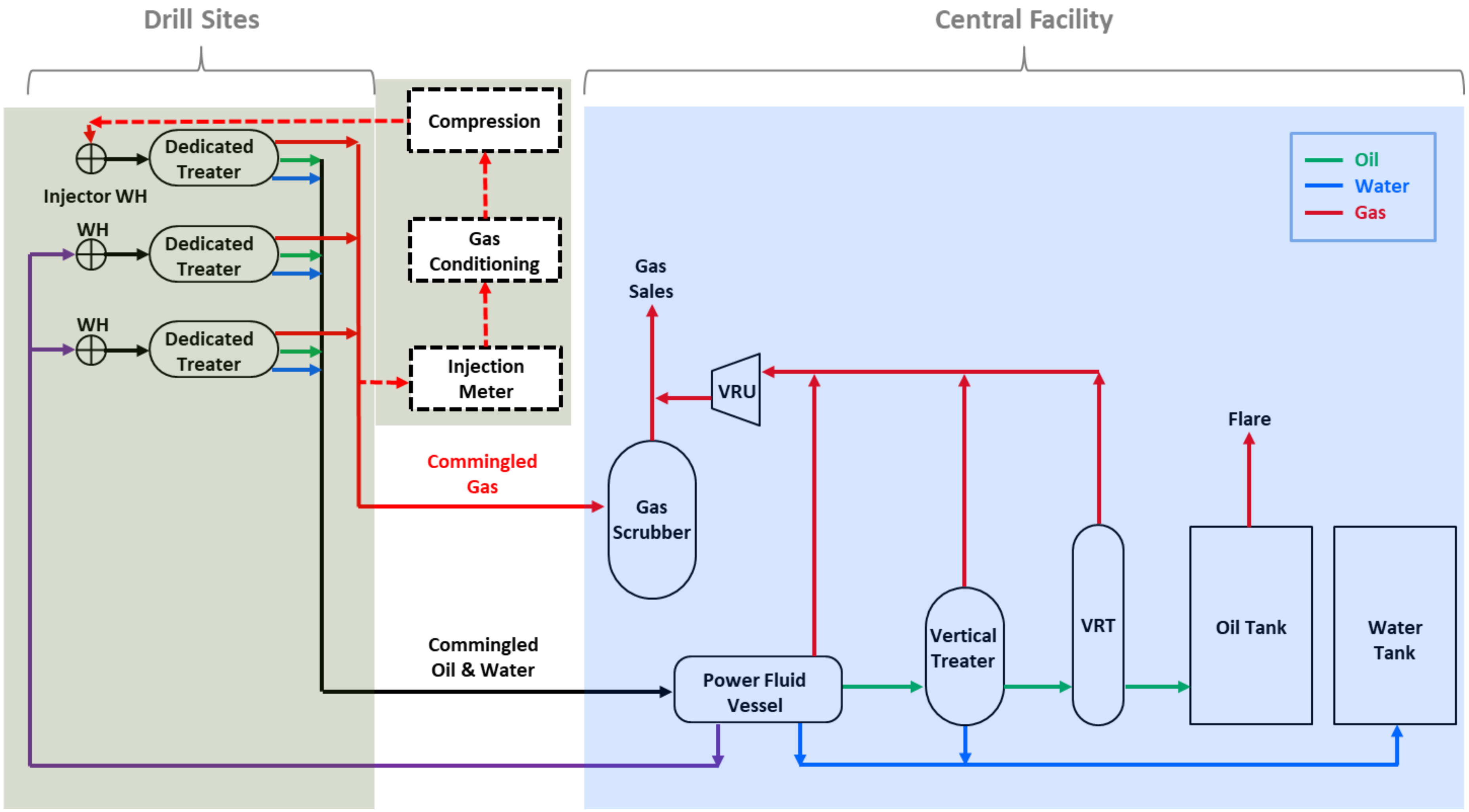
a) Top view of DSU sector model showing area of single-stage model, highlighted in pink.
b) Top view of single-stage model.
c) Cross-sectional view of single-stage model.

EERC JS58511.AI



(c)

Central Processing Facility Process Flow



Huff N Puff gas injection operations were integrated into production without major facilities modifications.

Real-Time Production Measurement

- Real-time measurement
  - Identify production-related issues and changes in production trends
  - Reservoir surveillance
- Oil, water, and gas measured prior to commingling
  - Oil – Coriolis meter on dump
  - Water – Coriolis meter on dump
  - Gas – EFM on gas outlet

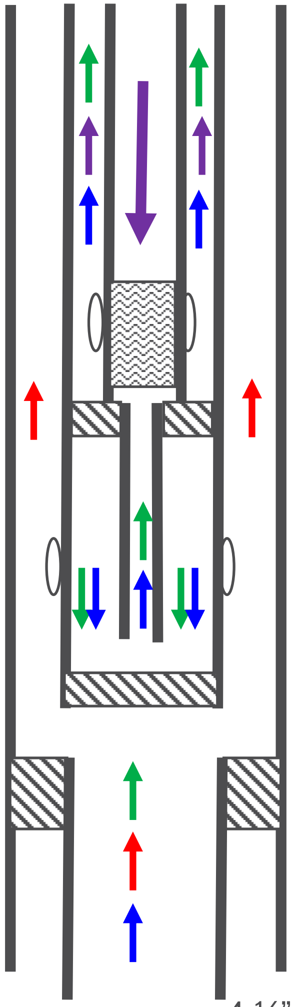
Individual wells have dedicated separation and three-phase measurement.

