PRODUCTION PERFORMANCE DIAGNOSTIC AND DECLINE CURVE ANALYSIS

WELL

AMBER ELIZABETH 36-25H

Source records, calculation results, and report tables are in the companion Excel report.

WELL ID
33053043310000::BAKKEN

STATE
North Dakota

OPERATOR
MUREX PETROLEUM CORPORATION

COUNTY
McKenzie

COUNTRY
United States

1. PROJECT BACKGROUND & OBJECTIVES

This report presents a detailed Decline Curve Analysis (DCA) performed for Well AMBER ELIZABETH 36-25H. The study was conducted to provide an independent, production data-driven evaluation of well performance, production decline behavior, flow regime characteristics and remaining recoverable reserves based exclusively on historical production data.

The analysis is based solely on available monthly production history, including oil, water and gas production together with days-on-production records. No reservoir simulation models, pressure transient analysis (PTA), rate transient analysis (RTA), bottom-hole pressure surveillance or detailed operational event databases were available as part of the study workflow.

The objective of the analysis is therefore to establish a transparent, reproducible and engineering-consistent production interpretation framework directly from historical production behavior.

1.1 PRIMARY OBJECTIVES

The primary objectives of the study are summarized below:

- To evaluate historical production performance and decline behavior of the well;
- To identify distinct production regimes and separate relatively stable decline periods from operationally unstable production behavior;
- To quantify decline parameters, including initial nominal decline rate (D_i), hyperbolic exponent (b) and terminal decline characteristics for each identified production regime;
- To generate deterministic segment-based production forecasts using Arps decline methodology;
- To estimate remaining recoverable reserves (EUR) based on forecasted production performance;
- To assess the impact of production instability, downtime and changing operating conditions on decline behavior;
- To evaluate long-term productivity degradation trends and changing fluid production characteristics over time;
- To perform production diagnostics supporting interpretation of possible flow regimes and reservoir behavior;
- To establish a transparent production baseline suitable for comparison with future surveillance studies or reservoir engineering evaluations.

1.2 WORKFLOW OVERVIEW

The analysis follows a production data-driven Decline Curve Analysis workflow based on standard Arps decline methodology and engineering review of historical production behavior.

The workflow consists of the following sequential steps:

Production Data Review and QA/QC

Engineering review of historical monthly oil, water and gas production together with days-on-production data. Consistency checks and production trend validation were performed prior to decline analysis.

Data Preparation

Preparation of production datasets, calculation of cumulative production volumes (Np, Wp, Gp), flowing-time normalization and generation of diagnostic production plots

Production Regime Identification and Segmentation

Identification of relatively stable production periods and production regime changes based on production data and its derivatives

Segment-Based Decline Curve Analysis

Application of Arps decline models, using engineering-constrained fitting of decline parameters and segment-based production interpretation.

Diagnostic Production Analysis

Forecast Generation

Construction of deterministic segment-based production forecasts using selected decline parameters and terminal decline assumptions.

Remaining Recoverable Reserves Estimation

Analytical estimation of remaining recoverable reserves (EUR) through integration of forecast production curves down to selected technical or economic production limits.

1.3 METHODOLOGY LIMITATIONS

The methodology presented in this report is based exclusively on historical monthly production data and production trend interpretation.

No full-physics reservoir simulation, pressure transient analysis (PTA), rate transient analysis (RTA), material balance modeling or integrated nodal analysis was performed as part of this study.

Accordingly, the resulting forecasts and interpretations should be considered engineering extrapolations of historical production behavior rather than deterministic reservoir simulation forecasts.

2. INPUT DATA INVENTORY AND QUALITY ASSESSMENT

The Decline Curve Analysis (DCA) workflow was performed using the available monthly production dataset summarized below.

2.1 DATA QUALITY ASSESSMENT

The available production dataset is considered suitable for production surveillance and decline curve analysis under the limitations associated with monthly aggregated production reporting.

The analysis was performed using historical monthly oil, water and gas production volumes together with monthly days-on-production records. No detailed operational event database, separator surveillance data, bottom-hole pressure measurements or intervention tracking records were available during the study.

The primary limitations affecting the analysis are summarized below.

MONTHLY DATA RESOLUTION

Production data are available only in monthly aggregated format. Short-duration transient behavior, operational disturbances and rapid production changes cannot therefore be resolved explicitly within the available dataset.

LIMITED OPERATIONAL CONTEXT

No systematic records of choke changes, artificial lift modifications, shut-ins, well interventions or facility constraints were available during the analysis period. As a result, observed production changes must be interpreted primarily from production behavior itself rather than direct operational evidence.

ABSENCE OF PRESSURE SURVEILLANCE

Bottom-hole and flowing pressure measurements were not available for integrated pressure-rate interpretation. The workflow therefore relies primarily on production-rate diagnostics and decline behavior analysis.

ALLOCATION AND MEASUREMENT UNCERTAINTY

Reported production rates represent historical allocated production data and may contain uncertainty associated with field allocation methodologies and measurement accuracy.

2.2 ANALYTICAL APPROACH AND DATA CONDITIONING PHILOSOPHY

The analysis workflow was intentionally designed to preserve observed production behavior rather than artificially smooth or statistically normalize the production history.

Aggressive statistical filtering, synthetic smoothing and probabilistic Monte Carlo methods were intentionally avoided in order to retain production characteristics potentially associated with reservoir behavior and operational changes.

Production anomalies and apparent discontinuities were reviewed directly within production trend context prior to inclusion in decline analysis intervals.

Where distinct production regime changes were identified from historical trends, multi-segment decline analysis was applied to isolate relatively stable flowing periods suitable for decline modeling.

Forecast confidence was assessed using:

- production history length,
- flowing trend stability,
- consistency of decline behavior,
- residual behavior of fitted decline models,
- and overall continuity of the production history.

Wells exhibiting unstable production behavior or insufficient stabilized production periods were classified as lower-confidence candidates for long-term extrapolation.

2.3 FLOW REGIME CONSIDERATIONS

Classical decline curve analysis methods are theoretically most reliable during stabilized flow. Early transient flow behavior and operationally unstable production periods may produce decline characteristics that are not representative of long-term reservoir performance.

Due to the limited operational and pressure surveillance data available, interpretation of flow regimes was performed primarily from production trend behavior and decline consistency.

The resulting forecasts should therefore be interpreted as engineering extrapolations of historical production behavior rather than deterministic full-physics reservoir simulation forecasts.

3. PRODUCTION DATA QA/QC WORKFLOW

All production data used in this report corresponds to Well `AMBER ELIZABETH 36-25H` . The analysis was performed using a monthly production dataset containing the following minimum input fields: production month/report date, API well number or well identifier, well name, operator/company name, oil production, gas production, water production, and days-on-production. Additional metadata such as field name, reservoir, section, township/range, and lease information were incorporated when available to support well identity validation and contextual interpretation.

Production QA/QC was performed before decline curve fitting, production segmentation, forecasting, and production diagnostics. The objective of the workflow was not to blindly clean the dataset or statistically smooth all irregular production behavior, but to verify that the production history is internally consistent, physically meaningful, operationally interpretable, and suitable for engineering analysis.

The QA/QC workflow was intentionally performed in the following order:

well identity validation → well naming and alias validation → operator/company continuity validation → timeline validation → production-value validation → uptime validation → rate normalization → cumulative validation → DCA eligibility screening → diagnostic eligibility screening

This sequence is important because production volumes cannot be interpreted correctly until the physical well identity, naming continuity, and reporting-company history are validated.

3.1 WELL IDENTITY, NAMING AND MASTER-DATA VALIDATION

The first QA/QC step verified that all monthly records belong to the same physical well. This step is critical because production databases frequently contain:

- inconsistent well-name spelling,
- formatting variations,
- renamed wells,
- merged datasets,
- legacy operator records,
- duplicated API identifiers,
- and alias-based reporting changes.

The following checks were performed:

A well-name change was not automatically treated as invalid production data. If the API number remained constant and production continuity was preserved, the record was retained and normalized to a canonical well name.

Similarly, spelling differences such as:

- “AMBER ELIZABETH 36-25H”
- “AMBER ELIZABETH 36-25H”
- formatting or punctuation variations

were treated as master-data normalization events rather than production anomalies.

Recommended master-data outputs include:

- Canonical Well Name,
- Reported Well Name,
- Well Alias Group,
- Well Identity Status,
- Company QC Status,
- Operator Transition Flag.

Applied identity and master-data checks

Applied to the selected well. Results are calculated server-side from governed Well Data → Production and update when the report well changes.

This check evaluates production-row identity keys (API identifier and wellbore identifier), reported well-name values, and nulls in the available required master-data fields: API identifier, wellbore identifier, reported well name, pool, field, section, township, range, and county.

Out of scope: fuzzy alias matching, proof that two names represent the same physical well beyond the governed identifiers, operator continuity, operational causes, and location-change interpretation. These require contracts or evidence not available to this formula block.

Identifier consistency

Distinct API identifiers: **1 Count: item** · Values: **33053043310000**

Distinct wellbore identifiers: **1 Count: item** · Values: **33053043310000::BAKKEN**

Distinct reported well names: **2 Count: item** · Values:
AMBER ELIZABETH 36-25H, AMBER ELIZABETH 36-25H

Required master-data completeness

Months with any required master-data null: **0 Count: item** · Months: **None**

Summary

Identity keys and required master data are consistent; 2 reported well-name values were observed: AMBER ELIZABETH 36-25H, AMBER ELIZABETH 36-25H. Name variants require review and are not treated as separate wells by this check.

3.2 COMPANY, OPERATOR AND LEGACY REPORTING VALIDATION

The second QA/QC step evaluates continuity of the reported operator_name value across chronological monthly production records. Each boundary is treated only as a change in the source-reported text.

Governed monthly records are sorted by period and grouped into contiguous runs with the same reported operator value. Each line shows the period start, period end, and reported operator value.

The checks identify the reporting sequence, the number of distinct source values, and months where period or operator_name is missing.

Out of scope: legal ownership, operator-of-record status, transfer or acquisition dates, successor relationships, alias equivalence, and causal interpretation of production changes. Those conclusions require evidence not available in governed Well Data → Production.

Applied reported-operator checks

Applied to the selected well. Results are calculated server-side from governed Well Data → Production and update when the report well changes.

Governed monthly Production records are sorted by period. Contiguous records with the same reported operator_name value are grouped into one period. Each line shows: period start — period end — reported operator.

Out of scope: legal ownership, operator-of-record status, transfer or acquisition dates, successor relationships, alias equivalence, and causal interpretation of production changes.

Reported operator history

- 2015-05 — 2026-04 — MUREX PETROLEUM CORPORATION

Supporting completeness checks

Distinct reported operator values: **1 Count: item**

Months with missing reported operator: **0 Count: item** · Months: **None**

Summary

PASS: One reported operator value appears across all observed production records: MUREX PETROLEUM CORPORATION. No operator-value change is evidenced in the governed field.

3.3 INPUT DATA STRUCTURE VALIDATION

After confirming well identity and operator continuity, the monthly production table was checked for structural completeness and calculation readiness.

The following checks were performed:

Duplicate monthly records were not automatically averaged because duplicates may represent:

- allocation revisions,
- regulatory corrections,
- data-loading issues,
- or commingled reporting adjustments.

Summary

PASS — The governed Production projection exposes the monthly period and typed numeric active_days, oil, water, and gas volume fields required by the downstream calculations in this chapter. Timeline completeness, duplicate periods, and null values are quantified separately in Section 3.4; no duplicate structural conclusion is inferred here.

3.4 MISSING MONTH AND NULL VALUE HANDLING

The production timeline was reviewed for:

- missing calendar-month records,
- null numeric values within an existing monthly record,
- incomplete phase reporting,
- and inconsistent production states.

Numeric null handling is deliberately separate from a missing month. The raw source value is never overwritten. For each existing monthly observation and each numerical production input, downstream formulas use the derived zero-normalized value:

$$x_i^{(0)} = \begin{cases} x_i, & x_i \text{ is present} \\ 0, & x_i \text{ is null} \end{cases}$$

The layer applies to Days On, oil, water, gas, gas sold, and flared volume. It does not create a source row for an absent calendar month.

The following handling is applied:

No observations are deleted in Section 3.4. This normalized layer is the input basis for calculations after Section 3.4; consolidated green/red decisions are assembled in Section 3.12, and physical row removal occurs only in Section 3.13.

Applied to the selected well. Results are calculated from Well Data → Production and update when the report well changes.

Timeline completeness

First observed period: **2015-05** · Last observed period: **2026-04**

Expected months: **132 Count: item** · Observed distinct months: **132 Count: item**

Duplicate month count: **0 Count: item** · Duplicate months:

Missing month count: **0 Count: item** · Missing months:

Null and state consistency

Required-field null month count: **0 Count: item** · Required-field null months:

All-phase-null month count: **0 Count: item** · All-phase-null months:

Partial-phase-null month count: **0 Count: item** · Partial-phase-null months:

Production > 0 with Days = 0 count: **0 Count: item** · Months:

Production = 0 with Days > 0 count: **0 Count: item** · Months:

Summary

Throughout the observation window 2015-05–2026-04, no completeness exceptions were detected; completeness quality is high.

3.5 CALENDAR DAYS, UPTIME AND FLOWING STATUS VALIDATION

This step uses the governed monthly period, active_days, oil_production_volume, water_production_volume, and gas_production_volume fields. active_days is the source-reported Days On value; it is not an operational event log.

Monthly uptime is defined as:

$$\text{Uptime} = \frac{\text{Days On}}{\text{Calendar Days In Month}}$$

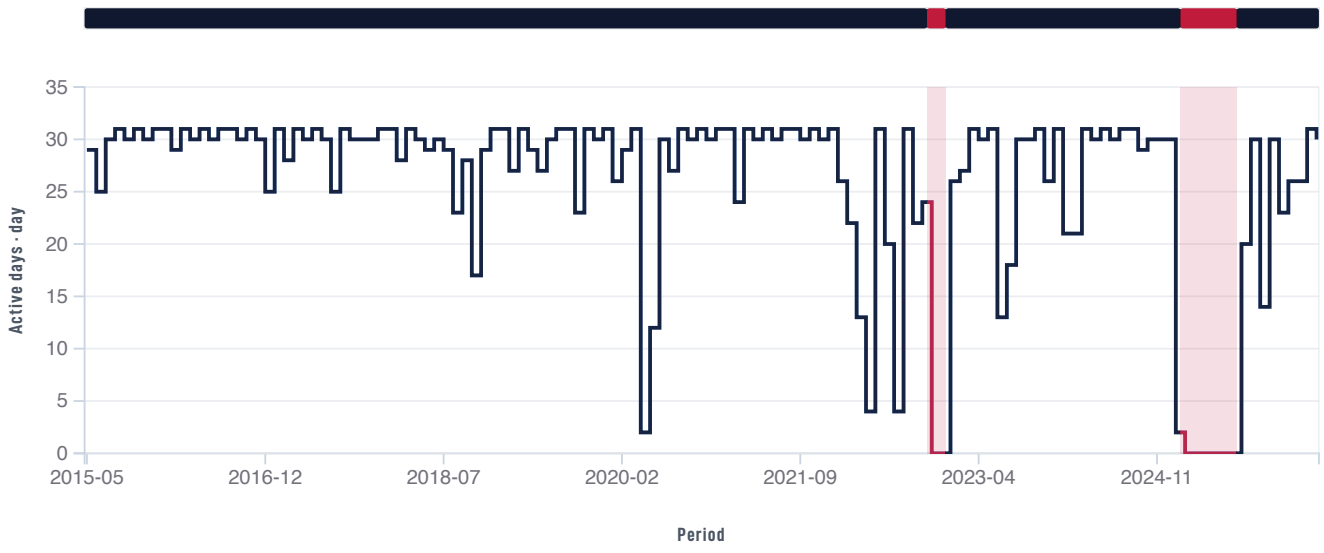
The following methodology screening logic is retained:

The applied table calculates calendar days from the monthly period, converts Days On and calendar days to durations, and evaluates the dimensionless uptime ratio. Each monthly row shows the applied QA/QC result; the grouped timeline summarizes adjacent rows with the same state.

Days On above calendar days is an EXCEPTION. Flowing and shut-down labels describe only the reported monthly evidence and do not establish an operational cause.

Out of scope: shut-in cause, equipment state, choke changes, interventions, allocation adjustments, or any other operational explanation.

Summary Flow Status Timeline



SERIES — Active days · day

STATUS — **Applied flowing-status QA/QC · PASS** — Active days · day

Applied flowing-status QA/QC · PASS — Status interval shown as chart background — Active days · day

Applied Days On and flowing-status checks

Applied to the selected well. Results are calculated server-side from governed Well Data → Production and update when the report well changes.

Calendar days are derived from period. Uptime is calculated as Days(active_days) divided by Days(calendar days), producing a dimensionless ratio; the table applies the supported row-level status without inferring an operational cause.

Flowing-status timeline

Monthly records are sorted by period and adjacent months with the same evidence-based status are grouped. Each line shows: period start — period end — status.

- 2015-05 — 2022-10 — PASS — ACTIVE
- 2022-11 — 2022-12 — PASS — SHUT DOWN
- 2023-01 — 2025-01 — PASS — ACTIVE
- 2025-02 — 2025-07 — PASS — SHUT DOWN
- 2025-08 — 2026-04 — PASS — ACTIVE

Supporting counts

Days On: **Missing Days On: 0 · Positive Days On: 124 · Zero Days On: 8 · Negative Days On: 0**

Status counts:

Meets flowing criterion: 124 · Meets non-flowing criterion: 8 · Other complete combinations: 0 · Missing classification fields: 0

Summary

PASS — 132 observed months: 132 PASS; 0 REVIEW; 0 EXCEPTION; 0 UNAVAILABLE. Every complete row matches the supported flowing or non-flowing condition; no operational cause is inferred.

3.6 UPTIME-BASED SCREENING FOR PRIMARY DCA

Uptime was used as the main operational screening criterion for decline analysis.

The 75% threshold represents an engineering screening criterion rather than a strict statistical cutoff. Low-uptime months are not necessarily invalid production data, but they may not represent sufficiently stable flowing conditions for reliable decline parameter estimation.

Low-uptime months were retained for:

- cumulative production,
- economics,
- operational review,
- and full-history interpretation.

However, they were excluded from:

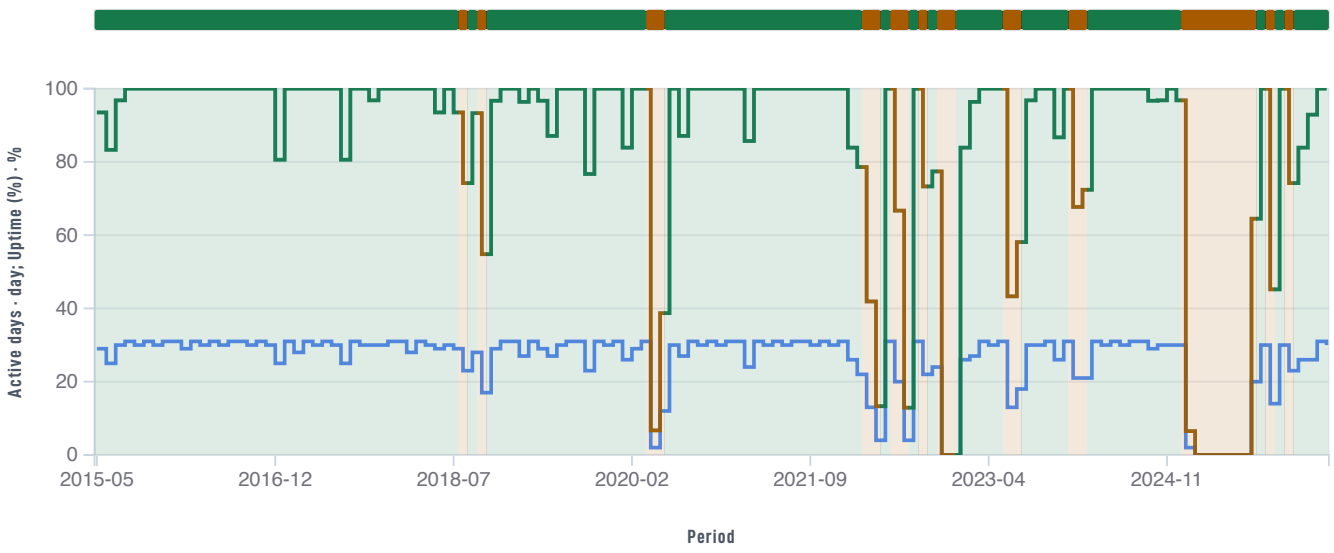
- primary Arps fitting,
- Chan diagnostics,
- and stable decline calibration.

