Beyond Decline Curves: Life-Cycle Reserves Appraisal Using an Integrated Work-Flow Process for Tight Gas Sands

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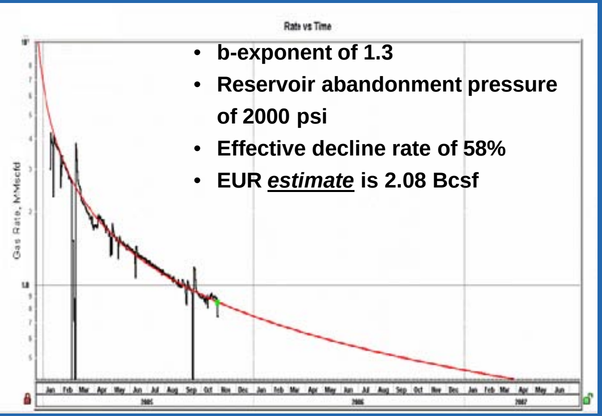
Methods of Reserves Estimates

- Arps decline curve method
- Calculating original volumetric gas-in-place and applying a recovery factor to estimate reserves.
- Conventional material balance models to estimate OGIP and applying a recovery factor to estimate reserves
- History match well and/or field production with a reservoir simulator, and estimate future production and reserves with the calibrated model.

Arps Methodology & Assumptions

- **Methodology for Estimating Gas Reserves**
  - Plot gas production rate against time & history match existing production using Arps models
  - Extrapolate history-matched trend into future and estimate reserves using economic cutoffs



- **Assumptions Implicit in Using Arps Equations**
  - Extrapolation of best-fit curve through existing data is accurate model for future trends
  - There will be no significant changes in current operating conditions that might affect trend extrapolation
  - Well is producing against constant bottom hole flowing pressure
  - Well is producing from unchanging drainage area, *i.e.*, the well is in boundary-dominated flow

Estimating Arps Decline Curve Parameters

1) $$q(t) = \frac{q_i}{\left(1 + bD_i t\right)^{1/b}}$$

D_i is the initial decline rate, q_i is the gas flow rate, and b is the Arps decline curve constant or exponent.

2) $$q(t) = \frac{q_i}{e^{D_i t}} = q_i e^{-D_i t}$$

The exponential decline equation can be derived from Equation (1) with a b-exponent of zero

3) $$q(t) = \frac{q_i}{\left(1 + D_i t\right)}$$

The harmonic decline is the special case of Equation (1) when the b-exponent equals one

4) $$q(t) = \frac{q_i}{\left(1 + bD_i t\right)^{1/b}}$$

The hyperbolic decline which can be derived from Equation (1) when b is between 0 and 1.0

- The value of b determines the degree of curvature of the semilog decline, ranging from a straight line with b=0 to increasing curvature as b increases.
- Values of b greater than one reflected transient or transitional rather than true boundary-dominated flow.

Problem Statement

- Reserves in tight gas sands typically evaluated using Arps decline curve technique
- Reservoir properties preclude accurate reserve assessments using *only* decline curve analysis
- Errors most likely during early field development period before onset of boundary-dominated flow

Paper Objectives

- Develop reserves appraisal work-flow process to reduce reserve estimate errors in tight gas sands

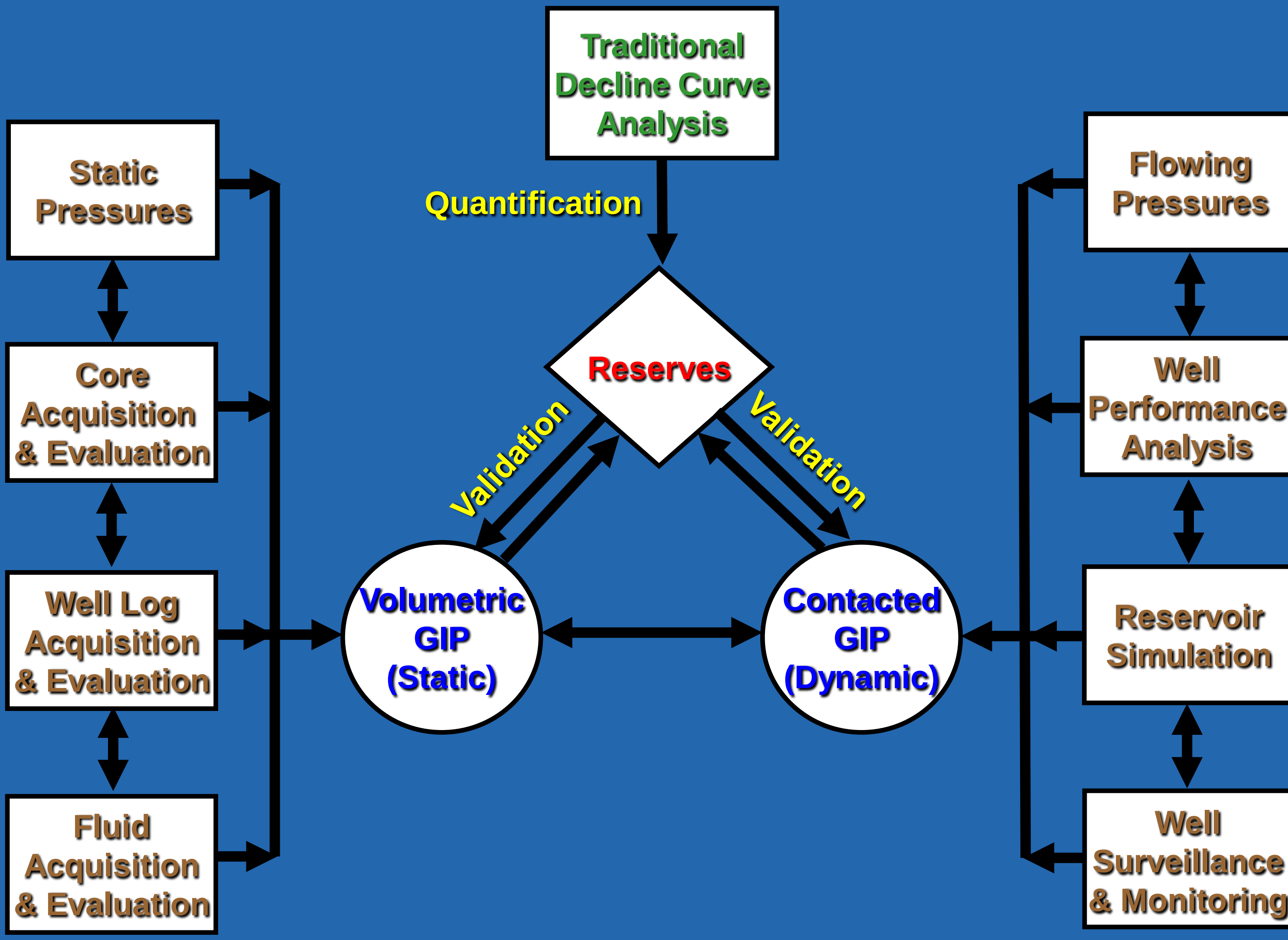
- Work-flow process model should:
  - Allow continuous but reasonable reserve adjustments over entire field development life cycle
  - Prevent unrealistic (either too low or too high) reserve bookings during any field development phase
  - Be applicable during early development phases when reserve estimate errors are most likely and are largest

Work-Flow Process Model Overview

- **Model Attributes**
  - Captures characteristic tight gas sand flow and storage properties
  - Incorporates comprehensive data acquisition and evaluation programs
  - Integrates static and dynamic data types (*i.e.*, engineering, geological, and petrophysical) at all reservoir scales

- **Model Hypothesis**
  - Complement rather than replace traditional decline curve analysis with deterministic evaluation program
  - Reduce reserve estimate uncertainties and errors with integrated work-flow process model

