Flowback Water Chemistry

Forecasting Flowback Water Recovery and Its Salinity Response to Adequately Prepare for Water Recycle and Reuse

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DISCLAIMER

Please note that methods and discussions presented in this presentation are related to work completed at the University of Calgary and are therefore not representative of the views of TAQA North Ltd. Further, examples presented in this presentation are not taken from TAQA North Ltd. operations and were conducted external to the company.
1. Quantitative Flowback Analysis
   - Conceptual Model of Flowback and Analysis Procedure
   - Case Study #1: Commingled Shale Gas Flowback
2. Flowback Water Salinity
   - Factors Effecting Flowback Water Salinity
   - Salinity Response of Select Western Canadian Unconventional Plays
3. Introduction of New Flowback Water Salinity Model
4. Key Takeaways
5. Discussion Points/Reference Material
6. Flowback Data Gathering and Assessment
7. Case Study #2: Commingled Tight Oil Flowback
8. Salinity Response of Additional Plays
9. Additional Salinity Model Slides
10. Load Fluid Recovery
11. Impact of HC Breakthrough and Shut-Ins During Flowback
CONCEPTUAL MODEL OF FLOWBACK
Common Frac Shapes:
1. Circular
2. Elliptical
3. Rectangular
CONCEPTUAL MODEL OF FLOWBACK

Slide 6

Quantitative Flowback Analysis/Salinity Modeling • Jesse Williams-Kovacs
ANALYSIS PROCEDURE

• 2 PDA methods used in flowback analysis:
  1. Analytical Simulation
     - History-match flowback data to estimate key frac parameters before and after formation fluid breakthrough and estimate frac water recovery
  2. RTA and Type-Curves
     - BBT single-phase: estimate key hydraulic fracture properties
       - Fracture conductivity (radial flow)
       - BBT half-length (fracture depletion)

• Analysis Procedure:

  Diagnostic Plots and BBT RTA ➔ Deterministic Match ➔ Stochastic Match ➔ Stochastic Output ➔ Comparison With Other Data Sources
CASE STUDY #1 – OVERVIEW

- Marcellus Shale dry gas window
- Cased hole completion
- Hydraulically fractured with slickwater in 12 stages, with 3 perf clusters per stage
- Perf clusters spaced at ~ 100 ft
- 6,800 STB of frac fluid and 115 T pumped per stage
- Microseismic on off-setting wells suggests circular fractures with complex geometry (minimal overlap between stages) – Frac Geometry #3
CASE STUDY #1 – RAW DATA AND DIAGNOSTICS

a) Fluid Production Rates

Gas production from onset of flowback

qg_data
qw_data
Pwf

b) GWR Versus Cumulative Gas Production

Linear Flow Becomes Dominant

Multi-Phase Depletion

Gas production rate (MSCF/D)

Cumulative Gas Produced (Mscf)
CASE STUDY #1 – DETERMINISTIC MATCH

- Good history-match to both phases throughout the flowback period
- Stochastic simulation could be applied to assess the uncertainty associated with our key parameter estimates

Frac FIP ~ 6,700
STB → Maximum
Load Fluid
Recovery (~ 8%)
CASE STUDY #1 – ONLINE PRODUCTION DATA AND RTA

a) Online Production Rates

b) Online RNP and RNP'

Online Early Linear Flow Plot

Good agreement With flowback half-length estimate
**Case Study #1 – Forward Forecast**

- **Slide 12**

**Minimal water production beyond ~100 days**

- Single-phase model over-predicts long-term production by ~20% between 7 and 200 days.

- Comparable match between 7 and 200 days.

- Single-phase model over-predicts cumulative production by ~20%.

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**Quantitative Flowback Analysis/Salinity Modeling • Jesse Williams-Kovacs**
Predicted Water Recovery ~ 5,900 STB (~ 7.2% Recovery, ~ 88% of Max)
Multi-Phase Flowback Data CAN Be Quantitatively Analyzed to Estimate Key Frac Properties and Water Recovery
FACTORS AFFECTING FLOWBACK WATER SALINITY

- Dissolution of salt at the fracture face or in the matrix
  - From deposition or hydrogeological process causing crystallization

- Diffusion/Dispersion of ions from high salinity matrix or secondary fractures
  - Secondary fractures typically have higher surface area than primary fractures
    (enhanced diffusion)

- Advection due to bulk motion of fracture and formation fluids

- Precipitation of salt within the fractures
  - i.e. calcium carbonate – influenced by partial pressure of carbon dioxide