Scientific References

Operational downtime and partial production periods can distort the production history used for decline-curve fitting and affect estimated DCA parameters. Published shale-production studies therefore exclude or separately treat shut-in, non-producing, and partial production periods before decline analysis. The 75% cutoff used here is a configurable engineering screening threshold, not a universal scientific constant.

1. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source
2. Guo, K., Zhang, B., Aleklett, K., & Höök, M. (2016). Production Patterns of Eagle Ford Shale Gas: Decline Curve Analysis Using 1084 Wells. Sustainability, 8(10), 973. Source
3. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source

Summary Uptime and Active Days Timeline



SERIES — Active days · day — Uptime (%) · %

STATUS

Applied uptime QA/QC · PASS

Status interval shown as chart background — Uptime (%) · %

Applied uptime QA/QC · REVIEW

Status interval shown as chart background — Uptime (%) · %

Applied uptime screening evidence

Applied to the selected well. Results are calculated server-side from governed Well Data → Production and update when the report well changes.

Monthly records are sorted by period and adjacent months with the same evidence-based state are grouped. Each timeline line shows: period start — period end — state.

Uptime is calculated as Days(active_days) divided by Days(calendar days), producing a dimensionless ratio. Each row is classified against the 75% screening threshold; the timeline groups adjacent rows with the same state. No operational cause is inferred.

Uptime evidence timeline

- 2015-05 — 2018-07 — 🟢 PASS — uptime at or above 75%
- 2018-08 — 2018-08 — REVIEW — uptime below 75%
- 2018-09 — 2018-09 — 🟢 PASS — uptime at or above 75%
- 2018-10 — 2018-10 — REVIEW — uptime below 75%
- 2018-11 — 2020-03 — 🟢 PASS — uptime at or above 75%
- 2020-04 — 2020-05 — REVIEW — uptime below 75%
- 2020-06 — 2022-02 — 🟢 PASS — uptime at or above 75%
- 2022-03 — 2022-04 — REVIEW — uptime below 75%
- 2022-05 — 2022-05 — 🟢 PASS — uptime at or above 75%
- 2022-06 — 2022-07 — REVIEW — uptime below 75%
- 2022-08 — 2022-08 — 🟢 PASS — uptime at or above 75%

- 2022-09 — 2022-09 — REVIEW — uptime below 75%
- 2022-10 — 2022-10 — 🟢 PASS — uptime at or above 75%
- 2022-11 — 2022-12 — REVIEW — uptime below 75%
- 2023-01 — 2023-05 — 🟢 PASS — uptime at or above 75%
- 2023-06 — 2023-07 — REVIEW — uptime below 75%
- 2023-08 — 2023-12 — 🟢 PASS — uptime at or above 75%
- 2024-01 — 2024-02 — REVIEW — uptime below 75%
- 2024-03 — 2024-12 — 🟢 PASS — uptime at or above 75%
- 2025-01 — 2025-08 — REVIEW — uptime below 75%
- 2025-09 — 2025-09 — 🟢 PASS — uptime at or above 75%
- 2025-10 — 2025-10 — REVIEW — uptime below 75%
- 2025-11 — 2025-11 — 🟢 PASS — uptime at or above 75%
- 2025-12 — 2025-12 — REVIEW — uptime below 75%
- 2026-01 — 2026-04 — 🟢 PASS — uptime at or above 75%

Supporting counts

Observed months: 132 · Missing active_days: 0 · Positive active_days: 124 · Zero active_days: 8 · Negative active_days: 0

Summary

REVIEW — 132 observed months: 107 PASS (uptime at or above 75%); 25 REVIEW (uptime below 75%); 0 EXCEPTION; 0 UNAVAILABLE. REVIEW months are excluded from primary DCA fitting and retained for cumulative, economic, and full-history analysis. No operational cause is inferred.

3.7 CONVERSION FROM MONTHLY VOLUMES TO AVERAGE DAILY RATES

Because the source data consisted of monthly aggregated production volumes, average daily rates were calculated using two independent normalization methods.

Calendar-day average rate:

$$q_{\text{calendar}} = \frac{\text{Monthly Production}}{\text{Calendar Days}}$$

Producing-day average rate:

$$q_{\text{flowing}} = \frac{\text{Monthly Production}}{\text{Days On}}$$

Calendar-day rates were retained for:

- production accounting,
- economics,
- and reporting context.

Producing-day rates were used for:

- Arps decline fitting,
- productivity analysis,
- flowing-time diagnostics,
- and production trend interpretation.

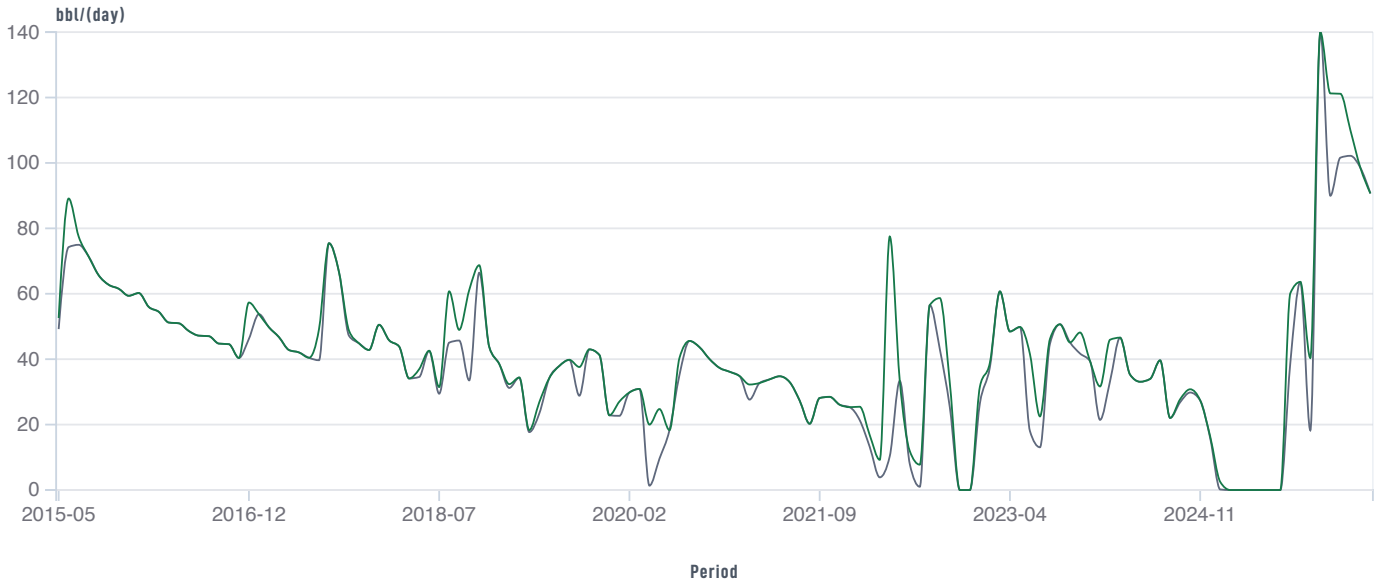
Scientific References

Monthly production is reported as a volume accumulated over a reporting interval. Converting that volume to an average rate therefore requires an explicit time basis. Calendar-day normalization preserves the rate corresponding to the complete reporting month, while producing-day normalization estimates the average rate during the days on which the well was actually producing. The two rates answer different engineering questions and are not interchangeable when uptime is below 100%. Calendar-day rate is retained for production accounting and reporting context. Producing-day rate is used for flowing-time diagnostics and decline-trend interpretation because it separates reported production intensity from the duration of monthly downtime. Published decline-analysis methodologies likewise normalize monthly production to an explicit time basis and treat partial or non-producing periods separately before fitting. The specific use of producing-day rate in this workflow is a declared engineering choice; it does not alter the reported monthly production volume.

1. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source
2. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source

3. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source

Calendar-day and Producer-day Oil Rates



SERIES — Calendar-day average · bbl/(day) — Producer-day average · bbl/(day)

Summary

PASS — 132 observed months: calendar-day oil rate available for 132; producer-day oil rate available for 132. Both rate calculations are available for every observed month.

3.8 DETAILED PRODUCTION VALUE QA/QC

Detailed QA/QC was then performed for oil, gas and water production values prior to cumulative calculations and diagnostic interpretation.

The following checks were applied:

Production spikes were not automatically removed because they may represent genuine engineering events such as:

- startup behavior,
- breakthrough events,
- facility constraints,
- changing drawdown,
- or operational interventions.

Scientific References

Production-value QA/QC must distinguish physically invalid data from unusual but potentially real production behavior. A negative monthly oil, water, or gas volume is incompatible with the physical meaning of a produced-volume observation and is therefore treated as an exception. Zero values, repeated values, abrupt changes, and isolated spikes are different. They may indicate a reporting problem, but they may also reflect shutdowns, restarts, well interventions, re-stimulation, facility constraints, allocation revisions, or genuine changes in well performance. Published shale-production studies show that such operating events can materially affect decline-curve parameters and that generic noise-removal methods are not universally reliable for highly fluctuating production histories. For that reason, this workflow flags unusual but physically possible values for review and does not automatically remove them unless an already-defined missing, invalid, or non-physical rule applies.

1. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source
2. Liang, H.-B., Zhang, L.-H., Zhao, Y.-L., Zhang, B.-N., Chang, C., Chen, M., & Bai, M.-X. (2020). Empirical methods of decline-curve analysis for shale gas reservoirs: Review, evaluation, and application. Journal of Natural Gas Science and Engineering, 83, 103531. Source
3. ISO/IEC 25012:2008. Software engineering — Software product Quality Requirements and Evaluation (SQuaRE) — Data quality model. Source

Applied detailed production-value QA/QC

Applied to the selected well. The monthly evidence table is calculated server-side from governed Well Data → Production and updates when the report well changes.

The table separates four concepts: Result status, Observed condition, Engineering meaning, and Data treatment. A data-treatment instruction is not the QA/QC result.

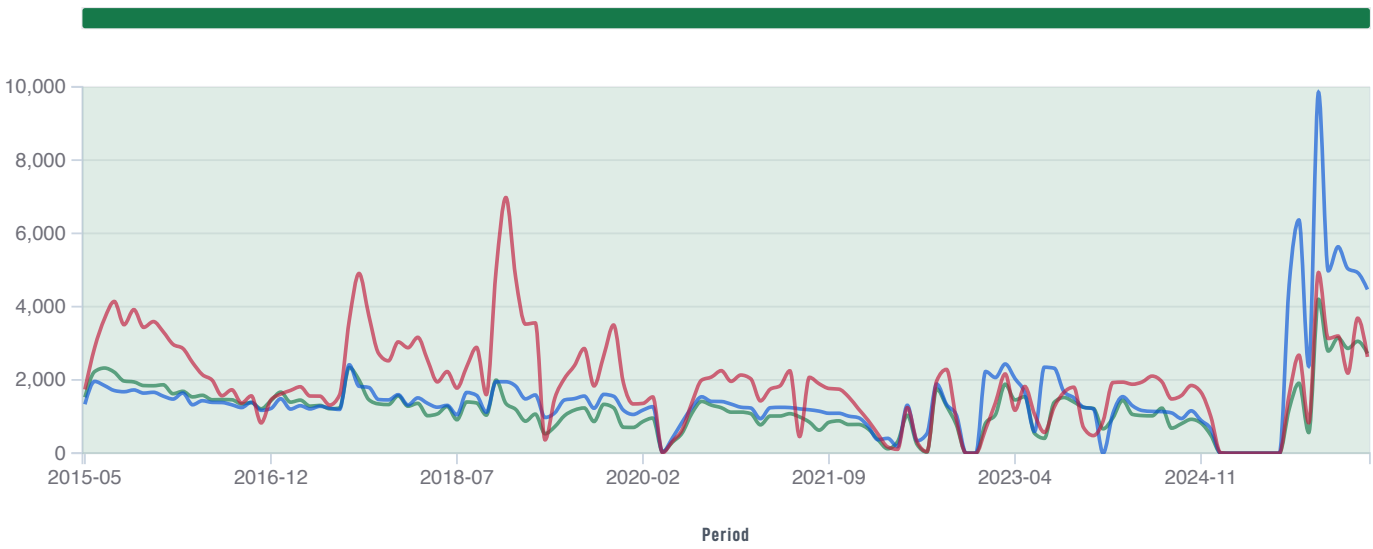
- **PASS** — required values are present and no configured exception or review condition was detected.

- **REVIEW** — a configured condition requires engineering or completeness review.
- **EXCEPTION** — at least one of oil, water, or gas is below zero.
- **UNAVAILABLE** — a required monthly value is missing; completeness is assessed in Section 3.4.

RETAIN appears only as a rule-specific data treatment where the methodology explicitly calls for it; it is not a result status. For a month with no issue under the checks above, the result is PASS and the data treatment is No automatic change.

Abrupt-jump, repeated-value and isolated-spike thresholds are not defined by the methodology and are therefore not invented. The monthly values remain visible for engineering interpretation and are not automatically removed.

Summary Production-Value QA/QC Timeline



SERIES — Oil production volume · bbl — Water production volume · bbl — Gas production volume · Mcf

STATUS

Result status · PASS
Status interval shown as chart background

Result status · REVIEW
Status interval shown as chart background

Result status · EXCEPTION
Status interval shown as chart background

Result status · UNAVAILABLE
Status interval shown as chart background

Summary

PASS — 132 observed months: 132 PASS; 0 REVIEW; 0 EXCEPTION; 0 UNAVAILABLE. No issues were identified.

3.9 RATIO AND DIAGNOSTIC QA/QC

Diagnostic ratios were calculated only where mathematically and physically meaningful.

Water cut:

$$\mathrm{WC} = \frac{q_w}{q_o + q_w}$$

Water-oil ratio:

$$\mathrm{WOR} = \frac{q_w}{q_o}$$

Gas-oil ratio:

$$\mathrm{GOR} = \frac{q_g}{q_o}$$

The following rules were applied:

Undefined ratios were not forced into artificial numeric values.

Scientific References

Water cut, water–oil ratio, and gas–oil ratio are standard production-performance diagnostics. Water cut represents produced water as a fraction of total produced liquid, while WOR and GOR compare the produced water and gas volumes with produced oil. Each ratio is meaningful only when its denominator is positive. If oil plus water equals zero, water cut is undefined. If oil equals zero, WOR and GOR are undefined. An undefined ratio is not equivalent to a measured value of zero and is therefore retained as blank rather than replaced by an artificial numeric value. For non-negative oil and water volumes, water cut must remain within the interval from 0 to 1. A value outside that interval, or a negative WOR or GOR, indicates inconsistent or non-physical inputs. Changes in otherwise valid ratios can provide useful diagnostic evidence, but they do not by themselves establish an operational cause or justify deletion of the underlying production observation.

1. SLB Energy Glossary. Water cut. Source
2. SLB Energy Glossary. Water/oil ratio (WOR). Source
3. SLB Energy Glossary. Gas/oil ratio (GOR). Source
4. Poston, S. W., & Laprea-Bigott, M. (2023). Waterflood Review. In Practical Aspects of Waterflooding. Society of Petroleum Engineers. Source
5. U.S. Energy Information Administration. (2021). Gas-to-oil ratios in U.S. primary oil-producing regions. Source

Applied ratio and diagnostic evidence

The calculated table above is the primary monthly evidence for the selected well. Water cut, water-oil ratio (WOR), gas-oil ratio (GOR), and the row-level QA/QC status are calculated server-side from governed Well Data → Production and update when the report well changes.

Undefined ratios remain blank: water cut is undefined when oil plus water equals zero; WOR and GOR are undefined when oil equals zero. Negative phase volumes are marked EXCEPTION, missing required phase volumes are UNAVAILABLE, and oil-zero months are marked REVIEW because WOR and GOR cannot be calculated. No operational cause is inferred.

Summary

REVIEW — 132 observed months: 124 PASS; 8 REVIEW; 0 EXCEPTION; 0 UNAVAILABLE. Total issues: 8. See the calculated table for the affected months.

3.10 CUMULATIVE PRODUCTION CONSISTENCY

Cumulative production was recalculated directly from monthly production volumes rather than relying on source cumulative fields.

Oil cumulative:

$$N_p(t) = \sum_{i=1}^{t} \mathrm{Oil}_i$$

Water cumulative:

$$W_p(t) = \sum_{i=1}^{t} \mathrm{Water}_i$$

Gas cumulative:

$$G_p(t) = \sum_{i=1}^{t} \mathrm{Gas}_i$$

The following checks were performed:

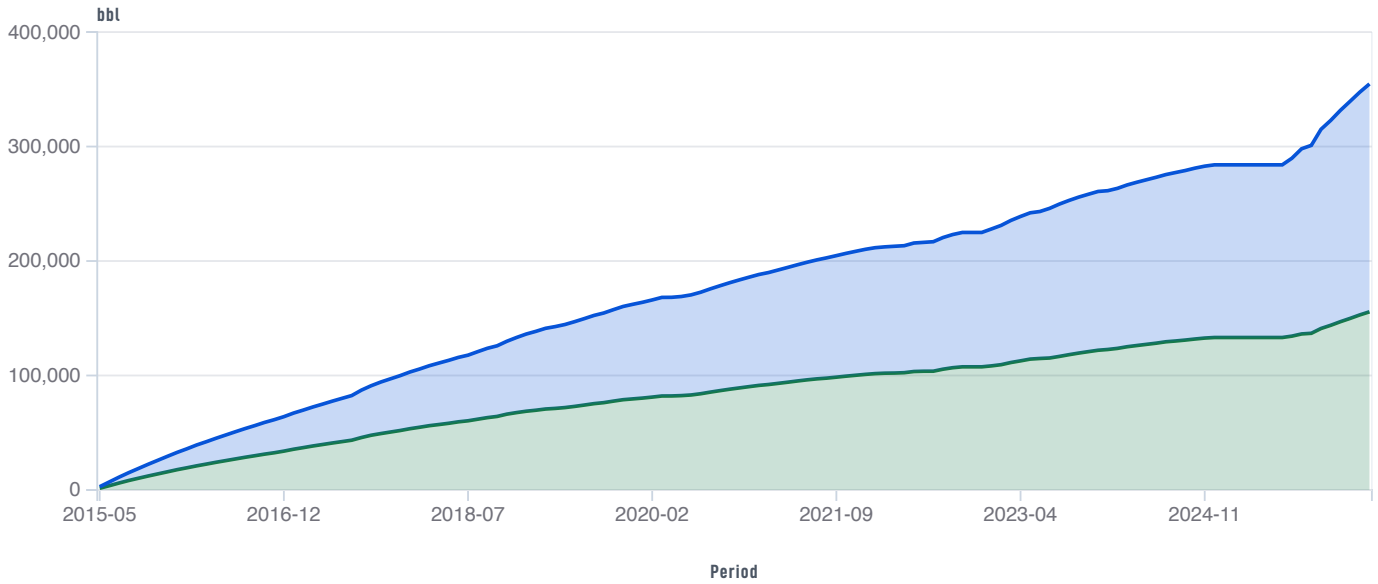
- monotonic cumulative behavior,
- cumulative consistency with monthly increments,
- duplicate/revision detection,
- and large cumulative discontinuity screening.

Scientific References

Cumulative production is the discrete integral of the observed production history. For monthly data, it is calculated as a prefix sum of the reported monthly phase volumes through each observed period. Recalculating cumulative oil, water, and gas directly from monthly increments provides an auditable internal consistency check and avoids depending on source cumulative fields that may contain revisions, duplicated periods, or a different reporting convention. When all monthly increments are non-negative, the resulting cumulative series must be non-decreasing. A decrease or discontinuity is therefore retained as diagnostic evidence of a negative increment, duplicate, revision, or source-data inconsistency. Section 3.10 exposes that evidence but does not silently repair, merge, or delete the underlying monthly observation.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Fetkovich, M. J. (1980). Decline Curve Analysis Using Type Curves. Journal of Petroleum Technology, 32(6), 1065–1077. Source
3. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source

Cumulative Oil and Water (Stacked)



SERIES Cumulative oil · bbl Cumulative water · bbl

Applied cumulative-production consistency

The native table above is the primary row-level evidence for the selected well. Monthly oil, water, and gas volumes remain visible alongside three server-calculated cumulative columns; all values update when the report well changes.

Cumulative values are prefix sums through each observed period. Negative monthly increments remain visible and may make a cumulative series decrease. Repeated periods are included as separate observed rows; no correction, revision, or operational cause is inferred.

