Recent Decline Models for Resource Plays

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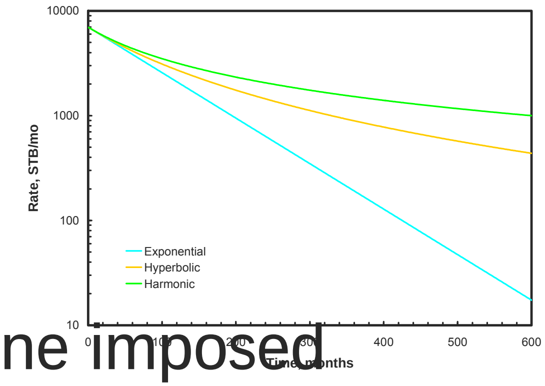
Important Digression First – State of New UH Petroleum Engineering Program

- In third year of undergraduate program
  - About 300 students enrolled
- Evening Masters program continues strong
  - About 80 students enrolled
- PhD research program targets growth
  - Currently ‘housed’ in Chemical Engineering
- Some needs
  - More internships for undergrads, particularly foreign nationals
  - More permanent faculty

Back to Decline Models: We Have a Problem

- Forecasting methods we use in conventional reservoirs may not work well in
  - Tight oil, gas
  - Gas, oil shales
  - Unconventional resources generally

Decline Curves: Approaches



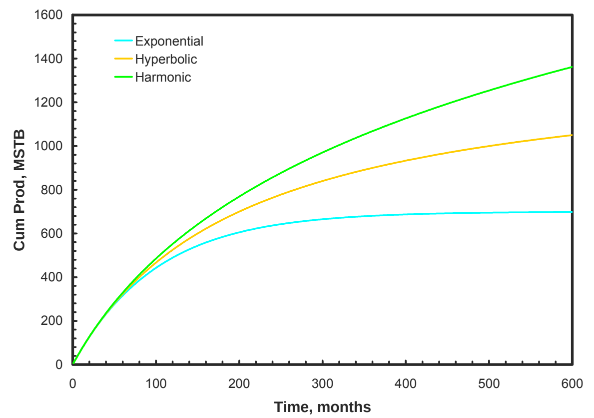
Major categories

- Arps empirical model
  - As originally proposed
  - With terminal exponential decline imposed
- Theoretical/semi-theoretical models
  - Long-duration linear flow
- Recent empirical models
  - Valkó "Stretched Exponential" model
  - Duong model

Critique of Arps Model

- Requires stabilized (not transient) flow for validity

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



- Transient flow likely for most, possibly all, life of well in ultra-low permeability reservoirs
  - Best-fit "*b*" values almost always >1
  - Hyperbolic decline equation derived assuming *b* constant (explicit in Arps' original paper)
  - Extrapolation to economic limit with high *b* value can lead to unrealistically large reserves estimates

Arps: Keeping Reserves Estimates Reasonable

- Common method: Use best-fit "*b*" until predetermined minimum decline rate reached; then impose exponential decline
- Problems
  - Extrapolation with best-fit *b* problematic – apparent "best" *b* decreases continually with time
  - Appropriate minimum decline rate based on observed long-term behavior in appropriate analogy – unavailable in new resource plays

Characteristics of Ideal Decline Model for Low Permeability

- Fits production data during transient flow, continues to fit during stabilized flow
- Forecasts reasonable even with limited historical production data available
- Leads to realistic reserves estimates

Valkó Decline Model – Stretched Exponential (SEDM)

- Empirical model

$$q = q_i \exp\left[-\left(\frac{t}{\tau} \right)^n \right]$$

- ‘Validated’ for wells with both transient and stabilized flow in Barnett Shale (horizontal, multi-stage fractures, Carthage Cotton Valley (vertical, layered, some depleted), others
- Three-parameter model, like Arps
- Forecasts based on limited history unreliable

SPE 109625

Rushing-Blasingame Study: 42 Simulated Cases

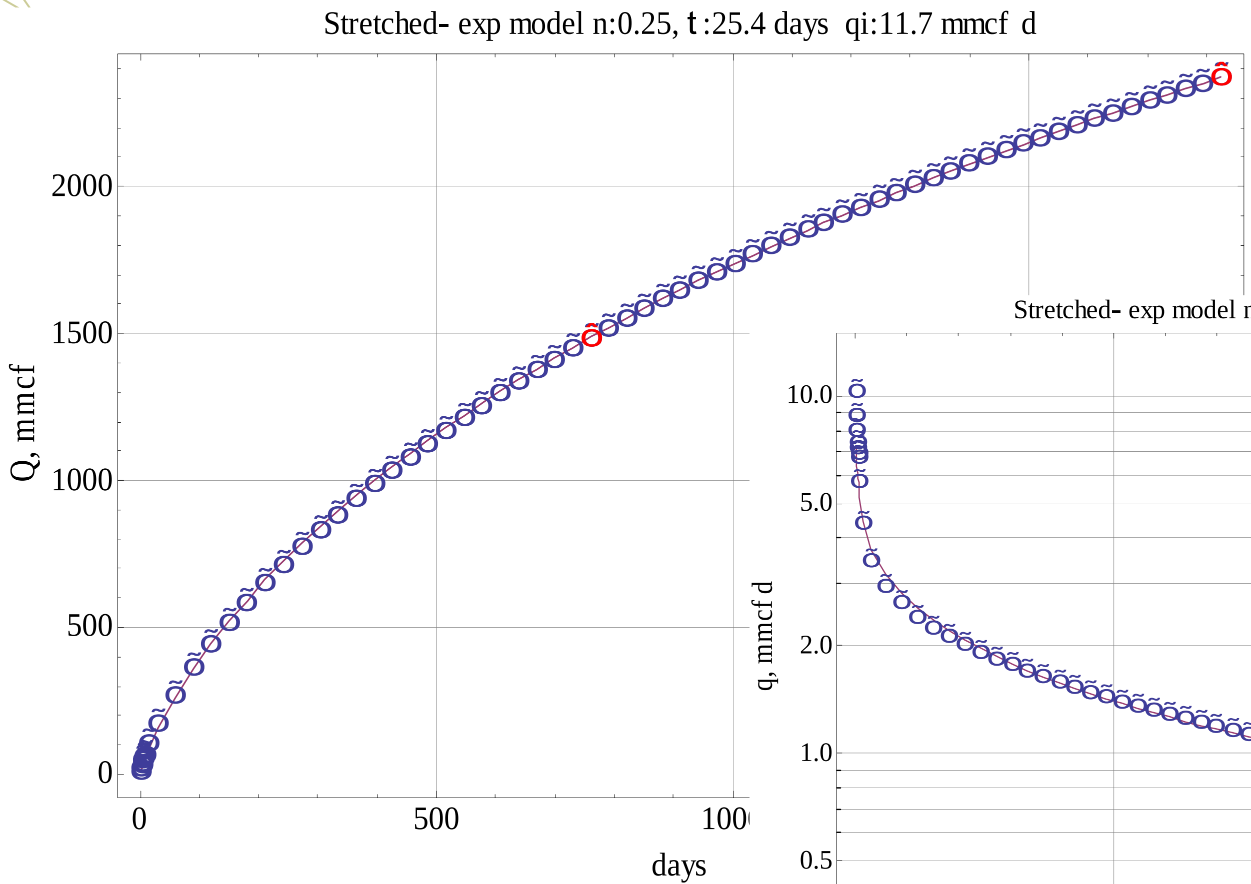
Case No.	Heterogeneity Investigated	Bottomhole Temperature (deg F)	Depth (ft)	Initial Pressure Gradient (psi/ft)	Initial Pressure (psia)	Net Thickness (ft)	No. of Layers	Avg. Eff. Porosity (frac.)	Avg. Eff. Perm. (md)	Avg. Water Saturation (frac.)	Reservoir kv/kh (frac.)	ky/kx (frac.)	Single-Value Layer Properties	Stress-Dependent Reservoir Properties
1 (Base)	Frac Half-Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
27.	Frac Half-Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
28.	Frac Half-Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
29.	Frac Half-Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
30.	Frac Half-Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
31.	Frac Half-Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
32.	Absolute Frac Perm.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
33.	Absolute Frac Perm.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
34.	Absolute Frac Perm.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
35.	Absolute Frac Perm.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
36.	Unequal Wing Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
37.	Unequal Wing Length	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
38.	Unequal Wing Length	[illegible]	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
39.	Unequal Frac Perm.	[illegible]	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
42.	Unequal Frac.Perm.	[illegible]	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
43.	Unequal Frac Perm.	[illegible]	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
55.	Frac w/Stress-Dep Frac Perm, Resin-Coated Sand	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
56.	Frac w/Stress-Dep Frac Perm, Resin-Coated Sand	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
57.	Frac w/Stress-Dep Frac Perm, Bauxite	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No
58.	Frac w/Stress-Dep Frac Perm, [illegible]	400.	18 000.	[illegible]	16 200.	200.	4.	[illegible]	0.00901666	0.364134	0.001	[illegible]	Yes	No
40.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
41.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

