非常规储层EUR储量计算的数值方法与解析方法的对比

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

Jim Erdle
VP USA & Latin America
Houston
June 21, 2016

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VP Engineering
Solutions & Marketing

Jim Erdle
VP USA & Latin
America

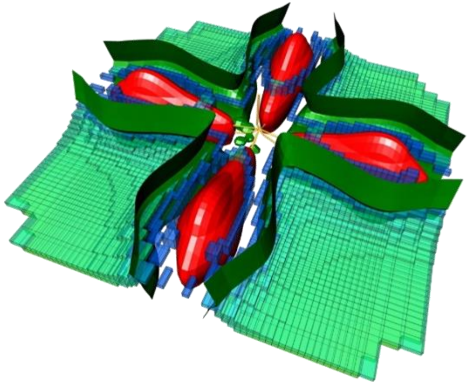
COMPUTER
MODELLING
GROUP LTD.

Agenda

- About CMG
- Why use Reservoir Simulation for Unconventional Reservoirs?
- CMG's Unconventional Reservoir Physics & Workflows
- RTA vs CMG for Unconventional EUR (SPE 180209)
- Data Analytics for Predicting Unconventional Well Performance?
- Conclusions
- Why use CMG for Unconventional Reservoir Modelling?

What We Do

- Reservoir Simulation Software Development & Licensing
- Specialized Consulting Services
- Customized Training
- Collaborative Research

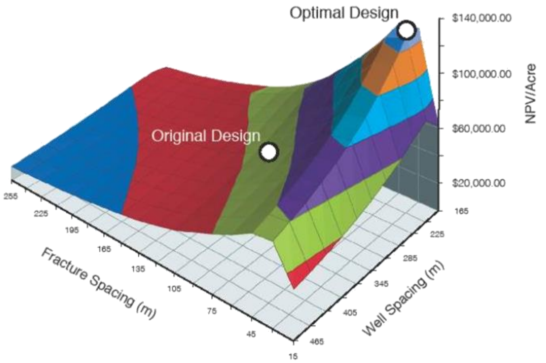


Cyclic Steam Stimulation (CSS) model

What We Do for Our Customers

CMG’s software suite helps oil and gas companies generate greater returns

- **Optimize E&P investments**
- **Improve recovery**
- **A relatively small investment can have a potentially huge impact**

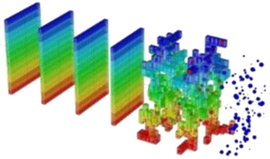


NPV/Acre vs. Well & Fracture Spacing

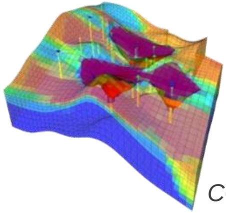
Our Specialization

Market leader in EOR and Advanced Recovery Processes

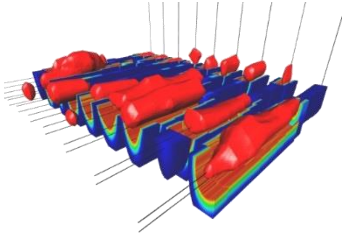
- Smart Water & Polymer flooding (Low Salinity)
- Unconventionals (CBM, Tight/Shale Oil & Gas)
- Chemical EOR (ASP, SP, Foam, LTG, etc.)
- Gas Injection EOR (Continuous, WAG, SWAG)
- Compositional (miscible flooding, volatile oils, gas condensates)
- CO2 Sequestration (with geochemistry)
- Thermal (Steamflooding, CSS, SAGD, ES-SAGD, Insitu Combustion, Electrical/Electromagnetic Heating)



Hydraulic Fractures & Microseismic

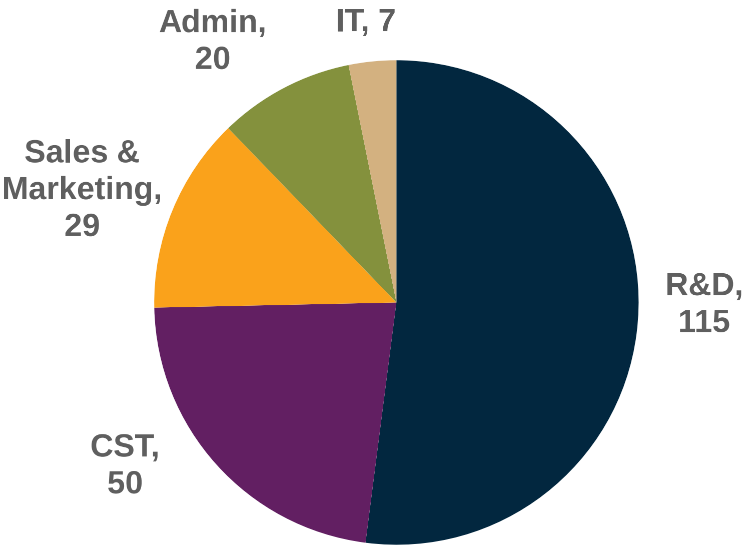


CO2 Injection



SAGD

Deep Bench of Intellectual Capital



Technical Strength

221 Total Employees

63 Ph.Ds

63 Masters

71 Bachelors

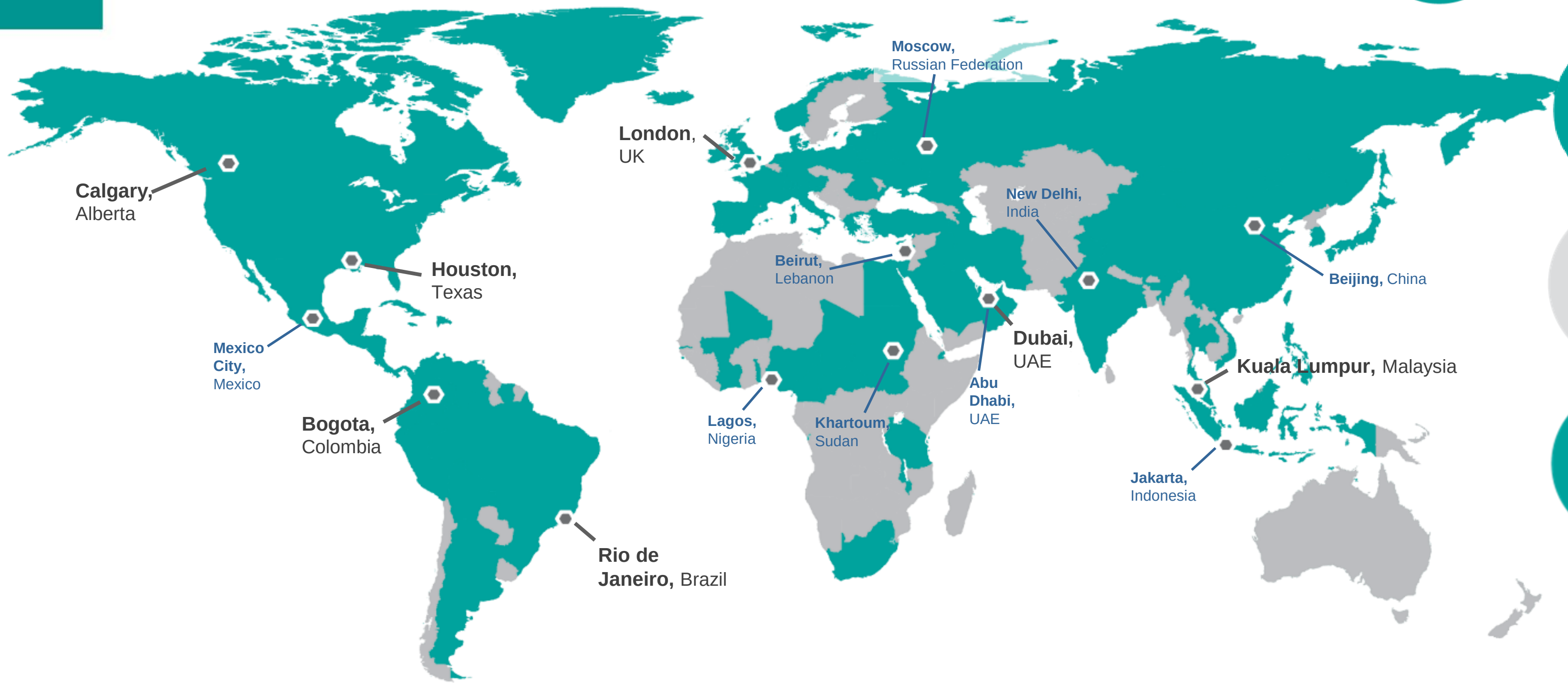
25 Others

As of March 31, 2016

Global Reach

572
customers

58
Countries



90%
Top-10
National Oil Companies

75%
Top-25 Oil Companies, by Production

100%
Super Major Oil Companies

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CMG’s Product Suite for Reservoir Simulation

CMOST
History Matching, Optimization & Analysis

IMEX
Black Oil & Conventional

GEM
Compositional & Unconventional

STARS
Thermal & Advanced Processes

COFLOW
Reservoir & Production System Modelling

BUILDER
Visualization: Pre-Processing

RESULTS
Visualization: Post-Processing

WINPROP
Fluid Property Modelling

iSEGWELL
Wellbore Modelling

Why Use Reservoir Simulation for Unconventional Reservoirs?

For Physics-based EUR's & Optimization

- Very long times to pseudo-steady-state (between perf clusters, stages & wells)
- Multi-phase Flow (effect of going below bubble or dew point pressures)
- Non-Darcy (turbulent) Flow
- Multi-Component Phase Behavior, Adsorption & Diffusion
- Compaction of Propped Fractures & Stimulated Natural Fractures
- Heterogeneous Rock Properties
- Heterogeneous Well Completions (Fracture Geometry & Dimensions)
- Geomechanics (modelling hydraulic fracturing & subsequent production)
- Geochemistry (modelling what happens to injected fluids)

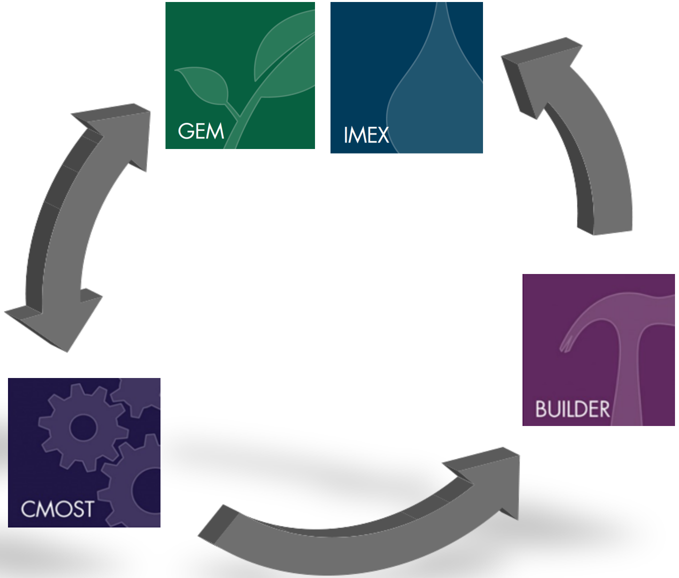
Why Use Reservoir Simulation for Unconventional Reservoirs?

To Accommodate Current Development Practices

- Analysis & Forecasting of multi-well pad models exhibiting interference
- Modelling of re-fracs & infill drilling (time-dependent fracs, compaction & rock-physics)
- Interpreting production surveillance data (DTS, Production logs, tracers)
- Accounting for many uncertain parameters simultaneously!

CMG's Unconventionals Workflows

1. Choose reservoir simulator with required physics



CMG's Numerical Simulation Physics For Unconventional Reservoirs

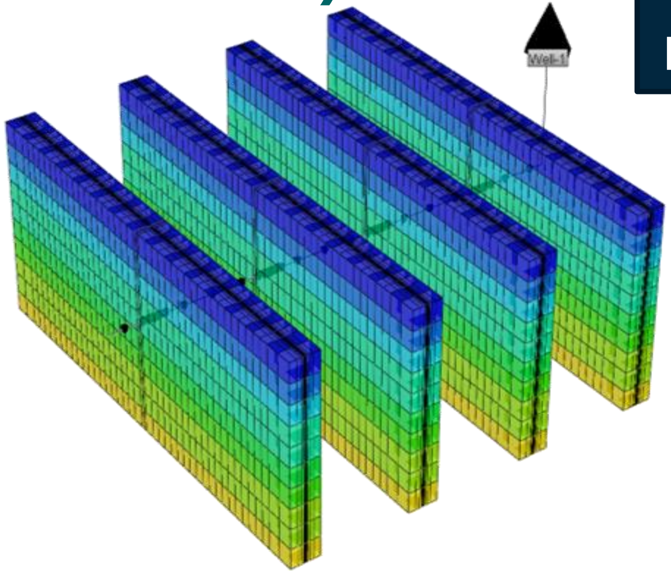
Physics	IMEX	GEM
PVT	BO, VO, GC, WG	EOS
Adsorbed Components	Gas Phase	Multi-Comp
Molecular Diffusion w/ Dispersion	-	Multi-Comp/OWG Phases
Natural Fracs (NF)	Dual Perm	Dual Perm
Propped Fracs (PF)	LS-LR in Matrix (MT)	LS-LR in Matrix (MT)
Non-Darcy (turbulent) Flow	MT, NF & PF	MT, NF & PF
Krel & Pc	MT, NF, PF & time	MT, NF, PF & time
Press-dependent Compaction	MT, NF, PF & time	MT, NF, PF & time
Stress-dependent Compaction	-	Geomechanics-based
Chemical Reactions	-	Ion Exchange & Geochemistry

Primary Production

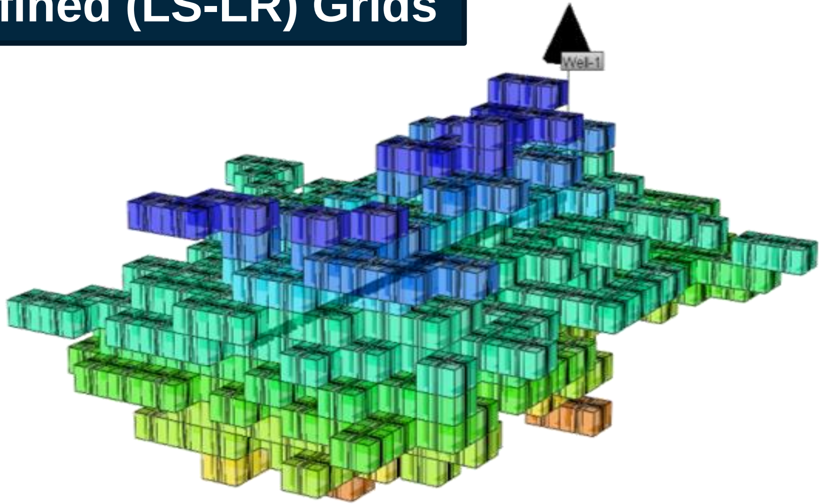
Primary Production & EOR

modelling Transient Flow from Rock Matrix to Fracs requires Proper Gridding (SPE 132093 & 180209)

