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Comparison of Numerical vs Analytical Models for EUR Calculation and Optimization in Unconventional Reservoirs

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SPE International
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Motivation

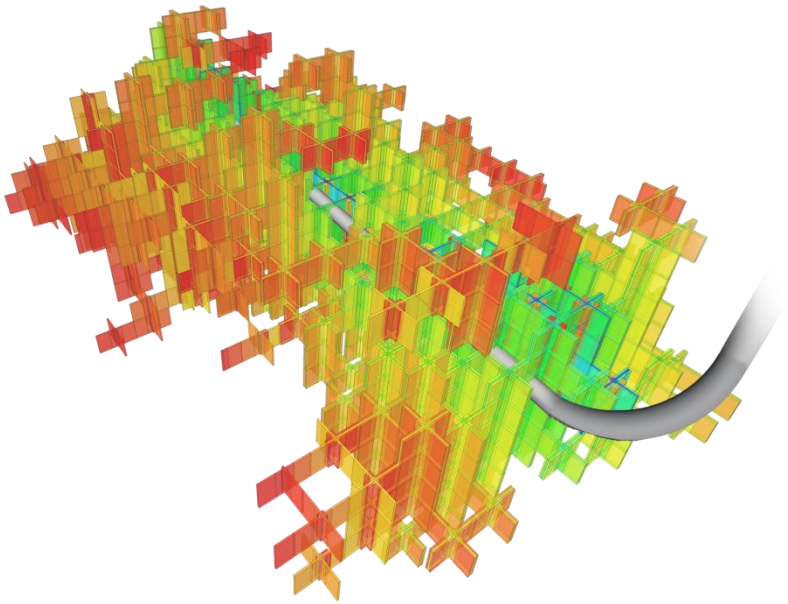
- Analytical models available in Rate-Transient-Analysis (RTA) packages are widely used for history matching and forecasting production in unconventional resources.
- There has also been an increasing interest in the use of numerical simulation of unconventional reservoirs.
- Goal of this study: Quantify the differences one might expect to encounter in a well's EUR when using RTA vs Numerical Simulation workflows in unconventional reservoirs.

Outline

- Numerical Simulation Workflow for Unconventional Reservoirs
- RTA Workflow for Unconventional Reservoirs
- Model Validation (RTA vs NS for simple case)
- Real-World Deviations from RTA Assumptions
- More Realistic Field Case with Multiple Deviations
- Computational Performance
- Summary and Conclusions

Numerical Simulation Workflow

- **Numerical Modeling Physics for Unconventional Reservoirs (SPE 180209)**
- **Modeling Transient Flow to Fractures using LS-LR Grids (SPE 132093)**
- **Bayesian History Matching, Probabilistic Forecasting (SPE 175122)**

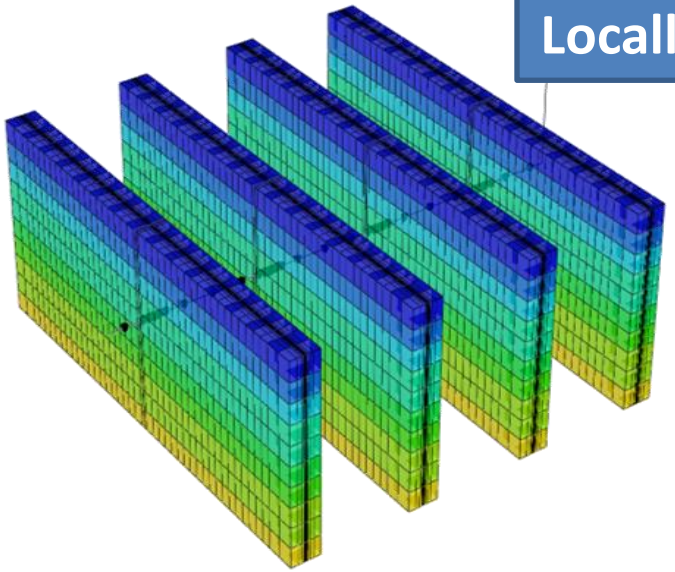


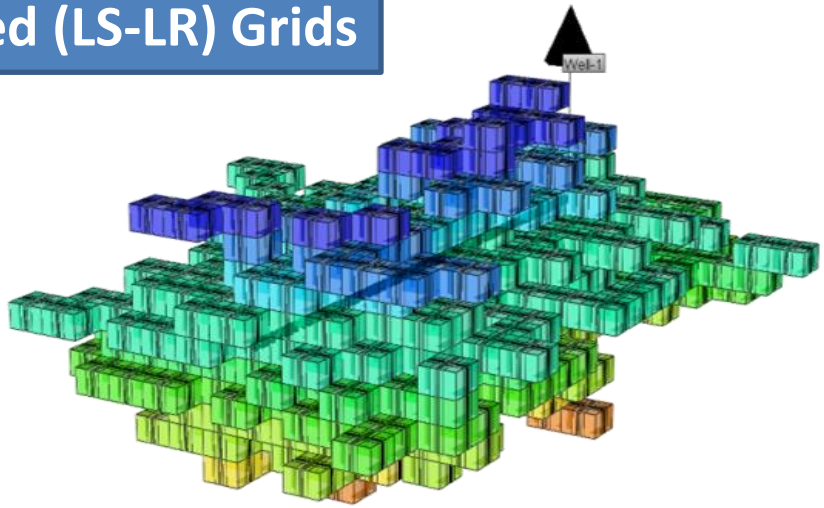
Unconventional Reservoir Physics

System Components	Numerical Simulator Features
Fluid PVT Models	Black Oil & EOS
Adsorbed Components	In Gas Phase by Component
Molecular Diffusion	In any Phase by Component
Natural Fractures	Dual Porosity & Dual Permeability
Well Completions	Planar & Complex Hydraulically-induced Fractures
Fluid Flow Types	Darcy, Turbulent & Slip flow
Fluid Flow Regimes	Transient Flow from Matrix to Fractures using LS-LR grids
Rock/Fluid Interaction	Relative Perm & Cap Pressure, with Hysteresis & with Geochemistry
Compaction/Dilation	function of Pressure OR Stress (when using 3D Geomechanics)
Flow in Wells	Steady-state, Homogenous Flow OR Transient, Segregated Flow