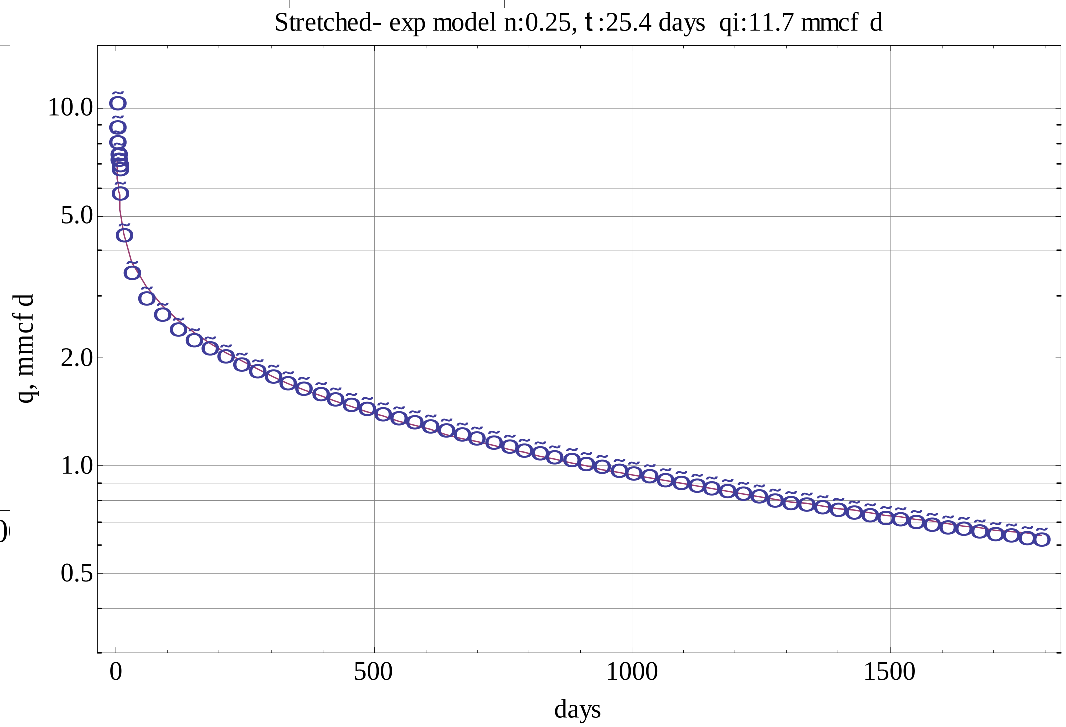
Case No.	Heterogeneity Investigated	Bottomhole Temperature (deg F)	Depth (ft)	Initial Pressure Gradient (psi/ft)	Initial Pressure (psia)	Net Thickness (ft)	No. of Layers	Avg. Eff. Porosity (frac.)	Avg. Eff. Perm. (md)	Avg. Water Saturation (frac.)	Reservoir kv/kh (frac.)	ky/kx (frac.)	Single-Value Layer Properties	Stress-Dependent Reservoir Properties	Fracture kv/kh (frac.)	Effective Fracture Half-Length (ft)	Absolute Fracture Permeabil (md)
1 (Base)	Layering	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.
2.	Layering	400.	18 000.	0.9	16 200.	200.	1.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.
3.	Layering	400.	18 000.	0.9	16 200.	200.	8.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.
4.	Layering	400.	18 000.	0.9	16 200.	200.	16.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.
5.	Reservoir kv/kh	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.01	1.	Yes	No	1.	200.	100.
6.	Reservoir kv/kh	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.1	1.	Yes	No	1.	200.	100.
7.	Reservoir kv/kh	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	1.	1.	Yes	No	1.	200.	100.
8.	Reservoir ky/kx	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	0.5	Yes	No	1.	200.	100.
9.	Reservoir ky/kx	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	0.1	Yes	No	1.	200.	100.
10.	Reservoir ky/kx	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	2.	Yes	No	1.	200.	100.
11.	Reservoir ky/kx	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	10.	Yes	No	1.	200.	100.
12.	Stress-Dep Res Prop	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	Yes	1.	200.	100.
13.	Stress-Dep Res Prop	400.	18 000.	0.9	16 200.	200.	1.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	Yes	1.	200.	100.
14.	Stress-Dep Res Prop	400.	18 000.	0.9	16 200.	200.	8.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	Yes	1.	200.	100.
15.	Stress-Dep Res Prop	400.	18 000.	0.9	16 200.	200.	16.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	Yes	1.	200.	100.
16.	Areal Heterogeneity	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	No	No	1.	200.	100.
17.	Areal Heterogeneity	400.	18 000.	0.9	16 200.	200.	1.	0.0660768	0.00901666	0.364134	0.001	1.	No	No	1.	200.	100.
18.	Areal Heterogeneity	400.	18 000.	0.9	16 200.	200.	8.	0.0660768	0.00901666	0.364134	0.001	1.	No	No	1.	200.	100.
19.	Areal Heterogeneity	400.	18 000.	0.9	16 200.	200.	16.	0.0660768	0.00901666	0.364134	0.001	1.	No	No	1.	200.	100.

