Geologic Observations & Preliminary Hypotheses
Regarding Bakken H2S Production
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Divide Co. the only HOC area that regularly produces prohibitive volumes of H2S.
- ~9000’ TVD, similar in depth to Ross/Parshall fields (no/minimal H2S).
- Middle Bakken is ~70’ thick in Divide, 1.5-2x thicker than Ross/Parshall and much of basin elsewhere.

We do not observe a relationship between H2S production and geological structure/faults.

We do not observe a relationship between H2S production and Middle Bakken vs Three Forks lateral target.

We presume the H2S observed to be thermogenic but have not been able to rule out biogenic sources yet.
Souring of Kaybob Duvernay Wells: Investigation of Hydraulic Fracture Barrier Effectiveness, Completions Design and Pre-Duvernay Structural Features*

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Abstract

The Devonian Duvernay Formation is an organic-rich mudrock that is a prolific self-sourcing light oil to condensate-rich gas reservoir in the Kaybob region of Central Alberta. Well tests show initial rates up to 3900 boe/d with EUR values less than 1.6 MMBOE. As the Duvernay play appraisal progressed since 2010, more wells are testing or producing sour hydrocarbons (0.5-8000 ppm) from a sweet hydrocarbon play. A need to understand and model the processes that sour Duvernay wells is crucial as souring impacts the economics, health and safety of operations. Both the underlying Beaverhill Lake Group and the Duvernay laterally equivalent Leduc Formation contain conventional oil and gas pools that are sour (< 45%). These sour pools are the most probable source of the H₂S seen in ~10% of drilled wells (June, 2015) within the Kaybob Duvernay play. The possible reasons for souring include artificial and natural fracture conduits, proximal Leduc reef facies changes, communication between existing sour Duvernay and Beaverhill Lake wells or in-situ thermal sulfate reduction processes. The most likely cause of this souring is artificial fracturing and the increase in sour wells over time is due to, in part, the increase in hydraulic fracture fluid volumes from 5-10 m³/m to 25-35 m³/m (2012-2015).

Companies have increased in hydraulic fracture volume designs based on observation that the EUR increases with increasing hydraulic fracture fluid volumes (including proppant loading). Cross plotting the hydraulic fracture fluid volume (m³/m) and the basal fracture barrier thickness indicates that as the basal fracture barrier thins (< 18 m) the barrier becomes less effective and the risk of souring increases. The basal fracture barrier consists of the Duvernay middle carbonate, Majeau Lake and Waterways formations. Increasing the hydraulic fracture fluid volume (i.e. from 15 m³/m to 30 m³/m) will reduce the effectiveness of the basal fracture barrier and also increase the risk of souring Duvernay wells in areas where the fracture barrier is greater than 18 m thick. Sour risking map has been created for the Kaybob Duvernay play based the basal fracture barrier thickness and mapping of Beaverhill Lake pools and Leduc reefs.
Observed H2S Production Curves

1. **Steady, low-to-no H2S production or persistent low-to-moderate H2S production**

2. **Some initial H2S, decreasing over time but experiences a bump, perhaps anomalous or following a workover.** Following bump:
   a) H2S production declines to previous state, or
   b) Increased H2S production persists, or even continues to increase beyond initial bump.

3. **Significant initial H2S production, followed by decline to steady, low-to-no production.**

4. **Substantial, persistent sour production.**
MRO Bernhardt 34-7H
Drilled & Completed in Scallion
No apparent H2S

Well has never produced > 100 ppm H2S
Well has produced > 100 ppm H2S but < 1000 ppm
Well has produced > 1000 ppm H2S
Well has never produced > 100 ppm H2S
Well has produced > 100 ppm H2S but < 1000 ppm
Well has produced > 1000 ppm H2S

HOC “Parshall”, Mountrail Co.
Well has never produced > 100 ppm H2S
Well has produced > 100 ppm H2S but < 1000 ppm
Well has produced > 1000 ppm H2S

HOC “Ross”, Mountrail Co.
Well has never produced > 100 ppm H2S
Well has produced > 100 ppm H2S but < 1000 ppm
Well has produced > 1000 ppm H2S
Well has never produced > 100 ppm H2S
Well has produced > 100 ppm H2S but < 1000 ppm
Well has produced > 1000 ppm H2S
Theories for thermogenic H2S presence

- Madison Sourced: assumes Bakken entirely sweet, H2S occurs when frac height reaches into, or natural fractures/faults extend to Lodgepole.
  - Convenient theory, especially where H2S boomer adjacent to H2S duster (ie, well by well basis).

- H2S (or chemical conditions required to create H2S) present in Bakken reservoir, but variable concentrations across basin.
  - ~Nil at Parshall and Bailey
  - ~Never at 0 in Divide Co., with localized concentrations higher/lower than regional.

- A combination of the 2 theories?
Questions for a Madison source

- Where is the storage?
  - Phi typically ~2%.
  - Fractures can contribute greatly to perm, but typically <2% to porosity.
    - Fracture density generally increases with decreasing porosity.
  - Considering low phi/k, proppant crushing, and fracture healing, would expect to lead to decreasing H2S concentrations with time.
  - Considering relative permeabilities between lower Lodgepole and Middle Bakken, and buoyancy (gas vs oil/water), assume there would be a “preference” to producing from Middle Bakken vs overlying Madison.
    - However, differential pressure between Lodgepole and Bakken could result in Lodgepole→Bakken flow, if Bakken reservoir pressure drops below Lodgepole fm pressure.