- Production of high salinity formation water

Measuring individual ion ratios can indicate dominant mechanisms and lab experiments can help determine transport coefficients
SALINITY RESPONSE – NE BC MONTNEY TIGHT OIL

Significant Formation Water

Formation Breakthrough:
Well 1 - 10 days
Well 2 - 11 days
Well 3 - 4.5 days

WOR signature suggest formation water production
Early-time salinity response suggests potential fracture complexity
BBT salinity response diffusion dominated
ABT salinity response dominated by mixing with hyper-saline formation water
No definitive plateau reached

Well 3 had 2-3x load fluid pumped leading to lower slope and later plateau

Approaching plateau at ~150,000 ppm?
**SALINITY RESPONSE – HORN RIVER SHALES**

- **No Long-Term Water Reported - Immediate Gas Breakthrough on All Wells**
  - Shut-In Time: Unknown

- **Horn River Shale Flowback Salinity vs Cum Water Produced**

- **Formation thought to produce minimal formation water**
- **Diffusion appears to be the dominant mechanism for mass transfer**
- **The salinity profile and plateau are similar for the Muskwa and Otter Park**
- **Salinity response in Evie may be due to higher fracture complexity and appears to plateau significantly higher**

**Plateau reached ~35,000 ppm**

**Approaching Plateau of ~70,000 ppm?**

**Horn River Shale Flowback Salinity vs Sqrt(Time)**

**Quantitative Flowback Analysis/Salinity Modeling • Jesse Williams-Kovacs**
SALINITY MODEL DEVELOPMENT – FULLY COUPLED APPROACH (RADIAL FRACTURES)

Repetitive Element

Matrix

A-D-R Mass Transfer

Fracture

A-D-R With Matrix Inflow

Matrix

A-D-R Mass Transfer

Matrix

A-D-R Mass Transfer

No Flux

No Flux

\( z = 0 \)

\( \frac{y_e}{2} \)

\( \frac{w_f}{2} \)

\( x_e \)

\( r = r_w \)

\( x_f \)
**Salinity Model Development – Fully Coupled Approach (Radial Fractures)**

**Matrix: Linear Advection-Diffusion-Reaction Equation**

\[
\frac{\partial C_m(z, t)}{\partial t} = D_m(t) \frac{\partial^2 C_m}{\partial z^2} - \frac{q_{w,m}(t)}{A_{m,w}(t)} \frac{\partial C_f}{\partial x} + k'(t)[C_{\text{max}} - C_m]
\]

- **Accumulation**
- **Diffusion/Dispersion**
- **Advection**
- **Reaction/Dissolution**

**Fracture: Radial Advection-Diffusion-Reaction-Inflow**

\[
\frac{\partial C_f(r, t)}{\partial t} = \frac{D_f(t)}{r} \frac{\partial}{\partial r} \left[ r \frac{\partial C_f}{\partial r} \right] - \frac{1}{r} q_{w,f}(t) \frac{\partial C_f}{\partial r} - k(t)C_f + \frac{\phi_{m,w}(t)}{\phi_{f,w}(t)} \left[ \left( \frac{D_m}{w_f / 2} \right) \frac{\partial C_m}{\partial z} \right]_{z=y_e/2}
\]

- **Accumulation**
- **Diffusion/Dispersion**
- **Advection**
- **Adsorption/Precipitation**

**Matrix Initial and Boundary Conditions**

Initial Condition: \( C_m(x, t = 0) = C_{mi} \)

Boundary Conditions:
1) No Flux at Center of Matrix Block \( - \frac{\partial C_f}{\partial x} \bigg|_{z=0} = 0 \)
2) Continuity at M · F Int \( - C_m \left( z = \frac{y_e}{2}, t \right) = C_f \)

**Fracture Initial and Boundary Conditions**

Initial Condition: \( C_f(x, t = 0) = C_{fi} \)

Boundary Conditions:
1) MB at Well \( - V_{w,w}(t) \frac{\partial C_f}{\partial t} \bigg|_{r=r_w} = -A_{f,w}(t)D_f(t) \frac{\partial C_f}{\partial r} \bigg|_{r=r_w} = 0 \) OR \( C_f(x_f, t) = C_{mi} \)
2) No Flux or Constant Point Source at Frac Tips \( - \frac{\partial C_f}{\partial r} \bigg|_{r=x_f} = 0 \)
**SALINITY MODEL DEVELOPMENT – FULLY COUPLED APPROACH (RADIAL FRACTURES)**

System Cannot Be Solved Analytically Without **MAJOR** Simplifications – Assuming No Mobile Water in The Matrix, Constant Coefficients and Linear Fractures The Solution Would Not Fit on A Slide in **10 pt Font** and Likely Could Not Be Applied in the Real World!!!