Low-Cost Injection Conversion

No workover cost for injection conversion; artificial lift system designed for high gas–liquid ratios.

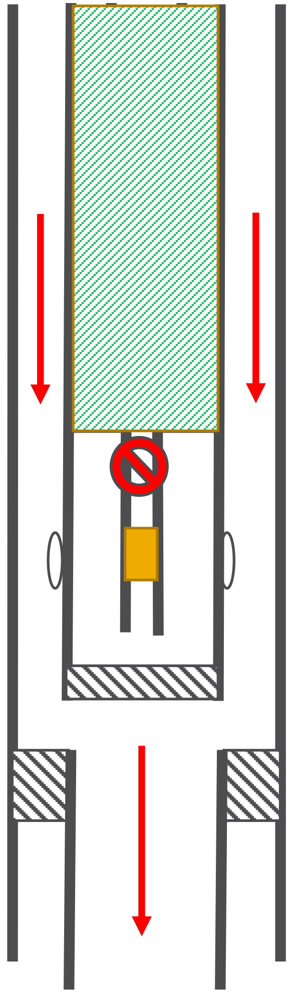
Normal Operation

- Hydraulic jet pump

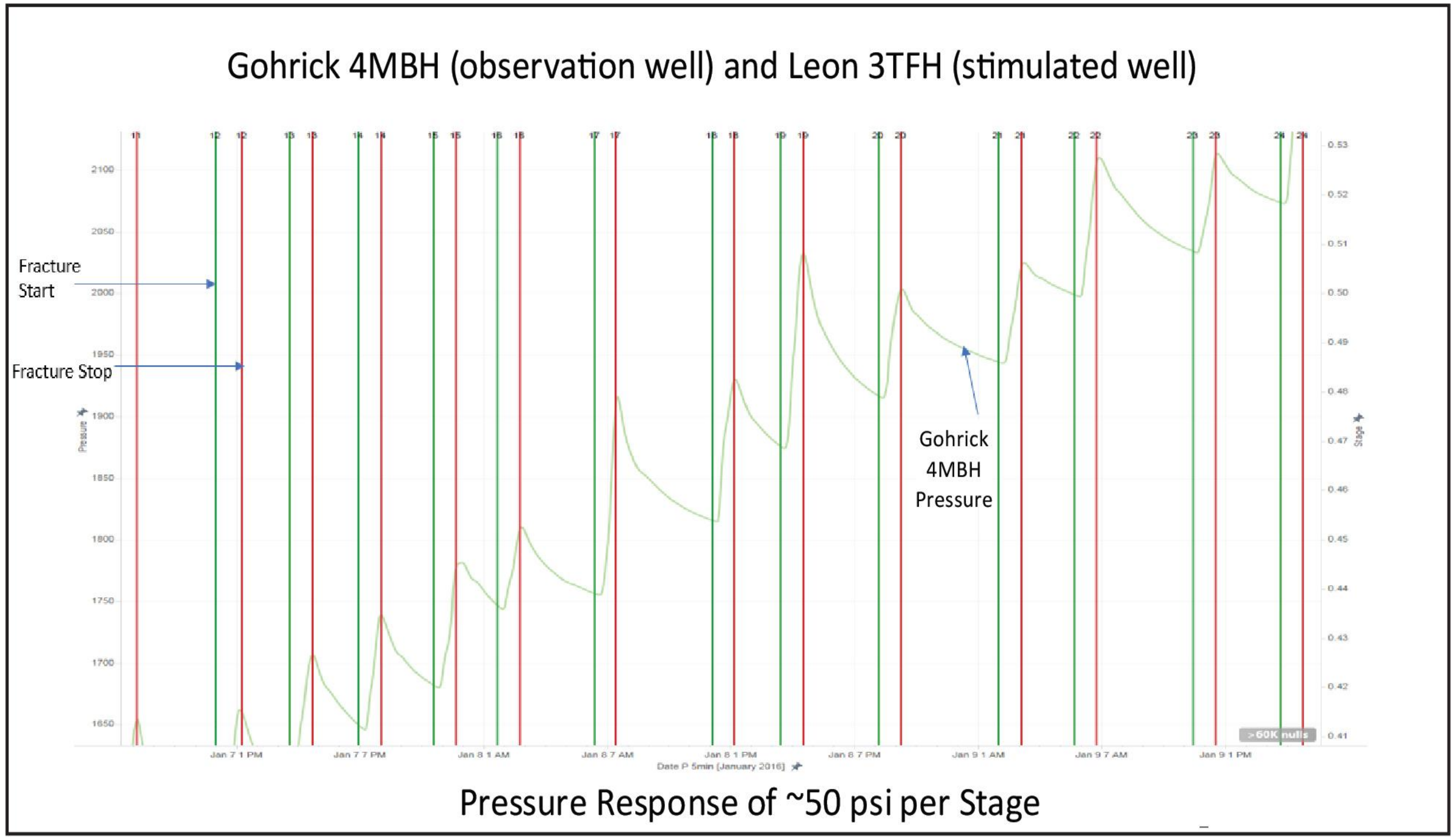


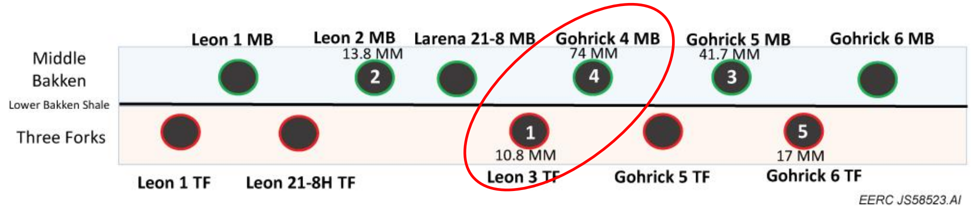
Injection Operation

- Isolate AL "Path"
- Pressurize 4-1/2" AL string