Work-Flow Process Diagram

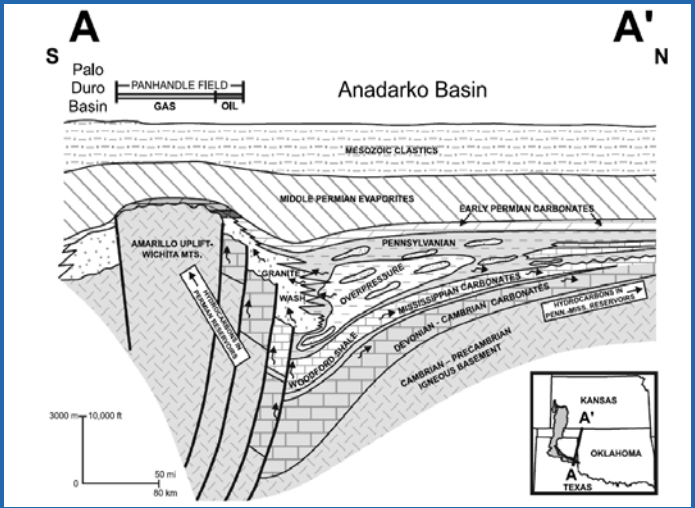


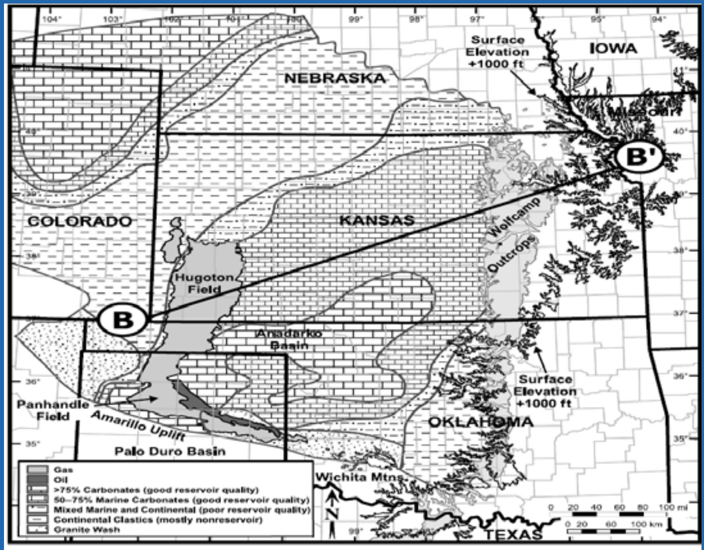
Expected Gas Volumes Relationships

Field Development Stage	Type of Flow Period	Relationships Among Gas Volumes
Early	Transient	G_p < CGIP << EUR < VGIP
Intermediate	Transitional	G_p < CGIP < EUR < VGIP
Late	Boundary-Dominated	G_p < EUR < CGIP ≤ VGIP
Abandonment	Boundary-Dominated	G_p < EUR ≤ CGIP ≤ VGIP

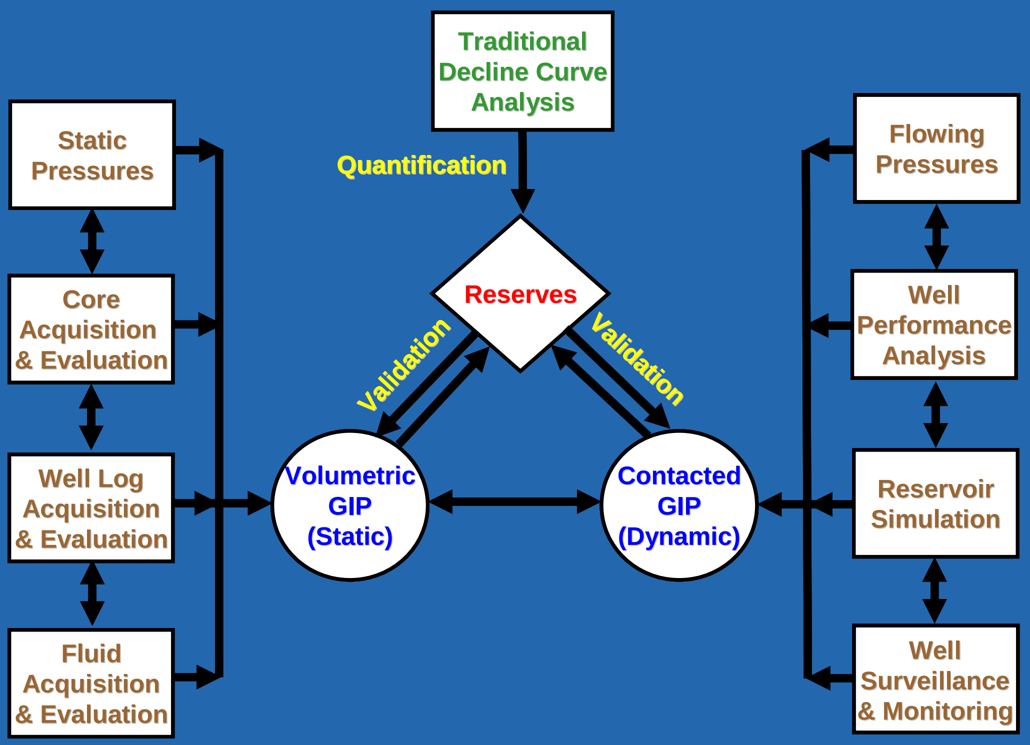
Example Application of Work-Flow Process Model

- Granite Wash of TX Panhandle
- 2000'+ Gross Interval
- Sand Geometry: fan - delta
- Mixed lithology and layered
- Porosity range: 0% - 15%
- Permeability: 0.0001 - 0.1 mD
- Pressure gradient ~ 0.47 psi/ft
- Multiple frac stages required





