INL/CON-24-76550-Revision-0

Numerically Testing Conceptual Models of the Utah FORGE Reservoir Using July 2024 Circulation Test Data

February 2024

Changing the World's Energy Future

Robert K Podgorney, Lynn Brendon Munday

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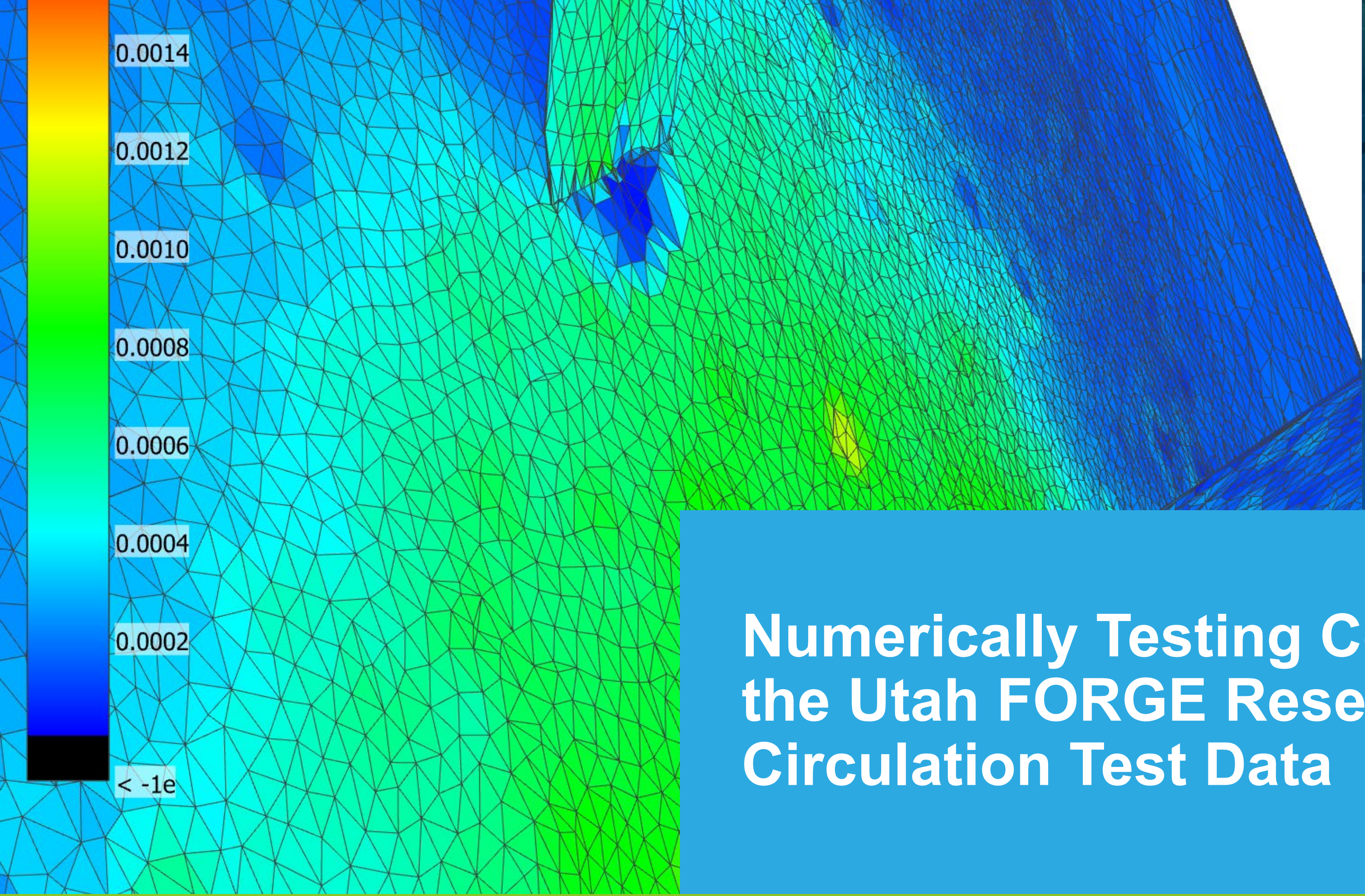


Robert Podgorney
Stanford Geothermal Workshop
February 2024

Numerically Testing Conceptual Models of the Utah FORGE Reservoir Using July 2024 Circulation Test Data

Lynn Munday and Robert Podgorney

Idaho National Laboratory

Introduction

- Many new data and observations have been made at the FORGE site over the past year or so
  - Stimulation of 16A
  - Drilling of 16B
  - Preliminary interwell flow testing
- In early October 2023, key members of the development, testing, and monitoring teams met for 2 days to review newly collected data and discuss ‘interesting’ or ‘key’ observations
- This presentation will briefly summarize that discussion, discuss selected key observations, and provide numerical sensitivity studies chosen to test the observations
- A full discussion of the conceptual model meeting can be found on the Utah FORGE website
- This is not meant to be a history matching exercise, rather an exploration to elucidate system behavior

Discussion Topics and Acknowledgements

Topic	Summary	Presenters
Observations from 16A Drilling and Characterization	Rock types, fractures, key observations	**Clay Jones and Aleta Finnila**
Stimulation of 16A	Pressures, fluids, flow rates and MEQ. Reservoir creation key takeaways	Pengju Xing, Branko Damjanac, Kevin England, Kris Pankow
16A Flowback geochemistry and tracers	Observation and trends in flowback waters. What do they tell us about the reservoir and fractures?	**Stuart Simmons**, Clay Jones, **Pete Rose**
16A Slug testing	Test description and procedures, observed pressures, flow rates, etc. Reservation permeability characterization key takeaways	Peter Meier, Rob Podgorney
Observations from 16B Drilling and Characterization	Rock types, fractures, key observations	**Clay Jones and Aleta Finnila**
16A-16B Interwell Flow Testing	Test description and procedures, observed pressures, flow rates, etc. Reservation connectivity key takeaways	Rob Podgorney, Peter Meier, **Kevin England**, Stuart Simmons, **Pengju Xing**, **Peter Niemz, Branko Damjanac**

7 Selected Key Takeaway Points

1. From the seismic team: *There is large uncertainty MEQ locations for stage 1 and 2 –. Fitting planes may be an over-interpretation.* Key Takeaway—The DFN based on the plane-fitting to the MEQ catalog that we have been using for modeling the reservoir may be an over-interpretation.

3. From the geology team: *>8 tons of saline material removed during flowback from 16A*. Key Takeaway—Likely a significant increase in porosity/permeability near the 16A wellbore, AND fracture filling material is likely dissolvable.

4. From the hydrogeology testing team: *Radial model was best fit for slug tests but volume interrogated likely small. Transmissivity (near wellbore) is quite high but extent is uncertain.* Key Takeaway—Potentially planar fractures stimulated near the 16A wellbore.

