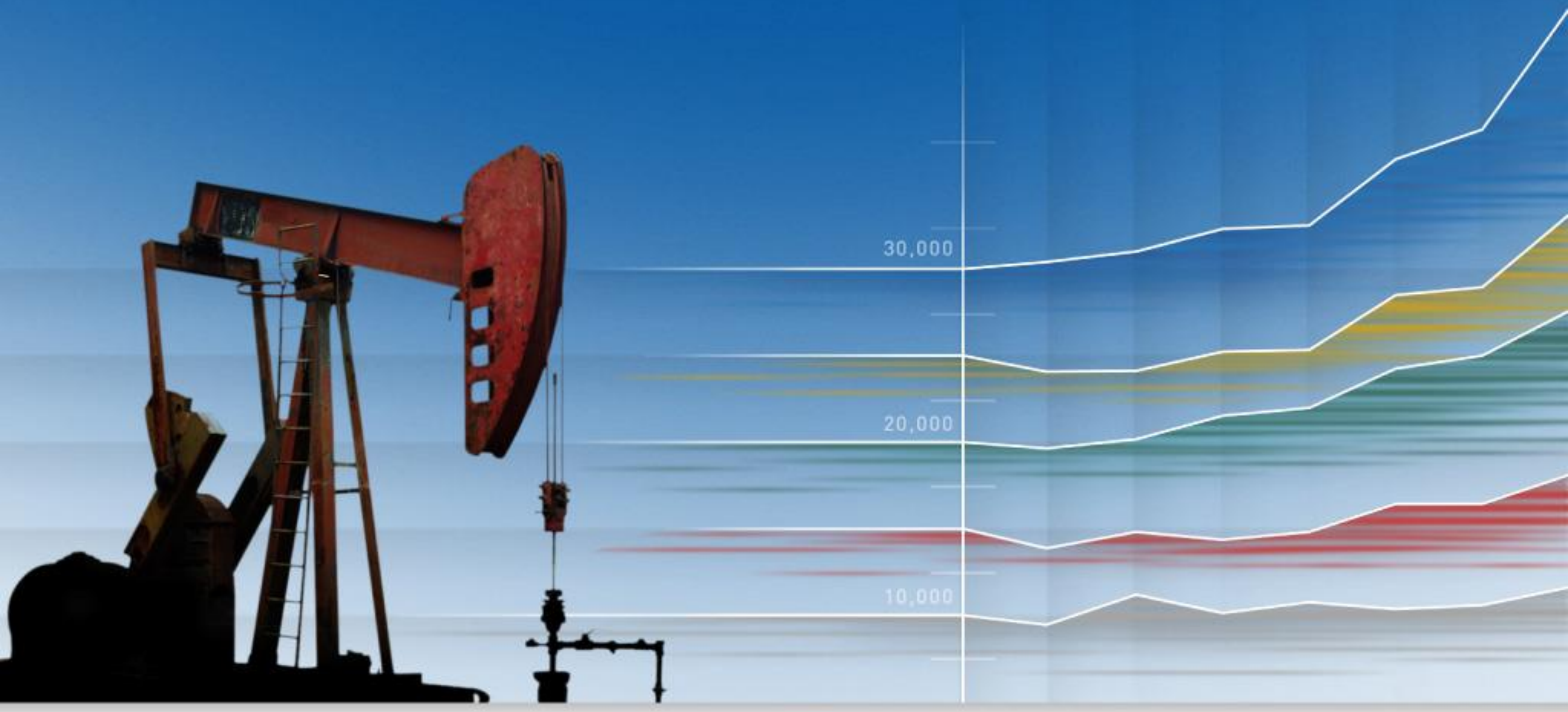
Understanding Type-well Curve Complexities & Analytic Techniques



Reservoir, Evaluation and Production Optimization Luncheon

SPE - Calgary Section Dec. 1st, 2015

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Introduction

- Thank you SPE
- Disclaimer and Objective
- Presentation
- Questions (jot down the topic number for any questions)

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Disclaimer and Objectives

- The content of this presentation is intended to illustrate the complexities associated with type-well curve development using monthly vendor/public production data and demonstrate analytic techniques that may provide insights when developing type-well curves.
- These type-well curve analysis techniques are complimentary and informative to workflows involving scientific modelling tools, forecasting tools and economic evaluation tools.
- The relevance of each topic will depend on what you're trying to accomplish.

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Clarification: Type-well Curve vs Type Curve

While Type-well Curves are often referred to as "Type Curves", they are different.

- **Type Curves** more properly refer to idealized production plots (based on equations and/or numerical simulation) to which actual well production results are compared.
- **Type-Well Curves** are based on actual well production data and represent an average production profile for a collection of wells for a specified duration.

Why are Type-well Curves Important?

Type-well Curves are a foundation of:

- reserves evaluations
- development planning
- production performance comparisons
- completion optimization analysis

The dangers of not understanding the complexities of Type-well Curves, and failing to communicate how they were designed/developed, can result in:

- large statistical variability
- inconsistent information used in development decisions
- unattainable economic plans (especially in the unforgiving times of low commodity prices).

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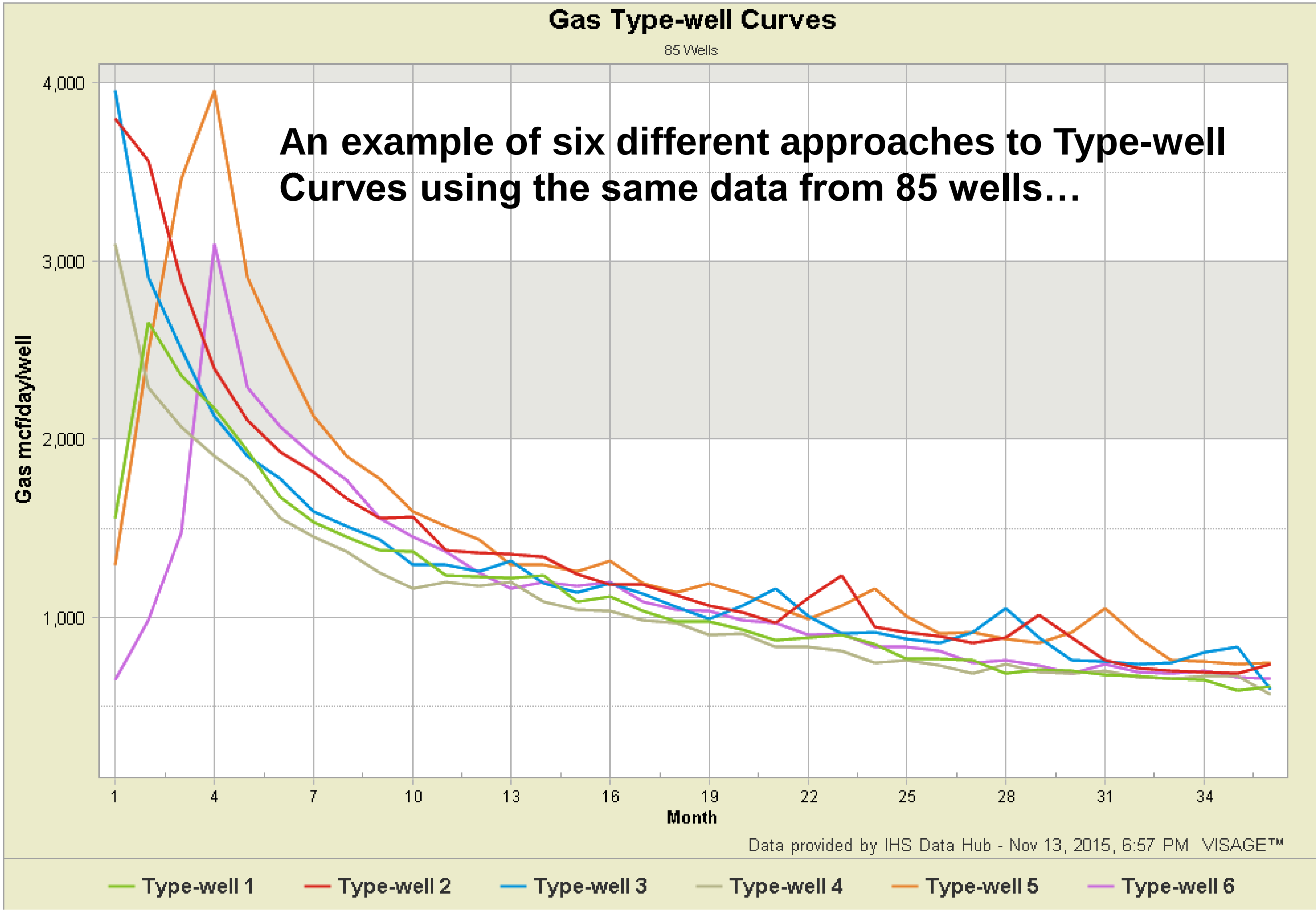
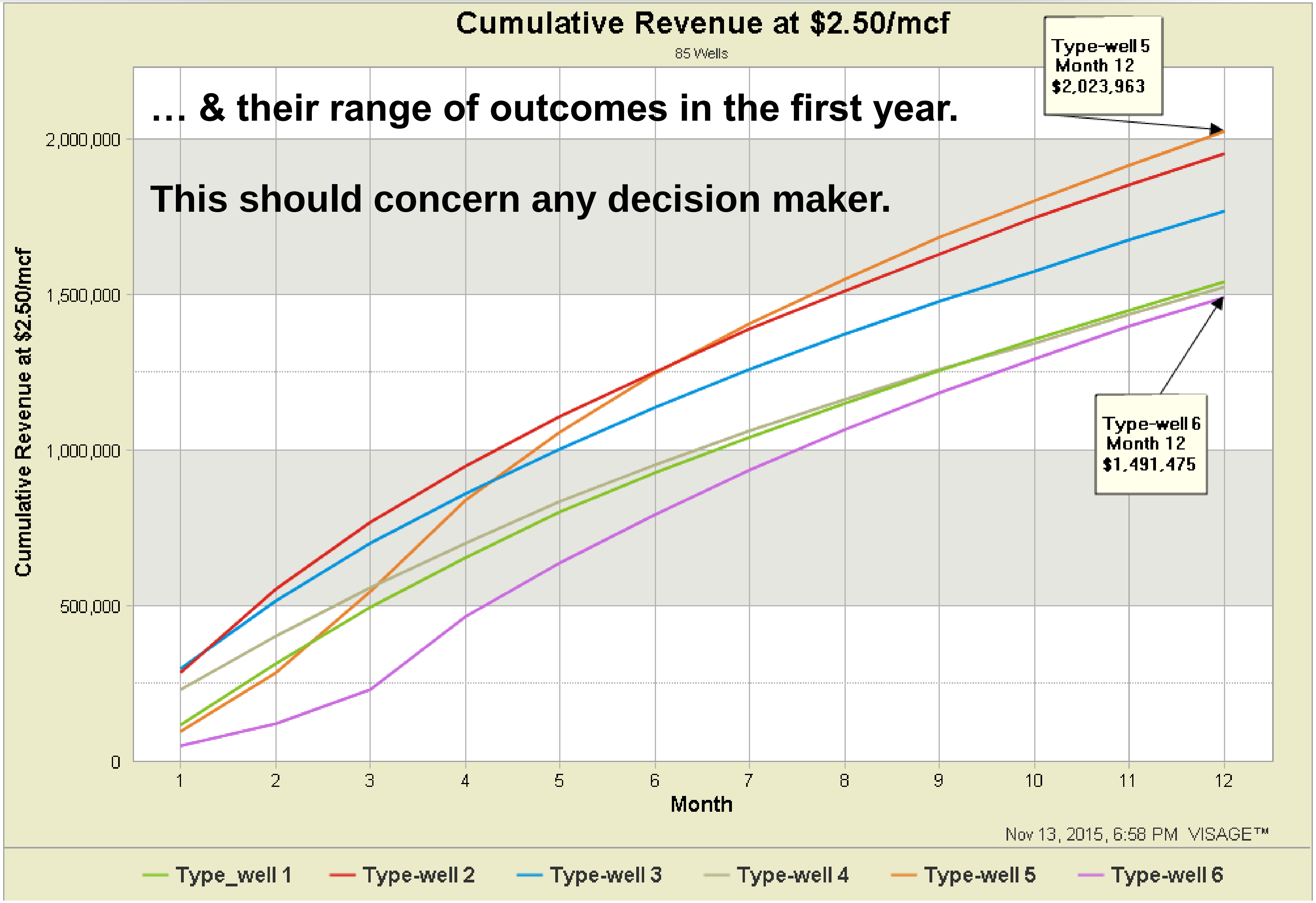
Why are Type-well Curves Important?



Why are Type-well Curves Important?



Presentation Outline

1) Chart Types
2) Analogue Selection
3) Normalization
4) Calendar Day vs Producing Day
5) Condensing Time
6) Operational/Downtime Factors on Idealized Curves
7) Survivor Bias
8) Truncation Using Sample Size Cut-off
9) Forecast the Average vs Average the Forecasts
10) Representing Uncertainty
11) Auto-forecast Tools

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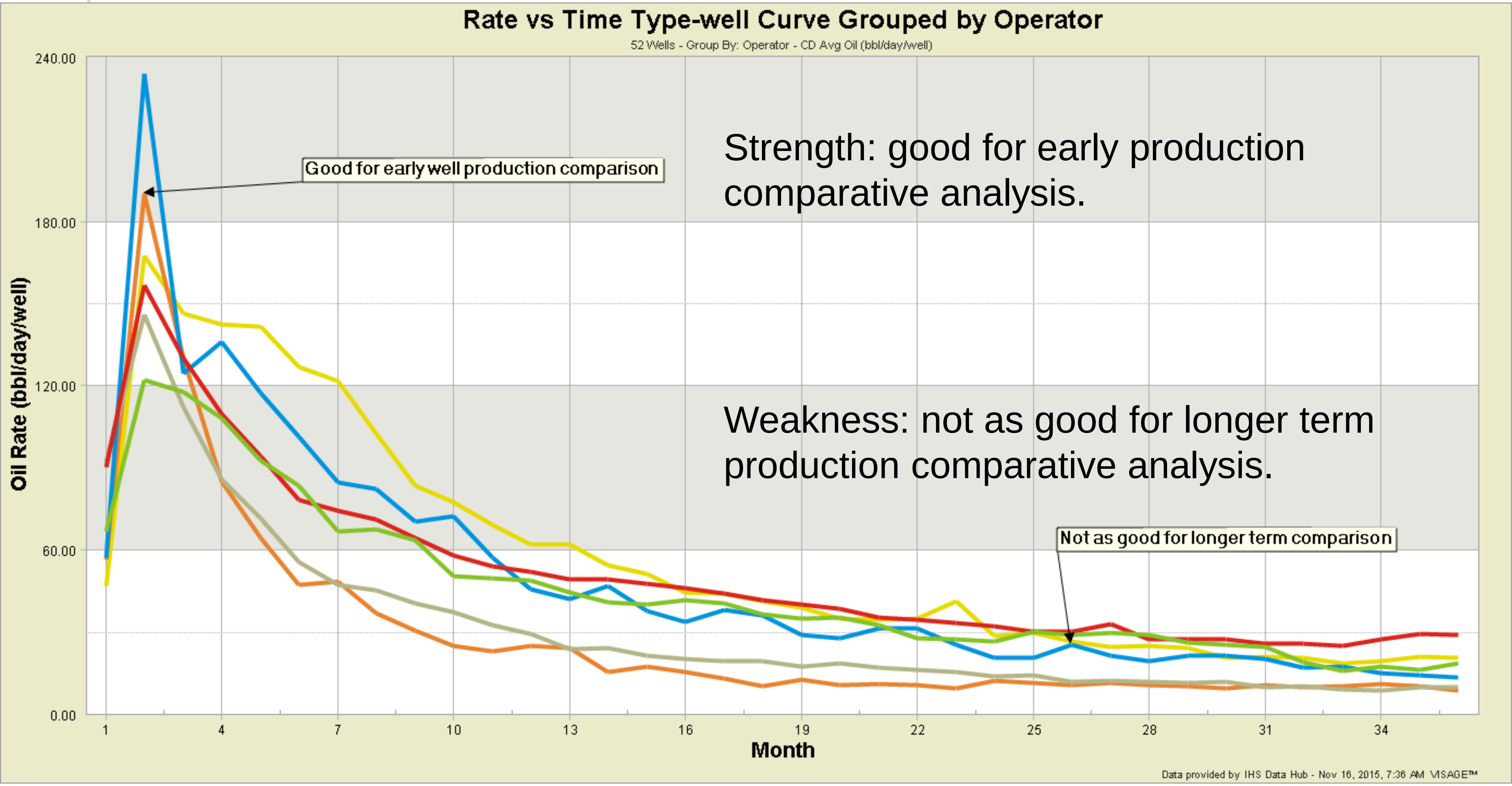
1) Chart Types

1) Rate vs Time
2) Cumulative Production vs Time
3) Rate vs Cumulative Production
4) Percentile (Cumulative Probability)
5) Probit Scale

Don’t rely on just one … collectively they construct an informative narrative.