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

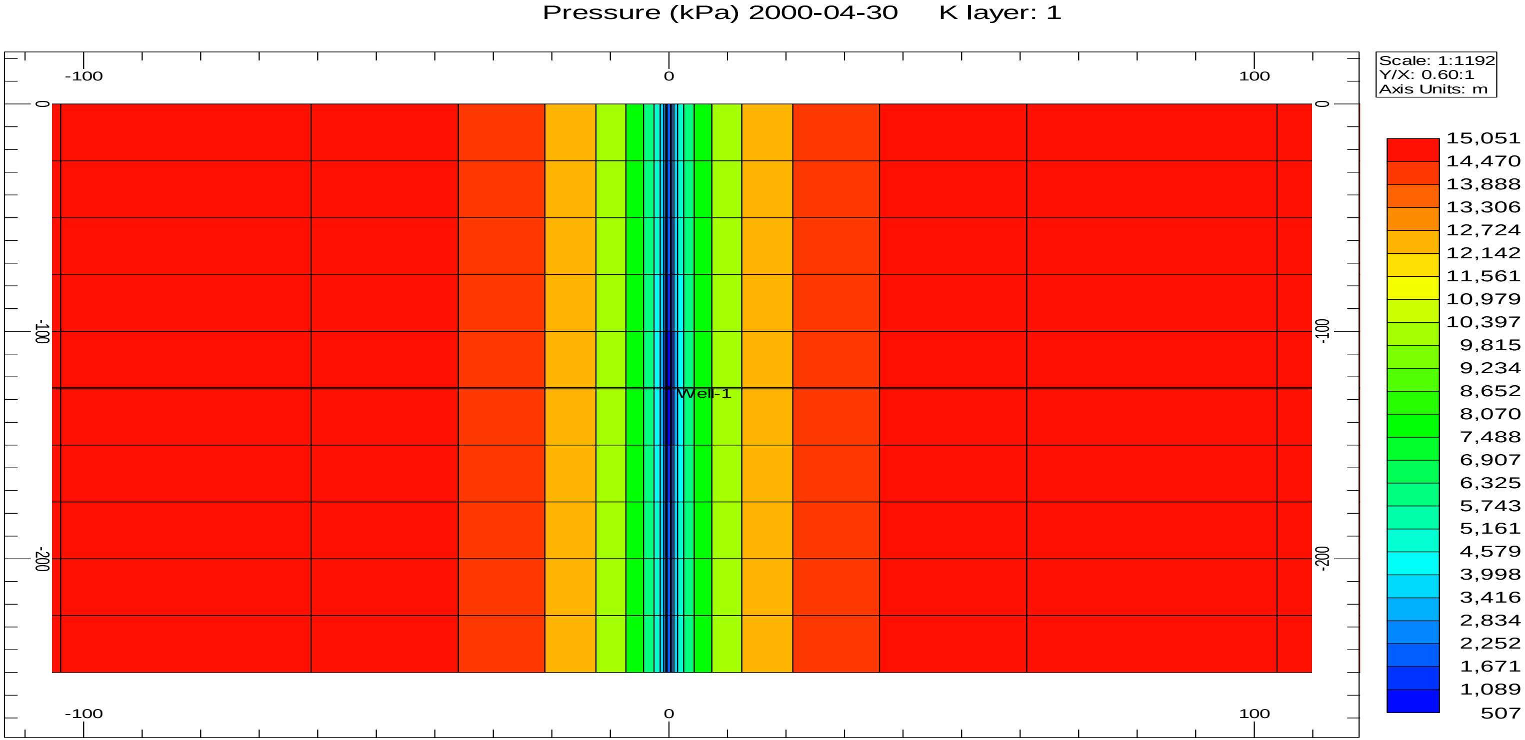


Planar Fractures in SRV

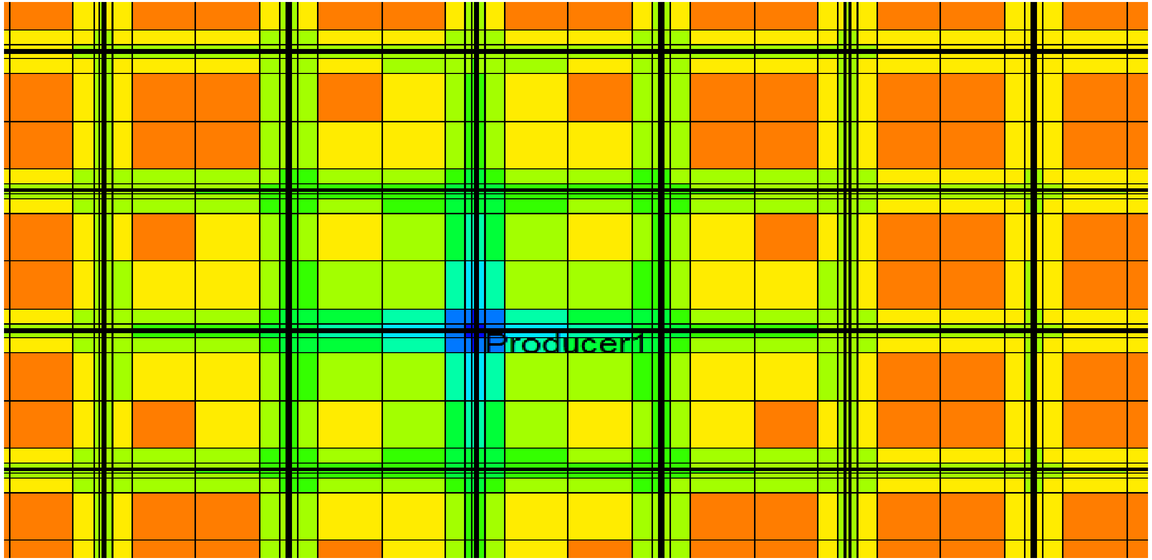


Complex Fractures in SRV

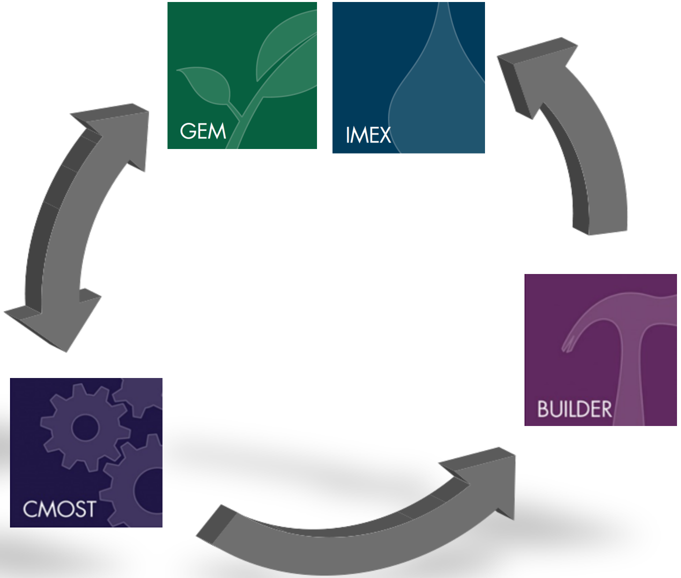
Logarithmic Gridding for Planar Fractures



Logarithmic Gridding for Complex Fractures

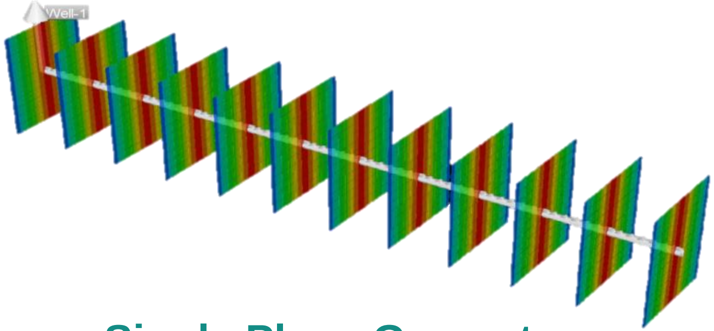


CMG's Unconventionals Workflows



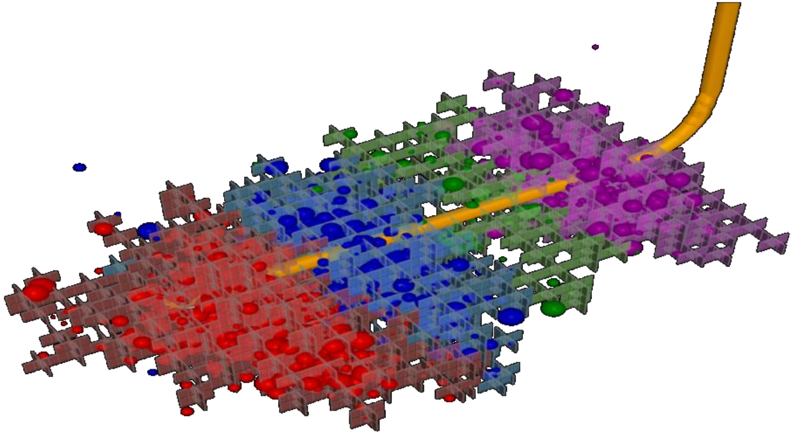
1. Choose reservoir simulator with required physics
2. Build base model

Propped Frac Gridding with CMG is *EASY, ACCURATE & EFFICIENT*



Single Plane Geometry

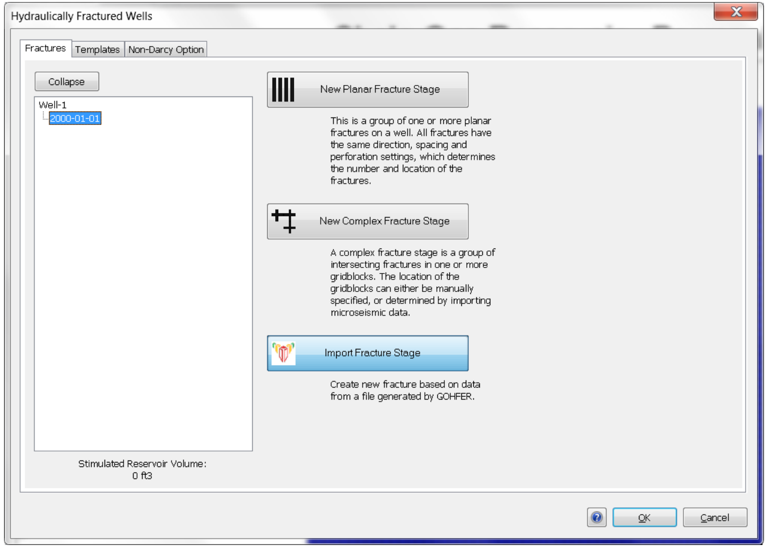
Create LS-LR-DK grids around fractures automatically



Complex Geometry

CMG’s Hydraulic Fracture Wizard

- **Creates planar or complex fractures, or**
- **Import fractures from GOHFER, StimPlan, FracProPT, FracGeo, FieldPro**

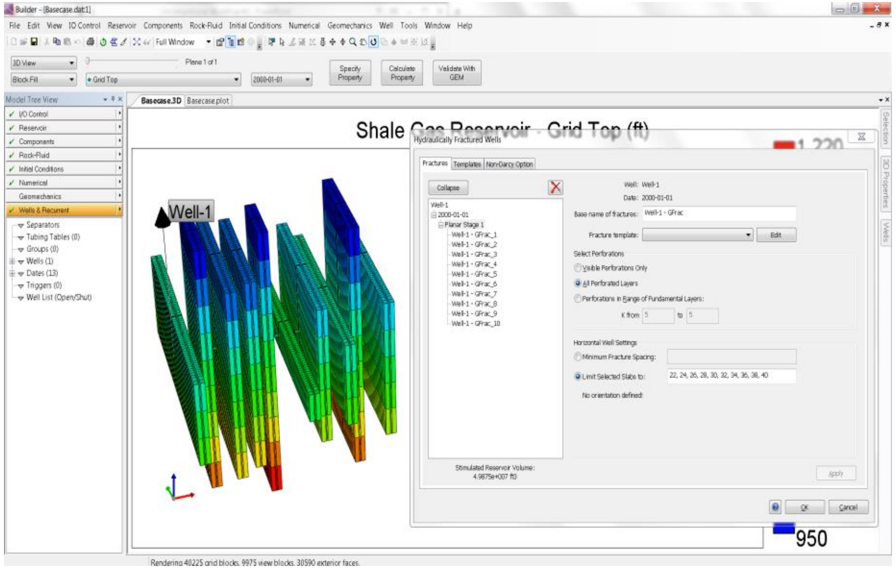


This is a group of one or more planar fractures on a well. All fractures have the same direction, spacing and perforation settings, which determines the number and location of the fractures.

A complex fracture stage is a group of intersecting fractures in one or more gridblocks. The location of the gridblocks can either be manually specified, or determined by importing microseismic data.

Create new fracture based on data from a file generated by GOHFER.

Stimulated Reservoir Volume:
0 ft3



Well: Well-1
Date: 2000-01-01
Base name of fractures: Well-1 - GFrac
Fracture template:

Select Perforations
○ Visible Perforations Only
● All Perforated Layers
○ Perforations in Range of Fundamental Layers:
K from 5 to 5

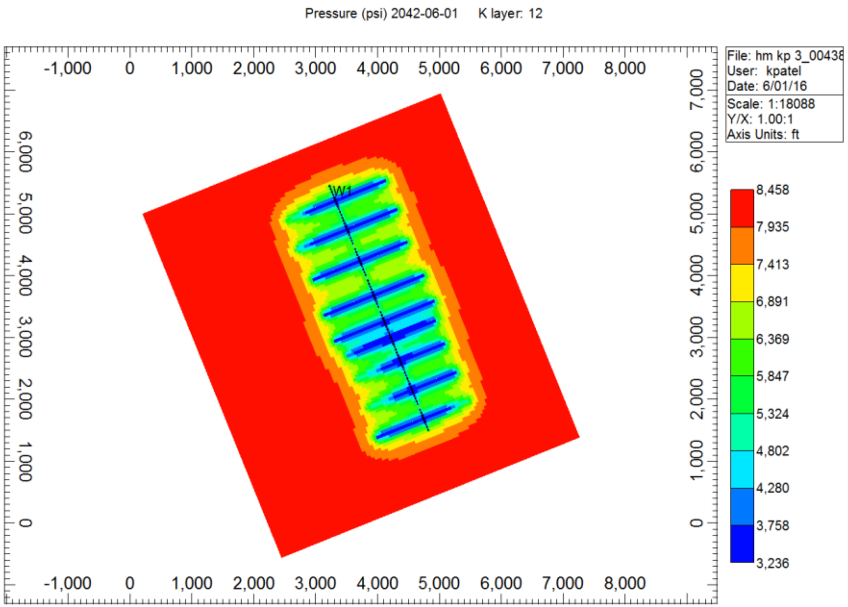
Horizontal Well Settings
○ Minimum Fracture Spacing:
● Limit Selected Slabs to: 22, 24, 26, 28, 30, 32, 34, 36, 38, 40

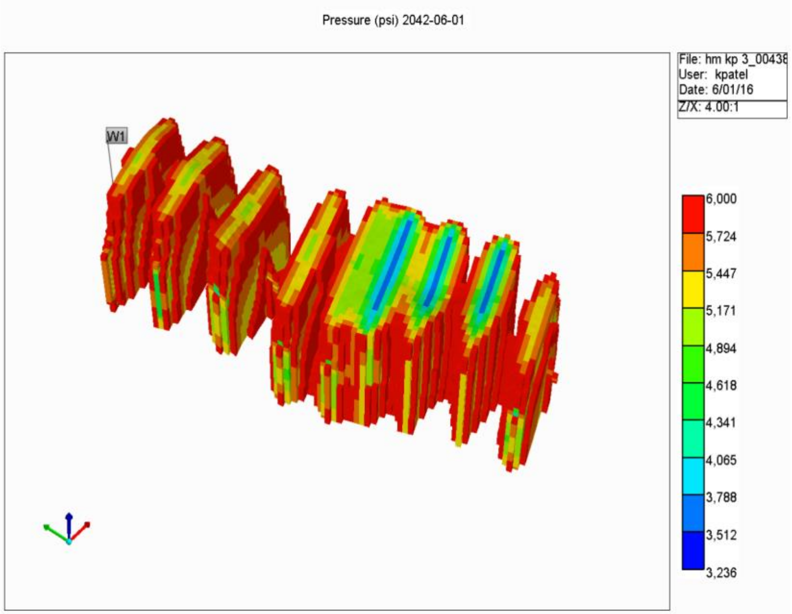
No orientation defined!

Stimulated Reservoir Volume:
4.9875e+007 ft3

Rendering 40225 grid blocks. 9975 view blocks. 30590 exterior faces.

Example showing Unsymmetrical, Variable Conductivity Fractures imported from GOHFER





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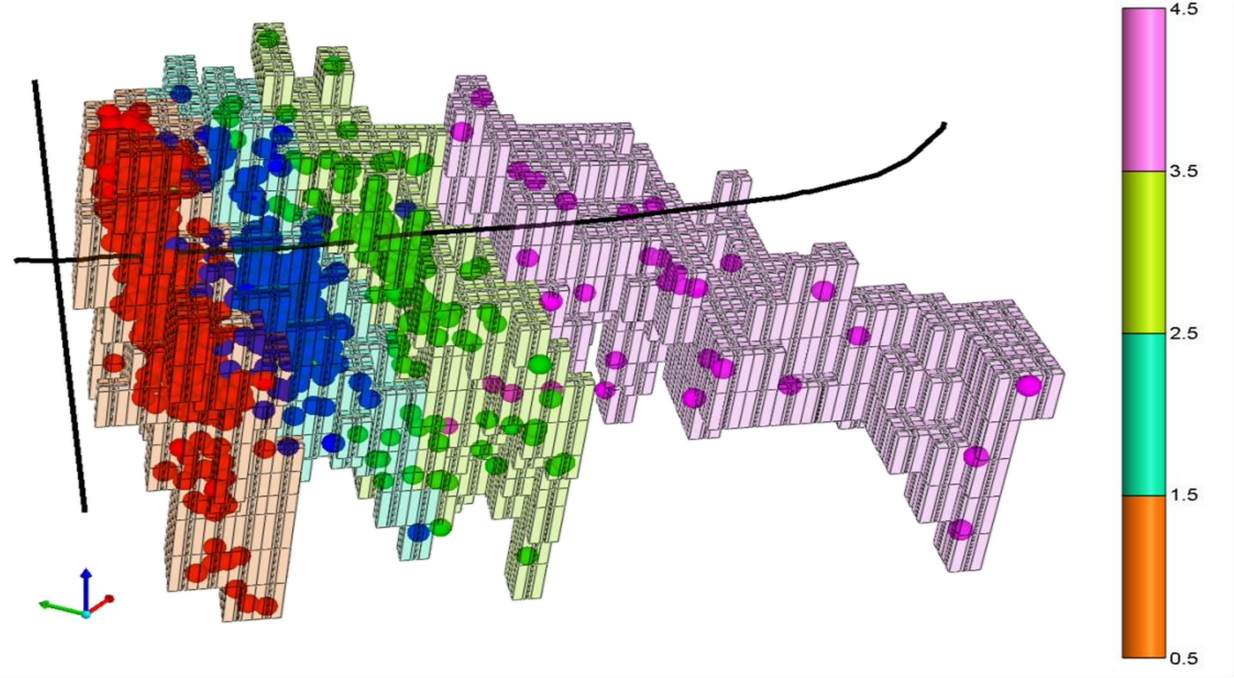
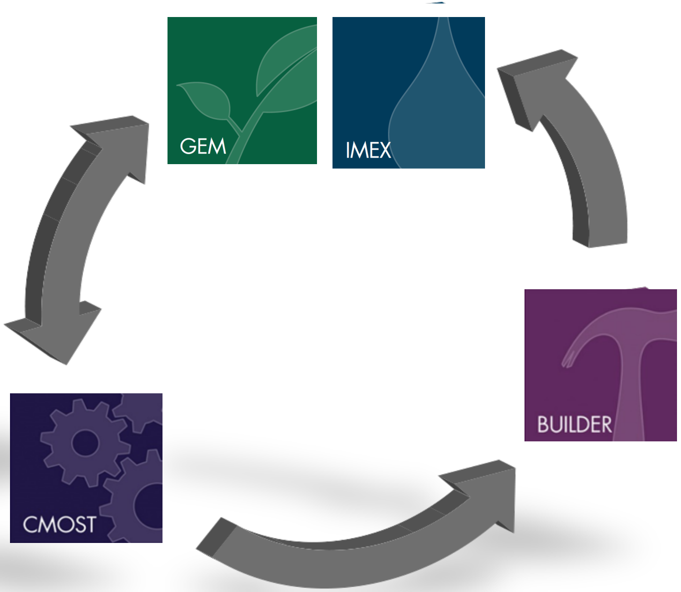
Example showing creation of Complex Fracturing in Symmetrical SRV by importing Microseismic Data

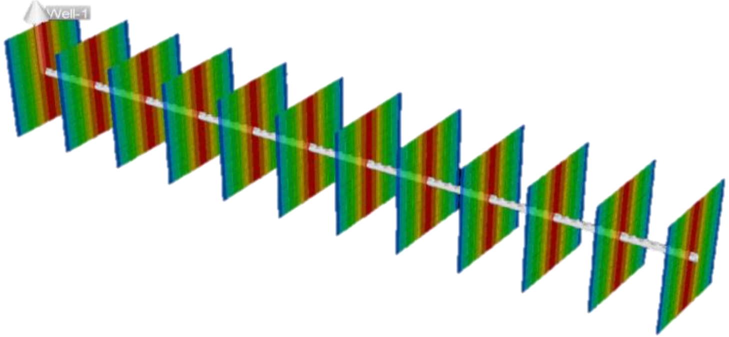


CMG's Unconventionals Workflows



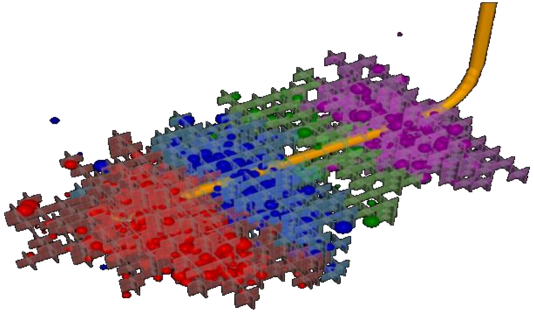
1. Choose reservoir simulator with required physics
2. Build base model
3. Sensitivity Analysis
4. Probabilistic History Matching
5. Probabilistic Forecasting
6. Optimization