6. From the geology team: *Zones of high fracture intensity ~align between 16A and 16B. Individual fractures (most highly conductive zones on FMI) seem to align vertically.* Key Takeaway—Geologic structure between Wells 16A and 16B has continuity but exact geometric relationship needs to be confirmed.

7 Selected Key Takeaway Points

13. From the hydrogeology testing team: *Seemingly no changes in permeability over the July 2023 testing campaign.* Key Takeaway—July 2023 injections did not have a permanent affect on the reservoir. Further, the reservoir permeability did not respond in an expected poroelastic way.

14. From the hydrogeology testing team: *There is zonation of permeability field between 16A & 16B.* Key Takeaway—Permeability near Well 16A is significantly higher than the permeability near Well 16B. The nature of the transition is uncertain.

15. From the seismic team: *Fracturing did occur during the July 2023 flow testing, mostly measurable in Stage 3*. Key Takeaway—Pressure drop associated with flowing Well 16B was not enough, or the well wasn't connected to the formation enough, to keep the far field pressure below the frack gradient.

16A Slug Testing

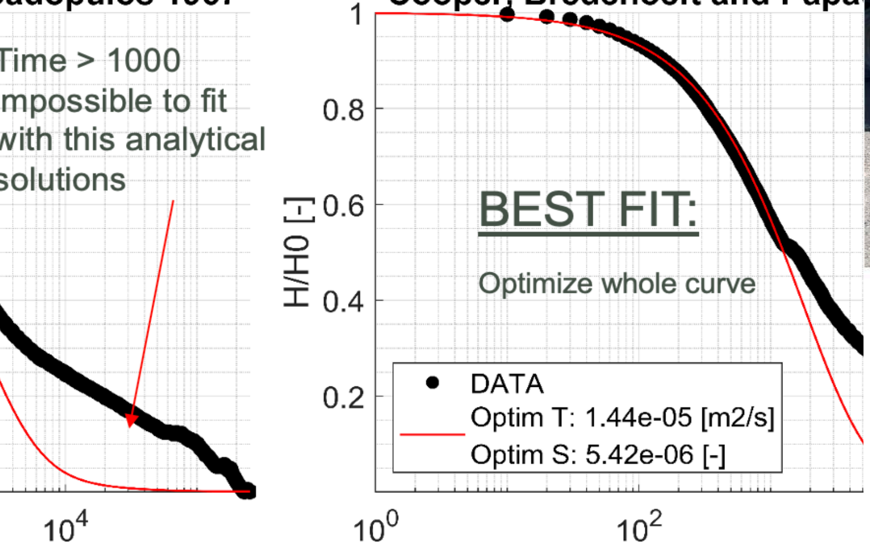
EST A. FULL dataset

09-06-2023 16A // log-time Absolute Pressure

adopulos 1967

Time > 1000
mpossible to fit
with this analytical
solutions

16A - TEST A - 09/06/2023
Cooper, Bredehoeft and Papa



5 [bar]

Formation Pressure 11
(absolute pressure)

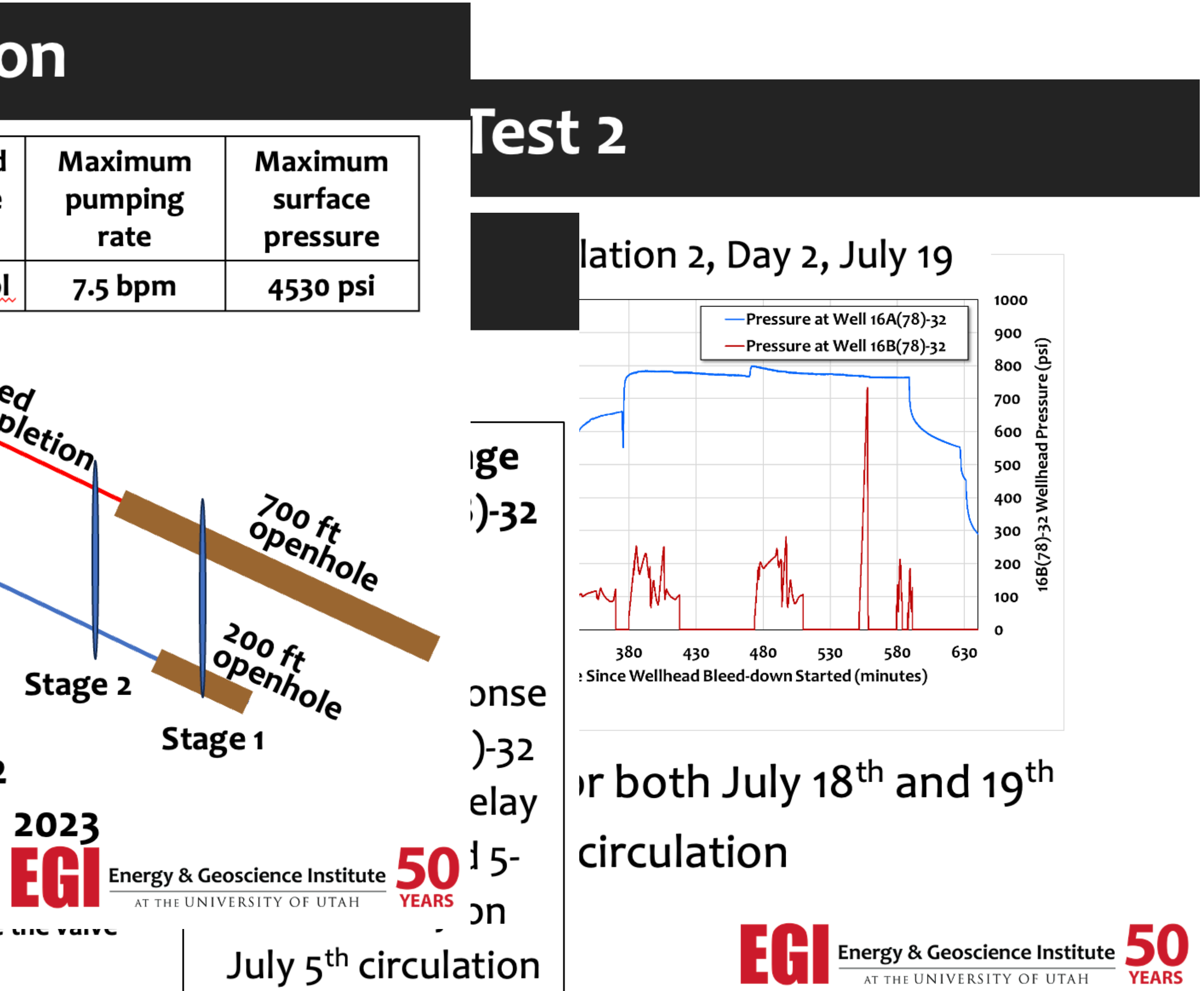
s]

FIT: time 0 [s] to 1500 [s]

E-5 [m2/s] with S of between 1E-4 and 5E-6 [-]