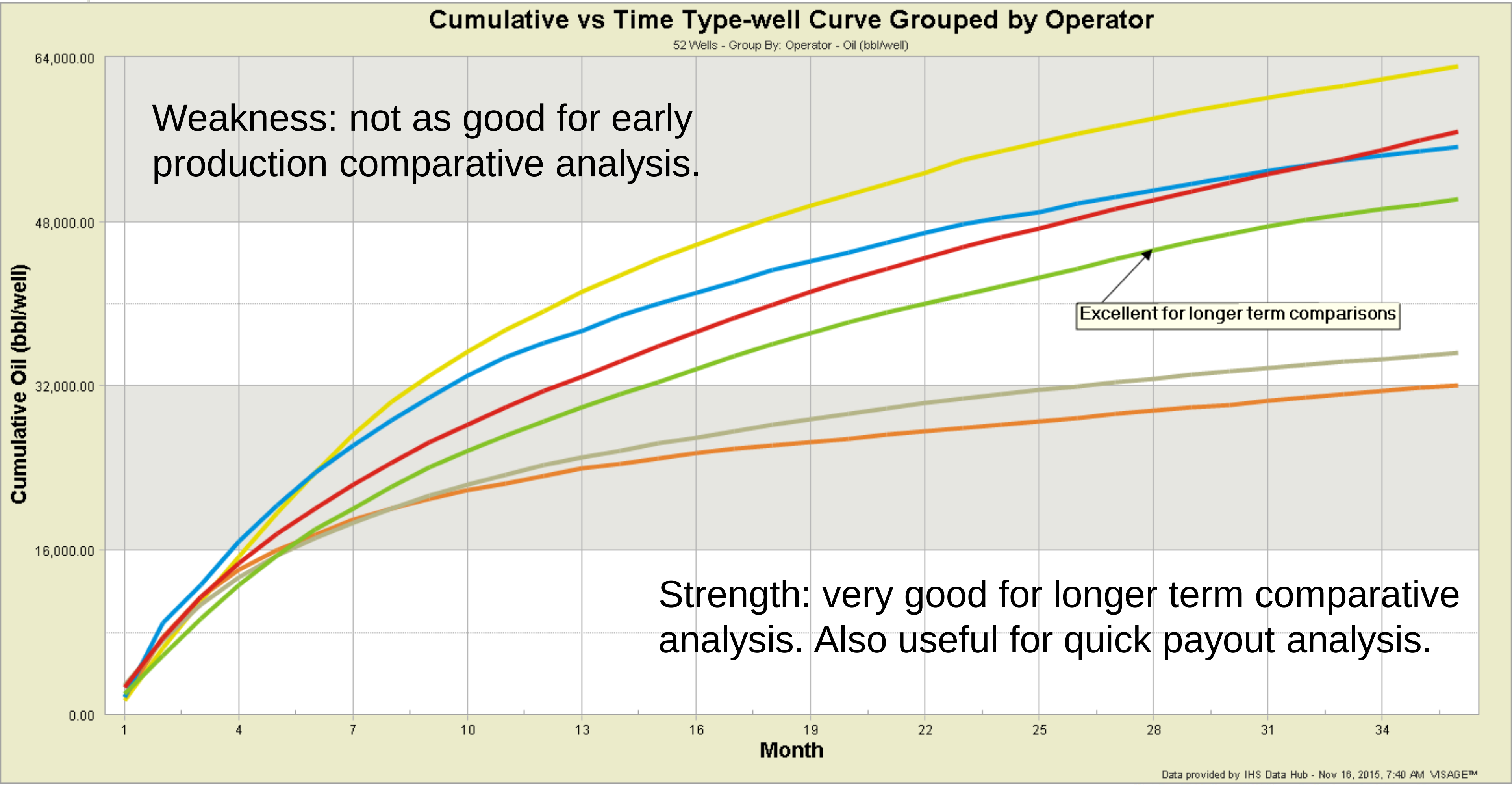
1.1) Rate vs Time



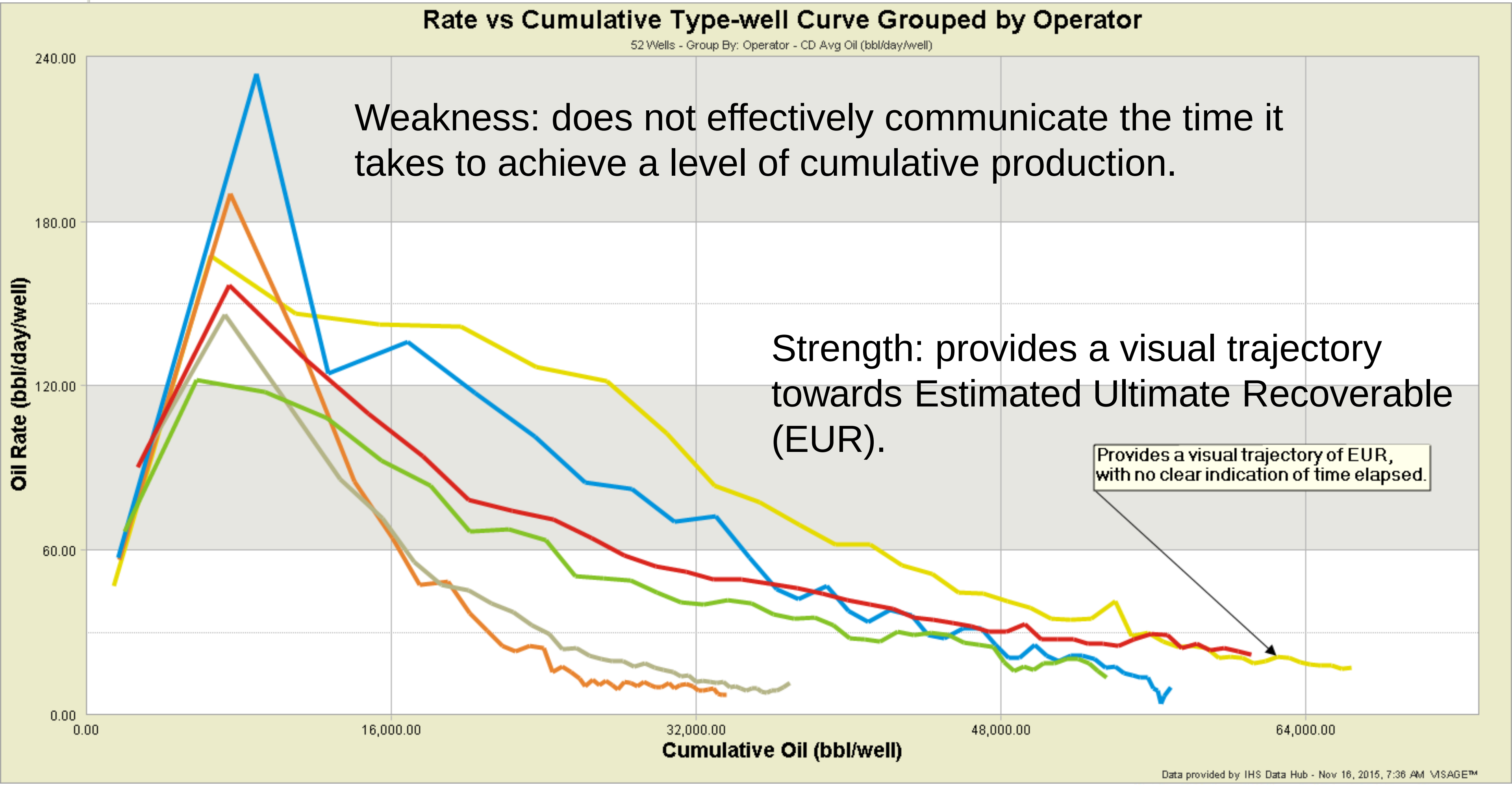
Strength: good for early production comparative analysis.

Weakness: not as good for longer term production comparative analysis.

1.2) Cumulative Production vs Time



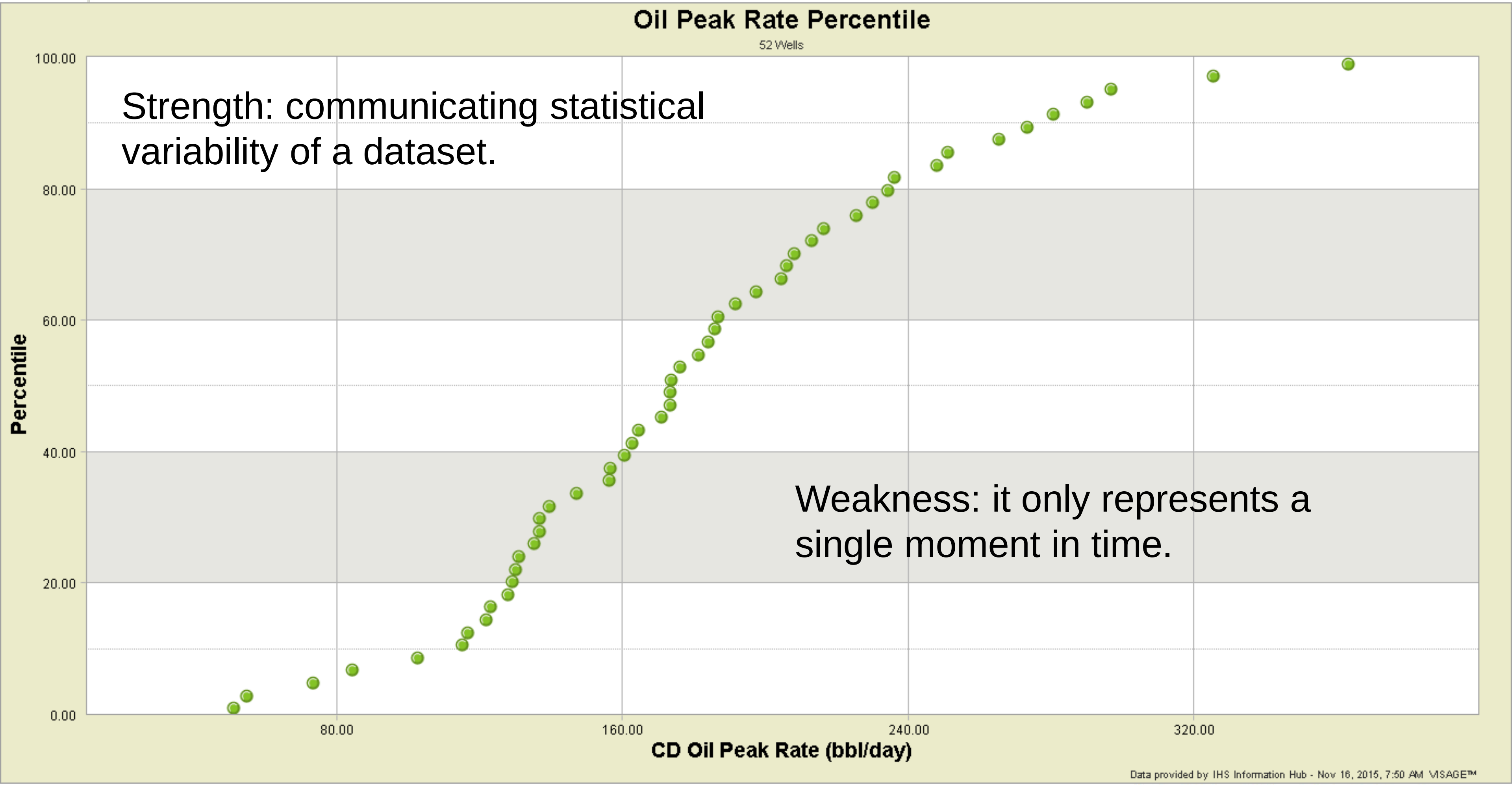
1.3) Rate vs Cumulative Production



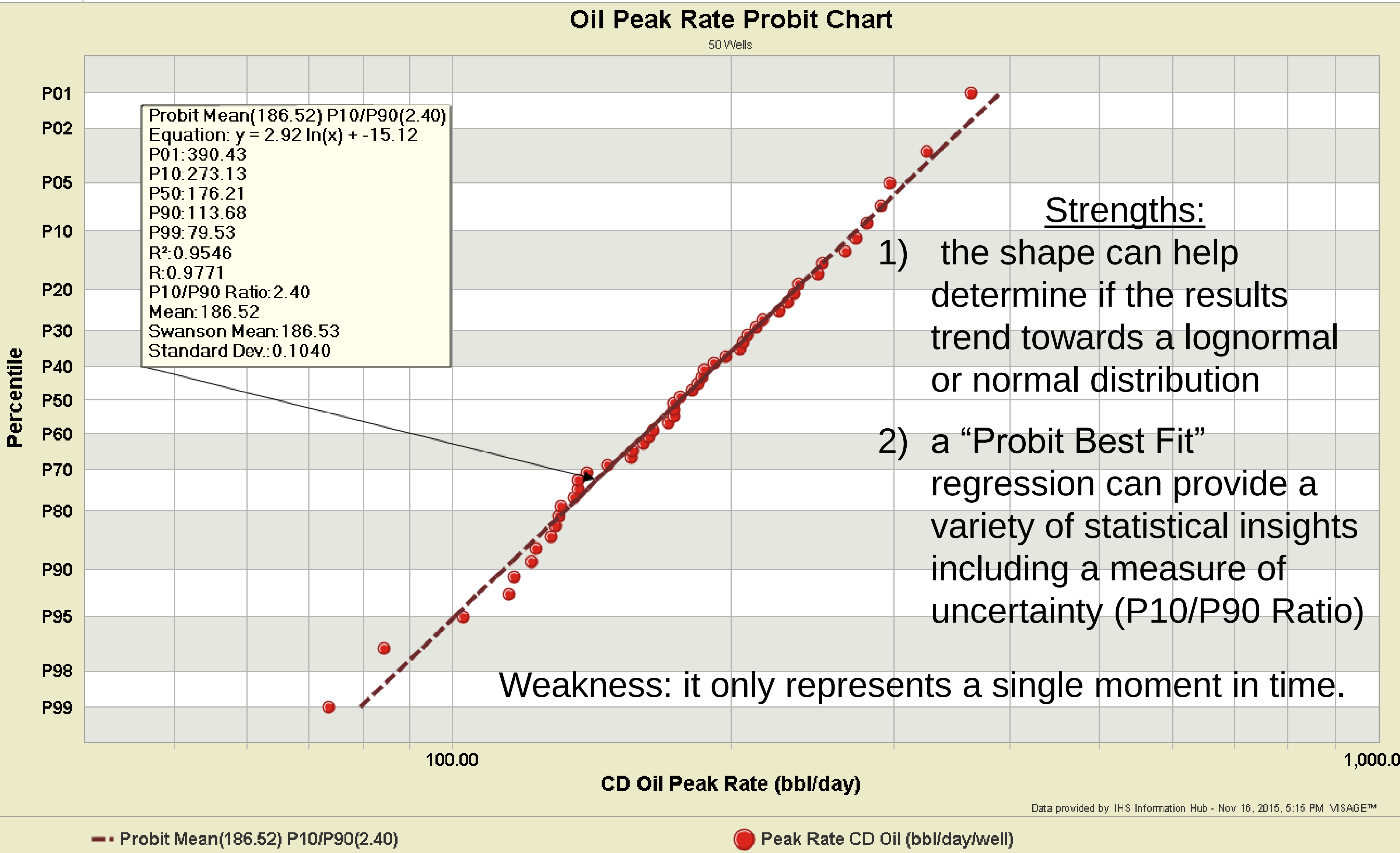
Weakness: does not effectively communicate the time it takes to achieve a level of cumulative production.

Strength: provides a visual trajectory towards Estimated Ultimate Recoverable (EUR).

1.1) Percentile (Cumulative Probability)



1.1) Probit Scale (Cumulative Probability)



<u>Strengths:</u>

1) the shape can help determine if the results trend towards a lognormal or normal distribution
2) a "Probit Best Fit" regression can provide a variety of statistical insights including a measure of uncertainty (P10/P90 Ratio)

Weakness: it only represents a single moment in time.

2) Analogue Selection (most important step)

- Analogue wells should have a similarity on which a comparison may be based and represent the range of possible outcomes (i.e. don't just select the best wells).
- Selecting wells with similar characteristics may reduce the range of uncertainty in your type-well curve.
- Common attribute categories:
    1) Geology
    2) Reservoir
    3) Well Design
    4) Well Density
    5) Operational Design

2.1) Analogue Selection (Geology & Reservoir)

Geology pertains to criteria like thickness, porosity, permeability, lithology, water saturation, faulting/fracturing etc.

Reservoir pertains to fluids, thermal maturity, pressure, temperature etc.

- Limited data available in vendor/public data.
- Use whatever information and expertise is available.
- Use maps to provide a geographical context.

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2.3) Analogue Selection (Well Design)

Well Design has experienced increasing variability in recent years. Things to consider include:

- Completion parameters like open/cased, lateral length, technology, fluids, energizers, proppant loading, and stages (number and spacing).
- Consider other parameters (e.g. vintage & operator) to see if you can further narrow down your analogue selection and reduce the uncertainty.
- Leverage dimensional normalization (e.g. normalizing to lateral length) to put wells on a level playing field for comparison and selection.

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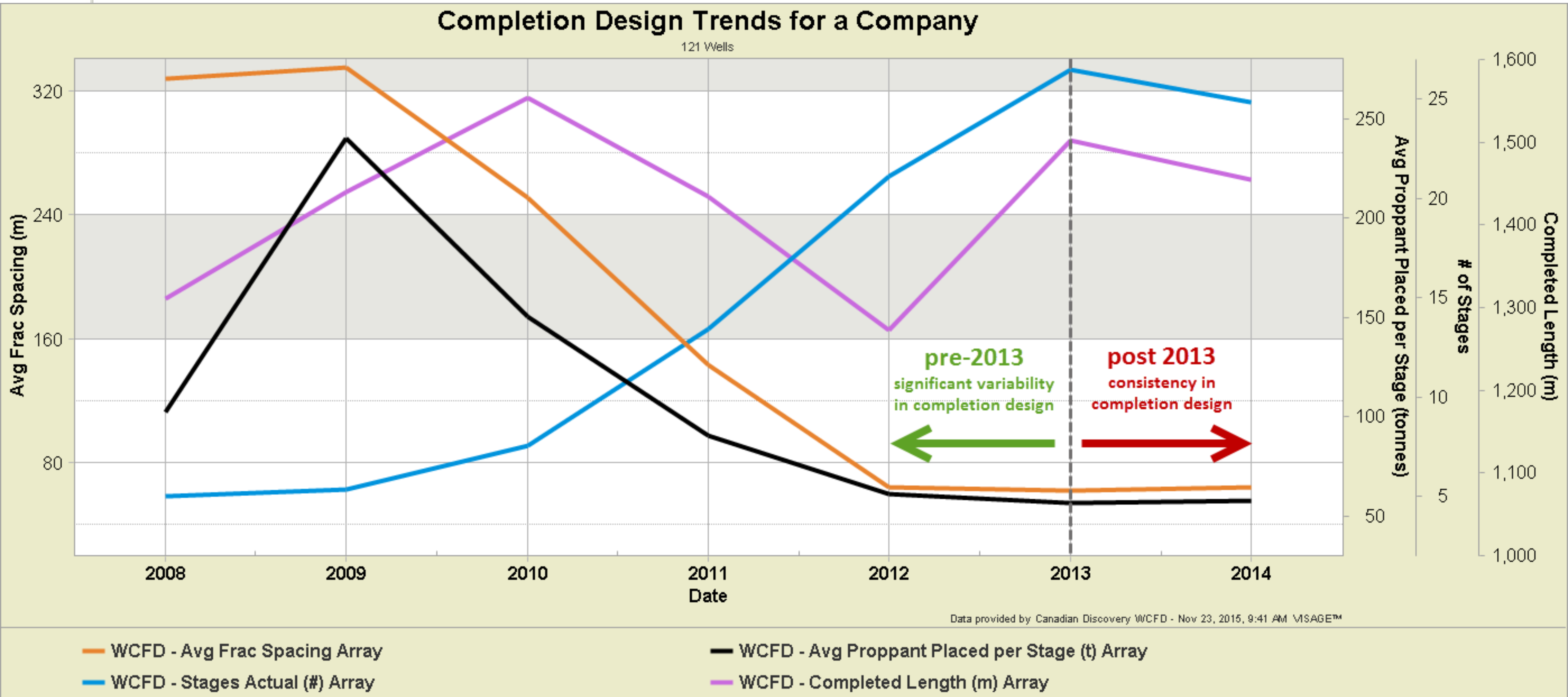
2.3) Analogue Selection (Well Design)