**So What Can We Do to Find a More Practical Solution?**

2) Continuity at M ⋅ F Int  \[ C_m \left( z = \frac{z_o}{2}, t \right) = C_f \]

**Fracture Initial and Boundary Conditions**

Initial Condition: \( C_f(x, t = 0) = C_{f_i} \)

Boundary Conditions: 1) MB at Well  \[ V_{w,w}(t) \left. \frac{\partial C_f}{\partial t} \right|_{r=r_w} = -A_{f,w}(t)D_f(t) \left. \frac{\partial C_f}{\partial r} \right|_{r=r_w} \]

2) No Flux or Constant Point Source at Frac Tips  \[ \left. \frac{\partial C_f}{\partial r} \right|_{r=x_f} = 0 \] OR \( C_f(x_f, t) = C_{m_i} \)
Fractures: Linear Advection-Diffusion-Reaction Equation

\[ \frac{\partial C_f(x, t)}{\partial t} = D \frac{\partial^2 C_f}{\partial x^2} - \frac{q_w}{A} \frac{\partial C_f}{\partial x} - k C_f \]

**Dimensionless Variables**

- **Concentration:** For BC 1a
  \[ -C_D f = C_f - C_f \]
  \[ C_m - C_f \]

- **For BC 1b**
  \[ -C_D f = C_f - C_f \]
  \[ C_m - C_f \]

**Time:**
\[ t_D = \frac{D t}{(w_f/2)^2} = \frac{4 D t}{(w_f)^2} \]

**Distance:**
\[ x_D = \frac{x}{w_f/2} \]

**Conceptual Model – Uncoupled Approach**

- **Initial Condition:** \( C_f(x, t = 0) = C_{fi} \)
- **Boundary Conditions:**
  1a) \( C_f(x = 0, t) = C_m \)
  1b) \( \frac{\partial C_m}{\partial t} \Big|_{x=0} = k'(C_{max} - C_m) \)
  2) \( \frac{\partial C_f}{\partial x} \Big|_{x=\frac{w_f}{2}} = 0 \)

Assuming no formation water production for now and constant coefficients

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**Simplified (Uncoupled) Model Development – Dimensional Form**
**SIMPLIFIED (UNCOUPLED) MODEL DEVELOPMENT – DIMENSIONLESS FORM**

**Fractures: Linear Advection-Diffusion-Reaction Equation**

\[
\frac{\partial C_{Df}(x_D, t_D)}{\partial t_D} = \frac{\partial^2 C_{Df}}{\partial x_D^2} - P_e \frac{\partial C_{Df}}{\partial x_D} - D_{a,1} C_{Df}
\]

- **Accumulation**
  \[ \frac{\partial C_{Df}(x_D, t_D)}{\partial t_D} \]
- **Diffusion/Dispersion**
  \[ \frac{\partial^2 C_{Df}}{\partial x_D^2} \]
- **Advection**
  \[ - P_e \frac{\partial C_{Df}}{\partial x_D} \]
- **Adsorption/Precipitation**
  \[ - D_{a,1} C_{Df} \]

Assuming \( C_m >> C_{fi} \) – frac water is typically quite fresh

**Conceptual Model – Uncoupled Approach**

- **Matrix**
- **Primary Fracture**
- **Matrix**

\[ x_D = 0 \]
\[ x_D = 1 \]

**Dimensionless Groups**

\[ P_e = \frac{\text{Advection}}{\text{Diffusion}} = \frac{q_w w_f}{2 \Phi D} \]
\[ D_{a,1} = \frac{\text{Adsorption}}{\text{Diffusion}} = \frac{k w_f^2}{4 D} \]
\[ D_{a,2} = \frac{\text{Surface Reaction}}{\text{Diffusion}} = \frac{k' w_f^2}{4 D} \]

**Initial and Boundary Conditions**

Initial Condition: \( C_{Df}(x_D, t_D = 0) = 0 \)

Boundary Conditions:
1a) \( C_{Df}(x_D = 0, t_D) = C_{Dm} = 1 \)
1b) \( \left. \frac{\partial C_{Dm}}{\partial x_D} \right|_{x_D=0} = D_{a,2} [1 - C_{Dm}] \)
2) \( \left. \frac{\partial C_{Df}}{\partial x_D} \right|_{x_D=1} = 0 \)
SOLUTION PROCEDURE

