SWD Effects on Bakken Drilling

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Continental RESOURCES

DRIVEN TO LEAD.

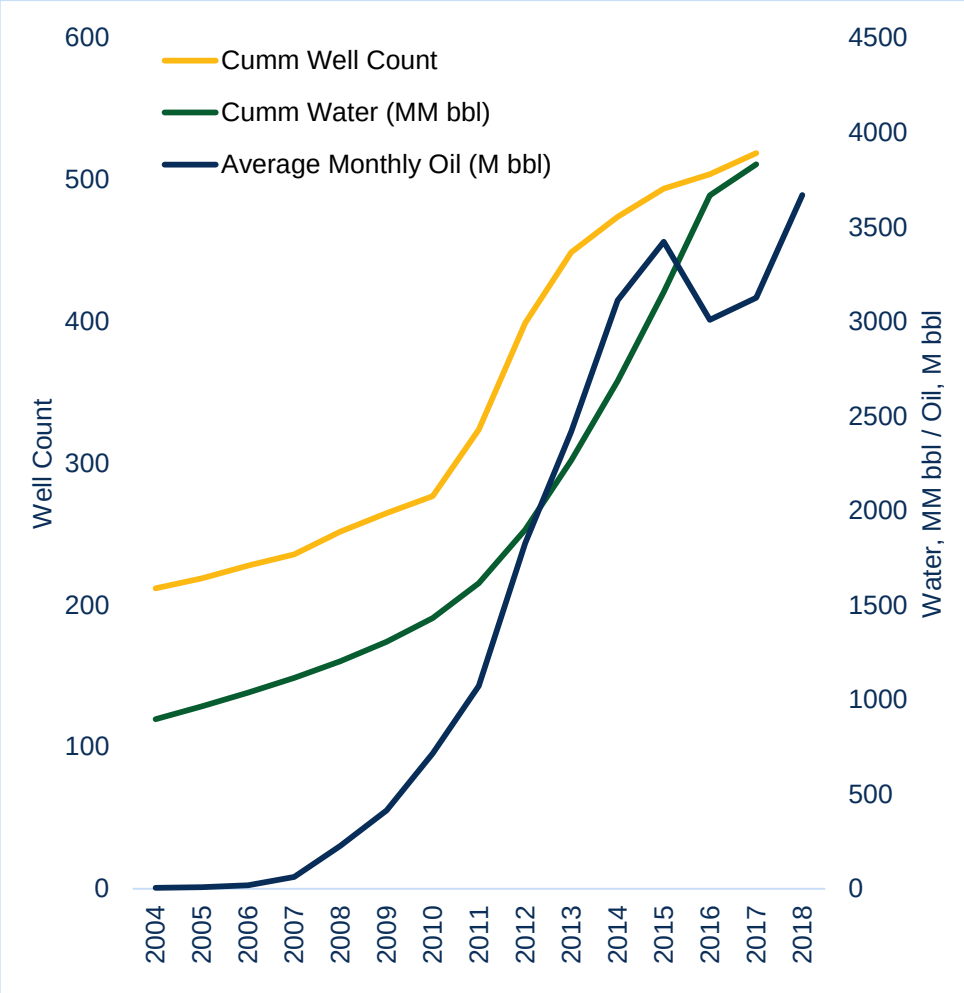
EMPOWERED TO EXPLORE.

NYSE: CLR

Outline

1) Water disposal in the Williston Basin, ND
2) Case studies: Drilling through the Dakota Sands
3) Geologic Background
4) Challenges predicting Dakota water flow
5) Bakken Casing design
6) Appraisal Well Program
7) Operational and Cost Impact
8) Future in the Bakken – Unanswered Question’s
9) Questions

