# Highlights from SPEE Monograph 4: Estimating Ultimate Recovery of Developed Wells in Low Permeability Reservoirs

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# Purpose of Monograph

- To provide an understanding of the methods used to analyze well performance
- To describe these methods in the context of
  - Consistent workflows
  - Estimating recoverable hydrocarbon volumes
  - Quantifying uncertainties
- Acknowledges that methods are constantly evolving and new approaches will be applied in the future
- Stops short of addressing the assignment of developed reserves

# Monograph Committee

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- Olivier Houzé, Kappa Engineering
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# Monograph Chapters

1. Introduction
2. Understanding Tight Reservoirs
3. Reservoir Characterization
4. Drilling, Completions, and Operations
5. Conventional DCA in Unconventional Wells
6. Fluid Flow and Alternative Decline Models
7. Model Based Well Performance Analysis & Forecasting
8. Application of Numerical Models
9. Quantifying Uncertainty
10. Example Problems

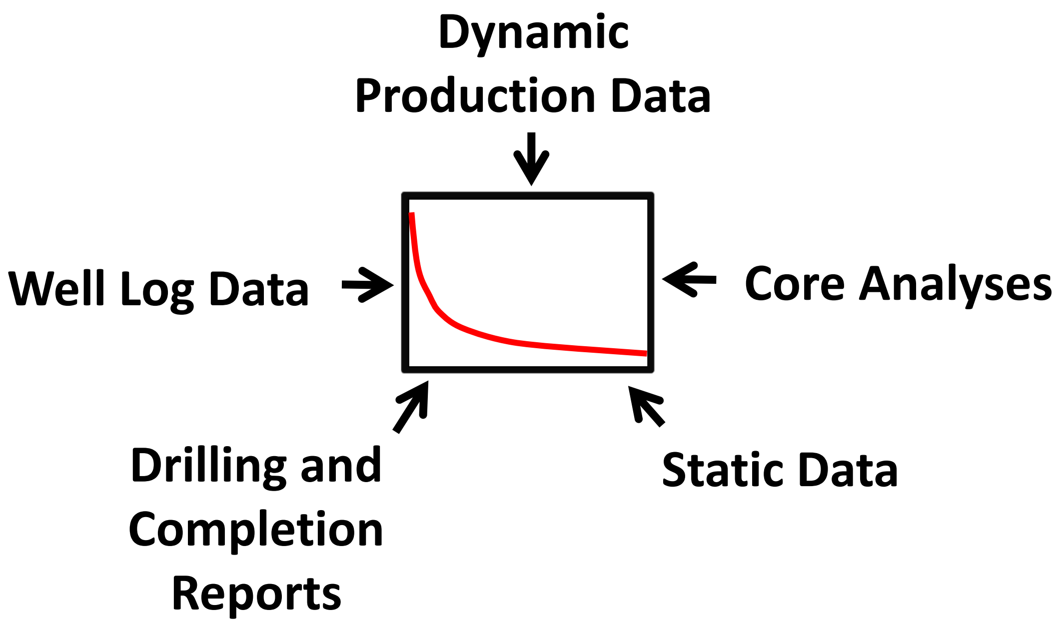
# Chapter 2: Understanding Tight Reservoirs

- What the Monograph covers:
  - Light tight oil/shale oil
  - Shale/tight gas
  - Coalbed methane (CBM)/coalseam gas
  - Basin-centered gas
- What the Monograph excludes:
  - Oil sands (bitumen)
  - Gas hydrates
  - Oil shale (kerogen)

# Characteristics of Tight Reservoirs

- Low K (<0.1 md)
- Continuous, regional hydrocarbon system
- Lack hydrodynamic influence
- May exist in conventional traps
- Discrete "fields" may merge into a regional accumulation
- Commonly abnormally pressured
- Evident production "sweet spots" or “fairways”
- Self-sourcing or in close proximity to source rocks
- Requires stimulation
- Repeatable statistical distribution of EURs
- Produces little water (except for some CBM and tight oil)
- Truly dry holes uncommon
- EURs generally lower than many conventional EURs
- Potential large-scale development footprint
- Extensive transient flow period
- Large in-place, low rec factor
- Potential interference due to spacing or induced fracturing

# Data Considerations and Workflow




Ensure Data Competency → Review and Describe Production Data → Analyze Data → Forecast Production → Model Economics and Plan Development

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# Chapter 3: Reservoir Characterization

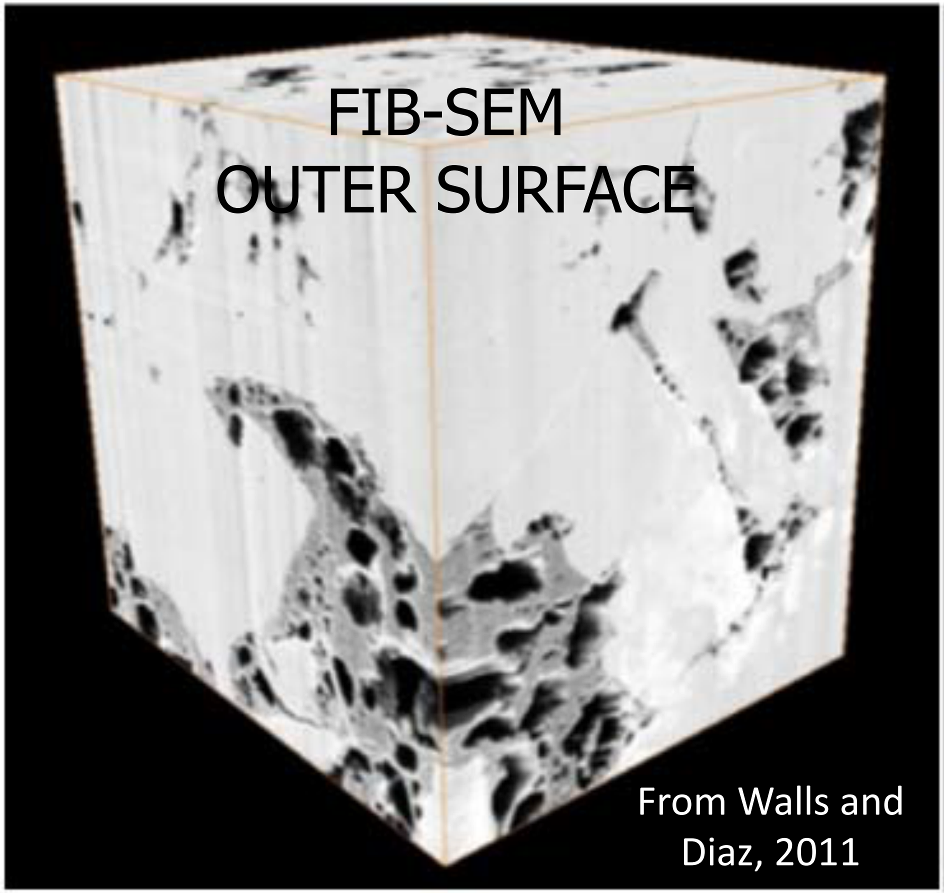
- Low permeability reservoirs are often referred to as "statistical" plays which implies some degree of irreducible uncertainty
- While this randomness does exist, there are also underlying rock and fluid property trends that control productivity and reserves
- This chapter focuses on charactering these trends and their impact on well performance