• Utilizing Laplace Transform Method:
  - Apply Forward Laplace Transform to PDE
  - Solve Resulting ODE in Laplace Space
  - Average Spatial Solution Over Domain of Interest
  - Numerically Invert Back to Time Domain Using Stehfest Algorithm

Laplace Domain Solutions For All Boundary Conditions are UGLY!
Uncoupled Salinity Model – Advection-Diffusion-Reaction with Static Boundary Condition

Type-Curve For $P_e = D_a = 0$ (Diffusion Only)

Pure diffusion is a straight-line on the square-root of time plot passing through the origin

$C_{D_{avg}}(t_D)$ vs $\sqrt{t_D}$

$P_e = 0$ (Diffusion)
UNCOPLED SALINITY MODEL – ADVECTION-DIFFUSION-REACTION WITH STATIC BOUNDARY CONDITION

Type-Curve Set For $D_a = 0$ (Advection-Diffusion Only)

- $Pe = 0$ (Diffusion)
- $Pe = 1$
- $Pe = 5$
- $Pe = 10$
- $Pe = 20$

Advection increases mass transfer rate

Pure diffusion is a straight-line on the square-root of time plot
Multi-phase flowback data can be quantitatively analyzed
  - Estimate key frac properties and load fluid recovery

Salinity response from play to play can be highly variable
  - Can also be variable for wells on the same pad

A new model was proposed for matching the salinity response of produced water during flowback
  - Multiple mechanisms considered
  - Simplified approach used to allow analytical solution

Future work will continue with development/application of salinity model
  - More advanced/realistic boundary conditions
  - Investigate additional approximate solution methods
  - Additional simplifications to the fully coupled model
Jesse Williams-Kovacs would like to thank the University of Calgary, TAQA North Ltd. AND Dr. Christopher Clarkson at the University of Calgary

DISCUSSION POINTS:
1. Impact of shutting in wells during flowback and methods to avoid this
2. Causes of high salinity of produced water
3. Benefits of detailed water analysis

REFERENCE MATERIAL:
1. Shale Gas: SPE 162593, SPE 164550, URTeC 2149183
2. Tight Gas Condensate: SPE 167231
4. Stage-by-Stage and Multi-Well Flowback: SPE 171591
5. Tight Oil Case Study (flowback + long-term production): The Leading EDGE, October 2014
FLOWBACK DATA GATHERING AND ASSESSMENT

**Data Gathering**

- Initial fracture pressure (frac modelling, other estimate typically 20-50% greater than PI)
- Indication of fracture geometry (microseismic, frac modelling, experience, etc.)
- Method to allocate data to individual stages (i.e. spinner & tracer logs, fibre-optic techniques)
- Sandface flowing pressures (downhole gauges)
- Salinity of frac fluid
- Estimate of fracture relative permeability curves (lab experiments)
- Fluid properties (oil, water and gas analysis)
- Formation temperature
- Estimate of initial reservoir pressure and matrix permeability (DFIT, pre-frac welltest, core)
- Estimates of net pay, porosity and fluid saturation (logs and core)

Optional:

- Detailed PVT analysis
- Estimate of matrix relative permeability curves (lab experiments)
- Offset well analysis

**Primary Diagnostic Plots:**

1. RNP vs. t or tca (water typically most diagnostic)
2. RNP Derivative vs. t or tca (water typically most diagnostic)
3. GWR vs. Gp (gas specific)

**Other Diagnostic Plots:**

1. RNP vs. cumulative production (all phases)
2. pcf vs. qw, qo and qg
3. Gp or Np vs. Wp

**Hydraulic Fracture Property Determination and Forecast:**

1. Rate-transient analysis (radial flow analysis, flowing material balance, Fetkovich type curve)
2. Analytical simulation (history-match)
3. Forecast long-term production
**Data Gathering**

**Flowback Specific:**
1) High-frequency rates and flowing pressures (hourly or more frequent – every 15-30 minutes desirable)
2) Initial fracture pressure (frac modelling, other estimate – typically 20-50% greater than Pi)
3) Indication of fracture geometry (microseismic, frac modelling, experience, etc.)