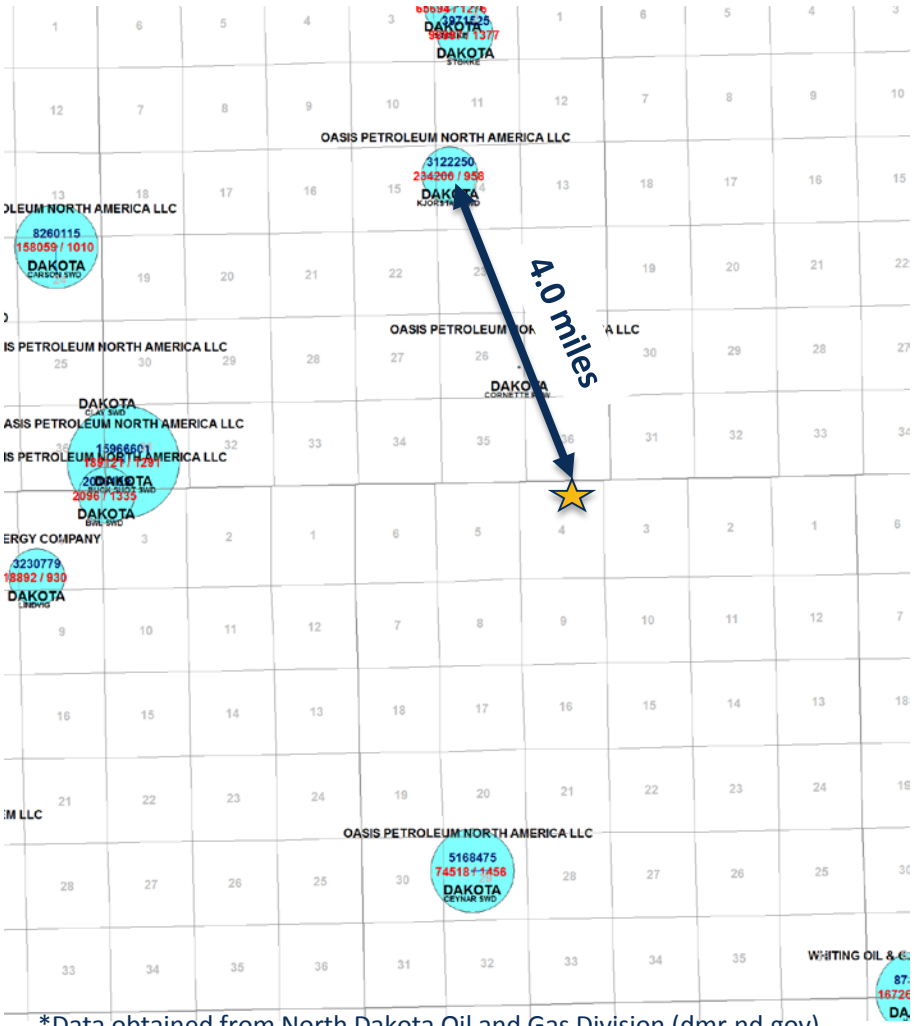
Dakota Water Disposal – North Dakota



- Over 15,000 horizontal wells in ND (Bakken/ Three Forks)
- ~2.4 billion bbls oil produced
- SWD well count growing
- Injection Interval -Dakota Sands

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)

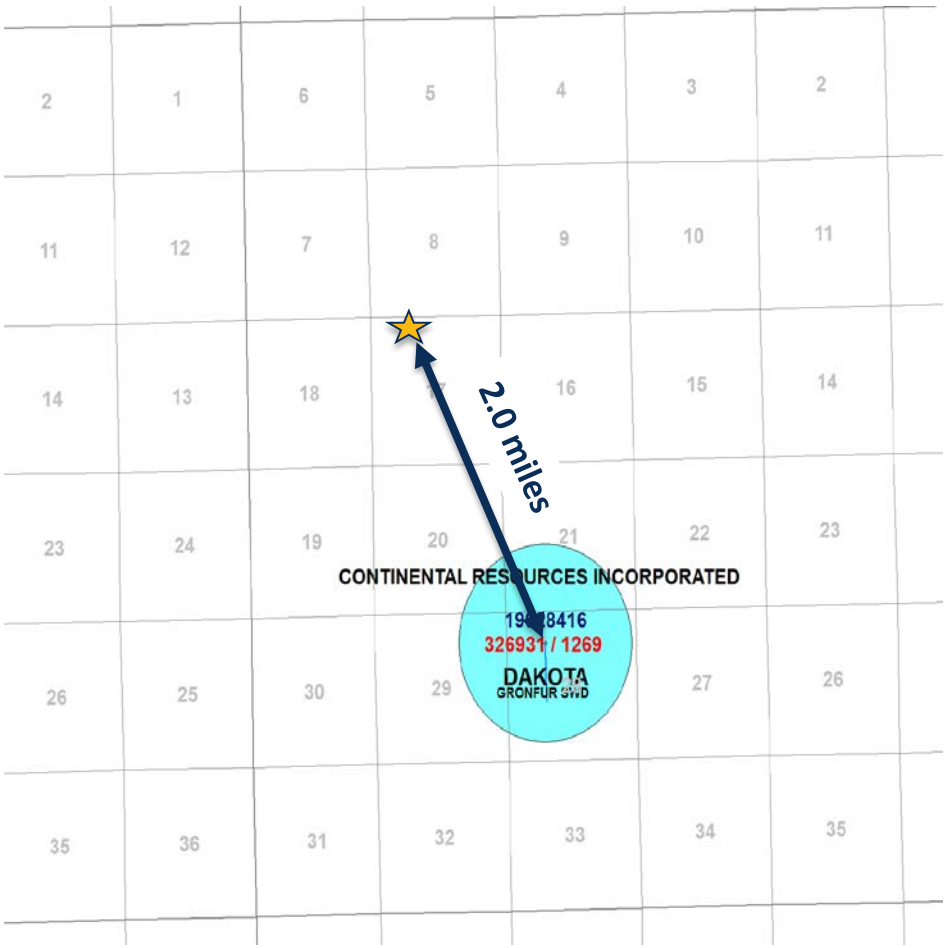
Case Study: Pad 1



*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)