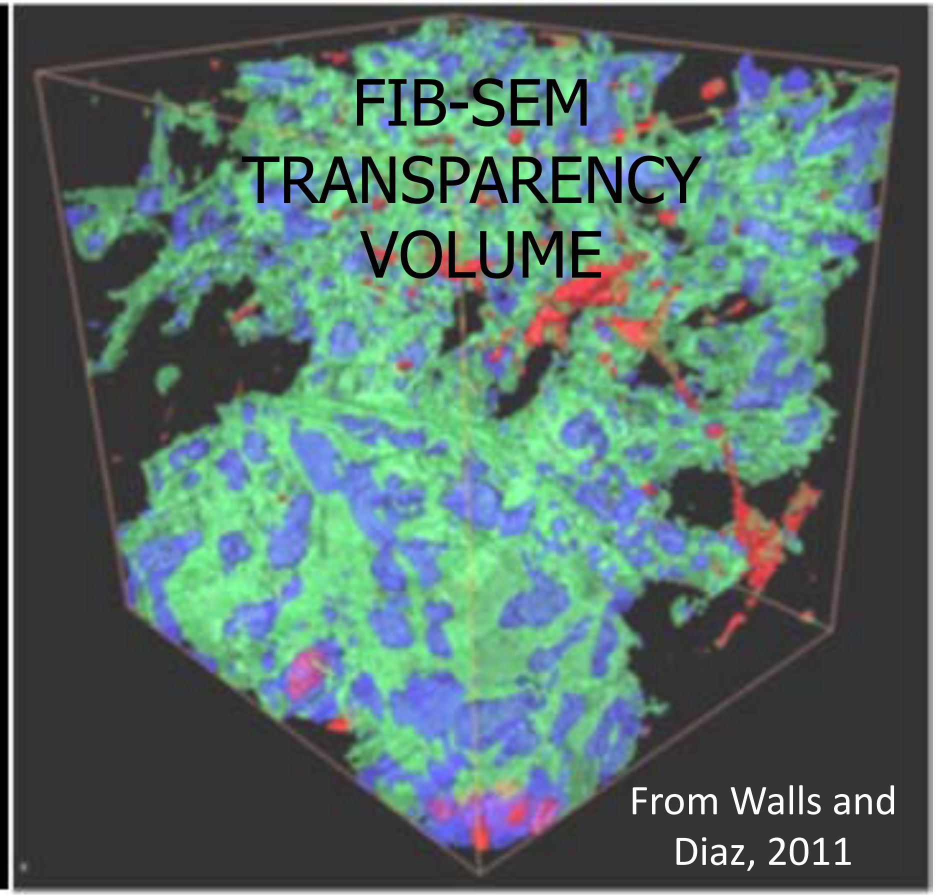
# Reservoir Properties Controlling Performance

- Regional geology
- Structural geology
- Stratigraphy
- Lithofacies types
- Depositional system
- Diagenesis
- Organic geochemistry
- Hydrogeology
- Natural fractures
- Geomechanical props.
- Rock properties
- Log properties
- Seismic scale props.
- Fluid properties

For each of these, there is a discussion of its relevance, an illustration emphasizing its importance, and a list of deliverables that should result from the associated technical work

# Rock Properties Example




- Pore system characterization: Pore types, sizes, connectivity
- Porosity, permeability, saturations
- Issues & calibration (e.g., pressure cores)

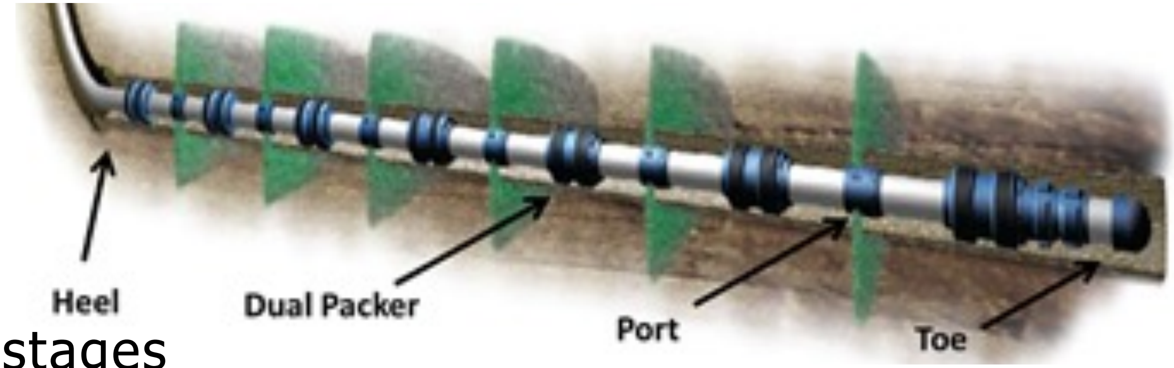
# Reservoir Characterization: Key Points