**Optional:**
1) Method to allocate data to individual stages (i.e. spinner & tracer logs, fibre-optic techniques)
2) Sandface flowing pressures (downhole gauges)
3) Salinity of frac fluid
4) Estimate of fracture relative permeability curves (lab experiments)

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**Diagnostics**

**Quantitative Assessment**

**Base Plots:**
1) \( q_w, q_o, \) and \( q_g \) vs. \( t \) (stage-by-stage if available)
2) Flowing pressure (surface, downhole or converted) and choke setting vs. \( t \)

**Primary Diagnostic Plots:**
1) RNP vs. \( t \) or \( t_{ca} \) (water typically most diagnostic)
2) RNP Derivative vs. \( t \) or \( t_{ca} \) (water typically most diagnostic)
3) GWR vs. \( G_p \) (gas specific)

**Other Diagnostic Plots:**
1) RNP vs. cumulative production (all phases)
2) \( p_{cf} \) vs. \( q_w, q_o \) and \( q_g \)
3) \( G_p \) or \( N_p \) vs. \( W_p \)

**Hydraulic Fracture Property Determination and Forecast:**
1) Rate-transient analysis (radial flow analysis, flowing material balance, Fetkovich type curve)
2) Analytical simulation (history-match)
3) Forecast long-term production

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**Other:**
1) Wellbore schematic, deviation survey and stimulation information
2) Fluid properties (oil, water and gas analysis)
3) Formation temperature
4) Estimate of initial reservoir pressure and matrix permeability (DFIT, pre-frac welltest, core)
5) Estimates of net pay, porosity and fluid saturation (logs and core)

**Optional:**
1) Detailed PVT analysis
2) Estimate of matrix relative permeability curves (lab experiments)
3) Offset well analysis
• Tight oil reservoir in the WCSB (NE BC)
• Cased hole completion
• Hydraulically fractured with hybrid water fracs in 18 stages
• Frac stages spaced at ~ 330 ft
• 1,350 STB of frac fluid and 45 T pumped per stage
• Microseismic suggests circular fractures with bi-wing planar geometry – Frac Geometry #1
CASE STUDY #2 – RAW DATA AND DIAGNOSTICS

QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS
**CAST STUDY #2 – RATE TRANSIENT ANALYSIS**

- **Frac FIP ~ 23,000 STB → Maximum Load Fluid Recovery (~ 92%)**

**Flowing Material Balance**

- BBT FIP ~ 23,000 STB
- $x_{f, BBT} = 421$ ft/stage
- $FcT \sim 150$ md-ft
CASE STUDY #2 – DETERMINISTIC HISTORY-MATCH

- Good match of water, oil and gas rate prior to gas breakthrough (~8 days)
- Significant uncertainty in analysis due to number of parameters being adjusted to achieve history-match (i.e. $x_f$, fracture permeability, thickness, etc.)

Gas breakthrough into the fractures – oil and water rate over-predicted after this point.
CASE STUDY #2 – STOCHASTIC HISTORY-MATCH

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CASE STUDY #2 – PARAMETER DISTRIBUTIONS

a) Cumulative Probability Distribution - Initial Fracture Pressure

b) Cumulative Probability Distribution - Fracture Permeability

c) Cumulative Probability Distribution - xf Pre-Break Through

d) Cumulative Probability Distribution - xf Post-Break Through
CASE STUDY #2 – FORWARD FORECAST

Water recovery takes > 1,200 days!

Long-Term Production Rate Forecast

Long-Term Production Rate Forecast

Long-Term Production Cum Forecast

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SALINITY RESPONSE – NW AB MONTNEY LIQUIDS-RICH TIGHT GAS

- Desiccated formation – possible to have salt precipitated prior to stimulation
- WGR signature suggest negligible formation water production
- Possible salinity measurement error early in time
- Variable plateau reached – possibly due to fracture complexity or longer shut-in in Well 2
**SALINITY RESPONSE – CENTRAL AB MONTNEY TIGHT OIL**

- **WOR signature suggest formation water production**
- **BBT salinity response diffusion dominated**
- **ABT salinity response dominated by mixing with hyper-saline formation water**
- **Plateau appears to be reached at ~150,000 ppm**

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**SALINITY RESPONSE – CENTRAL AB MONTNEY TIGHT OIL**

- **Formation Breakthrough**
- **Significant Formation Water**
- **Diffusion controlled BBT**
- **Mixing controlled ABT**
- **Approaching plateau at ~150,000 ppm**
SALINITY RESPONSE – SOUTH PEMBINA CARDIUM TIGHT OIL

No Long-Term Water Reported

- Shut-In Time:
  - Well 1 – 6 days
  - Well 2 – 9 days

Salinity response appears diffusion dominated both BBT and ABT

- Interpretation limited by data quality
- Plateau appears to be reached at ~ 20,000 ppm – likely below connate water salinity

South Pembina Cardium Flowback Salinity vs Sqrt(Time)