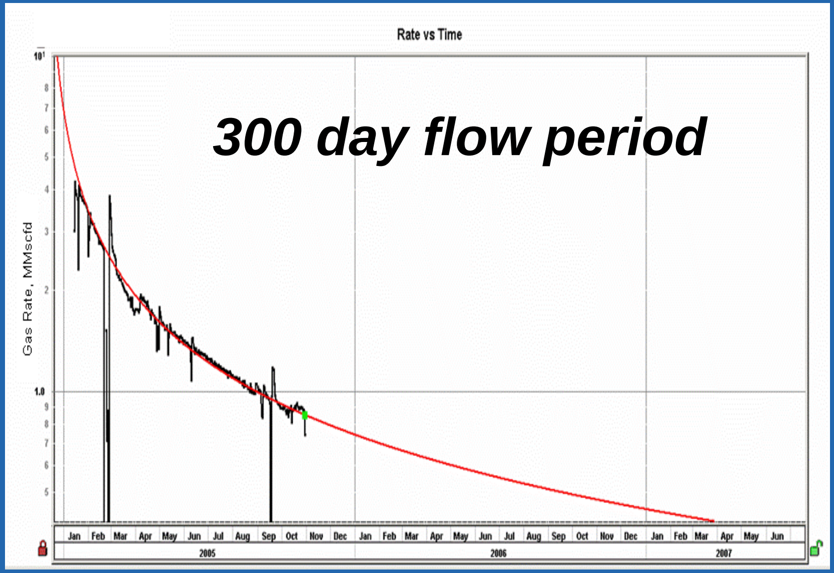
Application of Work-Flow Process Model



Reserves Quantification Stage

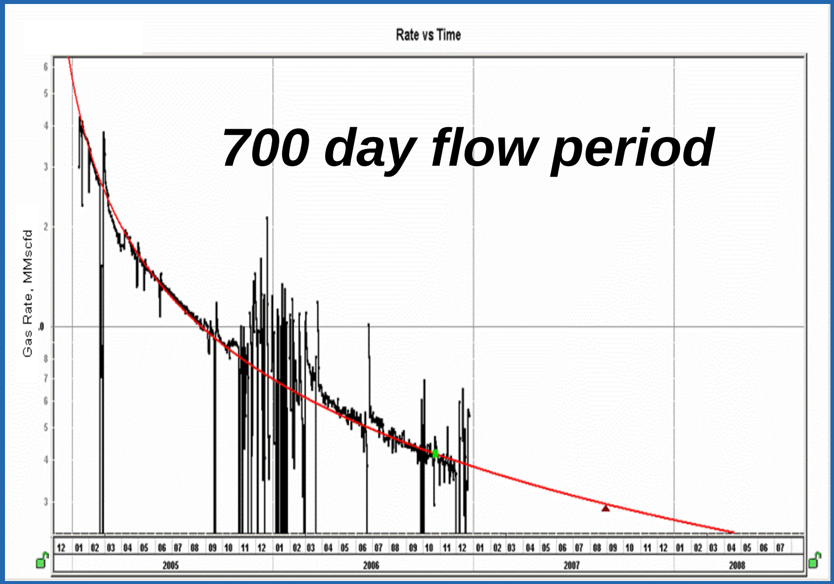
Traditional Decline Curve Analysis

Decline Curve Analysis; 300 & 700 Day



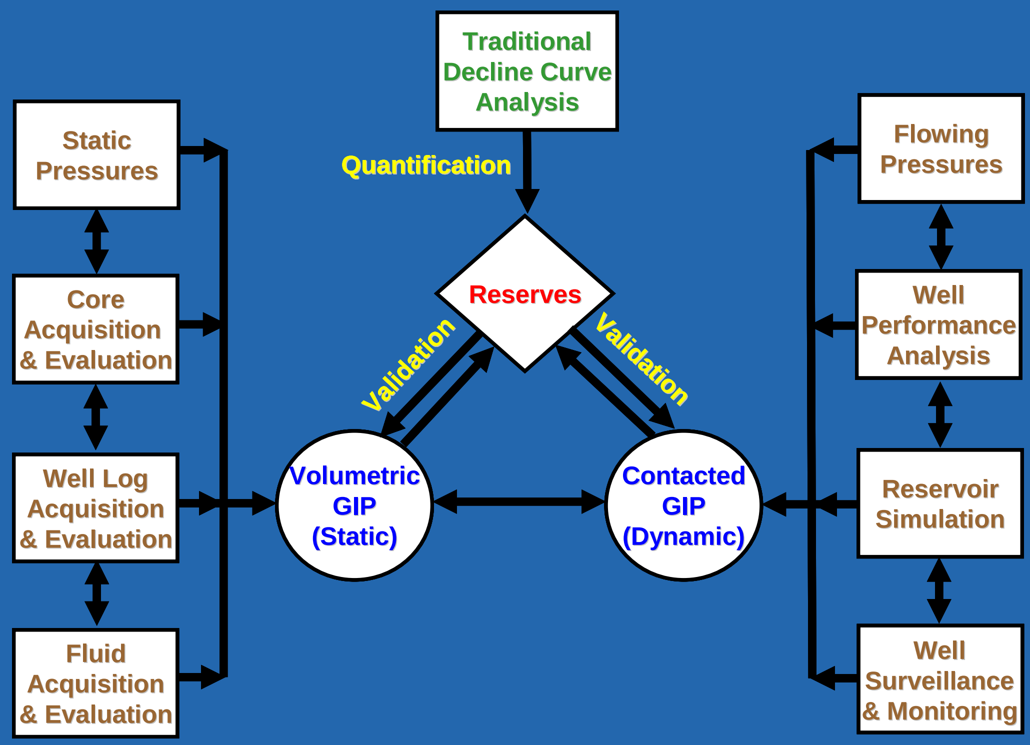
Abandonment pressure of 2000 psi

- b-exponent of 1.3
- Effective decline rate of 58%
- EUR ***estimate*** is 2.08 Bcsf
- Gp = 0.465 Bcsf gas, 15.5 Mbbl oil , and 27.1 Mbbl water.



- b-exponent of 1.0
- Effective decline rate of 38.8
- EUR ***estimate*** is 1.359 Bcsf
- Gp = 0.69 Bscf gas, 21.3 Mbbl oil, and 33.4 Mbbl water

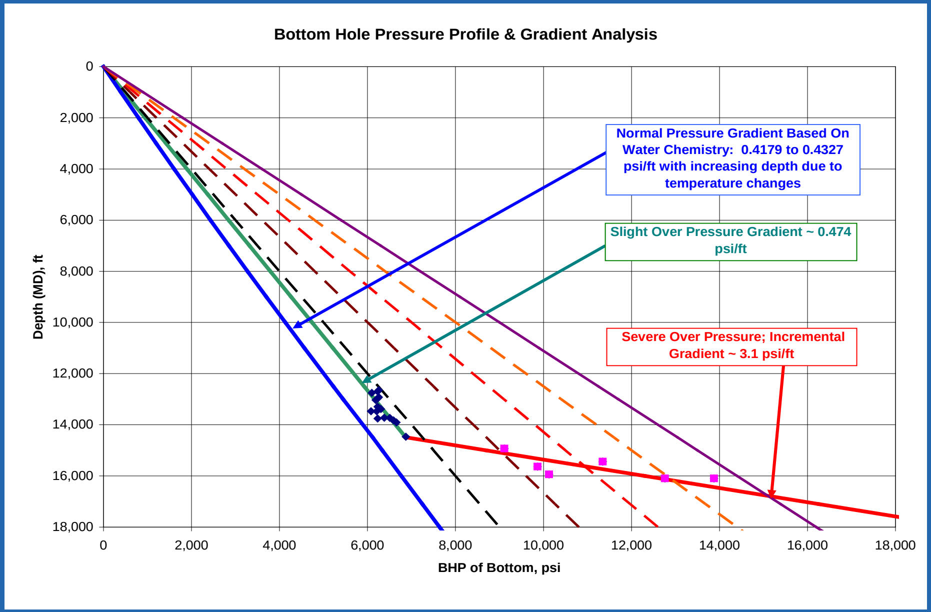
Application of Work-Flow Process Model



Reserves Validation Stage

Computing Volumetric Gas-in-Place (VGIP)

Key Data Requirements

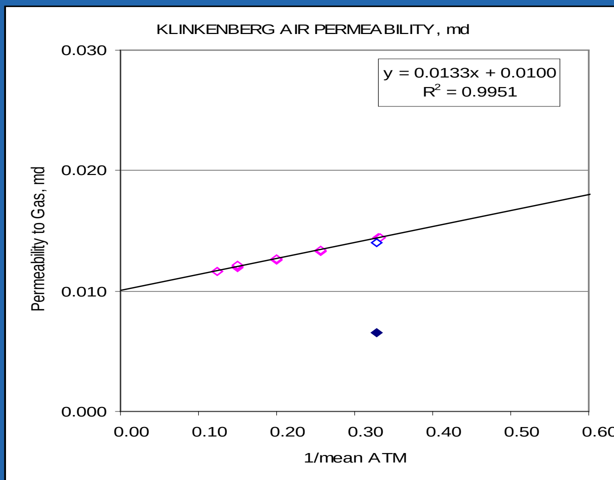


- Well and Reservoir Surveillance & Monitoring Program
  - Initial BHPs required to compute VGIP
  - Initial and subsequent BHPs required to monitor flow periods during field development and compute CGIP

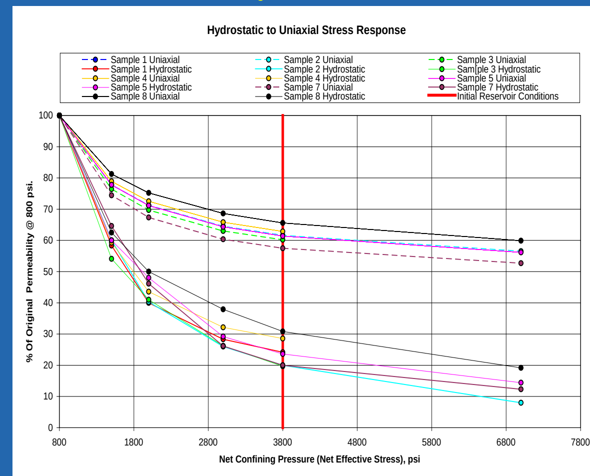
- Core Acquisition Programs
  - Recommend core samples be taken early in field development
  - Also recommend conventional whole core rather than sidewall cores taken through complete vertical sections
  - Use drilling fluids to minimize mud invasion and displacing connate water