Modeling Transient Flow to Planar & Complex Geometry Propped Fractures

Logarithmically-Spaced Locally-Refined (LS-LR) Grids

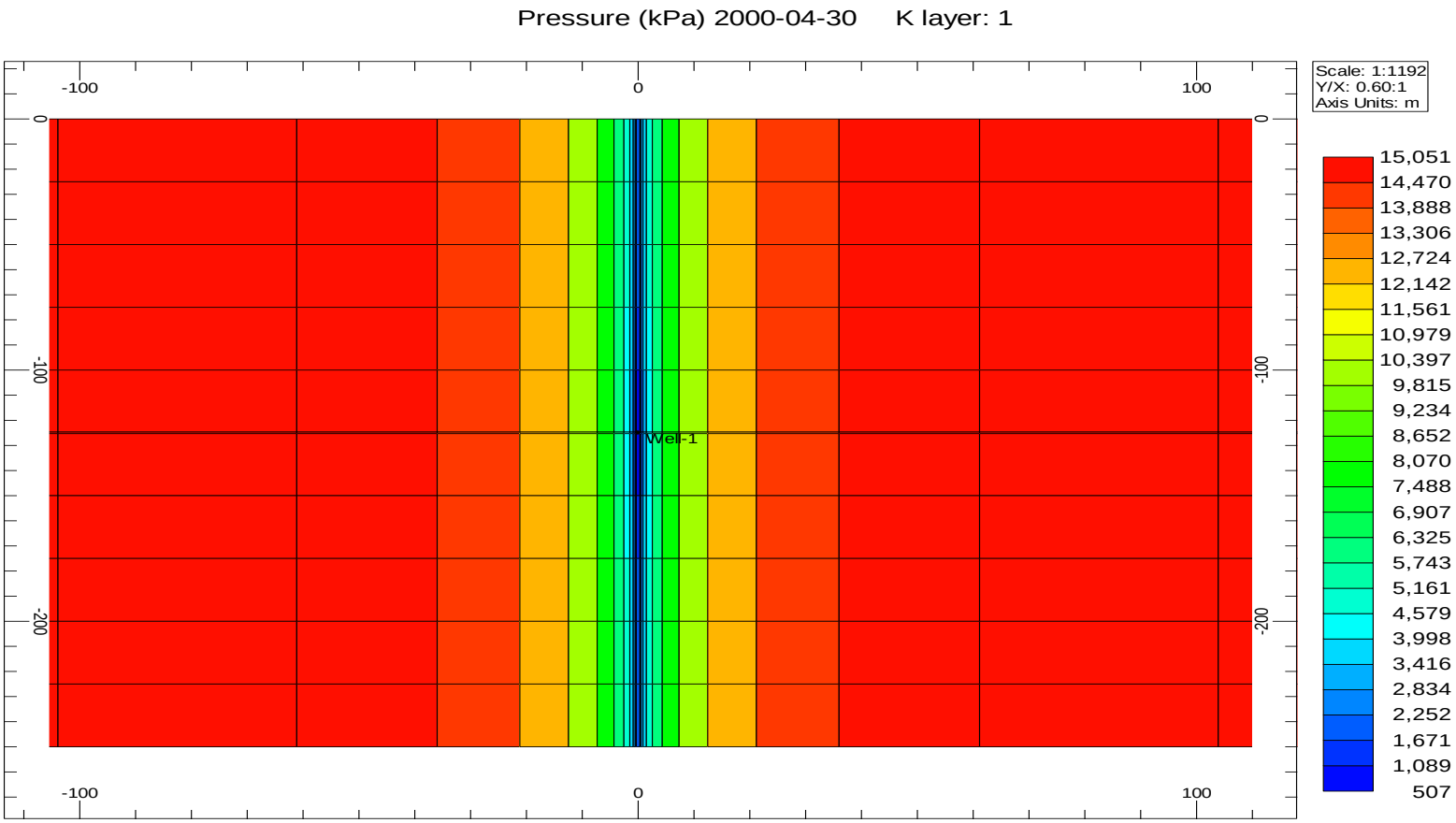




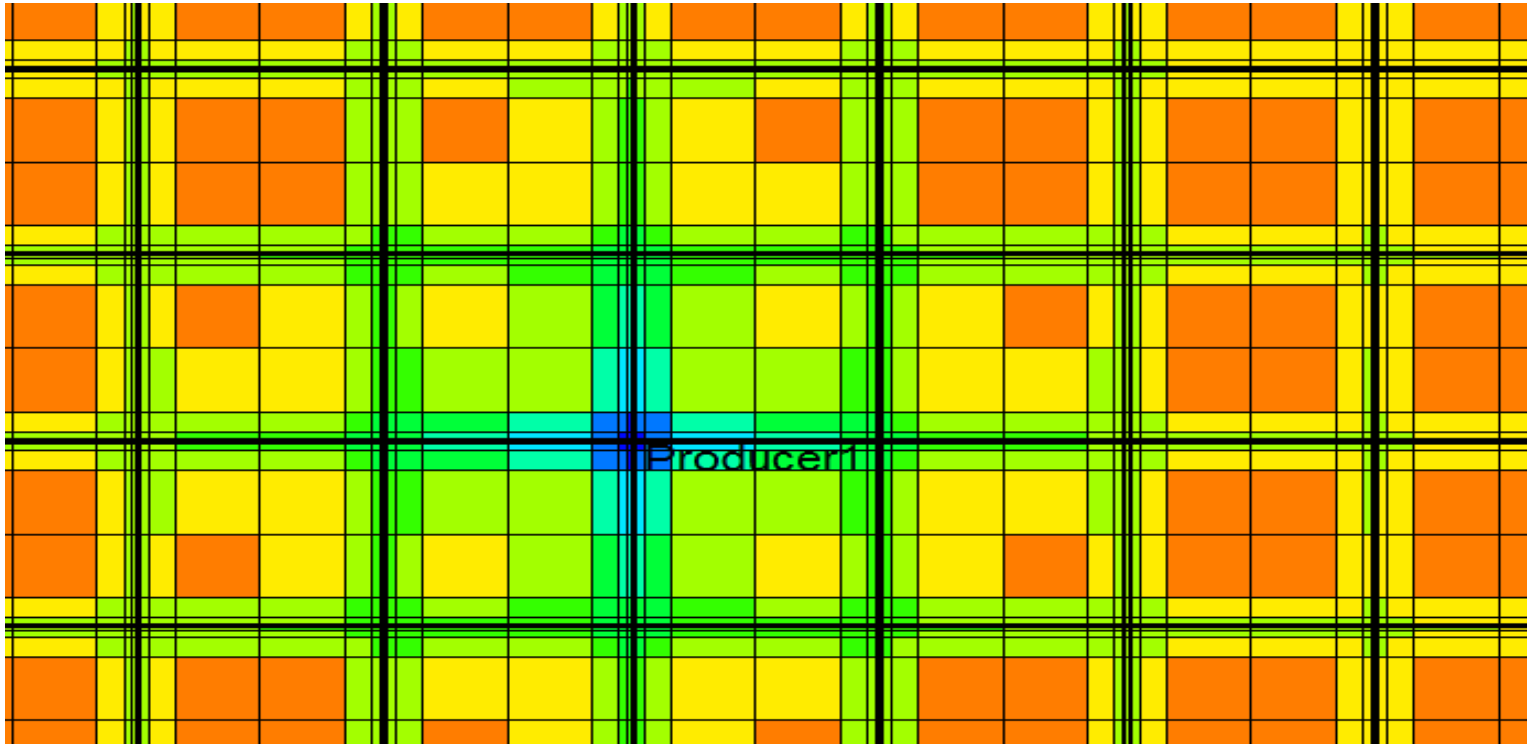
Planar Fractures in SRV

Complex Fractures in SRV

Logarithmic Gridding for Planar Fractures

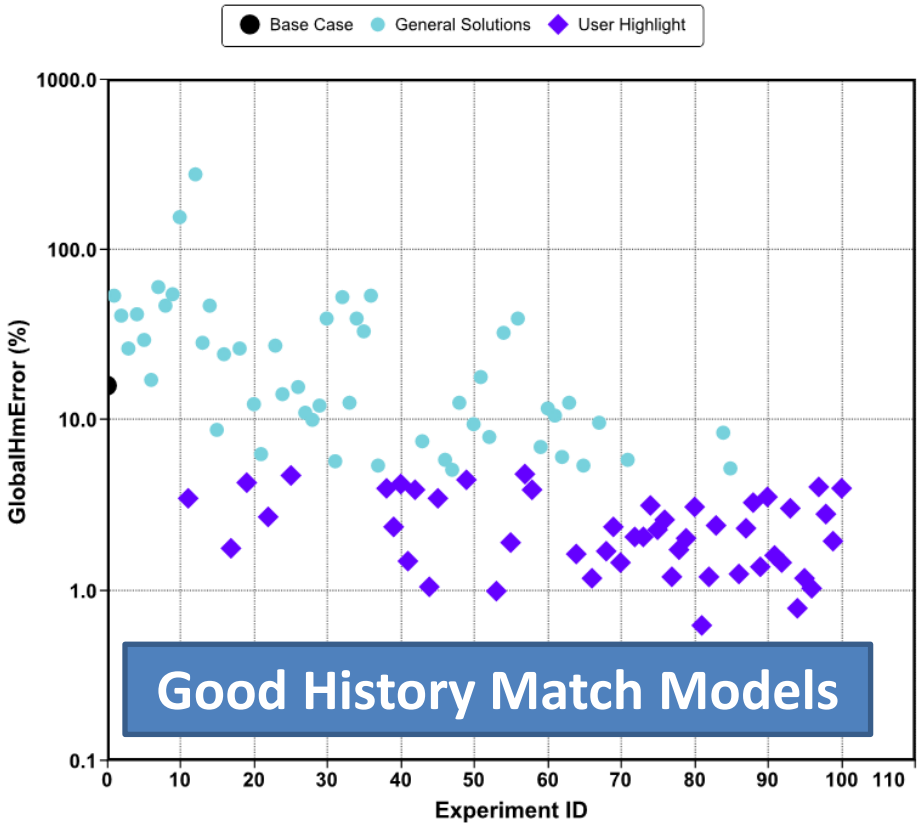


Logarithmic Gridding for Complex Fractures



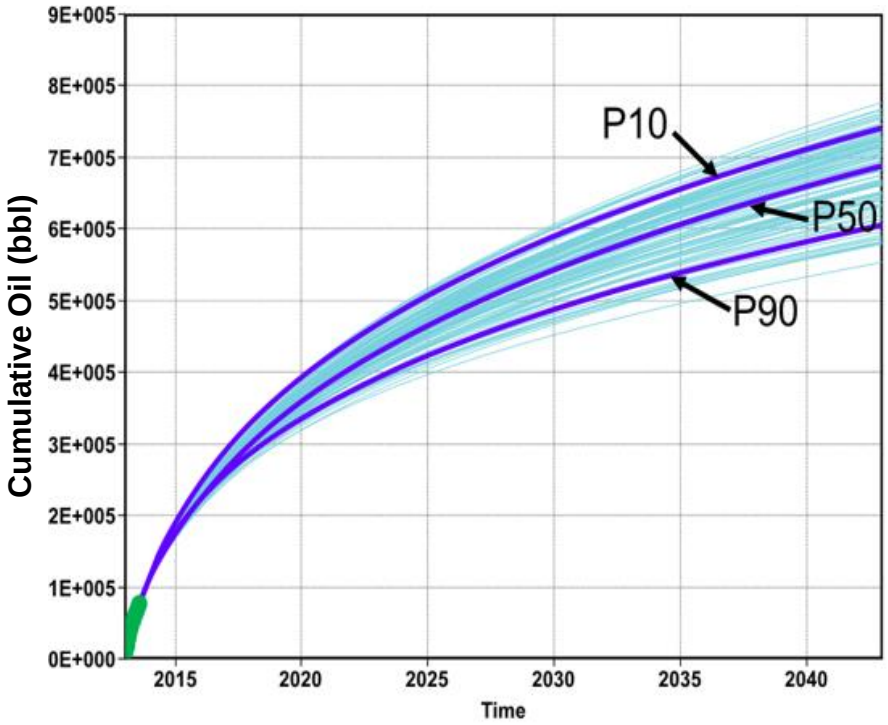
Bayesian History Matching

- History matching is an inverse problem with non-unique solutions
- Perfect HM ≠ Perfect Prediction



Probabilistic Forecasts

- Probabilistic forecasting reduces risk in making business decisions
- Provides range of possible outcomes along with
  - P90 (conservative)
  - P50 (most likely)
  - P10 (optimistic)

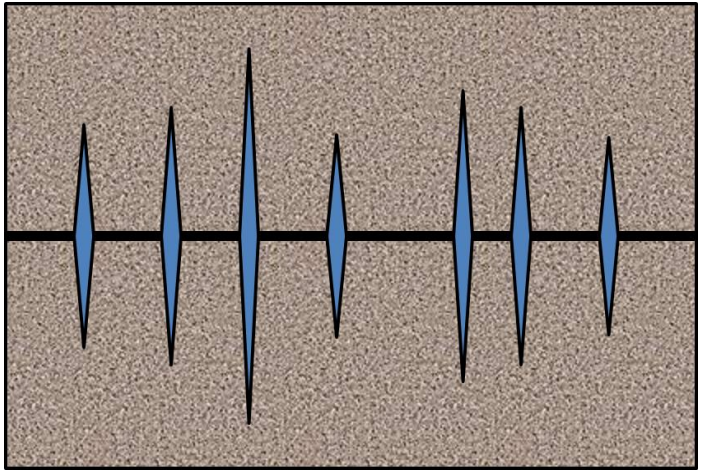


RTA Analytical Models

- **Analytical Models for Multi-Fractured Horizontal Wells (MFHWs)**
  - **General Horizontal Multifrac Model**
  - **Horizontal Multifrac Enhanced Frac Region Model**

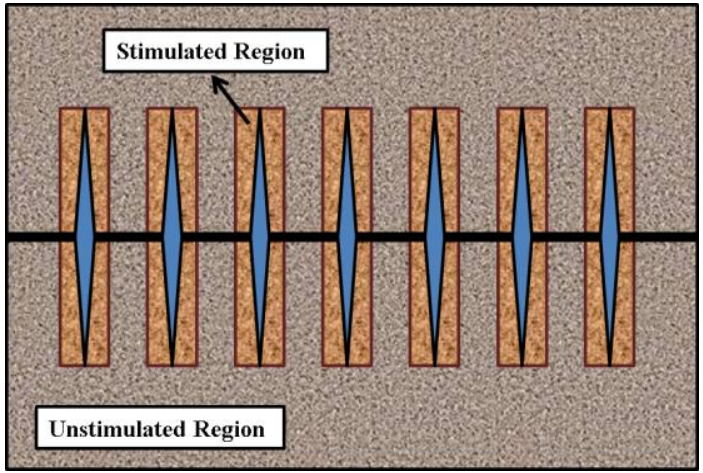
RTA Multi-Fractured Horizontal Wells

General Horizontal Multifrac Model



- Fractures have different lengths
- Fractures can be located anywhere along the well

Horizontal Multifrac Enhanced Frac Region Model

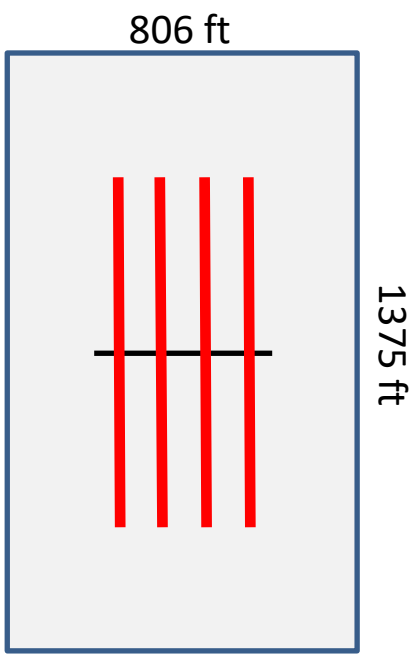


- Fractures are identical and uniformly distributed
- Each fracture is surrounded by a region of higher permeability (stimulated region)

Model Validation

- **3 Modeling Approaches:**
  - ✓ **Very-Finely-Gridded Numerical Model (Reference Solution)**
  - ✓ **LS-LR-Gridded Numerical Model**
  - ✓ **Analytical Model (General Horizontal Multifrac)**