- All forecasting techniques rely to some degree on reservoir characterization
  - Even for empirical methods (Arps) it is still important to understand the size and characteristics of the geobodies being drained, especially before BDF
  - Model-based analysis (RTA) assumes certain geologic conditions (such as homogeneity, constant thickness, regular fracture spacing) that need to be validated
  - Numerical simulation requires an extensive set of geoscience data to build a representative model
- As such, it is critical to incorporate reservoir characterization aspects

# Chapter 4: Drilling, Completions, Operations

- Previously unimaginable production rates and ultimate recoveries have been obtained using very long wells and multi-stage fracture stimulations
- But to be commercially successful, these need to be coupled with cost-effective practices
  - Efficient logistics
  - Economies of scale
  - Service industry engagement
- This chapter reviews these aspects and their impact

# Discussion Topics




- Drilling
  - Drilling techniques, stages
  - Drilling fluids, bits, muds
  - Drilling problems
  - Wellbore integrity
  - Vertical vs. horiz. wells
  - Orientation, landing zone
  - Cost reduction with time
- Operations
  - Choke mgmt, artificial lift
  - Water source and disposal
  - Fluid entry diagnostics
  - Producing rates and pressures
  - Wellpads, modular facilities
- Completions
  - Open vs. cased hole
  - Under-reaming, cavitation
  - Cluster and stage spacing
  - *Plug & perf* vs *ball & sleeve*
  - Fluids, proppants, additives
  - Slickwater, gel, hybrid fracs
  - Microseismic, frac geometry
  - Rock interaction, flowback
  - Fracture diagnostics

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# Drilling, Completions, Operations: Key Points

- Decisions about how to drill, complete, and operate wells strongly affects productivity
- Practices that lead to better results include
  - Consistently accurate geosteering
  - Ensuring wellbore integrity
  - Minimizing interference and undrained regions
  - Properly managing drawdown
  - Optimizing artificial lift and compression
  - Achieving long-term wellbore stability
  - Conducting successful well interventions
  - Minimizing wellbore loss (corrosion, collapse, etc.)

# Chapter 5: Conventional DCA in Unconv. Wells

- Purpose is to discuss the validity of applying the Arps equation to low permeability reservoirs
- Arps documented pre-existing empirical decline curve forms in 1944
  - Data quality was very bad--Arps “smoothed” monthly data to 2 points per year!
  - But well quality was very good--High rate, high quality, single layer reservoirs with low decline rates
  - Characterized by low hyperbolic “b” factors

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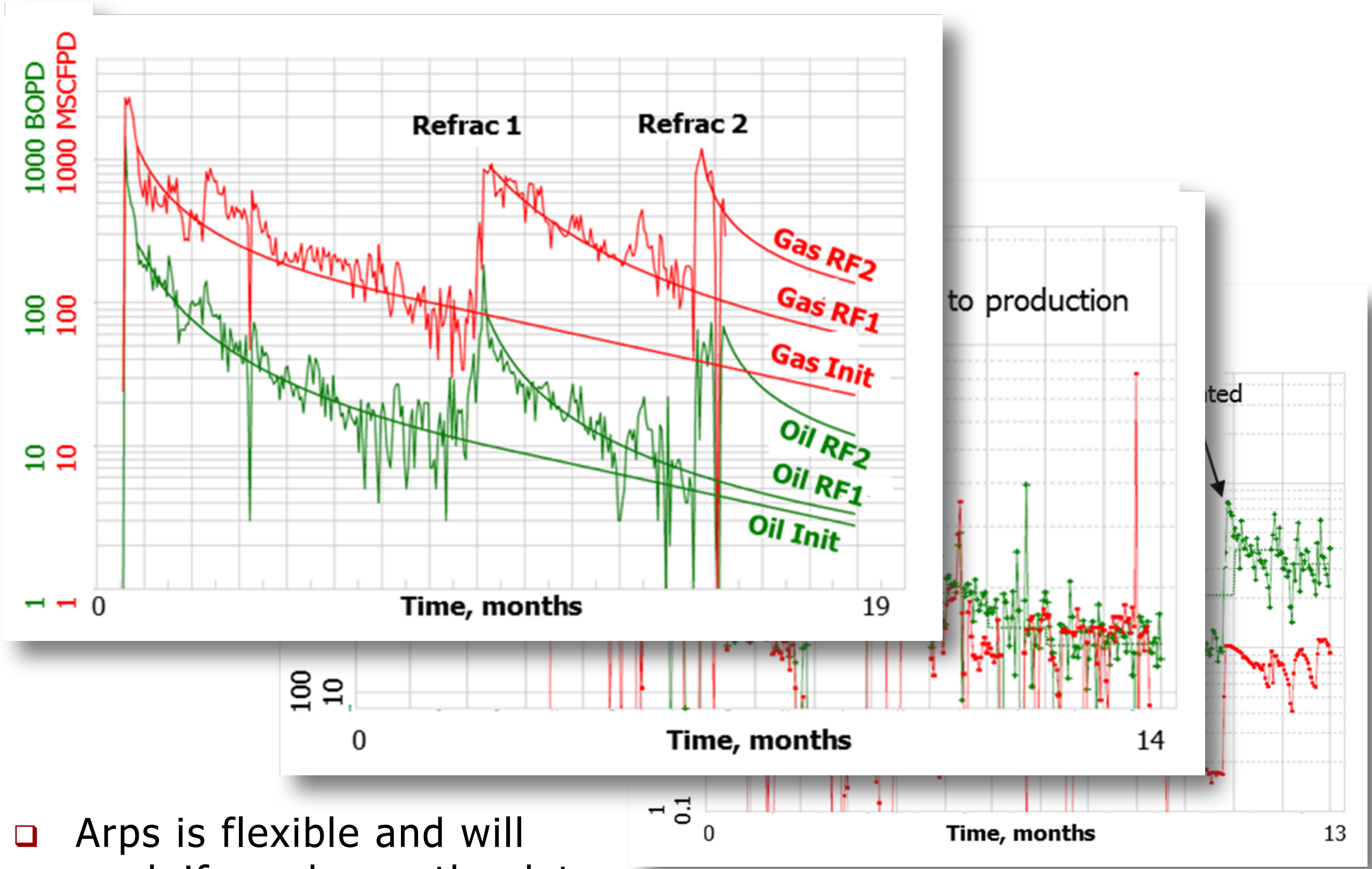
# Application of Arps in Unconv. Wells