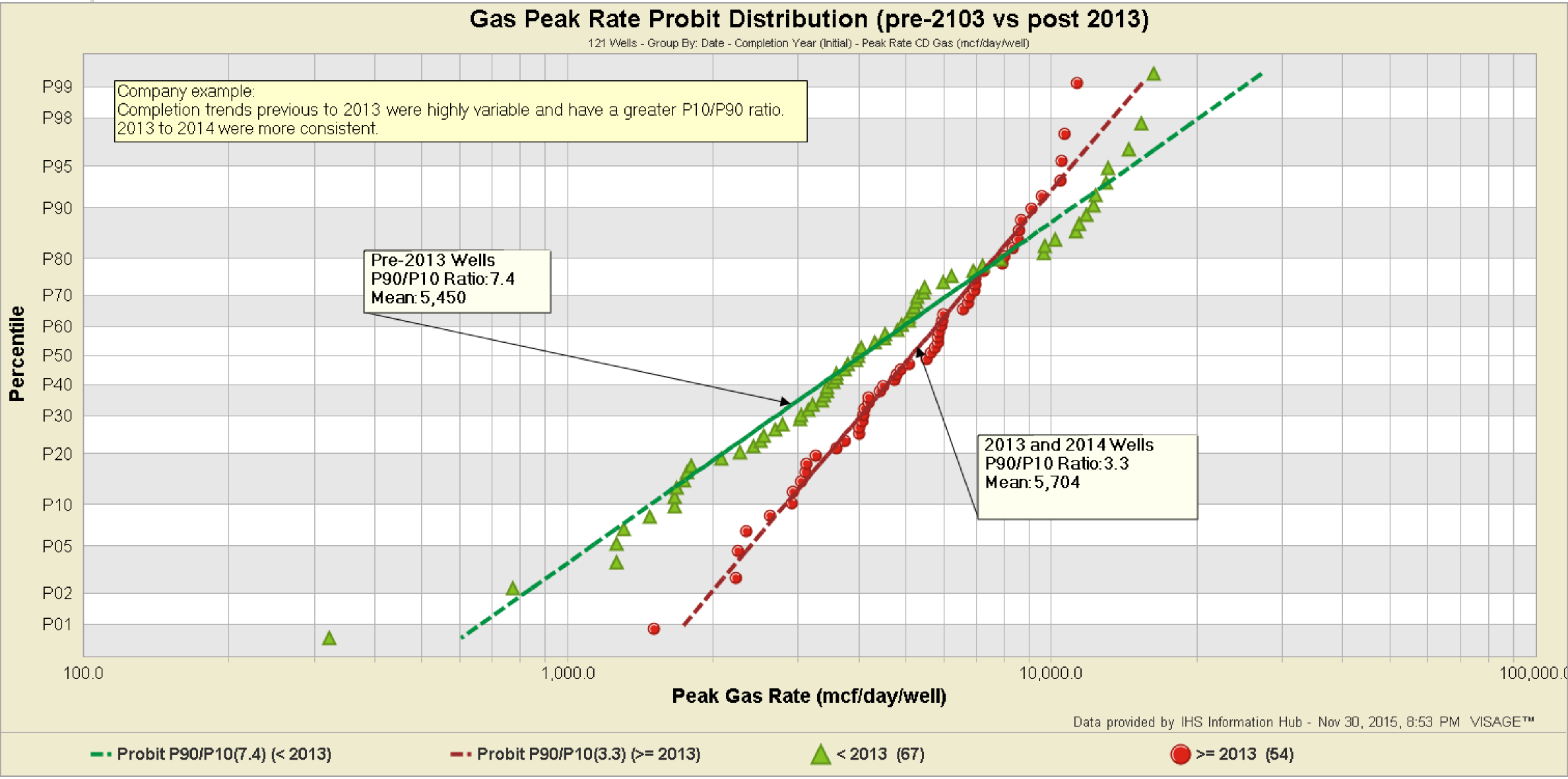
An illustration of how analogue selection can reduce uncertainty using pre-2013 data compared to post 2013 completion data.



	2008	2009	2010	2011	2012	2013	2014
WCFD - Completed Length (m) Array	1,312	1,440	1,554	1,434	1,273	1,502	1,455
WCFD - Stages Actual (#) Array	5	5	8	13	21	26	25
WCFD - Avg Proppant Placed per Stage (t) Array	102	241	150	90	61	56	58
WCFD - Avg Frac Spacing Array	328	335	251	143	64	62	64

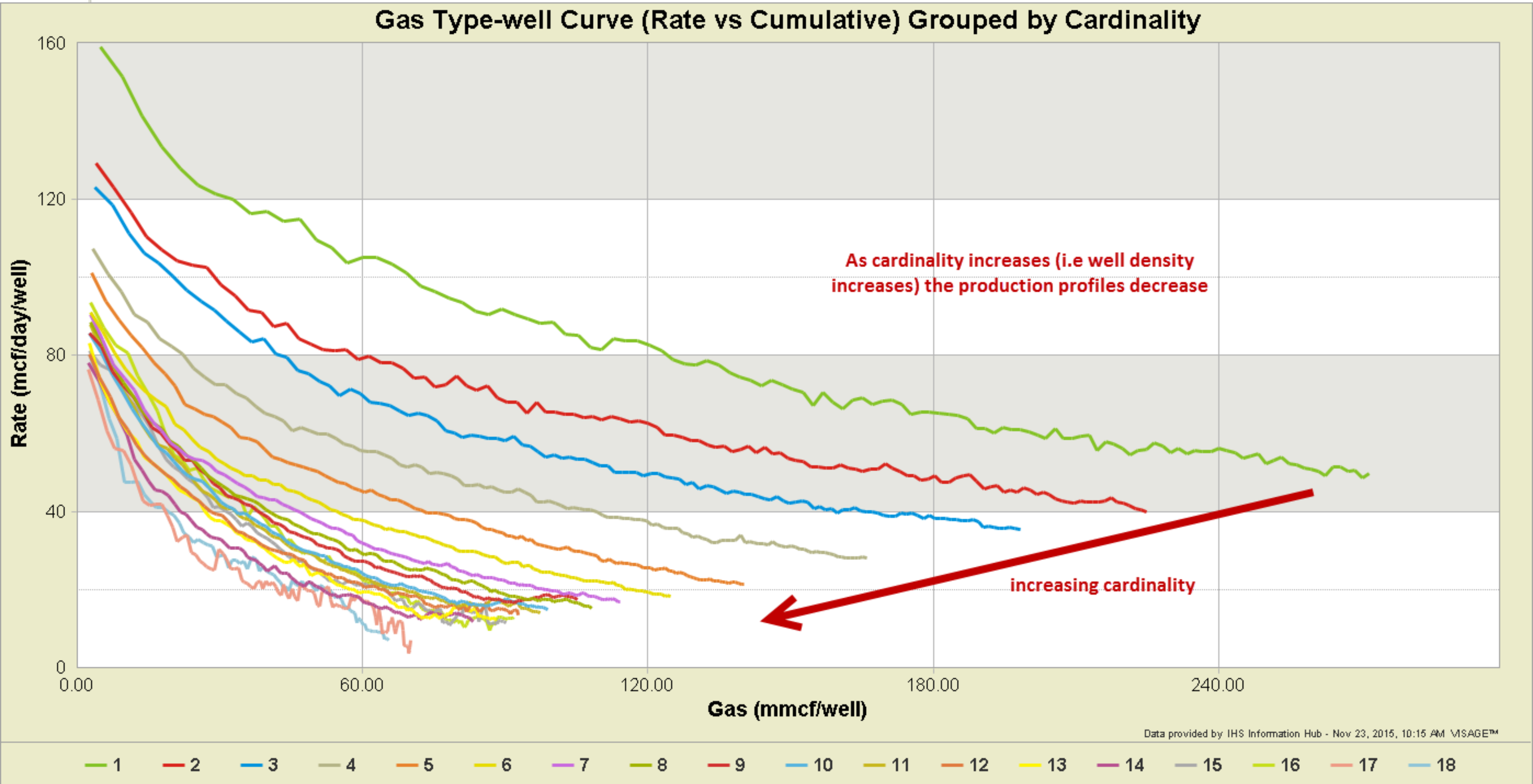
2.3) Analogue Selection (Well Design)

An illustration of how analogue selection can reduce uncertainty using pre-2013 data compared to post 2013 completion data.



2.4) Well Density (using Cardinality)

Cardinality is the drill order of wells within a square mile. As cardinality increases well interference results in lower production profiles.



2.5) Operational Design

- Capacity constraints (curtailment), contracts and operational constraints (line pressure) are examples of production restrictions <u>imposed on you given your operational environment</u>.

- With the increase in proppant loading and better deliverability some operational designs that <u>you choose to impose</u> may strive to maintain bottom hole pressure, control flowback of sand, minimize base decline, enhance production yields (e.g. condensate-gas ratio), or maximize EUR.

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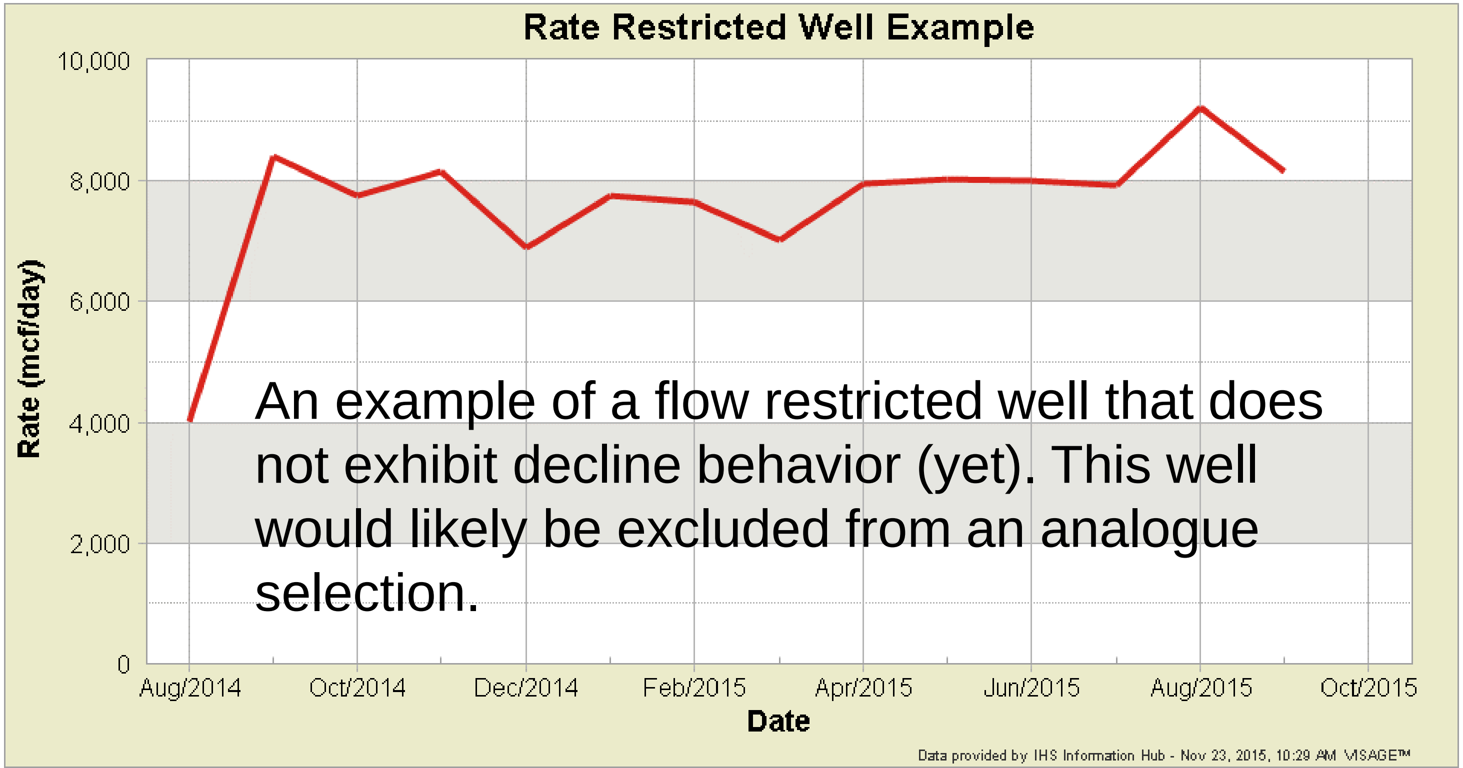
2.5) Operational Design

- scroll through your dataset and look at each well
- isolate and exclude wells that do not demonstrate expected production decline behavior
- where identifiable declines begin after a period of rate restriction, manually adjust the normalization dates and include the wells



3) Normalization

A means to improve comparability of wells or groups (i.e. the proverbial "level playing field").

1) **Time Normalization**
   - Alignment of months relative to a date or event
   - Common values = first production and peak rate date
2) **Dimensional Normalization**
   - Sometimes referred to as "Unitization"
   - Scaling production values relative to a well design parameter
   - Example: production/lateral length
3) **Fractional Normalization**
   - Scaling production values relative to the peak rate

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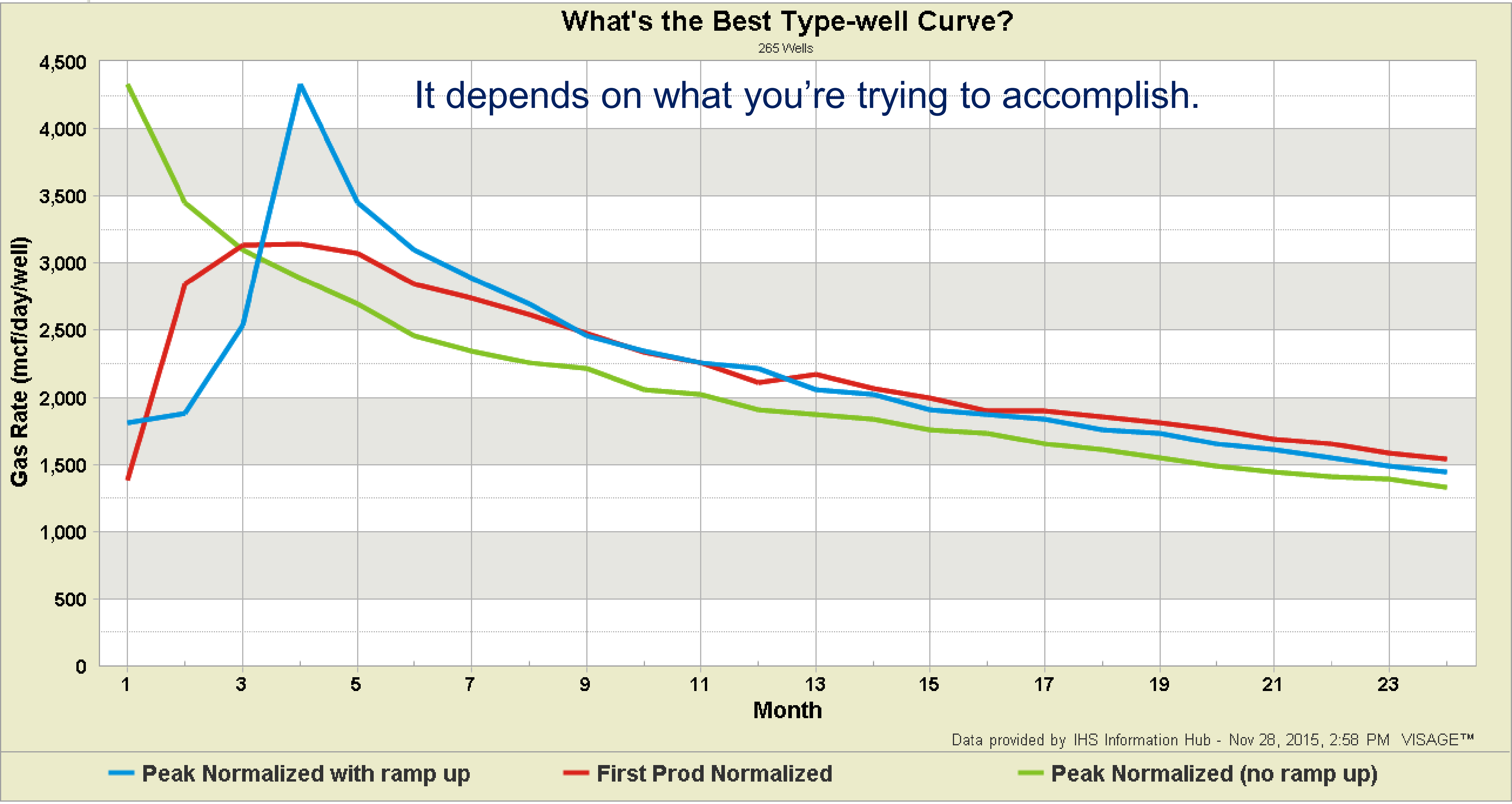
3.1) Time Normalization



3.1) Time Normalization

First Production

Strength: on larger well sets, communicates the average production profile taking into account variability in time to peak. Suitable for some comparisons (e.g. operator, vintage).

Weakness: may not accurately reflect production decline behavior.

Peak Rate Date:

Strength: more accurately reflects production decline behavior.

Weakness: excludes ramp up time (to peak) which is not important to EUR calculations but is important to first year revenue projections.