- **<u>Base Model</u>: An undersaturated shale oil reservoir that satisfies all assumptions inherent to analytical solution-based methods**

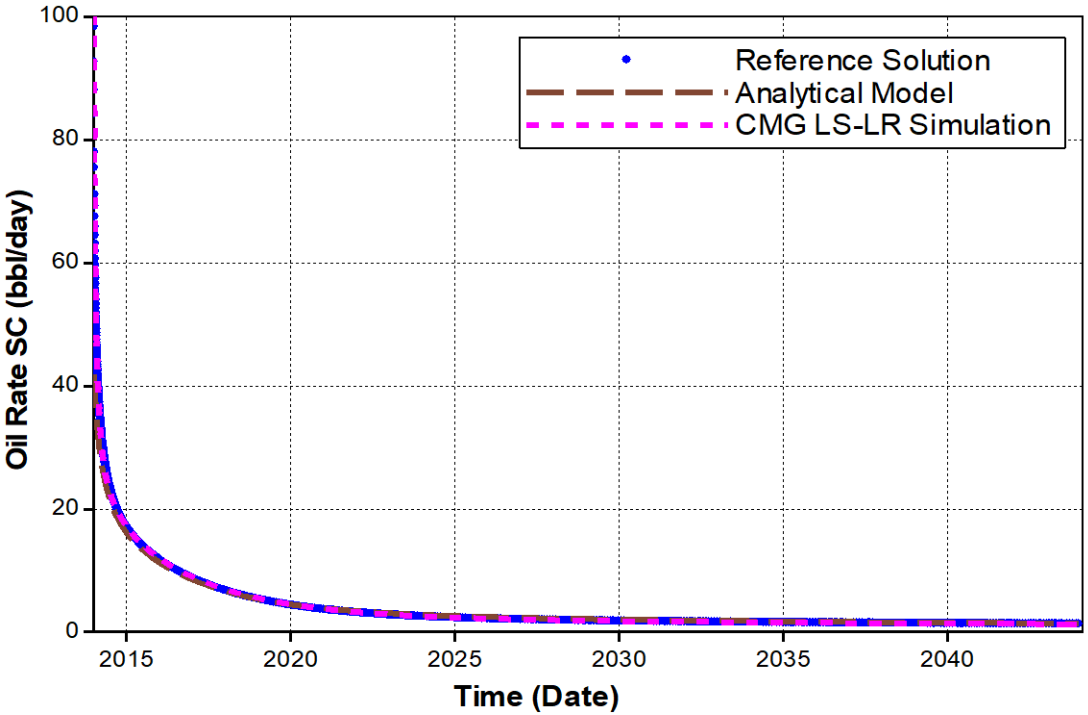


Base Model

- **Single-Phase Black Oil Model**
  - ✓ **Above bubble point pressure for entire 30-year forecast period**
  - ✓ **No free or frac'ing water present**
- **Homogeneous Porosity and Permeability**
- **Fully-Penetrating Planar Fractures**
- **Equal XF and FCD for Fractures**
- **No Fracture Compaction**

Property	Value
Matrix Permeability (nd)	100
Matrix Porosity (%)	6
Reservoir Thickness (ft)	105
Number of Fractures	4
Fracture Half-Length (ft)	400
Fracture Height (ft)	105
Fracture Spacing (ft)	100
FCD	100
Reservoir Pressure (psi)	7500
Operating Well BHP (psi)	2000
Bubble Point Pressure (psi)	1867

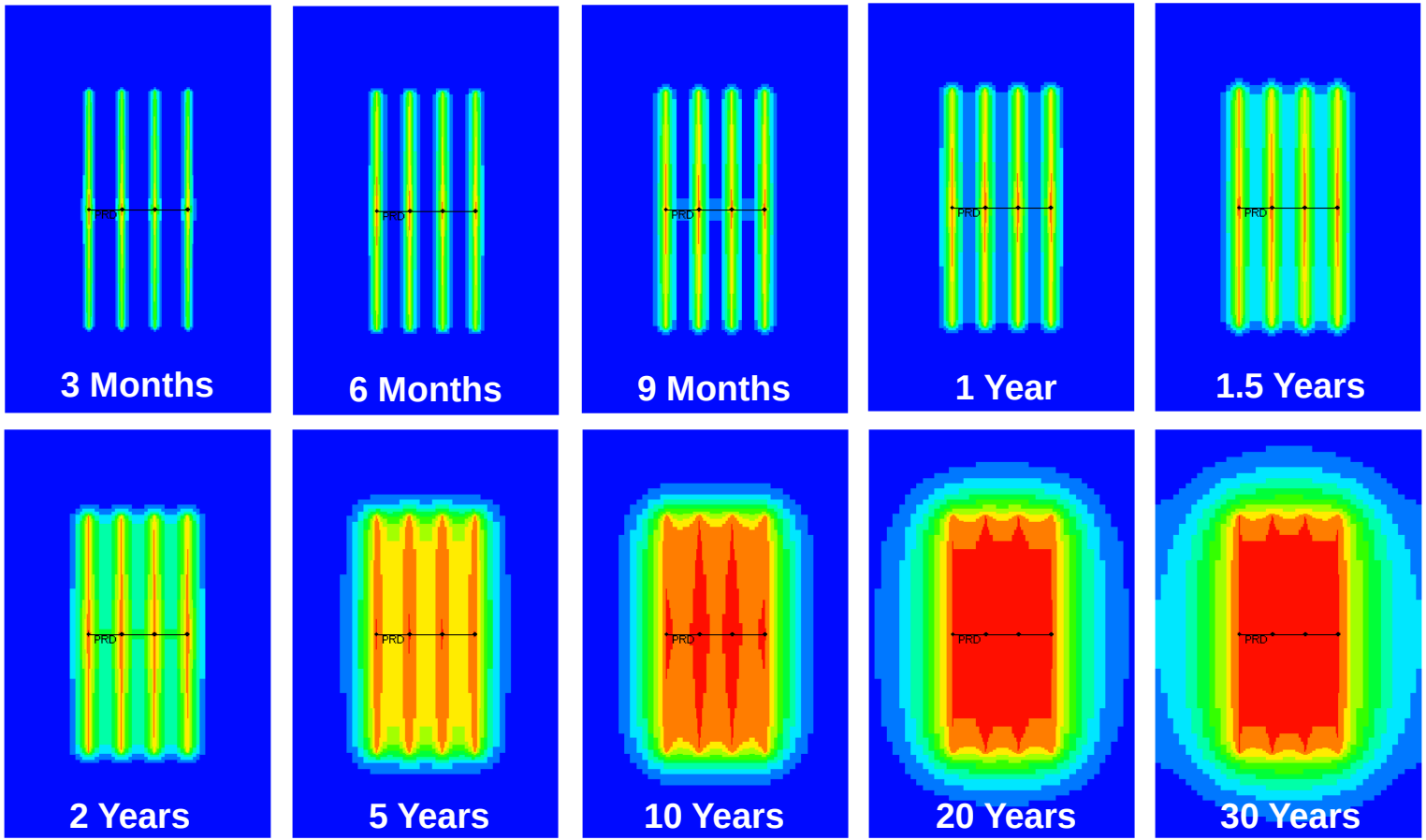
Base Model


Reference Solution
Analytical Model
CMG LS-LR Simulation
Oil Rate SC (bbl/day)
100
80
60
40
20
0
2015
2020
2025
2030
2035
2040
Time (Date)

Base Model

Method	Oil EUR, MSTB
Reference Solution	43.05
Analytical Model	43.27 (~0.5%↑)
CMG LS-LR Simulation	43.06 (~0.02%↑)

Pressure Change vs. Time



Pressure Depletion (psi)

6,000
5,400
4,800
4,200
3,600
3,000
2,400
1,800
1,200
600
0

Real-World Deviations From RTA Assumptions

1. Add one complexity at a time to the base model
2. Run very-finely-gridded numerical simulation model for thirty years to provide the reference solution
3. History match (HM) the first two years of production and forecast next 28 years of production to calculate 30-year EUR, using
   - RTA Workflow
   - Numerical Simulation Workflow

Real-World Deviations From RTA Assumptions

Common Complexities Not Taken into Account by Analytical Models:

- **Fracture Conductivity Loss (Scenario 1)**
- **Partially-Penetrating Fracture (Scenario 2)**
- **Presence of Water from Fracture Stimulation Treatment (Scenario 3)**
- **Presence of Two-phase Oil and Gas Flow (Scenario 4)**

Numerical Simulation Workflow

- Numerical Simulation workflow generates an ensemble of simulation models that ensure satisfactory HM quality.
- For each scenario, we selected the best eleven (11) HM models and performed forecast simulations.
- We then determined the P90 (conservative), P50 (most likely), and P10 (optimistic) values for the oil EUR. The simulation model corresponding to the P50 value is referred to as the "Simulation P50 Model".

RTA Workflow

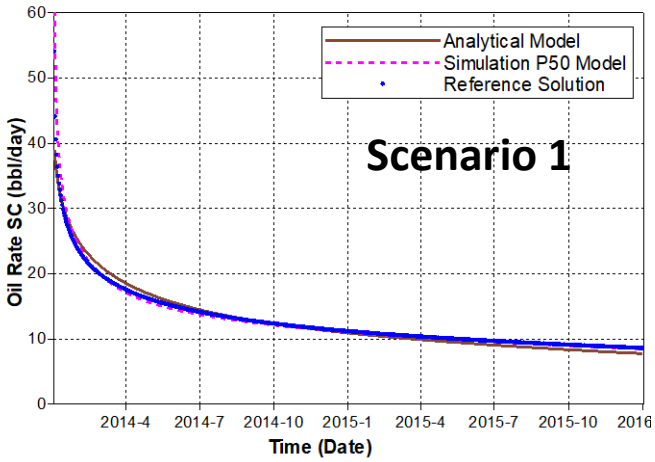
- **Analytical Models for Multi-Fractured Horizontal Wells (MFHWs)**
  - **General Horizontal Multifrac Model**
  - **Horizontal Multifrac Enhanced Frac Region Model**
- **History Matching using Automatic Parameter Estimation (APE)**
  - **APE is a mathematical multi-variable optimization technique to minimize error between an objective function and measured data**
  - **Depending on the analytical model, different sets of parameters can be specified to vary for APE.**
- **Production Forecast to Calculate a Deterministic Value for EUR**