- Long wells with multi-staged fracs are different
  - Steep early decline, shallow late decline, multiple flow regimes
- Arps forms are very flexible w/multiple segments
  - Need to honor all the data
  - High b values (1-2+) match early transient data
  - Lower b values (0-1) match later-life flow regimes
  - Most problems = user error
- So…the Arps equation, modified for use in different flow regimes, is a reasonable technique for forecasting wells

# Multi-segment (Modified Hyperbolic) Declines



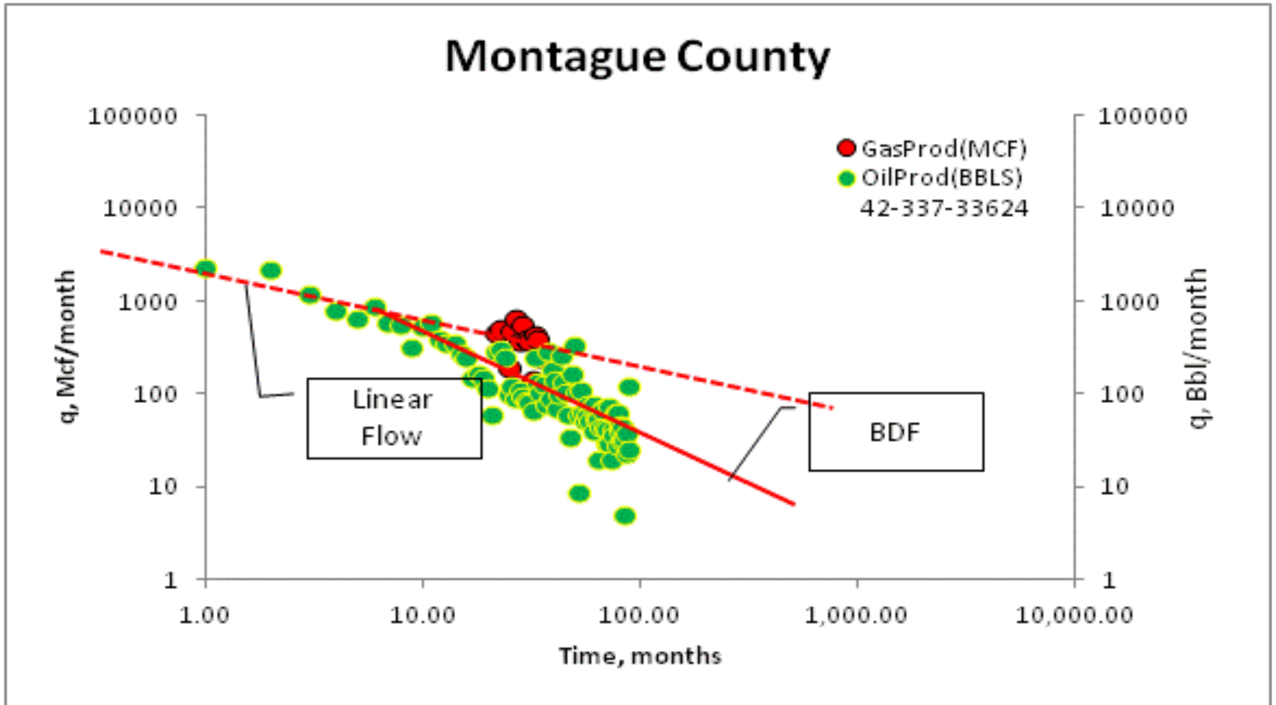

- Arps is flexible and will work if you honor the data in each event

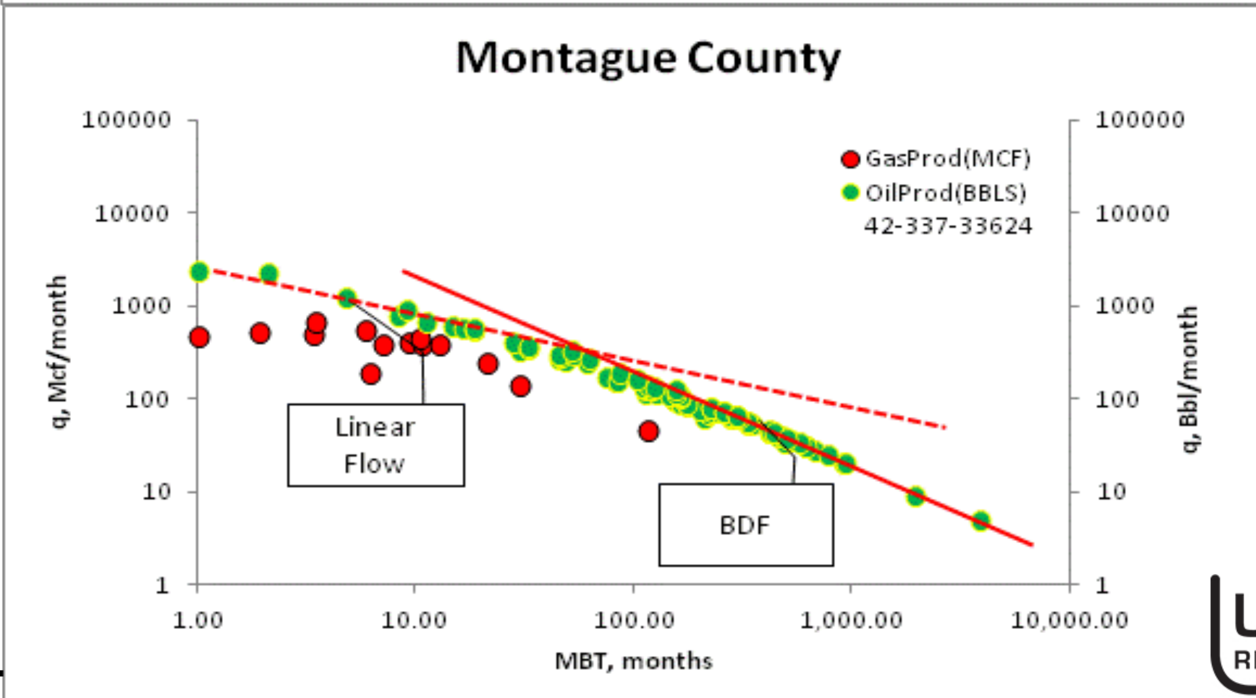
# Conventional DCA: Key Points

- Arps DCA can do a good job on unconventional wells… when used correctly
- Multiple segments are critical, with at least a trailing exponential to recognize late-life effects
- Important to plot secondary phases & pressures
  - Provide meaningful supplemental data which add depth and nuance to a primary phase forecast
  - Is your well loading-up? Was it frac-bashed? How are the GOR and WOR changing?
- RTA and numerical simulation complement Arps empirical forecasts

# Chapter 6: Fluid Flow & Alternative Decline Models

- Purpose is to analyze some of the more promising decline models as alternatives to Arps
- Begins with fluid flow theory to help us understand if proposed models are applicable
  - Linear flow, bilinear flow, BDF, depth of investigation
- Discusses alternative models that handle long-duration transient flow data
  - Stretched exponential, Duong
- Workflow used in decline curve analysis is more important than the specific model selected




# Flow Regime Identification is Critical

Top: Log-log rate vs time plot

Bottom: Log-log rate vs. MBT (Np/q)

# Workflow for Forecasting

- When BHP data are available and time permits, normalize rates before analysis
  - $(\frac{q}{p_i - p_{wf}})$ or $q_{corr} = q_{obs}\left(\frac{p_i - p_{wf,stab}}{p_i - p_{wf,obs}}\right)$