Core, Fluid & Log Programs

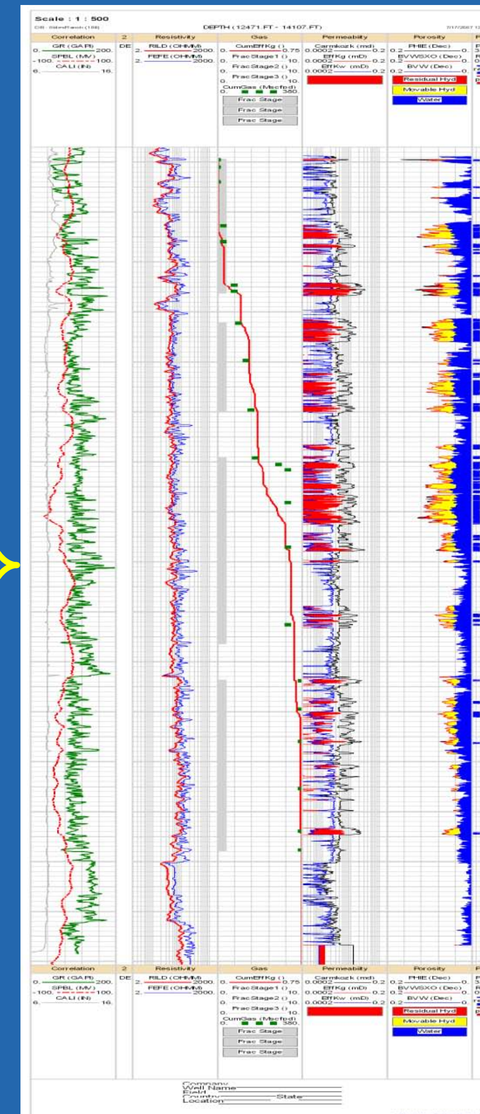
Absolute Permeability



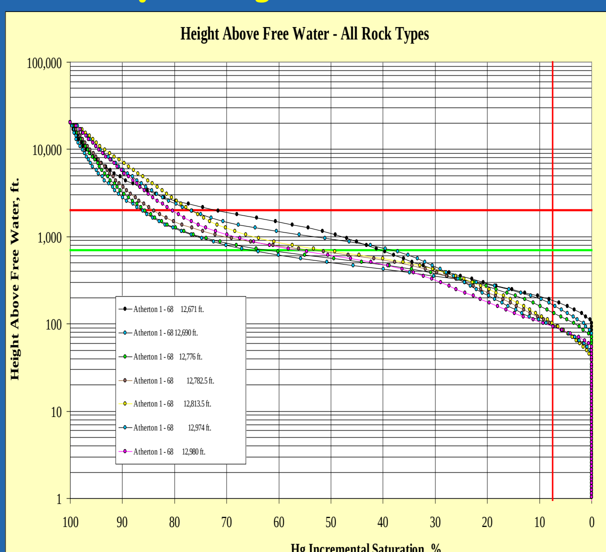
Stress Dependent P&P



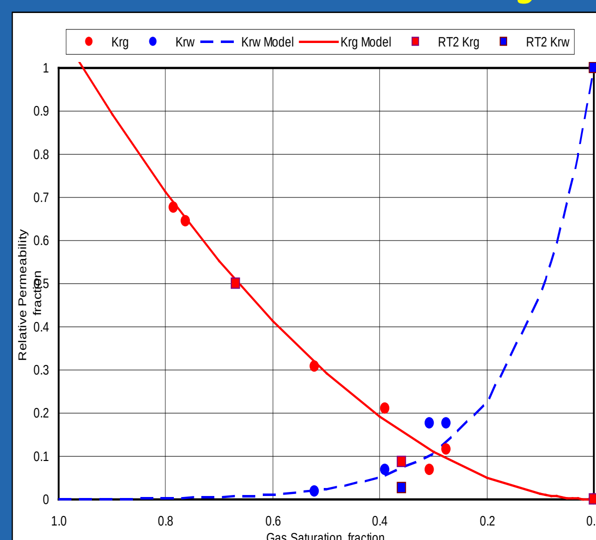
Log Profiles; Sw, ϕ, k



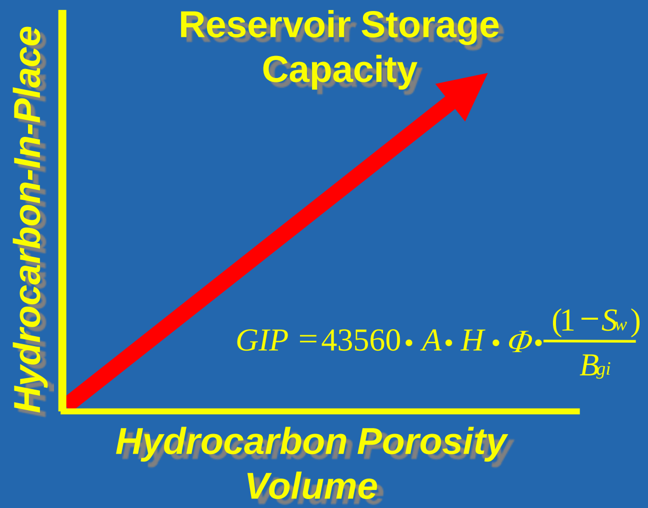
Capillary Pressure



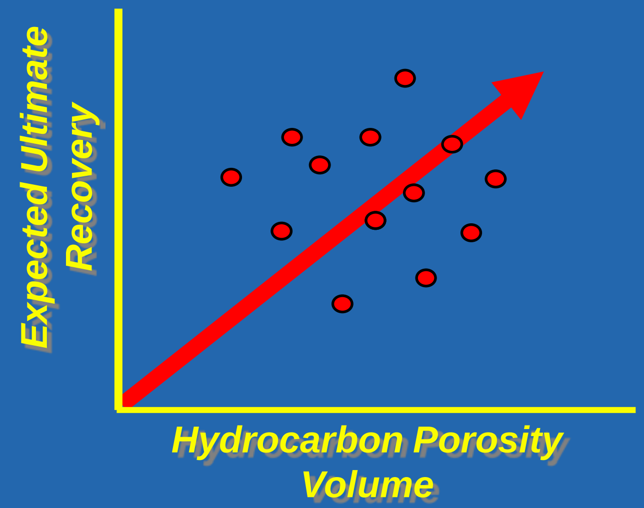
Relative Permeability

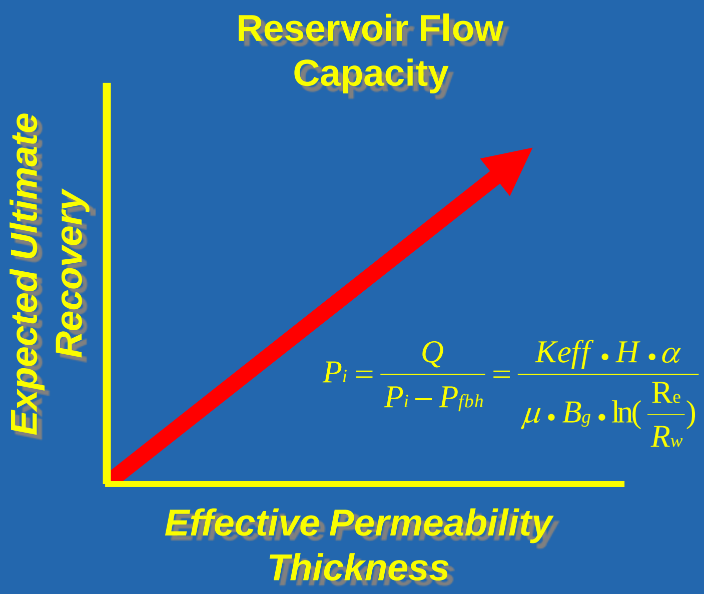


Storage and Flow Capacity Assumptions

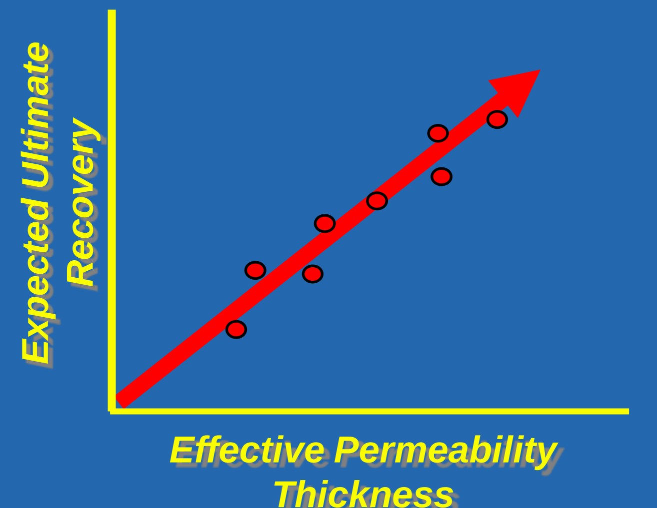


Traditional methods attempt to correlate storage capacity to EUR with little success