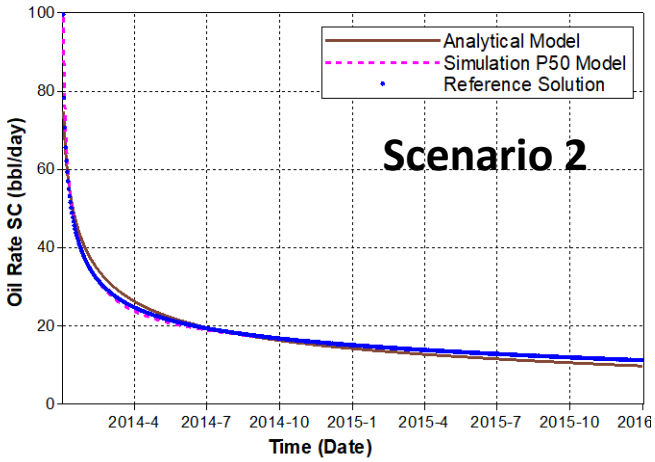
History Match 2 Years

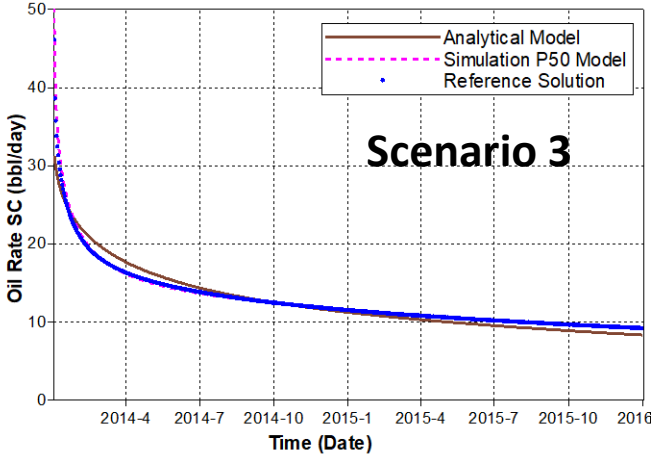
--- Analytical Model

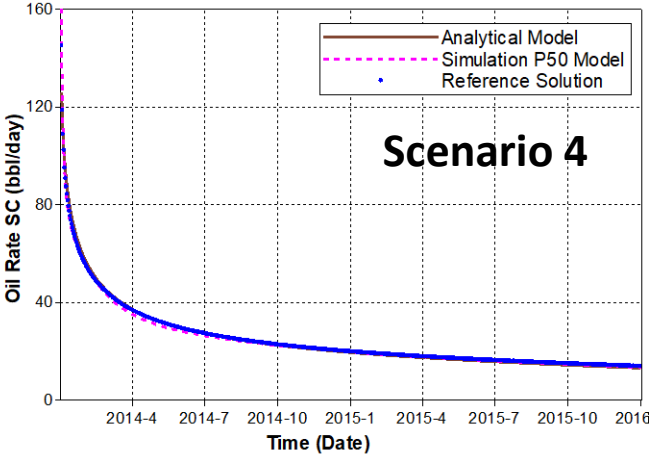
--- Simulation P50 Model

--- Reference Solution







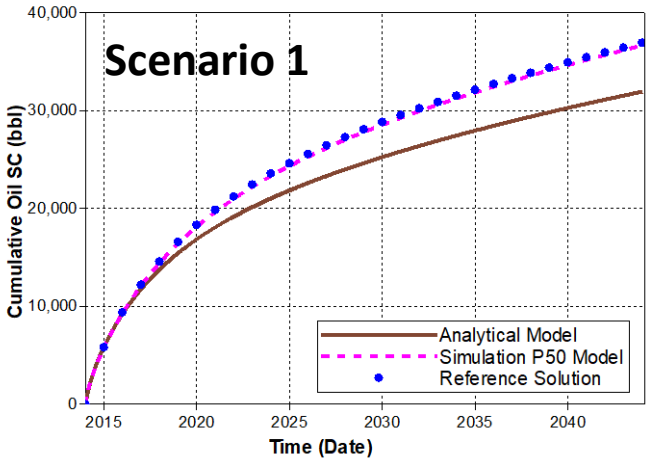


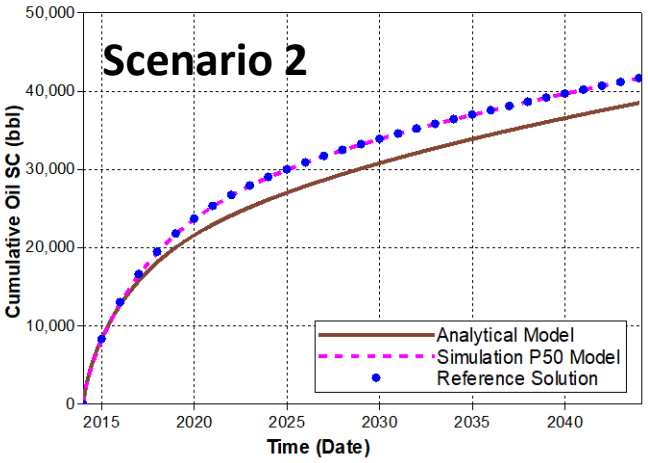
30-Year EUR Forecast

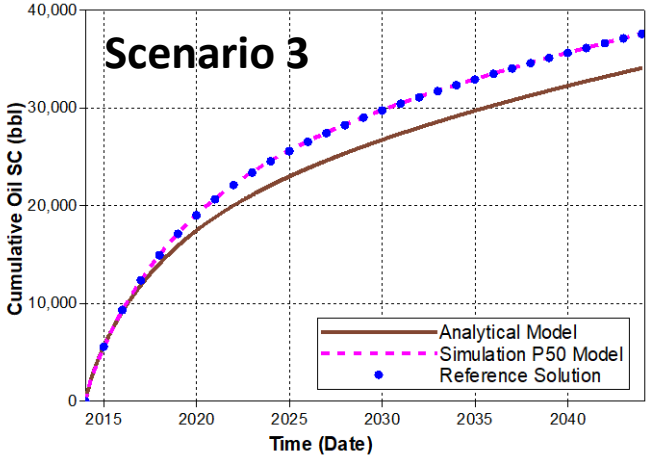
--- Analytical Model

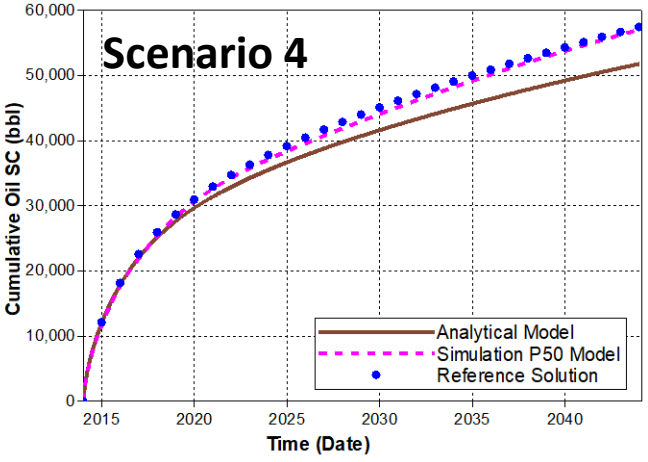
--- Simulation P50 Model

--- Reference Solution









Summary of HM Parameters & EUR Forecasts

Deviation from RTA Assumptions	History Match (HM) Parameters								Oil EUR Forecast, MSTB				
	Reference Model			RTA HM		Simulation P50 Model			Reference Solution	RTA Workflow	Numerical Simulation Workflow		
	XF (ft)	FCD	3rd Par.	XF (ft)	FCD	XF (ft)	FCD	3rd Par.			P90	P50	P10
Fracture Conductivity Loss	400	100	0.095*	273	41	406	136.2	0.057*	36.91	32.05 (-13.2%)	34.79 (-5.7%)	36.69 (-0.6%)	38.34 (+3.9%)
Partially-Penetrating Fracture	400	100	75**	338	74.1	397	100.2	75**	41.61	38.76 (-6.8%)	39.43 (-5.2%)	41.64 (+0.1%)	43.69 (+5.0%)
Presence of Water from Frac. Stimulation	400	100	0.45***	303	29.5	403	94.5	0.438***	37.56	34.18 (-9.0%)	35.33 (-5.9%)	37.64 (+0.2%)	39.26 (+4.5%)
Presence of Two-Phase Oil and Gas Flow	400	100	NA	361	99.6	385	120.3	NA	57.42	51.97 (-9.5%)	54.98 (-4.2%)	57.07 (-0.6%)	60.71 (+5.7%)

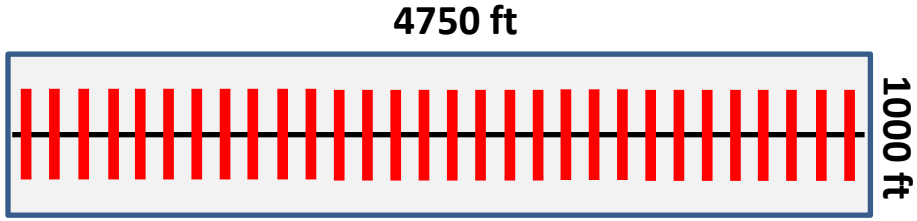
* Fracture compaction
**Fracture height
***Swi in fractures

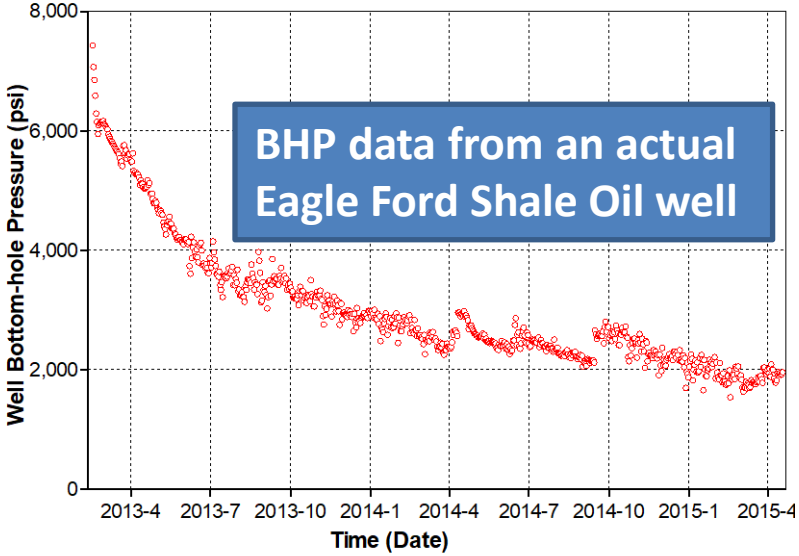
Oil EUR Error
- RTA Workflow: 6.5-13%
- Numerical Simulation Workflow
  - P90: <6%
  - P50: <1%
  - P10: <6%

Realistic Case Study

- Invoked all 4 of the previously studied real-world deviations from RTA assumptions.
- Considered more realistic well and completion configuration (4750-ft long horizontal well, 15 stages of fractures, 2 fractures per stage).
- Imposed 26 months of BHP data from an actual well as the operating well constraint.
- Included an enhanced permeability region around fractures to represent SRV.

Realistic Case Study





Property	Value
Fracture Half-Length (ft)	300
Fracture Height (ft)	105
Fracture Spacing (ft)	150
FCD	5.625
Fracture Perm. Multiplier at 750 psi	0.057
Stimulated Region Permeability (md)	0.008
Matrix Horizontal Permeability (nd)	380
Matrix Vertical Permeability (nd)	38
Matrix Porosity (%)	7.8
Reservoir Pressure (psi)	7810
Bubble Point Pressure (psi)	2860
Reservoir Temperature (°F)	275

Realistic Case Study

- Built an extremely fine-grid model and ran it to create a reference solution for our analysis. The first 26 months of production data computed by the reference simulation was used as the “production history” to be matched by both the RTA and Numerical Simulation workflows.
- After the 26 months of variable BHP operation, the well was then operated at constant BHP of 750 psi for 25 years to create a forecast period.
- Included higher number of history match parameters.