Supporting counts

Observed rows: 132 · Distinct nonblank periods: 132 · Duplicate period rows: 0 · Rows without a period: 0 · Numeric nulls: normalized in Section 3.4 · Negative oil increments: 0 · Negative water increments: 0 · Negative gas increments: 0

Summary

PASS — 132 observed row(s); 0 duplicate period row(s); 0 row(s) without a period; 0 negative-increment row(s). Cumulative inputs use the Section 3.4 normalized numeric fields: oil 155645; water 199057; gas 252425. All normalized monthly increments are nonnegative; the recalculated cumulative series are monotonic nondecreasing. No repeated nonblank period values were detected. Raw numeric nulls remain auditable in Section 3.4; they are normalized to zero only for downstream calculations.

3.11 TREND CONSISTENCY DIAGNOSIS

TREND CONSISTENCY DIAGNOSIS

This section creates a new local StableTrend diagnostic from the governed monthly production history. It tests whether a local declining trend is coherent; it is not a result reused from an earlier section.

The diagnosis does not delete observations, assign a final green/red QA/QC flag, or infer an operational cause. Its result is carried forward as trend-consistency evidence for the consolidated view in Section 3.12.

All numeric inputs below use the normalized values defined in Section 3.4: a null numeric value in an existing monthly record is evaluated as 0, while a calendar month that is absent from the source remains absent. The calculated monthly table is shown first so every subsequent formula and chart can be traced to the same rows.

NORMALIZED LOCAL DECLINE GRADIENT

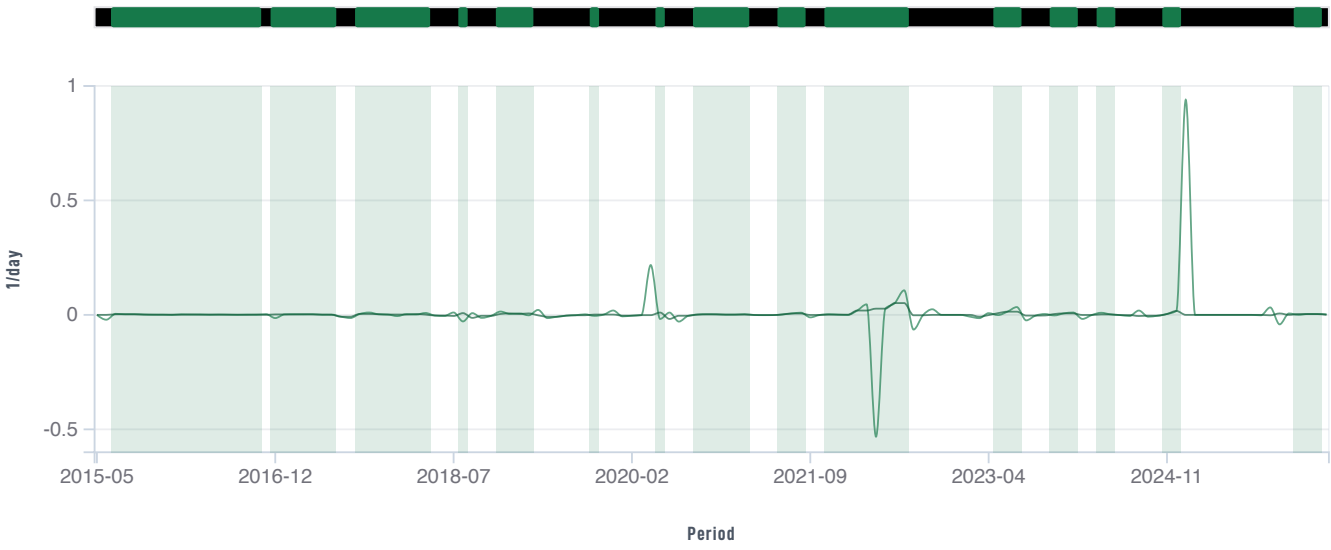
For each consecutive observed production pair, the calculation uses the producing-day-normalized oil rate. A positive decline gradient means that production is decreasing across the pair.

$$q_i = \frac{V_i^{\mathrm{oil}}}{\text{active days}_i}$$

$$D_i = -\frac{\ln(q_i / q_{i-1})}{t_i - t_{i-1}}, \qquad t_i - t_{i-1} = \text{active days}_i$$

The first observation and a pair without two positive producing-day rates return the numeric diagnostic value 0; a structurally missing period remains unavailable. The chart compares the pairwise D_i trace with its centred rolling median on a common 1/day axis.

Normalized local decline gradient



SERIES — Pairwise decline gradient D · 1/day — Rolling median decline gradient · 1/day

STATUS **Stable decline trend**

Status interval shown as chart background

LOCAL GRADIENT STABILITY

A centred window of three adjacent gradient values measures whether the local decline direction is coherent rather than driven by an isolated month.

$$W_i = \{D_{i-1}, D_i, D_{i+1}\}$$

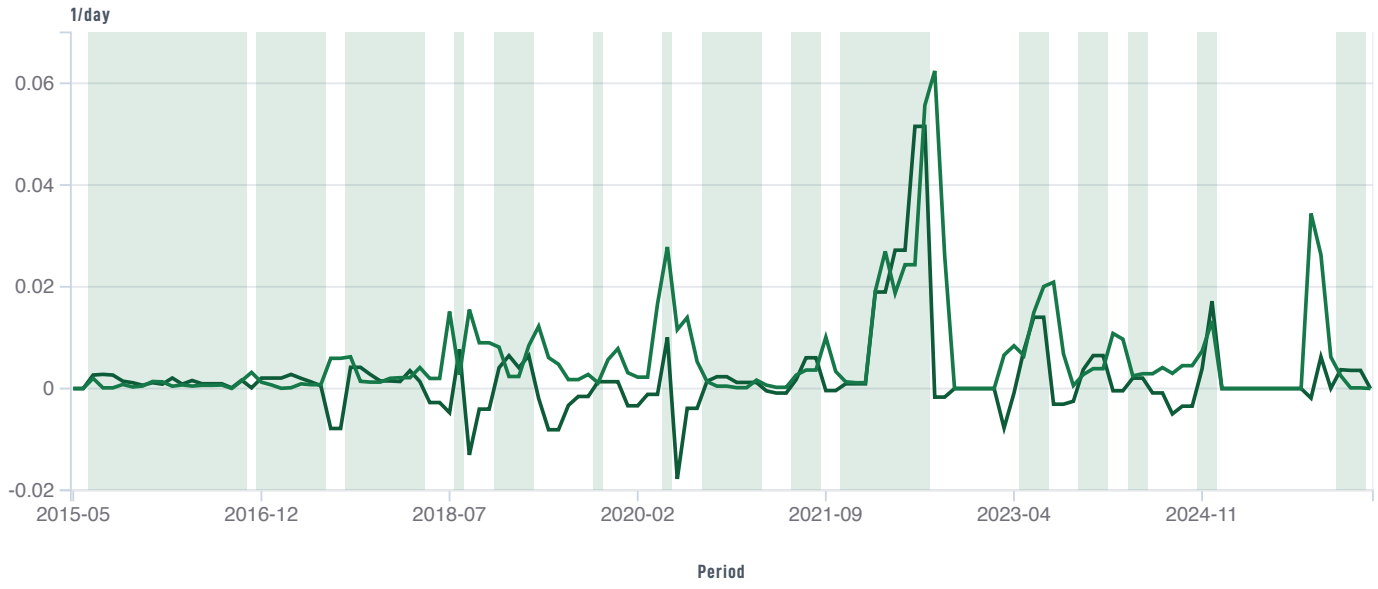
$$D_{\mathrm{med},i} = \mathrm{median}(W_i)$$

$$MAD_i = \mathrm{median}_{D_j \in W_i}(|D_j - D_{\mathrm{med},i}|)$$

$$GV_i = \frac{MAD_i}{|D_{\mathrm{med},i}| + \varepsilon}, \qquad \varepsilon = 10^{-8}$$

Only a complete three-gradient window can qualify. The chart below shows the local median gradient and its median absolute deviation; the following criterion evaluates the dimensionless GV value.

Centered local gradient stability



SERIES
- Centered three-gradient median decline gradient · 1/day
- Centered three-gradient median absolute deviation · 1/day

STATUS **Stable decline trend**
- Status interval shown as chart background

STABLE TREND CRITERION

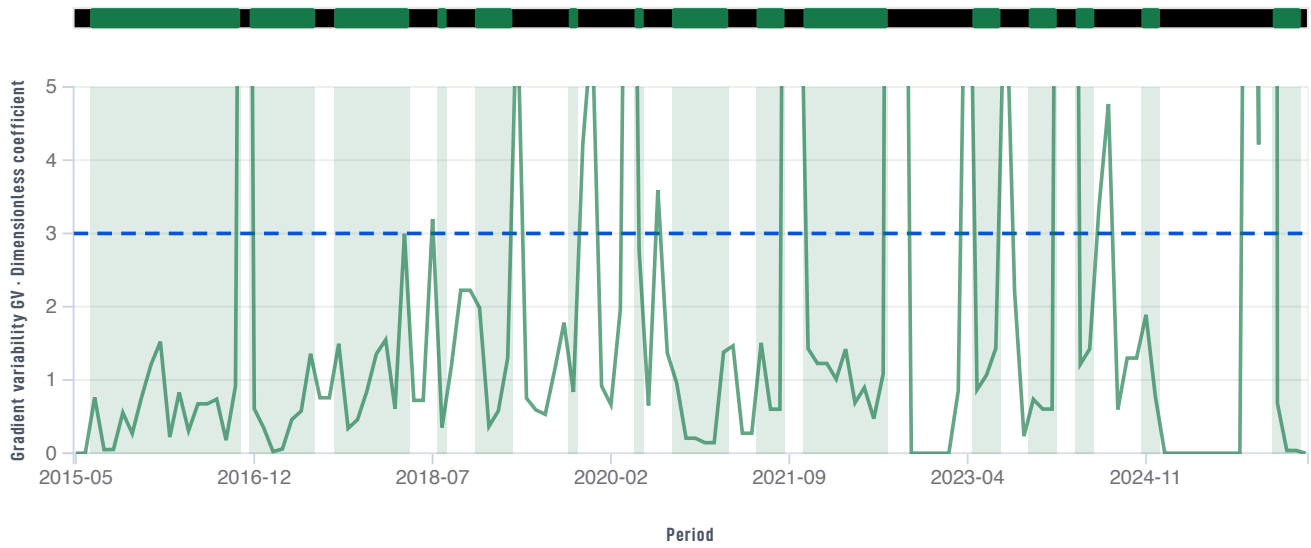
A month is classified as a stable declining trend only when its centred median gradient is positive and its normalized gradient variability does not exceed the configured threshold.

$$\mathrm{StableTrend}_i = (D_{\mathrm{med},i} > 0) \wedge (GV_i \leq 3)$$

Calculation parameters are window_size = 3, gradient_variability_threshold = 3, and epsilon = 10^-8. The threshold value 3 is part of the persisted calculation logic; the dashed chart line only makes that criterion visible.

StableTrend is diagnostic evidence only. It is neither an automatic red flag nor an instruction to delete a production observation.

Gradient variability criterion with stable intervals



SERIES — Gradient variability GV · Dimensionless coefficient — Threshold = 3

STATUS **Stable decline trend**

Status interval shown as chart background

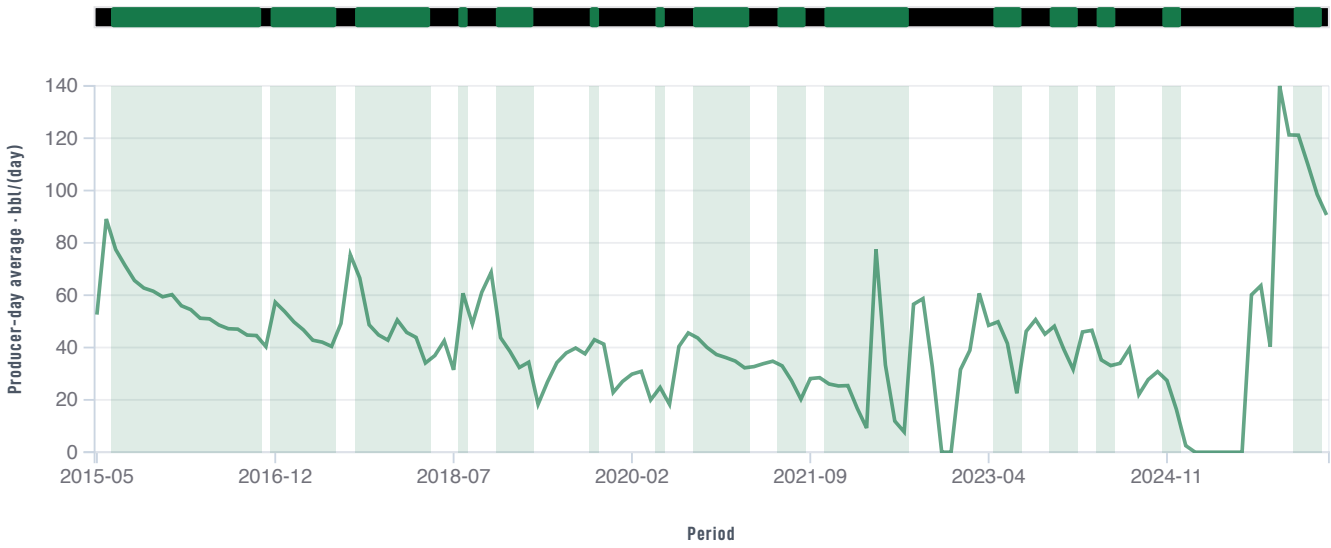
FINAL STABLE INTERVALS AND TREND

Adjacent months that satisfy the existing StableTrend calculation are joined visually into green intervals on the producer-day oil-rate trend. This is a presentation of the already calculated signal; it does not create a separate deletion rule or a final regime boundary.

$$\mathcal{I}_k = \{i : \ \mathrm{StableTrend}_i = \mathrm{true}\}_k \quad \text{for each contiguous run } k$$

The green bands identify candidate coherent decline windows for engineering interpretation. Consolidated QA/QC treatment and any regime-boundary presentation remain in Section 3.12; physical removal of red-flagged observations belongs only to Section 3.13.

Producer-day oil rate with stable decline intervals



SERIES — Producer-day average · bbl/(day)

STATUS **Stable decline trend**

Status interval shown as chart background

Scientific References

The normalized local log-rate gradient is a discrete estimate of the decline-rate concept used in rate–time production analysis. A positive value represents declining production between two consecutive observed producing-rate points. The centered median and median absolute deviation provide robust local measures of trend direction and variability. Their purpose is to reduce the influence of a single extreme monthly change while preserving the local structure of the production history. The scientific references support the use of rate-based decline diagnostics and median-based robust variability measures. They do not prescribe the exact three-gradient window, the normalization by |D_med| + epsilon, the value epsilon = 10^-8, or the threshold GV <= 3. Those values are configurable

parameters of this methodology and must remain visible as such. StableTrend is diagnostic evidence of a coherent local decline. It is not a statistical outlier-removal rule and does not independently invalidate or delete a production observation.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Fetkovich, M. J. (1980). Decline Curve Analysis Using Type Curves. Journal of Petroleum Technology, 32(6), 1065–1077. Source
3. Rousseeuw, P. J., & Croux, C. (1993). Alternatives to the Median Absolute Deviation. Journal of the American Statistical Association, 88(424), 1273–1283. Source

Summary

Trend-consistency result — 69 monthly observations satisfy D_med > 0 and GV <= 3 (window = 3; epsilon = 10^-8). Green intervals join contiguous StableTrend = true observations. This is diagnostic evidence, not a deletion rule.

3.12 CONSOLIDATED QA/QC FLAGS AND STABLE-REGIME BOUNDARIES

CONSOLIDATED QA/QC DECISION

This section does not recalculate production diagnostics, thresholds, or trend statistics. It consolidates the row-level results already produced in Sections 3.5, 3.6, 3.8, 3.9, and 3.11 for the same observed monthly production record.

The deletion decision is intentionally narrow. A monthly observation is invalid when at least one previously calculated red condition is present: Low Uptime, a Non-physical Ratio/Input exception, or a Missing/Invalid Record condition.

$$R_i = L_i \vee N_i \vee M_i$$

$$\text{Disposition}_i = \begin{cases} \text{RED}, & R_i = \text{true} \\ \text{GREEN}, & R_i = \text{false} \end{cases}$$

Here, L_i, N_i, and M_i are references to previously calculated QA/QC outcomes. They are not recalculated in Section 3.12.

FLAG SEMANTICS

- GREEN / VALID — Valid Full Month and Active are affirmative retained-data signals. A green monthly observation remains available for the clean dataset.
- RED / INVALID — Low Uptime, Non-physical Ratio/Input, and Missing/Invalid Record are deletion conditions. A red monthly observation will be removed in Section 3.13.
- CONTEXT / EVENT — Shut Down, Ratio Undefined, Transition, and Well Name Change describe the observation or source history. They do not turn a row red by themselves.
- TREND CONTEXT — StableTrend identifies a coherent local declining trend. It does not delete a row and does not override a red QA/QC condition.

If several red conditions apply to the same row, the row is still removed only once. The later reconciliation assigns one primary reason in the order Missing/Invalid Record, Non-physical Ratio/Input, then Low Uptime, so category counts cannot double-count removed observations.

QA/QC VALIDITY TIMELINE

The timeline below uses the complete observed monthly history. It shows the aggregate invalid union, every configured invalid reason, and the observed valid complement. Each configured invalid reason remains visible with its matching-month count, including zero.

The Periods register directly beneath the timeline interleaves valid and invalid intervals in chronological order. Each invalid period lists every exact Formula condition that applies; a row matching several conditions is still removed only once.

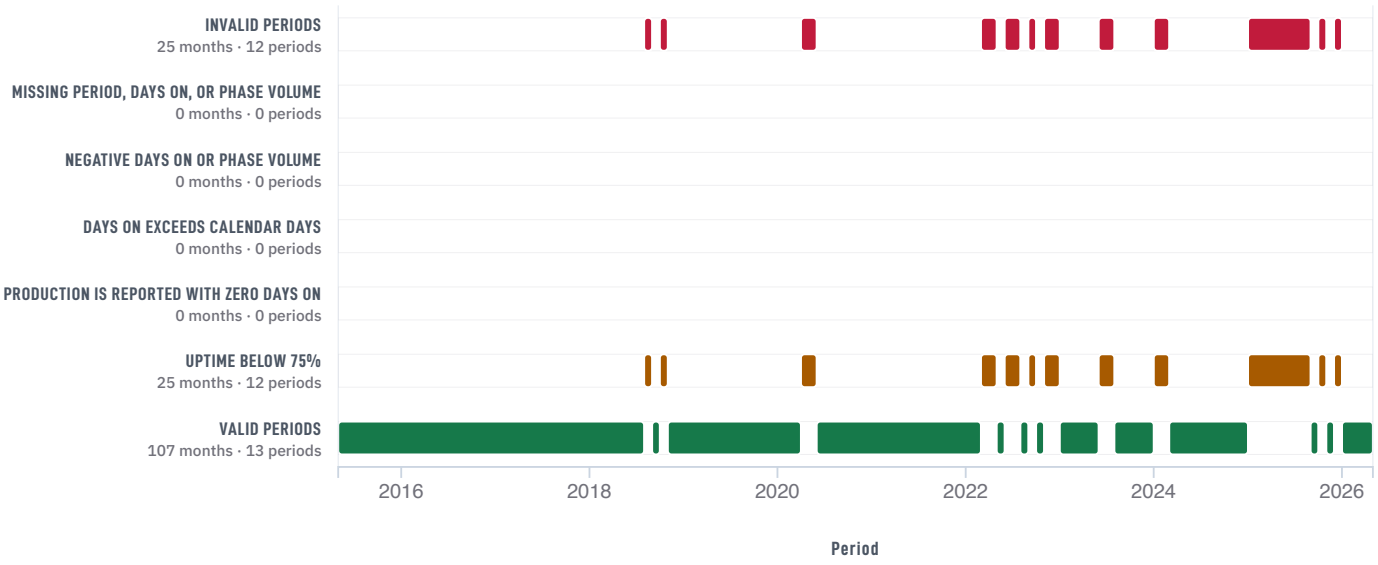
This is a read-only consolidation of canonical FormulaColumn outputs. Section 3.12 performs no new QA/QC calculation, changes no source values, and removes no rows. Section 3.13 applies the physical filter.

Scientific References

Section 3.12 is a decision and provenance layer rather than a new statistical calculation. It consolidates previously calculated monthly QA/QC results while preserving the source and meaning of each contributing flag. A row-level disposition must remain traceable to the upstream evidence that produced it. Green, red, contextual, and trend-related states are therefore kept semantically distinct: an operational event or an undefined diagnostic value is not converted into an invalid observation unless an explicit deletion condition already exists. The exact red-condition mapping, the primary-reason precedence, and the rule that a row is removed only once are workflow-governance decisions defined by this report. The cited data-quality and provenance standards support explicit requirements, traceability, and documented transformation; they do not prescribe these petroleum-specific flag names or priorities.