- Poor data?
- Plateau reached ~20,000 ppm
- Diffusion controlled throughout

- No online water reported – thought to be negligible from off-sets
- Quantitative Flowback Analysis/Salinity Modeling • Jesse Williams-Kovacs

South Pembina Cardium Flowback Salinity vs Cum Water Produced

- Well 1 ramps up Faster

- South Pembina CRDM 1
- South Pembina CRDM 2

Cumulative Water Produced (STB)

- Salinity (ppm)
Formation Breakthrough

SALINITY RESPONSE – HOADLEY GLAUCONITE TIGHT GAS

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**SALINITY RESPONSE – HOADLEY GLAUCONITE TIGHT GAS**

- **WGR signature suggest formation water production**
- **Early-time salinity response suggests possible measurement issues – missing BBT diffusion?**
- **ABT salinity response dominated diffusion**
- **Variable plateau reached – possibly due to fracture complexity and extent of formation water**

**Graphs:**

- **Graph a)** Hoadley Glauc Long-Term WGR vs Time
  - **Time (days)**
  - **WGR (STB/MMSCF)**
  - **Significant Formation Water**
  - **Shut-In Time:** Well 1 – 1 day, Well 2 – 1 day
  - **Graph b)** Hoadley Glauc Flowback Salinity vs Sqrt(Time)
    - **Salinity (ppm)**
    - **Sqrt(time) (hr^0.5)**
    - **Formation Breakthrough**
    - **Variable plateau reached**
    - **Mixing likely dominant ABT**
    - **Measurement issues? – missing impact of BBT diffusion**

**Graph c)** Hoadley Glauc Flowback Salinity vs Cum Water Produced

- **Salinity (ppm)**
- **Cumulative Water Produced (STB)**
- **Well 1 ramps up faster**

**Graphs**

- **Graph a)** Hoadley Glauc Long-Term WGR vs Time
  - **Time (days)**
  - **WGR (STB/MMSCF)**
  - **Significant Formation Water**
  - **Shut-In Time:** Well 1 – 1 day, Well 2 – 1 day

- **Graph b)** Hoadley Glauc Flowback Salinity vs Sqrt(Time)
  - **Salinity (ppm)**
  - **Sqrt(time) (hr^0.5)**
  - **Formation Breakthrough**
  - **Variable plateau reached**
  - **Mixing likely dominant ABT**
  - **Measurement issues? – missing impact of BBT diffusion**

- **Graph c)** Hoadley Glauc Flowback Salinity vs Cum Water Produced
  - **Salinity (ppm)**
  - **Cumulative Water Produced (STB)**
  - **Well 1 ramps up faster**
Salinity Model Development – Fully Coupled Approach (Linear Fractures)

Repetitive Element

Matrix

A-D-R Mass Transfer

Fracture
A-D-R Mass Transfer

Matrix

A-D-R Mass Transfer

Matrix

No Flux

z = 0

\[ \frac{y_e}{2} \]

\[ \frac{w_f}{2} \]

\[ x = 0 \]

\[ x_f \]

\[ x_e \]

A-D-R With Matrix Inflow

Mass Transfer

No Flux
**SALINITY MODEL DEVELOPMENT – FULLY COUPLED APPROACH (LINEAR FRACTURES)**

**Matrix: Linear Advection-Diffusion-Reaction Equation**

\[
\frac{\partial C_m(z,t)}{\partial t} = D_m(t) \frac{\partial^2 C_m}{\partial z^2} - \frac{q_{w,m}(t)}{A_{m,w}(t)} \frac{\partial C_f}{\partial x} + k'(t)[C_{max} - C_m]
\]

- **Accumulation**
- **Diffusion/Dispersion**
- **Advection**
- **Reaction/Dissolution**

**Fractures: Linear Advection-Diffusion-Reaction-Inflow**

\[
\frac{\partial C_f(x,t)}{\partial t} = D_f(t) \frac{\partial^2 C_f}{\partial x^2} - \frac{q_{w,f}(t)}{A_{f,w}(t)} \frac{\partial C_f}{\partial x} - k(t)C_f + \frac{\phi_{m,w}(t)}{\phi_{f,w}(t)} \left( \frac{D_m}{w_f/2} \right) \frac{\partial C_m}{\partial z} \bigg|_{z=y_e/2}
\]

- **Accumulation**
- **Diffusion/Dispersion**
- **Advection**
- **Adsorption/Precipitation**

**Matrix Initial and Boundary Conditions**

Initial Condition: \(C_m(x, t = 0) = C_{mi}\)