- BHP gauge deployed



Pressure Response During Fracture Stimulation





Key Points:

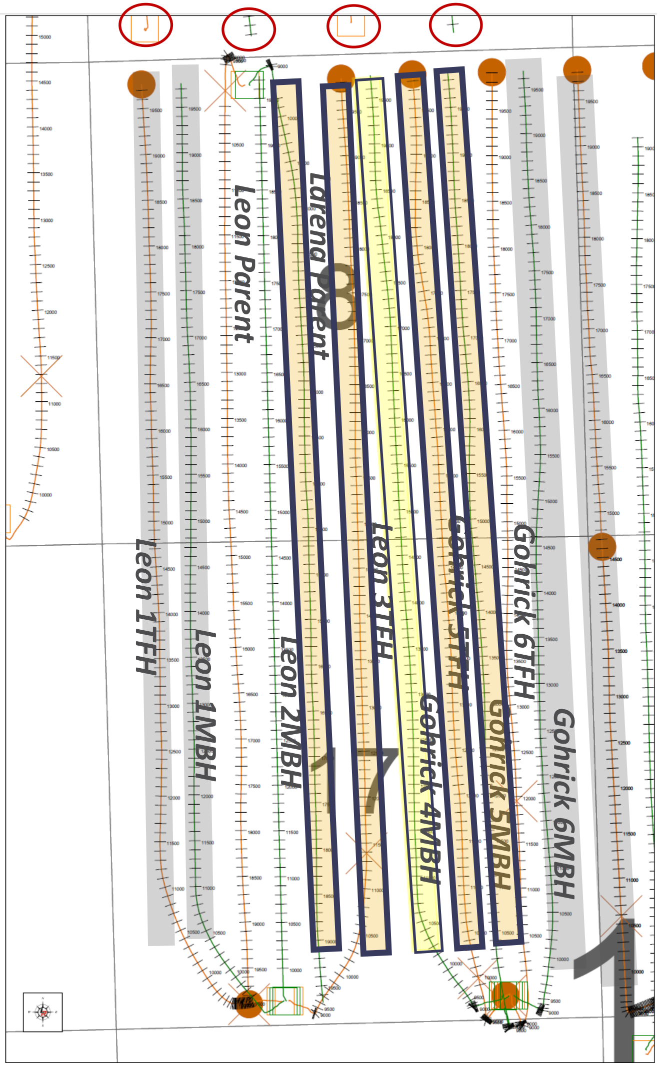
- Pressure monitoring in offset wells during stimulation shows degree of communication.
- Typical pressure response of ~50 psi on each stage.
- Pressure communication during gas injection was deemed likely but limited.