1. ISO/IEC 25012:2008. Software engineering — Software product Quality Requirements and Evaluation (SQuaRE) — Data quality model. Source
2. ISO 8000-1:2022. Data quality — Part 1: Overview. Source
3. Moreau, L., & Missier, P., eds. (2013). PROV-DM: The PROV Data Model. W3C Recommendation. Source

QA/QC Validity and Flag Timeline



PERIODS

2015-05 – 2018-07
Valid · 39 months

2018-08
Invalid · 1 month
uptime below 75%

2018-09
Valid · 1 month

2018-10
Invalid · 1 month
uptime below 75%

2018-11 – 2020-03
Valid · 17 months

2020-04 – 2020-05
Invalid · 2 months
uptime below 75%

2020-06 – 2022-02
Valid · 21 months

2022-03 – 2022-04
Invalid · 2 months
uptime below 75%

2022-05
Valid · 1 month

2022-06 – 2022-07
Invalid · 2 months
uptime below 75%

2022-08
Valid · 1 month

2022-09
Invalid · 1 month
uptime below 75%

2022-10
Valid · 1 month

2022-11 – 2022-12
Invalid · 2 months
uptime below 75%

2023-01 – 2023-05
Valid · 5 months

2023-06 – 2023-07
Invalid · 2 months
uptime below 75%

2023-08 – 2023-12
Valid · 5 months

2024-01 – 2024-02
Invalid · 2 months
uptime below 75%

2024-03 – 2024-12
Valid · 10 months

2025-01 – 2025-08
Invalid · 8 months
uptime below 75%

2025-09
Valid · 1 month

2025-10
Invalid · 1 month
uptime below 75%

2025-11
Valid · 1 month

2025-12
Invalid · 1 month
uptime below 75%

2026-01 – 2026-04
Valid · 4 months

SECTION 3.12 OUTCOME

The complete observed history is presented as one QA/QC validity timeline with one chronological Periods register directly beneath it.

- Invalid periods are the union of the exact deletion conditions and are removed only once even when several flags overlap.
- Valid periods are the observed complement and remain available for the retained dataset.
- Every invalid period lists all applicable flags in the configured rule order.
- Transition, Well Name Change, Shut Down, and undefined-ratio states remain contextual information and are not automatic deletion rules.

No observation is deleted in Section 3.12. Section 3.13 removes exactly the red rows, joins the retained observations, and creates the continuous Production Month index for the single reusable QA/QC production dataset.

3.13 CLEAN DATASET

FROM CONSOLIDATED DISPOSITION TO ONE REUSABLE DATASET

Section 3.12 determines the final row disposition. Section 3.13 introduces no new QA/QC criterion: it applies that disposition to the same observed monthly production history.

- QA/QC Valid = 1 — retain the observation.
- QA/QC Valid = 0 — remove the observation once, even when several red reasons apply.
- Sort retained observations by the absolute calendar Period and assign Production Month as their continuous position: 1, 2, 3, ..., N.

The result is one shared QA/QC production dataset. ARPS, UR, and other downstream analyses reuse this dataset and may add analysis-specific eligibility rules without changing the underlying QA/QC deletion history.

Section 3.13 creates one clean and reusable monthly production dataset from the consolidated disposition established in Section 3.12.

A row is retained only when no red condition is present. Low Uptime, Non-physical Ratio/Input, and Missing/Invalid Record remove the observation once. Active, Valid Full Month, Shut Down, Ratio Undefined, Transition, Well Name Change, and StableTrend remain available according to their established green or contextual meaning; they do not create an additional deletion rule here.

The clean result preserves the absolute calendar Period for auditability and adds Production Month as a continuous pseudo-time index after filtering: 1, 2, 3, ..., N. Removed observations create no gaps in Production Month, and absent calendar months are not generated.

The resulting output is named Clean Well Data. It is one shared dataset for subsequent ARPS, UR, and other production analyses, not separate model-specific copies. Downstream analyses may apply their own eligibility criteria to this shared base without changing the underlying QA/QC deletion history.

Scientific References

Clean Well Data is a derived view of the same observed monthly production history. It does not introduce a new QA/QC criterion. Rows with an accepted green disposition are retained, rows with an established red disposition are removed once, and the original calendar Period remains available for audit and reconciliation. Published decline-analysis workflows commonly exclude partial or non-producing periods before fitting because those periods can distort production-rate interpretation and model parameters. This literature supports the controlled exclusion of unsuitable observations; it does not define the exact red-flag logic used by this report. Production Month is a continuous pseudo-time index assigned after filtering. It represents the ordered position of a retained observation in Clean Well Data. It is a declared data-modeling convention, not a universal physical-time definition, and it does not replace the preserved calendar Period in the audit trail. The result is one governed and reusable dataset for ARPS, UR, decline diagnostics, forecasting, and other downstream production analyses. Those analyses may apply additional eligibility rules, but they must not create competing copies of the Chapter 3 cleanup result.

1. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source
2. Guo, K., Zhang, B., Aleklett, K., & Höök, M. (2016). Production Patterns of Eagle Ford Shale Gas: Decline Curve Analysis Using 1084 Wells. Sustainability, 8(10), 973. Source
3. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source
4. Moreau, L., & Missier, P., eds. (2013). PROV-DM: The PROV Data Model. W3C Recommendation. Source

SECTION 3.13 OUTCOME

132 input calendar observations → 107 retained production months; 25 red observations removed. Production Month is continuous from 1 through 107.

- Absolute Period is preserved for auditability.
- Production Month is continuous from 1 through N after filtering.
- No absent calendar months are generated.
- The saved clean SourceView is the reusable downstream dataset identity.

The reason-by-reason removal reconciliation is presented in Section 3.15. Section 3.14 remains the rationale for avoiding aggressive statistical filtering.

3.14 RATIONALE FOR AVOIDING AGGRESSIVE STATISTICAL FILTERING

No blind statistical spike removal, synthetic smoothing, or automatic outlier deletion was used as the primary QA/QC method.

Monthly anomalies may represent real engineering behavior including:

- downtime,
- restart behavior,
- breakthrough events,
- changing drawdown,
- facility constraints,
- productivity degradation,
- operator transition,
- or allocation revisions.

Therefore, the workflow prioritizes:

- physical validation,
- master-data consistency,
- uptime screening,
- and engineering-context interpretation

instead of purely statistical filtering.

Scientific References

Highly variable shale-production histories are not equivalent to random measurement noise. Shutdowns, restarts, well interventions, re-stimulation, changing constraints, and genuine changes in production regime can produce abrupt but physically meaningful changes in the observed series. Published reviews report that generic noise-reduction methods are not universally effective for production histories with strong fluctuations. Blind smoothing or automatic spike deletion may therefore remove engineering information, alter cumulative production, and bias later decline interpretation. This workflow uses explicit physical, completeness, uptime, and diagnostic rules for deletion. Other unusual observations remain visible for engineering review. The approach is conservative by design: absence of automatic deletion does not imply that every anomaly is valid, but it preserves the evidence required for an informed decision.

1. Liang, H.-B., Zhang, L.-H., Zhao, Y.-L., Zhang, B.-N., Chang, C., Chen, M., & Bai, M.-X. (2020). Empirical methods of decline-curve analysis for shale gas reservoirs: Review, evaluation, and application. Journal of Natural Gas Science and Engineering, 83, 103531. Source
2. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source
3. Society of Petroleum Engineers et al. (2018). Petroleum Resources Management System, revised June 2018. Source

Summary

Reported monthly anomalies are retained unless an evidence-based QA/QC rule identifies a missing, undefined, or non-physical value. No blind spike deletion, synthetic smoothing, operational-cause inference, or automatic regime assignment is applied.

3.15 QA/QC OUTCOME

At the end of the workflow, the production dataset was separated into:

This structure preserves the full production history while ensuring that decline parameters are estimated only from representative flowing production periods.

Scientific References

The final reconciliation is an audit and data-quality control rather than an additional cleaning calculation. Its purpose is to make the transformation from the reported input history to Clean Well Data explicit, countable, and governed by already-defined QA/QC decisions. Input, retained, and removed counts must reconcile exactly. A removed observation is counted once even when several red conditions apply, while its contributing flags remain available for detailed audit. This preserves the numerical integrity of the final dataset and the documented basis of every exclusion. The exact removal-reason precedence and the Clean Well Data contract are report-specific governance decisions. The cited ISO standards support explicit data-quality requirements, documented evaluation, and lifecycle management; they do not prescribe the petroleum-specific reason categories used here.

1. ISO 8000-1:2022. Data quality — Part 1: Overview. Source
2. ISO/IEC 25012:2008. Software engineering — Software product Quality Requirements and Evaluation (SQuaRE) — Data quality model. Source

Summary

132 input calendar observations → 107 retained production months; 25 red observations removed. Production Month is continuous from 1 through 107.

The full reported production history is preserved for audit and production overview. Each downstream use must consume the section-specific evidence and eligibility state appropriate to that analysis; unavailable or undefined results remain explicit instead of being replaced with artificial values.

4. DERIVED PRODUCTION AND SURVEILLANCE METRICS

4.1 PRODUCING-DAY PHASE RATE CALCULATIONS

The primary variables used throughout the decline analysis workflow were producing-day normalized phase rates.

Because the available dataset consists of monthly aggregated production volumes, direct comparison of monthly production totals may distort actual flowing performance during months with reduced uptime or intermittent production.

To minimize this distortion, average producing-day phase rates were calculated for each production phase.

Evidence and calculations

Oil production rate:

$$q_o = \frac{Q_o}{\mathrm{DaysOn}}$$

Water production rate:

$$q_w = \frac{Q_w}{\mathrm{DaysOn}}$$

Gas production rate:

$$q_g = \frac{Q_g}{\mathrm{DaysOn}}$$

where:

- Q_o = monthly oil production volume;
- Q_w = monthly water production volume;
- Q_g = monthly gas production volume;
- DaysOn = producing days during the reporting month.

These producing-day normalized rates represent average flowing performance during active production periods and were used as the primary input for:

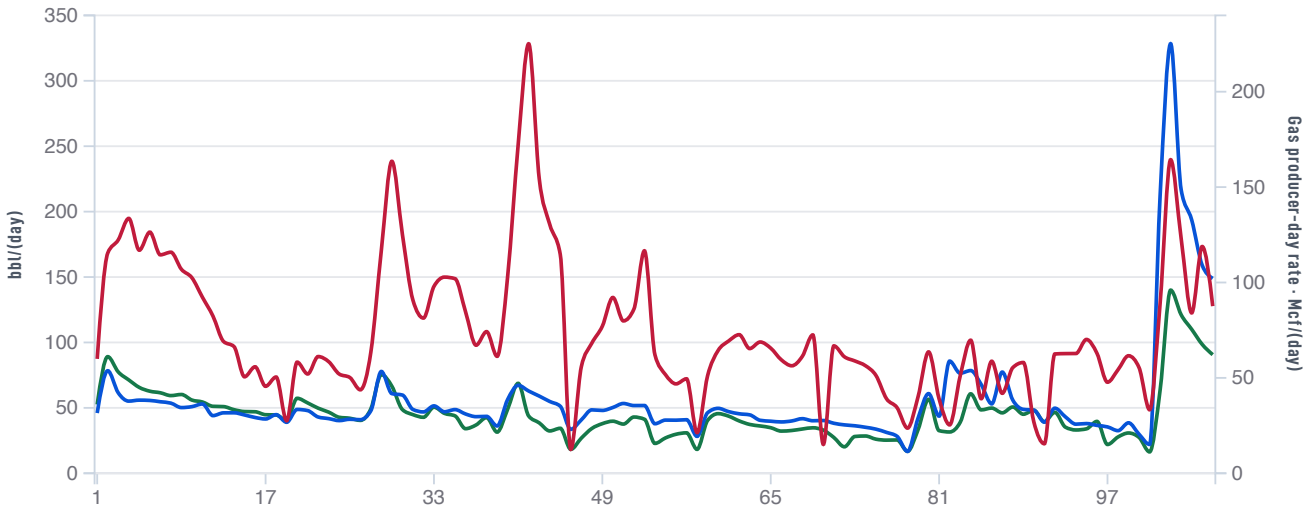
- decline curve fitting;
- rate-time diagnostics;
- production segmentation;
- fluid-behavior interpretation;
- and long-term production trend analysis.

Scientific References

Monthly production volumes require an explicit time basis before rate–time comparison. Dividing each phase volume by producing days estimates the average rate during active production and reduces the influence of downtime on flowing-rate interpretation. Published decline-analysis workflows likewise normalize monthly production and treat partial or non-producing periods separately before fitting. The literature supports explicit time normalization and the use of rate histories in decline analysis. It does not prescribe that producing-day rate must be the primary series in every study. That choice is a declared engineering convention of this report; the reported monthly phase volumes remain unchanged.

1. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source
2. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source
3. Guo, K., Zhang, B., Aleklett, K., & Höök, M. (2016). Production Patterns of Eagle Ford Shale Gas: Decline Curve Analysis Using 1084 Wells. Sustainability, 8(10), 973. Source

4.1 Chart — Producing-day Phase Rates by Production Month



SERIES

- Oil producer-day rate · bbl/(day)
- Water producer-day rate · bbl/(day)
- Gas producer-day rate · Mcf/(day)

Summary

The distinction between producing-day rates and calendar-day production is technically important.

For example, a well producing at stable flowing conditions for only 10–15 days during a month may appear artificially degraded when interpreted using full calendar-month averages. Producing-day normalization reduces this distortion and better preserves the actual flowing behavior of the well.

This is particularly important for:

- intermittent producers;
- wells with unstable operating schedules;
- wells affected by downtime;
- and mature wells operating under variable production continuity.

4.2 CALENDAR-DAY PRODUCTION RATES

In addition to producing-day rates, calendar-day average rates were also preserved for production accounting and long-term production context.

Evidence and calculations

Calendar-day oil rate:

$$q_{o,\text{calendar}} = \frac{Q_o}{\text{Days}_{\text{calendar}}}$$

where:

- Days_calendar = total calendar days in the reporting month.

Calendar-day rates represent the effective delivered production contribution over the full month, including downtime and non-producing periods.

These rates were primarily used for:

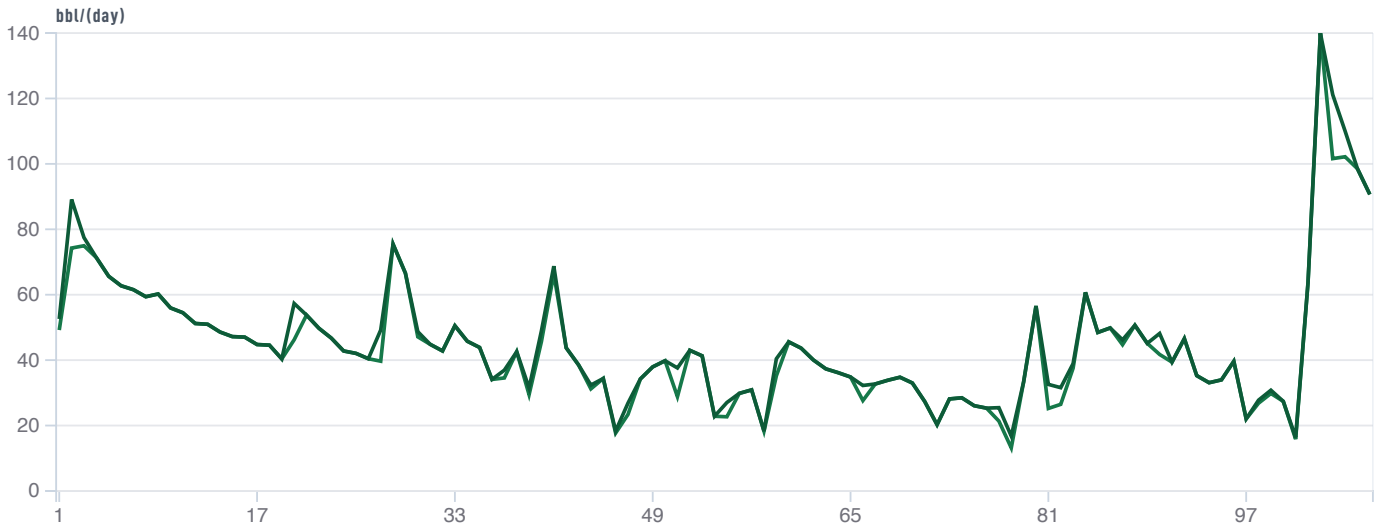
- historical production overview;
- economic production context;
- cumulative production reconciliation;
- and field-level performance comparison.

Scientific References

Calendar-day rate allocates the reported monthly production volume across the complete reporting interval. It therefore represents delivered average production over the month, including downtime and non-producing days, and is useful for production accounting, reconciliation, and period-to-period context. It is not a direct measure of flowing capacity. Published decline-analysis workflows likewise place monthly production on an explicit time basis; the EIA methodology, for example, normalizes monthly production and treats the first potentially partial month separately. The decision to retain both calendar-day and producing-day rates in this report is a declared analytical convention rather than a universal requirement.

1. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source
2. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source
3. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source

4.2 Chart — Calendar-day vs Producing-day Oil Rate by Production Month



SERIES — Calendar-day oil rate · bbl/(day) — Oil producer-day rate · bbl/(day)

Summary

Accordingly:

- producing-day rates represent flowing efficiency;
- calendar-day rates represent delivered production performance.

Both perspectives were retained throughout the analysis because they provide different engineering interpretations of well behavior.

4.3 LIQUID PRODUCTION RATE

Liquid-rate behavior was evaluated together with oil-rate decline because total fluid withdrawal often provides additional insight into reservoir and production-system behavior.

Evidence and calculations

Total liquid production rate was calculated as:

$$q_L = q_o + q_w$$

In many mature wells:

- oil production may decline progressively;
- while total liquid withdrawal remains relatively stable due to increasing water production.

As a result, liquid-rate trends may reveal production-system continuity that is not immediately visible from oil-rate decline alone.

Liquid-rate diagnostics were therefore used to support:

- production regime identification;
- flowing continuity interpretation;
- changing fluid composition analysis;
- and evaluation of mature production behavior.

Liquid-rate behavior was reviewed using:

- linear time plots;
- semi-log decline plots;
- and cumulative production diagnostics.

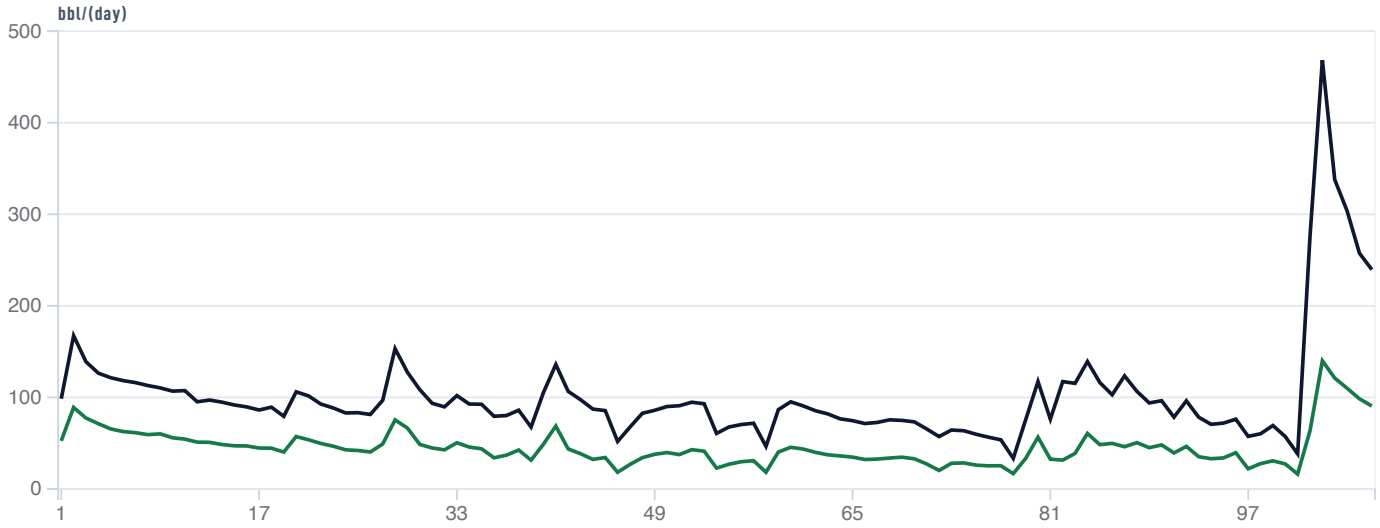
Scientific References

Total liquid rate is the arithmetic sum of produced oil and water rates. Reviewing liquid rate together with oil rate separates a decline in hydrocarbon contribution from the behavior of total produced fluid: oil can decline while water production sustains or increases total liquid withdrawal. Water-production and water-control literature supports the combined review of liquid, water, oil, and ratio histories as surveillance evidence. A liquid-rate plateau or discontinuity alone does not establish a specific reservoir or facility mechanism; causal interpretation requires supporting pressure, injection, completion, and operating information that is not available in this monthly dataset.