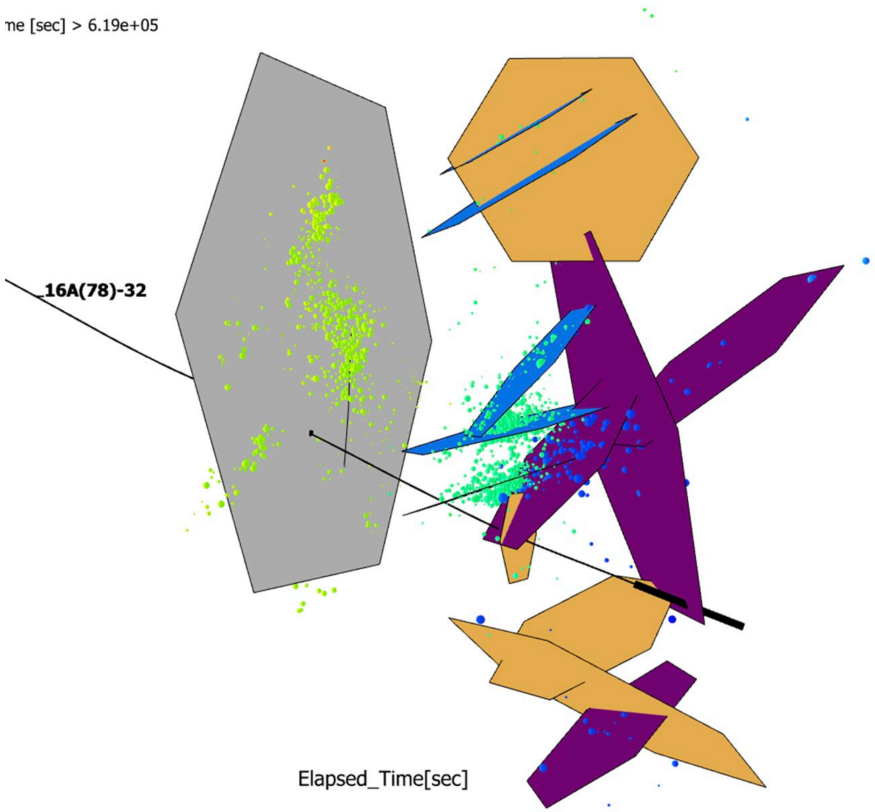
*See presentation by Pengju Xing

16A-16B Interwell Flow Testing

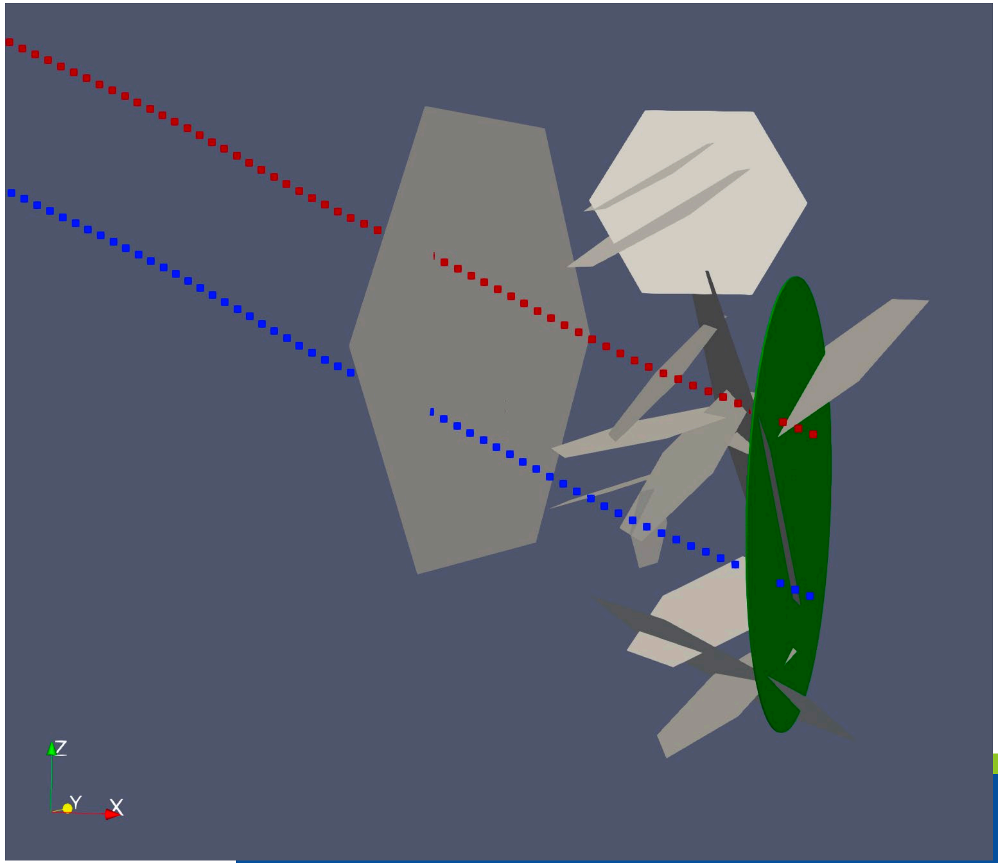


Stimulated Volume in Well 16A

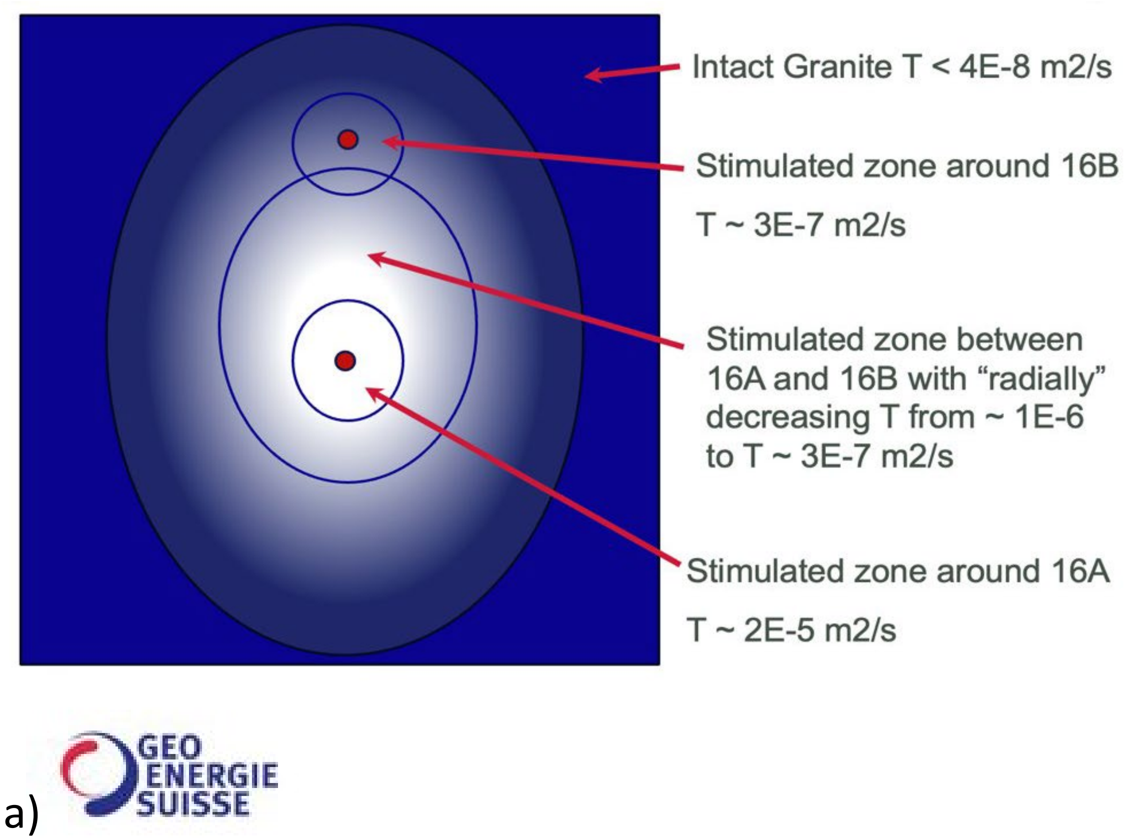
- MEQ data from April 2022 stimulation was used to create a DFN of potentially interconnected fractures