- Exclude first 6-12 mos (clean-up, choked flow)
  - Plot water rate vs. time to identify fracture cleanup
  - Don’t use data during cleanup—won’t fall on longer term trend since skin is continuously decreasing
- Determine flow regimes in available data
  - Minimum: log *q* vs. log *t*
  - Better: add log $(\frac{q}{p_i - p_{wf}})$ vs. log MBT ($G_p/q$, $N_p/q$)

# Workflow for Forecasting (Cont'd)

- Estimate time to BDF if not observed in data
  - Minimum: switch time from analogy
  - Better: depth of investigation or analytical model
- Don't try to fit all history with single model
  - Fit each flow regime with model appropriate for *that flow regime*
  - Extrapolate rate to well life or economic limit only with *final* flow regime observed or expected
    - Earlier flow regimes are important for understanding, but unimportant for extrapolation

# Chapter 7: Model-based Analysis

- This chapter presents the application of production diagnostics & model-based analysis to evaluate performance & forecast production
- We are still moving up the learning curve
  - Flow phenomena in low-permeability reservoirs is not completely known nor fully represented
  - Analysis and forecasting methods are based on conventional processes, with a few adaptations
  - Little empirical knowledge of long-term decline exists for multi-stage, fracture-stimulated laterals

# Data Requirements

- Production data
  - Time-rate-pressure at least on a daily basis
- Static reservoir properties
  - Porosity, thickness, water saturation, initial reservoir pressure and temperature
- PVT properties
  - Laboratory report preferred
- Well completion data
  - Number of stages and perf clusters, fluid entry data, artificial lift

# Workflow

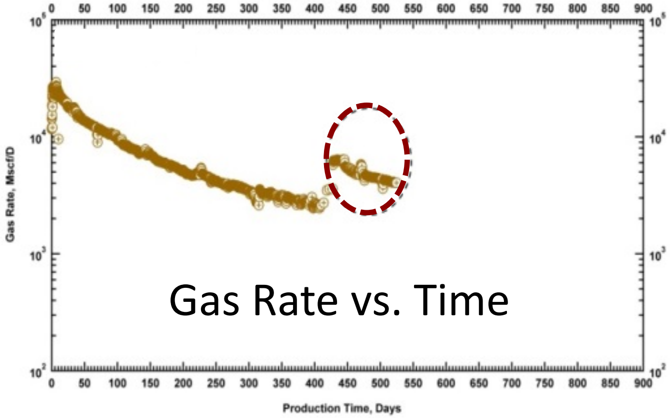
1. Identify outliers and inconsistencies, remove spurious data

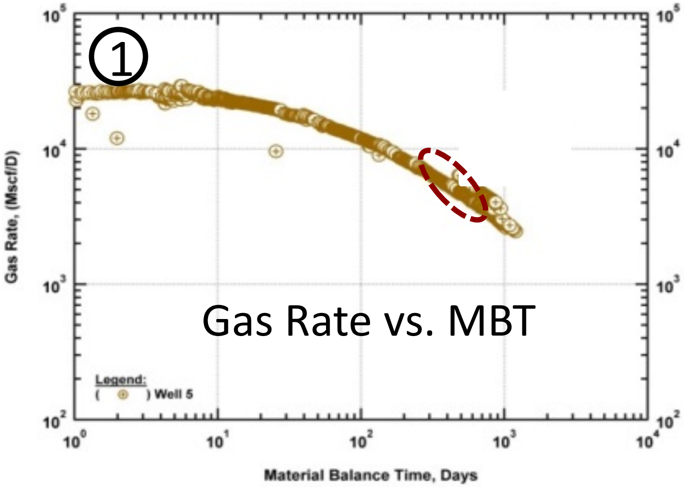
2. Identify flow regimes and well groupings