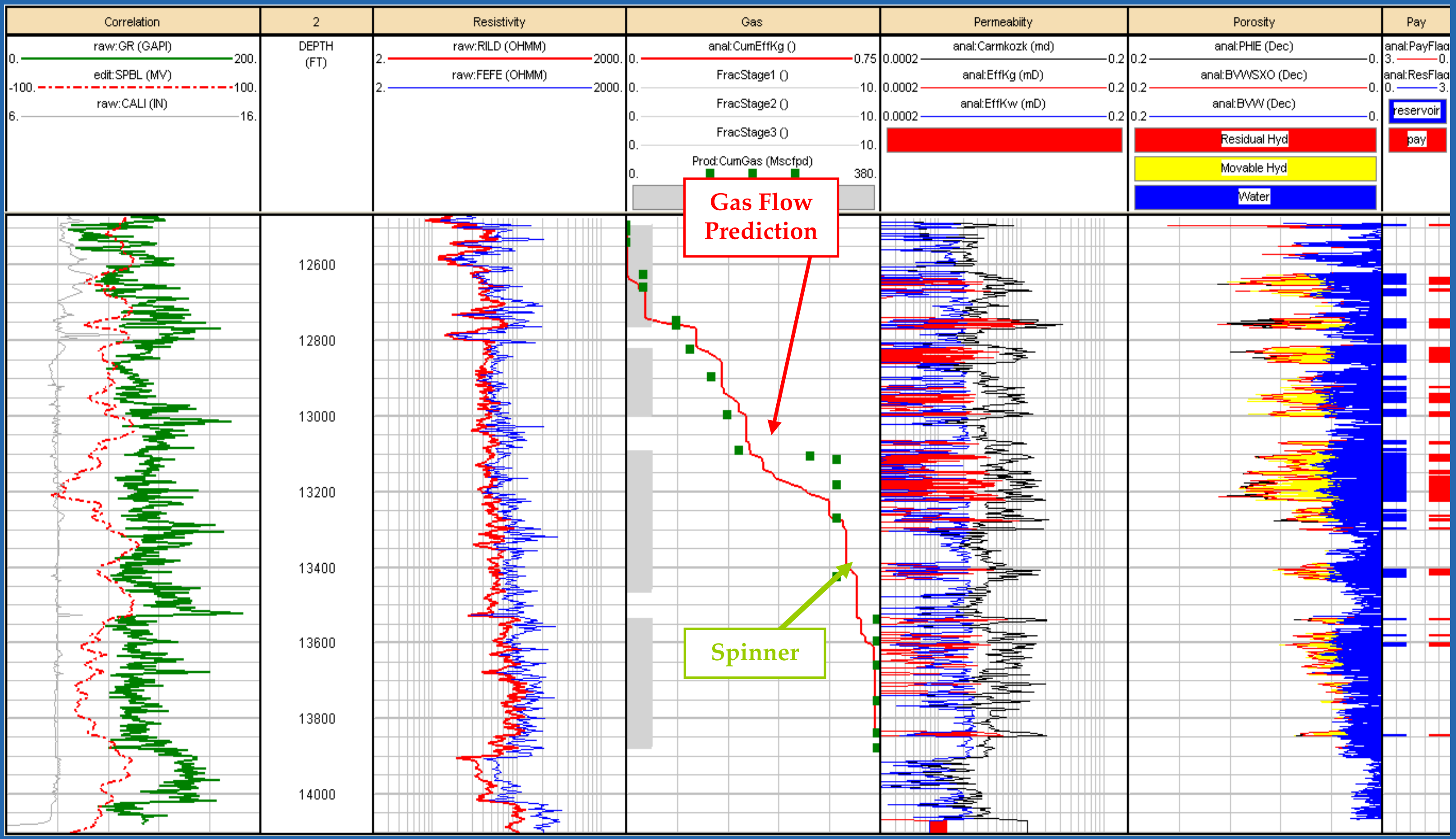


Advanced analysis method correlates flow capacity to EUR



Dynamically Calibrated Net Pay Thickness

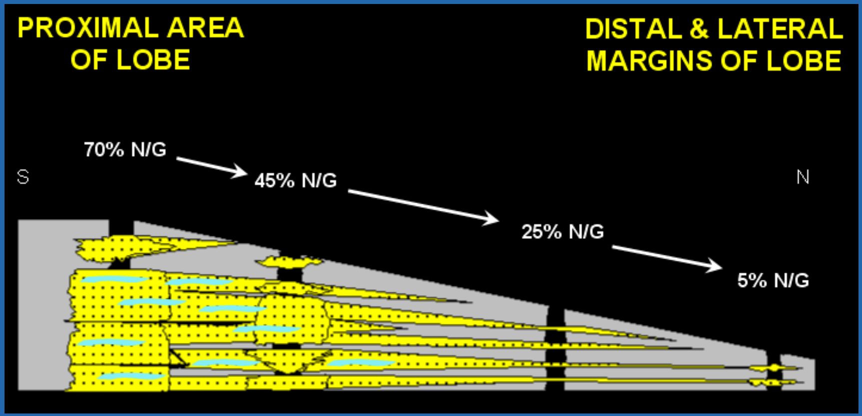
- Integrate log-based Keff, then
- Match log-based Keff to recorded PL gas in-flow, by
- Altering net pay threshold criteria (e.g. ϕ, Sw, Keff)