Well Spacing (acres)	OGIP (MMscf)	Bottomhole Temperature (deg F)	Depth (ft)	Initial Pressure Gradient (psi/ft)	Initial Pressure (psia)	Net Thickness (ft)	No. of Layers	Avg. Eff. Porosity (frac.)	Avg. Eff. Perm. (md)	Avg. Water Saturation (frac.)	Reservoir kv/kh (frac.)	ky/kx (frac.)	Single-Value Layer Properties	Stress-Dependent Reservoir Properties	Fracture kv/kh (frac.)	Effective Fracture Half-Length (ft)	Absolute Fracture Permeability (md)	Absolute Fracture Conductiv (md-ft)
80.	11 506.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.	50.
40.	5753.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.	50.
160.	23 012.	400.	18 000.	0.9	16 200.	200.	4.	0.0660768	0.00901666	0.364134	0.001	1.	Yes	No	1.	200.	100.	50.

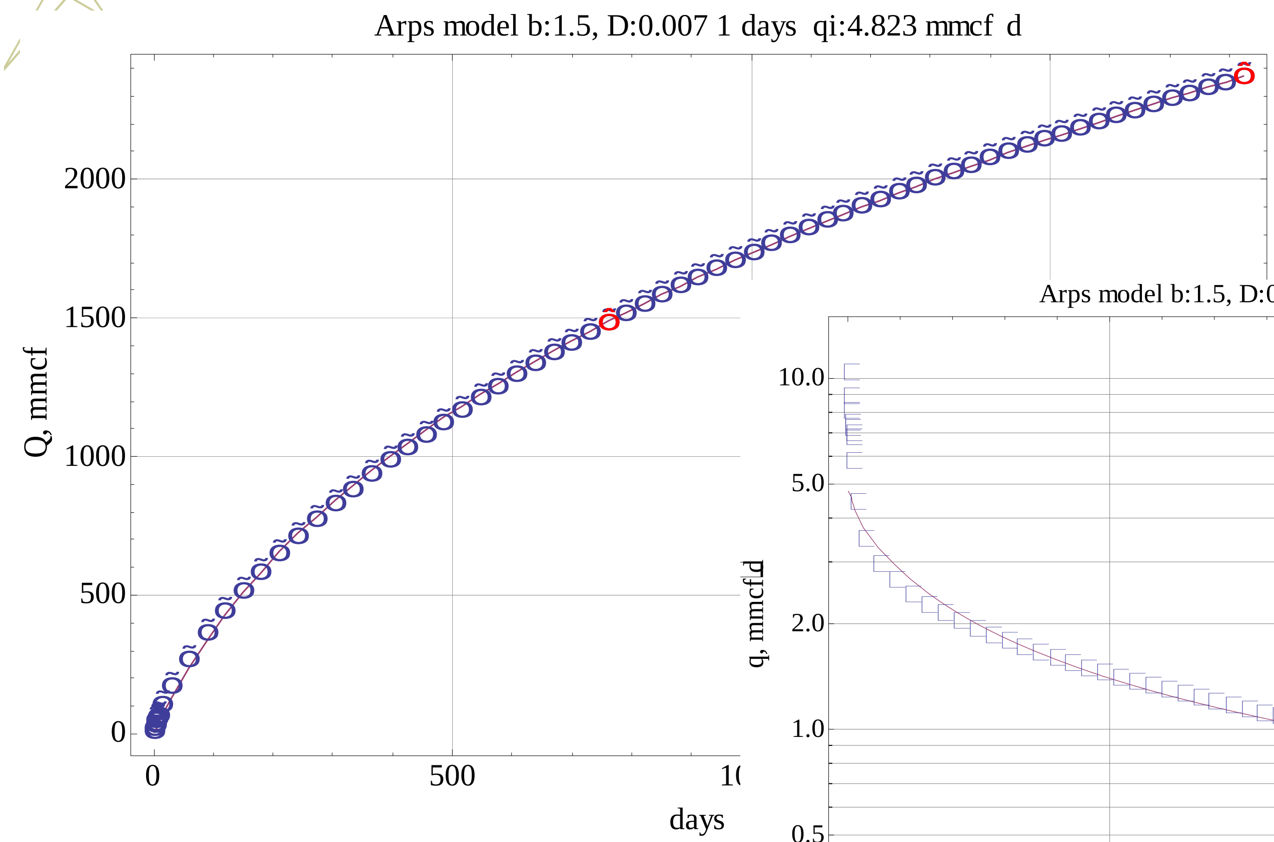
Base Case–Stretched-Exponential Model (based on 5-yr production history)