Huff N’ Puff Gas Injection

Operations & Surveillance Plan

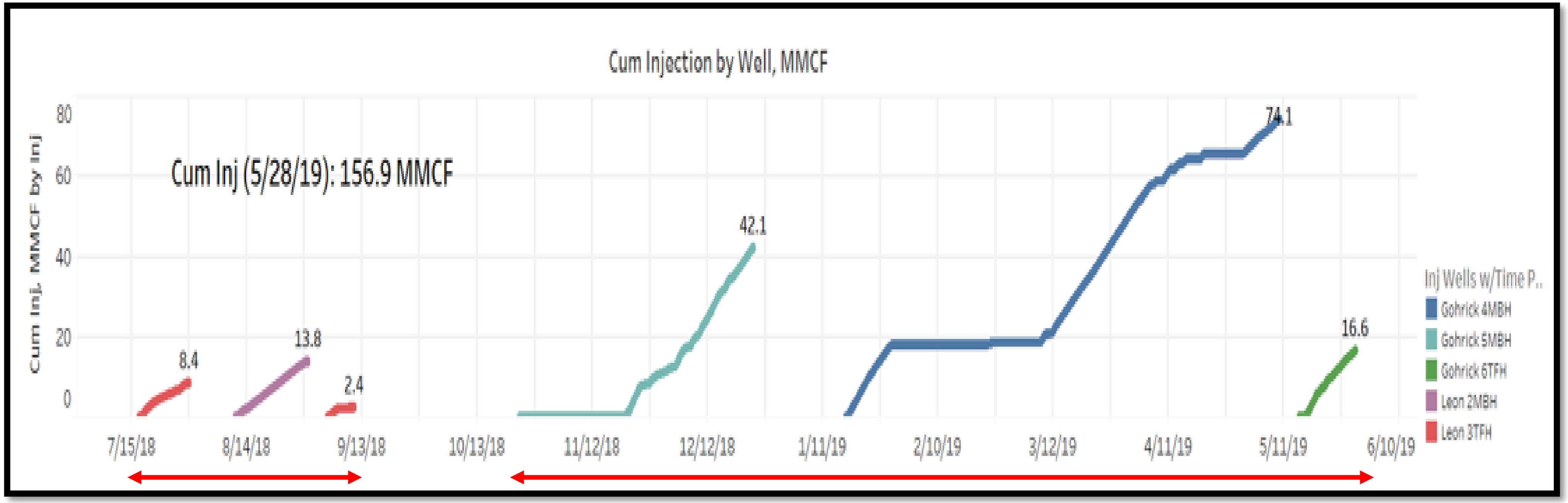
- Cycled gas in five interior wells in HnP scheme.
- Sourced lease gas at 1.8 to 3.0 mmscfd.
- Operate within max injection pressure at 5000 psi.
- The four wellbores offset the injector were equipped with bottom hole pressure gauges.
- The offset operator to the north provided daily production information.

Boundary Well
Injection Well
Monitor Well BHP Gauge
Monitor Well Gas Chromatograph
Offset Operator Notification



Pilot Gas Injection Summary

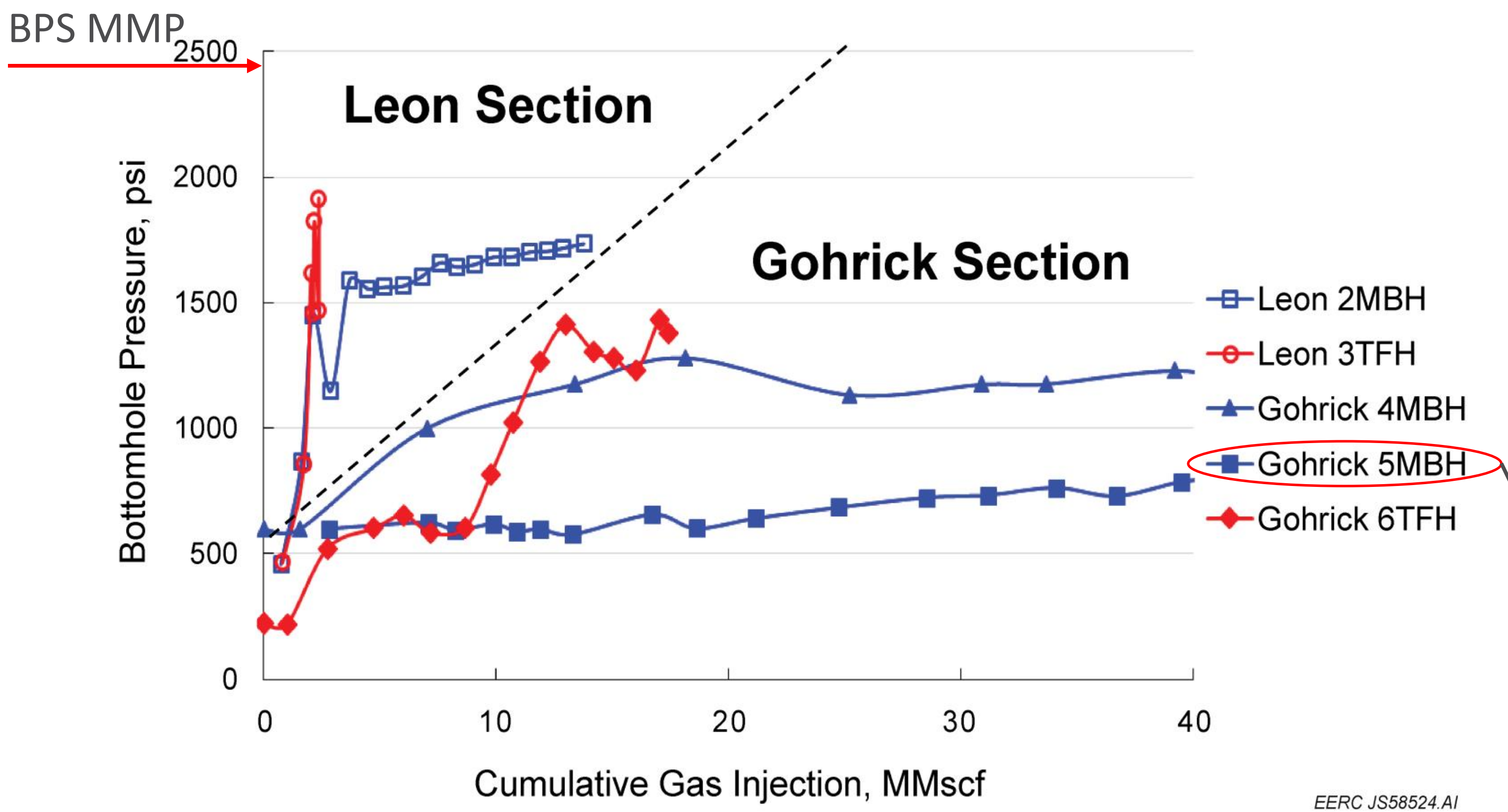
(Results as Reported to NDIC in September 2019)