Net Pay Layering Effects on VGIP

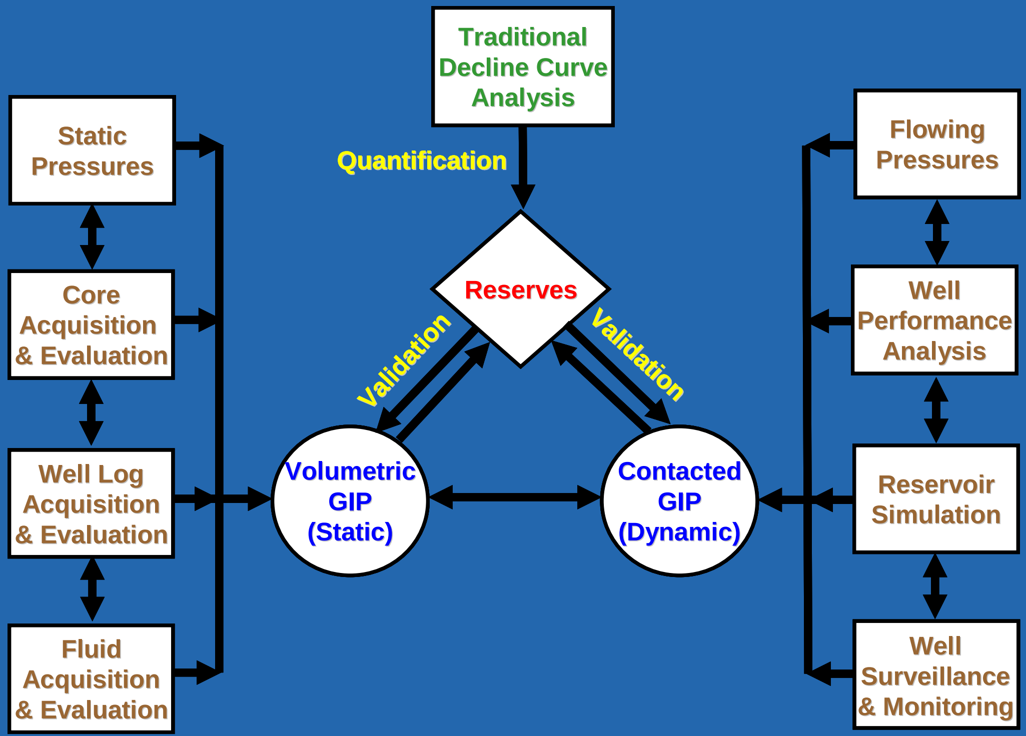
Nested Cutoffs:	Vcl < 25%	Phi > 6%	Sw < 60%							
Gross Interval	Gross Sand Thickness	Net Porous Sand Thickness	Net Pay Thickness	Gross Reservoir to Gross Interval	Net Porous Reservoir to Gross	Net Pay Reservoir to Gross Interval	Average Porosity	Average Water Saturation	Average Effective Peremability to Gas	Pore Pressure
ft	ft	ft	ft				v/v	v/v	mD	psi
116	17.052	6.5	2	0.147	0.056	0.017	0.138	0.341	0.001964	5946.804
116.5	92.035	36.5	21.5	0.79	0.313	0.185	0.104	0.4	0.002478	6001.9065
79.5	45.7125	24.5	21.5	0.575	0.308	0.27	0.096	0.311	0.006914	6048.3585
224	189.504	96.5	70.5	0.846	0.431	0.315	0.088	0.458	0.002111	6120.288
506.5	396.083	157.75	107	0.782	0.311	0.211	0.089	0.418	0.003047	6293.4165
537.5	389.6875	23	22	0.725	0.043	0.041	0.067	0.472	0.003213	6540.8445
1580	**1130.074**	**344.75**	**244.5**	**0.715**	**0.218**	**0.155**	**0.089**	**0.42**	**0.003073**	**6158.603**

- The reduction in gross to net ratios is a direct result of the loss of porosity and permeability by diagenesis and diminishes the connected or effective drainage area
- Well spacing is commonly used as the area for estimating initial VGIP (80 ac)
- VGIP was updated ~ 12.7 Bcsf by multiplying the net pay/gross interval ratio by the initial spacing



$$VGIP = 43560 \cdot A \cdot H \cdot \phi \frac{(1-Sw)}{B_g}$$

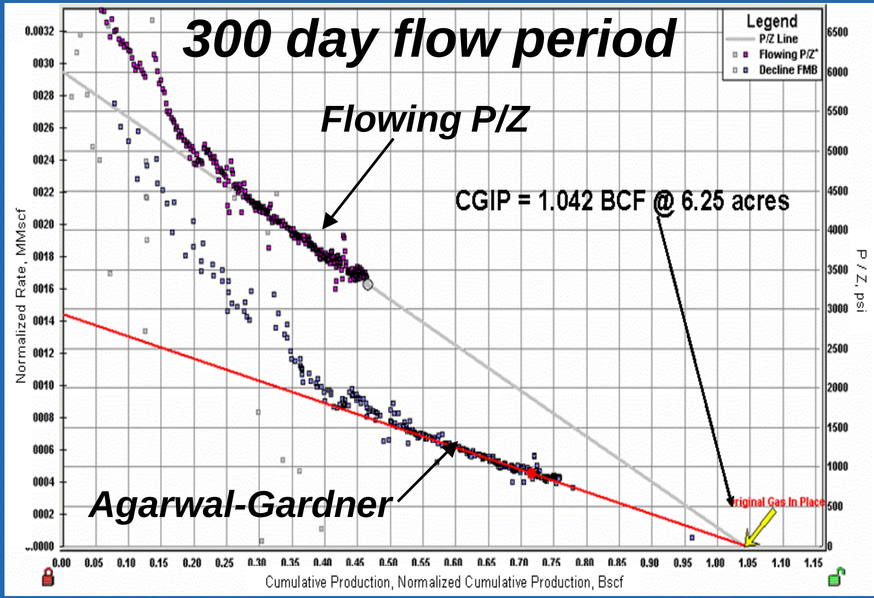
Application of Work-Flow Process Model

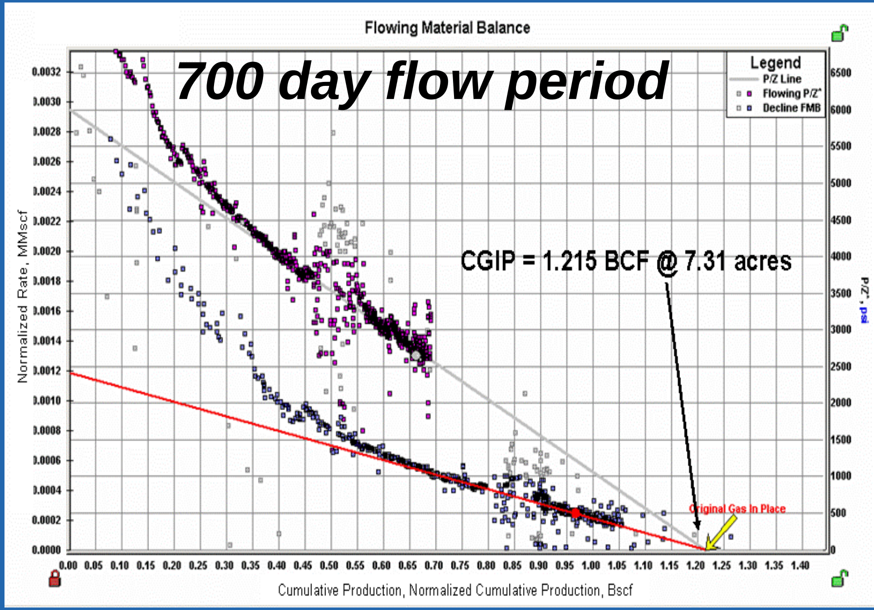


Reserves Validation Stage

Computing Contacted Gas-in-Place (CGIP)