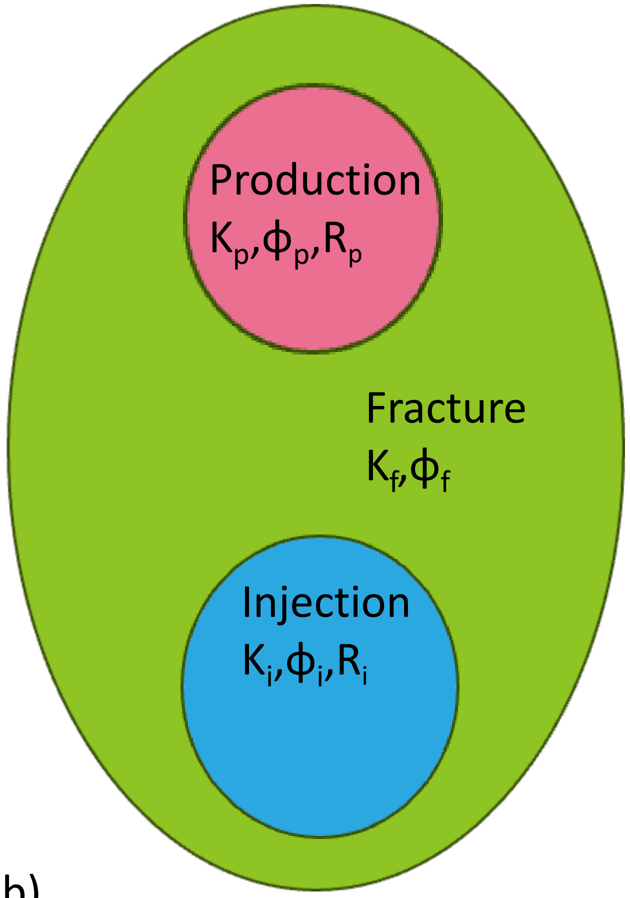
- Size of zone 3 fracture
- Ellipse with R_{maj}=140m, R_{min}=100m
- 100m separation of injection and production wells



Simplified Conceptual Model



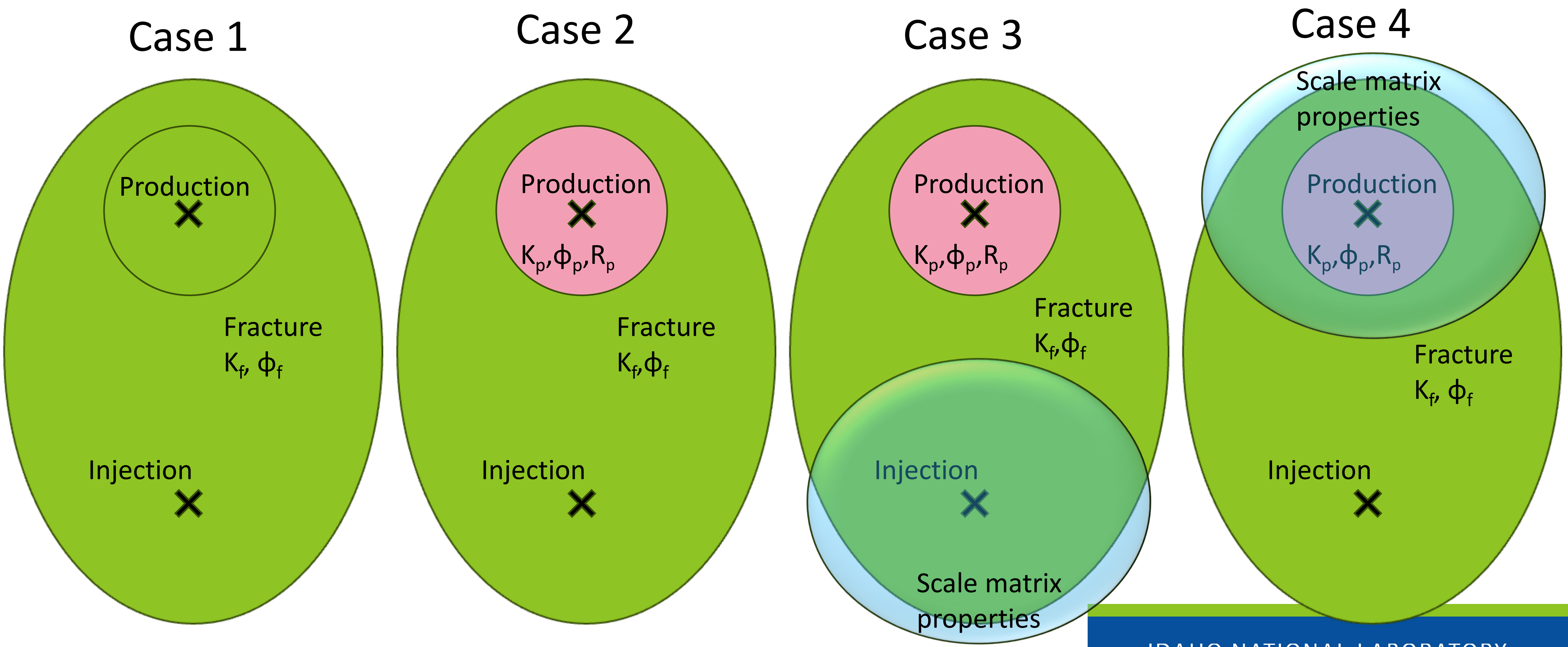
a)



b)