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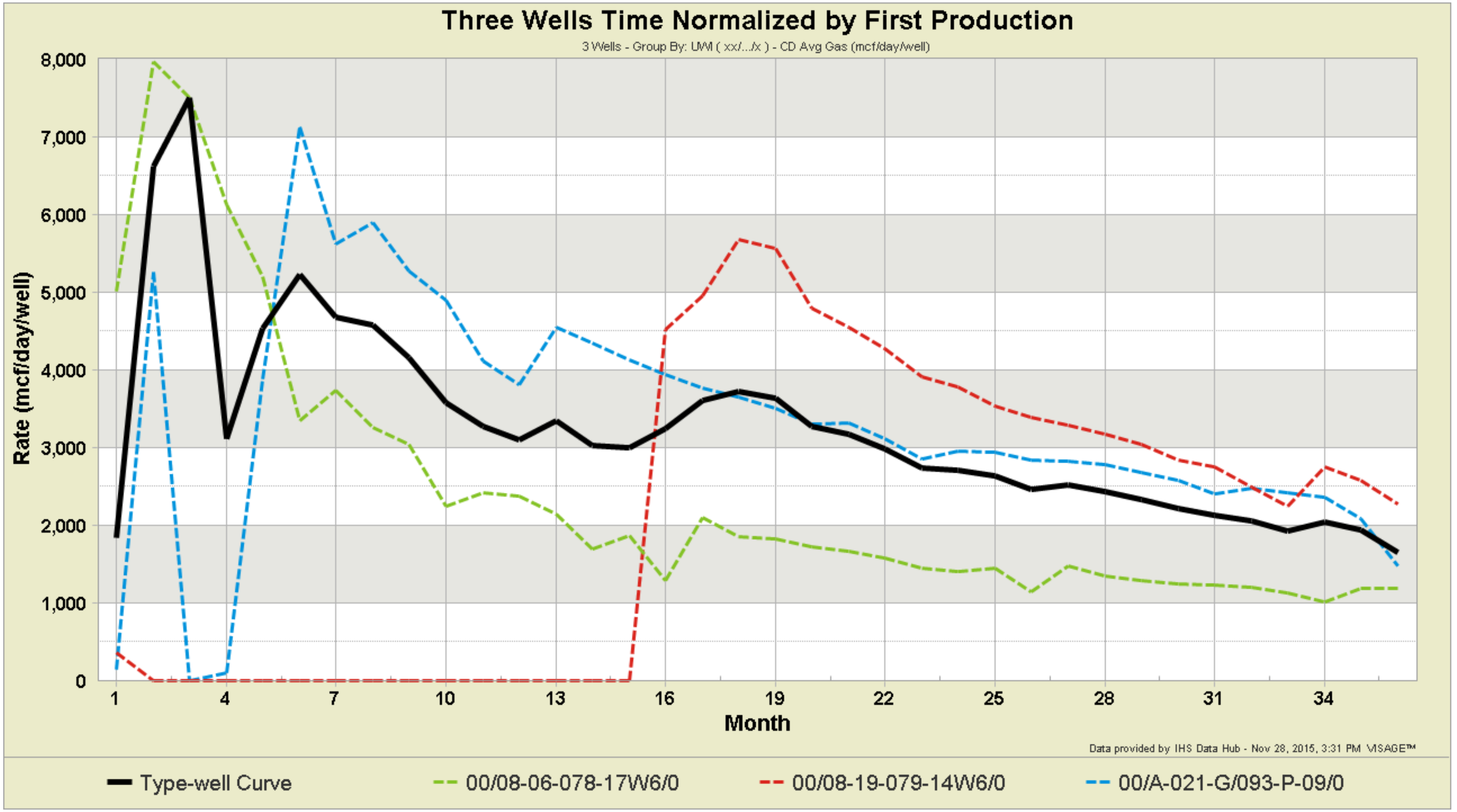
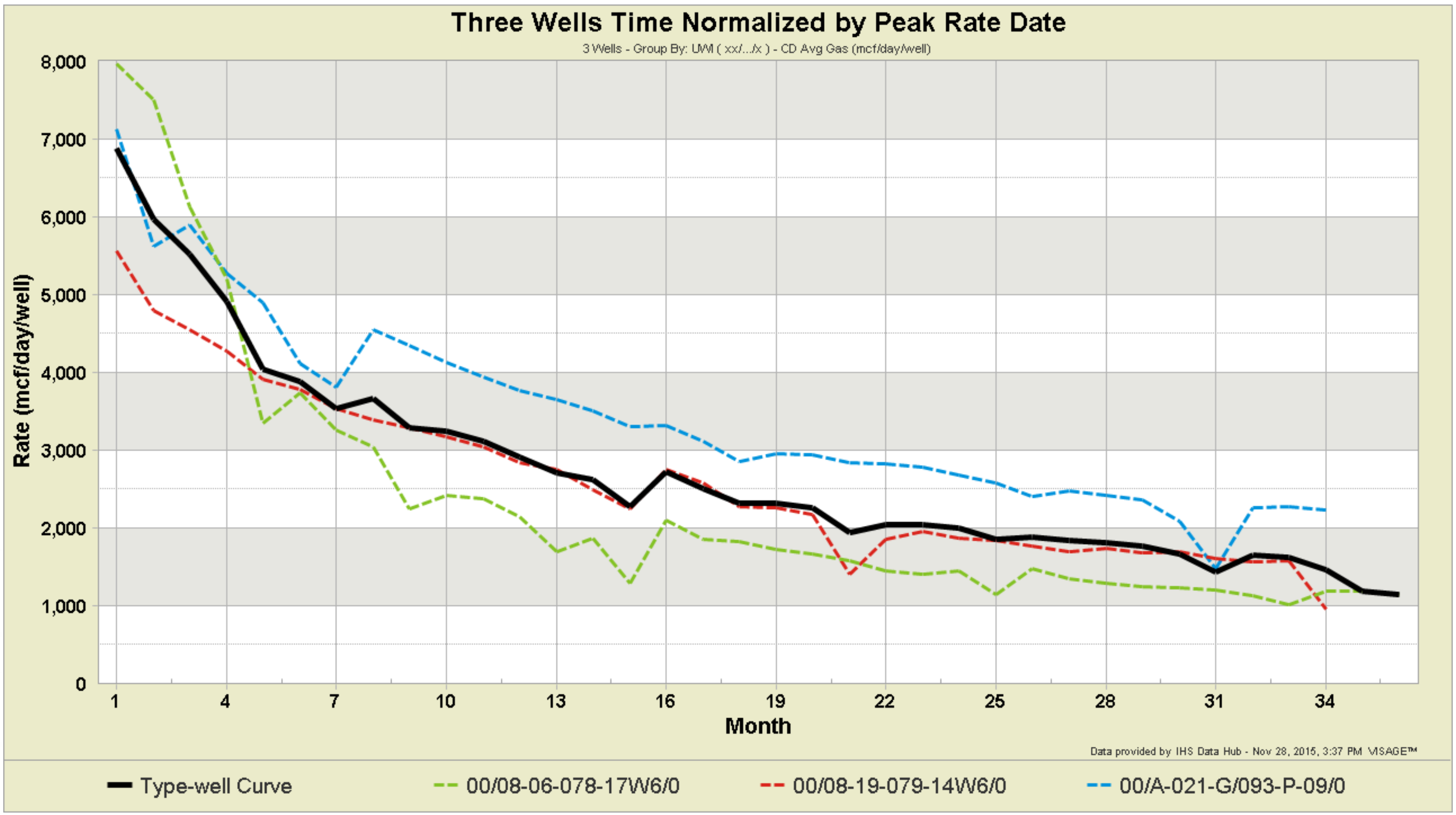
3.1a) Time Normalization on First Production

Shows average production profile (not decline profile).



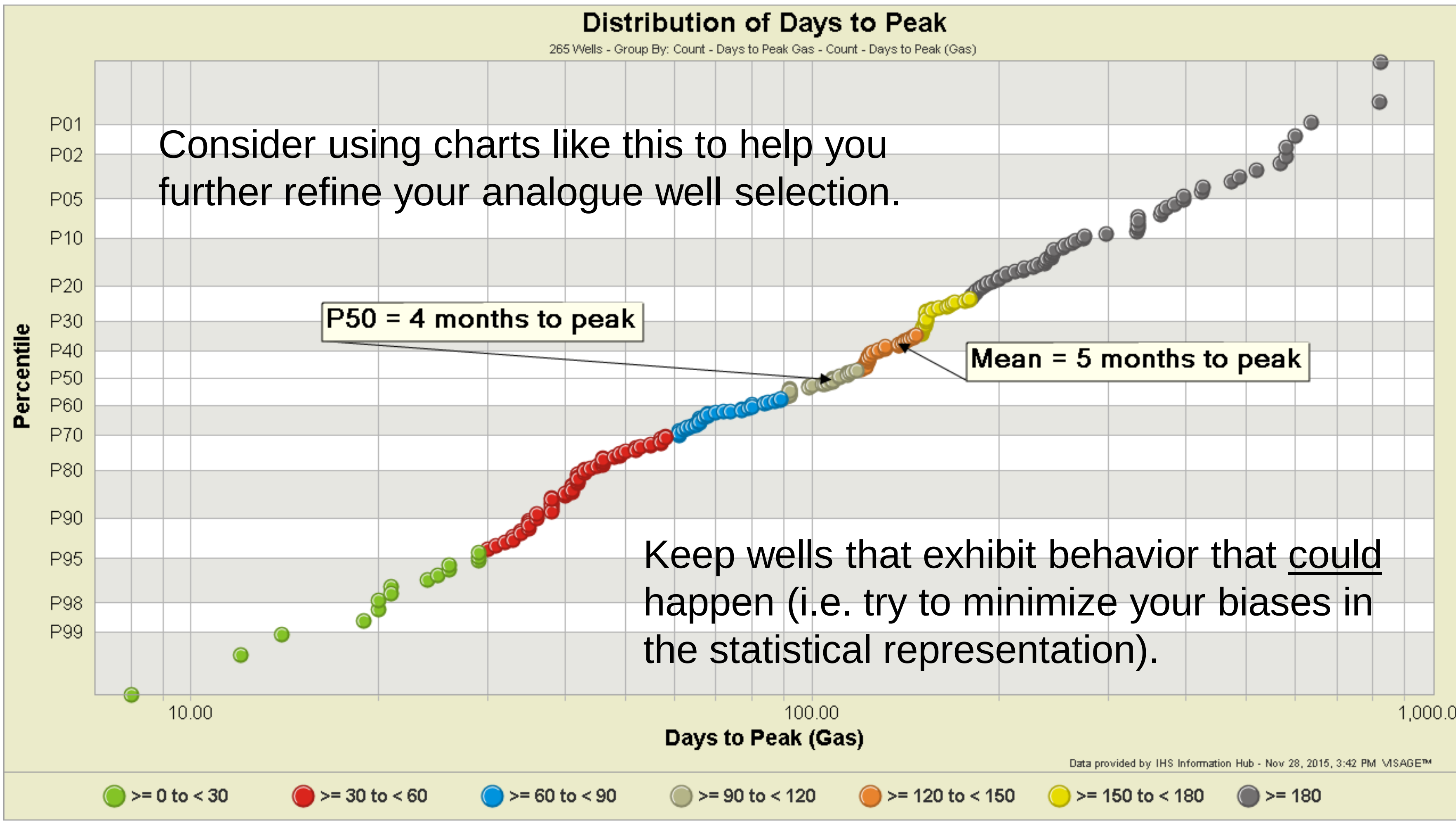
3.1b) Time Normalization on Peak Rate Date

Better reflects the production decline profile.



3.1c) Time to Peak (distribution)

Statistical analysis of time to peak (30 day bins)

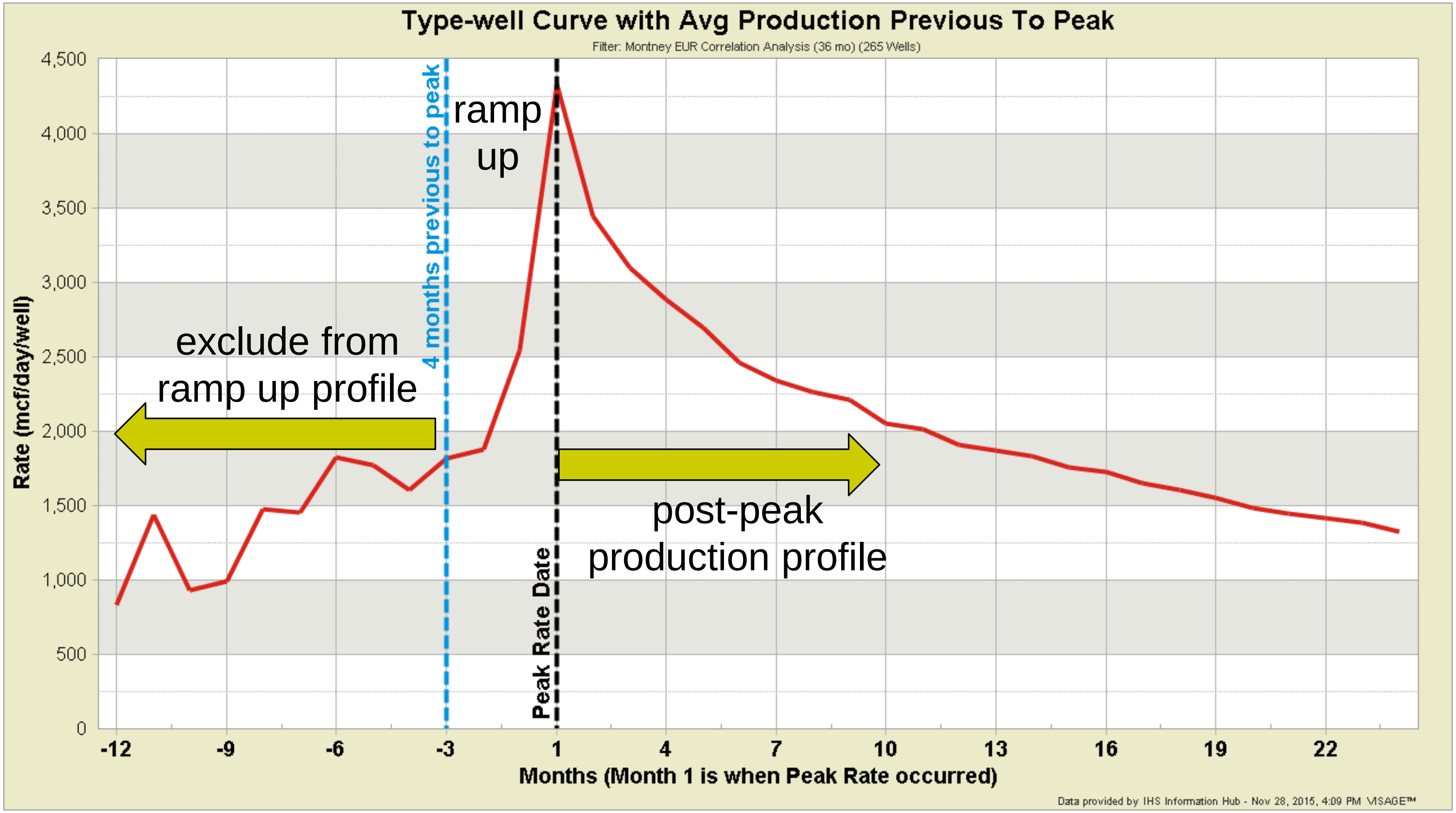


Consider using charts like this to help you further refine your analogue well selection.

Keep wells that exhibit behavior that <u>could</u> happen (i.e. try to minimize your biases in the statistical representation).

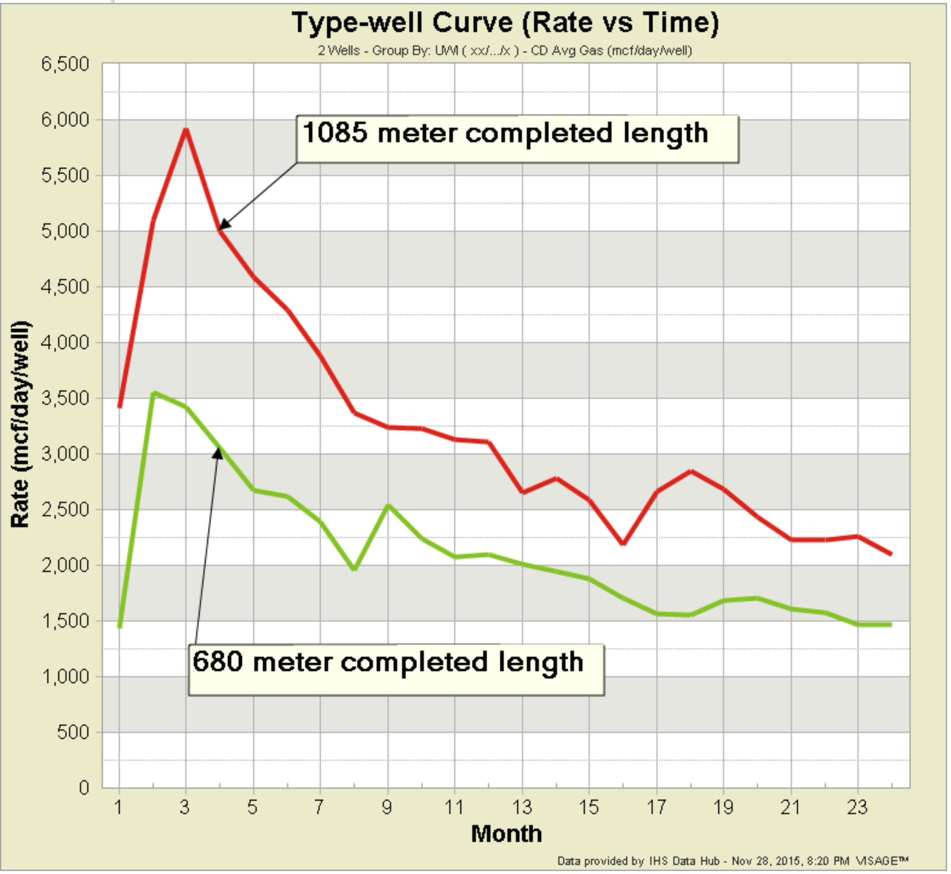
3.1c) Average Ramp Up to Peak (Negative Time)

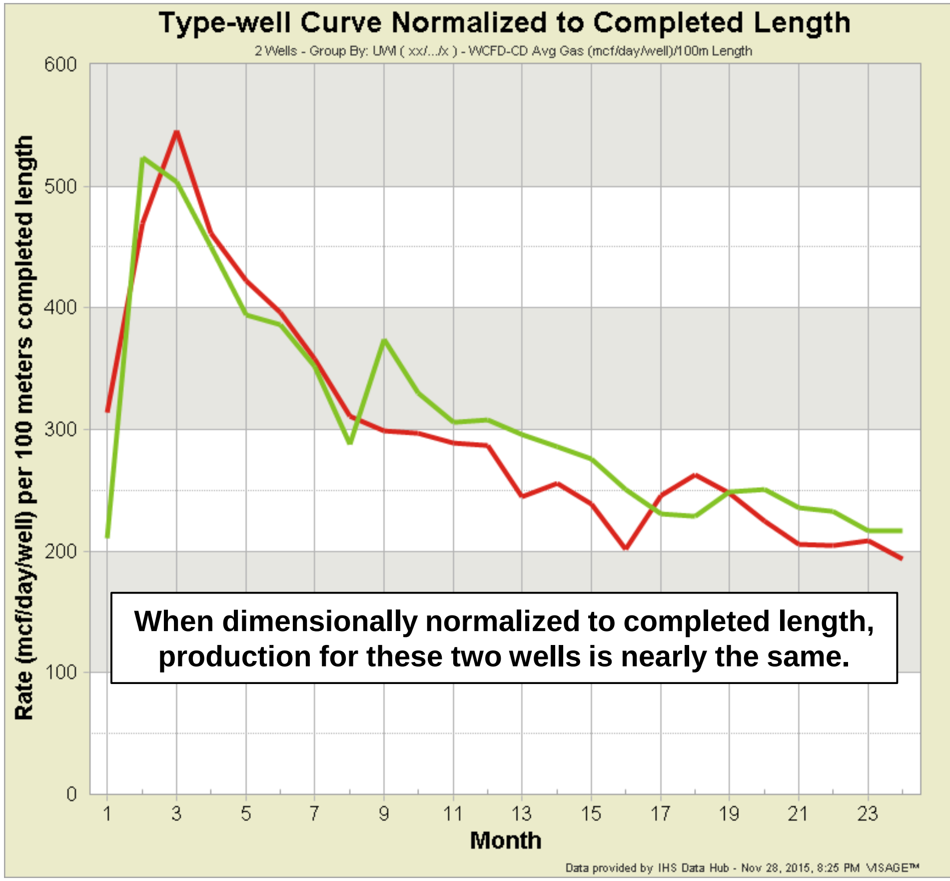
This should be consistent with your operational plans.