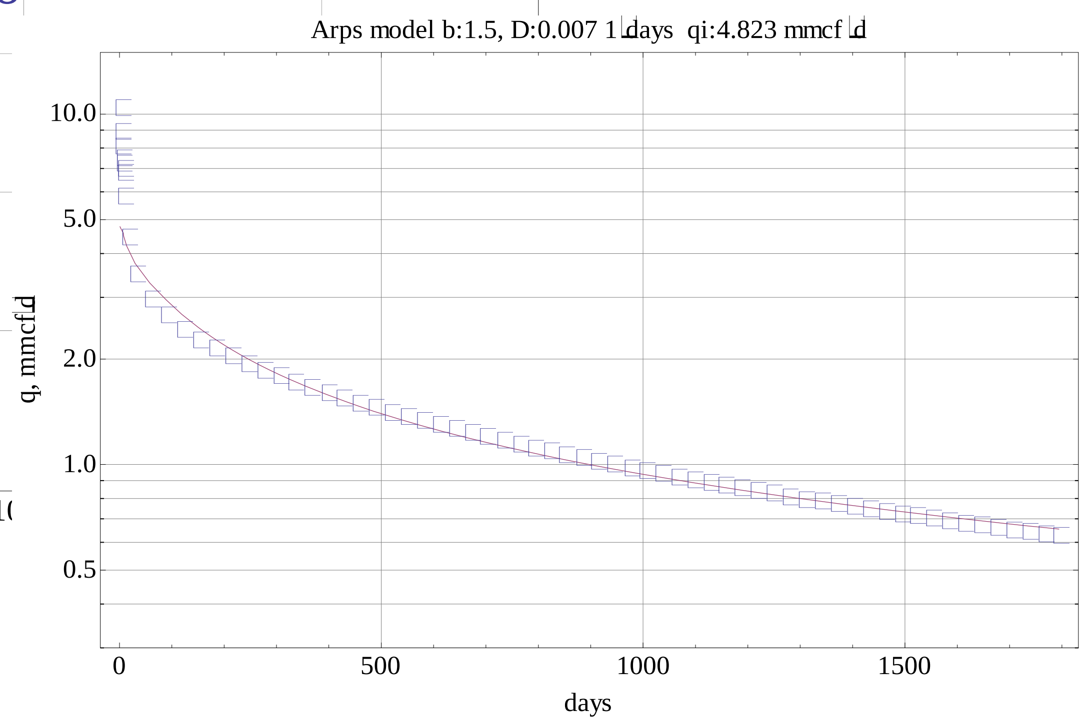
Out[930]=



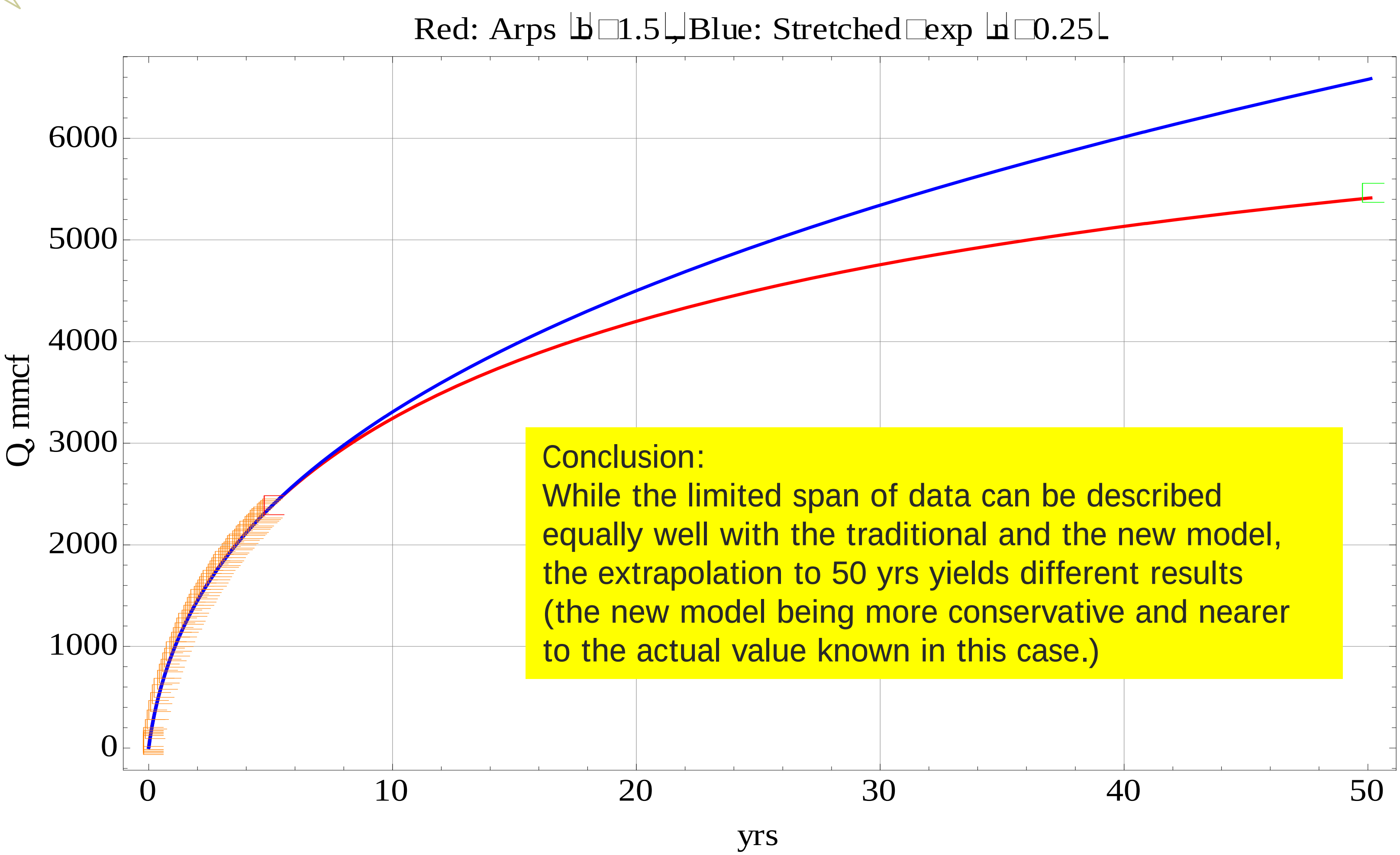


Base Case – Arps Model (based on 5-yr production history) – Just as good a fit





Comparison: 50- Year Forecasts Based on 5-Year Production History



Conclusion:
While the limited span of data can be described equally well with the traditional and the new model, the extrapolation to 50 yrs yields different results (the new model being more conservative and nearer to the actual value known in this case.)