Field Test Activities & Results:

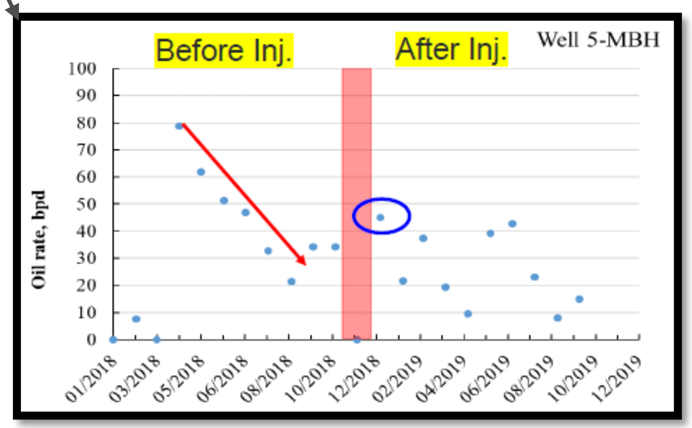
- Initiated low pressure gas injection (peak rate of 1.1 MMscfd) into Leon wells to investigate injectivity; gas rates and volume were ultimately injection pressure limited.
- Increased gas injection (peak rate of 2.2 MMscfd) in Gohrick wells with larger compressor to better assess pressure and EOR response.
- Gas injection rates were limited to DSU produced gas volumes as approved and injection was ultimately gas supply limited at <1.0 mmscf.
- Total of ~157 mmscf gas injected in five wells during over seven different injection periods.
- No gas detected off DSU. An estimated 144 mmcf (91%) of injected gas was recovered in HnP operations.

Bottom-hole Pressure vs. Cum Gas Injection



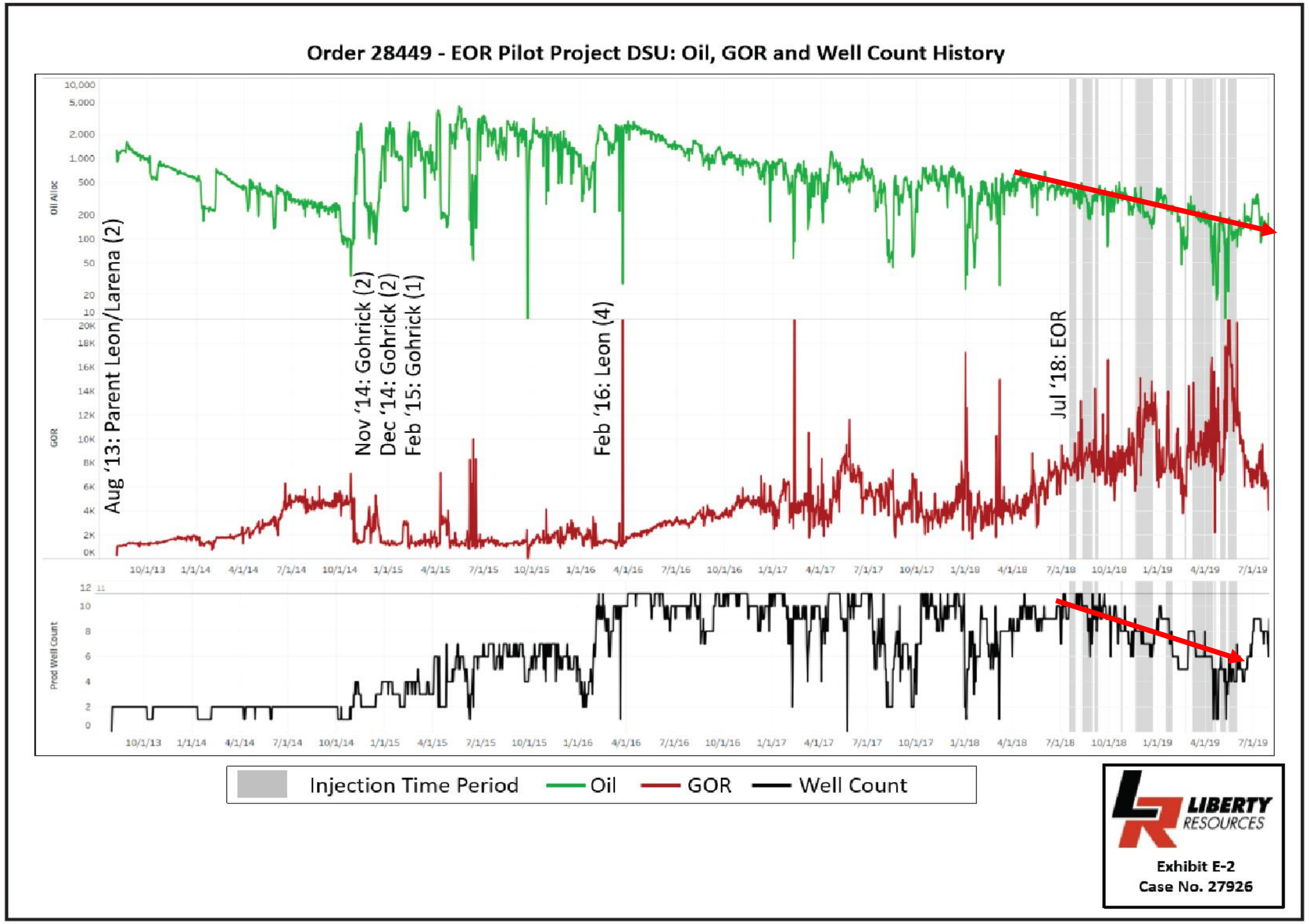
Key Points:

- Injected gas rates were too low to yield targeted BH pressure increases (>2500 psi).
- Higher pressures were reached in less depleted wells (Leon Section).
- Oil response was within noise of flush production after shut-in.



…Needed more gas!

DSU Production History



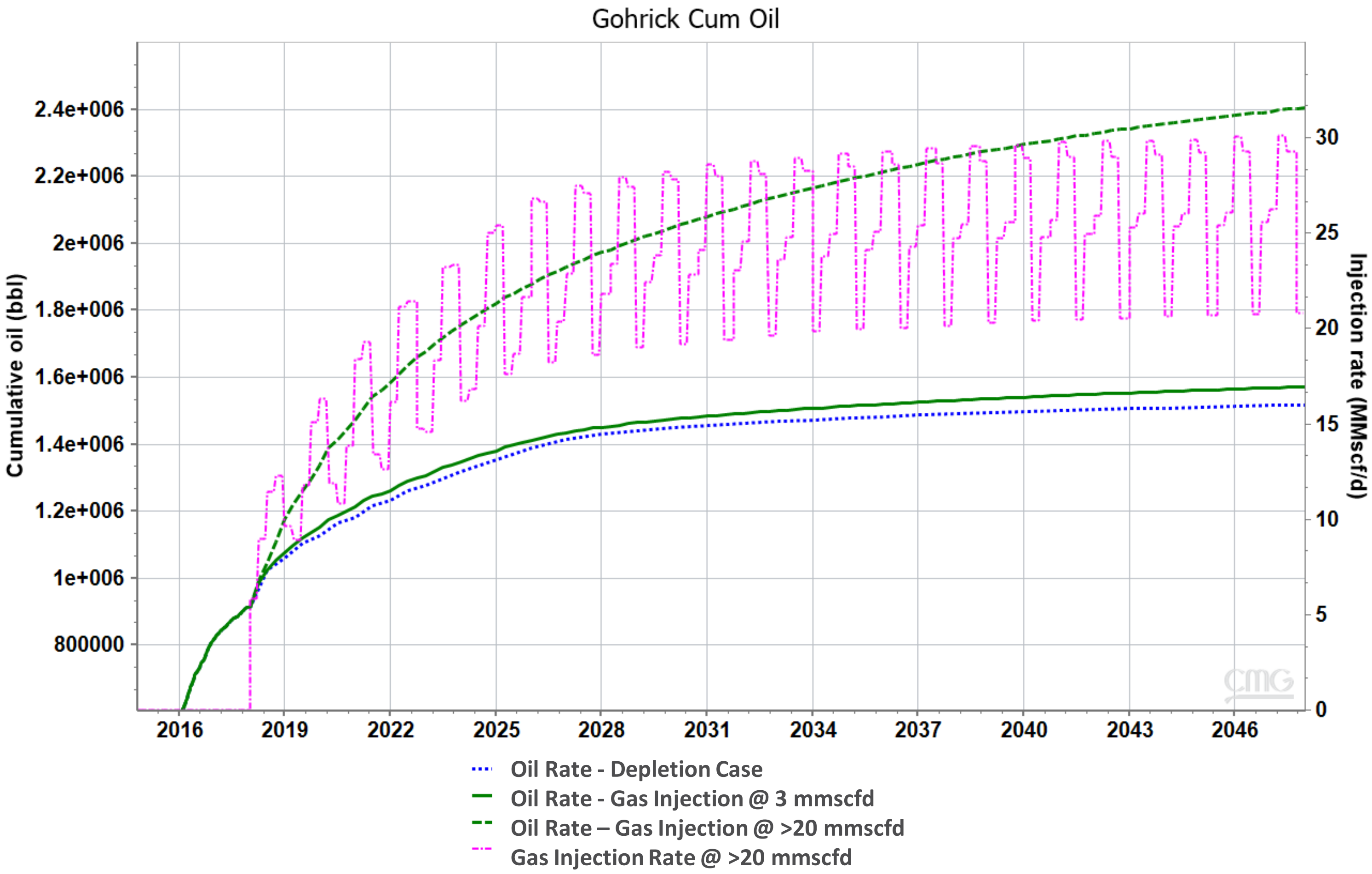
EERC JS58525.AI

Key Points:

- Well shut ins for HnP cycles offset oil rate benefits from gas injection.
- Long gas injection times at low rates are inefficient.
- Higher ratio of Production to Injection time is required for effective EOR.