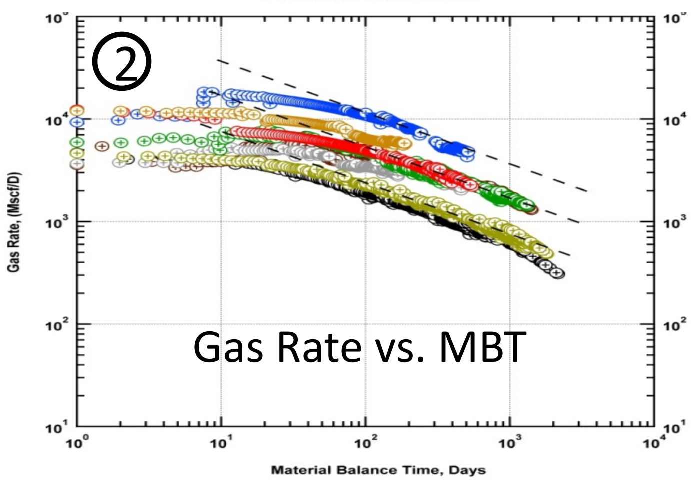
3. Build a representative model

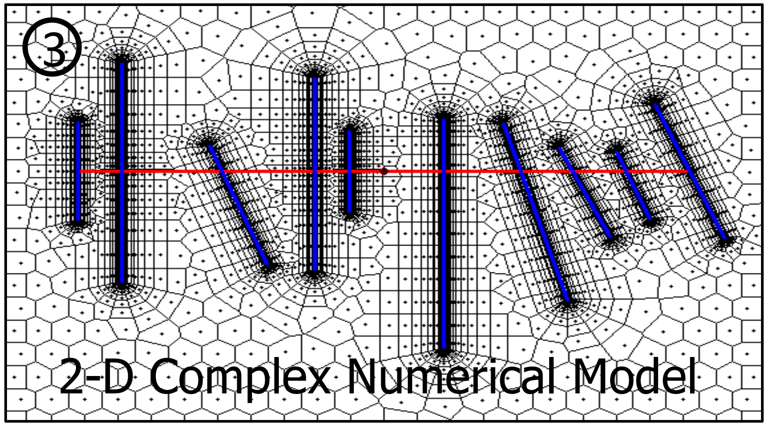
4. Conduct a model-based analysis (history matching)

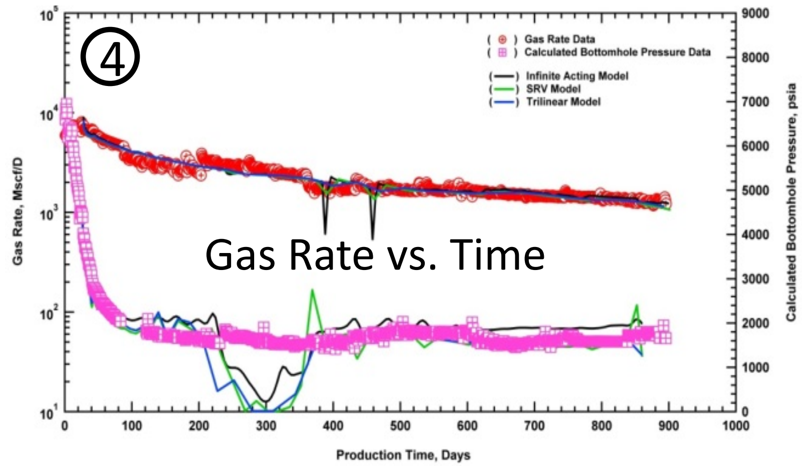
5. Extend the RTA results for production forecasting