1. SLB Energy Glossary. Water cut. Source
2. Chan, K. S. (1995). Water Control Diagnostic Plots. SPE Annual Technical Conference and Exhibition. SPE-30775-MS. Source

3. Poston, S. W., & Laprea-Bigott, M. (2023). Waterflood Review. In Practical Aspects of Waterflooding. Society of Petroleum Engineers. Source

4.3 Chart — Liquid and Oil Producing-day Rates by Production Month



SERIES — Oil producer-day rate · bbl/(day) — Liquid producer-day rate · bbl/(day)

Summary

Particular attention was given to:

- abrupt liquid-rate discontinuities;
- stabilization trends;
- prolonged plateau behavior;
- and transition between decline regimes.

4.4 WATER CUT (WC)

Water cut represents the volumetric fraction of produced water within the total liquid production stream.

Water-cut evolution is one of the primary surveillance indicators used in mature oil-field production analysis because it directly reflects long-term changes in produced fluid composition.

Evidence and calculations

Water cut was calculated as:

$$\mathrm{WC} = \frac{q_w}{q_o + q_w}$$

Increasing water cut may indicate:

- progressive water production dominance;
- advancing water movement toward the well;
- changing fluid mobility behavior;
- or late-stage production deterioration.

However, water-cut behavior must be interpreted carefully because:

- water cut may increase even when total liquid withdrawal remains stable;
- operational instability may influence apparent fluid ratios;
- and low-rate operating conditions may exaggerate month-to-month variability.

Accordingly, water cut was interpreted together with:

- oil-rate decline;
- liquid-rate behavior;
- WOR trends;
- and cumulative production diagnostics.

Water-cut behavior was reviewed using:

- linear time trends;
- cumulative production relationships;
- and segmented production diagnostics.

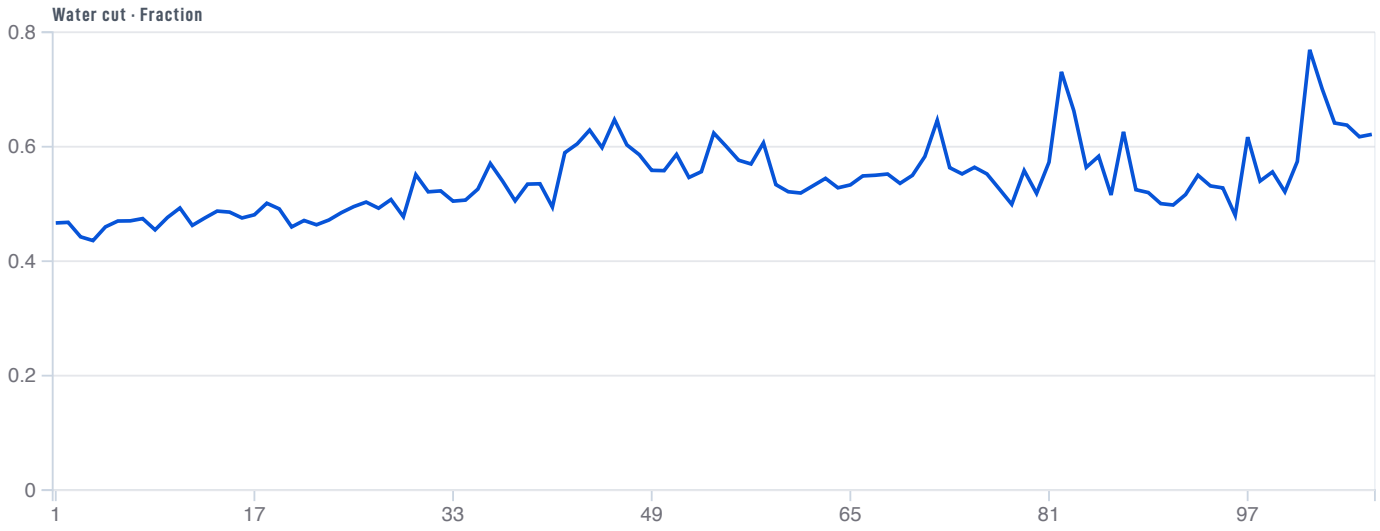
Scientific References

Water cut is the produced-water fraction of the total liquid stream. It is a standard production-surveillance measure of changing fluid composition, and its evolution can be compared with oil rate, liquid rate, cumulative production, and water–oil ratio. Published water-control diagnostics use water-production behavior and ratio trends to identify patterns that merit engineering investigation.

Monthly water-cut acceleration, stabilization, or discontinuity is therefore diagnostic evidence, not proof of water breakthrough, channeling, changing mobility, or another specific mechanism. Those interpretations require additional reservoir and operating data.

1. SLB Energy Glossary. Water cut. Source
2. Chan, K. S. (1995). Water Control Diagnostic Plots. SPE Annual Technical Conference and Exhibition. SPE-30775-MS. Source
3. Poston, S. W., & Laprea-Bigott, M. (2023). Waterflood Review. In Practical Aspects of Waterflooding. Society of Petroleum Engineers. Source

4.4 Chart — Water Cut by Production Month



SERIES — Water cut · Fraction

Summary

Special attention was given to:

- sustained water-cut acceleration;
- abrupt water-cut transitions;
- stabilization periods;
- and asymptotic late-time behavior.

4.5 WATER-OIL RATIO (WOR)

WOR was used as one of the primary long-term surveillance indicators for mature production behavior.

Evidence and calculations

Water-oil ratio was calculated as:

$$\mathrm{WOR} = \frac{q_w}{q_o}$$

Compared with water cut, WOR often provides greater sensitivity during advanced production stages because:

- water cut asymptotically approaches 1.0;
- whereas WOR continues increasing nonlinearly as oil production declines.

This makes WOR particularly useful for:

- identifying production deterioration trends;
- evaluating increasing water dominance;
- and interpreting late-stage fluid behavior.

WOR diagnostics were reviewed together with:

- oil-rate decline;
- liquid-rate trends;
- cumulative oil production;
- and production segmentation results.

WOR behavior was analyzed using:

- WOR vs time plots;
- WOR vs cumulative oil production plots;
- and semi-log production diagnostics.

Particular attention was given to:

- persistent WOR acceleration;
- changes in WOR slope;
- abrupt WOR discontinuities;
- and prolonged stabilized WOR trends.

These behaviors may indicate:

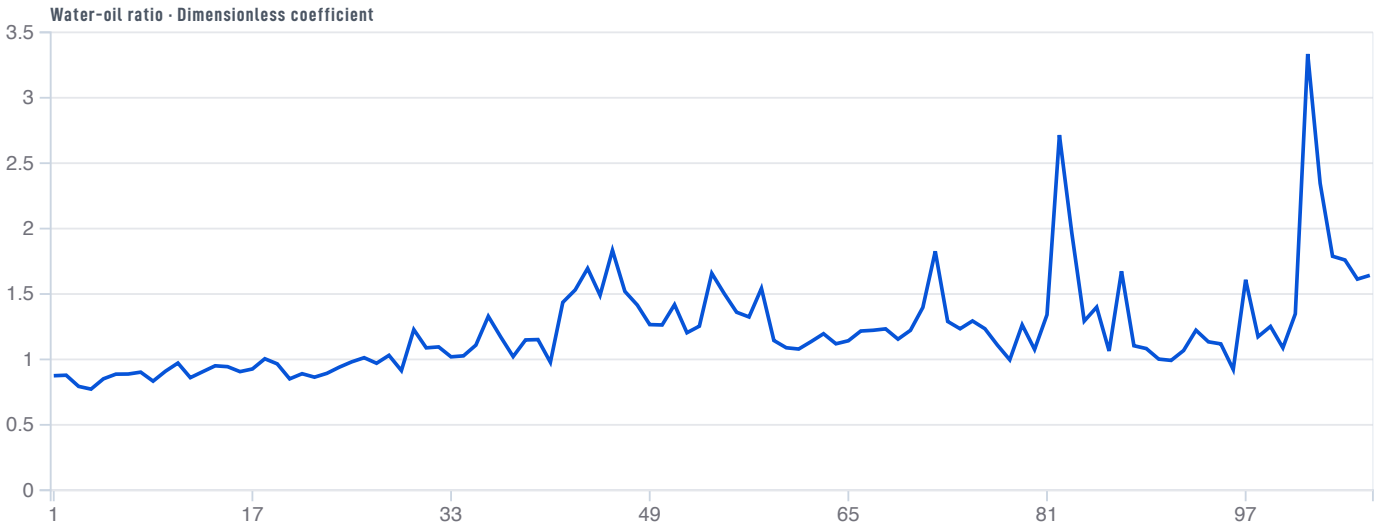
- transition between production regimes;
- changing fluid-production behavior;
- or progressive deterioration of oil productivity relative to water production.

Scientific References

Water–oil ratio compares produced water with produced oil. Its relationship to water cut is mathematical: WC = WOR / (1 + WOR). Consequently, as water cut approaches 1.0, WOR can continue increasing and may remain more visually sensitive to late-stage changes in water dominance. Water-control literature supports using WOR trends and WOR-versus-cumulative-production relationships as diagnostic plots. The slope, acceleration, or discontinuity observed in monthly WOR is not by itself a causal diagnosis or an automatic exclusion rule; it remains surveillance evidence to be interpreted with oil, liquid, cumulative, and operating history.

1. SLB Energy Glossary. Water/oil ratio (WOR). Source
2. Chan, K. S. (1995). Water Control Diagnostic Plots. SPE Annual Technical Conference and Exhibition. SPE-30775-MS. Source
3. Poston, S. W., & Laprea-Bigott, M. (2023). Waterflood Review. In Practical Aspects of Waterflooding. Society of Petroleum Engineers. Source

4.5 Chart — Water-Oil Ratio by Production Month



SERIES — Water-oil ratio · Dimensionless coefficient

Summary

Because only monthly production data were available, WOR interpretation was performed qualitatively rather than as high-resolution transient diagnostics.

4.6 GAS-OIL RATIO (GOR)

GOR served as the primary gas-phase surveillance indicator throughout the analysis workflow.

Evidence and calculations

Gas-oil ratio was calculated as:

$$\mathrm{GOR} = \frac{q_g}{q_o}$$

GOR behavior was reviewed to evaluate:

- long-term gas-production evolution;
- changing production behavior;
- increasing gas dominance;
- and production instability associated with gas-rate variability.

Increasing GOR behavior may indicate:

- evolving fluid-production conditions;
- changing depletion behavior;
- gas breakthrough signatures;
- or transition into late-stage production conditions.

GOR diagnostics were evaluated together with:

- oil-rate decline;
- liquid-rate behavior;
- cumulative production trends;
- and production segmentation results.

The following diagnostic visualizations were used:

- GOR vs time;
- GOR vs cumulative oil production;
- semi-log production diagnostics;
- and segmented production behavior review.

Particular attention was given to:

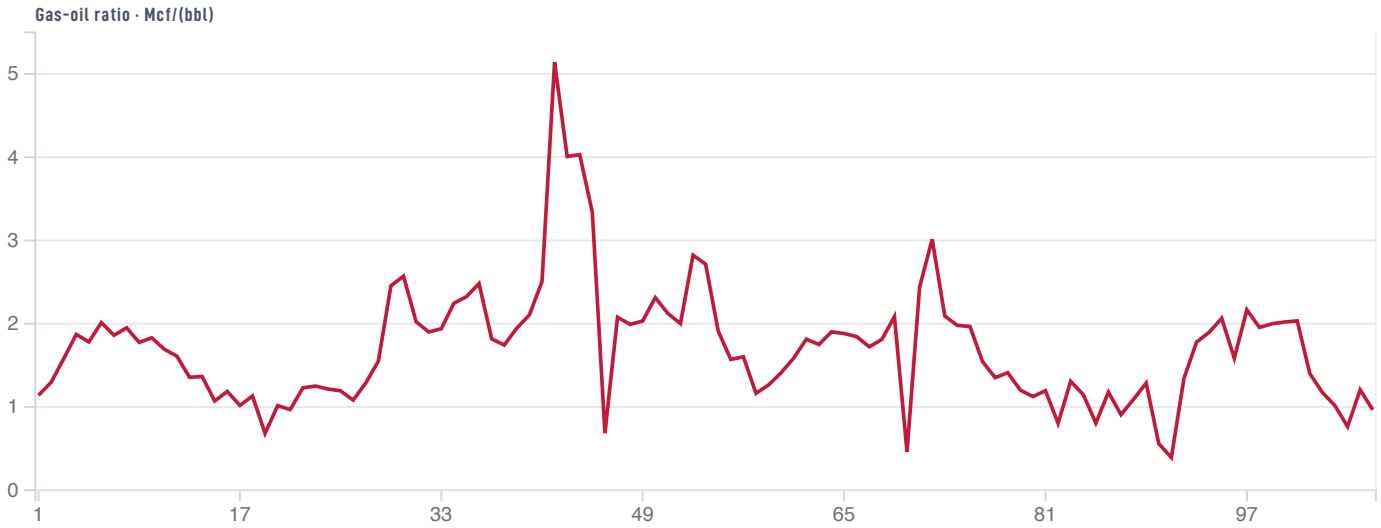
- sustained GOR acceleration;
- abrupt GOR spikes;
- stabilization periods;
- and changes in GOR trend consistency.

Scientific References

Gas–oil ratio compares produced gas volume with produced oil volume and is a standard indicator of the gas contribution to an oil-production stream. The EIA likewise uses GOR to describe and classify produced-fluid behavior across primary oil-producing regions. A sustained change in monthly GOR is useful surveillance evidence of an evolving produced-fluid mix. It cannot, by itself, distinguish reservoir-fluid evolution, gas breakthrough, depletion behavior, allocation changes, measurement effects, or operating instability. This report therefore uses GOR for production-behavior surveillance and not as a definitive reservoir-fluid diagnosis.

1. SLB Energy Glossary. Gas/oil ratio (GOR). Source
2. U.S. Energy Information Administration. (2021). Gas-to-oil ratios in U.S. primary oil-producing regions. Source
3. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source

4.6 Chart — Gas-Oil Ratio by Production Month



SERIES — Gas-oil ratio · Mcf/(bbl)

Summary

Because the workflow is based exclusively on monthly production data, GOR interpretation was limited to production-behavior surveillance and was not treated as a definitive reservoir-fluid diagnostic.

4.7 RELATIVE RATE CHANGE

Relative producing-day oil-rate change is recalculated between consecutive retained observations in Clean Well Data, ordered by continuous Production Month.

Evidence and calculations

Relative change between consecutive retained producing-day oil rates was recalculated as:

$$\frac{\Delta q}{q} = \frac{q_t - q_{t-1}}{q_{t-1}}$$

where:

- q_t = producing-day oil rate at the current retained Production Month;
- q_(t-1) = producing-day oil rate at the immediately preceding retained Production Month.

The result is blank for the first retained observation, when no preceding retained observation exists, or when the preceding producing-day oil rate is zero or undefined.

This metric was used to identify:

- abrupt production discontinuities;
- unstable production periods;
- restart behavior;
- production interruptions;
- and possible regime-transition intervals.

Relative rate change is particularly useful because:

- a 100 bbl/d change may be insignificant for a high-rate well;
- but highly significant for a mature low-rate producer.

Accordingly, normalized relative change provides a more scalable measure of production instability across different production magnitudes.

Relative rate-change diagnostics were used during:

- production segmentation;
- decline-interval selection;
- and production-regime interpretation.

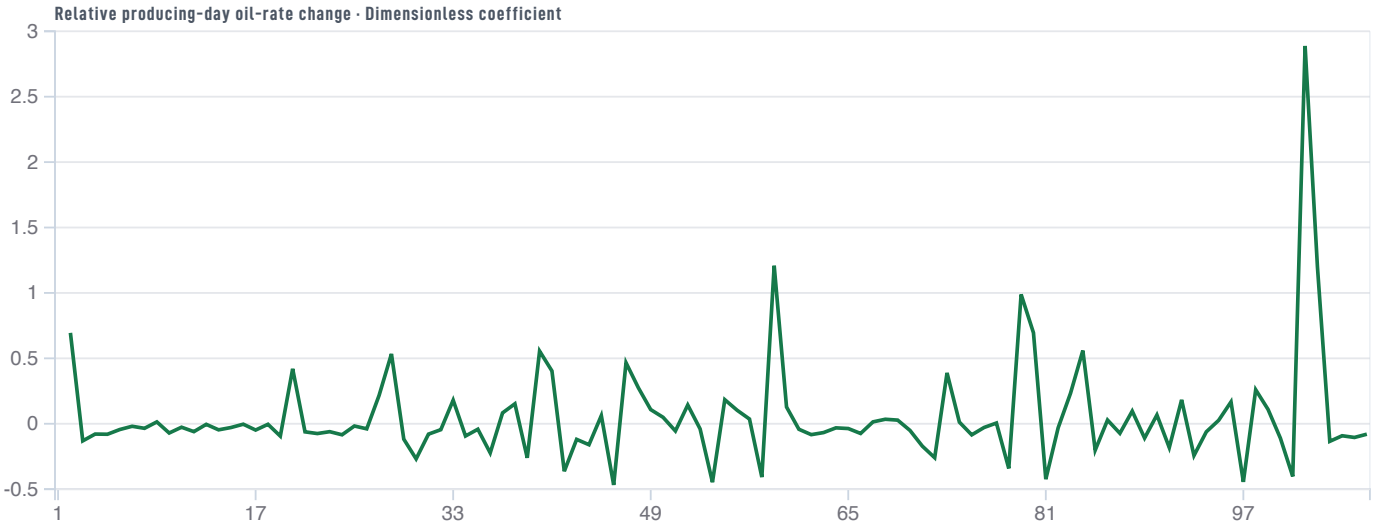
Scientific References

Rate–time and decline-curve literature establishes production-rate history as a primary diagnostic basis for decline interpretation. Expressing consecutive-month change relative to the preceding rate makes the change dimensionless and allows the same diagnostic to be compared across different

production magnitudes. The exact formula used here is a discrete workflow metric. The cited literature does not prescribe a universal relative-change threshold, classify every large change as an outlier, or prove a regime transition from one monthly observation. Restarts, interruptions, interventions, and genuine production changes must remain part of the engineering context.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Fetkovich, M. J. (1980). Decline Curve Analysis Using Type Curves. Journal of Petroleum Technology, 32(6), 1065–1077. Source
3. Liang, H.-B., Zhang, L.-H., Zhao, Y.-L., Zhang, B.-N., Chang, C., Chen, M., & Bai, M.-X. (2020). Empirical methods of decline-curve analysis for shale gas reservoirs: Review, evaluation, and application. Journal of Natural Gas Science and Engineering, 83, 103531. Source

4.7 Chart — Relative Producing-day Oil-Rate Change by Production Month



SERIES — Relative producing-day oil-rate change · Dimensionless coefficient

Summary

The metric was interpreted within engineering production context and not used as an automatic outlier-removal criterion.

4.8 CUMULATIVE PRODUCTION METRICS

Cumulative oil, water, and gas volumes were recalculated as prefix sums of retained monthly phase volumes in Clean Well Data, ordered by Production Month.

Evidence and calculations

Cumulative oil production:

$$N_p(t) = \sum_{i=1}^{t} Q_{o,i}$$

Cumulative water production:

$$W_p(t) = \sum_{i=1}^{t} Q_{w,i}$$

Cumulative gas production:

$$G_p(t) = \sum_{i=1}^{t} Q_{g,i}$$

For every phase, the summation domain is the retained Production Month sequence 1...t in Clean Well Data; calendar periods absent from this final view make no contribution to the cumulative total.

Cumulative production metrics were used extensively throughout the workflow for:

- EUR estimation;
- depletion tracking;
- rate-cumulative diagnostics;
- production-regime characterization;
- and long-term production interpretation.

Rate-cumulative relationships often provide additional engineering insight compared with rate-time plots alone because they may reveal:

- decline stabilization behavior;
- production regime transitions;
- and changes in long-term depletion trends.