Flowing Material Balance Analysis





Computing Contacted GIP

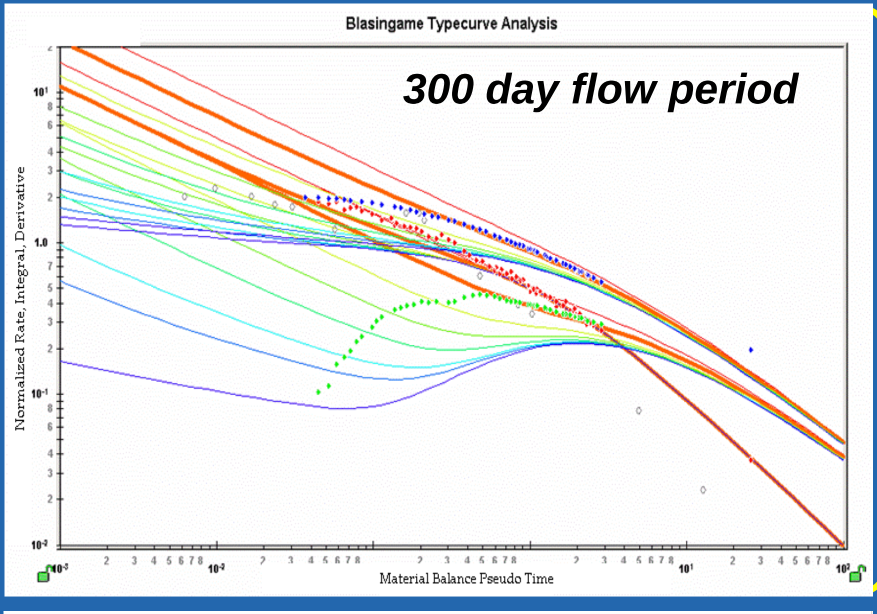
300 Day Flow Period

- CGIP = 1.042 Bscf
- Contacted area = 6.27 acres

700 Day Flow Period

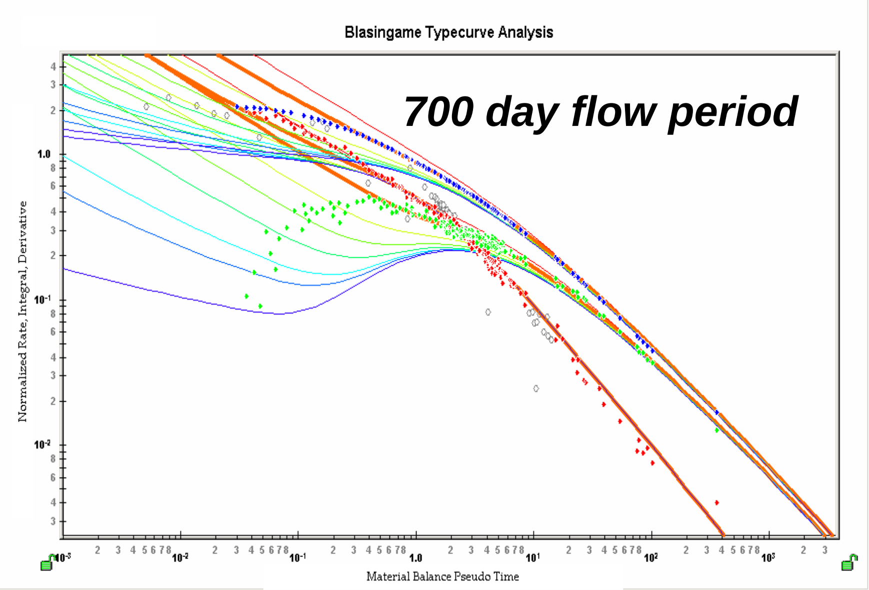
- CGIP = 1.215 Bscf
- Contacted area = 7.31 acres

Rate Transient Analysis; CGIP, k, F_h



300 Day Flow Period

- **CGIP = 1.038 Bscf**
- **Contacted area = 6.25 ac**
- **Keff = 0.0043 mD**
- **F_h = 147 ‘**



700 Day Flow Period

- **CGIP = 1.2 Bscf**
- **Contacted area = 7.25 ac**
- **Keff = 0.004 mD**
- **F_h = 158 ‘**

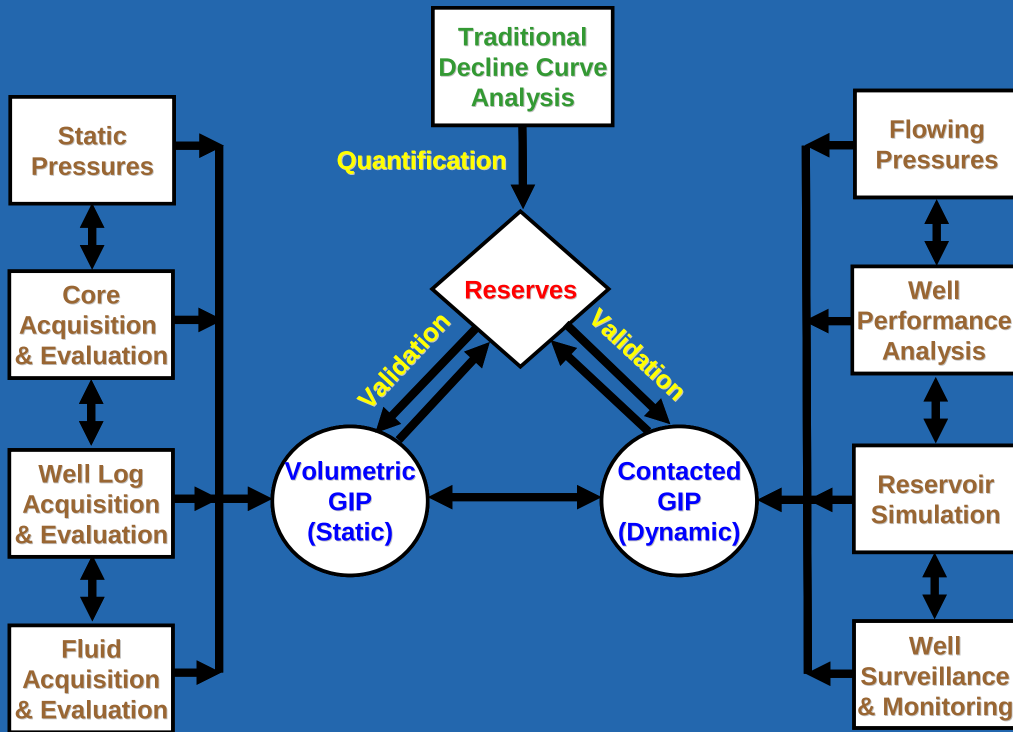
Rate Transient Analysis Summary

300 Day Flow Period: Analysis Type	CGIP	Area	Permeability	Frac Half Length
	Bscf	acres	mD	ft
Blasingame - Fracture	1.04	6.25	0.0043	147.134
Agarwal-Gardner - Fracture	1.03	6.2	0.002	293.305
Transient: Finite Conductivity	1.05	6.33	0.0027	262.505
NPI: Fracture	1.05	6.33	0.0022	296.211
Flowing Material Balance	1.04	6.27		
Averages	**1.042**	**6.276**	**0.0028**	**249.78875**

700 Day Flow Period: Analysis Type	CGIP	Area	Permeability	Frac Half Length
	Bscf	acres	mD	ft
Blasingame - Fracture	1.2	7.25	0.004	158.556
Agarwal-Gardner - Fracture	1.21	7.31	0.0019	318.427
Transient: Finite Conductivity	1.22	7.32	0.0039	282.365
NPI: Fracture	1.21	7.25	0.0021	317.138
Flowing Material Balance	1.22	7.31		
Averages	**1.212**	**7.288**	**0.002975**	**269.1215**

- CGIP increases by 20%
- Contacted area also increases
- Fracture half length increases
- The core-log model effective permeability of 0.0031 mD is very close to the average decline type-curve solution of 0.0029 mD.

Application of Work-Flow Process Model



Reserves Validation Stage

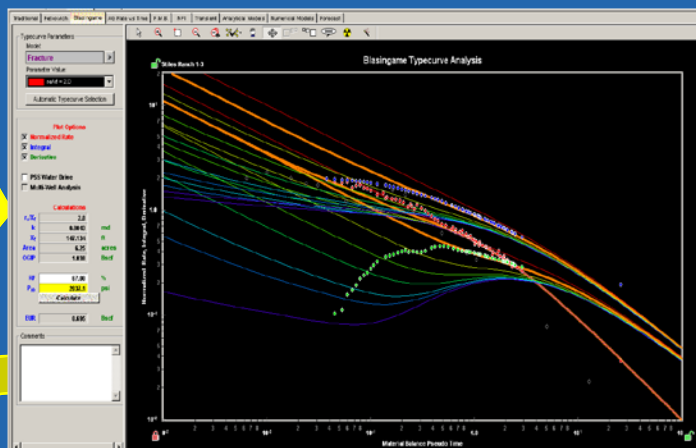
Reservoir Simulation; Estimation of Drainage Area &EUR

Reservoir Simulation Workflow

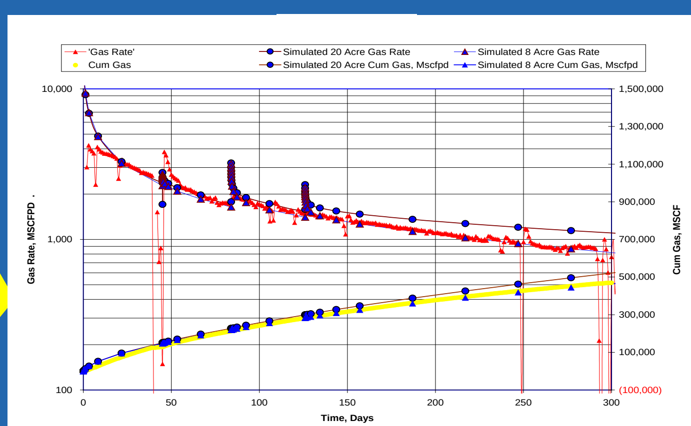
I

	Net	Av Phi	Av Sw	Av EKg	Pore Pressure
				Ari	psi
	2	0.138	0.341	0.001964	5946.804
	21.5	0.104	0.4	0.002478	6001.9065
	21.5	0.096	0.311	0.006914	6048.3585
	70.5	0.088	0.458	0.002111	6120.288
	107	0.089	0.418	0.003047	6293.4165
	22	0.067	0.472	0.003213	6540.8445
All Layers	**244.5**	**0.089**	**0.42**	**0.003073**	**6158.603**