- Initial Dakota water flow seen in Q1 2018
- Offset SWD
  - 3.1MM bbl cum injected volume*
  - 950 psi surface injection pressure *
- Dakota water flow while drilling w/ 10.5 ppg mud weight
- Required 11.6 ppg mud weight
- Drilled ahead to Mission Canyon and lost returns
- Unable to recover wellbore
- Redesign of well construction required re-drill of surface on all wells on pad

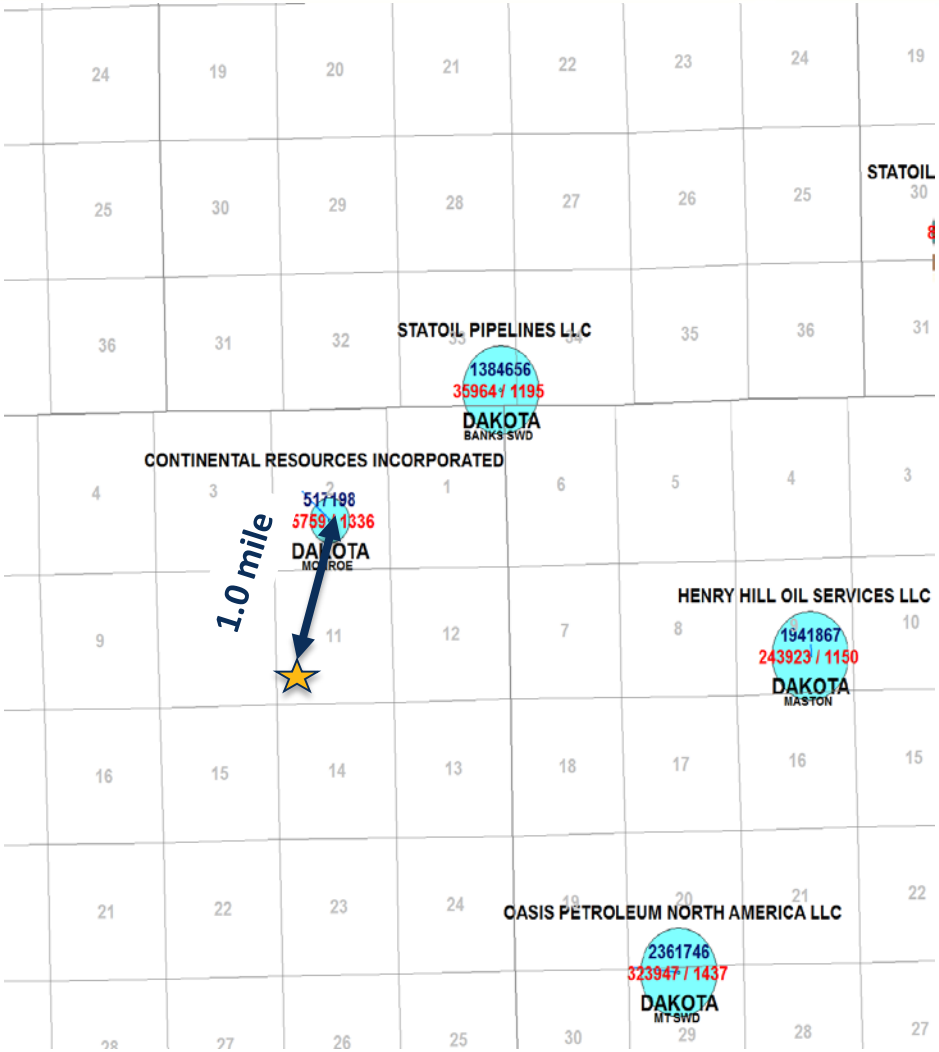
Case Study: Pad 2



- 4 well pad
- Offset SWD
  - 17.7MM bbl cum injected volume*
  - 1,100 psi surface injection pressure*
- Drilled Dakota w/ 10.6-10.9 ppg OBM, no flow

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)