Realistic Case Study

- **Oil EUR calculations are frequently performed for unconventional wells when *historical production data is limited*. We applied the same procedure to four scenarios with different durations of historical data available to be matched:**
  a) **26 months**
  b) **12 months**
  c) **6 months**
  d) **3 months**

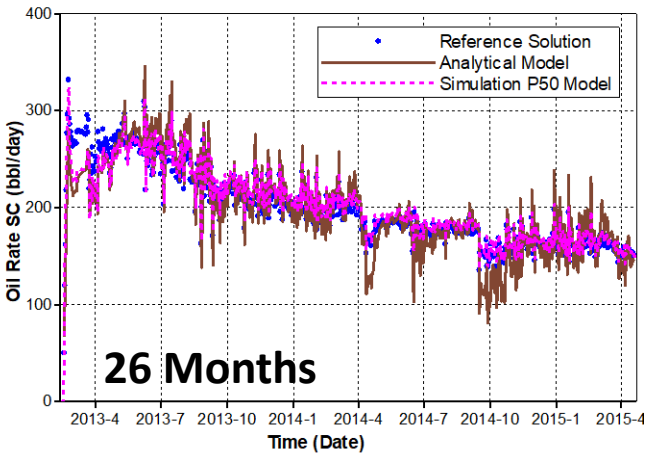
- **For each case, we selected the best 41 HM models from the Numerical Simulation workflow and performed forecast simulations to determine P90, P50, and P10 values for the oil EUR.**