3.2) Dimensional Normalization

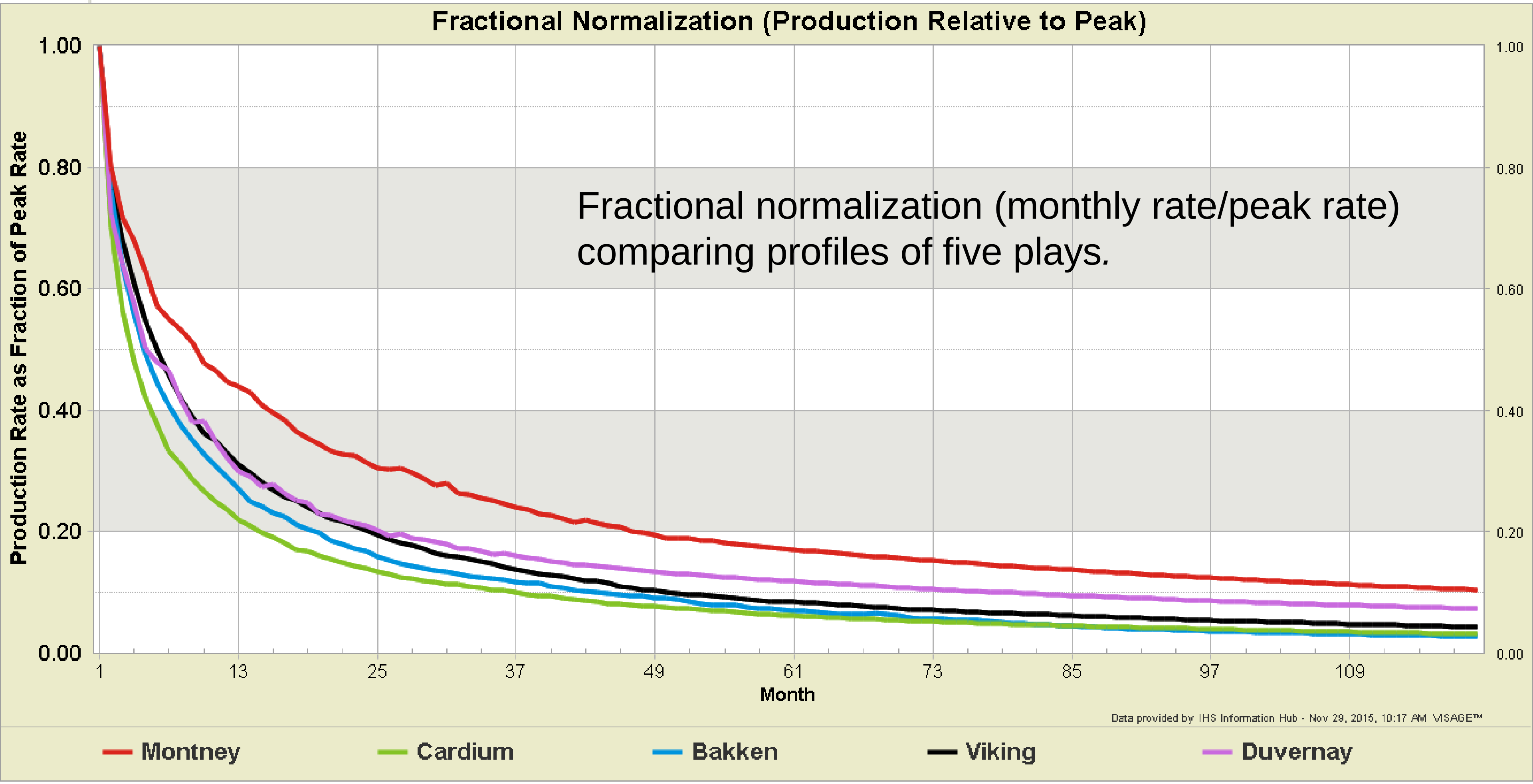
1) Can help you understand production performance changes or differences between vintages, operators, wells etc.
2) Very useful for completion optimization analysis





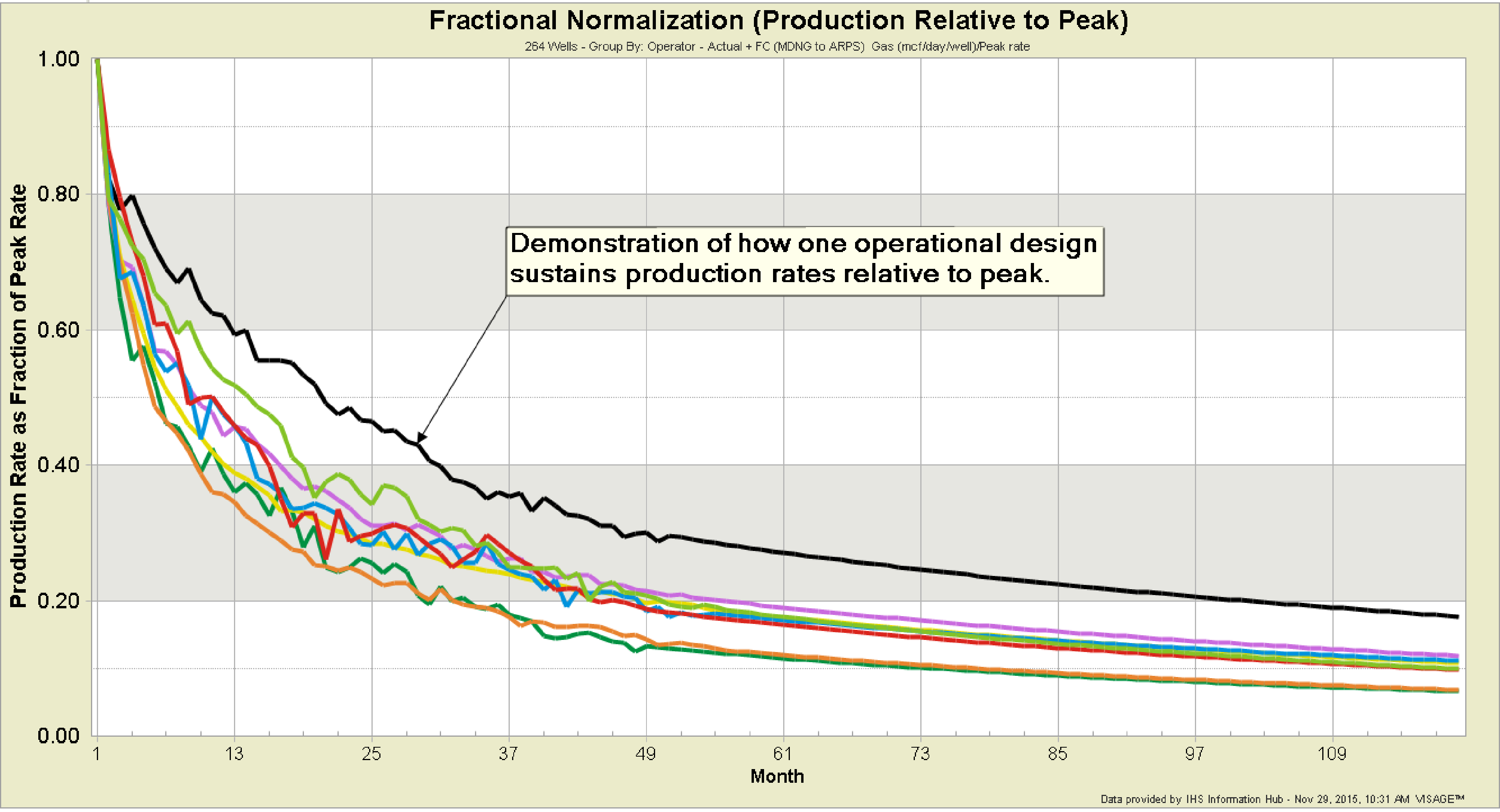
3.3) Fractional Normalization (Curve Shape)

1) What percent of peak rate can I expect in any given month?
2) Given a peak rate, you can generate a quick production profile.



3.3) Fractional Normalization

Compare operational or well design impacts on production profiles.



4) Calendar Day vs Producing Day Rates

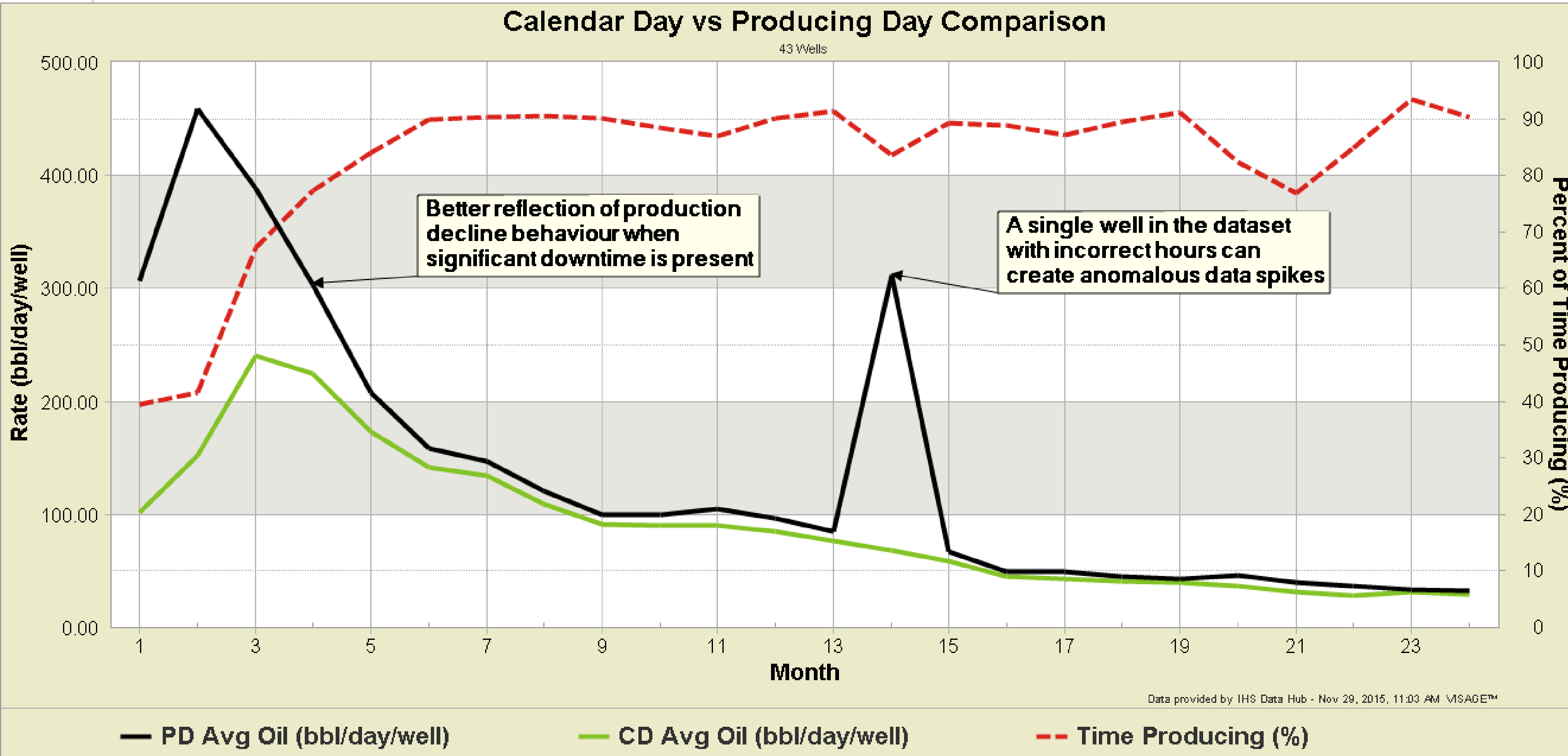
Calendar Day Rate = (volume) / (days in month)

- **Strength:** representative of operational reality (i.e. what actually happened).
- **Weakness:** significant downtime can disrupt the decline shape.

Producing Day Rate = (volume) / (hours producing) * 24

- **Strength:** sometimes more accurately reflects production decline behavior when significant downtime occurs.
- **Weakness:** inflates every production period's value (with downtime) and can overestimate EUR potential. Incorrect hours and flush production (on gas wells) can result in anomalous data spikes. This is reliant on accurate reporting of producing hours.

4) Calendar Day vs Producing Day Rates



	1	2	3	4	5	6	7	8	9	10	11	12
Time Producing (%)	39	42	67	77	84	90	90	90	90	89	87	90
CD Avg Oil (bbl/day/well)	102.27	152.10	240.84	224.46	173.41	142.29	134.04	109.31	91.51	89.96	89.90	85.25
PD Avg Oil (bbl/day/well)	306.20	459.28	388.38	303.62	208.01	158.43	147.32	120.52	99.85	100.04	104.81	96.88

	13	14	15	16	17	18	19	20	21	22	23	24
Time Producing (%)	91	84	89	89	87	89	91	82	77	85	93	90
CD Avg Oil (bbl/day/well)	76.93	68.12	59.33	45.06	43.54	40.54	39.68	36.70	31.65	28.67	31.07	29.76
PD Avg Oil (bbl/day/well)	84.79	312.00	66.71	49.32	49.23	45.68	43.25	46.37	39.47	36.45	33.32	32.56

5) Condensing Time (Idealized Type-well Curves)

"Idealized" type-well curves typically better reflect production decline profiles, but do not accurately reflect elapsed time.

Method 1 (remove months)

- **Example 1:** remove months where production values are zero. Aligns producing months across the dataset. Good on Rate vs Cumulative Charts (see Note below)
- **Example 2:** remove months where producing hours is less than a threshold of 200 hours. Isolates "representative" producing months (introduces bias).

Method 2 (cumulative producing time)

- **Example 1:** plot Producing Day Rate against Cumulative Hours produced.
- **Example 2:** plot Cumulative Production against Cumulative Hours produced.

Note: Excluding zero producing months on Rate vs Cumulative charts ensures that the average of the cumulatives equals the cumulative of the averages.

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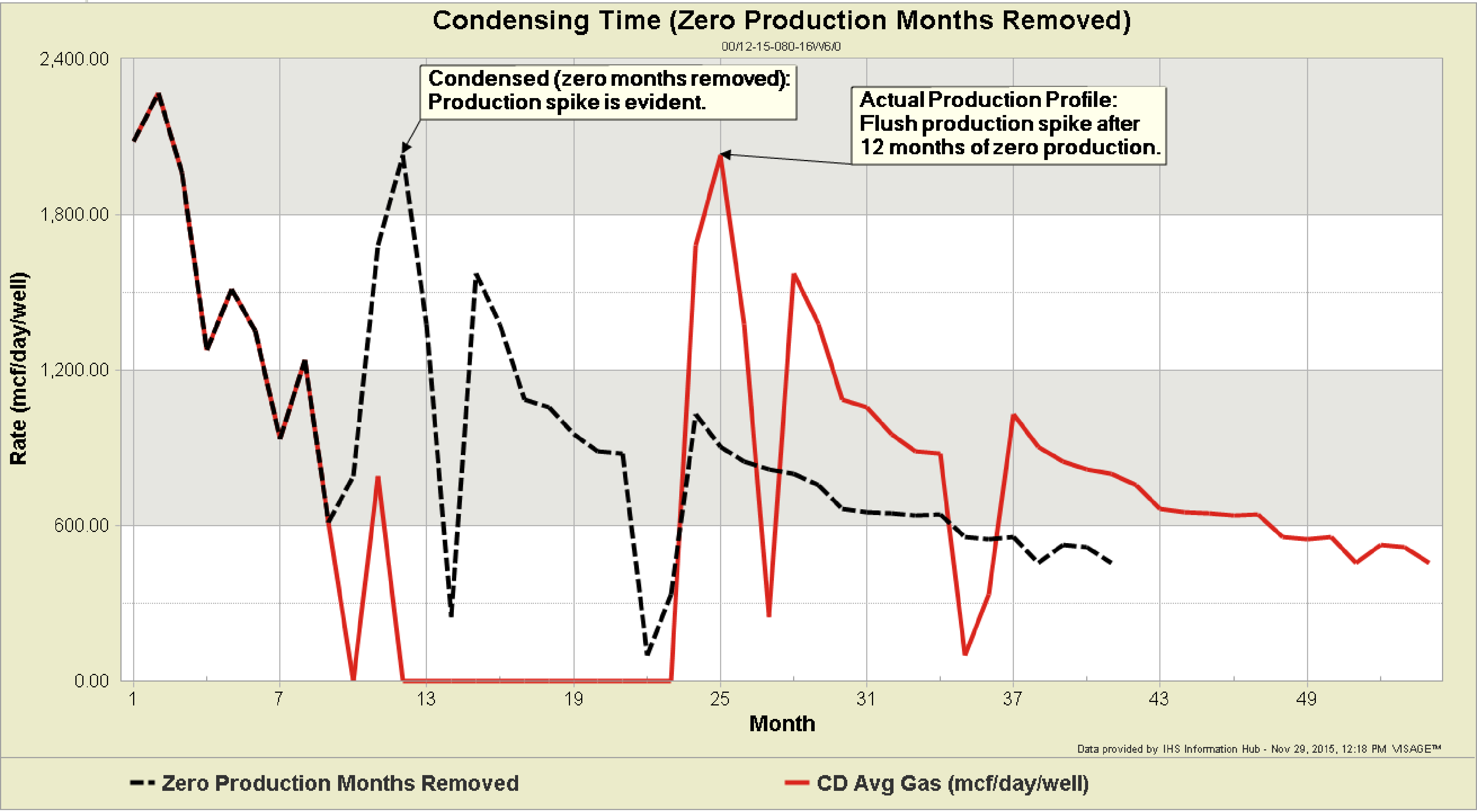
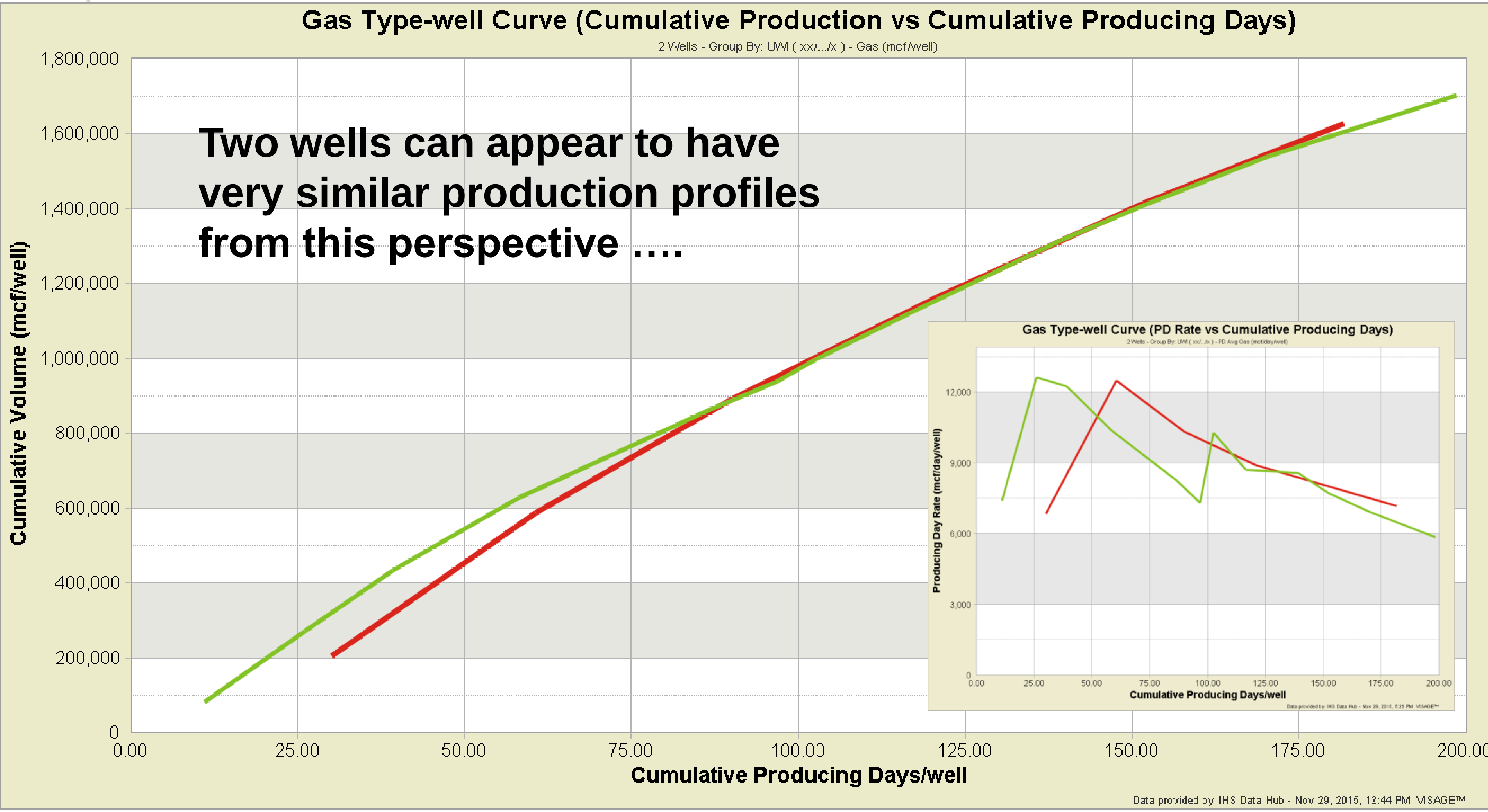
5.1) Condensing Time (removing months)

Beware of flush production spikes on gas wells when removing zero months.