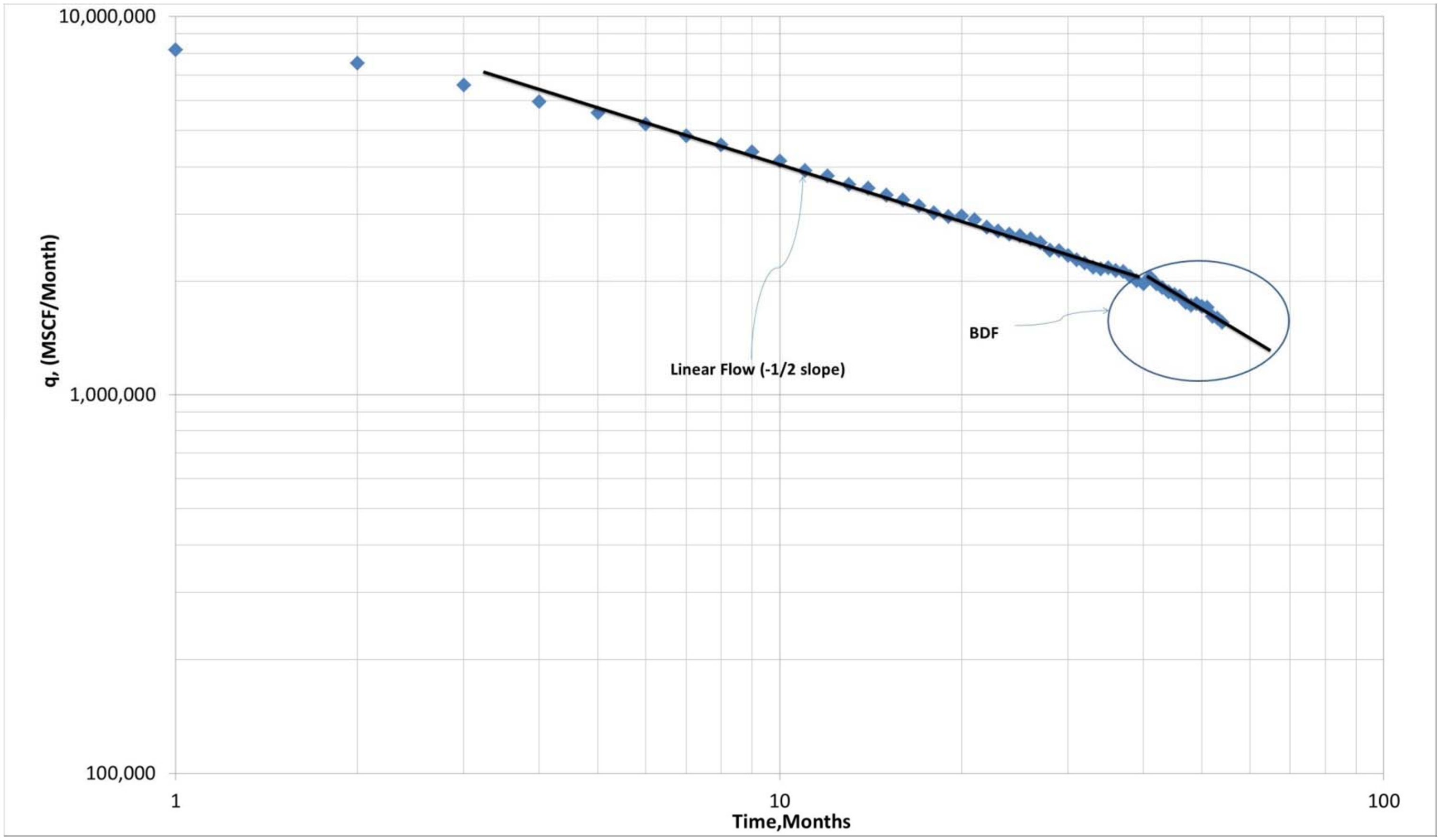
Forecasting Ability of SEDM Model Much Better

Years of History Matched	Best Fit, Arps “b”	Arps: Error in Remaining Reserves, %	SEDM: Error in Remaining Reserves, %
2	2.66	145	36.1
5	1.91	104	23.9
10	1.51	30.6	6.73
25	1.20	7.9	0.21
50	1.14	0	0

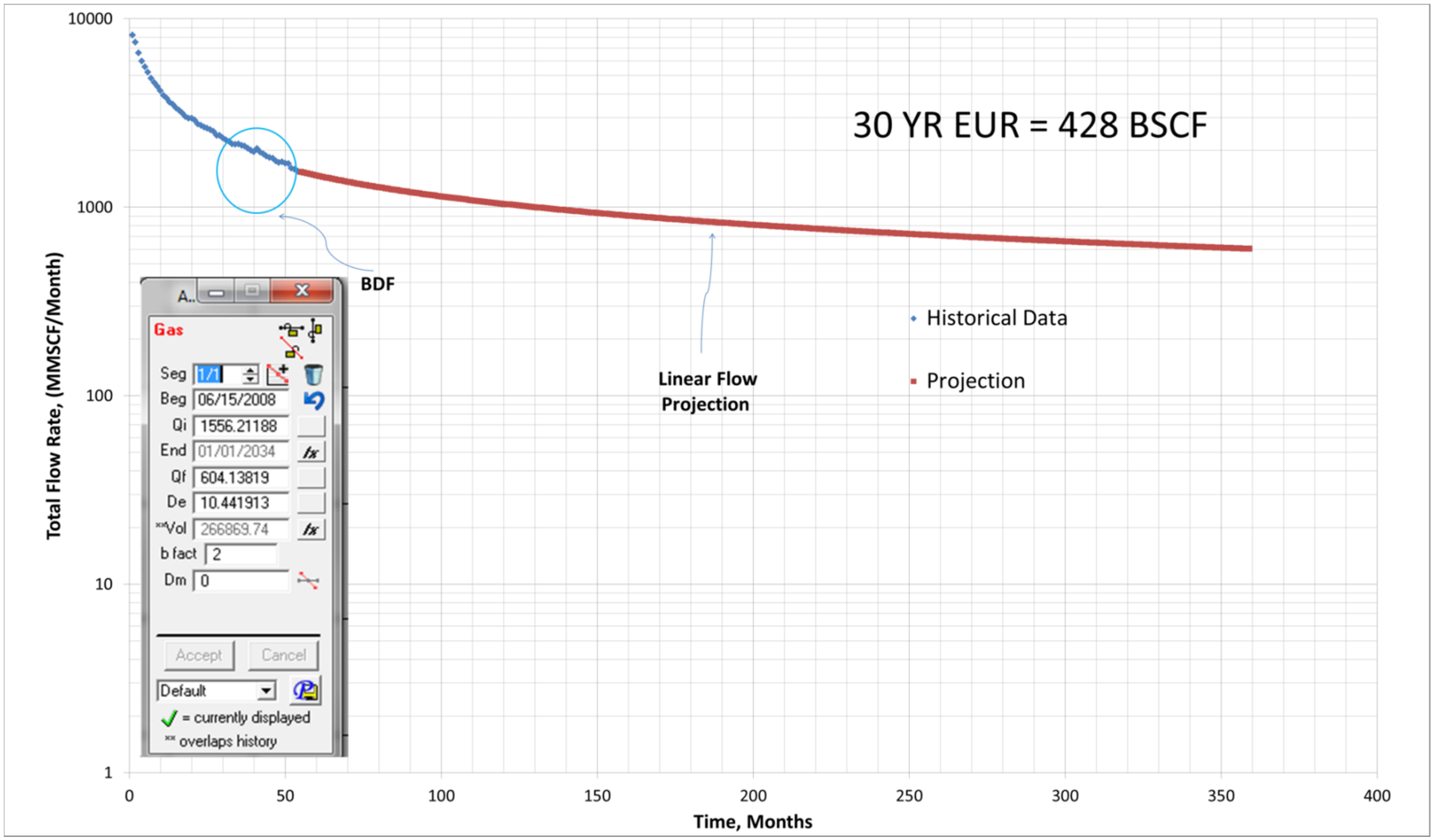
Long-Duration Linear Flow Model

- Reasonable expectation in formation with hydraulic fracture(s) in communication with wellbore
  - Characterized by slope = -(1/2) on log q – log t plot, b = 2 in Arps model
  - Linear flow possibly followed by boundary-dominated flow, $0 < b < 0.5$ in Arps model, when boundaries of Stimulated Reservoir Volume (SRV) felt
  - Linear flow may then reappear as flow from beyond SRV develops