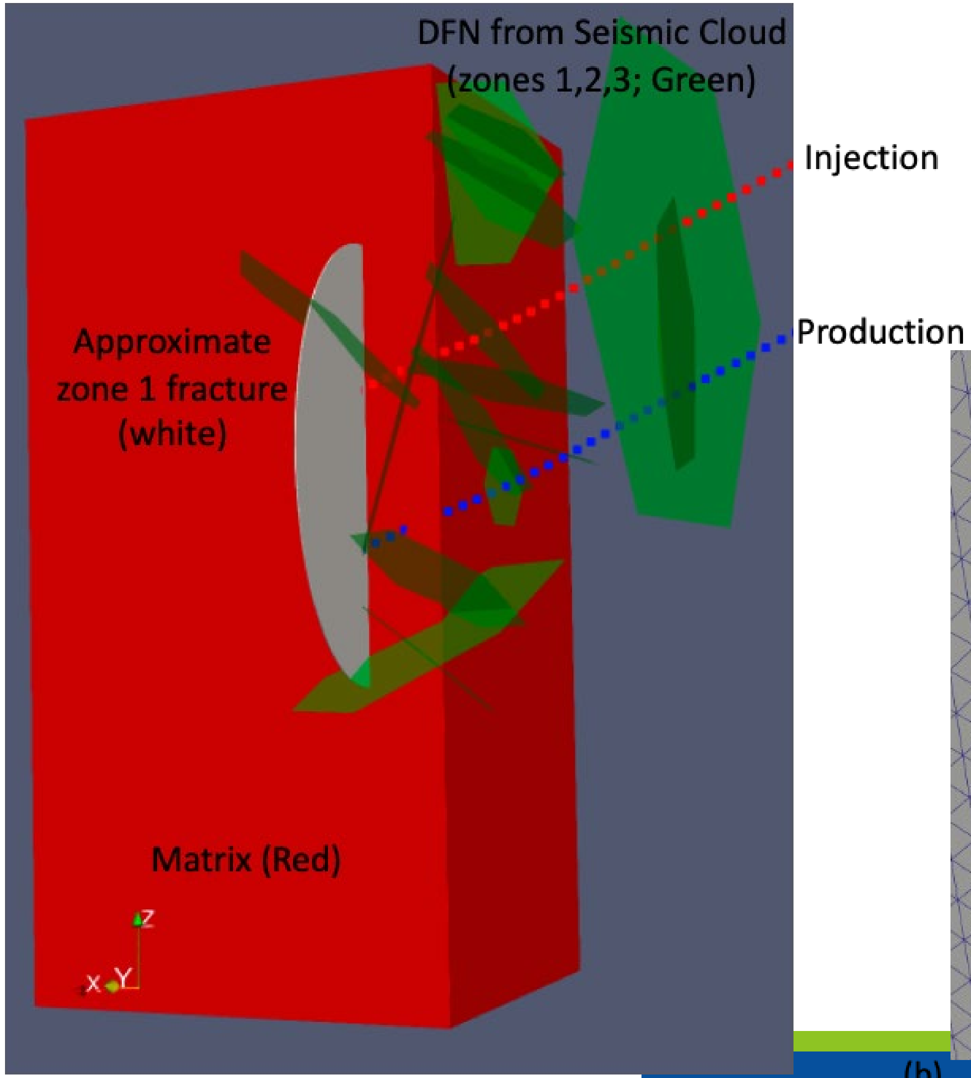
- 8 tons of Halite were washed out of injection well
- ~ Volume of Halite removed 3.6m^3
- A circular fracture w/ radius between 0.10 to 10mm would be ~10 to 100 meters
- Simulations were fairly insensitive to the injection radius when permeability is ~1e-12 m^2 or higher

Simplified Conceptual Model Cases

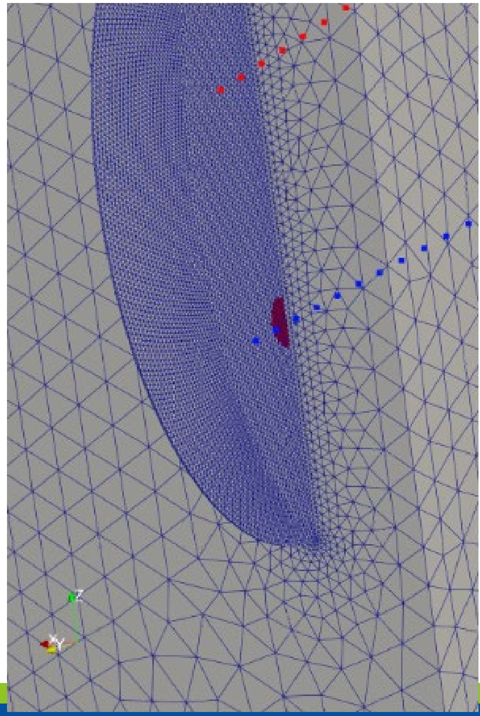


Model Domain and Boundary Conditions

- The fractures being modeled are located near the toe of Well 16A
- There are approx. 15 fractures interpreted in the stimulated volume in the original model
- Model domain is a 400 X 300 X 600m block of granitic rock reservoir
- Boundary and initial conditions are taken from the Phase 3 native state model
  - Dirichlet on top for pressure and temperature
  - Dirichlet on bottom for temperature



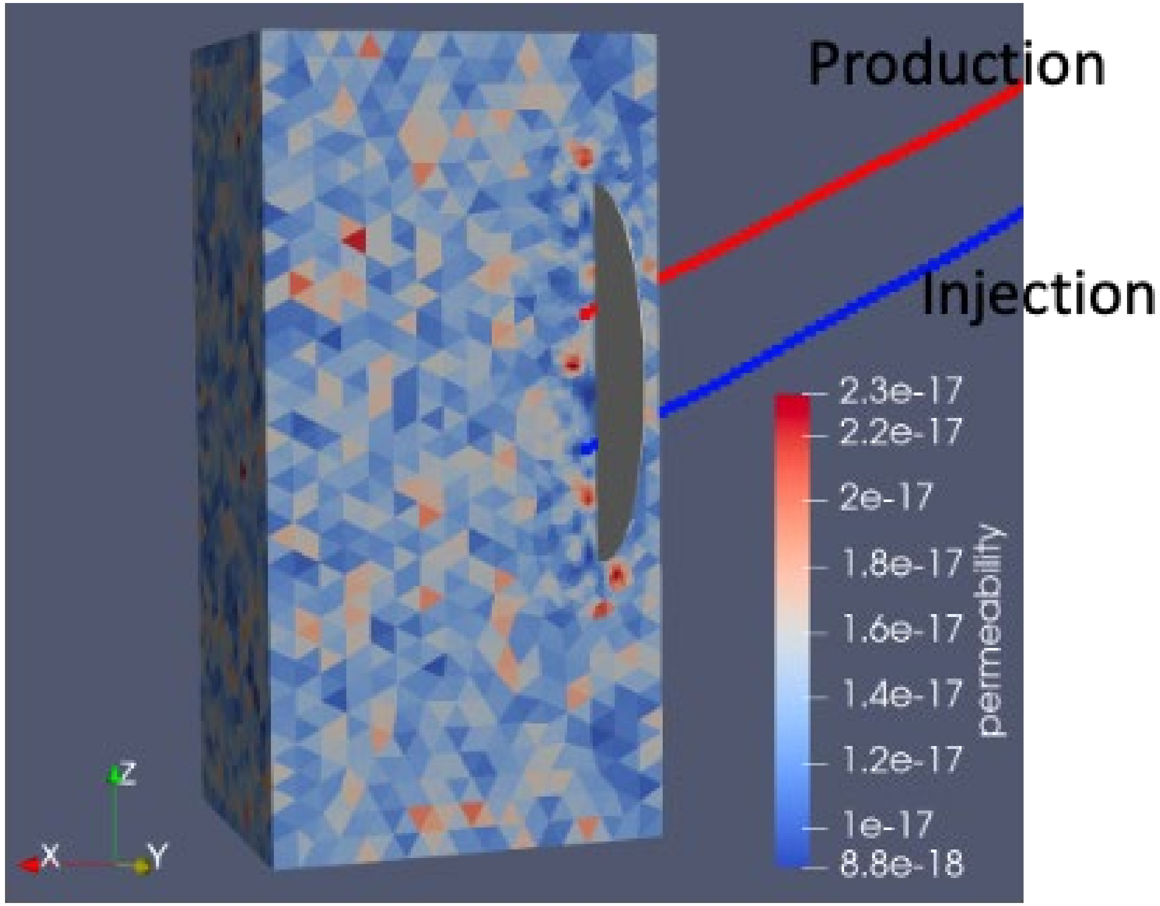
(a)