Parameterizing Propped Frac Properties & Dimensions with CMG is *EASY & FAST*

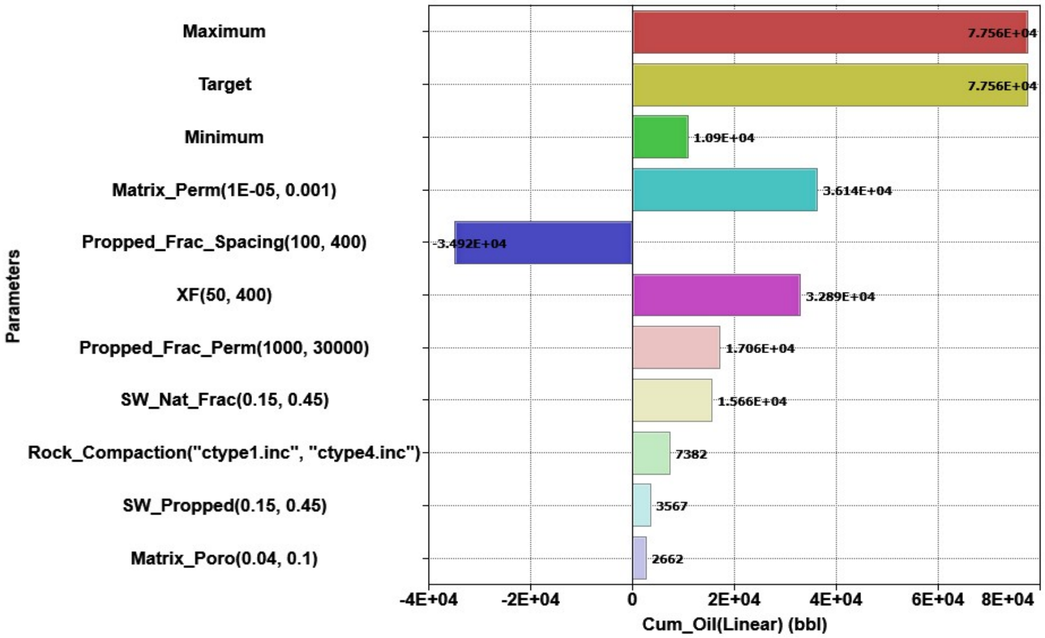


Propped Frac Properties:
Half-length, Width, Perm, Spacing, Height & Perm Gradient
Stimulated Natural Frac Properties:
Width, Perm

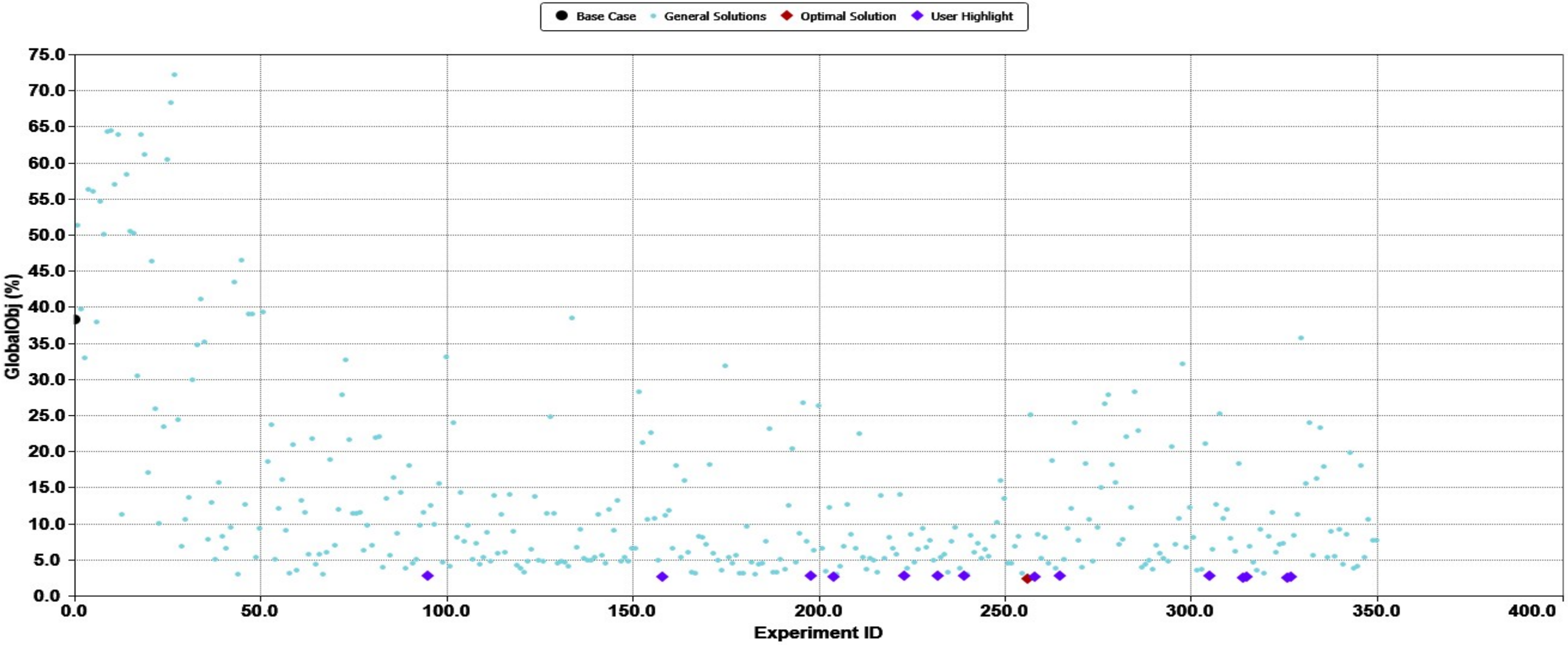
SRV Size & Shape:
 # MS events per gridblock
MS Moment Magnitude
MS Confidence Value
Etc.



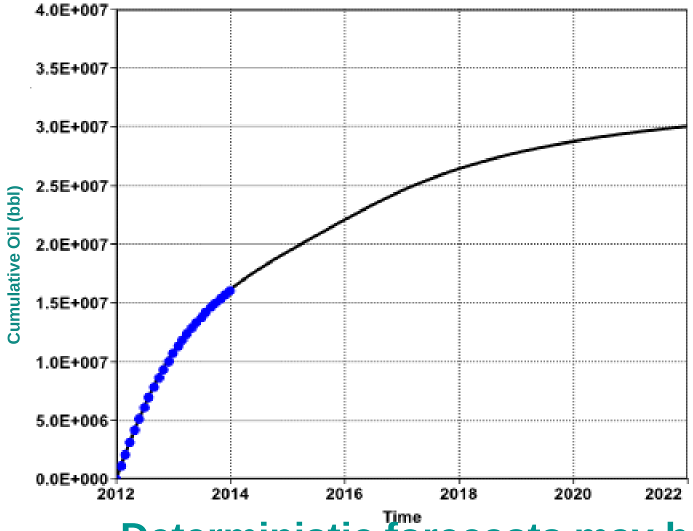
CMG's Workflow for Unconventionals: Sensitivity Analysis



CMG's Workflow for Unconventionals: History Matching

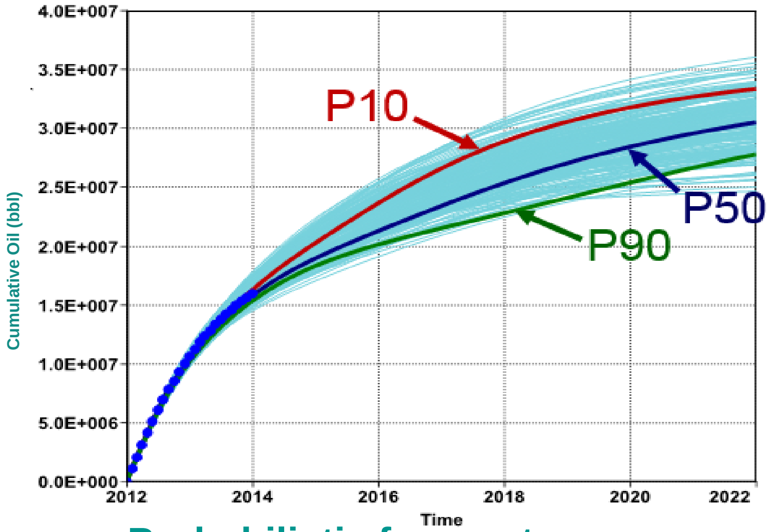


CMG's Workflow for Unconventionals:
Probabilistic History-Matching & Forecasting



Deterministic forecasts may be misleading

- Only provides one solution
- Ignores Uncertainty

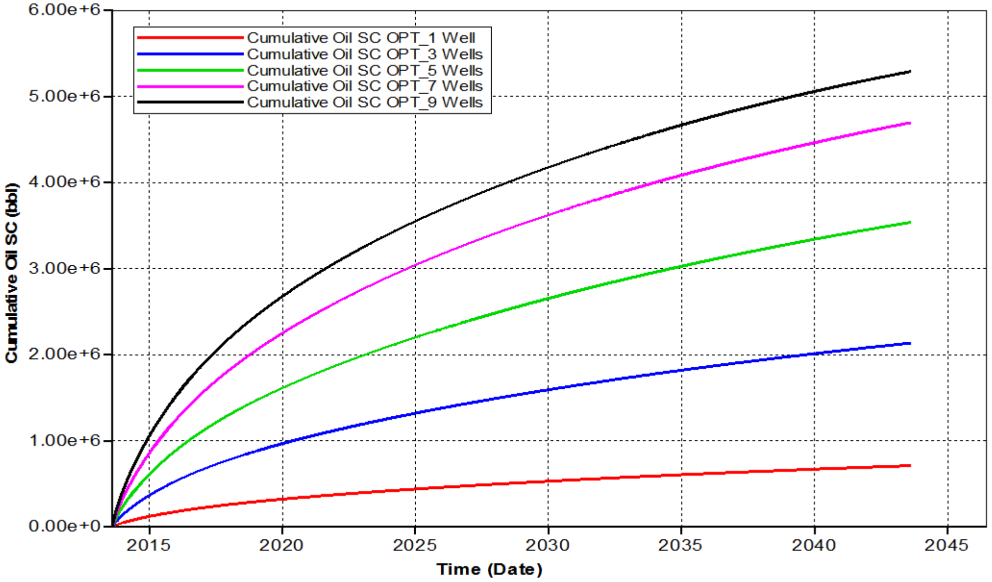


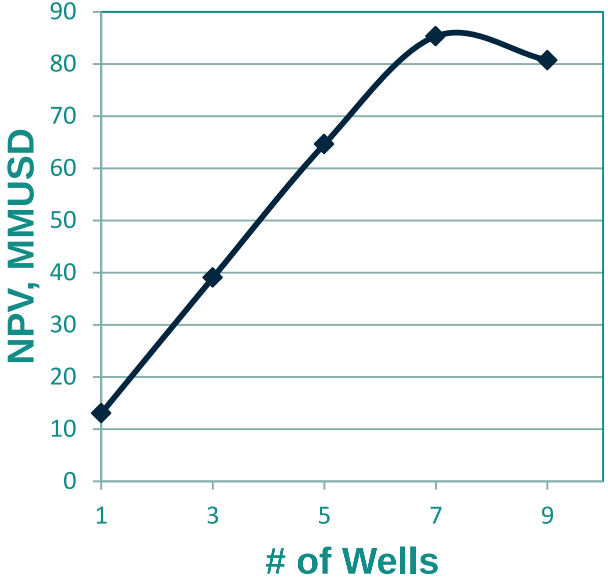
Probabilistic forecasts are preferred

- Range of Possibilities
- Quantification of risk

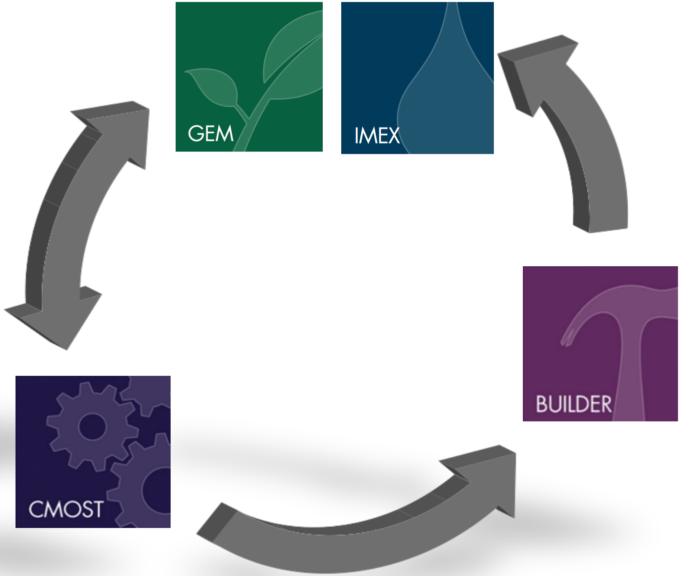
CMG's Workflow for Unconventionals:
Optimization

Cum Oil & NPV after 30 years vs # of Wells





CMG's Unconventionals Workflows



1. Choose reservoir simulator with required physics
2. Build base model
3. Sensitivity Analysis
4. Probabilistic History Matching
5. Probabilistic Forecasting
6. Optimization

Engineer should only have to build base reservoir simulation model, then decide which parameters to be varied. CMOST does the rest!

SPE-180209

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

A. Moinfar, J.C. Erdle, K. Patel, Computer Modelling Group Inc.

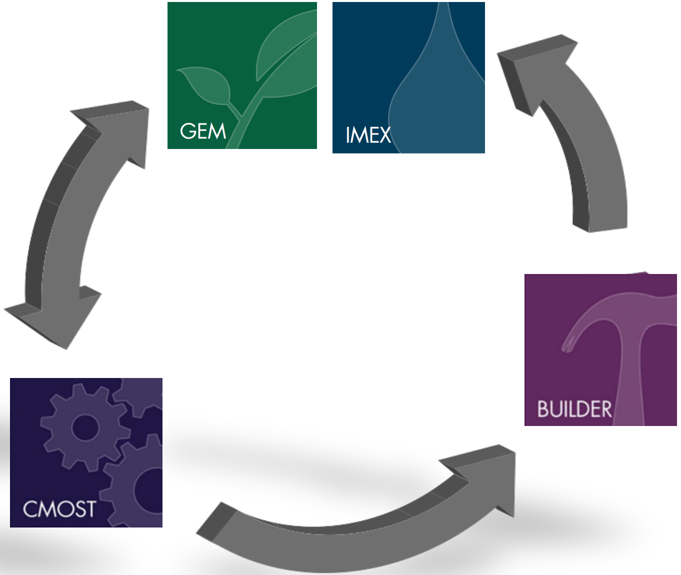
Motivation

- **Analytical models available in Rate-Transient-Analysis (RTA) packages are widely used for history matching and forecasting production in unconventional resources.**
- **The use of numerical simulation for modelling unconventional reservoirs is increasing.**
- **Goal of this study: Quantify the differences one might expect to encounter in EURs when using RTA vs Numerical Simulation workflows in unconventional reservoirs.**

Outline

- **Numerical Simulation Workflow for Unconventional Reservoirs**
- **RTA Workflow for Unconventional Reservoirs**
- **Model Validation**
- **Real-World Deviations from RTA Assumptions**
- **Computational Performance**
- **Summary and Conclusions**

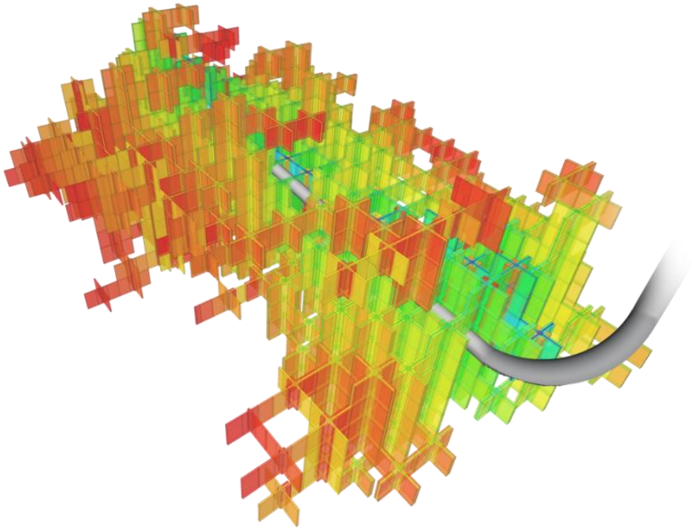
CMG’s Unconventionals Workflows



1. Choose reservoir simulator with required physics
2. Build base model
3. Sensitivity Analysis
4. Probabilistic History Matching
5. Probabilistic Forecasting
6. Optimization

Numerical Simulation Workflow

- **CMG's Numerical modelling Capabilities for Unconventional Reservoirs**
- **modelling Transient Flow to Fractures using LS-LR Grid**
- **Assisted History Matching, followed by Probabilistic Forecasting**