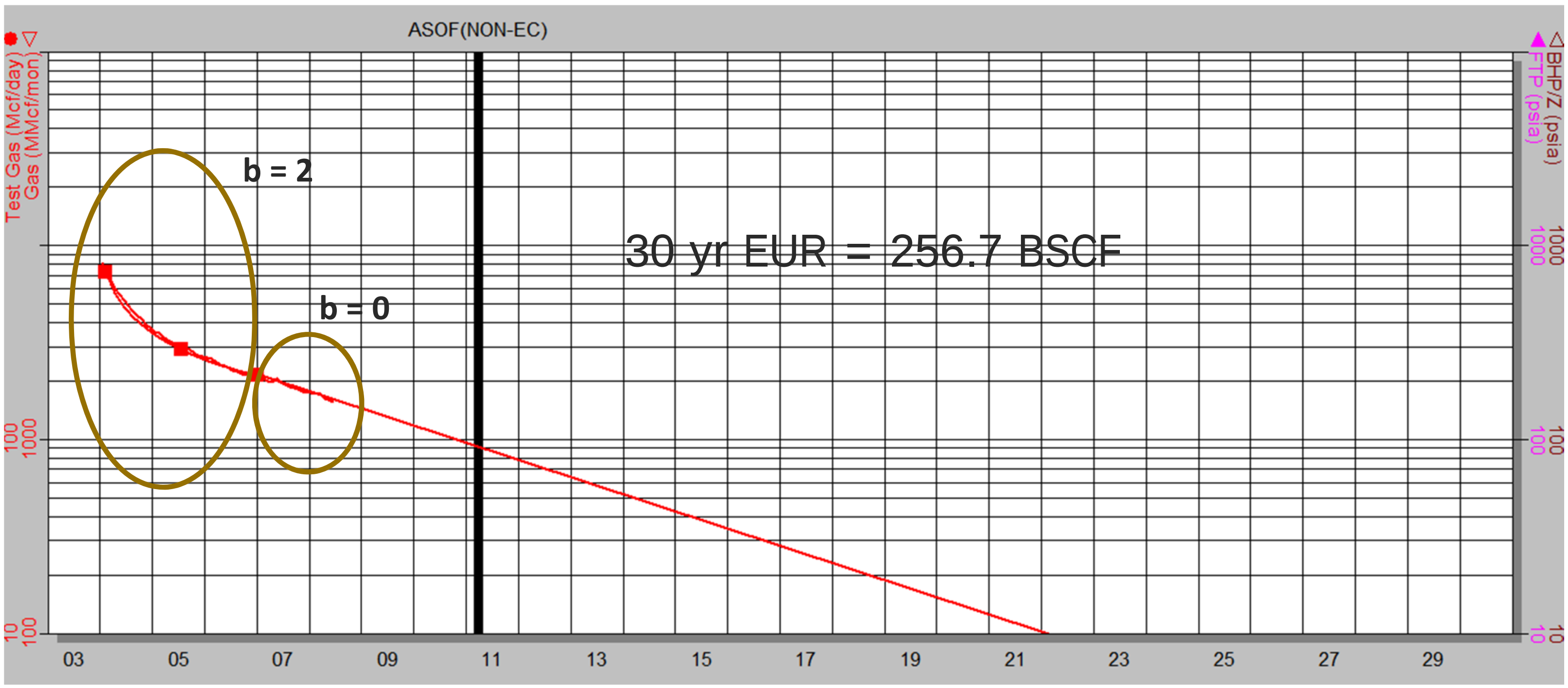
Linear Flow, Boundary-Dominated Flow Observed in Denton County Well Group (234 Wells)



Upper Bound of EUR for Denton County Well Group: Immediate Resumption of Linear Flow



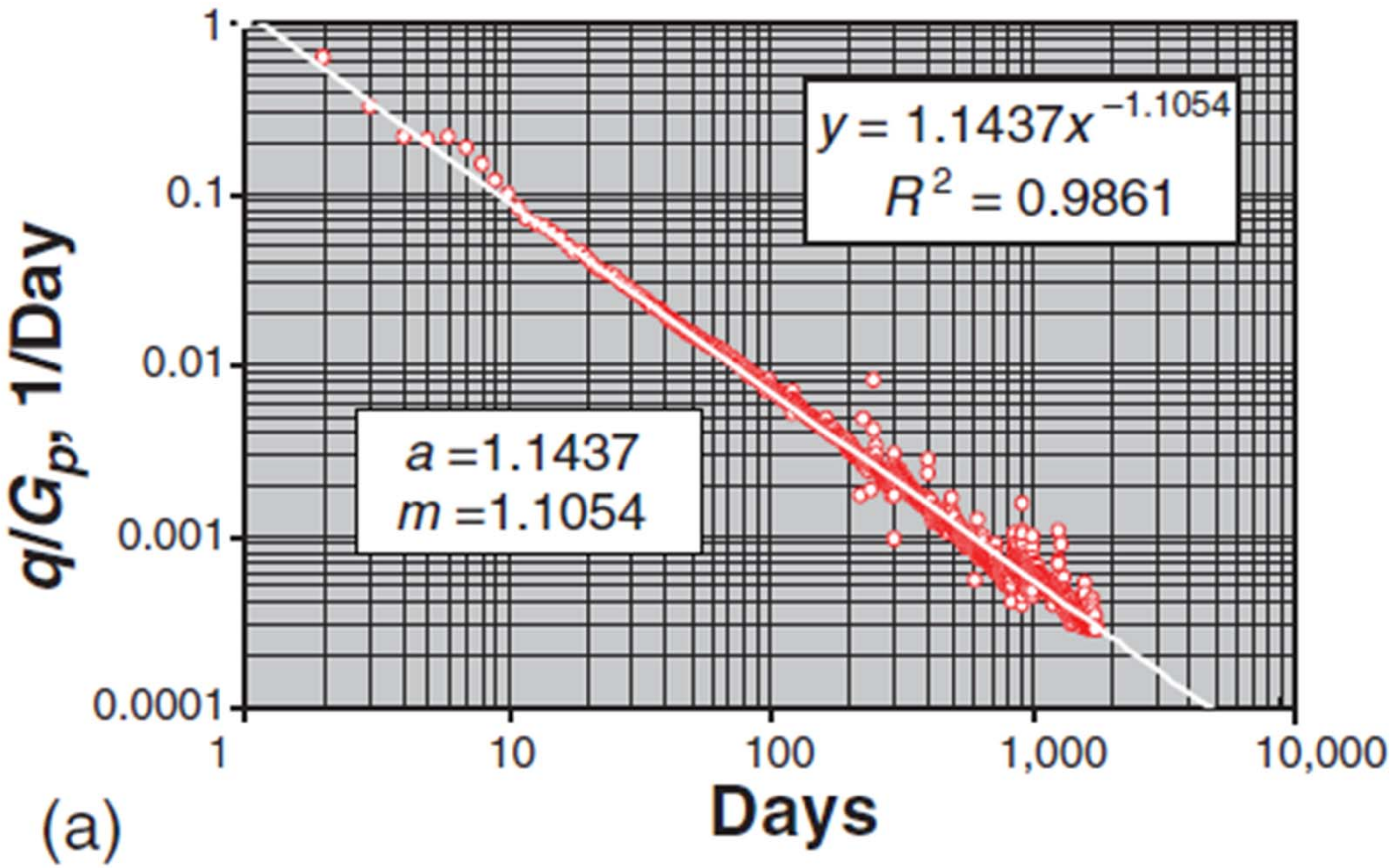
Lower Bound of EUR for Denton County Well Group: Well Declines Exponentially for Remaining Life