Simulation Modeling EOR Predictive Runs

Go big with HnP Gas Injection for EOR in the Bakken!



- Low gas injection rates (<3 mmscfd) result in minimal EOR response.
- High gas injection rates (>20 mmscfd) yield high EOR response, similar to Eagle Ford reported results.

Field Observations

- Injectivity was readily established, and injection cycles could be integrated into routine operations; however, low gas injection rates had negligible EOR benefits.

- Reservoir surveillance and monitoring confirmed the injected gas can be controlled and contained within the Bakken and Three Forks intervals of the DSU.

- Pressure buildup occurred with gas injection and showed a positive trend toward achieving MMP.

- Static BHPs in wells after 3–5 years of production can be expected to be well below the bubble point and require substantial gas volumes to increase above an estimated MMP of ~2450 psi.

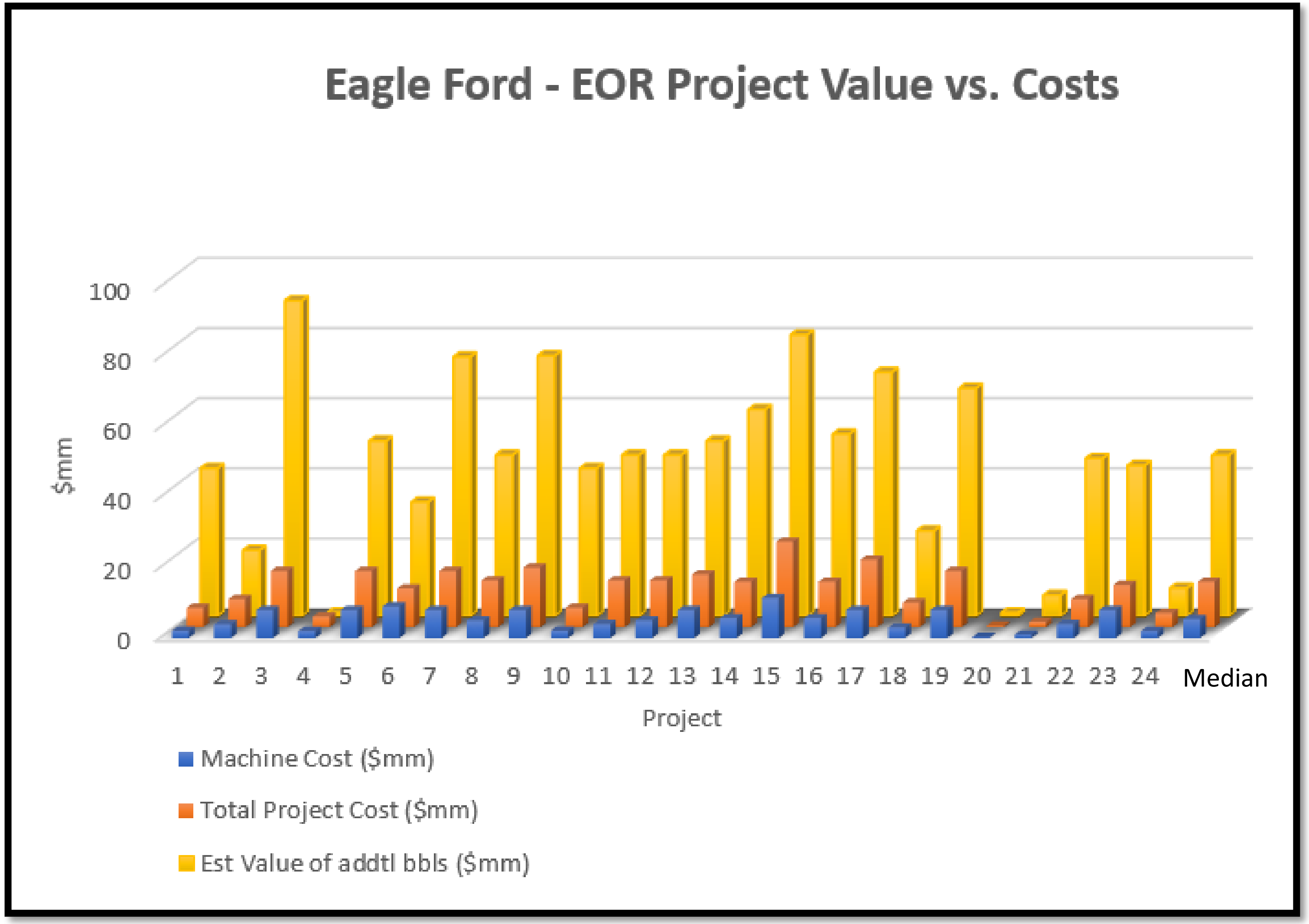
Key Lessons

- Lab studies indicate that produced gas is miscible with Bakken oil at pressures above 2450 psi.
- Reservoir pressures at or above MMP at start of injection would be most efficient to the EOR process.
- Jet pump artificial lift presents a cost-effective means for well huff ‘n’ puff conversion to gas injection and BHP monitoring.
- Huff ‘n’ puff cycles will require supplemental gas (above DSU volumes) to be economically viable.