CMG's Numerical Simulation Physics For Unconventional Reservoirs

Physics	IMEX	GEM
PVT	BO, VO, GC, WG	EOS
Adsorbed Components	Gas Phase	Multi-Comp
Molecular Diffusion w/ Dispersion	-	Multi-Comp/OWG Phases
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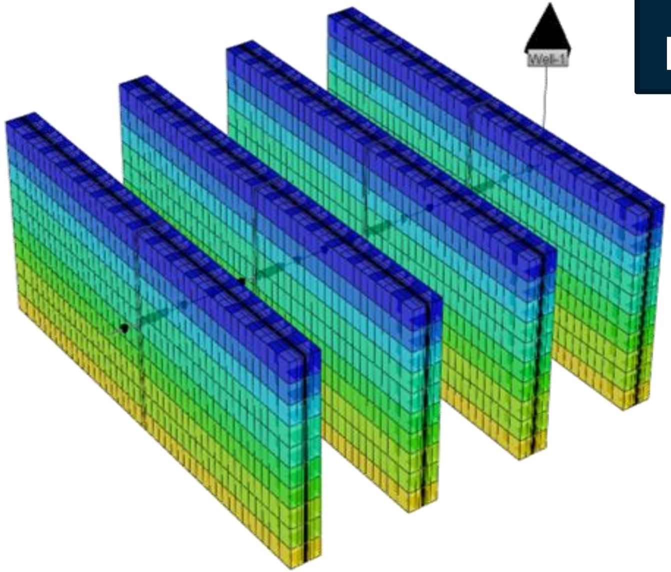
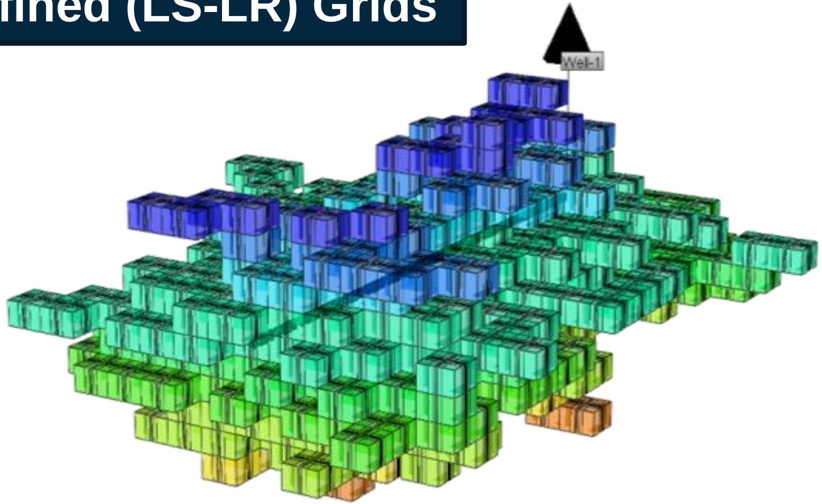
Non-Darcy (turbulent) Flow	MT, NF & PF	MT, NF & PF
Krel & Pc	MT, NF, PF & time	MT, NF, PF & time
Press-dependent Compaction	MT, NF, PF & time	MT, NF, PF & time
Stress-dependent Compaction	-	Geomechanics-based
Chemical Reactions	-	Ion Exchange & Geochemistry
	Primary Production	Primary Production & EOR

modelling Transient Flow to Planar & Complex Geometry Propped Fractures

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



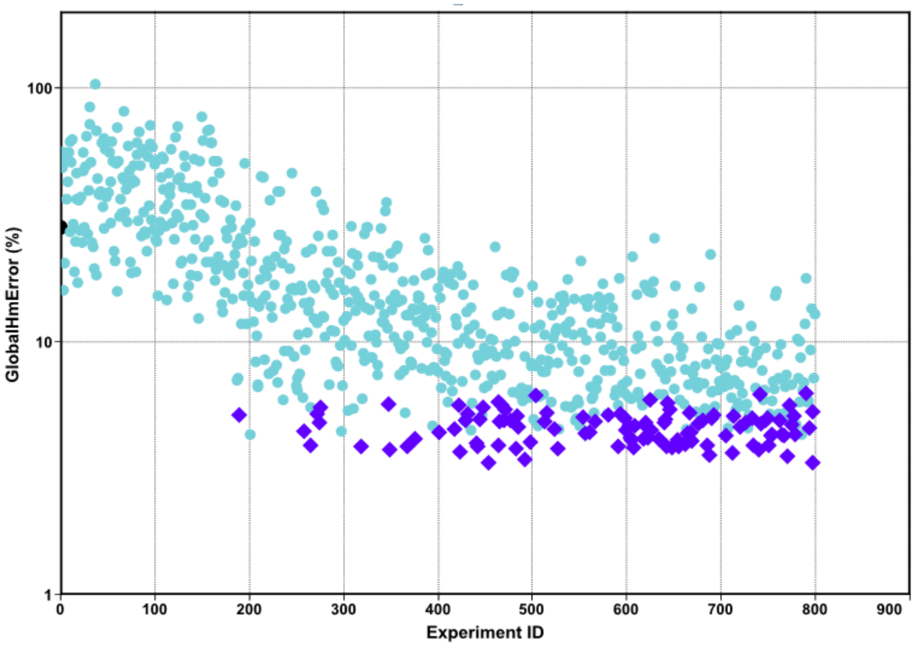
Planar Fractures in SRV



Complex Fractures in SRV

History Matching

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

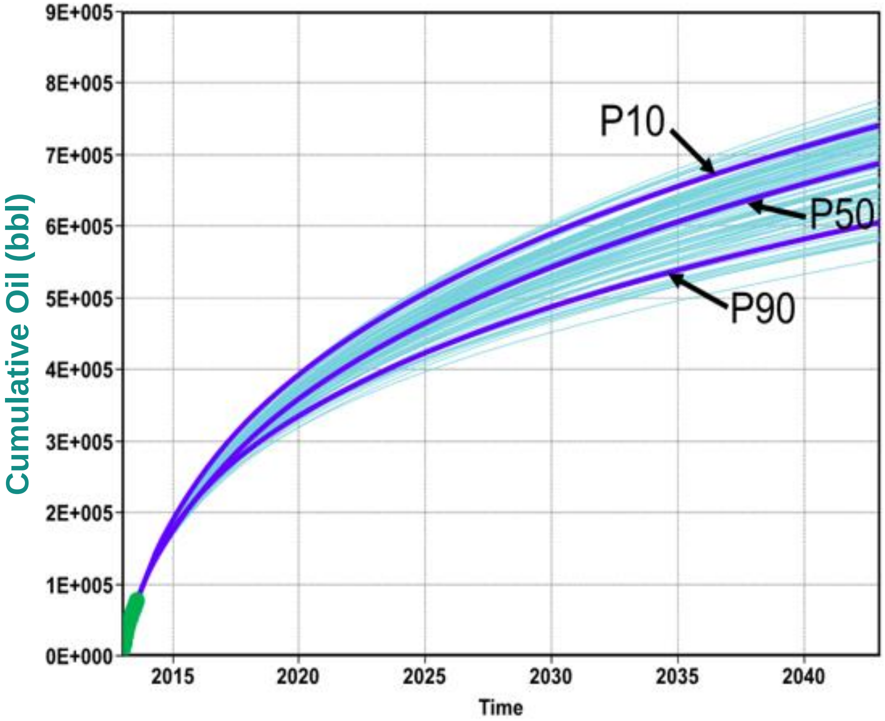


Good History Match Models

Probabilistic Forecasts

- Probabilistic forecasting reduces risk in making business decisions

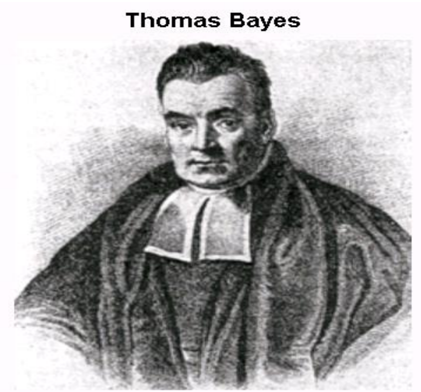
- Provides range of possible outcomes along with
  - ✓ P90 (conservative)
  - ✓ P50 (most likely)
  - ✓ P10 (optimistic)



Bayesian Formulation

Uses Bayes theorem to define posterior PDF’s and quantify model uncertainty by taking into account the misfit between simulation results and production history

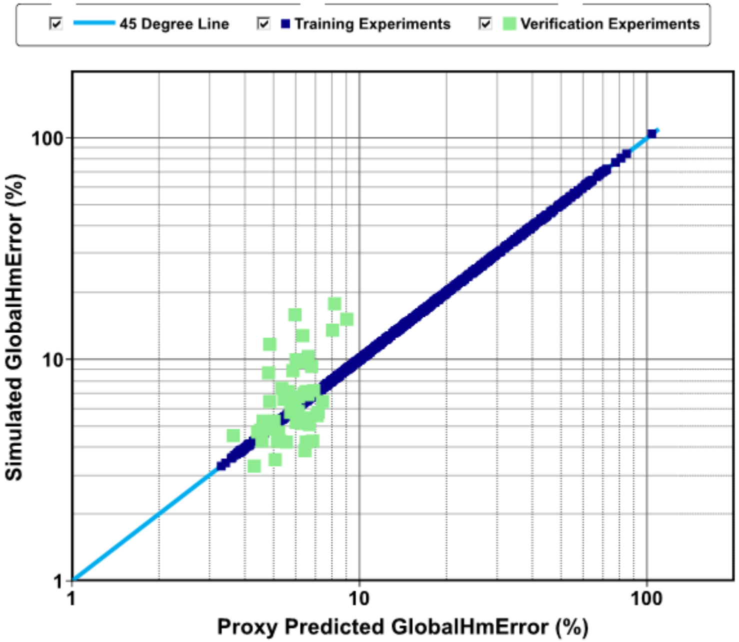
$$\underbrace{\mathrm{P}(model\ data)}_{\text{Posterior Probability}} = \underbrace{P(model)}_{\text{Prior Probability}}\underbrace{\frac{\mathrm{P}(data\ model)}{\mathrm{P}(data)}}_{\text{Normalizing constant}}$$

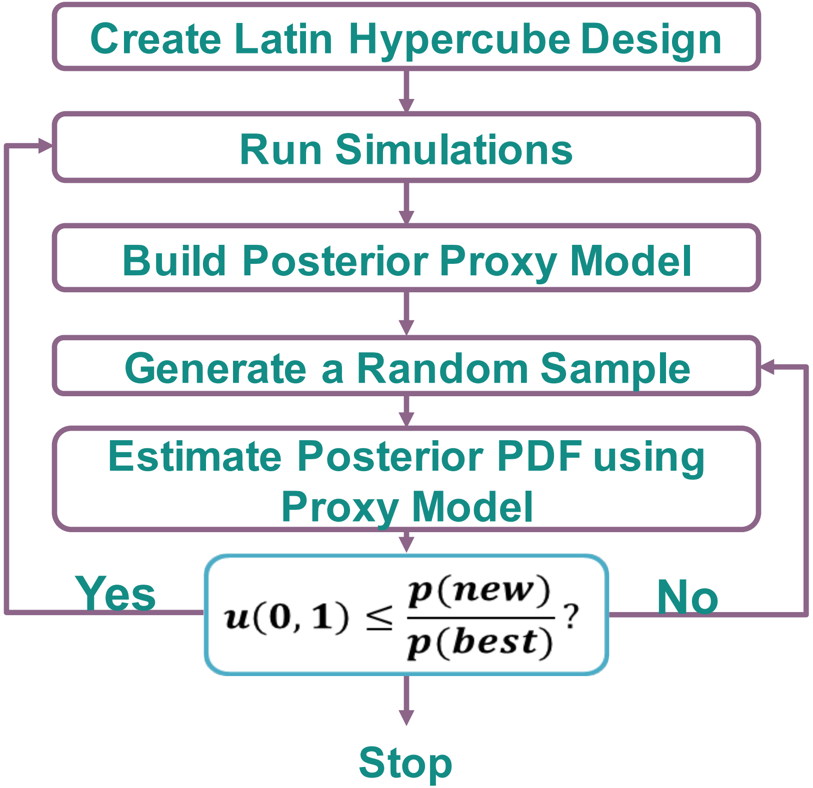

Thomas Bayes

1701-1761

Posterior Sampling Using Proxy-based Acceptance-Rejection (CMG PAR)

SPE 175122





Create Latin Hypercube Design

Run Simulations

Build Posterior Proxy Model

Generate a Random Sample

Estimate Posterior PDF using Proxy Model

$$u(0,1) \le \frac{p(new)}{p(best)}?$$

Yes

No

Stop

Probabilistic Forecast Workflow using CMG PAR Sampling Method

Bayesian HM Using CMG PAR Method

- Experimental design
- RBF proxy modelling
- Proxy-based acceptance-rejection (PAR) sampling

Filtering HM Result

- Review HM result
- Determine HM quality thresholds
- Identify models with acceptable HM quality

Probabilistic Forecast

- Set forecast well constraints
- Forecast simulations based on acceptable HM models
- Statistical analysis

- 10x fewer simulation runs than Metropolis-Hasting MCMC sampling
- Results include P10, P50 & P90 simulation models & proxy models

RTA Workflow

Analytical Models for Multi-Fractured Horizontal Wells (MFHWs)

- ✓ **General Horizontal Multifrac Model**
- ✓ **Horizontal Multifrac Enhanced Frac Region Model**

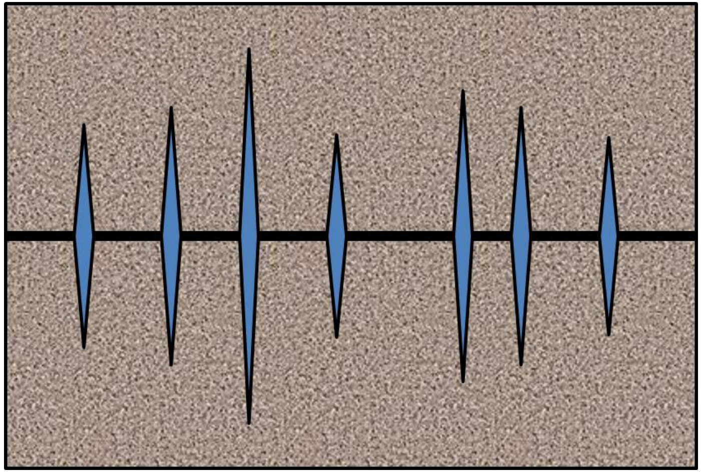
History Matching using Automatic Parameter Estimation (APE)

- ✓ **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

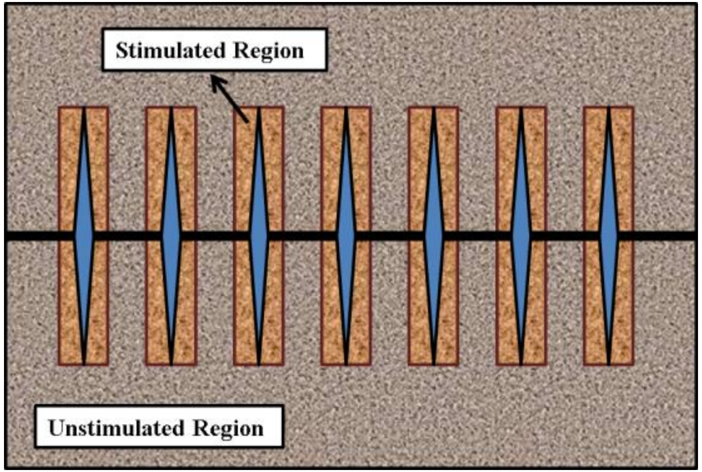
Multi-Frac'd Horizontal Wells

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)

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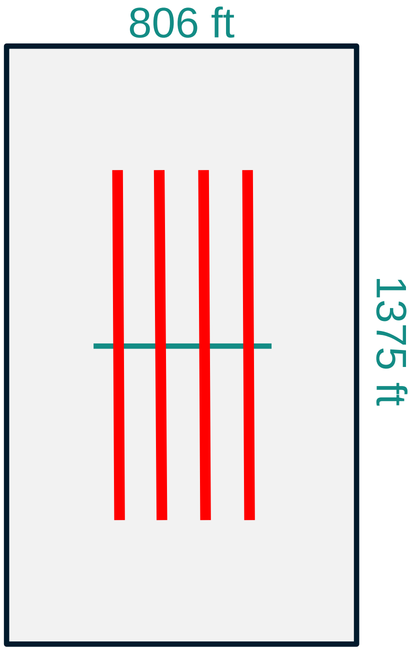
Model Validation

3 Modelling Approaches:

- ✓ **Very-Finely-Gridded Numerical Model (Reference Solution)**
- ✓ **LS-LR-Gridded Numerical Model**
- ✓ **Analytical Model (General Horizontal Multi-frac)**

Base Model

- ✓ **An undersaturated shale oil reservoir that satisfies all assumptions of analytical solution methods available in RTA**