Case Study: Pad 3

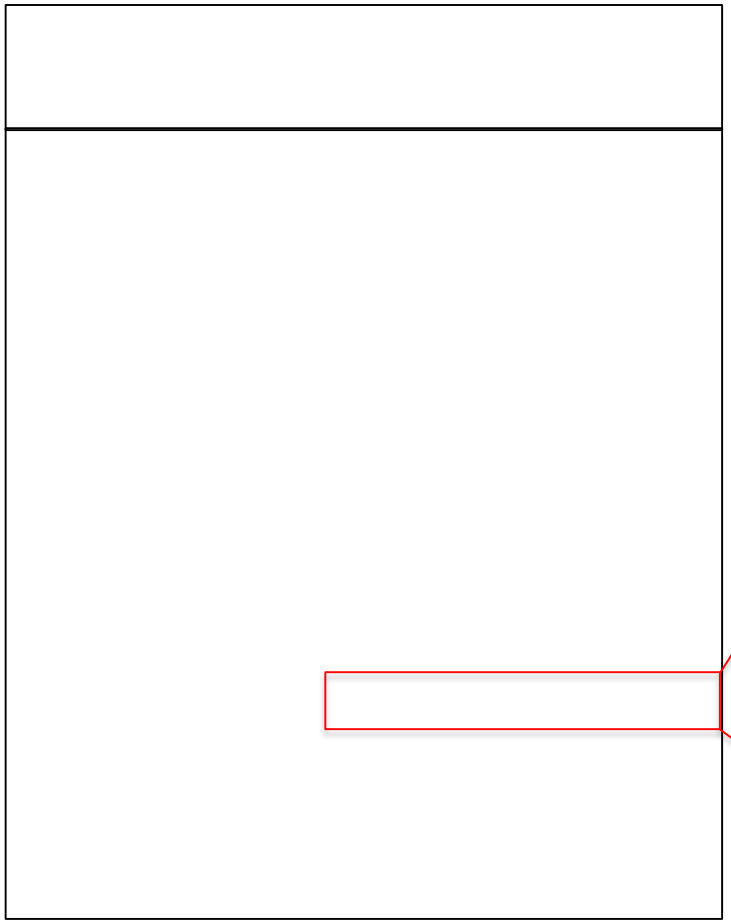


- 6 well pad (45’ well spacing)
- Offset SWD
  - 517K bbl cum injected volume*
  - 1,100 psi surface injection pressure*
- Well 1 – Drilled Dakota w/ 10.1 ppg, water influx, required 11.1 ppg
- Well 2 – Drilled Dakota w/ 11.1 ppg, no flow
- Well 3 – Drilled Dakota w/ 11.1 ppg, water influx, required 12.5 ppg
- Set intermediate casing across Dakota on remaining wells on pad

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)