II



III

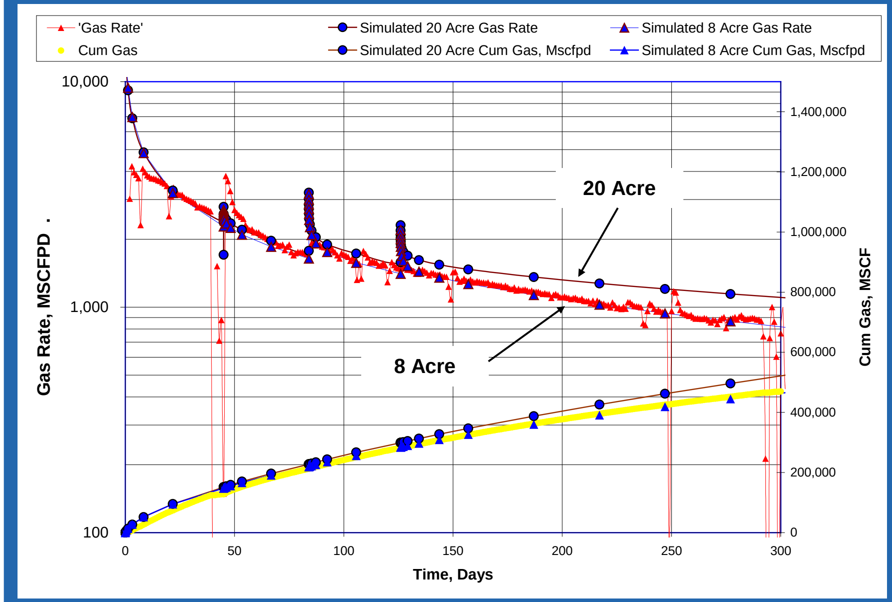


I. Input core-log-based intrinsic reservoir layer properties into RTA

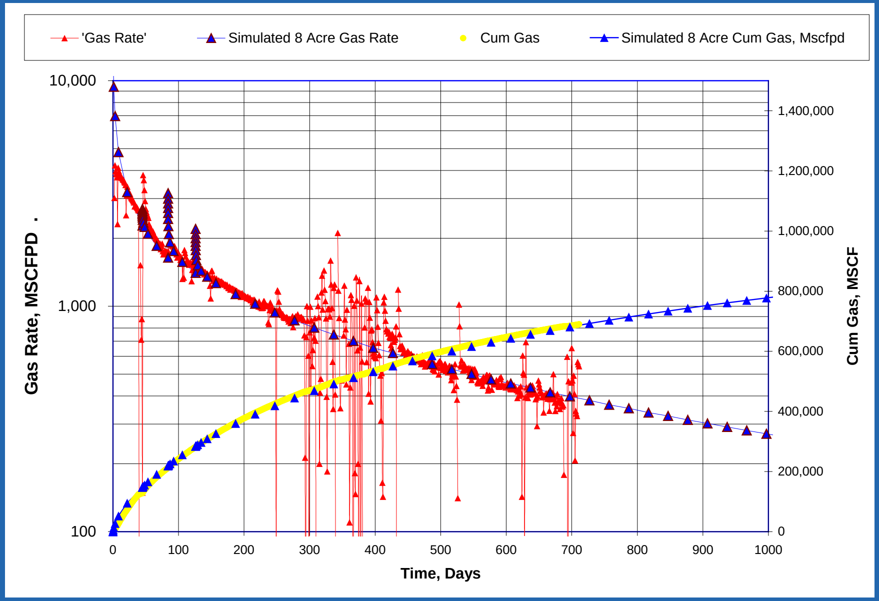
II. Fracture dimensions, conductivity and effective permeability from Rate Transient Analysis

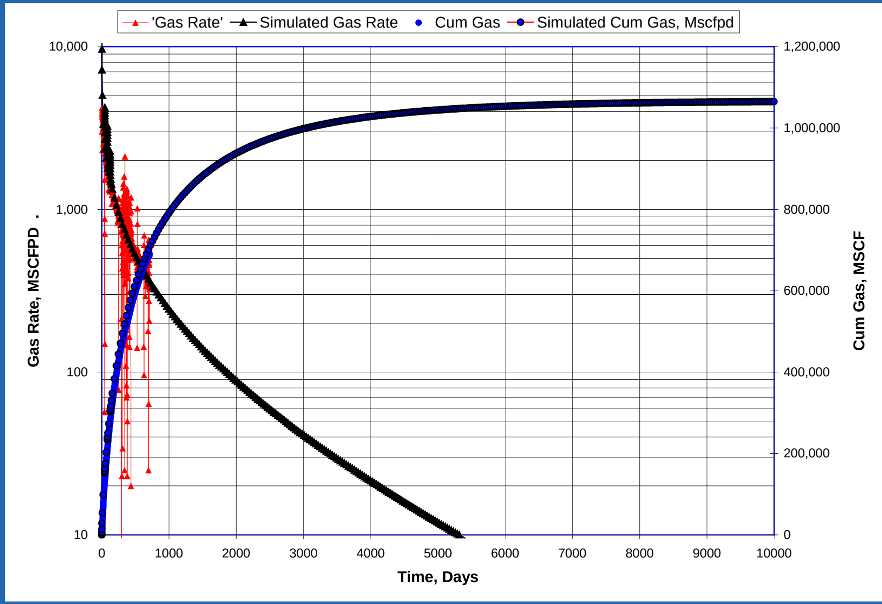
III. Numerical reservoir simulation where the drainage area is controlling variable. All other inputs have been constrained from the core-log and rate transient analysis.

Reservoir Simulation; 300 - 10000 Day



- 8 acre drainage area is the best match
- < 80 acre well spacing
- > than the contacted area observed at the 300 (1.04 ac) and 700 (1.21 ac) day RTA analysis
- EUR = 1.06 Bscf at day 10000





Reservoir Simulation Summary

Flow Period	Drainage Area[1]	Produced Gas, G_p	Contacted Gas-In-Place, CGIP	[2] Expected Ultimate Recovery,EUR	[3] Volumetric Gas-In-Place, VGIP
Days	acres	Bscf	Bscf	Bscf	Bscf
0	80	0			12.754
300	12	0.465	1.04	1.06	1.913
700	8	0.69	1.21	1.06	1.294
10000	8	1.06	1.21	1.06	1.294

[1] Drainage area would not normally change. Down scaling of area is indicative of uncertainty in the knowledge of geology and the impact of pore disconnection due to diagensis on effective drainage area.

[2] EUR estimated from 10000 day numeric reservoir simulation

[3] VGIP is decreasing due to decreases in estimated drainage area.

Flow Period, Days	Fluid Relationships	Type of Flow Period	Stage of Production
300	G_p < CGIP << EUR < VGIP	Transient	Early
700	G_p < EUR < CGIP $\leq$ VGIP	Boundary-Dominated	Late
10000	G_p = EUR $\leq$ CGIP $\leq$ VGIP	Boundary-Dominated	Abandonment

Summary & Conclusions

- Developed reserves appraisal work-flow process specifically for tight gas sands
- Work-flow process
  - Designed specifically to incorporate tight gas sand production characteristics
  - Intended to complement rather than replace traditional decline curve analysis
  - Integrates both static and dynamic data with appropriate evaluation techniques

Summary & Conclusions
(continued)

- Work-flow is adaptive process that allows continuous but reasonable reserve adjustments over entire reservoir life cycle

- Process is most beneficial during early field development stages before boundary-dominated flow conditions have been reached and when reserve evaluation errors most likely

Thank You