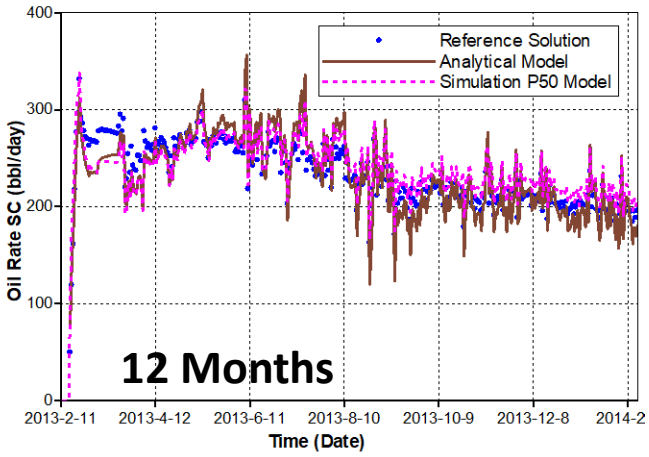
History Match Prod. Data

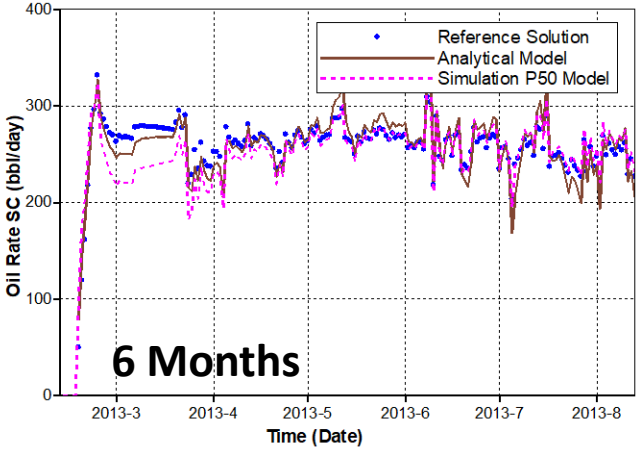
--- Analytical Model

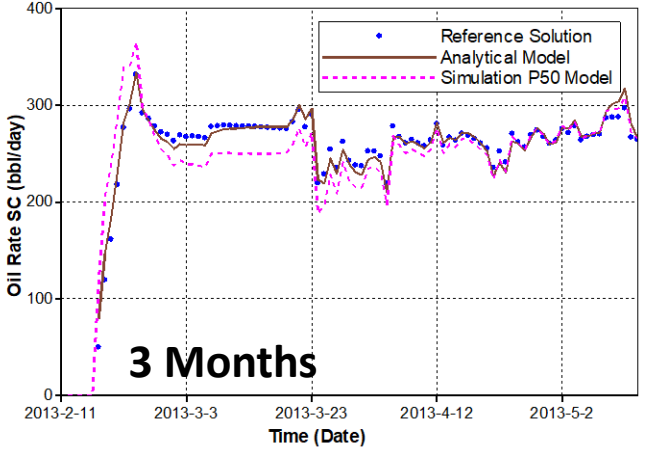
--- Simulation P50 Model

--- Reference Solution







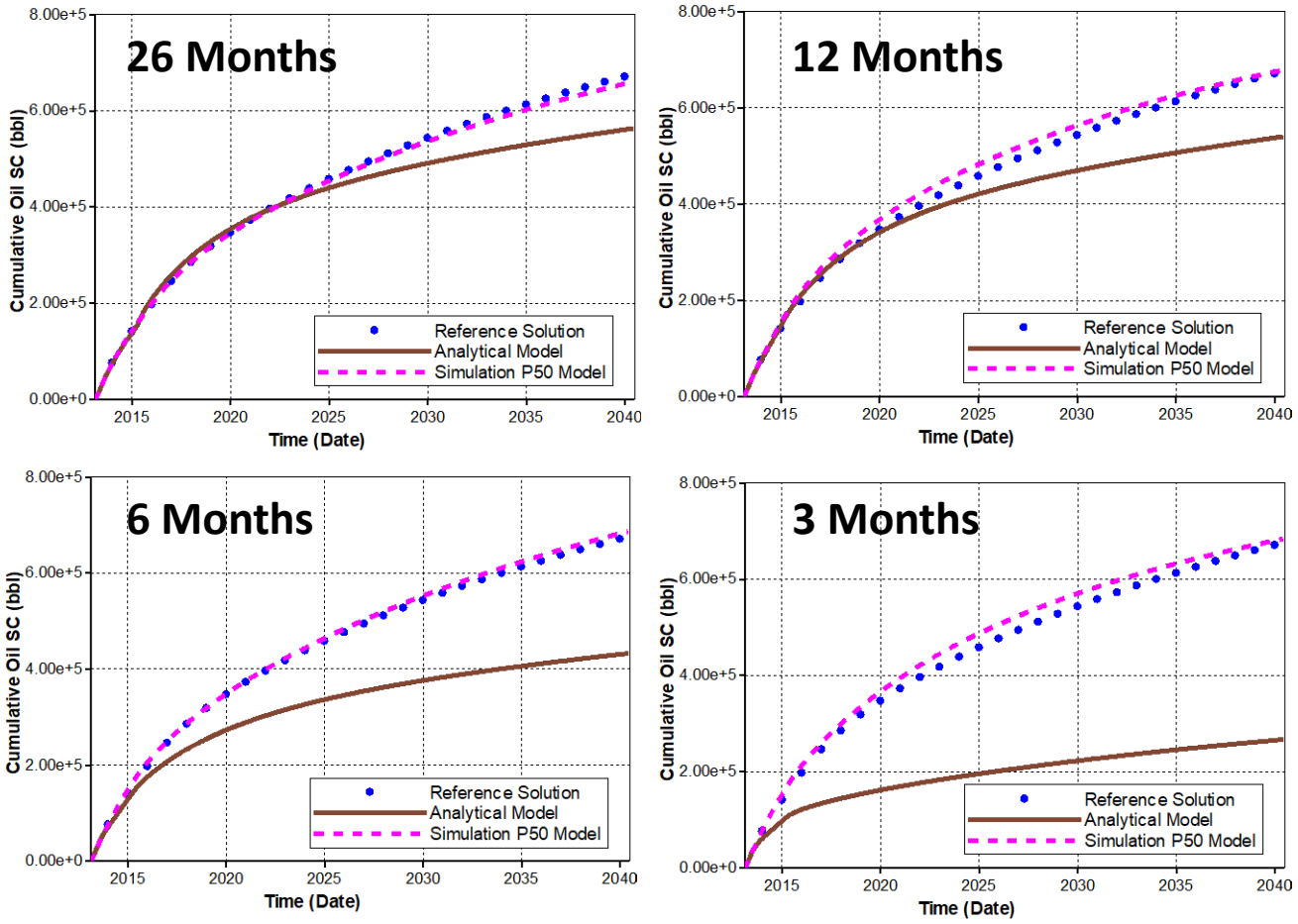


25-Year EUR Forecast

--- Analytical Model

--- Simulation P50 Model

--- Reference Solution

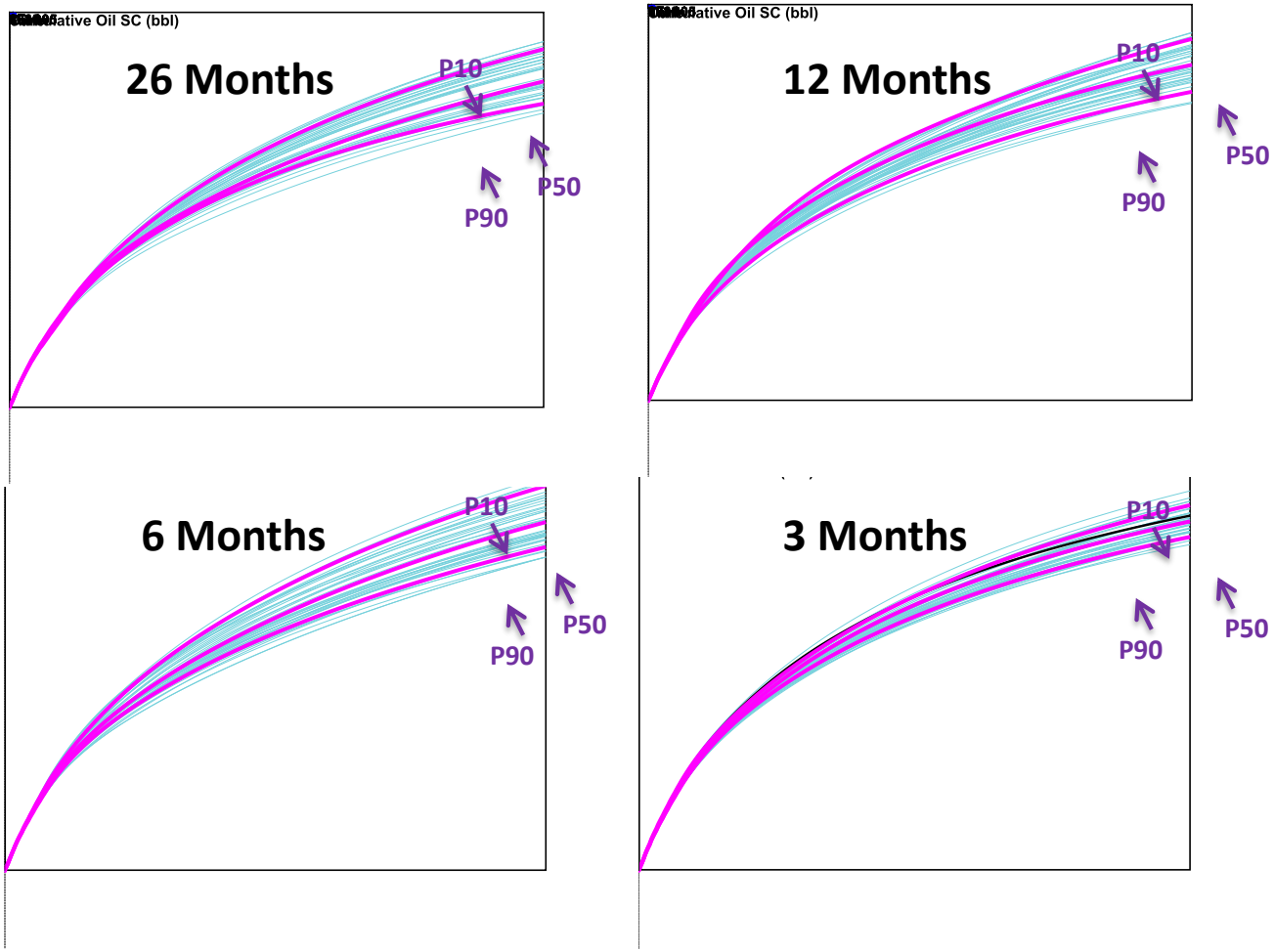


Probabilistic Forecast

--- 41 HM Models

--- P90, P50, P10 Models

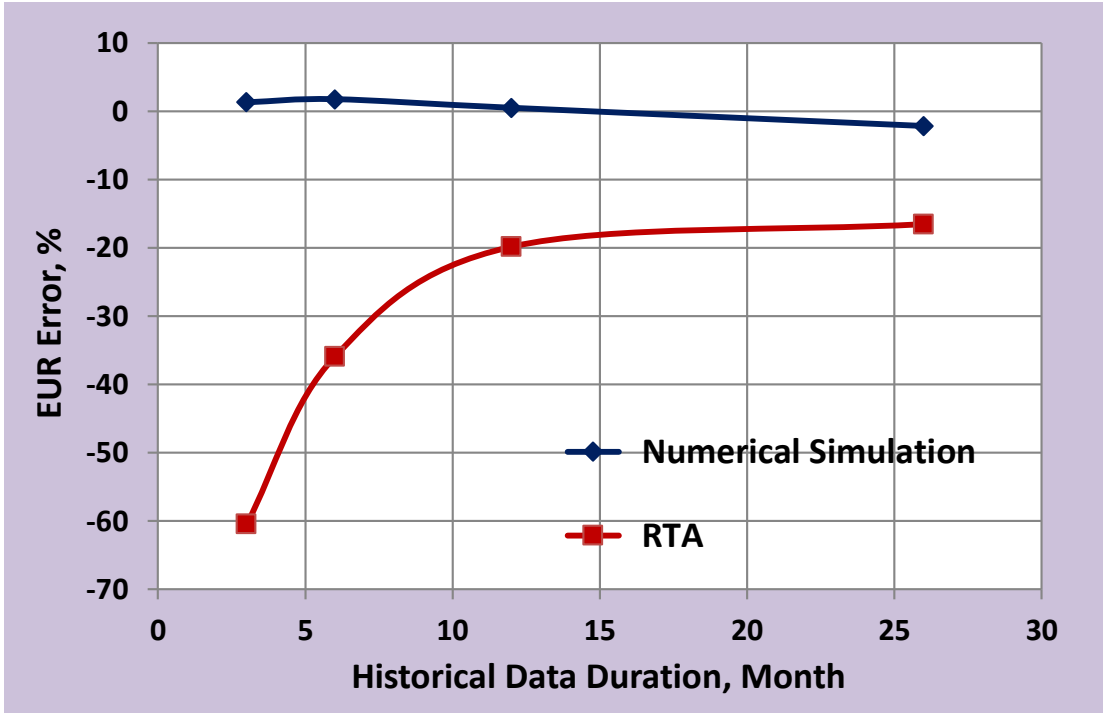
--- Reference Solution



Summary of HM Parameters & EUR Forecasts

History Match (HM) Parameters	Min. Value	Max. Value	Reference Model	26 Months of History		12 Months of History		6 Months of History		3 Months of History	
				RTA HM	Simulation P50 Model	RTA HM	Simulation P50 Model	RTA HM	Simulation P50 Model	RTA HM	Simulation P50 Model
XF (ft)	50	400	300	192	303.4	179	327.4	149	183.6	176	346.2
Fracture Height (ft)	45	135	105	135	105	135	105	135	105	135	75
FCD	1	41.6	5.625	5.2	5.925	12.1	5.662	11.2	8.44	8.2	7.25
Stimulated Region Perm. (md)	0.001	0.02	0.008	0.00936	0.0168	0.00518	0.00922	0.0069	0.0032	0.00796	0.0102
Stimulated Region Width (ft)	0	100	25	18	25	20	25	34	25	36	25
Matrix Perm. (nd)	50	800	380	779	369	768	331	456	724	54	502
Matrix Porosity (%)	6	10	7.8	7.8	6.97	7.8	6.53	7.8	8.35	7.8	6.46
Proppant Perm. Reduction Due to Compaction	0.005	0.2	0.057	NA	0.0597	NA	0.105	NA	0.0635	NA	0.0864
Fracture Swi (frac.)	0	0.4	0.75*	NA	0.239	NA	0.156	NA	0.314	NA	0.195
Stimulated Region Swi (frac.)	0.3	0.4	0.32	NA	0.326	NA	0.358	NA	0.374	NA	0.336
Oil EUR Forecast, MSTB			675.2	563.5	660.5	541.2	678.5	432.6	687	266.9	683.9
EUR Error (%)			NA	-16.5	-2.2	-19.8	0.5	-35.9	1.7	-60.5	1.3

Summary of HM Parameters & EUR Forecasts



Computational Performance

Production History Duration (months)	History Match Time (hours)	Forecast Time (hours)	Total Time (hours)
26	9.8	1.4	11.2
12	6.2	1.0	7.2
6	2.4	0.7	3.1
3	1.7	0.7	2.4

- 600 total simulator runs for each history match
- 41 total simulator runs for each forecast
- Forecasts all done to June of 2040 and include history
- 16 simultaneous 8-way parallel simulator runs per task

DCA Assumptions

- Assumed forecasts are for PDP reserves, so interested in matching recent history
- DCA used multi-segment curves (hyperbolic with Dmin of 10%)
- All forecasts done with Harmony Decline Plus

Summary of HM Parameters & EUR Forecasts

Deviation from RTA Assumptions	History Match (HM) Parameters								Oil EUR Forecast, MSTB				
	Reference Model			RTA HM		Simulation P50 Model			Reference Solution	DCA Workflow	Numerical Simulation Workflow		
	XF (ft)	FCD	3rd Par.	XF (ft)	FCD	XF (ft)	FCD	3rd Par.			P90	P50	P10
Fracture Conductivity Loss	400	100	0.095*	273	41	406	136.2	0.057*	36.91	25.95 (-30.7%)	34.79 (-5.7%)	36.69 (-0.6%)	38.34 (+3.9%)
Partially-Penetrating Fracture	400	100	75**	338	74.1	397	100.2	75**	41.61	30.41 (-26.9%)	39.43 (-5.2%)	41.64 (+0.1%)	43.69 (+5.0%)
Presence of Water from Frac. Stimulation	400	100	0.45***	303	29.5	403	94.5	0.438***	37.56	32.3 (-14.0%)	35.33 (-5.9%)	37.64 (+0.2%)	39.26 (+4.5%)
Presence of Two-Phase Oil and Gas Flow	400	100	NA	361	99.6	385	120.3	NA	57.42	33.78 (-41.2%)	54.98 (-4.2%)	57.07 (-0.6%)	60.71 (+5.7%)

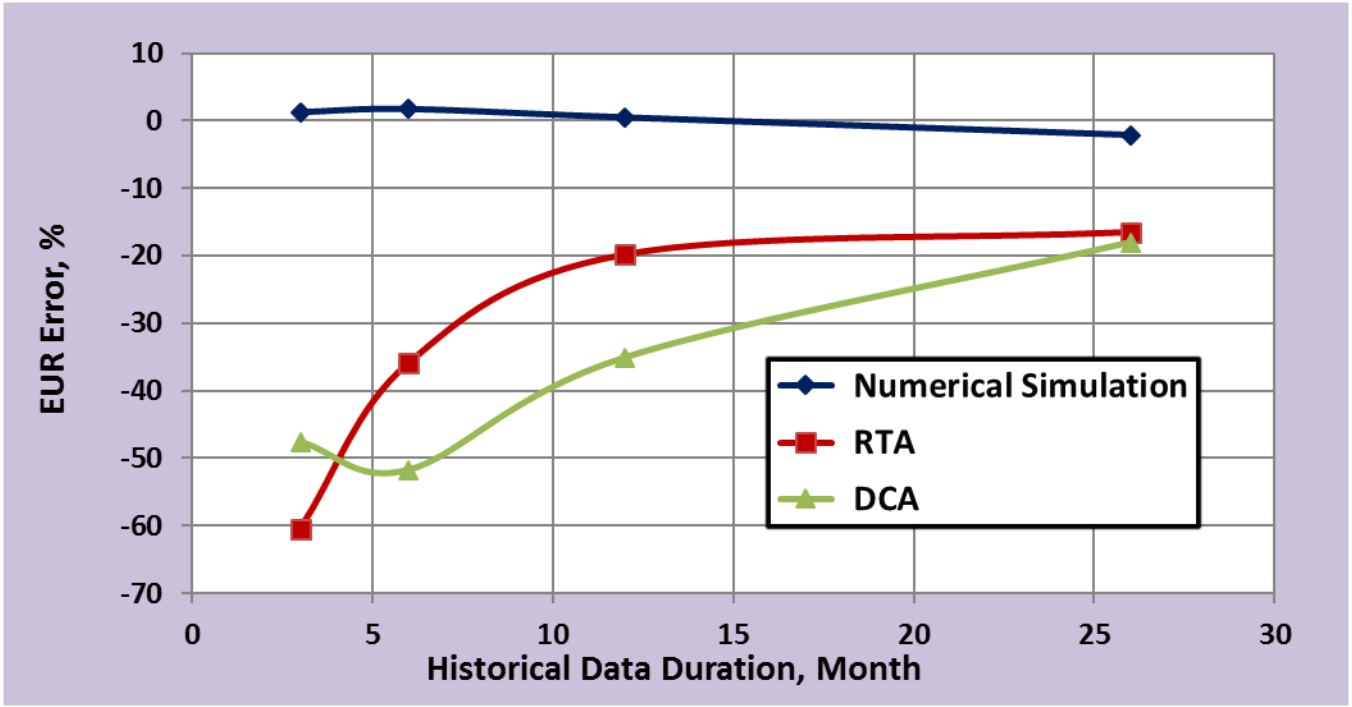
* Fracture compaction
**Fracture height
***Swi in fractures

Oil EUR Error
- DCA Workflow: -14 to -34%
- Numerical Simulation Workflow
  - P90: <6%
  - P50: <1%
  - P10: <6%

Summary of HM Parameters & EUR Forecasts

History Match (HM) Parameters	Min. Value	Max. Value	Reference Model	26 Months of History		12 Months of History		6 Months of History		3 Months of History	
				DCA HM	Simulation P50 Model	DCA HM	Simulation P50 Model	DCA HM	Simulation P50 Model	DCA HM	Simulation P50 Model
XF (ft)	50	400	300	NA	303.4	NA	327.4	NA	183.6	NA	346.2
Fracture Height (ft)	45	135	105	NA	105	NA	105	NA	105	NA	75
FCD	1	41.6	5.625	NA	5.925	NA	5.662	NA	8.44	NA	7.25
Stimulated Region Perm. (md)	0.001	0.02	0.008	NA	0.0168	NA	0.00922	NA	0.0032	NA	0.0102
Stimulated Region Width (ft)	0	100	25	NA	25	NA	25	NA	25	NA	25
Matrix Perm. (nd)	50	800	380	NA	369	NA	331	NA	724	NA	502
Matrix Porosity (%)	6	10	7.8	NA	6.97	NA	6.53	NA	8.35	NA	6.46
Proppant Perm. Reduction Due to Compaction	0.005	0.2	0.057	NA	0.0597	NA	0.105	NA	0.0635	NA	0.0864
Fracture Swi (frac.)	0	0.4	0.75*	NA	0.239	NA	0.156	NA	0.314	NA	0.195
Stimulated Region Swi (frac.)	0.3	0.4	0.32	NA	0.326	NA	0.358	NA	0.374	NA	0.336
Oil EUR Forecast, MSTB			675.2	553.4	660.5	438.3	678.5	325.7	687	353.7	683.9
EUR Error (%)			NA	-18.0	2.2	-35.1	0.5	-51.8	1.7	-47.6	1.3

Summary of HM Parameters & EUR Forecasts



Conclusions

- Analytical models do not account for many important aspects of fluid-flow in unconventional reservoirs.
- RTA only provided deterministic EURs whereas the Numerical Simulation workflow provides probabilistic EURs conditioned by historical production data.
- RTA was found to under-predict oil EUR by ~10% when only one deviation from RTA assumptions was present at a time, whereas Numerical Simulation workflow produced P50 oil EUR values within 1% of the correct answer.