Geologic Setting

- Inyan Kara (*Dakota*)
  - Lower Cretaceous



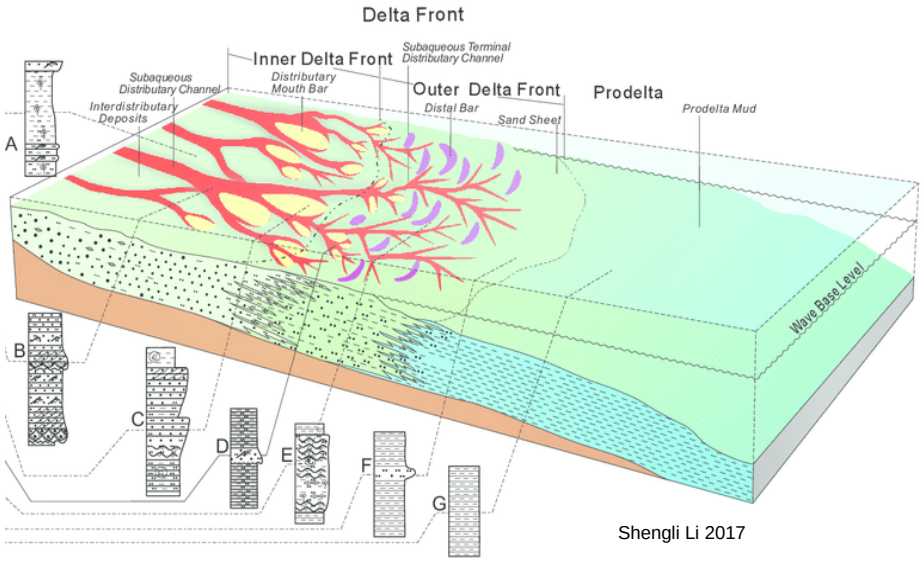
Murphy 2009

- Western Interior Seaway Transgression
- Fluvial/Deltaic System

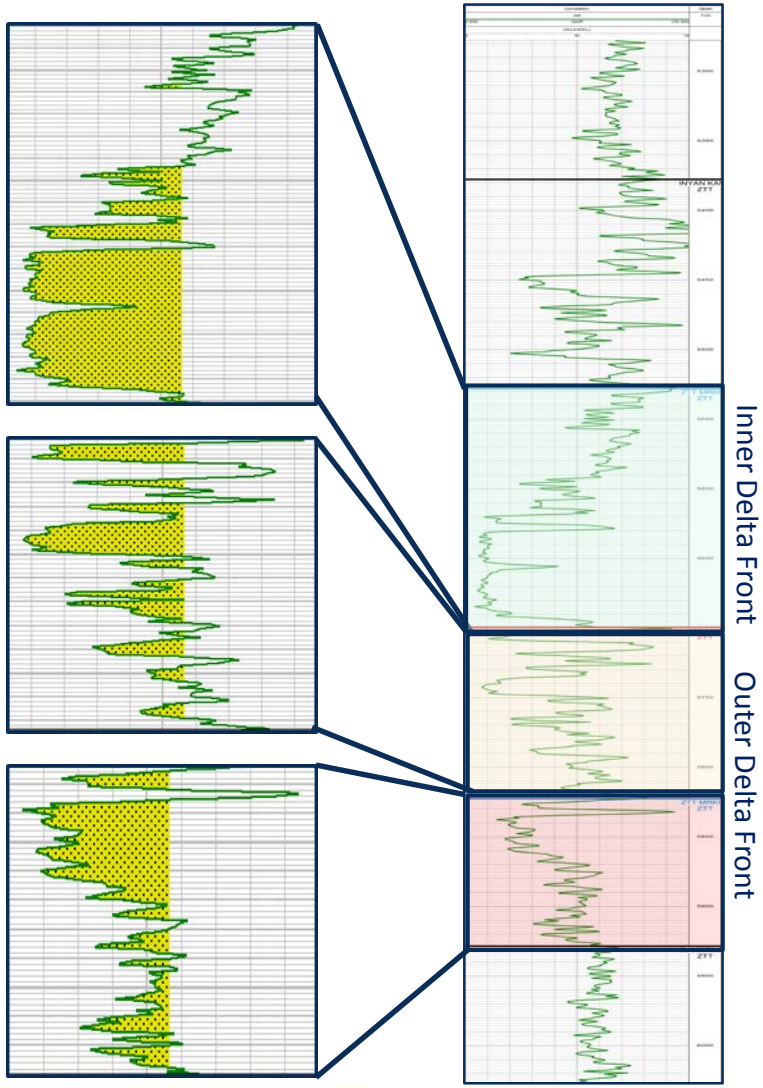
Blakey 2012

Depositional Environment

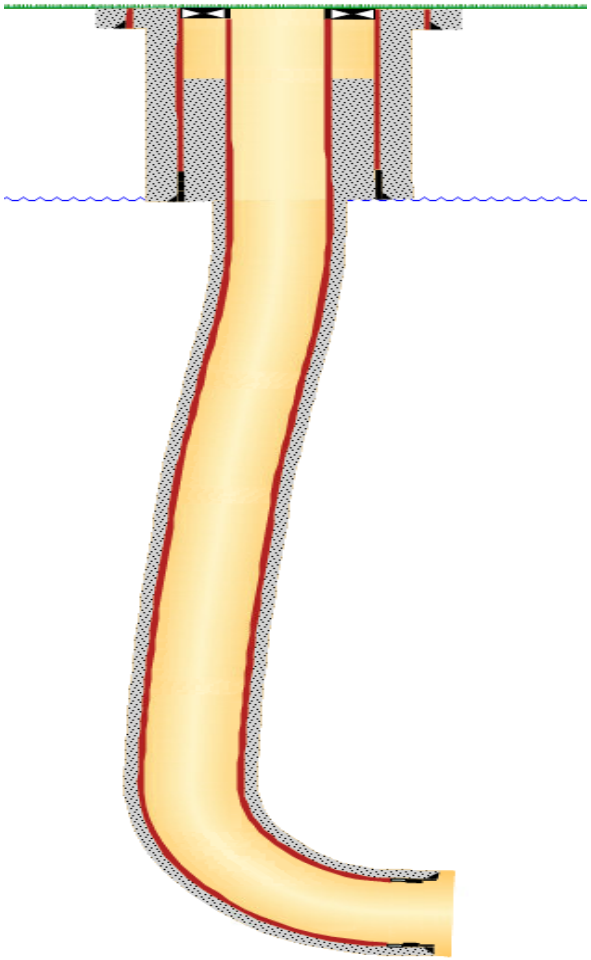
- Inner Delta Front
  - I. Fluvial & Distributary Channels
  - II. Delta Progradation
- Outer Delta Front
  - I. Prograding Distal Bars
  - II. Tidal Channels
  - III. Central Bay/Prodelta