Recommendations for Future Projects

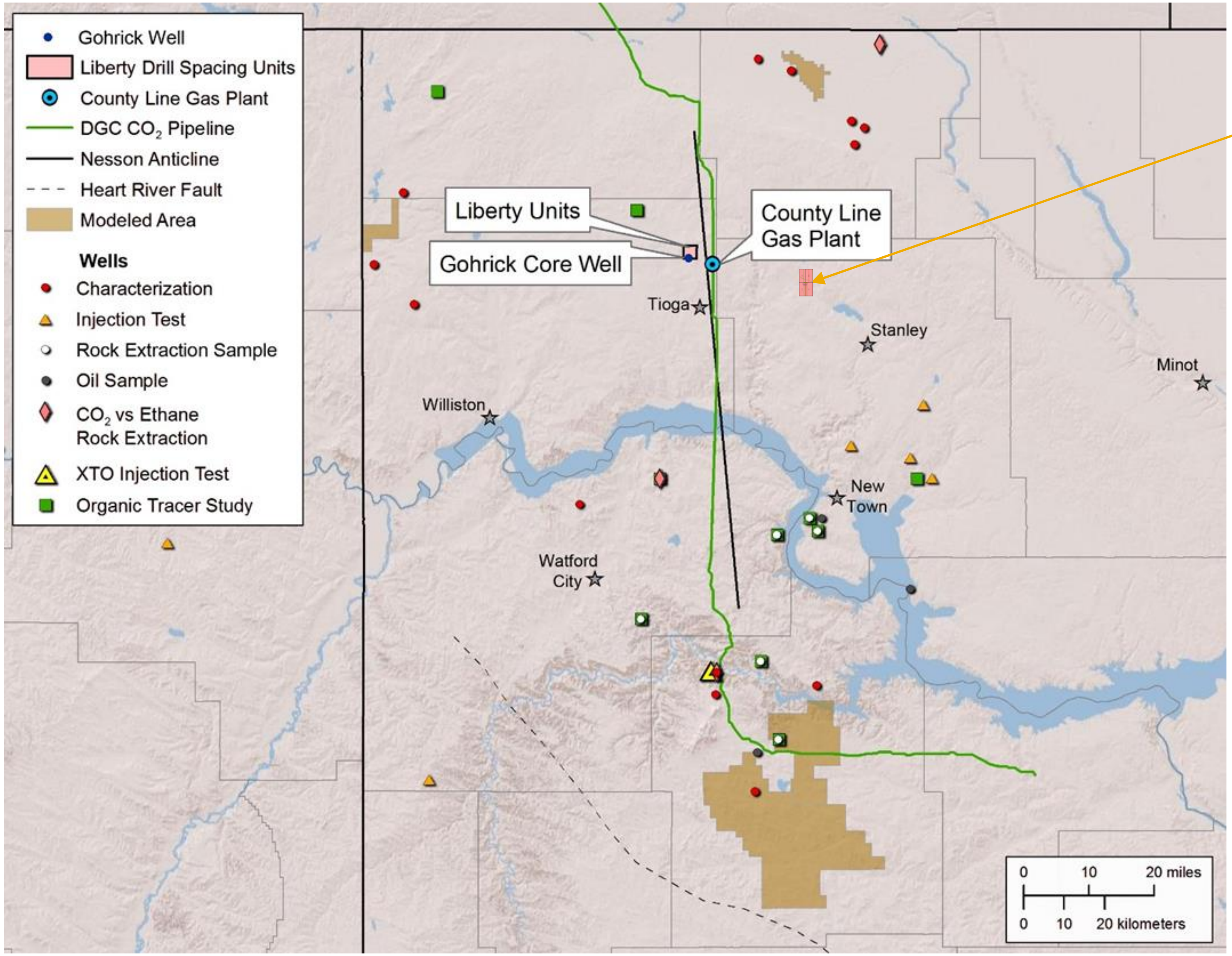
- Identify pilot or project locations with less depletion (higher BHPs) at the time of gas injection start-up or design for higher injection rates and volumes.
- Establish a regulatory basis and provide for larger gas supply rates.
- Consider water alternating gas injection for increased pressure and improved conformance.
- Implement huff ‘n’ puff cycles with BHPs clearly above MMP for injected gas to achieve predicted mechanistic production response.
- Consider geologic complexity and well spacing in site selection criteria and project design.

Eagle Ford Gas HnP EOR – TRRC Reported Results



Average project delivers >3.7X Value of Oil over Cost

Future Bakken EOR Projects



- **Liberty Resources –**
  - HnP Water/surfactant produced gas
  - 158-93-29/30/31/32
  - Simultaneous injection
  - ~3 mmscfd; ~5 mbwpd

NDIC Approved HnP Pilots:

- **Hess – HnP gas & foam**
  - 156-95-8/17
  - 8 mmscfd; 3.2 BCF
- **XTO – HnP produced gas**
  - 148-96-27/34
  - 8 mmscfd; 5.0 BCF
- **EOG – HnP produced gas**
  - 155-90-10/15,22,23, 27
  - >5 mmscfd;

Acknowledgments/Thank You/Questions

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