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

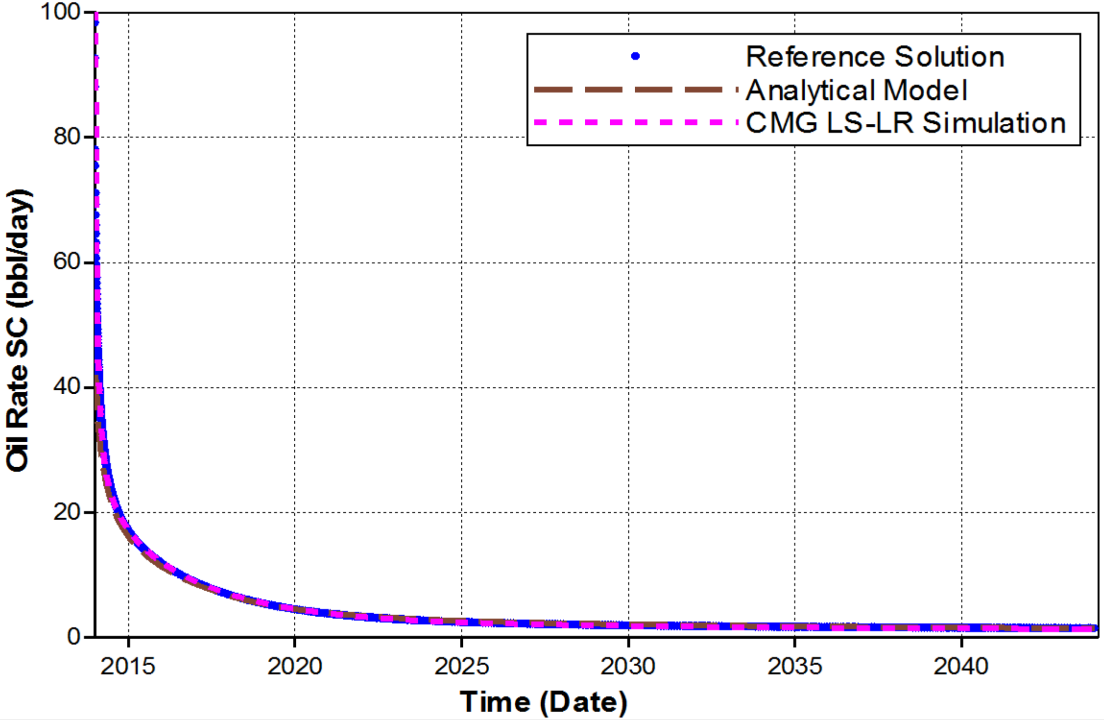
Fully-Penetrating Planar Fractures

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

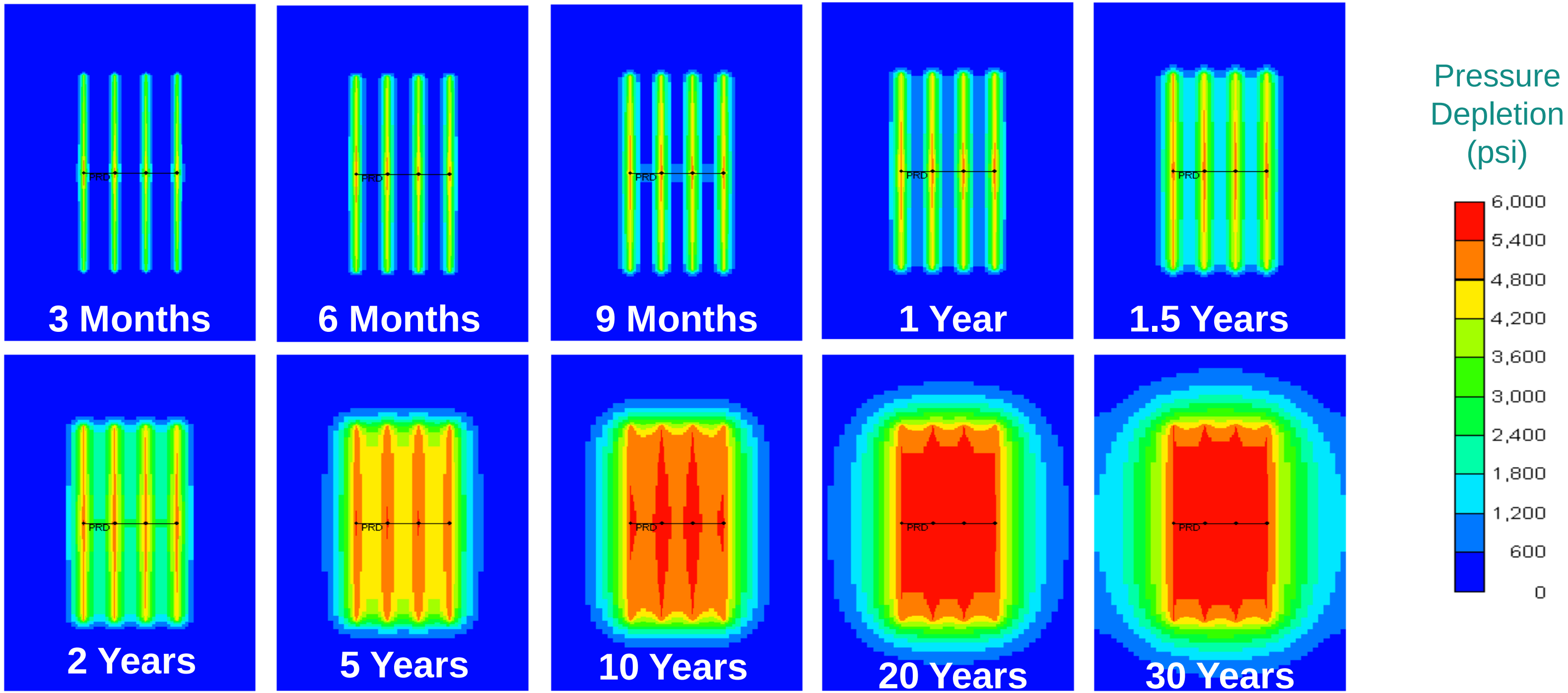
Base Model Comparison



Base Model Comparison

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



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 and CMG's Numerical Simulation-based Workflow

Real-World Deviations From RTA Assumptions

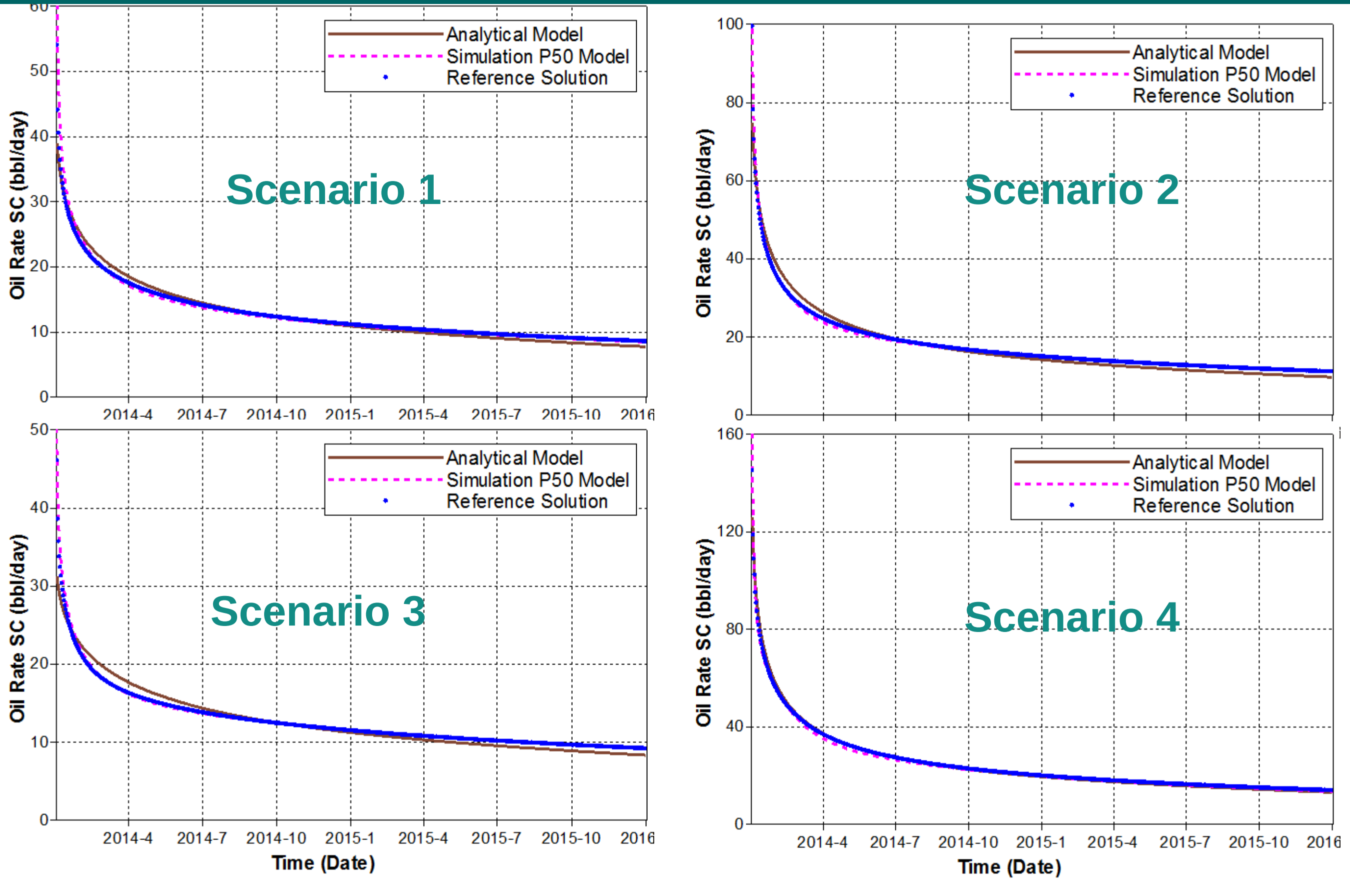
Common Complexities Not Taken into Account by Analytical Models:

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

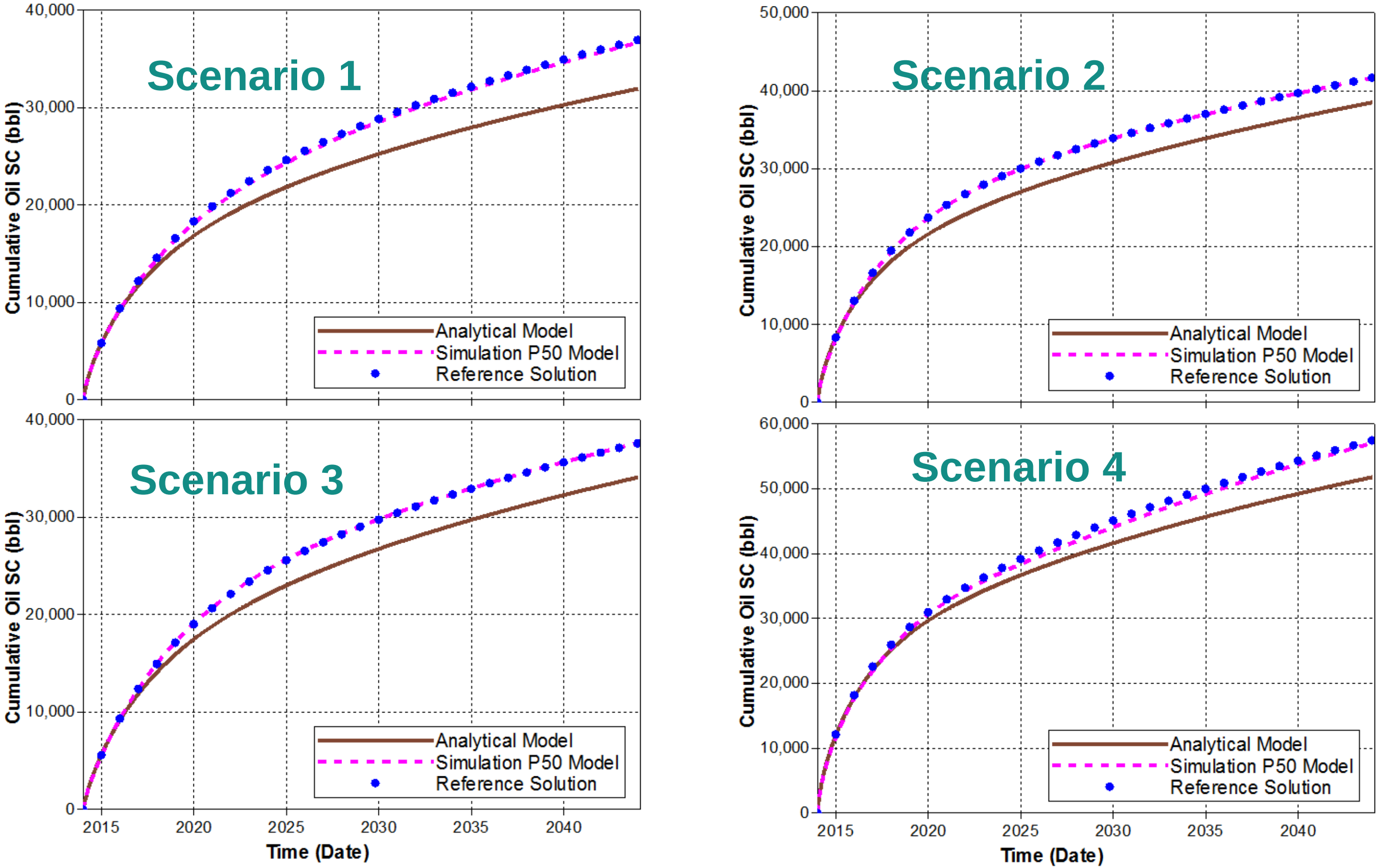
Numerical Simulation Workflow

- 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".

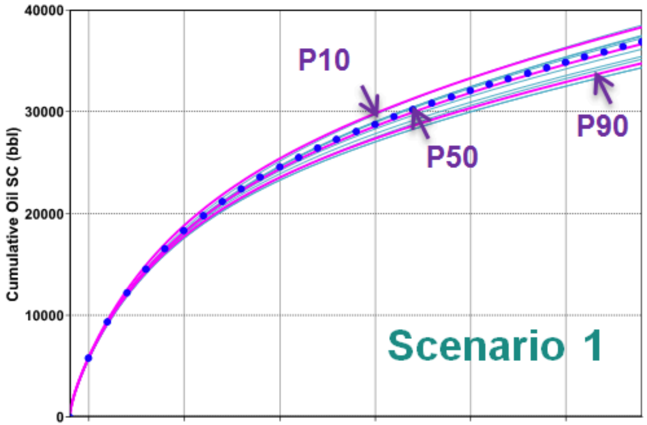
CMG & RTA 2-Year Oil Rate Match

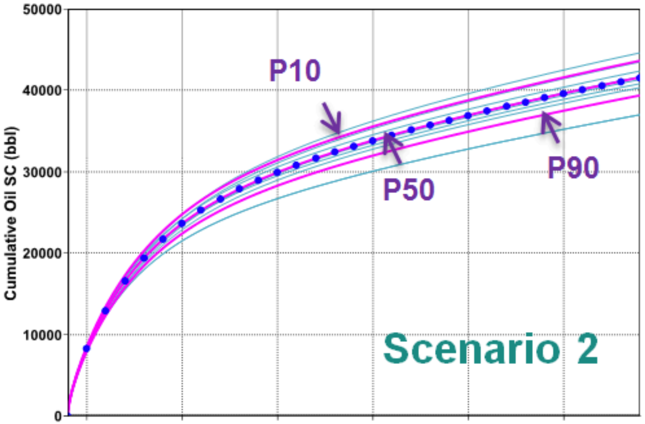


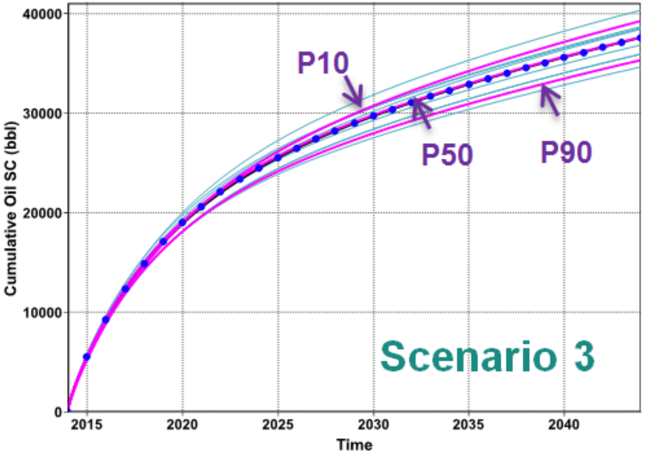
CMG & RTA 30-Year EUR Forecast

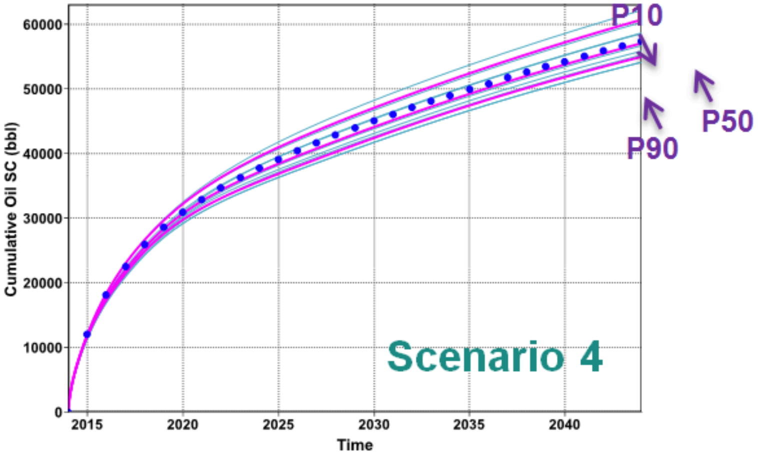


CMG Probabilistic Forecasts









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 {

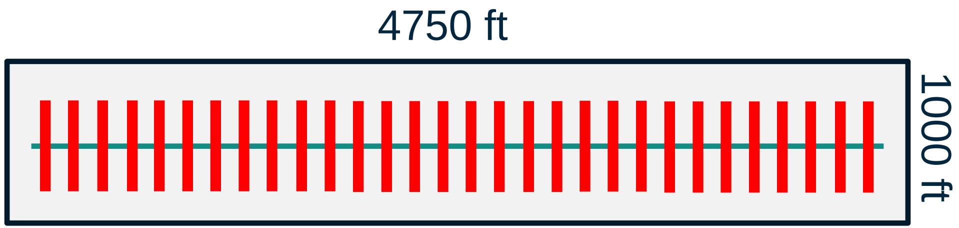
RTA Workflow: 6.5-13%

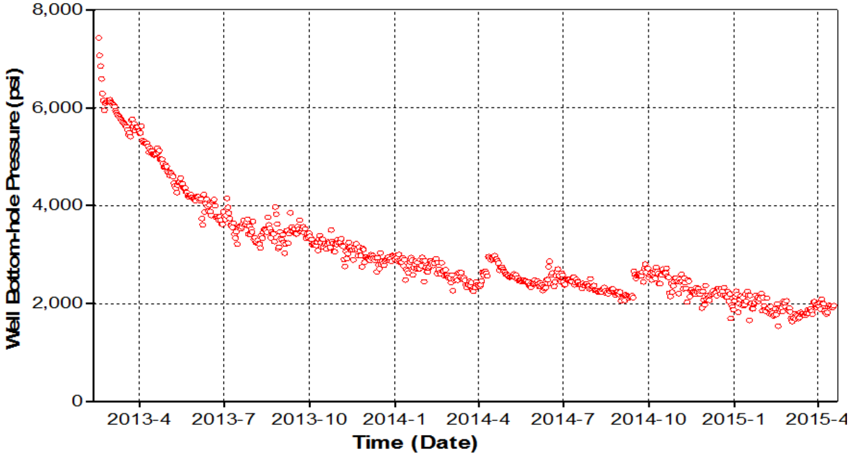
CMG Workflow: P90 <6% P50 <1% P10 <6%

Realistic Case Study

- Invoked all four 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





BHP data from an actual Eagle Ford Shale Oil well

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

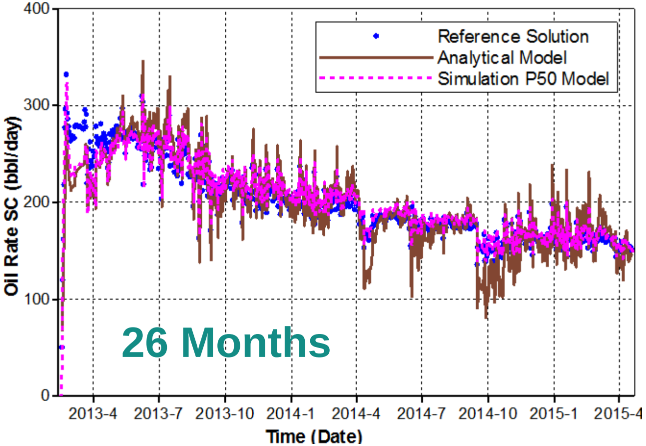
- Built a fine-grid model and ran it to create a 30 year production history.
- The first 26 months of that data was used as the “production history” to be matched by both the RTA and Numerical Simulation workflows.
- After the 26 months of variable BHP operation, the well was then operated at constant BHP of 750 psi for 28 years to create a forecast period.