Cumulative diagnostics were reviewed using:

- rate vs cumulative production plots;
- WOR vs cumulative oil production;
- GOR vs cumulative oil production;

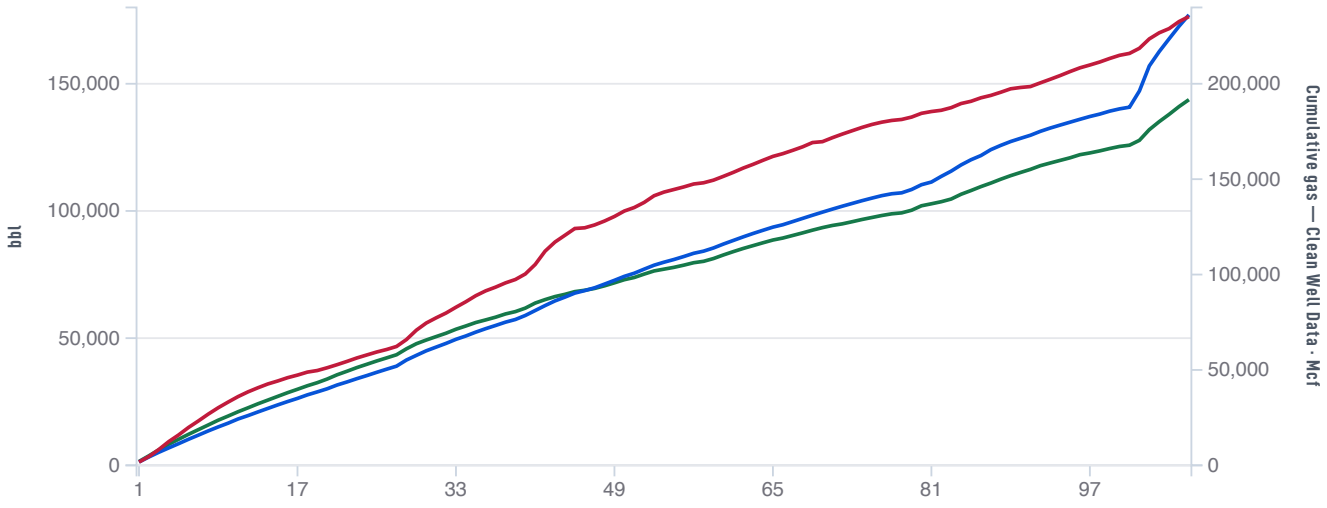
- and cumulative phase-behavior trends.

Scientific References

Cumulative production is the discrete integral of the observed production history and is calculated here as the prefix sum of actual monthly phase volumes. Using reported volumes rather than uptime-normalized rates preserves volumetric balance. Rate–cumulative relationships are established decline-analysis diagnostics, while EUR combines observed cumulative production with forecast production under an explicit model and horizon. The literature supports those uses; it does not prescribe the report-specific Production Month index, interval-selection decisions, or a particular forecast as uniquely valid. Any reserves or resources interpretation remains subject to the uncertainty and classification requirements of PRMS.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Fetkovich, M. J. (1980). Decline Curve Analysis Using Type Curves. Journal of Petroleum Technology, 32(6), 1065–1077. Source
3. U.S. Energy Information Administration. (2021). Production Decline Curve Analysis in the Annual Energy Outlook 2021. Source
4. Society of Petroleum Engineers et al. (2018). Petroleum Resources Management System, revised June 2018. Source

4.8 Chart — Cumulative Production by Phase and Production Month



SERIES

- Cumulative oil — Clean Well Data · bbl
- Cumulative water — Clean Well Data · bbl
- Cumulative gas — Clean Well Data · Mcf

Summary

All cumulative calculations use the actual phase volumes of retained monthly observations—not uptime-normalized rates—so the volumetric balance is preserved over the final Production Month sequence.

4.9 INTEGRATION OF DERIVED METRICS WITHIN THE WORKFLOW

The derived production metrics were integrated into multiple analytical workflows throughout the study.

Evidence and calculations

Scientific References

The workflow combines complementary production diagnostics because each metric answers a different engineering question. Rate and cumulative history support decline interpretation; liquid, water cut, and WOR support water-production surveillance; GOR describes the gas contribution to produced fluids; and reserves or EUR statements require explicit forecast and uncertainty governance. Table 4.1 is therefore a report-specific mapping of metrics to analytical tasks, not a universal causal model. No single monthly indicator independently identifies reservoir state, flow regime, breakthrough, or recoverable reserves. Interpretations must remain consistent with the complete production history and the limitations of the available data.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Chan, K. S. (1995). Water Control Diagnostic Plots. SPE Annual Technical Conference and Exhibition. SPE-30775-MS. Source
3. U.S. Energy Information Administration. (2021). Gas-to-oil ratios in U.S. primary oil-producing regions. Source
4. Society of Petroleum Engineers et al. (2018). Petroleum Resources Management System, revised June 2018. Source

Summary

Different derived metrics therefore provide different engineering perspectives on:

- flowing performance;
- changing fluid composition;
- production continuity;
- long-term decline behavior;
- and production regime evolution over time.

No single metric was interpreted independently from the broader production history.

5. PRODUCTION REGIME SEGMENTATION

5.1 SEGMENTATION PHILOSOPHY

The calculation follows the retained production sequence separately for each well and pool. It evaluates the link from the current observation to the next retained observation, assigns a link status, and joins observations connected by passing links.

A failing or non-evaluable link ends the current connected run. All observations supporting a qualifying run receive the same segment ID and selected flag. Short runs and isolated observations remain available in the audit tables.

The supplied technical specification is reference material for the liquid-change profile. In this report, the accepted Clean Well Data sequence defines adjacency; calendar-gap rejection is not part of the applied profile.

5.2 PRIMARY SEGMENTATION CRITERIA

The limits, inclusivity switches and minimum link count are explicit constants in the saved Formula definitions. Changing the profile requires saving the changed definition and recalculating; the resulting exact Formula versions identify the applied profile.

Scientific References

The cited literature provides background for rate-based decline analysis. The numerical liquid-change limits and minimum passing-link rule are defined by the supplied Stable Production Segment Selection methodology and the applied report profile. This report uses consecutive Clean Well Data observations in Production Month order; it does not add a calendar-gap rejection rule. The references do not independently validate a selected segment or a fitted DCA model.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Fetkovich, M. J. (1980). Decline Curve Analysis Using Type Curves. Journal of Petroleum Technology, 32(6), 1065–1077. Source
3. Tang, H., Zhang, B., Liu, S., Li, H., Huo, D., & Wu, Y.-S. (2021). A novel decline curve regression procedure for analyzing shale gas production. Journal of Natural Gas Science and Engineering, 88, 103818. Source

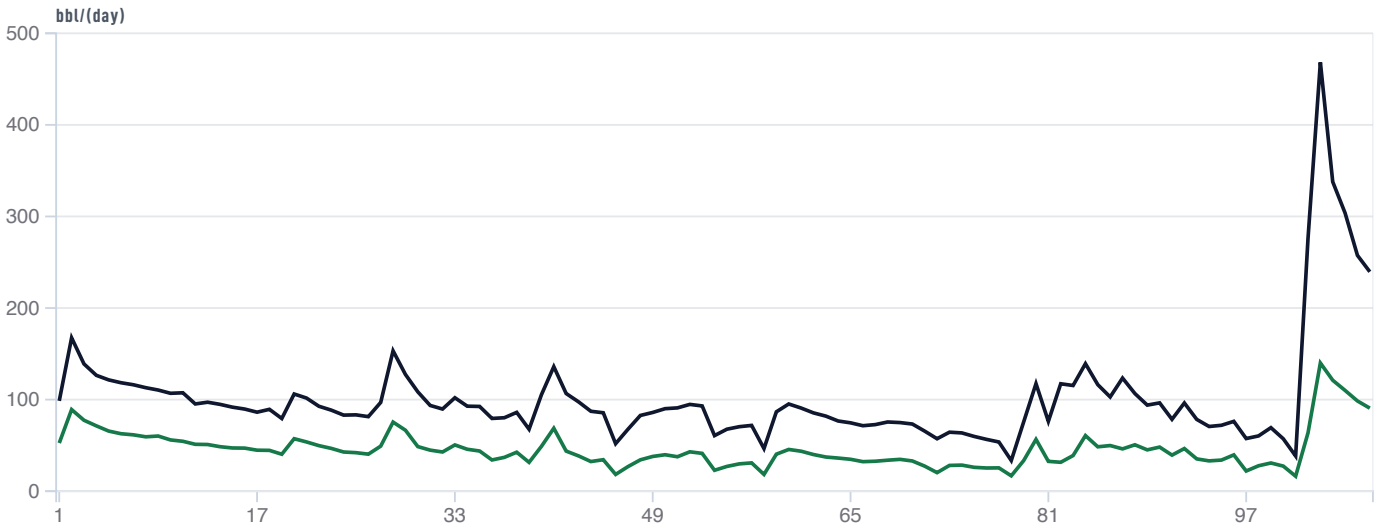
5.3 LIQUID-RATE STABILITY ASSESSMENT

This chapter consumes the oil and liquid producer-day rates already defined in Chapter 4. Those shared Formula outputs use Clean Well Data and are reused directly in the calculations below.

$$q_{L,i} = \frac{V_{o,i} + V_{w,i}}{d_i}$$

The forward-change calculation uses the existing liquid-rate output. A zero starting liquid rate or the absence of a next observation yields no calculable outgoing change. Input completeness and valid producing days are guaranteed by the upstream QA/QC workflow and are not checked again here.

5.3 Chart — Oil and Liquid Producing-day Rates by Production Month



SERIES — Oil producer-day rate · bbl/(day) — Liquid producer-day rate · bbl/(day)

Liquid-rate change supplies the selection criterion. Oil rate remains visible for interpretation of the produced-fluid history. Selection is evaluated on the complete retained sequence, and all supporting observations of a qualifying segment remain visible.

5.4 OIL-RATE DECLINE CONTINUITY

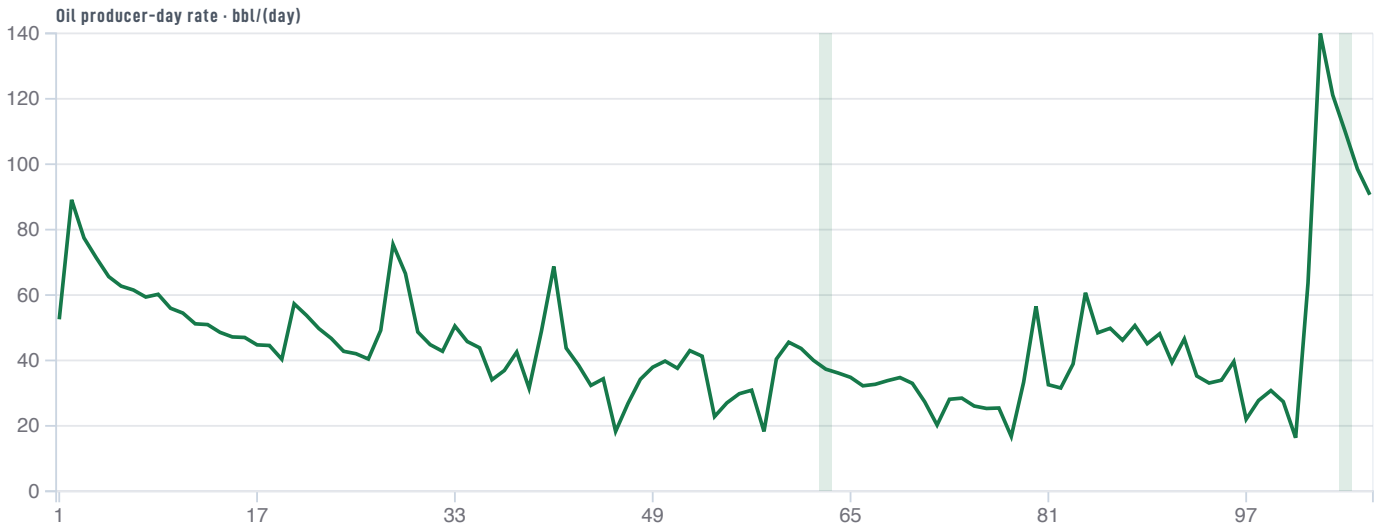
Figure 5.4 is a local oil-decline diagnostic. Each green highlight marks a Production Month where the five-gradient StableTrend test passes. These highlights show individual diagnostic positions; the selected liquid segments are shown separately in Figure 5.11-2.

$$D_i = -\frac{\ln(q_{o,i}/q_{o,i-1})}{d_i}$$

$$GV_i = \frac{MAD_i}{|D_{\mathrm{med},i}|}$$

StableTrend requires five supported gradients, a positive centered median and GV ≤ 0.30. Liquid-segment selection instead requires at least three consecutive links with −0.50 < dl < 0. StableTrend is not a selection gate, so the number of green diagnostic positions need not equal the number of selected liquid segments. A false StableTrend result does not remove an observation from a selected segment.

5.4 Chart — Producer-day Oil Rate with StableTrend Evidence



SERIES — Oil producer-day rate · bbl/(day)

STATUS **Stable trend — Clean Well Data**

Status interval shown as chart background

Scientific References

The normalized local log-rate gradient is a discrete decline diagnostic, while the centered median and median absolute deviation provide robust local measures of direction and variability. The cited literature supports rate-based decline interpretation and median-based robust variability measures.

It does not prescribe the report-specific five-gradient window, epsilon, GV threshold of 0.30, or the conversion of StableTrend observations into production-regime boundaries. Those remain explicit project methodology choices.

1. Arps, J. J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(1), 228–247. Source
2. Fetkovich, M. J. (1980). Decline Curve Analysis Using Type Curves. Journal of Petroleum Technology, 32(6), 1065–1077. Source
3. Rousseeuw, P. J., & Croux, C. (1993). Alternatives to the Median Absolute Deviation. Journal of the American Statistical Association, 88(424), 1273–1283. Source

Read the oil-rate diagnostic together with the selected liquid segment when assessing whether subsequent DCA is appropriate. A local diagnostic flag is neither a segment identifier nor a validation of an Arps model.

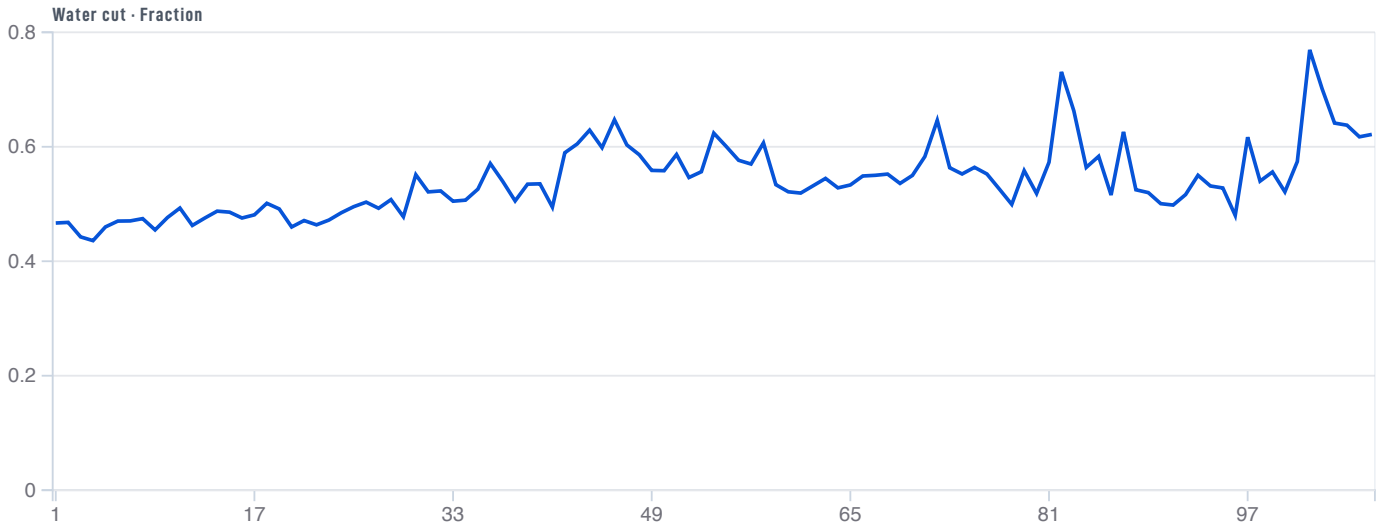
5.5 WATER-CUT EVOLUTION

Water cut is used as supporting evidence of changing produced-fluid composition and is reviewed together with oil rate, liquid rate, and WOR.

$$WC_i = \frac{Q_{w,i}}{Q_{o,i} + Q_{w,i}}$$

Acceleration, stabilization, or discontinuity in water cut may support a candidate transition, but it does not prove breakthrough, channeling, changing mobility, or another reservoir mechanism without additional pressure, injection, completion, and operating data.

5.5 Chart — Water Cut by Production Month



SERIES — Water cut · Fraction

Water-cut evolution describes changing produced-fluid composition. It does not enter DL Status, segment construction or the minimum passing-link test.

5.6 WOR AND GOR TREND REVIEW

WOR and GOR are supplementary surveillance indicators. WOR describes produced-water volume relative to oil; GOR describes produced-gas volume relative to oil.

$$WOR_i = \frac{Q_{w,i}}{Q_{o,i}}, \qquad GOR_i = \frac{Q_{g,i}}{Q_{o,i}}$$

Only observations with a positive oil denominator carry a defined ratio. Abrupt changes, trend reversals, acceleration, or stabilization remain diagnostic evidence and are not automatic boundary or deletion rules.

5.6 Chart — WOR and GOR by Production Month



SERIES — Water-oil ratio · Dimensionless coefficient — Gas-oil ratio · Mcf/(bbl)

Scientific References

Water cut and WOR are established water-production surveillance measures, while GOR describes the gas contribution to the produced-fluid stream. Their trends can identify patterns that warrant engineering review. A monthly ratio trend cannot independently distinguish reservoir-fluid evolution, breakthrough, depletion, allocation effects, measurement effects, or operating instability. This chapter therefore uses the ratios as corroborating evidence only.

1. Chan, K. S. (1995). Water Control Diagnostic Plots. SPE Annual Technical Conference and Exhibition. SPE-30775-MS. Source
2. SLB Energy Glossary. Water/oil ratio (WOR). Source
3. U.S. Energy Information Administration. (2021). Gas-to-oil ratios in U.S. primary oil-producing regions. Source

WOR and GOR remain supplementary surveillance evidence. Their values and trends do not change the liquid-profile selection flag.

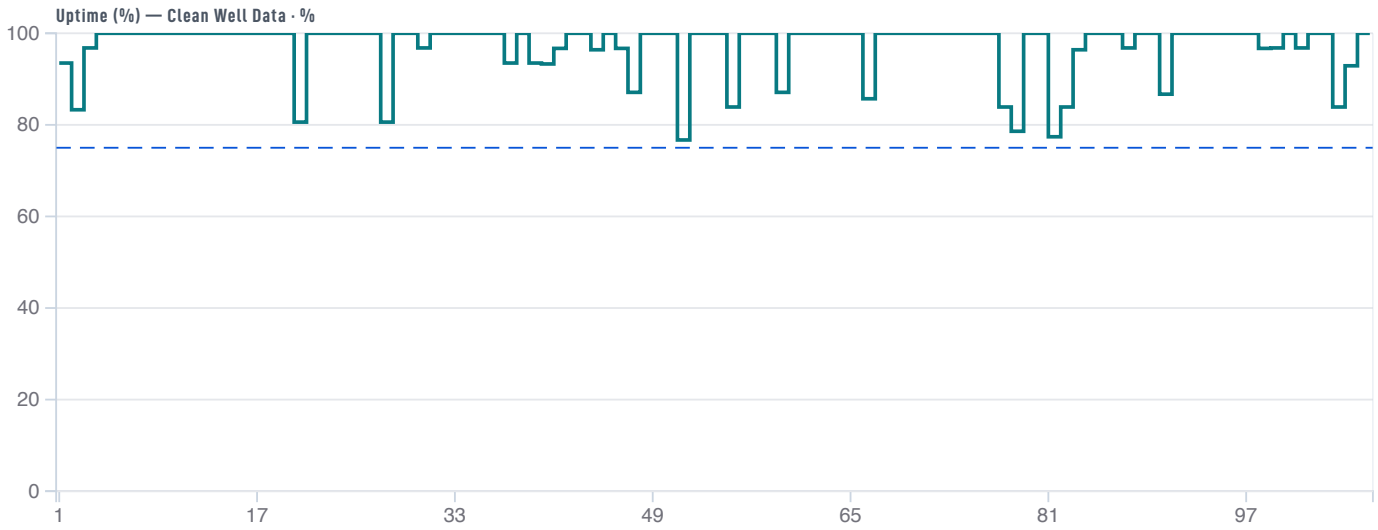
5.7 UPTIME CONTINUITY ASSESSMENT

Uptime is shown for the observations already retained in Clean Well Data. The upstream QA/QC workflow owns membership; this chapter does not apply a second uptime threshold.

$$\text{Uptime}_i = 100 \frac{d_i}{\text{days in the reporting period}}$$

Producing days normalize the liquid rate. Uptime provides operating context and does not create additional segment boundaries.