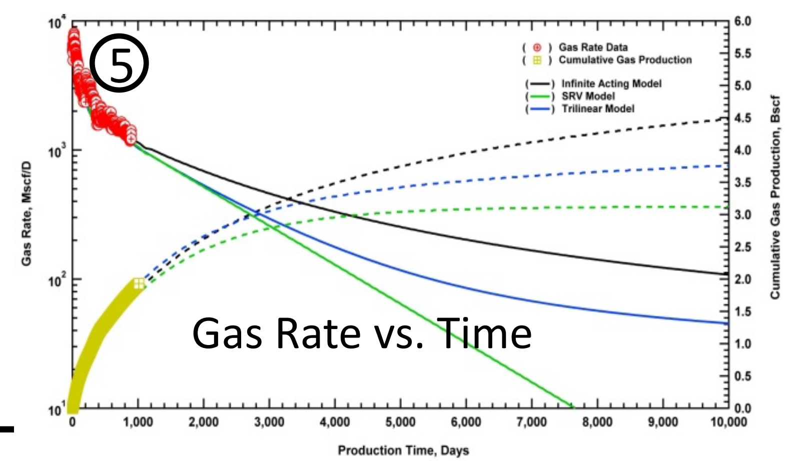


# Model-Based Analysis: Key Points

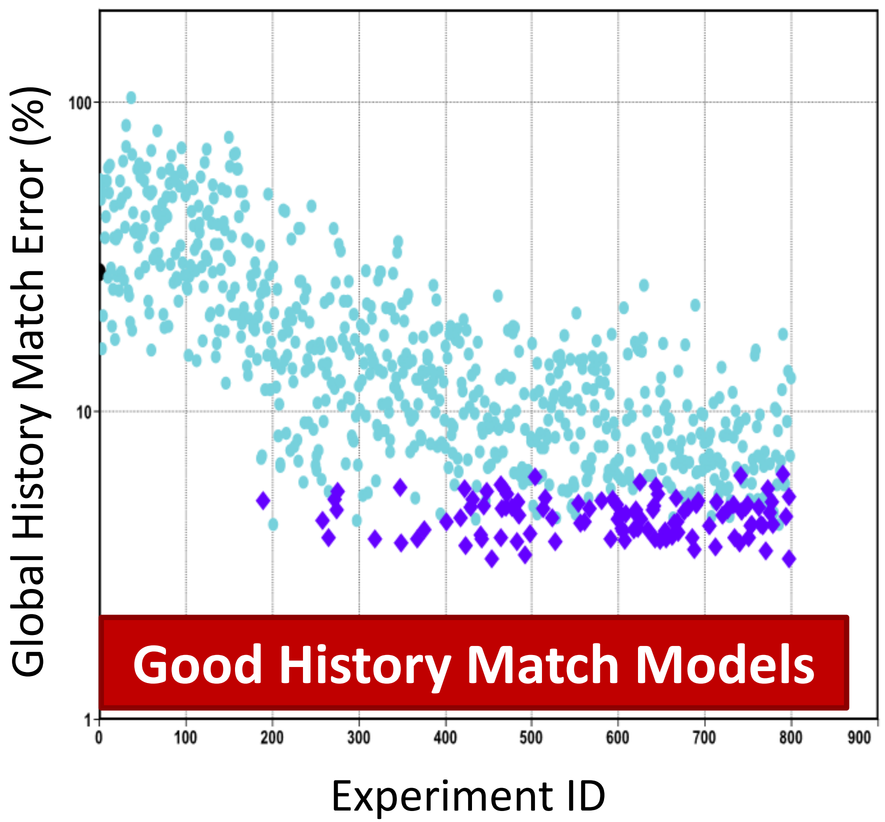
- A large number of models (from simple to complex) exist for representing production
  - But models are only as good as the reservoir and completion data used to construct them

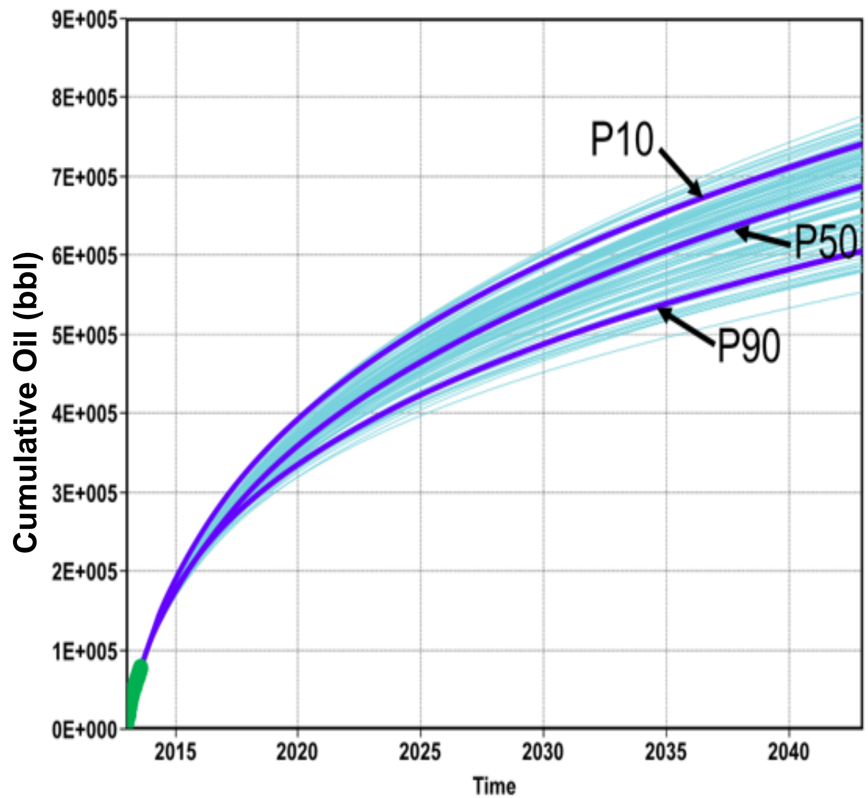
- Several factors should be considered in the context of model-based analysis & forecasting:
  - Non-uniqueness (various solutions may honor data)
  - Factors affecting flow behavior (PVT, stress-dependence, drainage area patterns, etc.)
  - Diagnostics (flow regimes, data quality)
  - Ranges of model parameters to quantify the uncertainty of forecasts

# Chapter 8: Application of Numerical Models

- To understand physics-based EURs, optimization
  - Multi-phase (below bubble/dew pt) & non-darcy flow
  - Multi-component phase behavior, adsorption, diffusion
  - Heterogeneous rock properties and completions
  - Changing reservoir/completion parameters with time
- To accommodate current development practices
  - Analysis of flowback rates, drawdown mgmt. strategy
  - Analysis/forecasting of well pads showing interference
  - Interpreting production surveillance data
  - Modelling of re-fracs and infill drilling

# History Matching & Probabilistic Forecasts




- History matching is an inverse problem with non-unique solutions
- Perfect history match ≠ perfect prediction

- Probabilistic forecasting helps reduce risk in decision-making
- Provides range of possible outcomes