Conclusions

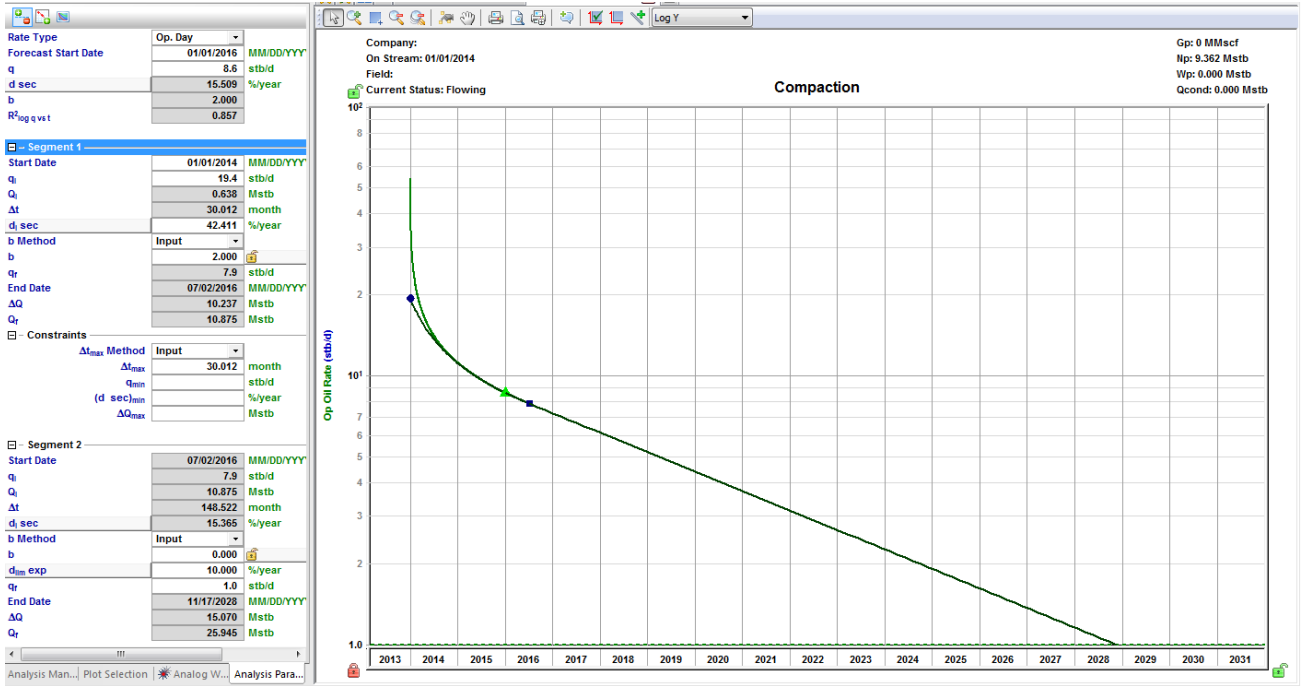
- RTA under-predicted oil EUR by 16.5% when all four deviations from RTA limitations were enabled. The P50 oil EUR from Numerical Simulation workflow was only 2.2% under the correct value.
- The RTA oil EUR under-prediction grew to 60% when the historical production period was only 3 months.
- The discrepancy between the correct answer and P50 oil EUR from Numerical Simulation workflow was not dependent on the production history duration, and the maximum discrepancy was only 2.2%.

Conclusions

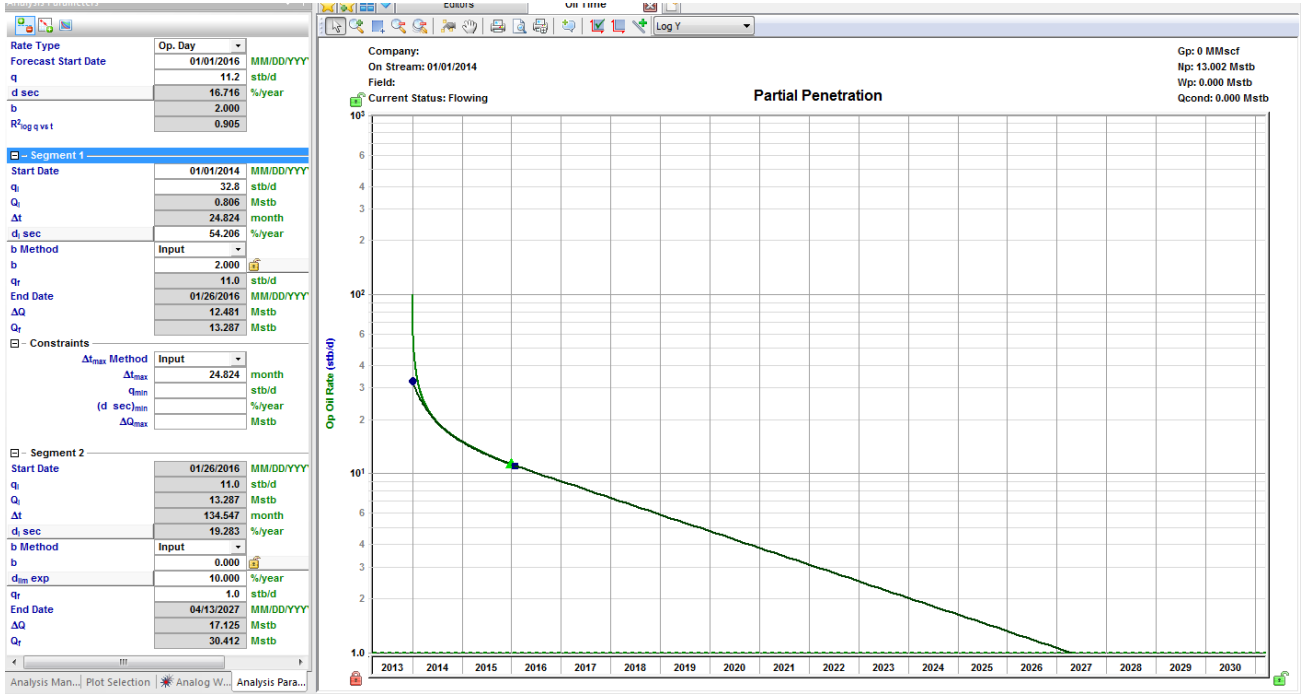
- RTA-derived history match parameters were off by far greater percentages.
- RTA workflow under-predicts EURs even though rate matches “look good”.
- Computation times for the Numerical Simulation workflow were on the order of 1 working day or less, making it a practical solution for calibration of RTA or other methods for EUR calculation in unconventional reservoirs.