5.7 Chart — Uptime by Production Month



SERIES — Uptime (%) — Clean Well Data · % ---- Threshold = 75

The table and chart describe uptime within the retained population. No observation is removed or reclassified by this section.

5.8 FORWARD LIQUID-RATE CHANGE

For observation i, compare its producing-day liquid rate with the next retained Clean Well Data observation i+1. Store the result and status on the starting observation i.

$$dl_i = \frac{q_{L,i+1} - q_{L,i}}{q_{L,i}}$$

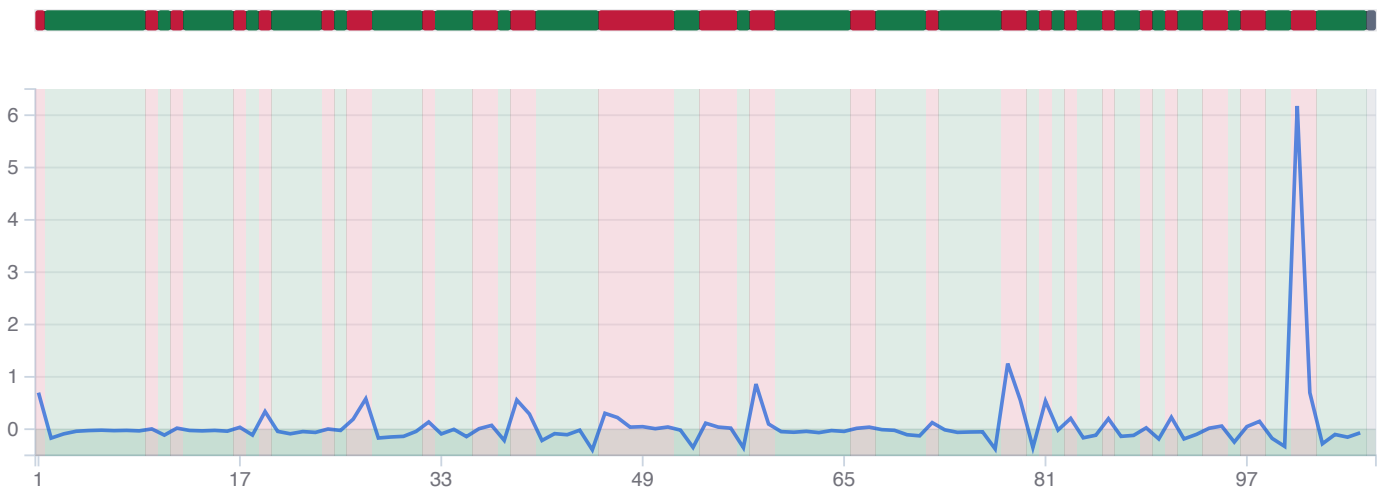
$$\mathrm{PASS}_i \iff -0.50 < dl_i < 0$$

A calculable change outside these exclusive limits is FAIL. A zero starting liquid rate or the absence of a next observation yields NOT_EVALUABLE and a blank dl. The calculation reuses the Chapter 4 liquid-rate output and the retained Clean Well Data sequence. The well and pool are never mixed. Calendar spacing is not a criterion.

The chart uses Production Month and plots dl at its starting observation. The green horizontal band shows the passing-change range between −0.50 and 0; both boundary values remain excluded. The row-level audit table in Section 5.10 exposes exact values and statuses.

The status timeline above the plot shows the calculated outgoing DL Status at each Production Month: green for PASS, red for FAIL and gray for NOT_EVALUABLE. These link statuses are separate from the full-segment selection shown in Section 5.11.

Figure 5.8. Forward Liquid-Rate Change by Production Month



SERIES — Forward liquid-rate change (dl) · Dimensionless coefficient — Reference range: -0.5 – 0

STATUS

DL Status (outgoing link) · PASS
Status interval shown as chart background

DL Status (outgoing link) · FAIL
Status interval shown as chart background

DL Status (outgoing link) · NOT_EVALUABLE
Status interval shown as chart background

PASS describes one link. A selected segment requires a sufficiently long consecutive run of passing links. A final supporting observation can remain selected even when its outgoing status is FAIL or NOT_EVALUABLE.

5.9 MINIMUM SUPPORT FOR SEGMENT SELECTION

$$N_{\mathrm{obs},s} = N_{\mathrm{links},s} + 1, \qquad \mathrm{Selected}_s = \mathbf{1}[N_{\mathrm{links},s} \geq 3]$$

The minimum applies to the whole run. It must not select only the rows where a running counter has already reached three.

The active profile uses three passing links as its only minimum-length gate. No separate six-observation gate is applied in this chapter. Short runs remain in the result with a false selected flag.

Selection identifies candidates for subsequent DCA assessment. Requirements for a particular model, parameter fitting, residual quality and forecast uncertainty are separate decisions.

This section defines the support rule. Its application to the selected well is shown in the calculation tables in Section 5.10 and the segment register in Section 5.11.

5.10 STABLE SEGMENT CONSTRUCTION

Calculated results for the selected well are available in the two expandable tables below: Complete Liquid-Segment Audit shows the outgoing change and link status; Complete Segment Membership shows each observation's segment, support counts and selection. Section 5.11 presents the resulting intervals and segment register.

The saved calculation chain is: forward liquid-rate change → outgoing DL Status → segment-start flag → segment ID → observation and passing-link counts → stable-segment flag and selection outcome. All stages use the same Clean Well Data Relation.

A new component begins at the first observation, or immediately after an outgoing link that is not PASS. Observations connected by passing links therefore remain in one maximal component. This definition includes the last observation supporting the last passing link.

$$B_i = \begin{cases} 1, & i = 1 \text{ or } DL_Status_{i-1} \neq \text{PASS} \\ 0, & DL_Status_{i-1} = \text{PASS} \end{cases}$$

$$G_i = \text{concat}(\text{Well}, \text{Pool}, \sum_{j \leq i} B_j)$$

The segment ID includes well and pool identity. Its sequence number is local to the exact calculated result and may change when the input or profile changes.

$$N_s = \#\{i : G_i = s\}, \quad L_s = N_s - 1, \quad \text{Stable}_s = \mathbf{1}[L_s \geq 3]$$

Segment start and end are the minimum and maximum Production Month of its supporting observations. Passing links in segment is the complete-run count. Stable run length is the outgoing-link counter: it increases on PASS and returns zero on FAIL or NOT_EVALUABLE. These two counts answer different audit questions.

A row at the end of a selected segment can have a zero running counter and a failing or non-evaluable outgoing link. It remains selected because it supports the preceding passing link. The next row starts a new component.

The interval register selects each component-start row once from the same Clean Well Data population. It keeps short runs and isolated observations for audit. The monthly tables preserve the full retained population. No calendar-duration condition, second QA/QC filter or physical-regime classifier is applied.

Observation number in segment runs from 1 to the full observation count. It is calculated as Production Month minus segment-start Production Month plus 1, including the final supporting observation.

$$k_i = t_i - t_{\text{start}(G_i)} + 1, \qquad k_i \in \{1, \ldots, N_{G_i}\}$$

DCA Segment Observations retains the segment ID, local observation number, Chapter 4 rates and selection flag for every retained observation. DCA Segment Register records each component once with its bounds, support counts and boundary rates. Later DCA assessment can use the selected components and their complete supporting observations as prepared inputs.

The source population, link criterion and complete-run minimum are explicit. A nonselected component remains part of Clean Well Data. The audit tables distinguish outgoing-link status from membership in a selected segment.

Review the dl calculation first, then the segment ID, full-run support and both endpoints. This prevents an off-by-one error from dropping the last supporting observation or the first observations before the counter reaches three.

5.11 SEGMENTATION OUTCOME

The figures and interval register below report the selected well using the saved liquid-change profile. The complete Clean Well Data history remains visible. Green identifies selected segments; red identifies components not selected by this profile.

Figure 5.11-1 shows the full liquid-rate sequence with selection context. Figure 5.11-2 preserves distinct calculated segment IDs and their Production Month bounds. Adjacent components must be read using their IDs and register entries rather than inferred from similar colours.

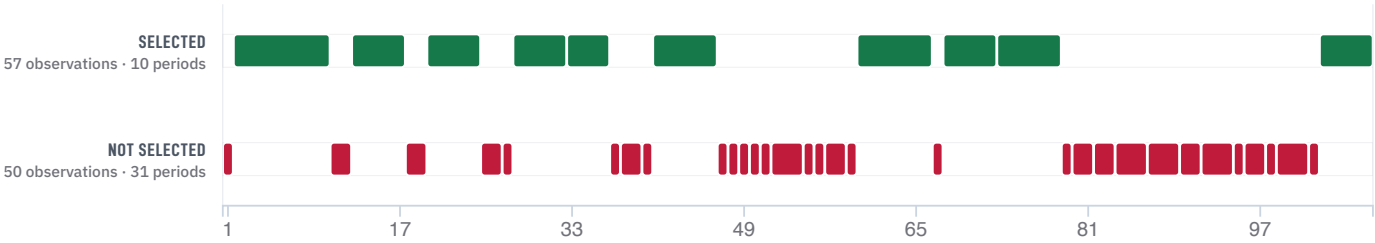
Table 5.4 records one row per component, including short runs and isolated observations. It reports the start and end Production Month, observation count, passing-link count, boundary liquid rates, overall liquid-rate change and selected flag.

For the selected well, the prepared segmentation input contains **107 Count: item** retained observations. The segment register contains **41 Count: item** components in total, including both selected and nonselected components. Read each component's selected flag and complete support in Table 5.4 before using it for subsequent DCA assessment.

Figure 5.11-1. Liquid Rate with Selected Segments by Production Month



Figure 5.11-2. Selected and Nonselected Liquid Segments



PERIODS

1
Segment 1 · 1 observation
Not selected

2 – 10
Segment 2 · 9 observations
Selected

11 – 12
Segment 3 · 2 observations
Not selected

13 – 17
Segment 4 · 5 observations
Selected

18 – 19
Segment 5 · 2 observations
Not selected

20 – 24
Segment 6 · 5 observations
Selected

25 – 26
Segment 7 · 2 observations
Not selected

27
Segment 8 · 1 observation
Not selected

28 – 32
Segment 9 · 5 observations
Selected

33 – 36
Segment 10 · 4 observations
Selected

37
Segment 11 · 1 observation
Not selected

38 – 39
Segment 12 · 2 observations
Not selected

40
Segment 13 · 1 observation
Not selected

41 – 46
Segment 14 · 6 observations
Selected

47
Segment 15 · 1 observation
Not selected

48
Segment 16 · 1 observation
Not selected

49
Segment 17 · 1 observation
Not selected

50
Segment 18 · 1 observation
Not selected

51
Segment 19 · 1 observation
Not selected

52 – 54
Segment 20 · 3 observations
Not selected

55
Segment 21 · 1 observation
Not selected

56
Segment 22 · 1 observation
Not selected

57 – 58
Segment 23 · 2 observations
Not selected

59
Segment 24 · 1 observation
Not selected

60 – 66
Segment 25 · 7 observations
Selected

67
Segment 26 · 1 observation
Not selected

68 – 72
Segment 27 · 5 observations
Selected

73 – 78
Segment 28 · 6 observations
Selected

79
Segment 29 · 1 observation
Not selected

80 – 81
Segment 30 · 2 observations
Not selected

82 – 83
Segment 31 · 2 observations
Not selected

84 – 86
Segment 32 · 3 observations
Not selected

87 – 89
Segment 33 · 3 observations
Not selected

90 – 91
Segment 34 · 2 observations
Not selected

92 – 94
Segment 35 · 3 observations
Not selected

95
Segment 36 · 1 observation
Not selected

96 – 97
Segment 37 · 2 observations
Not selected

98
Segment 38 · 1 observation
Not selected

99 – 101
Segment 39 · 3 observations
Not selected

102
Segment 40 · 1 observation
Not selected

103 – 107
Segment 41 · 5 observations
Selected

Use a selected segment as an input candidate for the next DCA assessment. Its complete supporting observation set is defined by its ID and inclusive Production Month bounds.

The profile does not fit a decline equation, estimate parameters, forecast production, or identify interventions, facility constraints or reservoir mechanisms. Further model and engineering evidence is needed for those conclusions.

6. ARPS CURVE FITTING

6.1 OBJECTIVE AND SCOPE

This chapter defines how to compare exponential, hyperbolic and harmonic Arps curves for each finalized production segment and select one historical best fit. Each segment is fitted independently using exactly the same supplied observations for every candidate.

The fitting method uses the final expert answers for the developer [M2], with the original technical specification [M] as background. It adds fitting after the prepared-segment workflow; it preserves upstream QA/QC, observations and segment membership. This chapter compares historical fits and retains their 240-month model continuations. Engineering interpretation and accumulated effects belong to Chapter 7; these continuations are not reserve estimates.

Methodology status: final expert answers incorporated. The report owner subsequently approved using the existing Chapter 4 Production Month for fitting, with D in 1/month. Definitions are prepared for the scheduled recalculation; displayed previous results may still use the earlier clock. Results in Section 6.7 follow the well selected in the report; segment identifiers and counts come from that well's saved outputs.

Calculation sequence

Receive one finalized segment with declared phase, rate units and time basis → attempt all three constrained models on the complete observation set → calculate candidate statistics → apply the confirmed selection and acceptance rules → retain all attempts and the selected result → inspect the historical comparison plot.

6.2 SEGMENT INPUTS AND TIME BASIS

Each fit uses the complete prepared observation series for one segment admitted by Chapter 5. The input relation is Clean Well Data. Segment identity, membership and the DCA eligibility flag are inherited without a new segmentation or cleaning pass.

$$t_j = m_j - m_{\text{start}}, \qquad [t] = \text{month}, \quad [D_i] = \text{month}^{-1}, \quad [q_i] = [q_j] = \text{bbl/day}, \quad [b] = 1$$

The fitting clock is the existing Production Month coordinate. It does not imply 30 days per month. Retain the original YYYY-MM period and actual active_days for traceability and volume conversion. No new observation filter, resampling, smoothing or segment construction is applied.

The upstream register below shows segment construction and selection. An invalid input within an admitted segment produces an explicit fitting failure for that segment; it is not repaired by removing the offending point.

6.3 CANDIDATE DECLINE MODELS

All three candidates express rate as a function of the same segment-local time. The classical rate–time forms are documented in the ResInsight technical reference [1]. The strict hyperbolic range and parameter constraints below follow the supplied fitting profile [M].

Exponential decline has two fitted parameters and fixed b = 0.

$$\hat{q}(t) = q_i \exp(-D_i t), \qquad q_i > 0, \quad D_i > 0$$

Hyperbolic decline has three fitted parameters, with b strictly between zero and one.

$$\hat{q}(t) = \frac{q_i}{(1 + b D_i t)^{1/b}}, \qquad q_i > 0, \quad D_i > 0, \quad 0 < b < 1$$

Harmonic decline has two fitted parameters and fixed b = 1.

$$\hat{q}(t) = \frac{q_i}{1 + D_i t}, \qquad q_i > 0, \quad D_i > 0$$

Constraints apply during optimization. A fit obtained outside the permitted domain and clipped afterwards is not a constrained solution. A fitted initial rate is estimated from the full segment; it need not equal its first observed rate.

6.4 NONLINEAR LEAST-SQUARES FITTING

Fit exponential, hyperbolic and harmonic candidates independently by minimizing unweighted squared residuals on the original rate scale. Each candidate uses the same complete prepared segment.

$$e_j = q_j - \hat{q}(t_j), \qquad \mathrm{SSE} = \sum_{j=1}^{n} e_j^2$$

The implementation uses SciPy least_squares with the bounded trust-region reflective method and linear loss [2]. Time is divided by segment span and rate by the maximum observed rate for numerical conditioning; exported parameters are restored to their original physical units. This constant scaling preserves the least-squares minimizer.

Deterministic initialization uses the first normalized rate for q_i and the logarithmic first-to-last rate ratio for decline over the normalized span, with a positive fallback of 0.01. Hyperbolic starts use b_0 = 0.10, 0.30, 0.50, 0.70 and 0.90. Retain the lowest-SSE converged admissible start for each model.

The implementation policy sets solver tolerances to 10^{-10} and a budget of 3,000 residual calls per start, including finite-difference Jacobian probes. The hyperbolic interval is bounded numerically by $10^{-8} \le b \le 1 - 10^{-8}$; the exact endpoints are fitted separately as exponential and harmonic candidates. These are versioned engineering settings, not additional geological selection criteria.

A segment is limited to 4,096 observations by the numerical work guard. Reaching a work limit or failing convergence remains a visible candidate status. Numerical convergence does not establish a global minimum or engineering validity.

6.5 FIT STATISTICS AND THEIR DOMAINS

These statistics answer three questions: how closely does the curve match the prepared observations, how large are its errors, and are those errors consistently above or below the observations? Calculate them separately for each candidate on the same unchanged segment. The definitions below follow the final developer answers [M2].

6.5.1 RESIDUALS AND SSE — THE ERRORS USED IN FITTING

Start with the difference between each observed rate and the rate predicted by the candidate at that same observation.

$$e_j = q_j - \hat{q}_j$$

A positive residual means the model underestimates the observed rate; a negative residual means it overestimates it. A residual of zero means an exact match at that point. Residuals have the same units as the rate.

$$\mathrm{SSE} = \sum_{j=1}^{n} e_j^2$$

SSE is the sum of squared errors. Squaring prevents positive and negative errors from cancelling and gives larger errors more weight. Lower SSE means a closer match on this same observation set; zero means a perfect match. Its units are squared rate units. Section 6.4 minimizes this quantity.

6.5.2 MEAN RATE AND SST — THE REFERENCE FOR R^2

To judge whether the curve improves on a simple constant rate, first calculate the segment's average observed rate.

$$\bar{q} = \frac{1}{n} \sum_{j=1}^{n} q_j$$

The average $\bar{q}$ is a reference level, not an Arps parameter. SST then measures how much the observations vary around that level.

$$\mathrm{SST} = \sum_{j=1}^{n} (q_j - \bar{q})^2$$

SST is fixed for all candidates fitted to the same segment. It has squared rate units. If all observed rates are identical, SST is zero and the R^2 statistics below are undefined.

6.5.3 R^2 — IMPROVEMENT OVER A CONSTANT-RATE REFERENCE

R^2 compares the candidate's squared error with the error of using the segment mean as the prediction at every point.

$$R^2 = 1 - \frac{\mathrm{SSE}}{\mathrm{SST}}$$

Higher is better: 1 means an exact historical match, 0 means the same squared error as the constant mean, and a negative value means a worse match than that reference. R^2 is dimensionless. It describes the historical fit, not the probability that a forecast is correct.

Show R^2 for interpretation, but do not rank it again alongside RMSE: for the same observations, both improve when SSE decreases. The selection sequence in Section 6.6 avoids counting that same improvement twice.

6.5.4 ADJUSTED R^2 — ACCOUNT FOR THE NUMBER OF FITTED PARAMETERS

The hyperbolic model has an additional fitted parameter. Adjusted R^2 accounts for that difference when comparing it with exponential and harmonic candidates.

$$R^2_{\mathrm{adj}} = 1 - (1 - R^2)\frac{n-1}{n-k}$$

Higher is better. This is the first comparison criterion in Section 6.6 when it is defined. Here k includes the initial rate q_i, so the accepted denominator is n − k, not n − k − 1 [M2]. The statistic is dimensionless and requires SST > 0 and n > k.

With four observations and three hyperbolic parameters, n − k = 1. The result is retained with LOW_DEGREES_OF_FREEDOM; this means the segment provides little remaining information for assessing fitting error. It does not automatically disqualify the model.

6.5.5 RMSE — ERROR MAGNITUDE WITH EMPHASIS ON LARGE MISSES

RMSE is the square root of the average squared residual.

$$\mathrm{RMSE} = \sqrt{\frac{1}{n}\sum_{j=1}^{n} e_j^2} = \sqrt{\frac{\mathrm{SSE}}{n}}$$

Lower is better; zero means every fitted value matches its observation. RMSE returns the error to the original rate units, which makes its size easier to interpret than SSE. Large residuals influence it more strongly than small ones.