Realistic Case Study

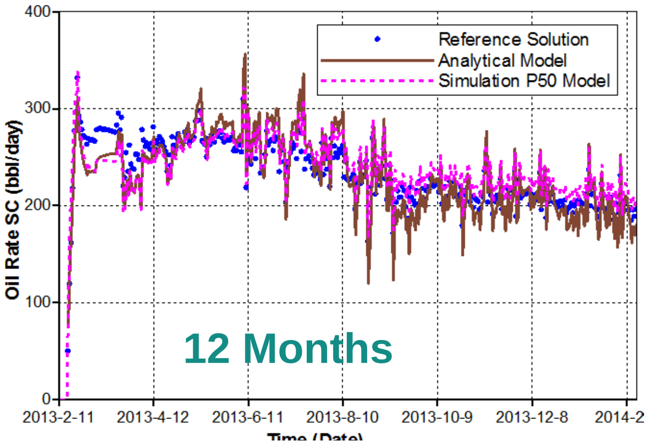
- **Oil EUR calculations are frequently performed for unconventional wells when *historical production data is limited*. We applied the same procedure to four scenarios with different durations of historical data:**
  - ✓ **26 months**
  - ✓ **12 months**
  - ✓ **6 months**
  - ✓ **3 months**

- **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.**

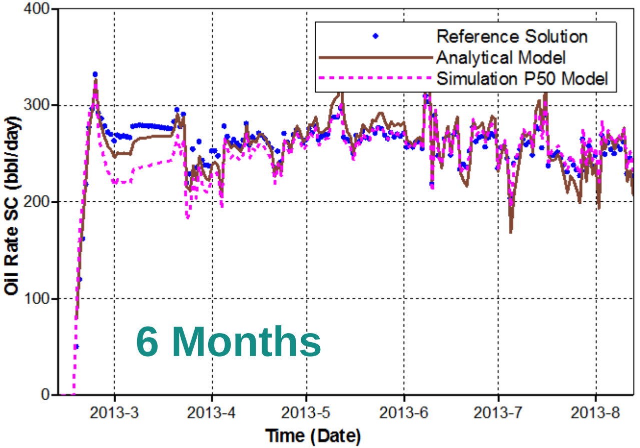
CMG & RTA Oil Rate History Matches



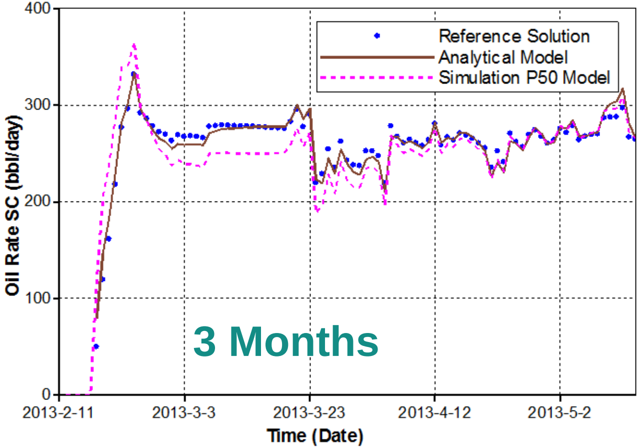
26 Months



12 Months

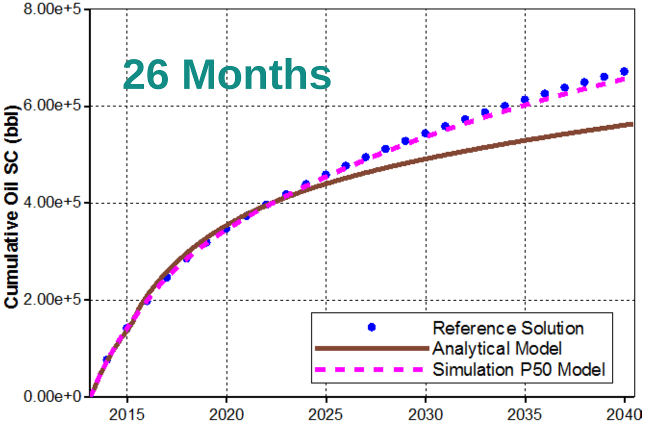


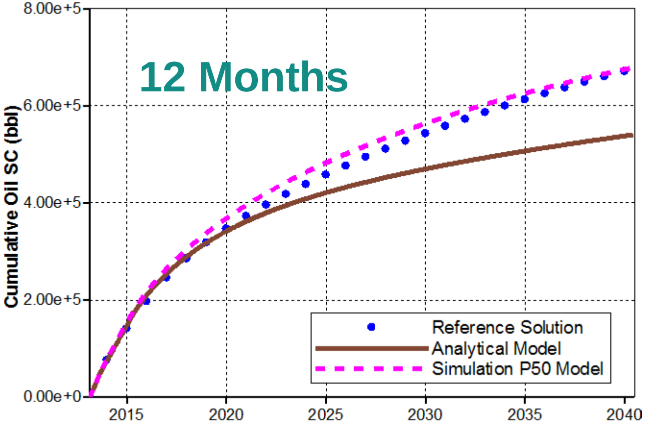
6 Months

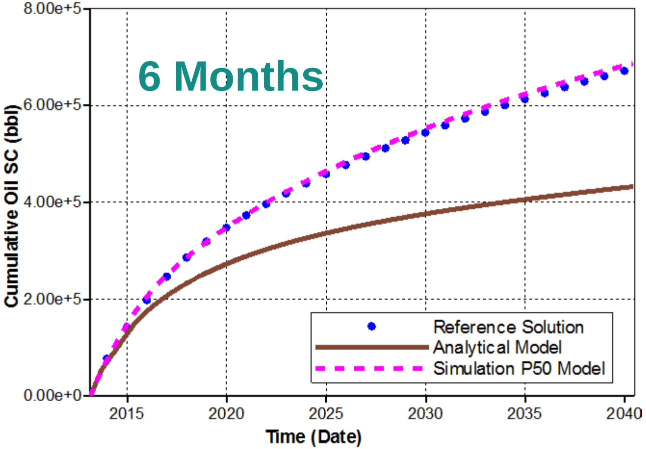


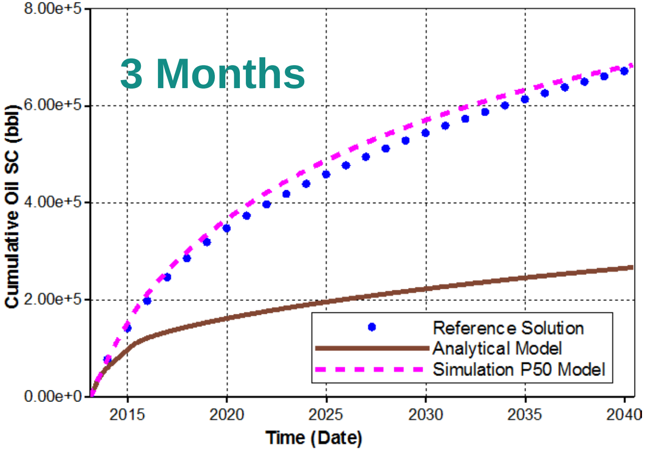
3 Months

CMG & RTA Forecasts

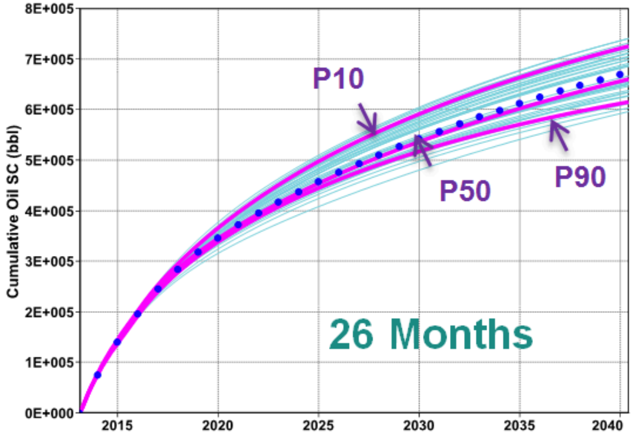


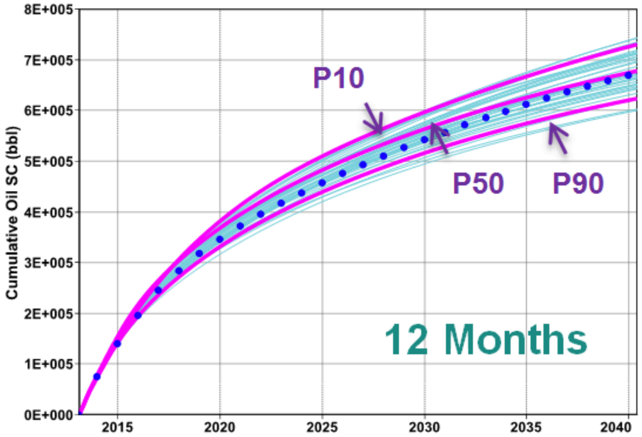


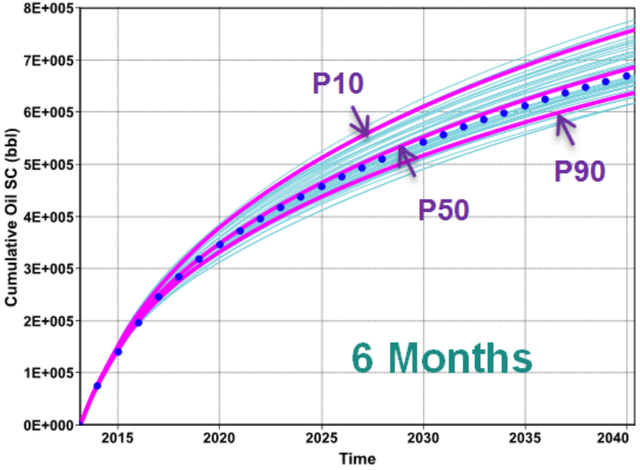


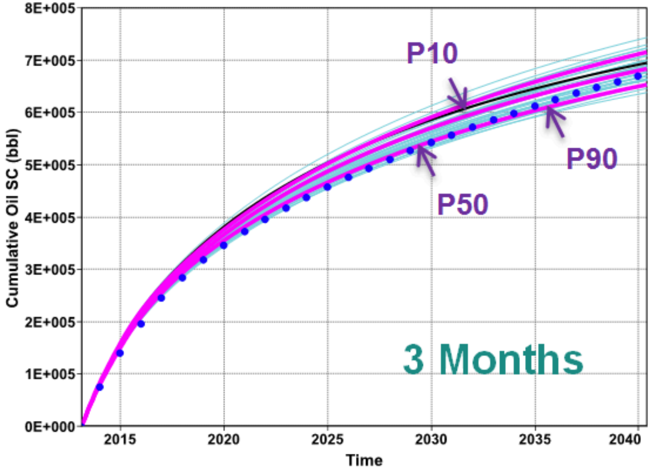


CMG Probabilistic Forecasts





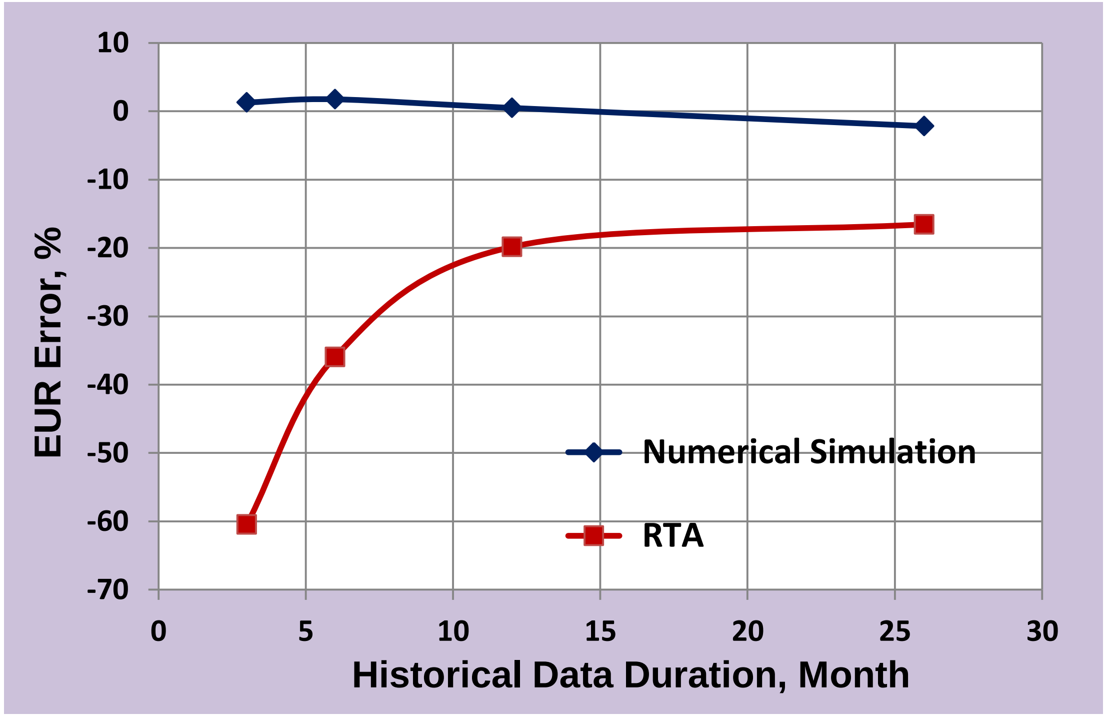




Comparison of HM Parameters & EURs

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**

Comparison of EURs



CMG Workflow Timing

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**

Conclusions

- Analytical models do not account for many important aspects of fluid-flow in unconventional reservoirs.
- RTA only provides 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.

Data Analytics &
Unconventional Well Performance Prediction:
Why Caution is Warranted!

Jim Erdle PhD – VP/USA & Latin America

Unconventional Well Production Prediction Methods

1. ***Decline Curve Analysis*** – Automated Curve Fitting to Empirical Models without regard for fluid-flow Physics

2. ***Rate-Time Analysis*** – Automated History Matching using Analytical Models with limited fluid-flow Physics

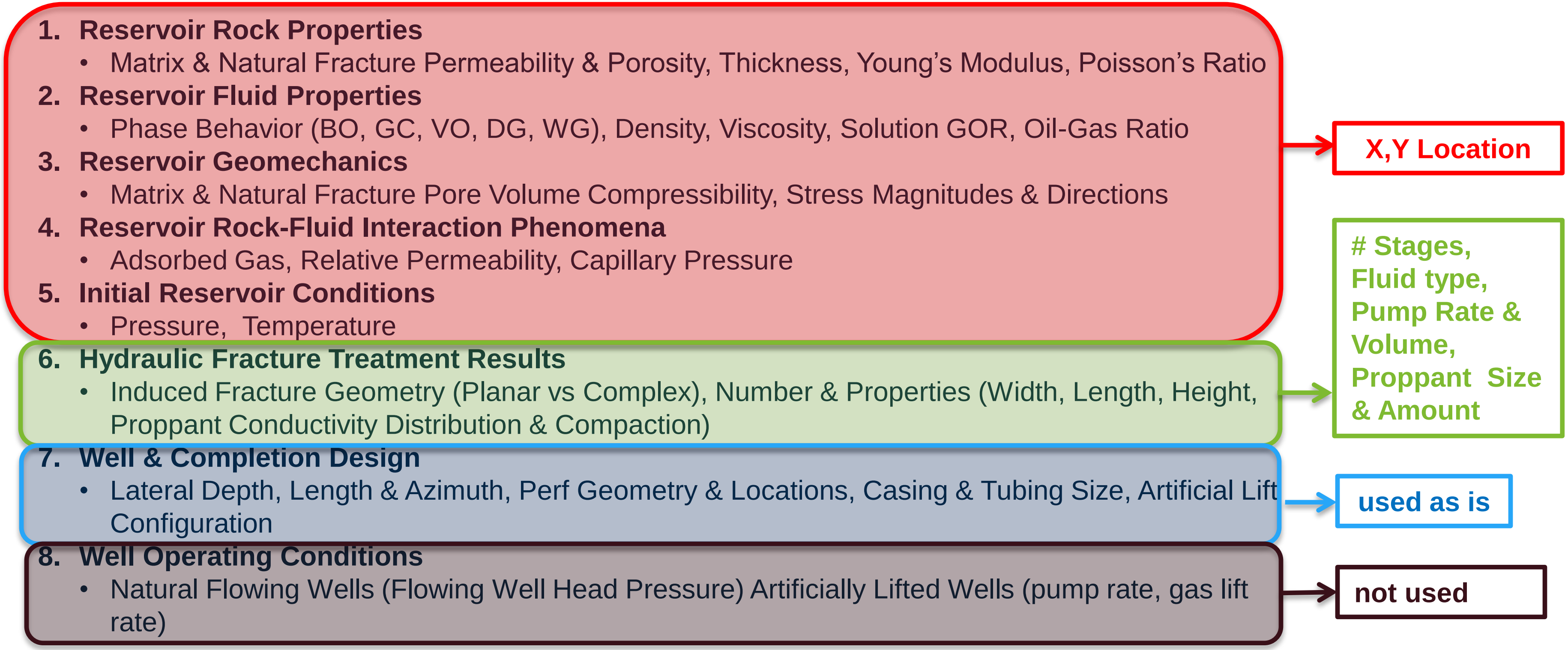
3. ***Numerical Reservoir Simulation*** – Automated History Matching using Numerical Models with unlimited fluid-flow Physics

4. ***Data Analytics*** – Automated Proxy Modelling using any data considered to be relevant but usually without regard for fluid-flow Physics