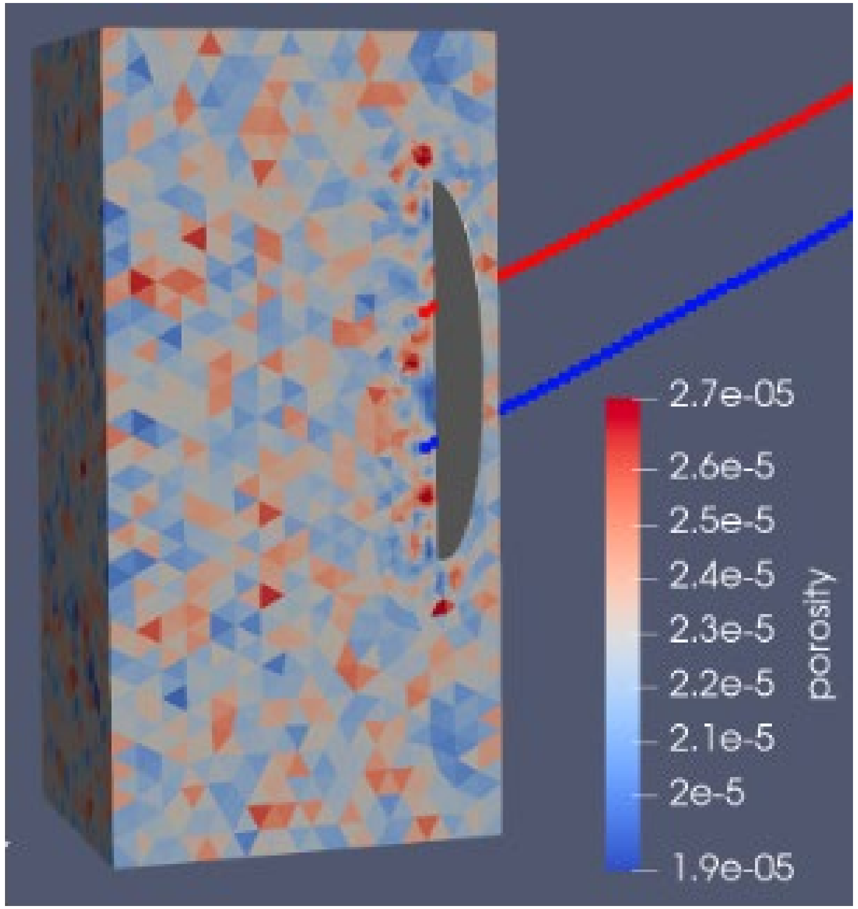
(b)

Background Matrix Properties

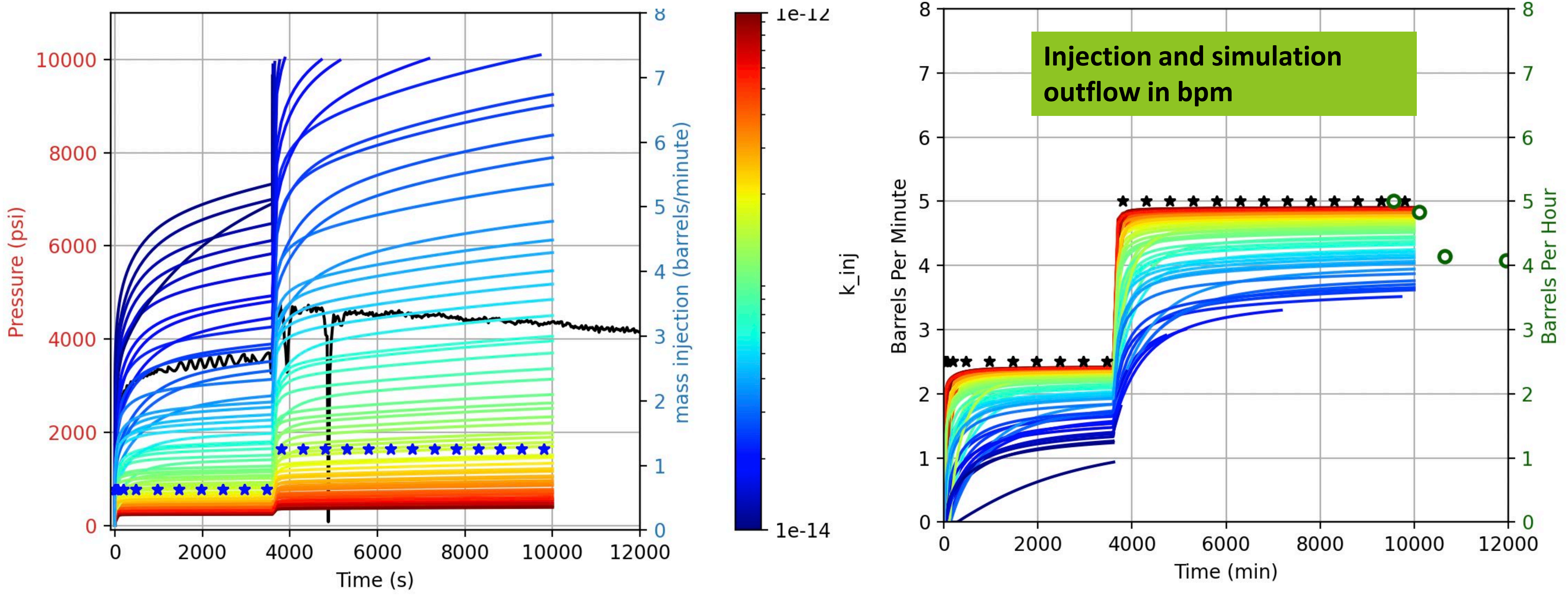
(a)