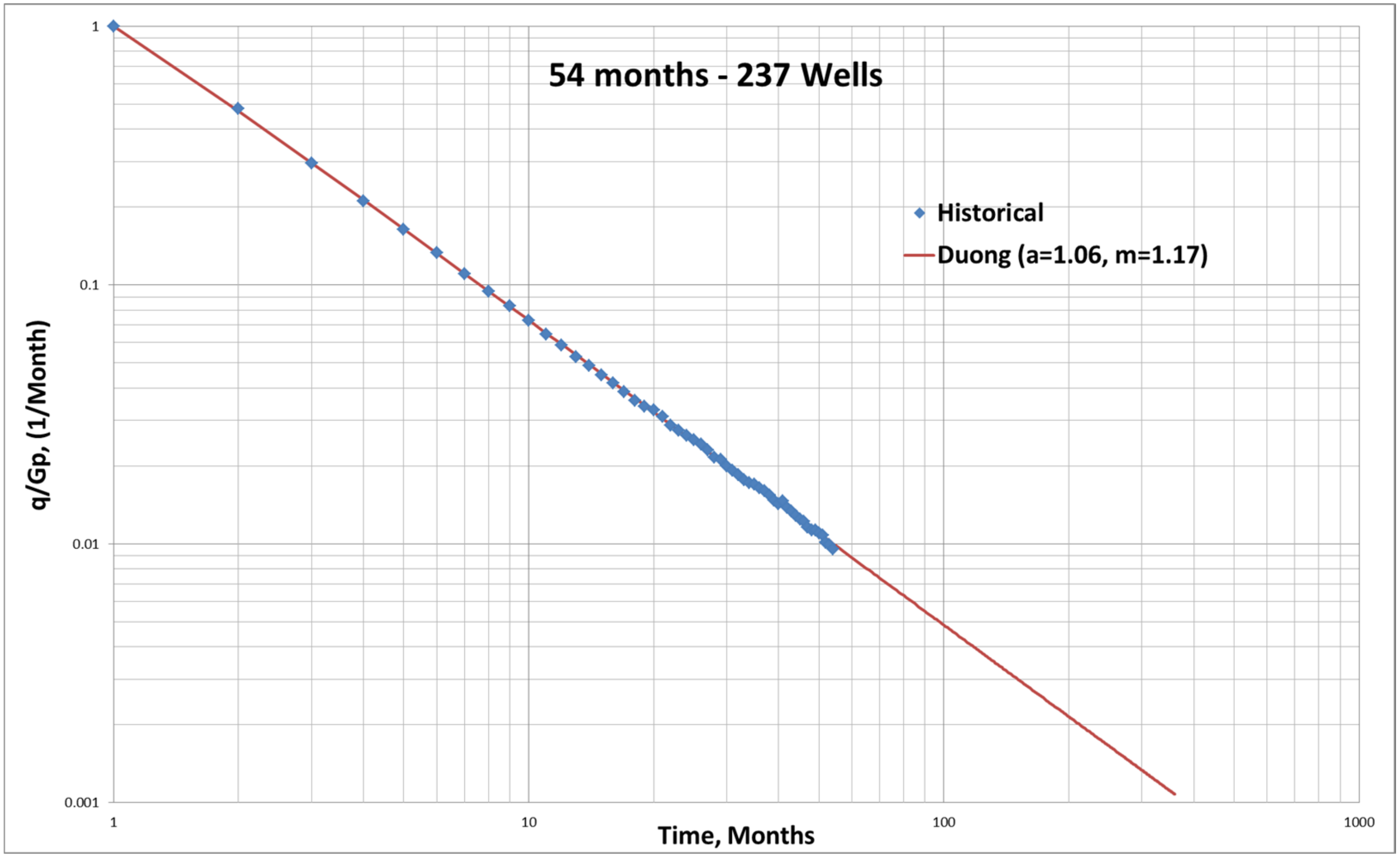
Duong Method (SPE 137748, June 2011 SPEREE)

- For linear or bilinear flow, $q = q_1 t^{-n}$
- Cumulative production, $G_p = \frac{q_1 t^{1-n}}{(1-n)}$
- Ratio $\frac{q}{G_p} = \frac{(1-n)}{t}$
- Real life $\frac{q}{G_p} = a t^{-m}$ ... which models observed behavior remarkably well