Parameters that Control Production from Unconventional Wells

1. **Reservoir Rock Properties**
    - Matrix & Natural Fracture Permeability & Porosity, Thickness, Young’s Modulus, Poisson’s Ratio
2. **Reservoir Fluid Properties**
    - Phase Behavior (BO, GC, VO, DG, WG), Density, Viscosity, Solution GOR, Oil-Gas Ratio
3. **Reservoir Geomechanics**
    - Matrix & Natural Fracture Pore Volume Compressibility, Stress Magnitudes & Directions
4. **Reservoir Rock-Fluid Interaction Phenomena**
    - Adsorbed Gas, Relative Permeability, Capillary Pressure
5. **Initial Reservoir Conditions**
    - Depth, Pressure, Temperature
6. **Hydraulic Fracture Treatment Results**
    - Induced Fracture Geometry (Planar vs Complex), Number & Properties (Width, Length, Height, Proppant Conductivity Distribution & Compressibilty)
7. **Well & Completion Design**
    - Lateral Length & Azimuth, Perf Geometry & Locations, Casing & Tubing Size, Artificial Lift Plumbing
8. **Well Operating Conditions**
    - Natural Flowing Wells (Flowing Well Head Pressure) AL Wells (pump rate, gas lift rate)

Parameters typically used in Data Analytics as Unconventional Well Production Predictors



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   - Natural Flowing Wells (Flowing Well Head Pressure) Artificially Lifted Wells (pump rate, gas lift rate)

X,Y Location

 # Stages, Fluid type, Pump Rate & Volume, Proppant Size & Amount

used as is

not used

A Single-Well Numerical Experiment to Test the Validity of using DA to Predict Unconventional Well Performance

1. **Reservoir Rock Properties**
   - Matrix & Natural Fracture Permeability & Porosity, Thickness, Young's Modulus, Poisson's Ratio
2. **Reservoir Fluid Properties**
   - Phase Behavior (BO, GC, VO, DG, WG), Density, Viscosity, Solution GOR, Oil-Gas Ratio
3. **Reservoir Geomechanics**
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4. **Reservoir Rock-Fluid Interaction Phenomena**
   - Adsorbed Gas, Relative Permeability, Capillary Pressure
5. **Initial Reservoir Conditions**
   - Pressure, Temperature

***Fixed:* All**

6. **Hydraulic Fracture Treatment Results**
   - Induced Fracture Geometry (Planar vs Complex), Number & Properties (Width, Length, Height Proppant Conductivity Distribution & Compaction)

Variable:
# of Fracs,
Half-Length,
Height,
Spacing,
Permeability
Fixed:
Frac Surface Area

7. **Well & Completion Design**
   - Lateral Depth, Length & Azimuth, Perf Geometry & Locations, Casing & Tubing Size, Artificial Lift Configuration

***Fixed:* All**

8. **Well Operating Conditions**
   - Natural Flowing Wells (Flowing Well Head Pressure) Artificially Lifted Wells (pump rate, gas lift rate)

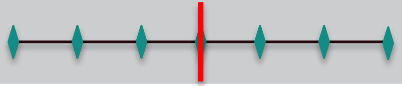
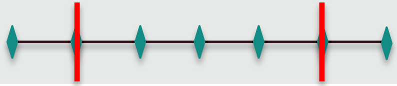
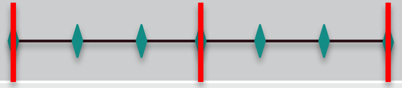
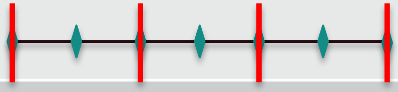
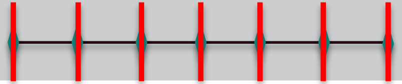
Variable:
BHP

A Single-Well Numerical Experiment to Test the Validity of using DA to Predict Unconventional Well Performance

Parameter	Type	Default	min	max	PDF
Operating BHP (psig)	Continuous	2000	500	2000	uniform
Frac_Perm (md)	Continuous	10000	2000	20000	uniform

Parameter	Type	Default	Values				
No_Fracs (-)	Discrete	17	17	34	51	68	119
Frac_Height (ft)	Discrete	132	60	84	108	132	
Layers (-)	Formula	5	2	3	4	5	
Frac_Spacing (ft)	Formula	280	280	140	105	70	35
Frac_Half_Length (ft)	Formula	525	= 17*525*132/(No_Fracs*Frac_Height)				

A Single-Well Numerical Experiment to Test the Validity of using DA to Predict Unconventional Well Performance

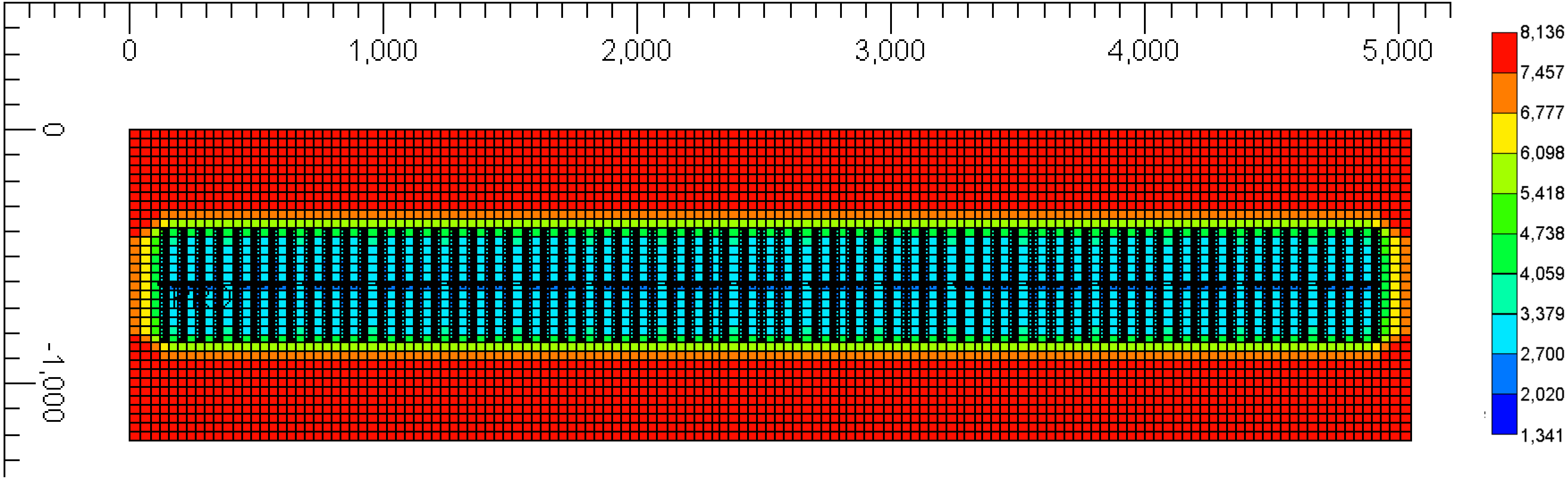
Fracture Geometry at Each Stage *	# of Fractures Per Stage	Fracture Spacing (ft)	Fracture Half-Length (ft)	Fracture Height (ft)	Total Fracture Surface Area (ft^2)
	1	280	525	132	2356200
	2	140	320.83	108	2356200
	3	105	275	84	2356200
	4	70	206.25	84	2356200
	7	35	165	60	2356200

*** 17 stages / 7 perforations each stage**

Frac half-lengths not drawn to scale

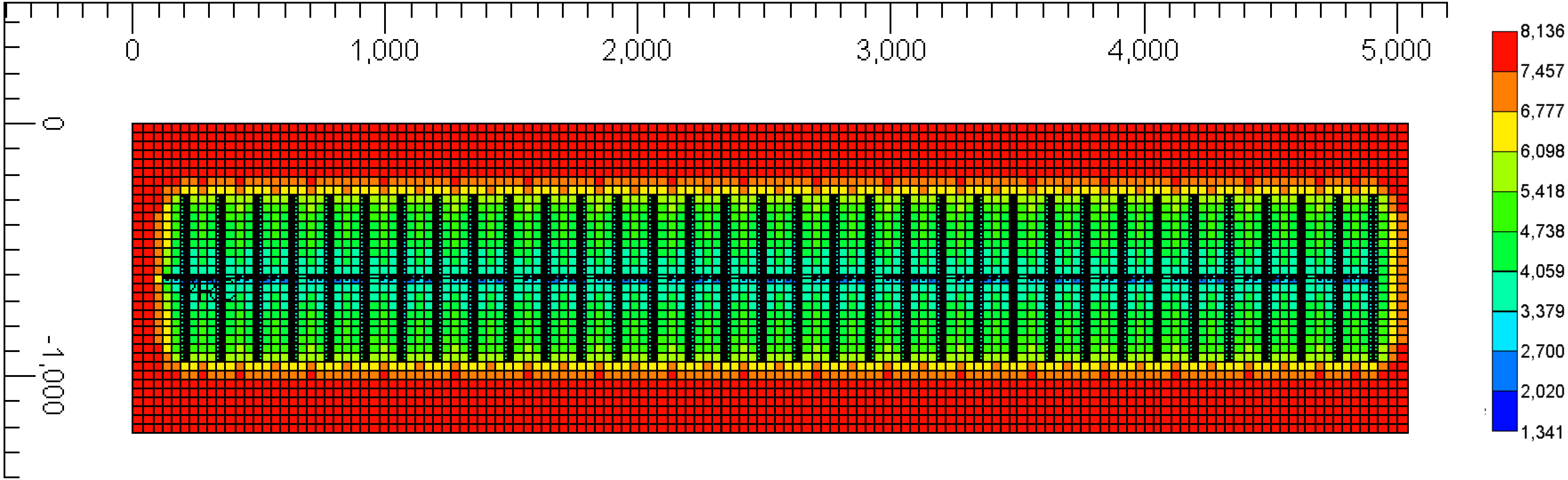
A Single-Well Numerical Experiment to Test the Validity of using DA to Predict Unconventional Well Performance

4 Fractures Per Stage Case – Pressure Profile

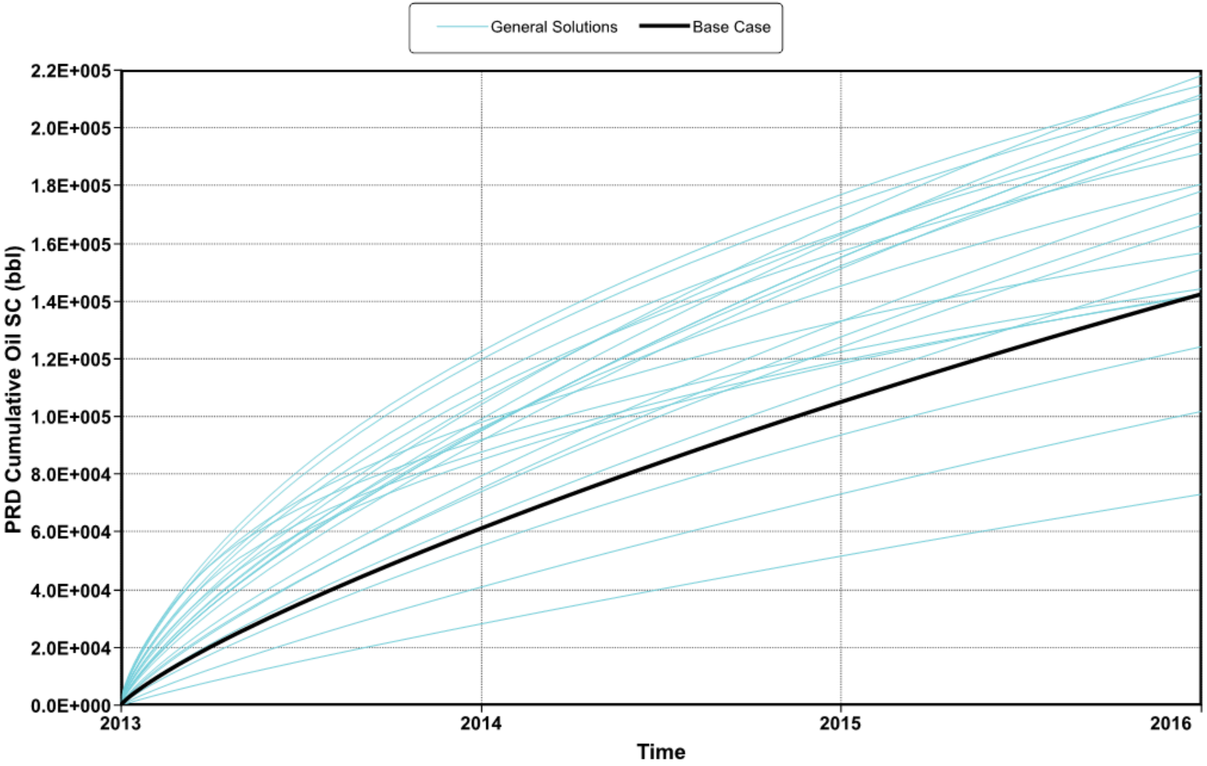


A Single-Well Numerical Experiment to Test the Validity of using DA to Predict Unconventional Well Performance

2 Fractures Per Stage Case – Pressure Profile



3-Year Cumulative Oil Production Variation with BHP and Frac Configuration while holding Total Frac Surface Area CONSTANT

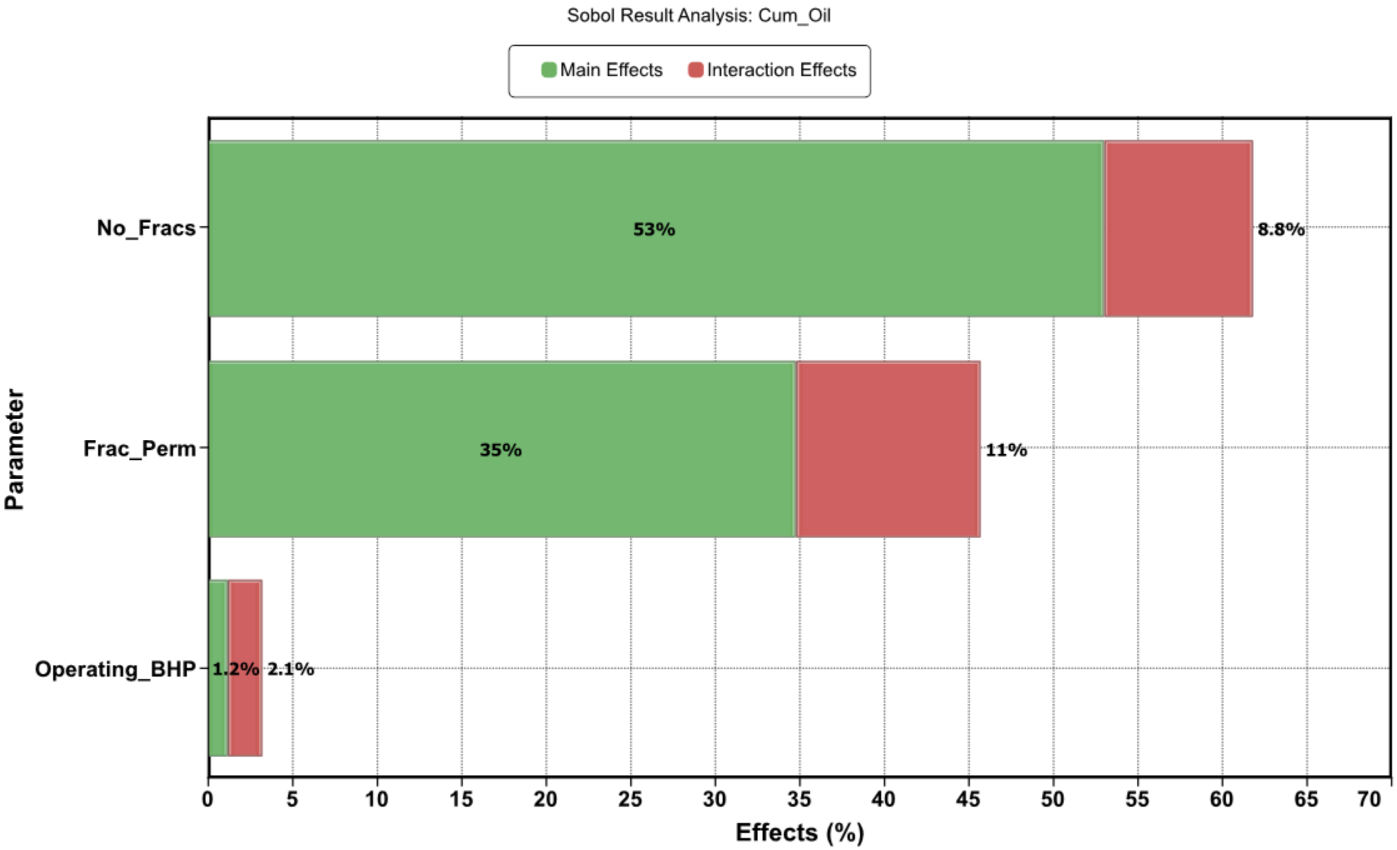


218,286 STB

73,265 STB

COMPUTER MODELLING GROUP LTD.

A Single-Well Numerical Experiment to Test the Validity of using DA to Predict Unconventional Well Performance



Conclusions

1. All data that Data Analytics would normally use as “performance predictors” was held constant for all simulation runs for a 1-well model

2. The cumulative oil production varied by 3x simply by allowing flowing BHP and several stimulation treatment parameters to vary while constrained to have the same total fracture surface area (akin to saying the pumped frac fluid and prop volume was constant)

3. This simple case demonstrates that DA cannot be predictive without incorporating parameters associated with reservoir fluid flow physics.

How is Reservoir Simulation Helping?

- Reservoir Simulation incorporates reservoir heterogeneity, well complexity & the physics of fluid flow, heat flow, geomechanics and geochemistry necessary to understand and predict tight & shale well production
- Reservoir Simulation combined with an Integrated Productivity Enhancement tool (e.g. CMOST) enables "physics-based" analysis and optimization of tight & shale plays in an efficient manner:
  - EUR Calculation & Validation
  - Well Completion Design Optimization
  - Well Spacing Optimization

Conclusions

CMG’s Numerical Simulation-based Workflows for Unconventional Wells were shown to be:

- **More accurate and consistent than the RTA-based Workflow**
- **Sufficiently fast to be employed as a routine calibration tool for results derived from other less physics based methods**

Data Analytics is a poor predictor Unconventional Well Performance without using reservoir and completion parameters as “predictors”.