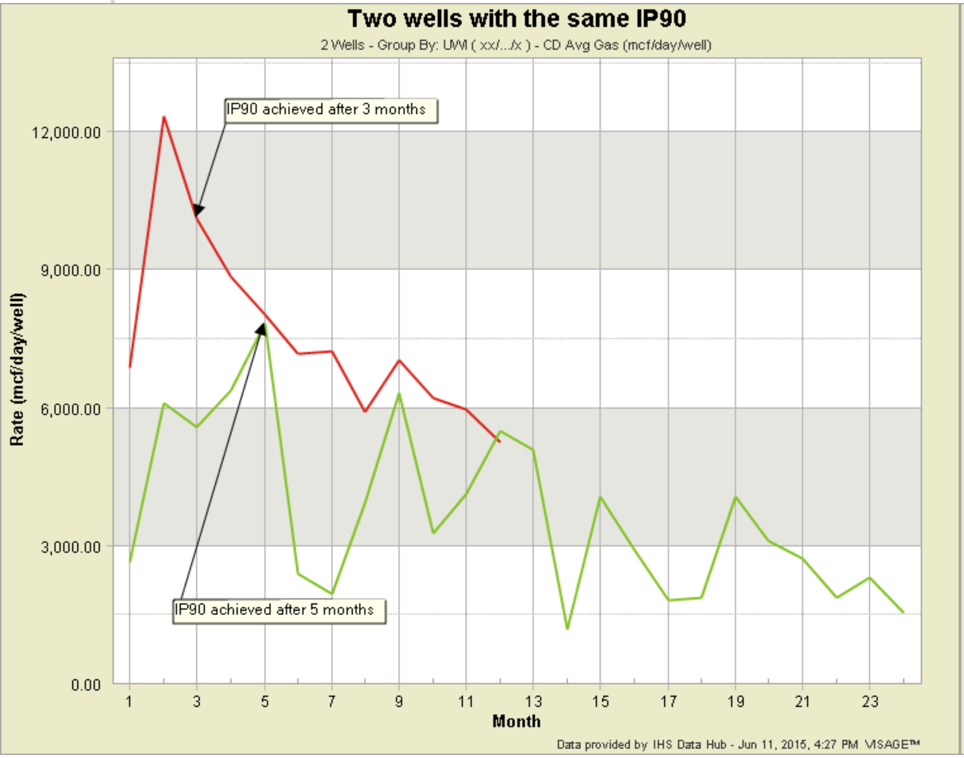


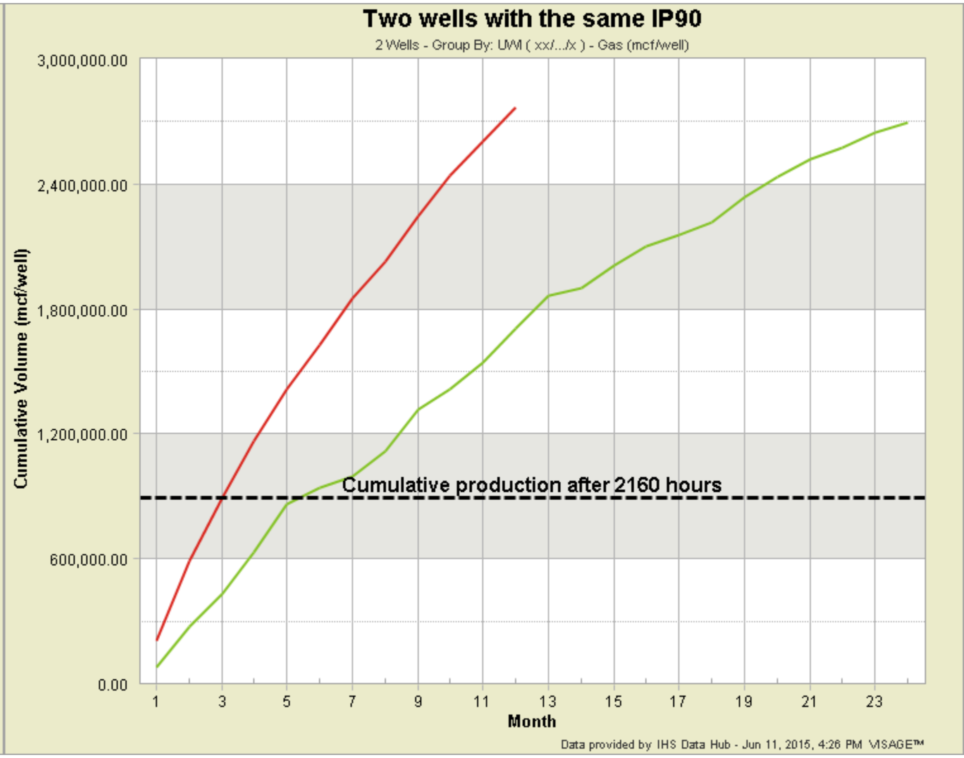
5.2) Condensing Time (cumulative hours producing)



5.2) Condensing Time (cumulative hours producing)

Beware of the danger of factoring out elapsed time. Condensing using cumulative producing hours could represent two wells as similar (in previous slide), while there is dramatic differences in actual production performance (same two wells shown below in rate vs time and cum vs time).





Source: [How useful are IP30, IP60, IP90 … initial production measures?]

6) Important Questions for Decision Makers

How was this type-well curve developed? What does it represent?

Is it being used to inform economic decisions or development plans?

Yes… then has it been scaled to accurately reflect operational realities?

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6) Applying Operational/Downtime Factors

These are sometimes applied to “idealized” type-well curves to better reflect realistic or expected operating conditions. Idealized type-well curves include:

- Producing Day Rate
- Condensed Time (downtime removed)
- Condensed Time (cumulative producing days)

1) Percent Downtime approach
    - May not accurately reflect each well’s production weighting.
    - Does the amount downtime change over the life of a well?
2) Factor based on relative cumulative production in month N
    - e.g. (avg cum production)/(idealized cum prod) in month 60

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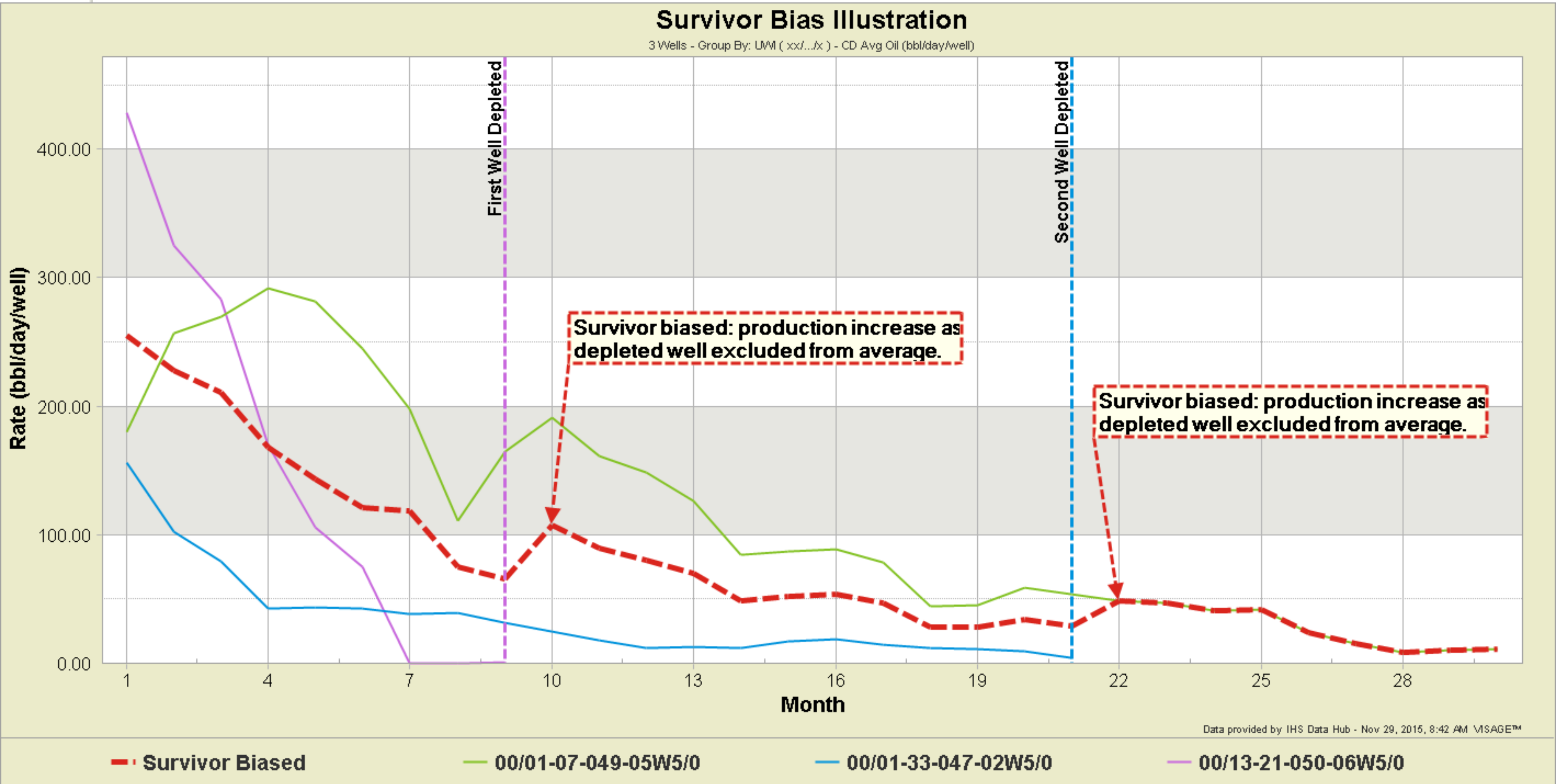
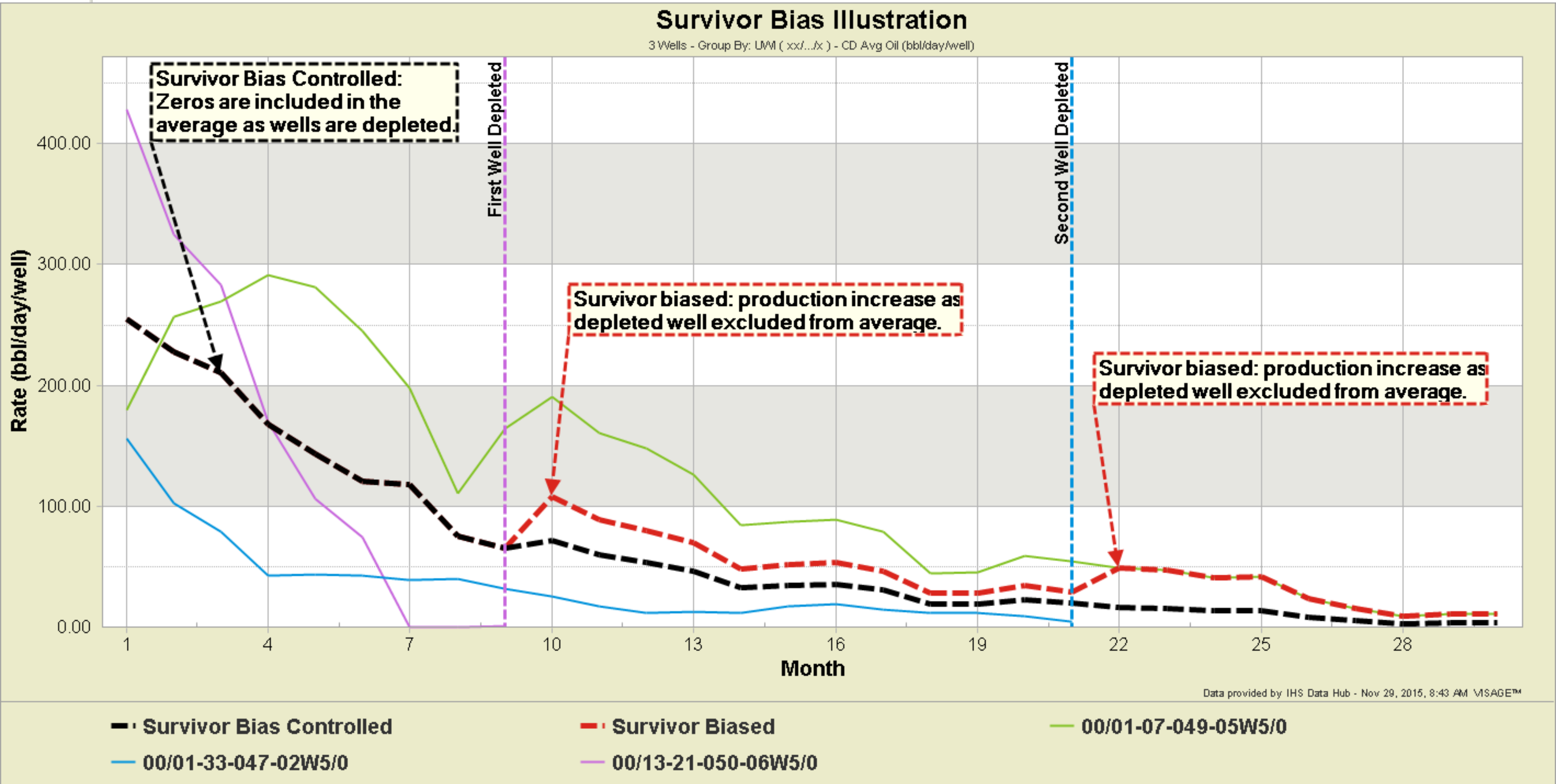
7) What is Survivor Bias?

Definition: as depleted wells are excluded from the average, the type-well curve values are biased by the surviving wells.



7) Survivor Bias Controls

Survivor bias controls will include zeros in the average for wells after they are identifiably depleted (e.g. no production in last 12 months).



8) Truncation using Sample Size Cut-off

- Sample sets often have wells with a range of production history, meaning the latter portion of the type-well curve is based on, and increasingly biased by, older wells.

- Sample size cut-off is expressed as a percent of the first month's sample size. When the number of producing wells contributing to the average drops below the specified percentage the type-well curve average will stop calculating.

- Common values used are 50% or greater.

- Consider selecting wells by vintage to ensure contributing wells have a similar amount of production history.

9) Forecast the Average vs Average the Forecasts

Forecast the Average

- Apply a decline profile to the truncated average type-well curve to get a single full life profile of EUR
- Time effective, but does not provide a distribution of EUR values
- Limits the well sample size, potentially increasing the uncertainty of the mean on smaller datasets (based on the principle of Aggregation ***)

Average the Forecasts (of all wells)

- Time consuming unless auto-forecasting is used
- Auto-forecasting typically does not have any "human" judgement applied to it, but human's can vet the forecast results
- Useful for statistical evaluation and P10/P90 quantification of EUR uncertainty

*** consult experts like **Rose & Associates**, **GLJ Petroleum Consultants** or **McDaniels & Associates Consultants** to understand Aggregation principles in the context of production forecasts and reserve evaluations.

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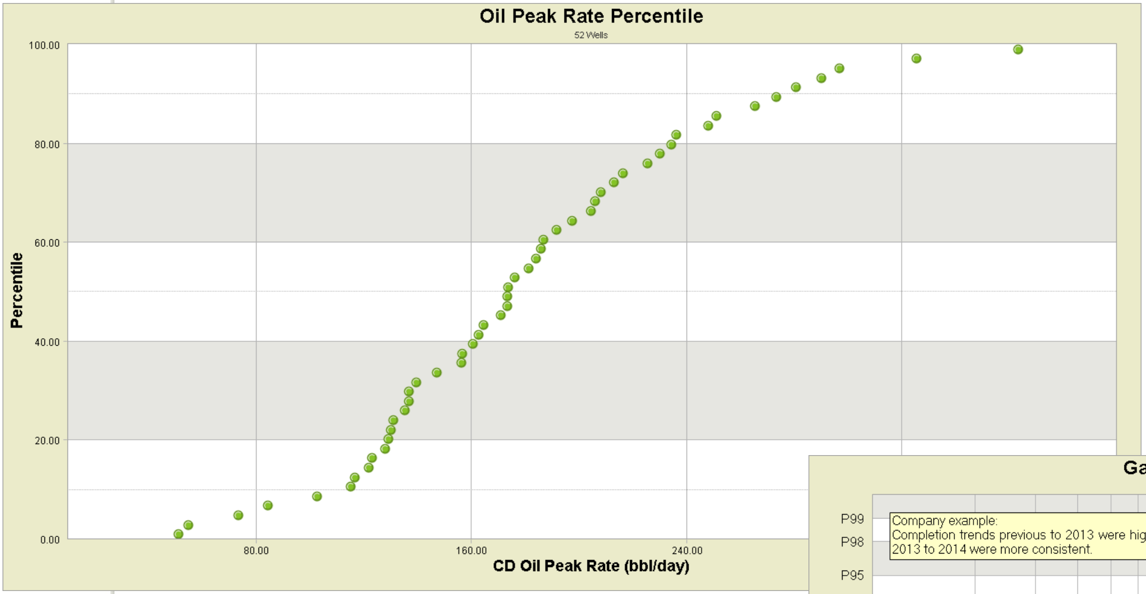
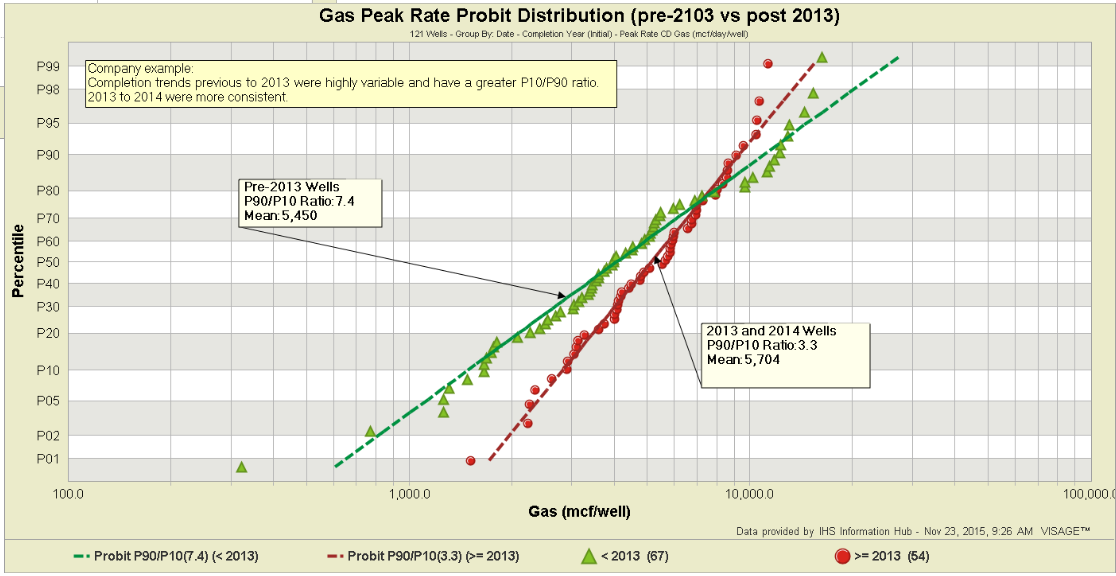
10.1) Representing Uncertainty (Distributions)