(b)

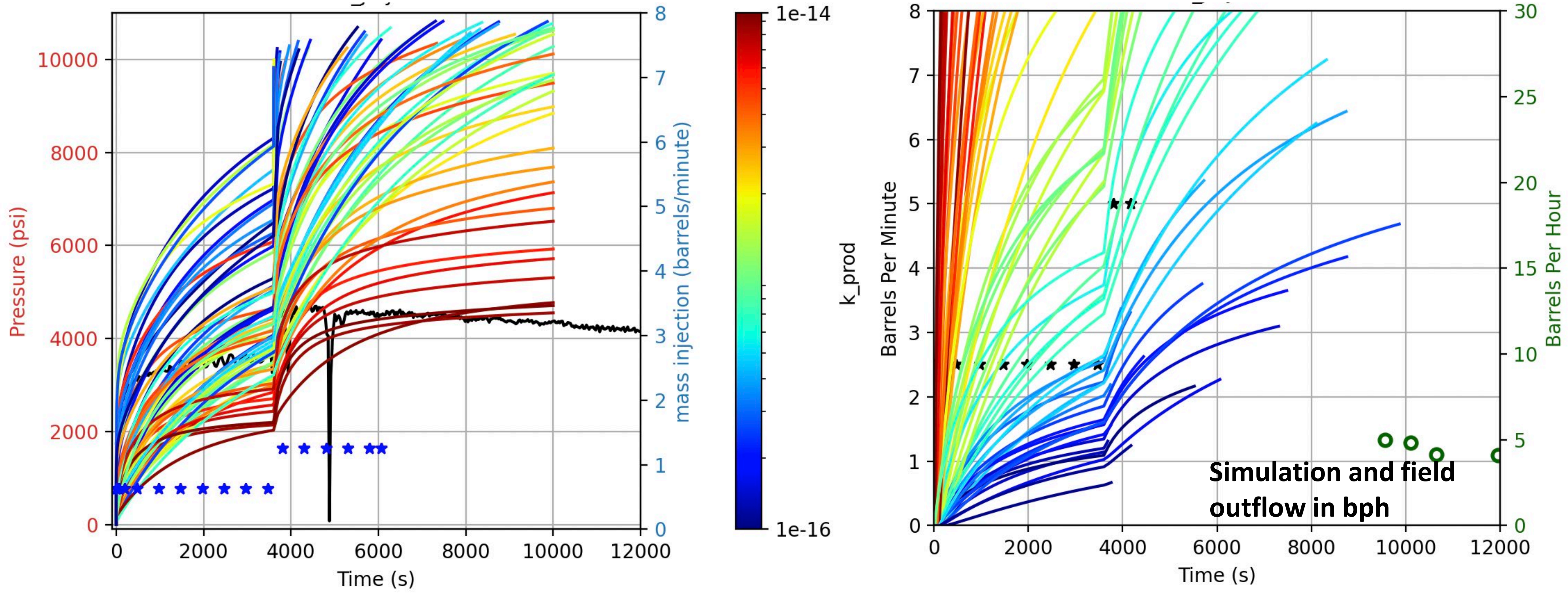


Case 1: July 18 TH Results



Match 2.5 bpm pressure but outflow is 60x too high

Case 2: July 18 TH Results

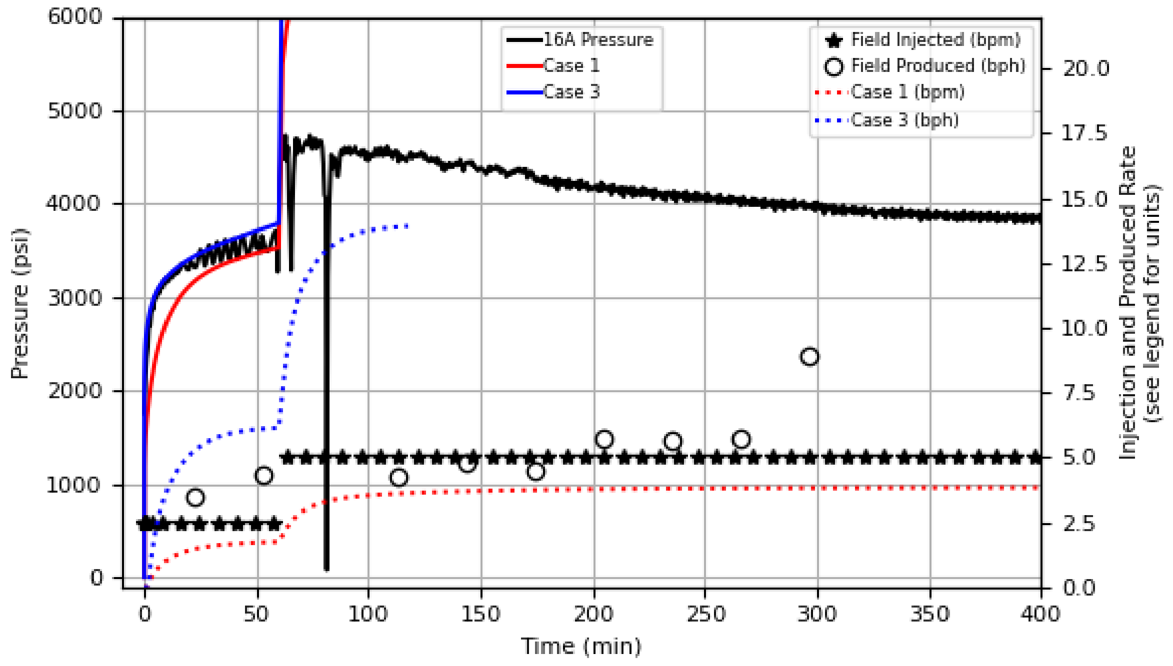


Better match to outflow (~2x) but pressure is too high.