- How are we reaching it?
  - Our frac modeling suggests frac height rarely reaches higher than ~100’ above Middle Bakken.
  - Modeled downward growth suggests only 10-20’ growth below Middle Bakken.
    - Suggests deeper H2S source less plausible than overlying Madison source.

- Is porosity and permeability over frac height interval in lower Lodgepole sufficient to justify observed concentrations and persistence of H2S production?

Patten 1-27H capable of producing 20,000 ppm H2S, yet adjacent HOC wells produce none.
How do Bakken H2S concentrations compare spatially to Madison H2S concentrations? Is there a relationship?

- General assumption is that all Madison is sour.

- Outlier? MRO Bernhardt 34-7H (NDIC# 17784, T145N-R92W-S7/6), Lake Ilo field (~Bailey area)
  - Drilled and completed in Scallion (ie, no Upper Bakken “buffer” to restrict frac), no apparent indications of H2S.
  - HOC has not experienced any Bakken H2S volumes in this area.
  - So appears that sour Madison production is not universal.

- Is historical Madison H2S production data available?
  - Considering long history of Madison production in ND and industry awareness of sour Madison production, would believe that maps or datasets exist.
Hypothesis

T1
- Frac reaches into Lodgepole, but higher pressure of Bakken prevents migration of Lodgepole fluids.
- Greatest pressure sink is near-wellbore in Middle Bakken. Production almost exclusively Middle Bakken fluids.

T2
- Bakken reservoir pressure is depleted below formation pressure of Lodgepole.
- Pressure sink of Middle Bakken enables Lodgepole fluids to flow downward into Middle Bakken/wellbore.

- Depletion would not be necessary if Lodgepole P > Bakken P initially (east margin of Bakken productive footprint? Divide Co.?).
  - Ie, implies significant H2S production possible from onset.

- Bakken reservoir pressure data/maps available (Theloy 2013, etc), but unknown how Lodgepole P varies.
  - Lodgepole measurements available publicly?
  - Can Lodgepole P be accurately estimated from other data (wireline logs, mud wts, etc.?)?
Indications for Bakken-sourced H2S

- Sum of DWSU from top of Upr Bakken to base of Lwr Bakken.
- Indicates variability in total Sulfur volume in Bakken Fm.
- Map consistent with HOC experience but not with all apparent High H2S areas.
Indications for Bakken-sourced H2S

**ECS Logs: Sulfur Concentration**

- Sum of DWSU from top of Upr Bakken to base of Lwr Bakken, divided by thickness of same.
- Indicates variability in Sulfur concentration in Bakken Fm.
- Map consistent with HOC experience but not with all apparent High H2S areas.
Some authors have suggested a relationship between Pyrite (FeS) and H2S.

Some geochemical logs include calculated pyrite volume, which shows a relationship with Dry Wt Fraction Sulfur as mentioned previously. Perhaps one log can be used in lieu of other when one but not both logs available.

HOC Experience: areas with highest, regular H2S also observed the most pyrite while drilling.

Mud logs, XRD studies, and core descriptions are additional sources for estimated pyrite volumes.

Indications for Bakken-sourced H2S

H2S-rich area

H2S-poor area
Indications for Bakken-sourced H2S

Produced water analyses reveal low Fe concentrations generally consistent with Apparent High H2S Areas and HOC experience.

- Fe + H2S => FeS + 2H
  - FeS: Iron Sulfide (Pyrite)

Hypothesis:
- Fe ions are consumed by chemical reaction with H2S resulting in low/no Fe concentration in produced water.
- Continued production of H2S implies that Fe is the limiting factor.
- Plausible that depletion of Fe in reservoir will result in increased H2S production over time.

Implication: H2S may be treatable by injecting Fe back into reservoir, but theoretically could result in increased precipitation of pyrite.

Caveat: timing of water analysis may impact whether measuring true reservoir or frac fluid.
Multiple sources of data exist in the public domain.
  – NDIC provides access to logs, cores, and well files.
  – Numerous published studies exist on a wide range of Bakken mineralogy, reservoir parameters, etc.

The biggest hurdle is knowing where H2S is an issue and where it isn’t.
  – Just about anything we map can display promising trends and variability consistent with a theoretical solution, but we can only compare to what-we-know.
Questions/Proposed Future Work

- Are our frac models correct regarding frac height?
- Are variations in Bakken H2S produced volumes more closely associated with geography or with operator?
  - What is the nature of geographical/operator outliers?
- Is there sufficient porosity and permeability over the modeled frac height in the Lodgepole to account for the entirety of H2S observed in Bakken production?
- Is there a spatial, and possibly proportional, relationship between Madison H2S concentrations and produced Bakken H2S volumes?
- Is the key to solving Bakken H2S issues found in better understanding Lodgepole “reservoir” parameters? What data is available to measure/predict variations in Lodgepole reservoir pressure?
- Could H2S, or the conditions required to create H2S, be naturally present in the Bakken reservoir? If so, how do the concentrations vary spatially across the basin?
  - ECS logs, publicly available from NDIC well files, theoretically measure sulfur. Are variations in ECS sulfur consistent with observed variations in Bakken H2S production? Is ECS sulfur an accurate predictor of Bakken H2S production?
  - Water analyses regularly conducted by operators and sometimes included in the NDIC well files. Do any particular, standard-measured ions act as a proxy for H2S potential?
    - Possibly Fe?
  - Mineralogical indicators: is there a relationship between particular minerals to Bakken H2S production? If so, mud logs and cores may provide insight.
    - Divide Co., which is our most problematic H2S area, also appears to have the highest volumes of pyrite (FeS). A relationship between pyrite and H2S has been discussed by multiple authors.