Boundary Conditions:
1) No Flux at Center of Matrix Block \(- \frac{\partial C_f}{\partial x} \bigg|_{x=0} = 0\)
2) Continuity at M – F Int \(- C_m\left(z = \frac{y_e}{2}, t\right) = C_f\)

**Fracture Initial and Boundary Conditions**

Initial Condition: \(C_f(x, t = 0) = C_{fi}\)

Boundary Conditions:
1) MB at Well \(- V_{w,w}(t) \frac{\partial C_f}{\partial t} \bigg|_{x=0} = -A_{w,w}(t)D_f(t) \frac{\partial C_f}{\partial x} \bigg|_{x=0} = 0 \text{ for } V_W = 0\)
2) No Flux or Constant Point Source \(- \frac{\partial C_f}{\partial t} \bigg|_{x=x_f} = 0 \text{ OR } C_f(x_f, t) = C_{mi}\)
UNCOPLED SALINITY MODEL – ADVECTION-DIFFUSION-REACTION WITH STATIC BOUNDARY CONDITION

Type-Curve Set For $P_e = 5$

Extent of adsorption in fracture impacts max concentration

- $P_e = 0$ (Diffusion)
- $D_a = 1$
- $D_a = 5$
- $D_a = 10$
- $D_a = 20$
UNCOUPLED SALINITY MODEL – ADVECTION-DIFFUSION WITH REACTIVE BOUNDARY CONDITION

Type-Curve Set For $C_{Dmi} = 0.5$, $P_e = 0$

- $P_e = Da = 0$ (Diffusion)
- $Da = 1$
- $Da = 5$
- $Da = 10$
- $Da = 20$

Increasing rate of surface reaction causes solution to approach diffusion with static BC at $C_{Dmi}(0,t) = 1$
Increasing rate of surface reaction causes salinity to increase more rapidly.
NE BC Montney Long-Term WOR vs Time

- **NE BC MNTN Hybrid 1**
- **NE BC MNTN Hybrid 2**
- **NE BC MNTN Hybrid 3**

**Significant Formation Water**

**WATER RECOVERY – NE BC MONTNEY TIGHT OIL**

*QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS*
NE BC Montney Fluid Recovery

- **18 Stages** Slickwater/Linear Gel Hybrid
  - 22.9 MSTB Load
  - 10 Day Shut-In
  - Planar Fractures

- **18 Stages** Slickwater/Linear Gel Hybrid
  - 34.4 MSTB Load
  - 11 Day Shut-In
  - Planar Fractures

- **33 Stages** Slickwater/Linear Gel Hybrid
  - 61.3 MSTB Load
  - 4.5 Day Shut-In
  - Planar Fractures

**WATER RECOVERY – NE BC MONTNEY TIGHT OIL**

QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS
WATeR RECOVeRY – NW AB MONTNEY LIQUIDS-RICH TIGHT

NW AB Montney Long-Term WGR vs Time

Possible Frac Communication With Water-Bearing Formation

Minimal Formation Water

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WATER RECOVERY – NW AB MONTNEY LIQUIDS-RICH TIGHT GAS

NW AB Montney Fluid Recovery

- NW AB MNTN N2 Foam 1: 12 Stages, N2 Foam, 3.6 MSTB Load, 6 Day Shut-In, Planar Fractures
- NW AB MNTN N2 Foam 2: 12 Stages, N2 Foam, 3.9 MSTB Load, 4 Day Shut-In, Planar Fractures
- NW AB MNTN N2 XLink: 13 Stages, N2 XLink Gel, 11.2 MSTB Load, 4.5 Day Shut-In, Planar Fractures
- NW AB MNTN N2 XLink 2: 13 Stages, N2 XLink Gel, 11.1 MSTB Load, 5 Day Shut-In, Planar Fractures

Water Recovery (%)
- Water Recovery %
- Gas Recovery Volume

Graphical representation showing water recovery and gas recovery volumes for different treatments and shut-in periods.
Spikes in water production – measurement problems or frac'd into water-bearing zone.