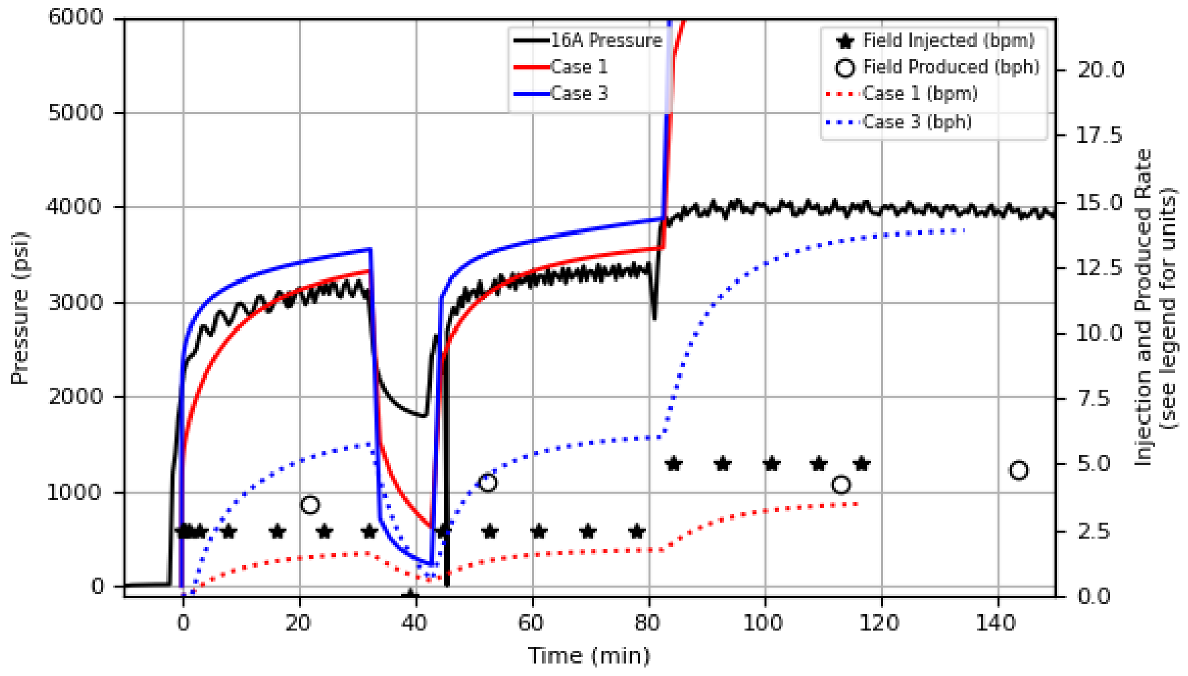
July 18 &19 TH Cases 1 & 3

By logarithmically decaying permeabilities in fracture and logarithmically scaling matrix properties, early time well head pressure and outflow can be fit with the same parameter for both days

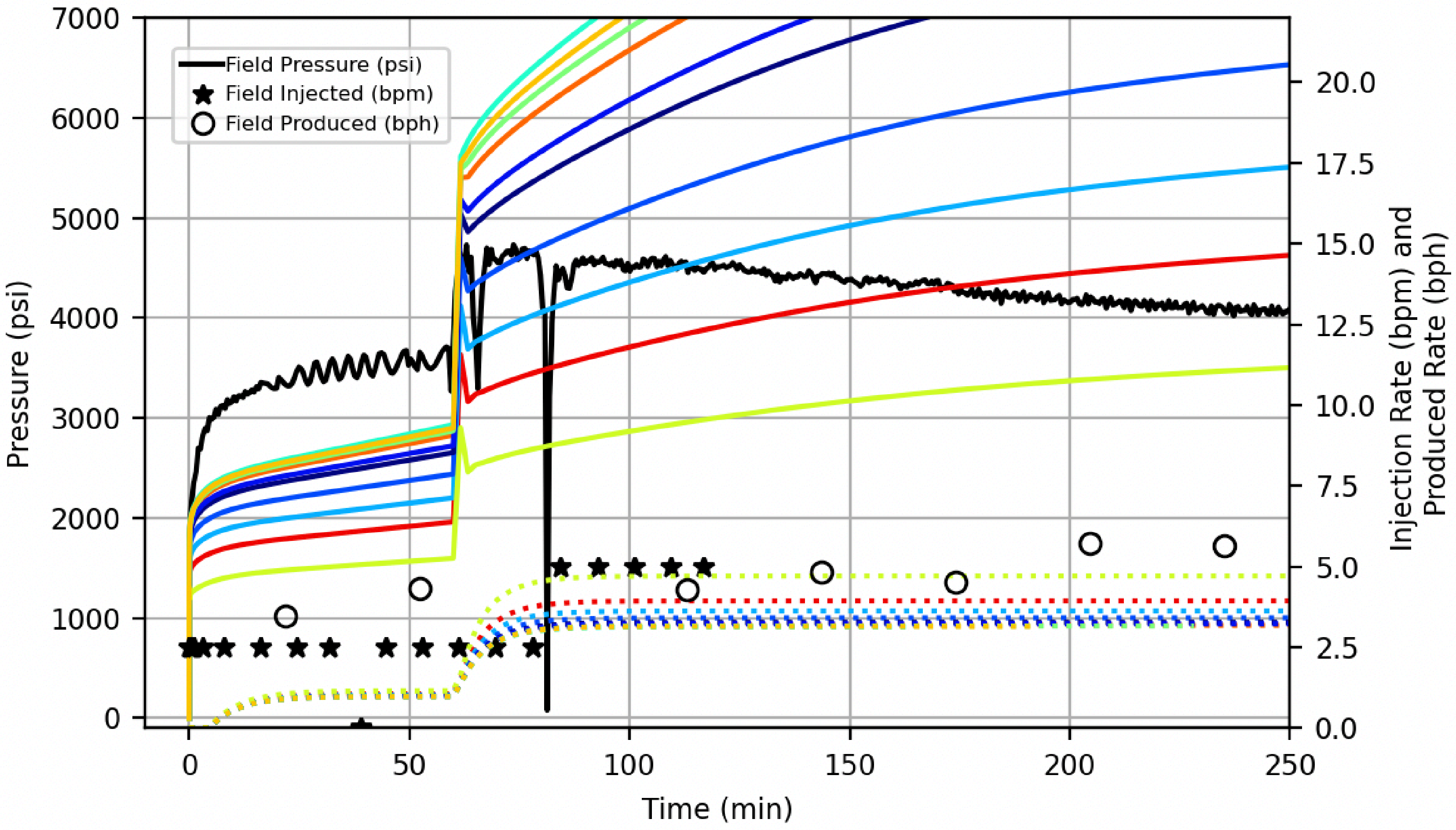
July 18



July 19



THM Case 3—Strain Based Fracture Permeability



Sample over fracture permeability scaling factor C: $k = k_o(1 + C\epsilon_{vol})$

Summary and Conclusions

- Fractures connect wells 16A & 16—with uncertainty in their geometry, permeability and porosity
- Simulations were insensitive to the radius around injection well where salt conceptually “washed out” so long as permeability of zone was ~1e-12 m2 or higher
- Case 3 produced the best match to field data
  - Need a low permeability zone around 16B
  - Matrix flow properties scaled to all fluid leakoff from fracture, moderated pressure response
  - Linearly coupled elastic mechanics to fracture permeability and porosity
- Pressure drop can only be captured with nonlinear fracture mechanics
- Fracture growth needs (and will be) included, but likely will not add enough volume to accommodate injected fluid
  - Single fracture model not enough….

Case 3