Shengli Li 2017



Standard Well Design



Surface

- 9-5/8” set at ~2,000’ TVD

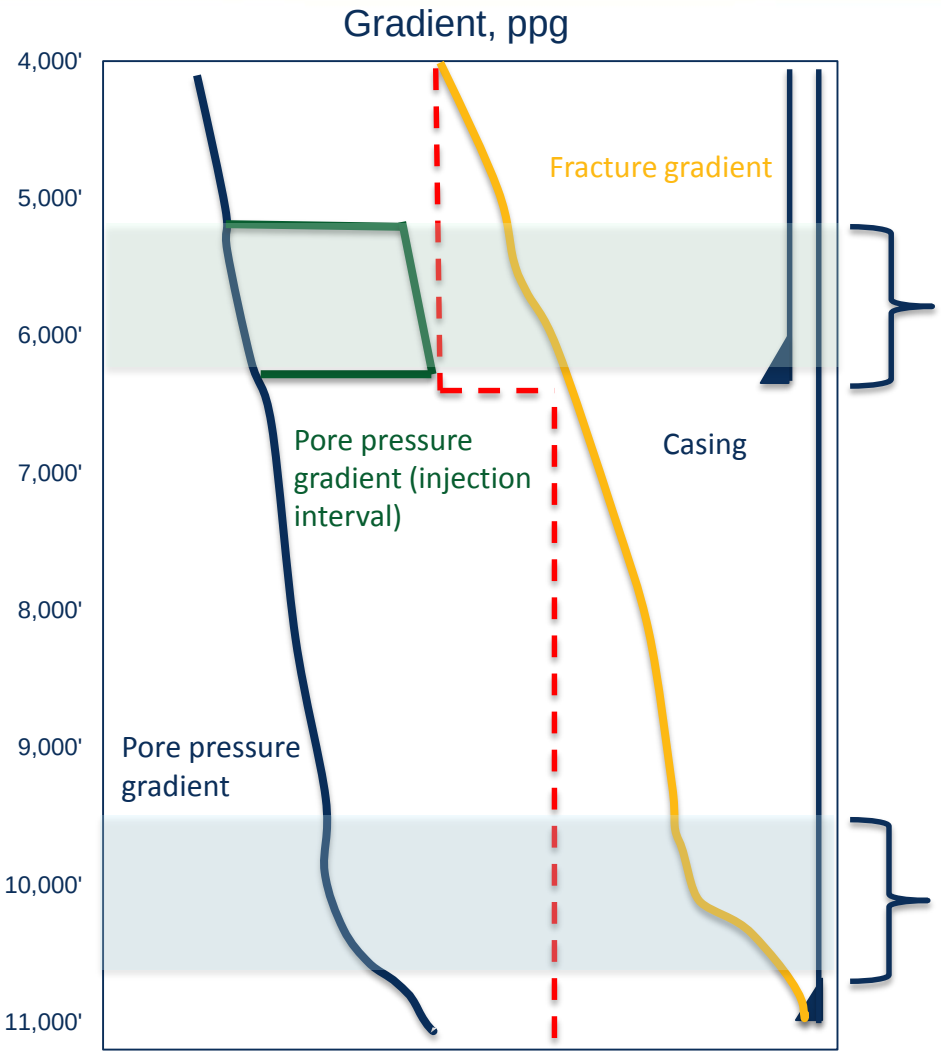
Intermediate

- 7” set at ~11,150’ TVD/ 11,500’ MD
- Casing set at end of curve

Production Liner

- 4-1/2” Cemented liner from TD to KOP

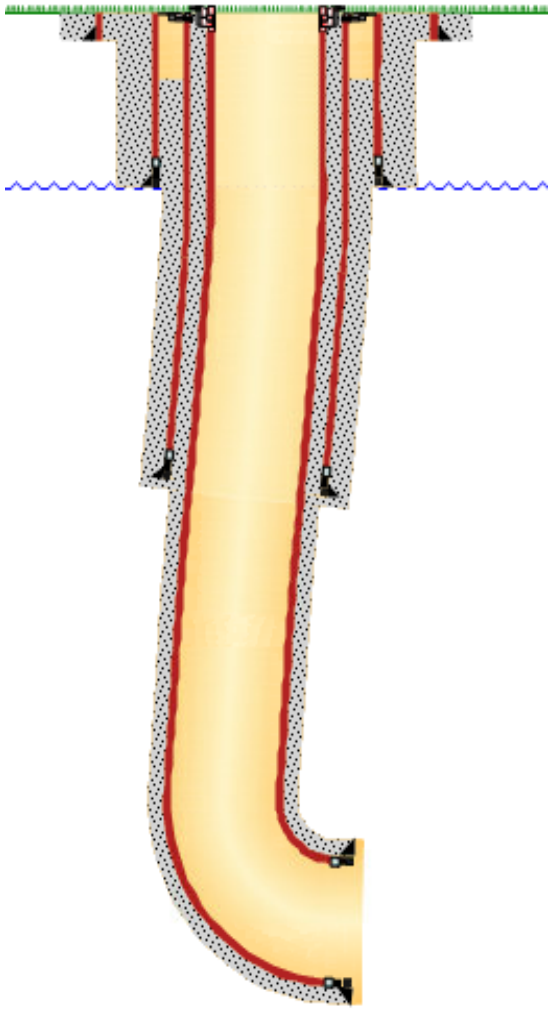
Over pressured Dakota Sands



Dakota Group: Injection zone can be up to 2.5 ppg over normal pressure gradient

Mission Canyon: Known loss circulation zone above 10.8 – 11.0 ppg

“4 String” Well Design