Thank You / Questions

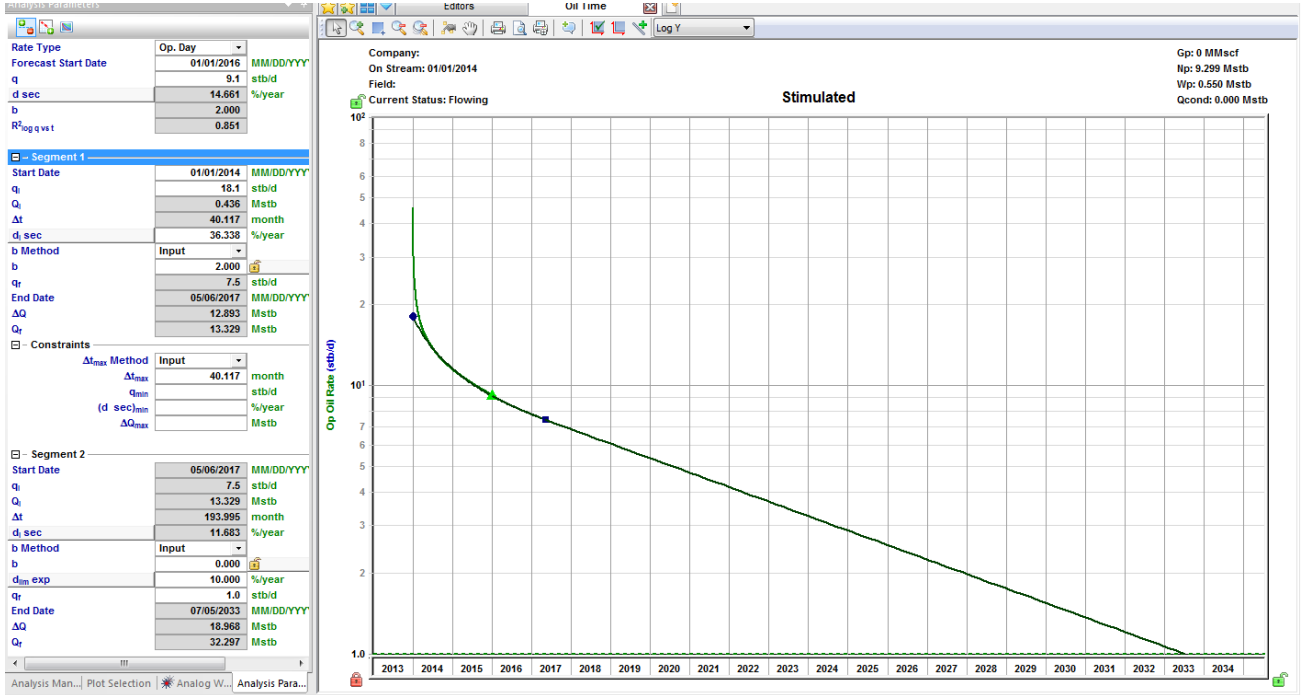
Fracture Conductivity Loss



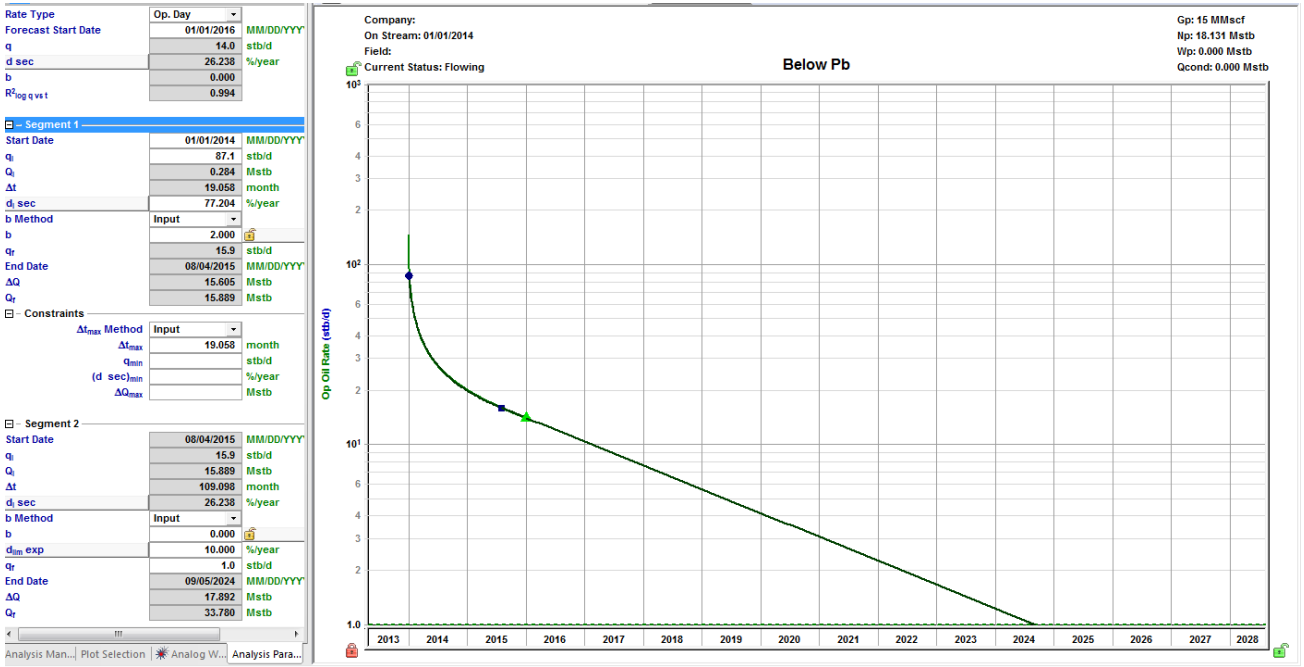
Partially Penetrating Fractures



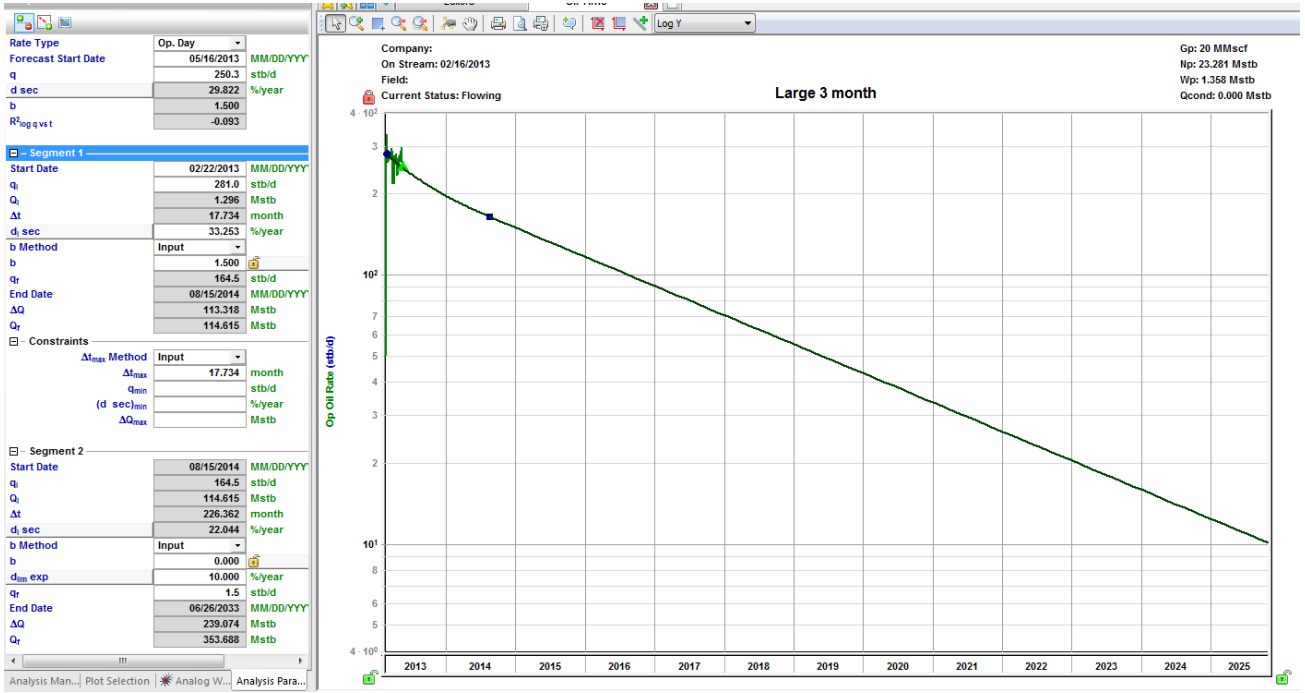
Frac Water Flowback



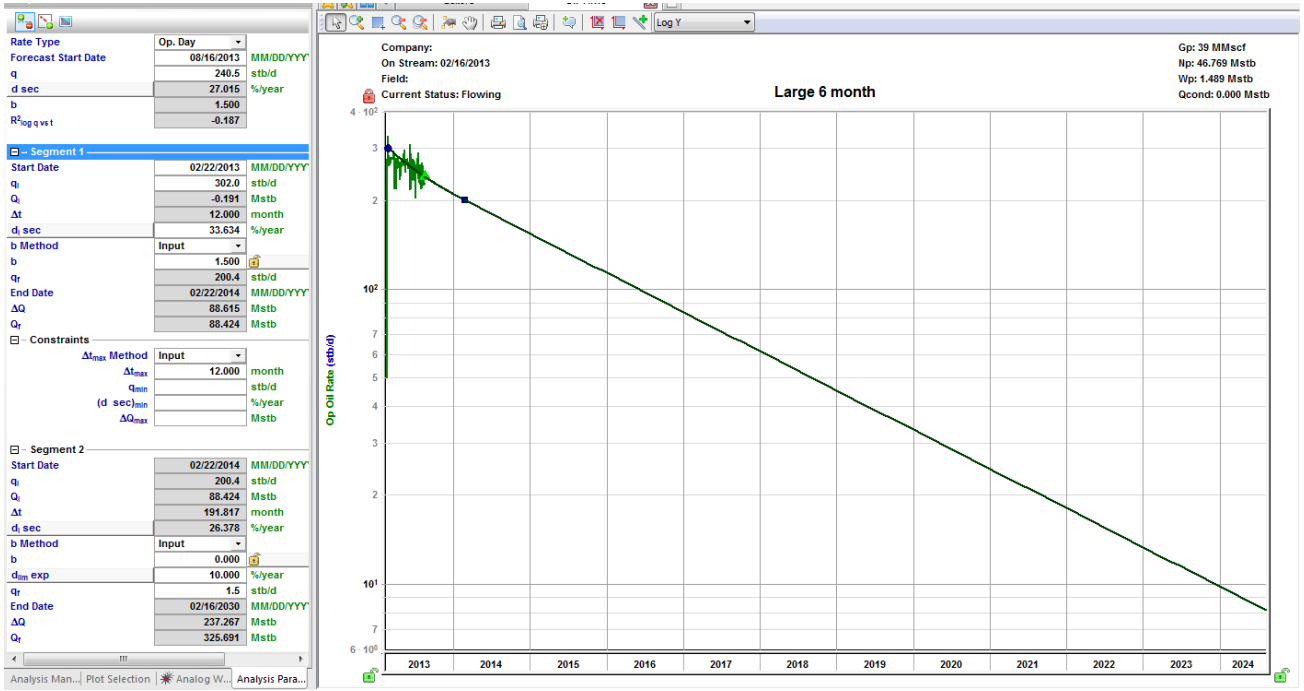
2-Phase Oil & Gas Flow



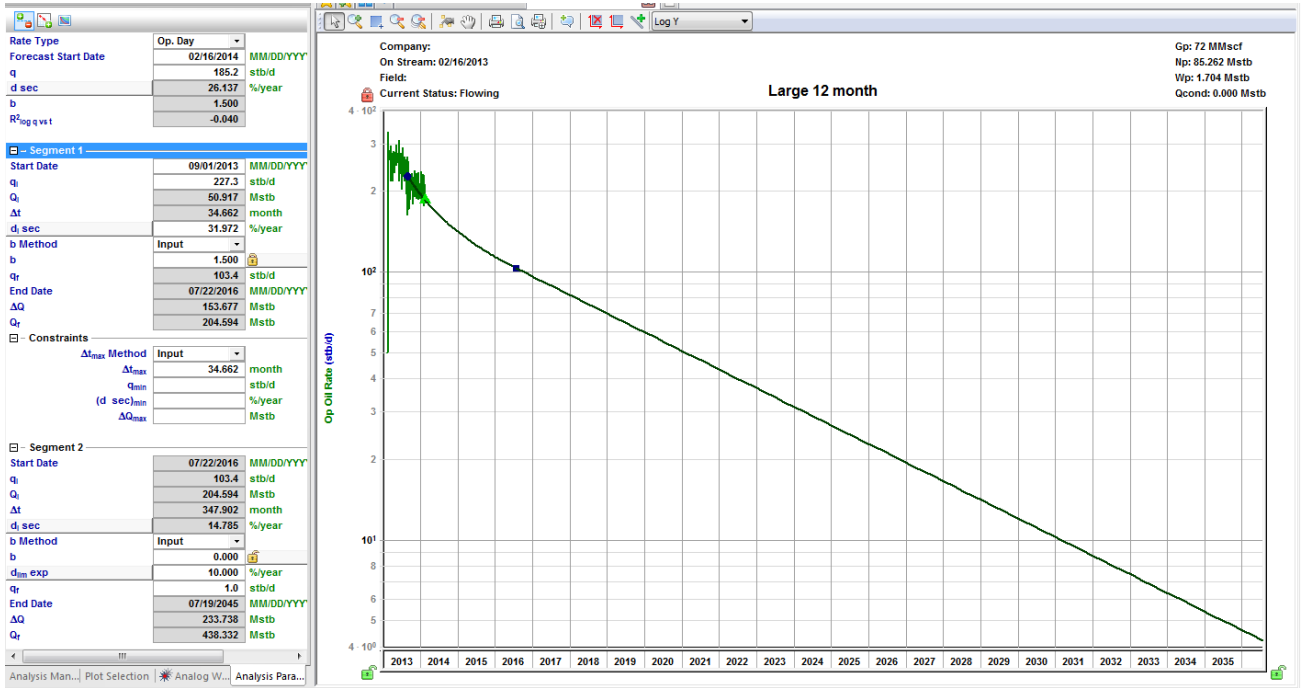
3 month prod history



6 month prod history



12 month prod history



24 month prod history