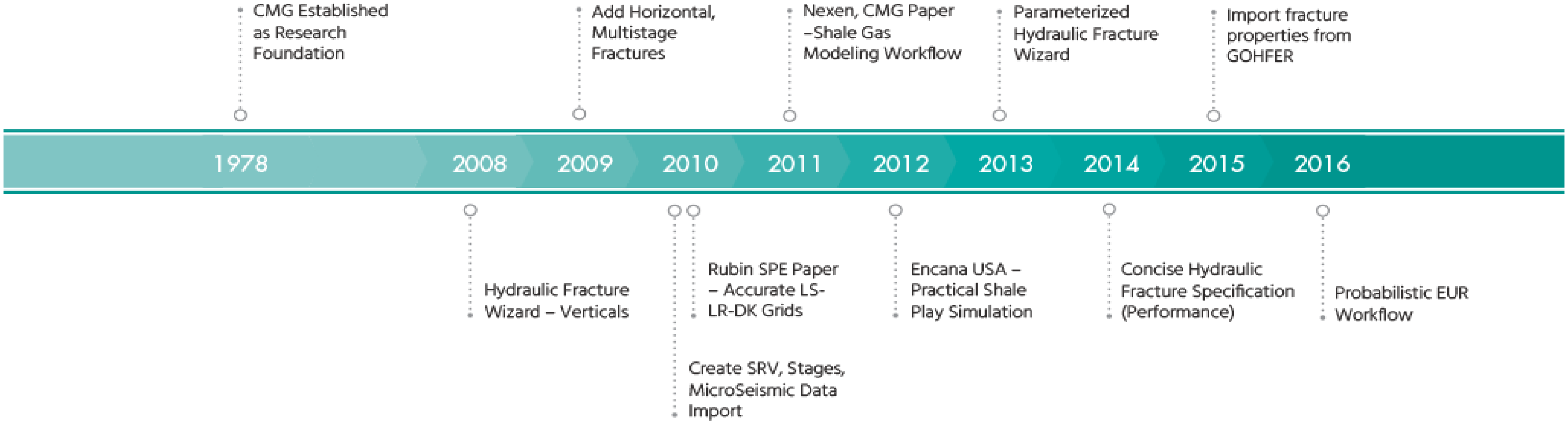
Why use CMG for Modelling Tight & Shale Plays?

1. CMG has the physics required to history match and forecast production from Unconventional Wells & Reservoirs
2. CMG makes it easy to import geologic models from the leading 2D and 3D geologic modelling tools to jump-start your modelling workflows
3. CMG makes it easy to add planar, complex or mixed geometry propped and stimulated natural fractures to your models
4. CMG makes it easy to use microseismic data into the model building process

Why use CMG for Modelling Tight & Shale Plays?

5. **CMG makes it easy and efficient to build single and multi-well models**
6. **CMG makes it easy to parameterize reservoir and hydraulic fracture properties & sizes for history-matching & optimization**
7. **CMG's track record of enhancements to our capabilities and workflows for Unconventional Wells & Reservoirs**

Milestones in CMG's Unconventional Reservoir Modelling Capabilities & Workflows



CMG Established as Research Foundation

Add Horizontal, Multistage Fractures

Nexen, CMG Paper –Shale Gas Modeling Workflow

Parameterized Hydraulic Fracture Wizard

Import fracture properties from GOHFER

1978 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016

Hydraulic Fracture Wizard – Verticals

Rubin SPE Paper – Accurate LS-LR-DK Grids

Create SRV, Stages, MicroSeismic Data Import

Encana USA – Practical Shale Play Simulation

Concise Hydraulic Fracture Specification (Performance)

Probabilistic EUR Workflow

SPE Papers featuring the use of CMG Reservoir Simulation Technology since 2010

- **525 papers featuring CMG**
- **74 Shale papers featuring CMG**
- **25 on EOR in Shales**

E&P Co.'s who have licensed CMG to Model Unconventional Reservoirs

56

E&P

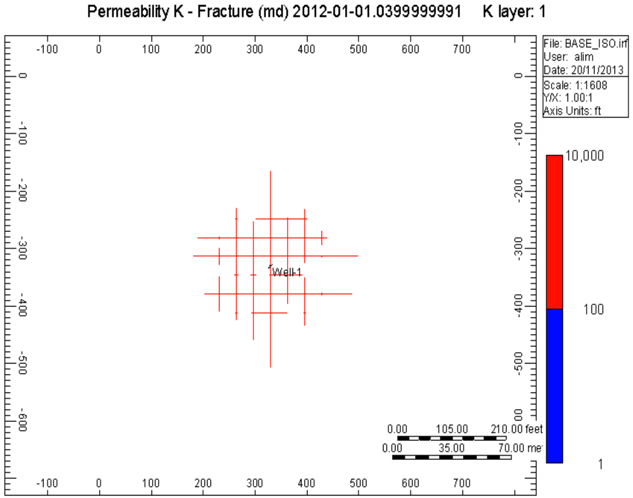
Companies

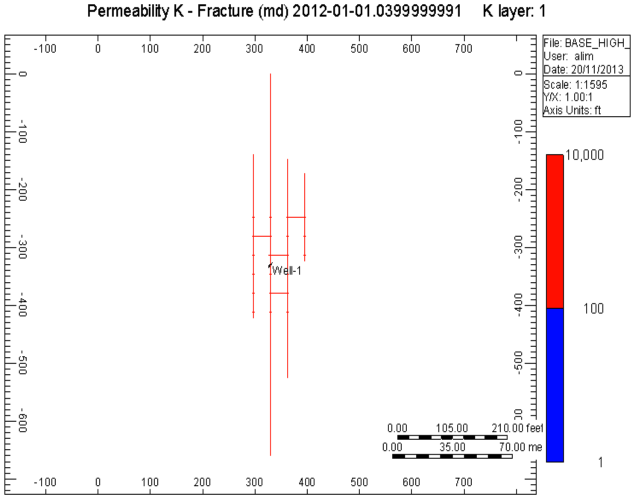
Consulting & Service Co.'s who have licensed CMG to Model Unconventional Reservoirs

19 Service/Consulting Companies

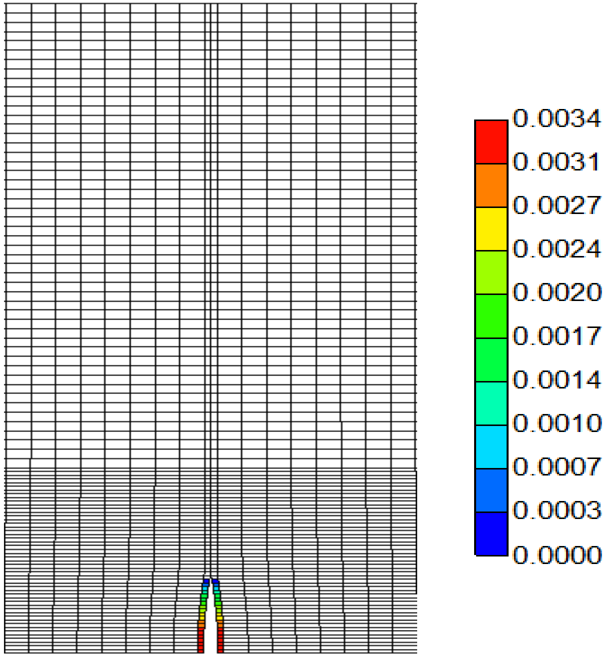
Use of GEOMECH for Modelling Unconventional Reservoirs

- For modelling permeability change (with hysteresis) as a function of stress change during production and shut-in periods (SPE 175029)
- For fracture opening during hydraulic fracturing treatments, DFITs (SPE 166201)

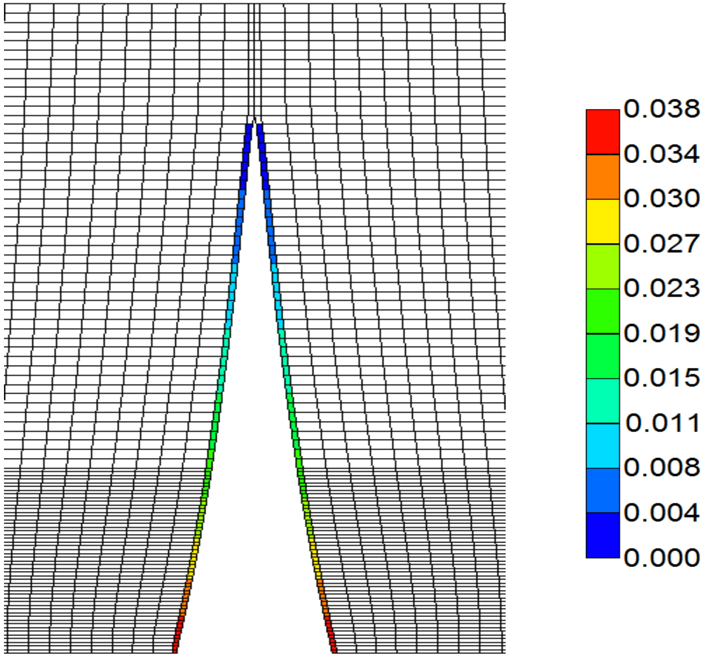

Permeability K - Fracture (md) 2012-01-01.0399999991 K layer: 1


Permeability K - Fracture (md) 2012-01-01.0399999991 K layer: 1

Future: Geogrid splitting during HF propagation using CMG's GEOMECH

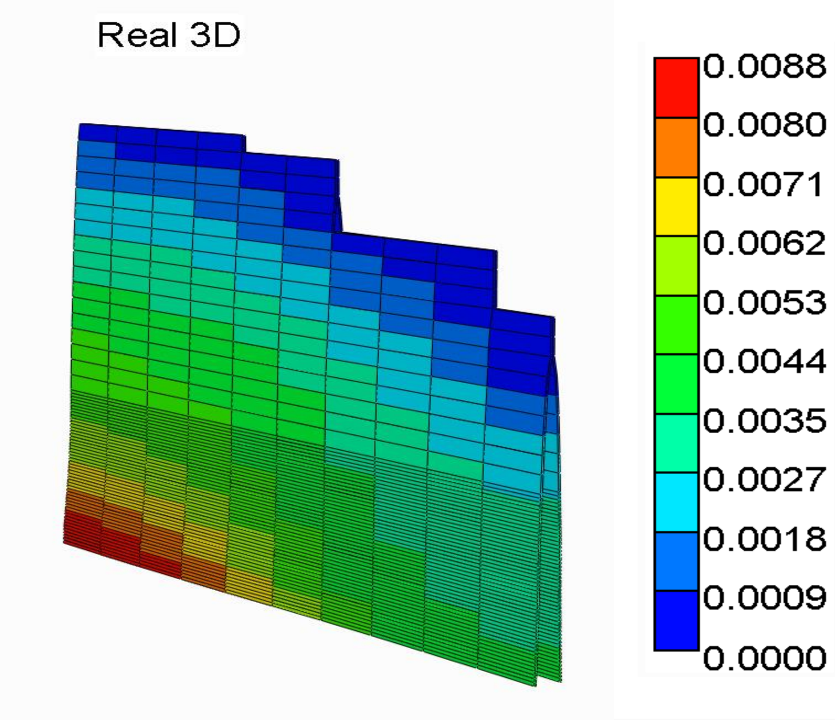


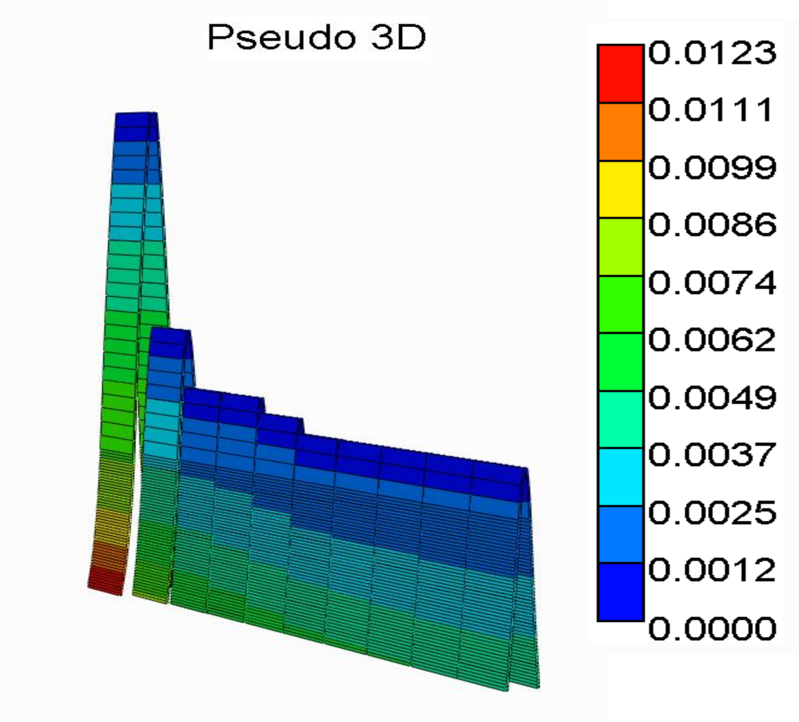
Matrix $k_x = k_y = k_z = 0.6$ md

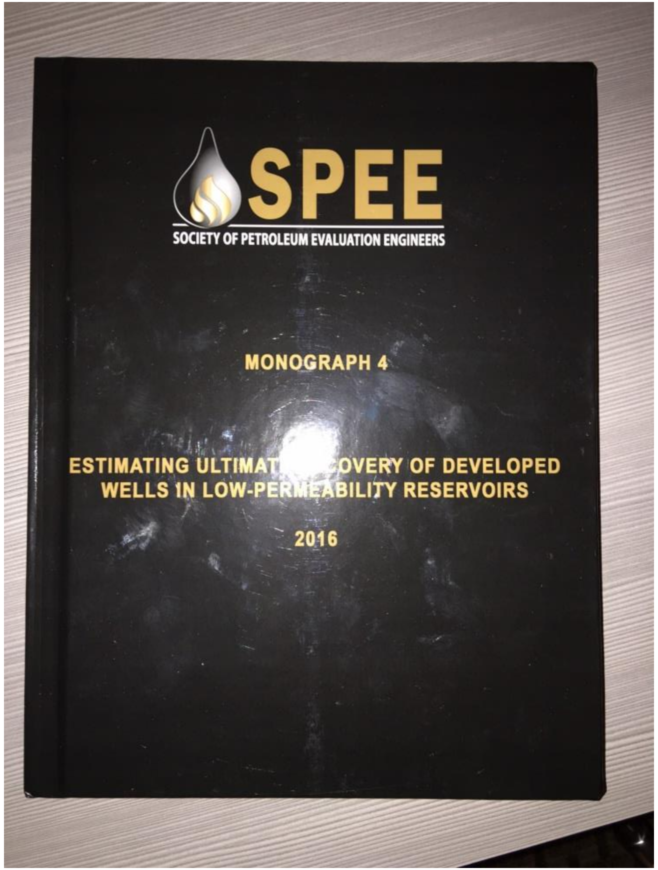


Matrix $k_x = k_y = k_z = 0.1$ md

Future: Fracture widths in real 3D and pseudo 3D







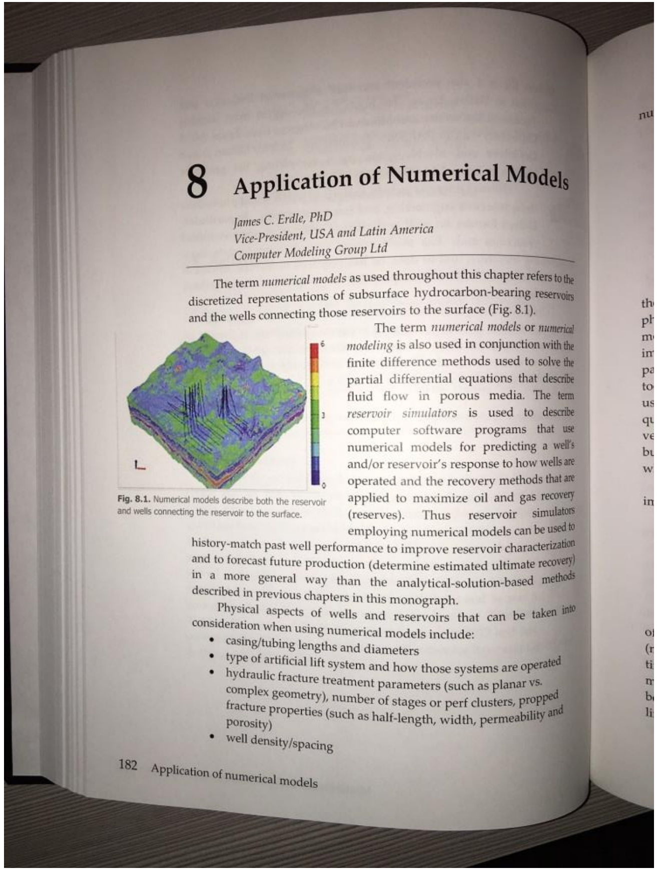
SPEE

SOCIETY OF PETROLEUM EVALUATION ENGINEERS

MONOGRAPH 4

ESTIMATING ULTIMAT[illegible]OVERY OF DEVELOPED WELLS IN LOW-PERMEABILITY RESERVOIRS

2016



8 Application of Numerical Models

James C. Erdle, PhD
Vice-President, USA and Latin America
Computer Modeling Group Ltd

The term *numerical models* as used throughout this chapter refers to the discretized representations of subsurface hydrocarbon-bearing reservoirs and the wells connecting those reservoirs to the surface (Fig. 8.1).

Fig. 8.1. Numerical models describe both the reservoir and wells connecting the reservoir to the surface.

The term *numerical models* or *numerical modeling* is also used in conjunction with the finite difference methods used to solve the partial differential equations that describe fluid flow in porous media. The term *reservoir simulators* is used to describe computer software programs that use numerical models for predicting a well's and/or reservoir's response to how wells are operated and the recovery methods that are applied to maximize oil and gas recovery (reserves). Thus reservoir simulators employing numerical models can be used to history-match past well performance to improve reservoir characterization and to forecast future production (determine estimated ultimate recovery) in a more general way than the analytical-solution-based methods described in previous chapters in this monograph.

Physical aspects of wells and reservoirs that can be taken into consideration when using numerical models include:

- casing/tubing lengths and diameters
- type of artificial lift system and how those systems are operated
- hydraulic fracture treatment parameters (such as planar vs. complex geometry), number of stages or perf clusters, propped fracture properties (such as half-length, width, permeability and porosity)
- well density/spacing

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