Surface

- 13-3/8” set at ~2,000’ TVD

Intermediate 1

- 9-5/8” set at ~6,100’ TVD
- Casing shoe ~100’ below Dakota Base

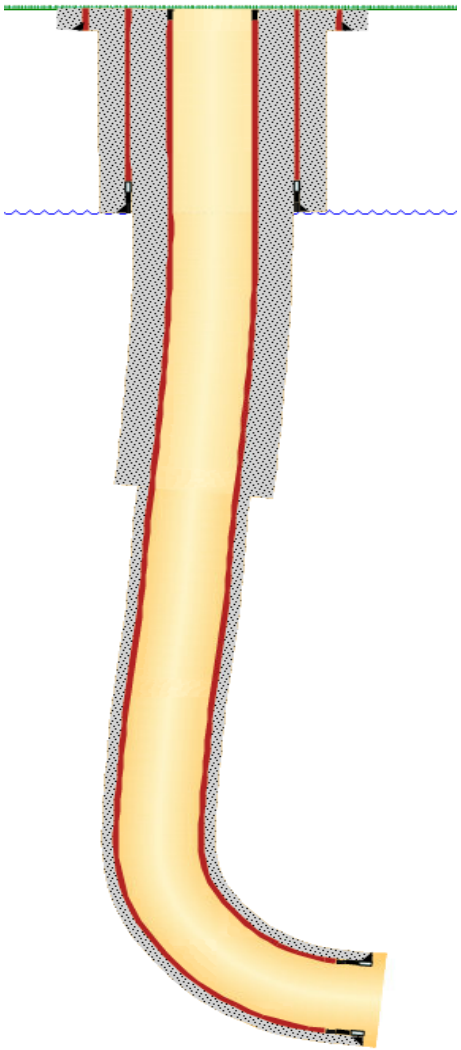
Intermediate 2

- 7” set at ~11,150’ TVD/ 11,500’ MD
- Casing set at end of curve

Production Liner

- 4-1/2” Cemented liner from TD to KOP

Appraisal Well



Surface

- 13-3/8” set at ~2,000’ TVD

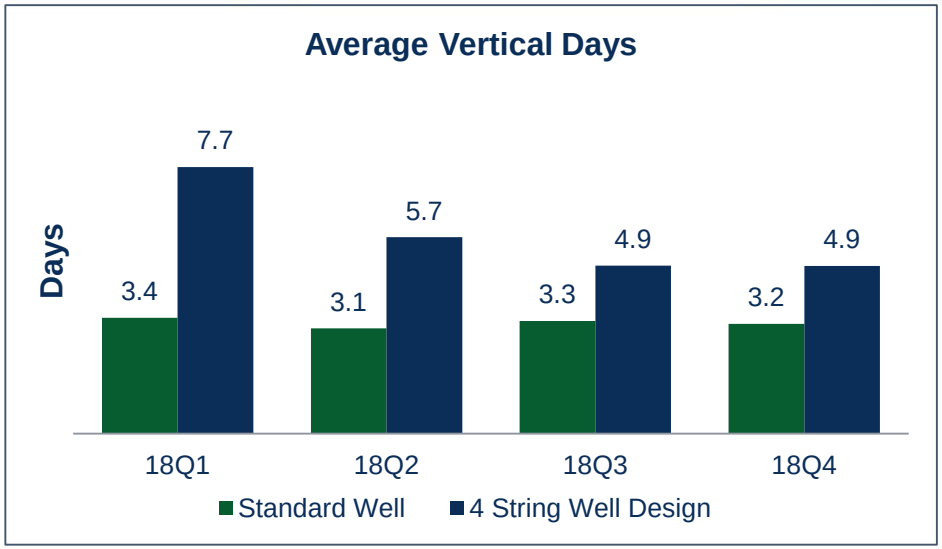
Intermediate

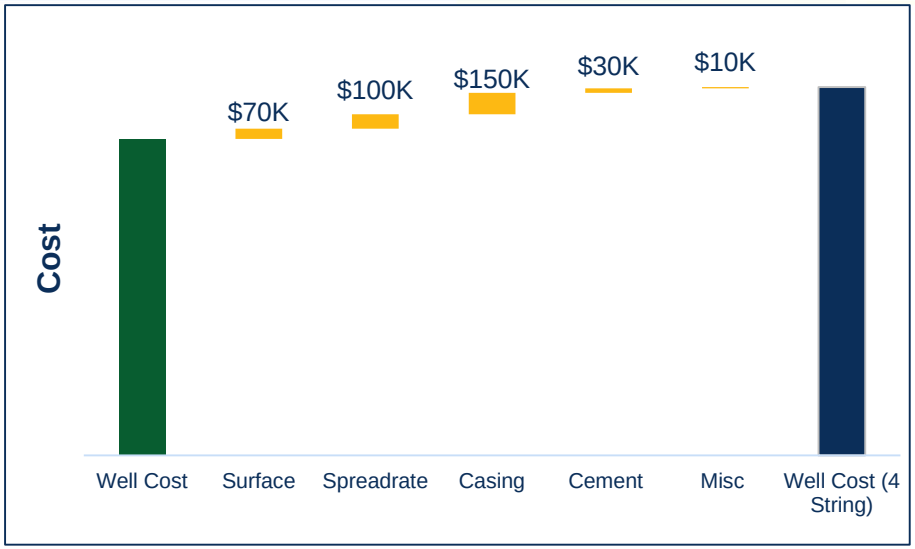
- 12-1/4” hole to Dakota Base, if no flow then 8-3/4” hole to end of curve