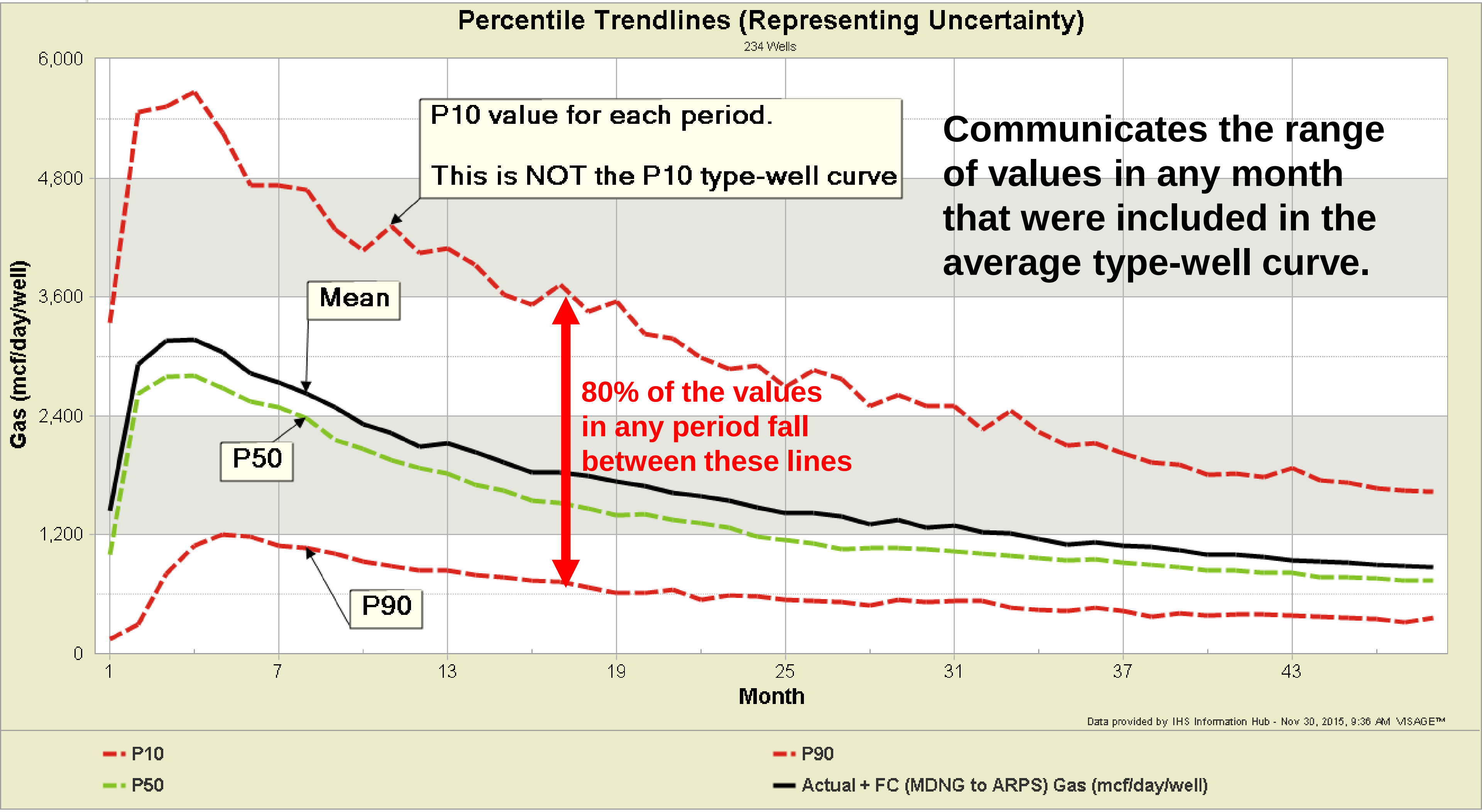
Percentile (Cumulative Probability)



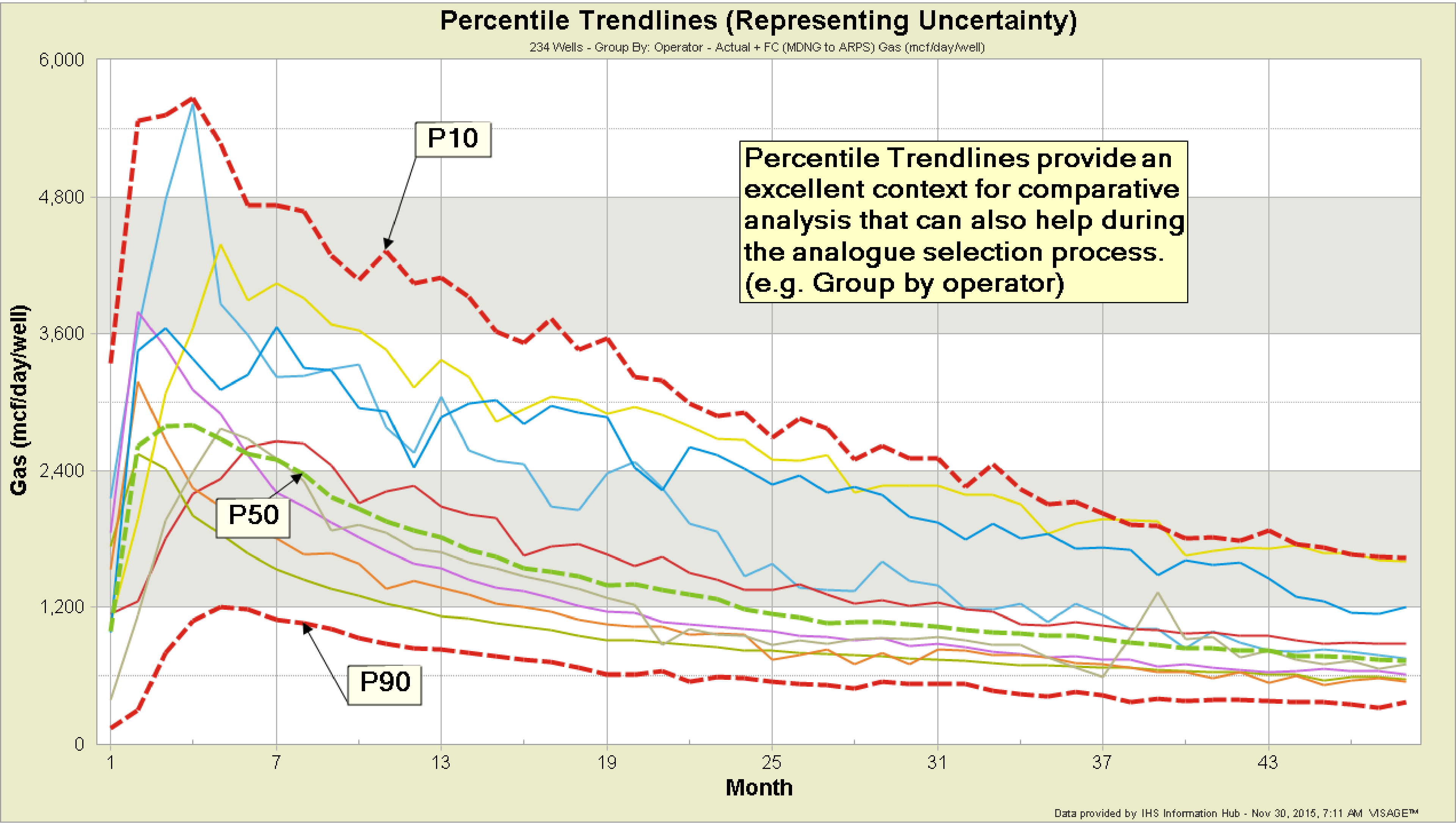
Probit with P10/P90 ratio



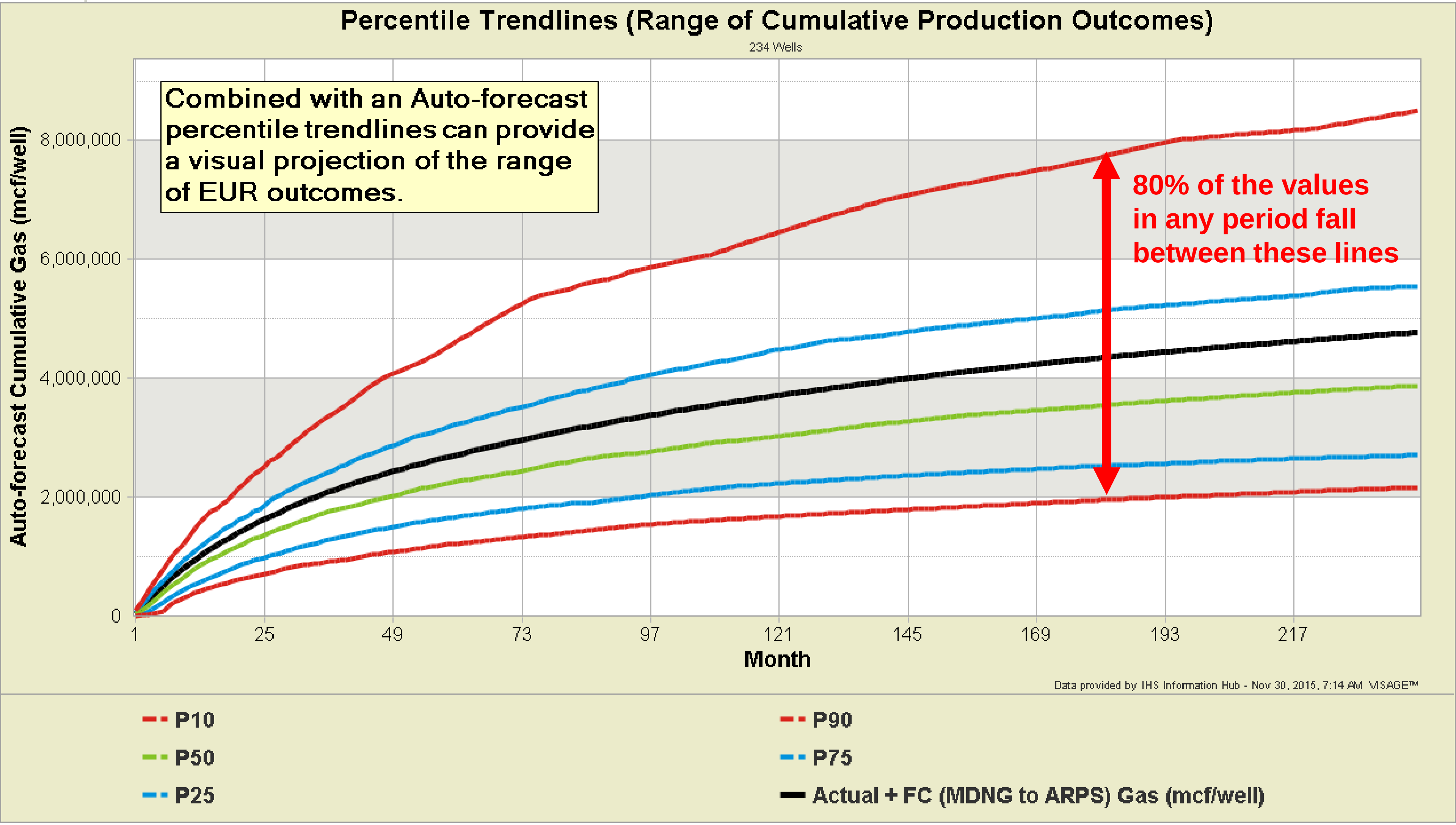
10.2) Percentile Trendlines



10.3) Percentile Trendlines



10.4) Percentile Trendlines (EUR Outcomes)



11) Auto-forecast Tools

Auto-forecasts provide a complementary set of tools and insights that can not be achieved by looking at production history alone. They include:

- **EUR Half-life**
- **Instantaneous b values**
- **Effective Annual Decline Rates**
- **EUR (distributions, dimensional normalization)**

These can be used to characterize uncertainty, validate manual forecasts, provide supporting material for multi-segment Arps forecasts, and spatial analysis.

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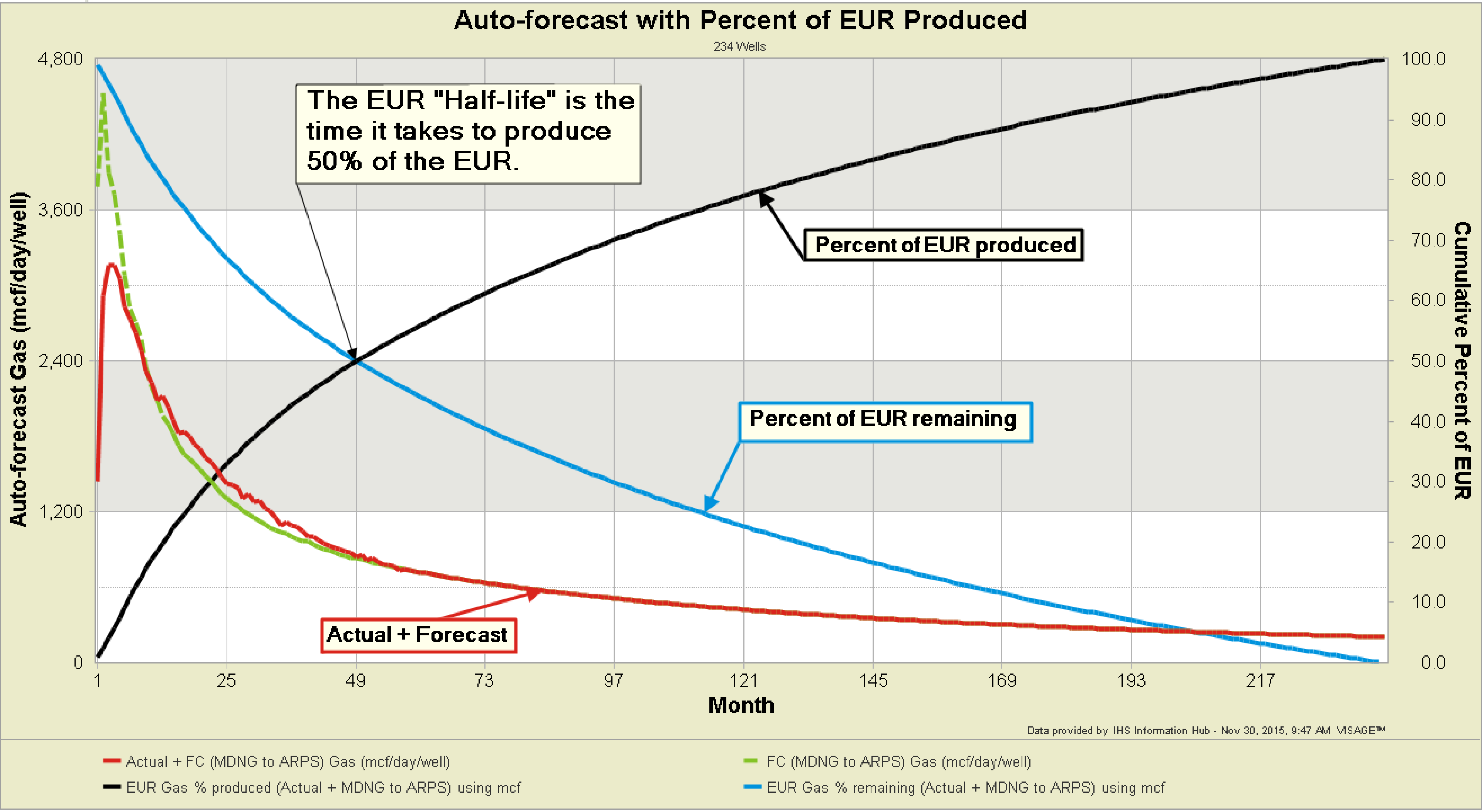
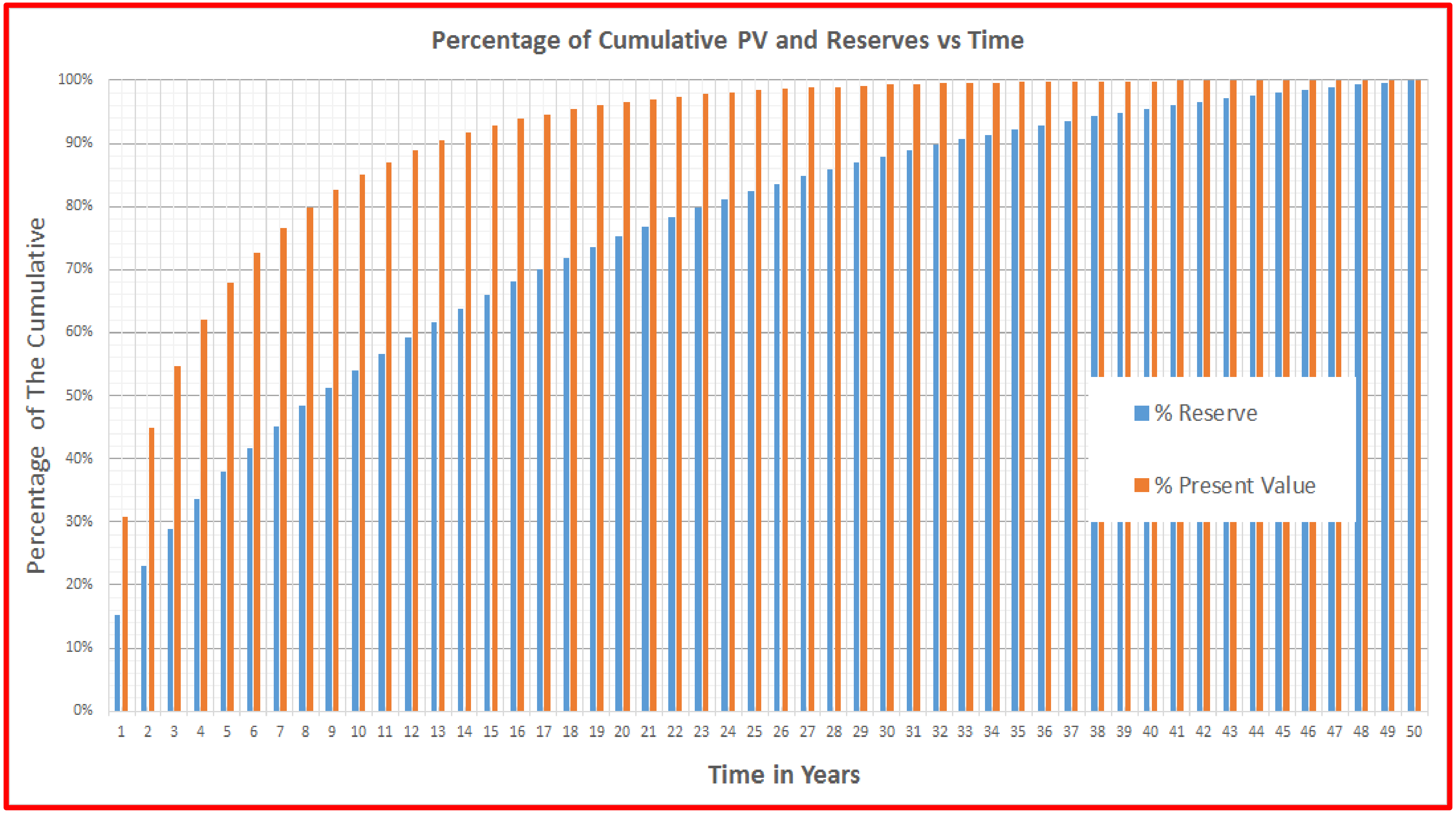
11.1) Auto-forecast Tools (EUR "Half-life")