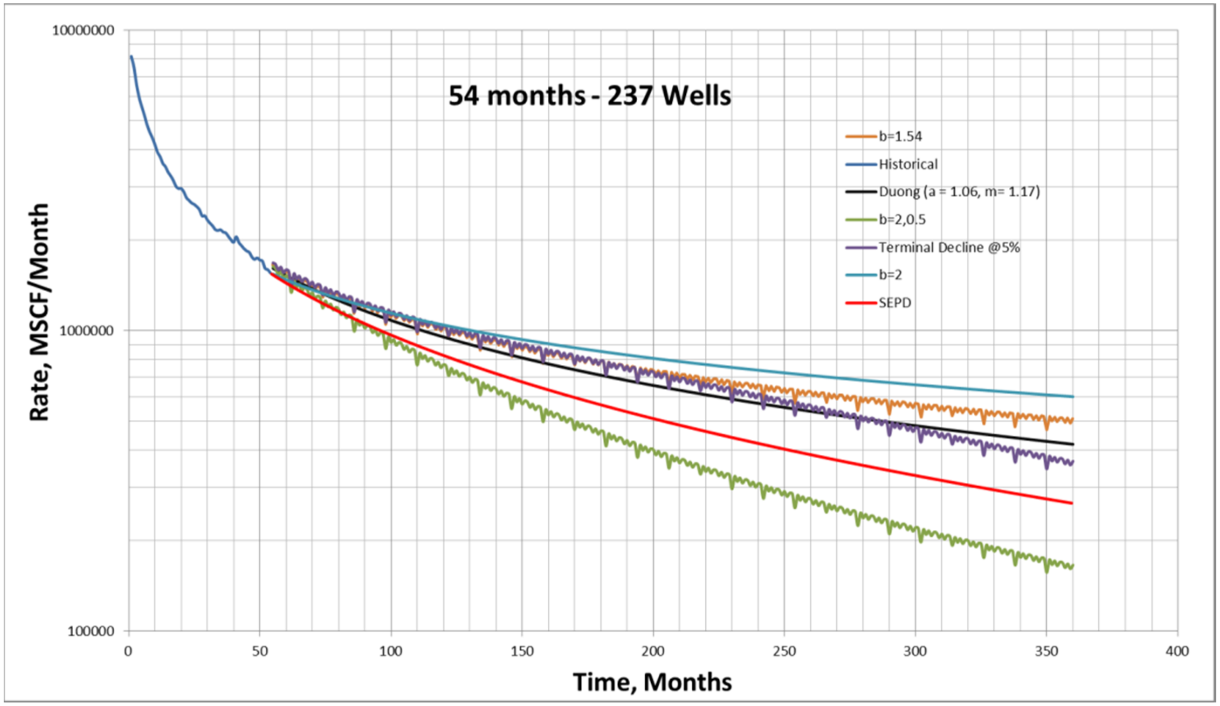
Duong Method Applied to Shale Well



Barnett Shale – Denton County

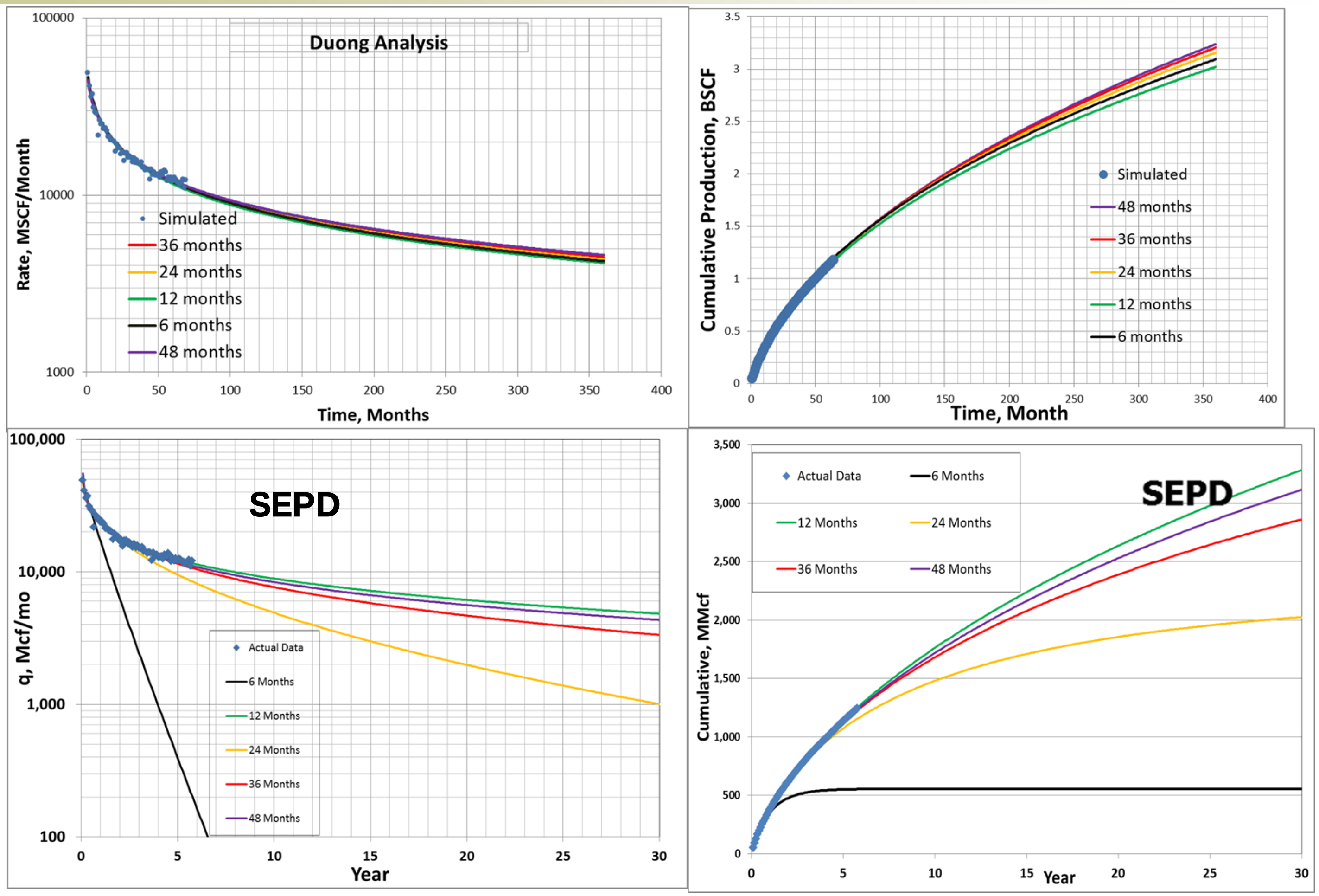


Barnett Shale – Denton County



No. of months	No. of wells	30 Yr EUR (BSCF)	BSCF/Well	b value
54	237	319.463	1.348	b=2,0.5
54	237	428.165	1.807	b=2 (EOP)
54	237	408.459	1.723	b=1.54
54	237	388.521	1.639	Duong (a = 1.06, m= 1.17)
54	237	397.583	1.678	Terminal Decline @5%
54	237	346.763	1.463	SEPD

Barnett Shale: Wise (42-497-35766)



Critique of Duong Method

- Easily applied to forecast future production and reserves for low-permeability wells
- Reliable method when less than two years history available to match
- Appears to be reliable for both horizontal and vertical wells, but validation for shales not possible without long-term performance data for comparison
- Method currently unproved for wells with transitions from linear (or bilinear) flow to boundary dominated flow

Conclusions

- Forecasting in resource plays uncertain
  - Understanding of basic physics incomplete
  - Ability to rigorously model hypothesized controls on production limited by incomplete data, difficulty in validating models due to limited duration well histories

Conclusions

- Arps production decline model inappropriate without empirical modifications
  - Example: Minimum terminal (exponential) decline
- Other models arguably more appropriate for resource play evaluations – but more complete validation desirable
  - Valkó (SEDM)
  - Long-duration linear flow
  - Duong

Recent Decline Models for Resource Plays

John Lee
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1 February 2012