- 7” set at ~11,150’ TVD/ 11,500’ MD
- Casing set at end of curve

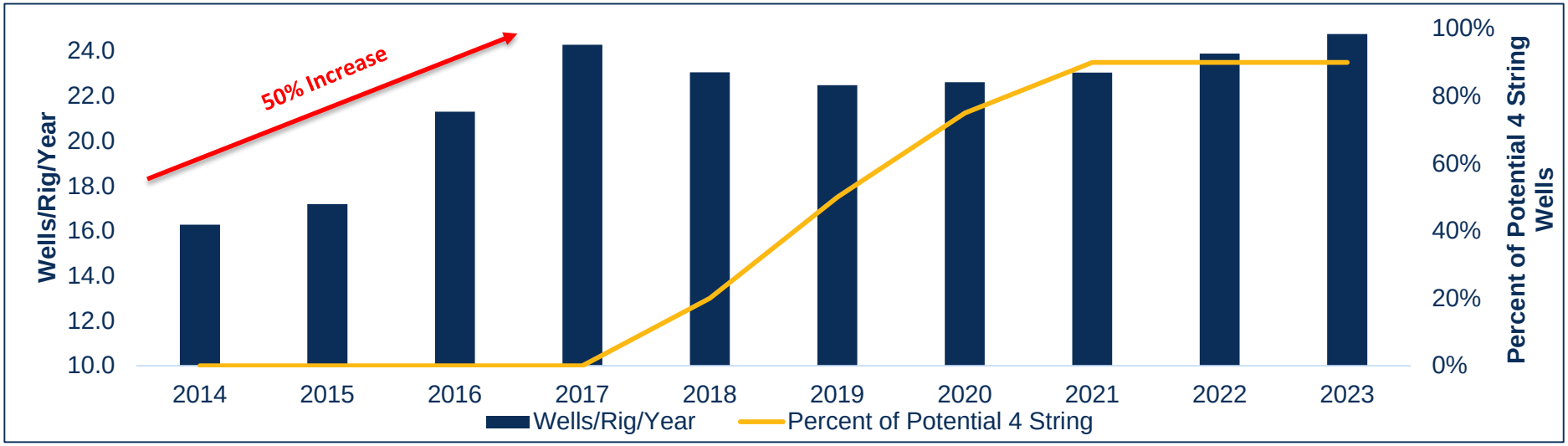
Production Liner

- 4-1/2” Cemented liner from TD to KOP

Operation Impact







What's Next – Unanswered Questions

- Will Dakota injection affect the well life of current producers?
- How can the Dakota sands be mapped to better predict drilling impacts?
- Economics and viability of alternative injection intervals above and below the Bakken/ Three Forks?

Questions?