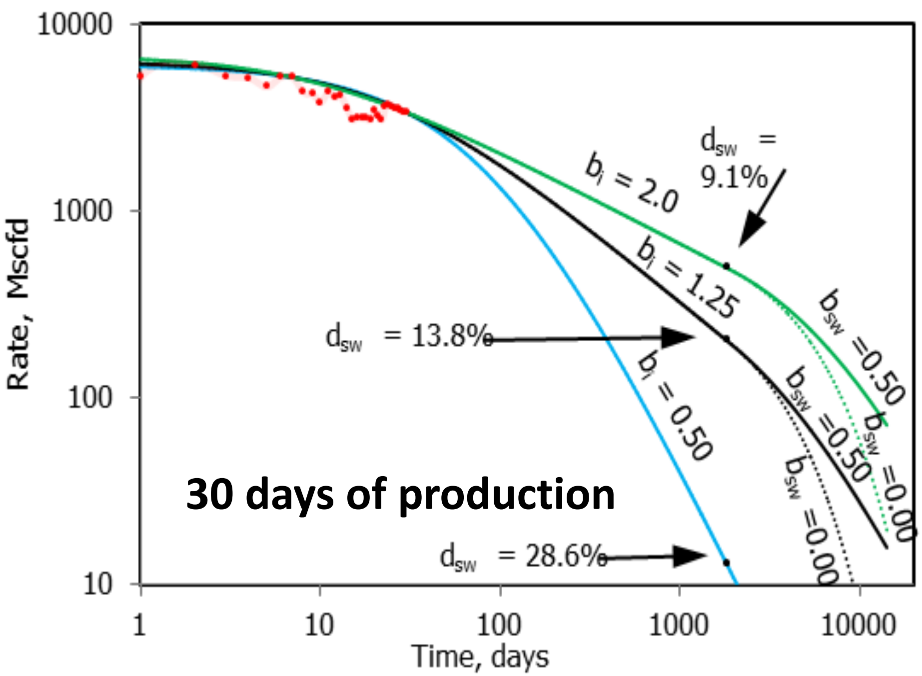
# Numerical Modeling: Key Points

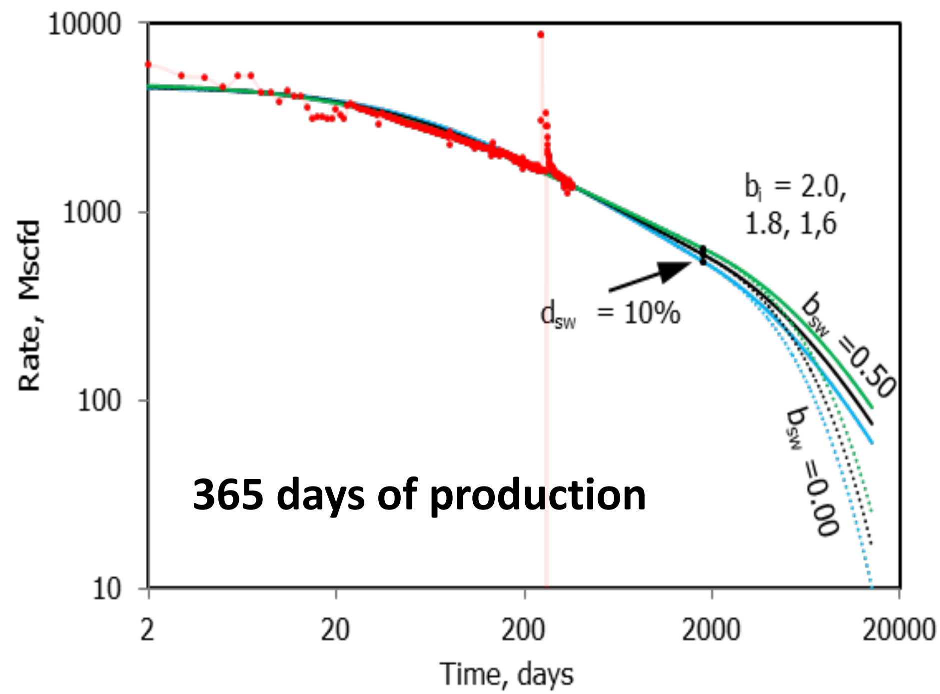
- Essential tool when simpler methods fail the "physics test"
- Practical tool when combined with productivity enhancement tools (PETs)
- Requires properly constructed grids to capture transient flow behavior between stages/wells
- Chapter provides several application examples:
  - Calculating EURs regardless of whether drainage-boundary-dominated behavior is observed
  - Optimizing the number and size of propped fractures for a single well
  - Optimizing well spacing

# Chapter 9: Quantifying Uncertainty

- Chapter focuses on uncertainties encountered in forecasting and how to address them
- There are multiple methods to express, quantify, and reduce forecast uncertainty
  - For single wells
  - For multiwell groups
- The best way to reduce forecast uncertainty is to make small improvements to those steps that are most often applied.
  - However, minimizing uncertainty will not eliminate uncertainty

# Example of Forecast Uncertainty Reduction w/Time




- After 30 days
  - Initial b factor: 0.5-2
  - Dsw: 9-29%
  - Final b factor: 0-0.5
  - EUR: 0.5-3.5 BCF
  - Reservoir modeling and/or analogs are needed to reduce uncertainty
- After 365 days
  - Initial b factor: 1.6-2
  - Dsw: 10%
  - Final b factor: 0-0.5
  - EUR: 3.8-4.9 BCF
  - Transition to BDF: 1,800 days

# Quantifying Uncertainty: Key Points

- Focus efforts on variables that have the most impact and eliminate data outliers
- Use P10/P90 ratios, probit plots, trumpet charts, and stat. type wells to quantify data uncertainty
- Use multiple plots to display data, understand trends, identify flow regimes, and check models
- Use a group-level forecast to validate well-level forecasts where wells are in communication
- Note when sample size is too small or coefficients of determination are too low to be meaningful

# Chapter 10: Example Problems

- Methods presented in Monograph 4 are applied to three real data sets
  - Bakken oil, Eagle Ford condensate, Marcellus gas
- A similar approach is used for each
  - Assessment of data quality
  - Construction of diagnostic plots
  - Use of simple models requiring only rate data
  - Performance data analysis using rate/pressure data
  - Numerical simulation
- Purpose is to provide example workflows that readers can modify and apply to their wells

# Linkage with Estimates of Developed Reserves

- Rate-time (DCA) analysis is accepted by company management and industry regulators when used with good engineering judgment
- DCA should be validated with diagnostics
- Overbooking of reserves still occurs due to the lack of understanding of flow regimes
- For a proper analysis, it is critical to utilize both rate and pressure data
- We should focus on building representative analytical and numerical models to provide insights and direction

# Further Assistance…

- SPEE will be holding Monograph 4 training sessions in the near future— two are now scheduled:
  - 4 October, Denver, John Seidle
  - 14 November, Houston, John Lee
- Check the SPEE website periodically for more information and other offerings later

Thank You!

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