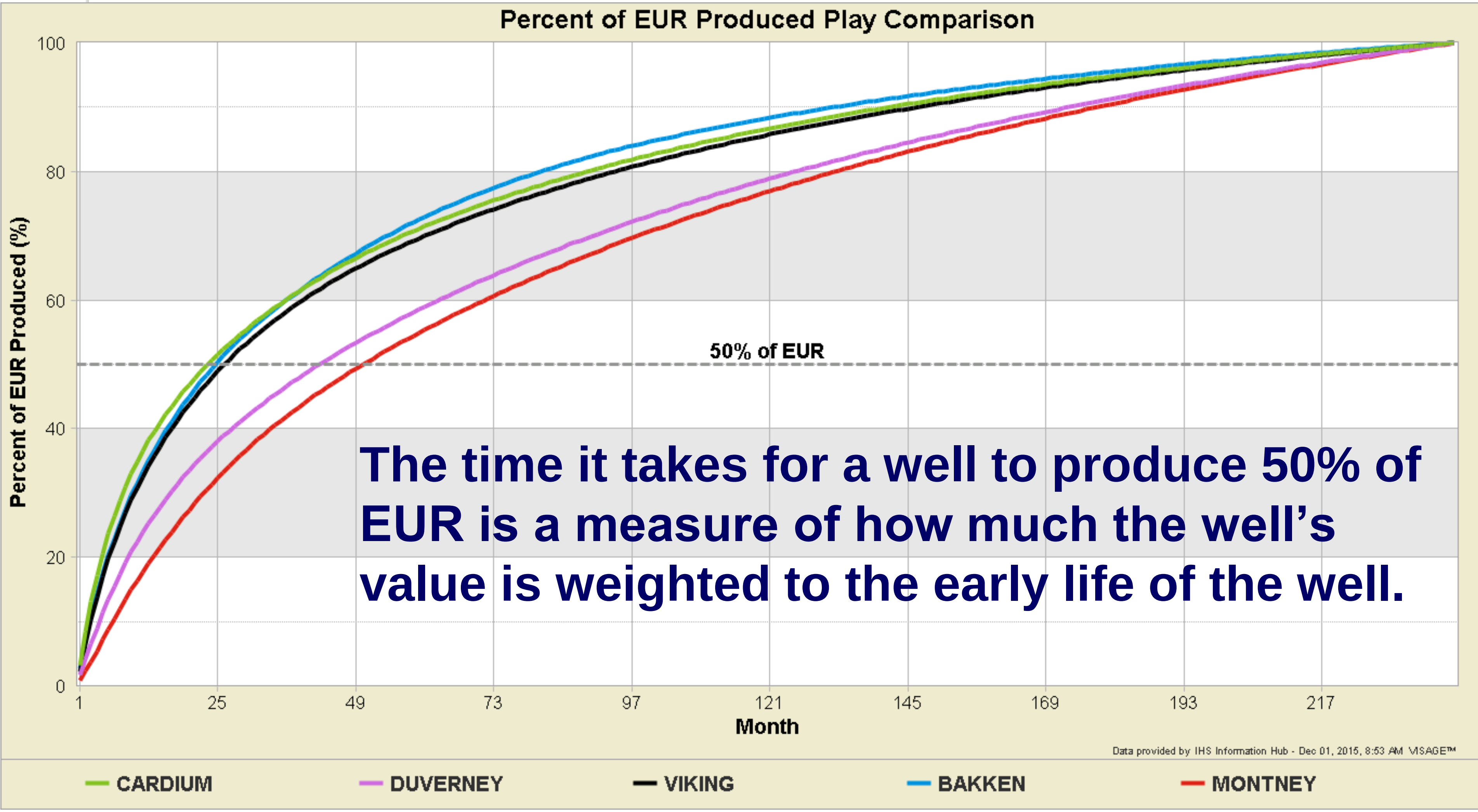
11.2) Value vs Volume

Example where 80% of a well's value is achieved around the same time that 50% of the EUR is produced.



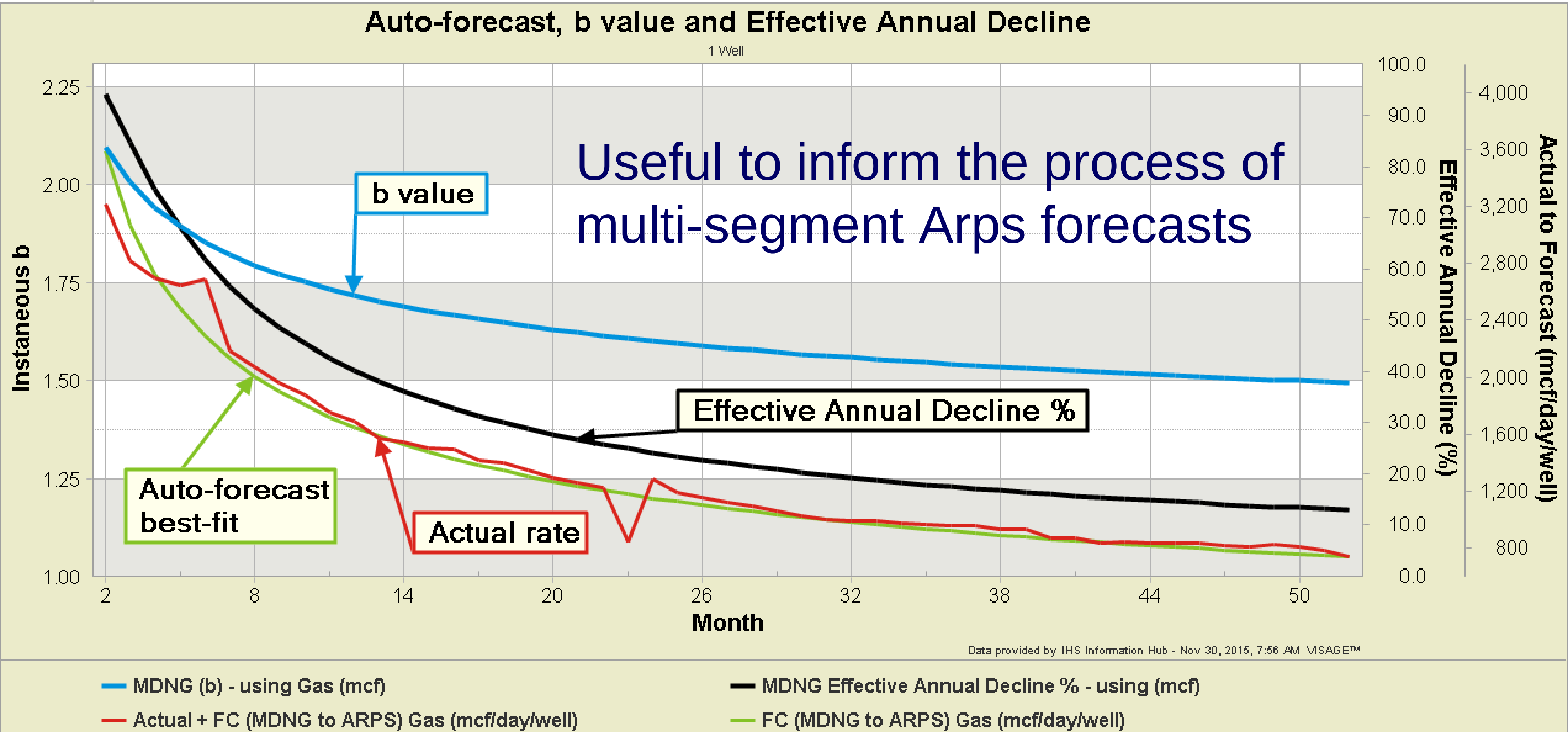
Courtesy of [Rose & Associates]

11.3) EUR Half Life Comparison



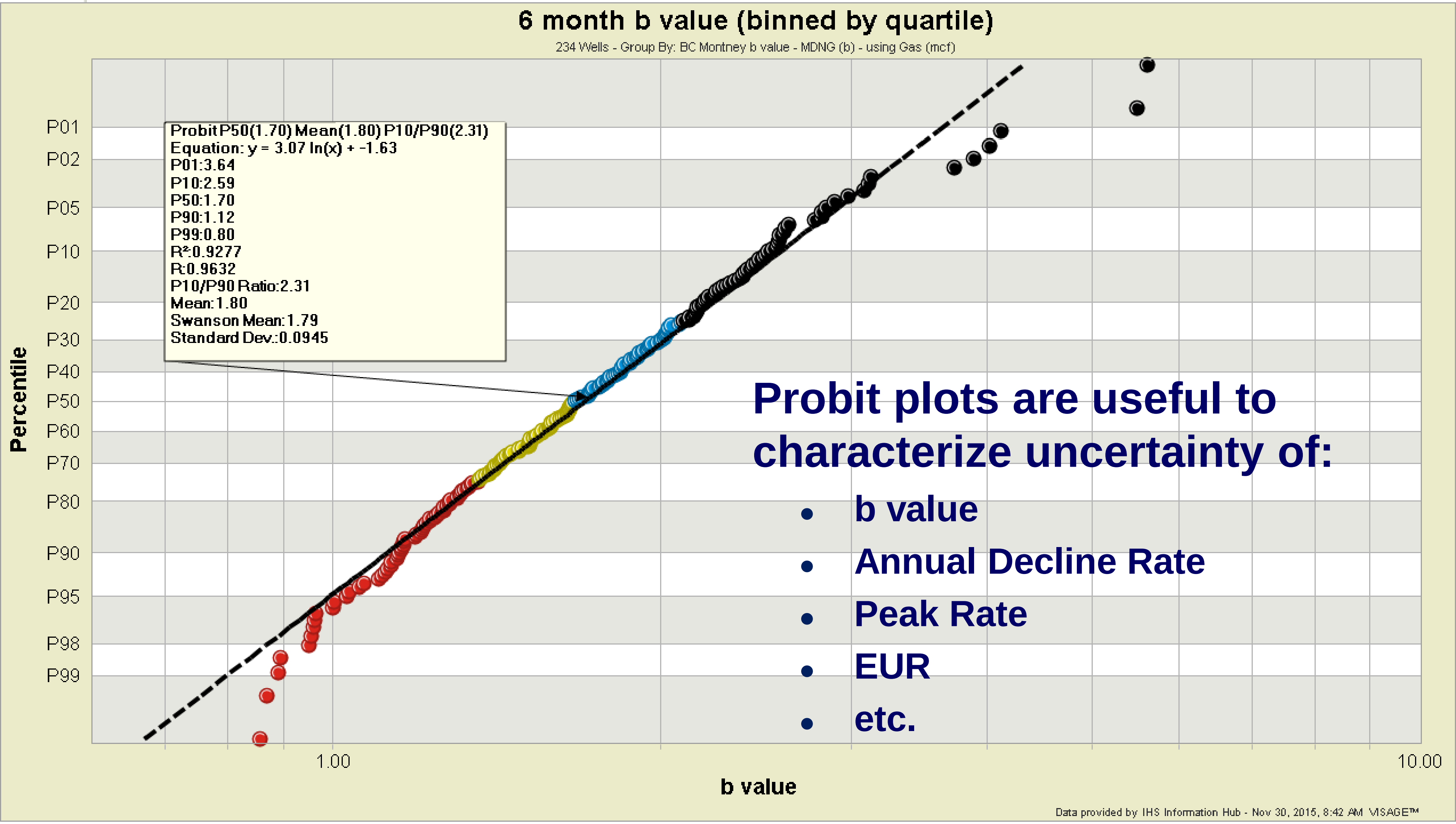
The time it takes for a well to produce 50% of EUR is a measure of how much the well's value is weighted to the early life of the well.

11.4) b value and Annual Decline Rate



	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
FC (MDNG to ARPS) Gas (mcf/day/well)	3,591	3,070	2,728	2,480	2,288	2,134	2,006	1,898	1,804	1,722	1,650	1,585	1,527	1,475	1,426	1,382	1,342	1,304	1,269	1,237	1,206	1,177
Actual + FC (MDNG to ARPS) Gas (mcf/day/well)	3,223	2,817	2,698	2,650	2,688	2,189	2,074	1,960	1,874	1,757	1,695	1,576	1,546	1,506	1,492	1,414	1,398	1,343	1,297	1,262	1,221	844
MDNG Effective Annual Decline % - using (mcf)	94.3	84.8	75.7	68.2	61.9	56.7	52.4	48.7	45.5	42.7	40.2	38.1	36.1	34.4	32.8	31.4	30.1	28.9	27.8	26.8	25.9	25.0
MDNG (b) - using Gas (mcf)	2.10	2.01	1.94	1.89	1.85	1.82	1.79	1.77	1.75	1.73	1.72	1.70	1.69	1.68	1.67	1.66	1.65	1.64	1.63	1.62	1.61	1.61

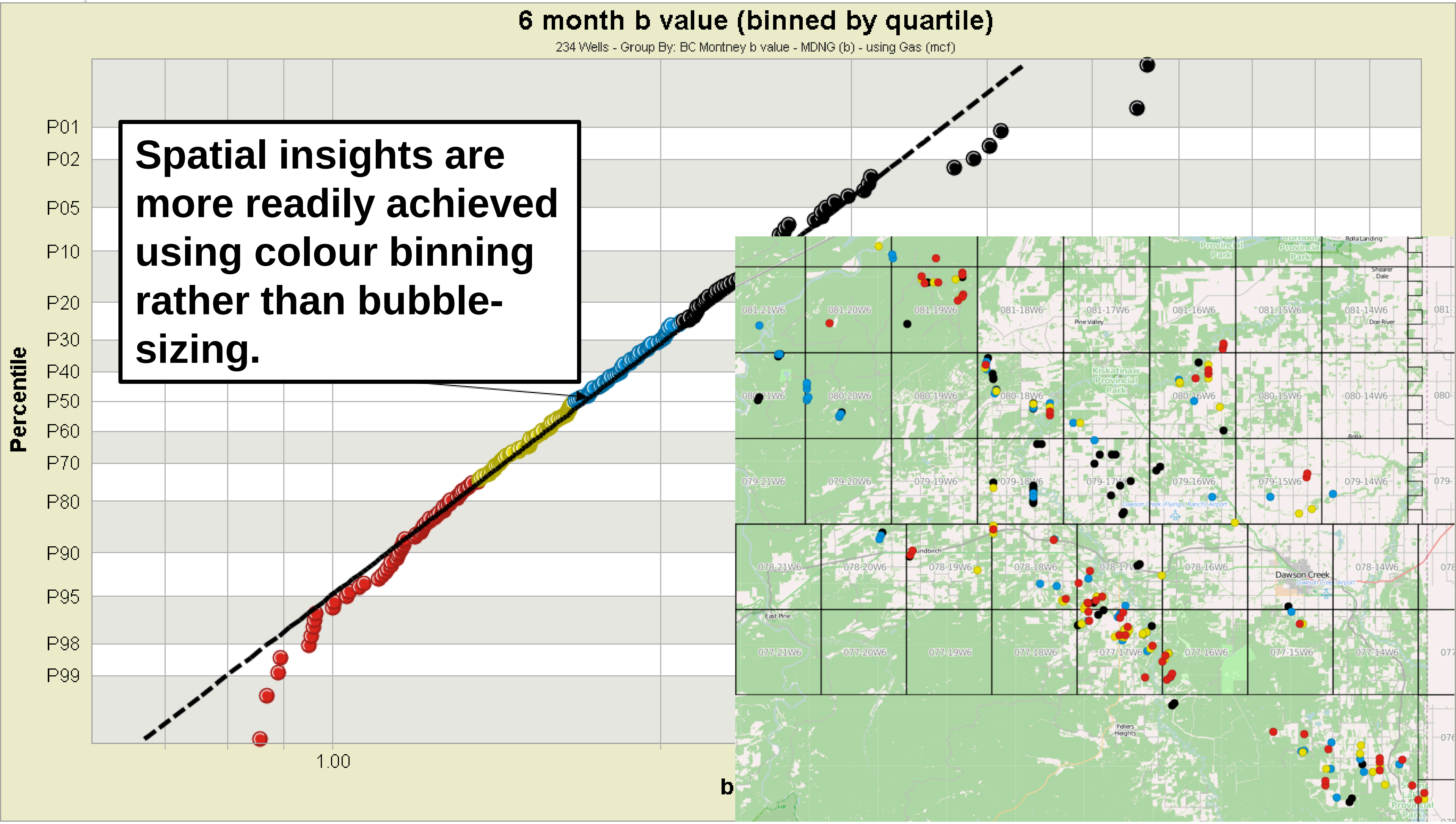
11.4) Probit Plots on Forecast Parameters



Probit plots are useful to characterize uncertainty of:

- b value
- Annual Decline Rate
- Peak Rate
- EUR
- etc.

11.5) Percentile Quartile Binning on Maps



Spatial insights are more readily achieved using colour binning rather than bubble-sizing.

Presentation Recap

1) Chart Types
2) Analogue Selection
3) Normalization
4) Calendar Day vs Producing Day
5) Condensing Time
6) Operational/Downtime Factors on Idealized Curves
7) Survivor Bias
8) Truncation Using Sample Size Cut-off
9) Forecast the Average vs Average the Forecasts
10) Representing Uncertainty
11) Auto-forecast Tools

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Closing Comments

- All of the techniques that I have shown you today take minutes to perform (with the right tools). They are within your grasp.
- Taking the time to investigate and ask questions can help characterize, and potentially reduce, uncertainty.
- Understanding what you're trying to accomplish with your analysis can help you focus on the techniques that will best meet your needs.
- Capture the steps, assumptions, analogue selection criteria, well exclusions… to help communicate with colleagues how your type-well curves were developed.
- Use many charts … build a narrative!

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- **Matt Ockenden**
  Auto-forecast design contributions, quartile mapping & industry expertise
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- **GLJ Petroleum Consultants**
  Industry expertise, technical advice & software design contributions
- **Brian Hamm (McDaniel & Associates)**
  Survivor bias design contributions & type-well curve insights

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Data Sources used in VISAGE charts:

IHS

Information Hub

Canadian Discovery Ltd.

WELL COMPLETIONS & FRAC DATABASE

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