Significant Formation Water
Central AB Montney Fluid Recovery

- 23 Stages
  - N₂ Foam
  - 25.6 MSTB Load
  - 3 Day Shut-In
  - Planar Fractures

- 20 Stages
  - N₂ Foam
  - 30.5 MSTB Load
  - 1.5 Day Shut-In
  - Planar Fractures

WATER RECOVERY – CENTRAL AB MONTNEY VOLATILE TIGHT OIL

Oil Recovery (MSTB)

Water Recovery (%)

- 72 Hours
- 7 Days
- 14 Days
- 30 Days
- 90 Days

Central AB MNTN N2 Foam 1

Central AB MNTN N2 Foam 2

WATER RECOVER – CENTRAL AB MONTNEY VOLATILE TIGHT OIL

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QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS
Long-Term Water Data Not Gathered – Appears Minimal Based on Offset Production
South Pembina Cardium Fluid Recovery

- 14 Stages
- N₂ Foam
- 9.8 MSTB Load
- 6 Day Shut-In
- Planar Fractures

- 14 Stages
- N₂ Foam
- 15.8 MSTB Load
- 9 Day Shut-In
- Planar Fractures

**WATER RECOVERY – SOUTH PEMBINA CARDIUM TIGHT OIL**

14 Stages
N₂ Foam
9.8 MSTB Load
6 Day Shut-In
Planar Fractures

14 Stages
N₂ Foam
15.8 MSTB Load
9 Day Shut-In
Planar Fractures

**QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS**
WATER RECOVERY – HOADLEY GLAUCONITE TIGHT GAS

Hoadley Glauc Long-Term WGR vs Time

Significant Formation Water

Spikes in water production – measurement problems or frac’d into water-bearing zone

Hoadley Glauc N2 Foam 1  Hoadley Glauc N2 Foam 2
WATER RECOVERY – HOADLEY GLAUCONITE TIGHT GAS

Hoadley Glauc Fluid Recovery

12 Stages
N₂ Foam
4.3 MSTB Load
1 Day Shut-In
Planar/Complex Fractures

Central AB MNTN N2 Foam 1

Water Recovery %
Gas Recovery Volume

Central AB MNTN N2 Foam 2

72 Hours 7 Days 14 Days 30 Days 90 Days

WATER RECOVERY – HOADLEY GLAUCONITE TIGHT GAS

QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS
WATER RECOVERY – MARCELLUS SHALE GAS

Marcellus Shale Long-Term WGR vs Time

- Negligible Formation Water

- Marcellus Slickwater 1
- Marcellus Slickwater 2

QUANTITATIVE FLOWBACK ANALYSIS/SALINITY MODELING • JESSE WILLIAMS-KOVACS
Marcellus Shale Fluid Recovery

- **Marcellus Shale Slickwater 1**
  - 12 Stages Slickwater
  - 84.3 MSTB Load
  - 60 Day Shut-In
  - Complex Fractures

- **Marcellus Shale Slickwater 2**
  - 12 Stages Slickwater
  - 82.7 MSTB Load
  - 35 Day Shut-In
  - Complex Fractures

**Water Recovery (%)**
- 72 Hours
- 7 Days
- 14 Days
- 30 Days
- 60 Days

**Gas Recovery Volume**
- 72 Hours
- 7 Days
- 14 Days
- 30 Days
- 60 Days

**Marcellus Shale Slickwater 1**
- Water Recovery
- Gas Recovery Volume

**Marcellus Shale Slickwater 2**
- Water Recovery
- Gas Recovery Volume

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**Quantitative Flowback Analysis/Salinity Modeling • Jesse Williams-Kovacs**
1. Long shut-ins reduce recovery
   - Loss of frac energy
   - Gravity segregation in fractures

2. Foam fracs increase water recovery
   - Maximum frac energy
   - Minimum water requirement
   - Slickwater typically has lowest energy/recovery

3. Fracture complexity reduces recovery
   - Water retention in secondary fractures (low conductivity)

4. Shales reservoirs have low load fluid recovery relative to sandstone/siltstone reservoirs
   - Water imbibition into matrix due to capillary pressure
   - Water intake by clays

5. High drawdowns typically increase load fluid recovery
   - May damage fractures and impact long-term performance
IMPACT OF HYDROCARBON BREAKTHROUGH AND SHUT-INS

Single-phase flow

Shut-in reduces $x_{f,\text{eff}}$

Tight Gas Condensate

Gas Break-through reduces $x_{f,\text{eff}}$

Shut-in reduces $x_{f,\text{eff}}$

Tight Gas

Gas Break-through reduces $x_{f,\text{eff}}$

Example From SPE 119894

Oil Break-through reduces $x_{f,\text{eff}}$

Deterministic Rate Match

Water or Oil Rate (STB)

Time (days)

Gas Rate (MSCF/D)

Tight Gas Condensate

Deterministic Rate Match

Water or Condensate Rate (STB/D)

Time (days)

Gas Rate (MSCF/D)
Flowback Operations Impact Long-Term Productivity