6.5.6 MAE — AVERAGE ABSOLUTE ERROR

MAE averages the size of each error without preserving its sign or squaring it.

$$\mathrm{MAE} = \frac{1}{n}\sum_{j=1}^{n} |e_j|$$

Lower is better. MAE is in the original rate units and answers: on average, how far is the curve from an observation? Each error contributes in direct proportion to its size, so large misses receive less emphasis than in RMSE.

6.5.7 MEAN RESIDUAL — THE DIRECTION OF SYSTEMATIC ERROR

Average the signed residuals to see whether the model tends to sit below or above the observations.

$$\bar{e} = \frac{1}{n}\sum_{j=1}^{n} e_j$$

A positive mean indicates average underestimation; a negative mean indicates average overestimation. Values closer to zero mean less average signed bias. However, positive and negative errors can cancel, so a mean near zero does not by itself mean a good fit. Read it together with RMSE or MAE.

6.5.8 RESIDUAL VARIANCE — SCATTER AROUND THE AVERAGE ERROR

Residual variance measures how much individual errors vary around their own mean, rather than around zero.

$$\mathrm{Var}(e) = \frac{1}{n}\sum_{j=1}^{n}(e_j - \bar{e})^2$$

Lower means less scatter. The accepted definition is centered population variance with denominator n [M2]; its units are squared rate units. A consistently displaced curve can have little residual scatter but substantial bias, which is why the mean residual is retained separately.

RMSE describes overall error magnitude; mean residual describes its direction; residual variance describes its scatter. These are different readings of the same residuals, not three independent datasets.

HOW THESE STATISTICS FEED MODEL SELECTION

Section 6.6 compares valid candidates in order: highest adjusted R^2, then lowest RMSE, residual variance and MAE, then the fewest fitted parameters. The later criteria resolve ties under the declared numerical tolerance; they are not added into a score.

If SST = 0, retain the fit and mark R^2 and adjusted R^2 as undefined, then use the remaining comparison criteria. Never replace an undefined statistic with zero. A selected model is the best available candidate under these rules; selection alone does not establish a reliable forecast.

6.6 FINAL FIT SELECTION

Compare only converged admissible candidates on the same segment. Apply the expert-confirmed criteria in order; do not sum ranks or rank raw R^2 separately [M2].

At each metric, compare candidates with the best remaining value using $|a - b| \leq 10^{-10} + 10^{-8} \times \max(|a|, |b|)$. These implementation tolerances are retained as part of the versioned numerical policy.

Select the best available valid candidate without an arbitrary minimum-R^2 threshold. If some models fail, preserve all attempts and mark the selection SELECTED_WITH_LIMITED_COMPARISON. If no model converges, retain FAILED_NO_CONVERGED_MODEL. Invalid input fails the complete segment with an explicit reason.

Selection identifies the preferred historical curve under this declared policy. It does not constitute a forecast, reserve estimate or independent determination of a reservoir flow regime.

6.7 RESULTS FOR THE SELECTED WELL

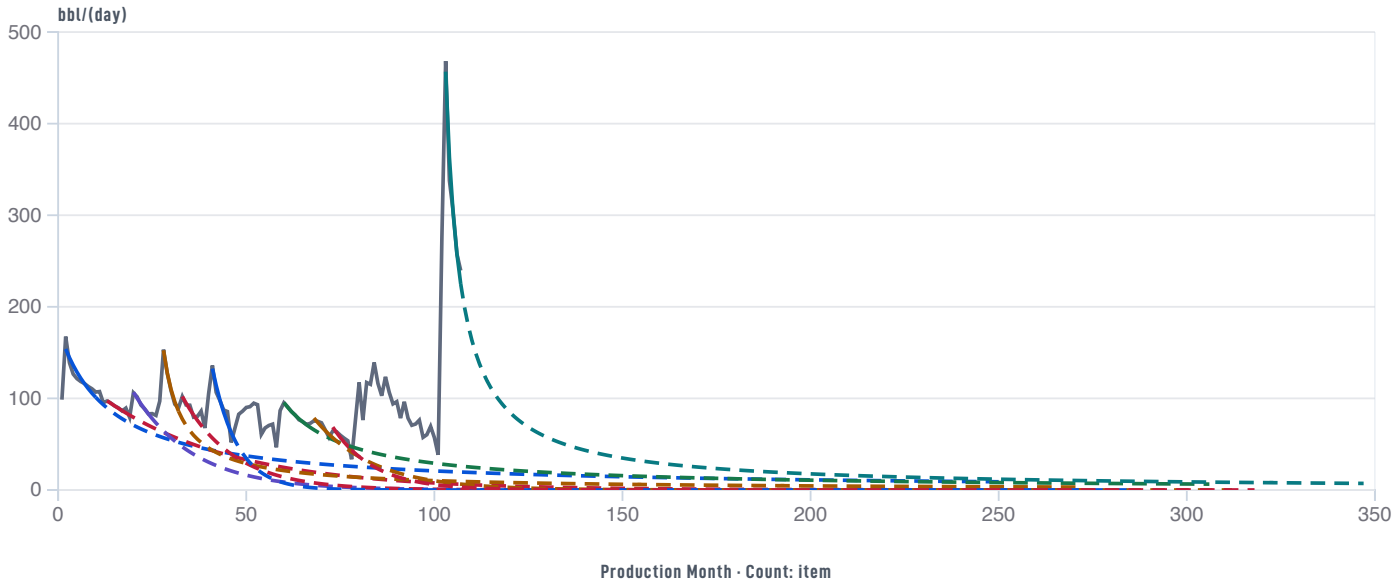
The chart and tables follow the well selected at the top of the report. They use its prepared Chapter 5 segments and retained Chapter 6 results. Segment labels and counts are derived from that well's available fits.

The common chart uses Production Month and total-liquid rate per producing day. The neutral line shows production history. Colored solid lines show the selected historical fit for each segment; dashed lines continue that same model from its fitted endpoint for 240 further production months. The continuation preserves the saved initial rate, decline, exponent and time origin without refitting or shifting the curve to the last observation.

Choose a segment to compare its exponential, hyperbolic and harmonic candidates while retaining the production context. Use the interval zoom to inspect the fit locally. Solid fits connect values at retained Production Month coordinates; dashed continuations use the same coordinate on a monthly model grid. Model samples are calculated values, not additional observations. A failed or unavailable model remains a diagnostic status without an invented curve.

The selected-model register identifies the preferred curve and its exact parameters; candidate tables provide fit statistics and diagnostics. Observations and model continuation samples remain saved separately for inspection and reuse. The 240-month continuations support comparison. Intersections, exposure-weighted accumulated production differences and interpretation belong to Chapter 7. Rounded displayed values are not inputs to later calculations.

Production History, Arps Fits and Model Continuations



SERIES

- Production · bbl/(day)
- Selected fit: segment-2 · 2 — 10 · bbl/(day)
- Selected fit: segment-4 · 13 — 17 · bbl/(day)
- Selected fit: segment-6 · 20 — 24 · bbl/(day)
- Selected fit: segment-9 · 28 — 32 · bbl/(day)
- Selected fit: segment-10 · 33 — 36 · bbl/(day)
- Selected fit: segment-14 · 41 — 46 · bbl/(day)
- Selected fit: segment-25 · 60 — 66 · bbl/(day)
- Selected fit: segment-27 · 68 — 72 · bbl/(day)
- Selected fit: segment-28 · 73 — 78 · bbl/(day)
- Selected fit: segment-41 · 103 — 107 · bbl/(day)
- Model continuation: segment-2 · 2 — 10 · bbl/(day)
- Model continuation: segment-4 · 13 — 17 · bbl/(day)
- Model continuation: segment-6 · 20 — 24 · bbl/(day)
- Model continuation: segment-9 · 28 — 32 · bbl/(day)
- Model continuation: segment-10 · 33 — 36 · bbl/(day)
- Model continuation: segment-14 · 41 — 46 · bbl/(day)
- Model continuation: segment-25 · 60 — 66 · bbl/(day)
- Model continuation: segment-27 · 68 — 72 · bbl/(day)
- Model continuation: segment-28 · 73 — 78 · bbl/(day)
- Model continuation: segment-41 · 103 — 107 · bbl/(day)

6.8 SAVED RESULTS AND DOWNSTREAM REUSE

Chapter 6 retains the fitted curves, parameters and numerical diagnostics for every eligible segment. Engineering comparison and interpretation of those models belong to Chapter 7.

Later chapters consume the exact saved parameters, candidate statistics, selected model and per-row predictions through normal report dependencies. The reusable result includes segment identity, Production Month time origin, D in 1/month, upstream rate unit, method version and run identity. Rounded report values are not calculation inputs.

Calculated outputs from the completed report run of 21 September 2026 are retained at full precision. Changing the selected well, chart grouping, chapter text or heading font does not refit models. A missing model is exposed through its calculation status; it is not replaced with another well's example. Any projected continuation must reuse the same saved parameters and carry its own explicit temporal domain.

Continuation outputs retain paired Production Month coordinates and selected-model rates at each fitted segment endpoint. Their explicit domain extends 240 production months after that endpoint. Chapter 7 consumes the same full-precision parameters, respecting each curve's horizon.

6.9 REFERENCES

References and Methodology Sources

[M] FieldState. Chapter 6 Arps Curve Fitting — Technical Specification, Fitting Only. Version 2.0, 14 September 2026. User-supplied reference: Chapter_6_Arps_Fitting_Only_Technical_Specification.docx. Retained background for the fitting-only scope and candidate models. [M2] Chapter_6_Arps_Final_Answers_for_Developer_RU.docx. User-supplied final developer answers. This clarification replaces the earlier rate, statistical-denominator and ranking choices: total-liquid producing-day rate, adjusted R^2 with $n - k$ including q_i, centered population residual variance with denominator n, ordered comparison without summed ranks, and explicit partial-comparison/failure handling. The report owner subsequently replaced the original calendar fitting clock with the existing Production Month coordinate and D_i in 1/month; prepared observations and segments remain unchanged. Solver tolerances and work limits are versioned implementation settings. Project evidence: current saved Chapters 4–5, independently read on 19 September 2026; Clean Well Data, prepared liquid rate, complete segment membership and the DCA eligibility flag. Literature supports the model and numerical method; it does not independently verify a report calculation.

1. ResInsight. Decline Curve Analysis. Origins and Rate-Time Decline Curves. Accessed 19 September 2026. Source
2. SciPy. scipy.optimize.least_squares. API documentation: methods and bounds. Accessed 19 September 2026. Source

7. MULTI-SEGMENT COMPARISON AND INTERPRETATION

7.1 PURPOSE, INPUTS AND CALCULATION STATUS

Chapter 7 compares the independent production regimes already fitted in Chapter 6. It consumes the selected model, qi, D, b, reference Production Month and final observed Production Month for each eligible segment. It does not clean observations, change segment membership, select another model, refit parameters or force continuity between regimes.

All comparisons belong to the currently selected well. Two families are retained: each segment versus its immediate predecessor (LOCAL), and each later segment versus the first eligible fitted segment (BASELINE). The first-to-last result is calculated directly; local effects are never summed to manufacture a net effect.

The calculation uses the existing prepared Production Month coordinate. Each curve retains its own origin and ends 240 production months after its historical endpoint. A comparison is limited to the overlap of the two available forward horizons and never evaluates the target before its start.

Calculation status: the full report completed successfully on 21 September 2026 at 21:56 Asia/Almaty. This chapter uses the retained results of that calculation. Presentation settings can be updated without refitting the models. A missing final effect is distinct from a failed calculation: check the comparison status and whether a finite crossing exists within the permitted horizon.

Methodology source: FieldState Multi-Segment Production Effect Analysis Technical Specification supplied by the user. Accepted project choices: preserve the prepared segments, use Production Month, extend each segment by 240 production months, and assume continuous operation in future calendar months.

7.2 INDEPENDENT CURVES ON THE PRODUCTION MONTH AXIS

Let x be the existing Production Month coordinate, and $x_{0,s}$ the fitted origin of segment s. Evaluate each curve with its own retained qi, D and b at elapsed time $x - x_{0,s}$. The liquid rate is expressed per producing day; D is per production month.

$$q_s(x) = \begin{cases} q_{i,s}\exp[-D_s(x - x_{0,s})], & b_s = 0 \\ q_{i,s}/[1 + D_s(x - x_{0,s})], & b_s = 1 \\ q_{i,s}[1 + b_s D_s(x - x_{0,s})]^{-1/b_s}, & 0 < b_s < 1 \end{cases}$$

Production Month is the consecutive index of retained Clean Well Data observations. It is not a fixed 30-day duration. Retain the original period and active_days alongside the index. Excluded historical records are not reinserted, and neither the index nor segment boundaries are rebuilt here.

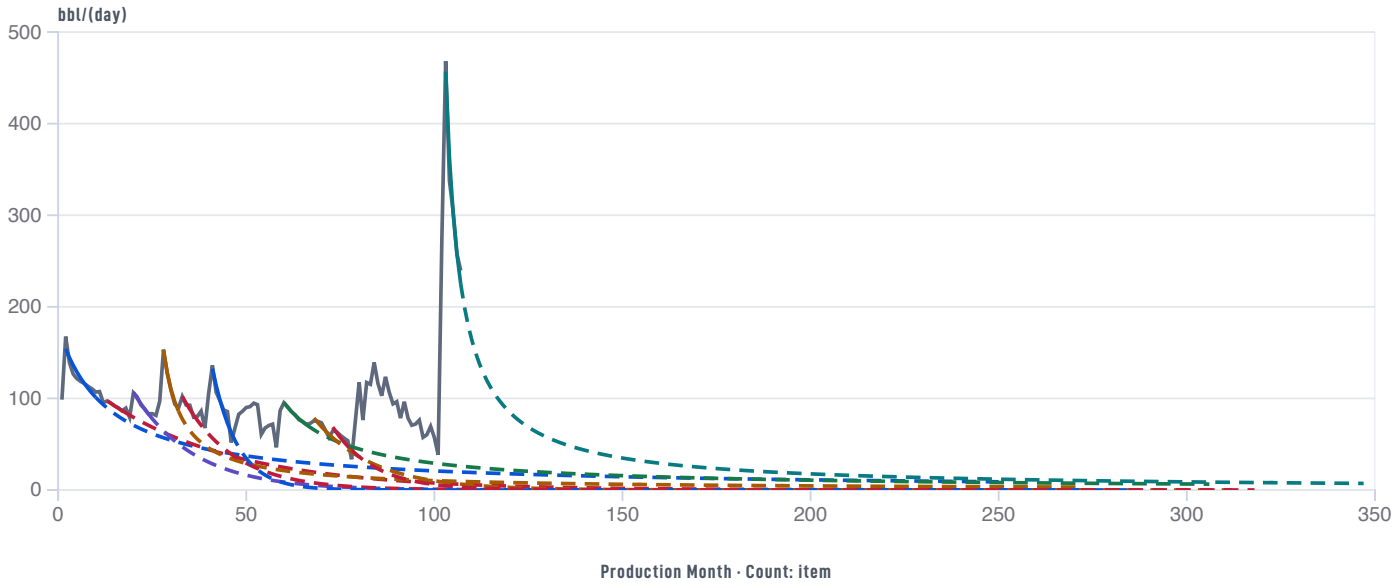
$$x_{F,s} = x_{\text{last},s} + 240, \qquad x_F = \min(x_{F,A}, x_{F,B})$$

For pair A → B the comparison starts at $x_{0,B}$ and ends at the common horizon xF. If no forward interval remains, retain the pair with NO_COMMON_FORECAST_WINDOW and leave effect calculations blank. Never extrapolate B backward or extend A beyond its declared horizon.

Chapter 6 provides the overview of all complete model continuations. The comparison plots in this chapter show the selected pair to its first sign-changing crossing, or to the common horizon when no crossing exists. The shaded separation is a visual representation of the selected interval, not a second volume calculator.

The overview below shows the observed liquid rate in gray, each selected fitted regime in its segment color, and its independent continuation as a dashed line. Select a segment to inspect it; use zoom for the transition region. The curves retain their original fitted origins.

Independent fitted regimes and 240-month continuations



7.3 LOCAL AND BASELINE RATE EFFECTS

LOCAL compares each eligible fitted segment with the immediately preceding eligible fitted segment. BASELINE compares each later eligible fitted segment directly with the first eligible fitted segment of the selected well. Original segment identifiers are retained.

$$\Delta q_0 = q_B(x_{0,B}) - q_A(x_{0,B}), \qquad \Delta q_{\%} = 100\,\frac{\Delta q_0}{q_A(x_{0,B})}$$

A positive difference is a higher modelled liquid rate in the target regime; a negative difference is a lower rate. The percentage is undefined when the reference rate is zero. Absolute differences retain the upstream liquid-rate unit.

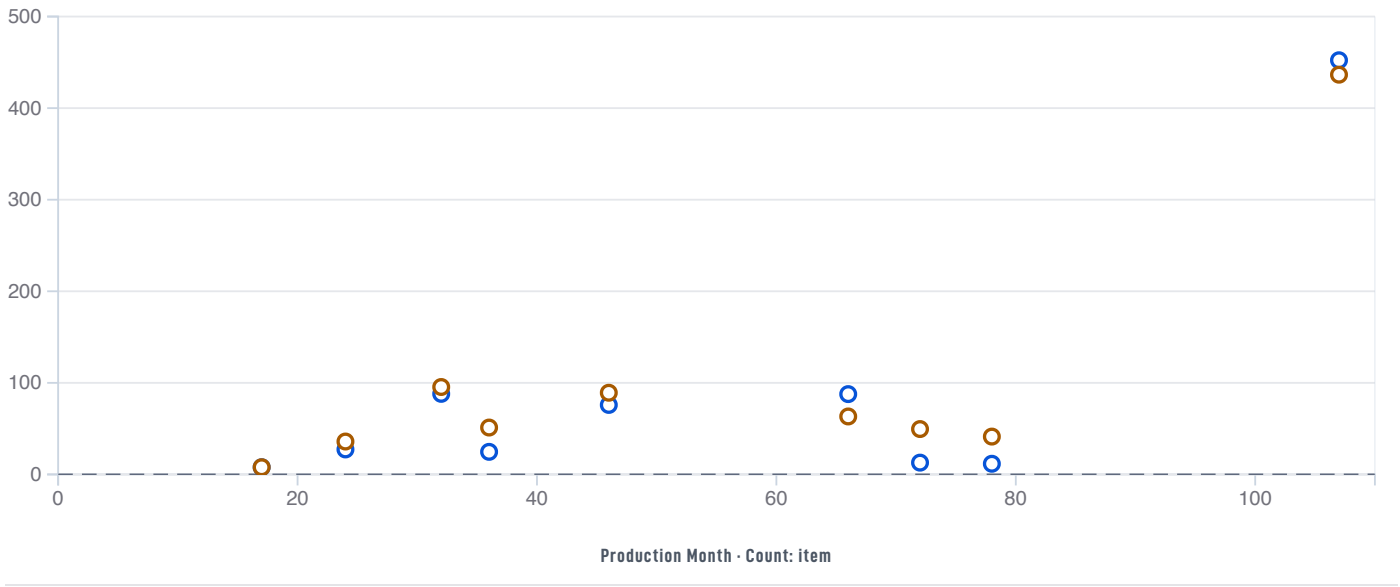
Both curves are evaluated at the same coordinate. The new segment starts at its fitted initial rate, not at a manually adjusted observed endpoint. Do not shift either curve to force continuity.

The first-to-last baseline effect is computed directly. Adding adjacent effects would mix different reference curves and overlapping intervals and does not produce the net effect.

For each comparison, retain reference and target identities, origins, common horizon, point effect, percentage and classification. A zero initial difference is labelled ZERO_INITIAL_DIFFERENCE; no unapproved engineering significance tolerance is introduced.

In the summary chart, X is the Production Month of each retained segment endpoint; each pair of points describes that target segment. Blue is LOCAL and amber is BASELINE. Points above zero indicate a higher initial modelled liquid rate; points below zero indicate a lower rate. Values are in source liquid units per producing day. The first eligible segment has no comparison and is not a zero effect.

Initial liquid-rate change — LOCAL versus BASELINE



7.4 INTERSECTIONS AND EFFECT DURATION

Define the signed difference after the target starts. Search only within the common forward interval.

$$\Delta q(x) = q_B(x) - q_A(x), \qquad x \in [x_{0,B}, x_F]$$

$$\Delta q(x_{\text{cross}}) = 0, \qquad T_{\text{effect}} = x_{\text{cross}} - x_{0,B}$$

The first meaningful crossing requires a change in sign. A tangency or coincident curves is not treated as the end of an effect. The calculation uses the log-rate ratio to avoid losing crossings when very small rates underflow. Its possible stationary point separates monotone search intervals; a bracketed bisection resolves the first crossing.

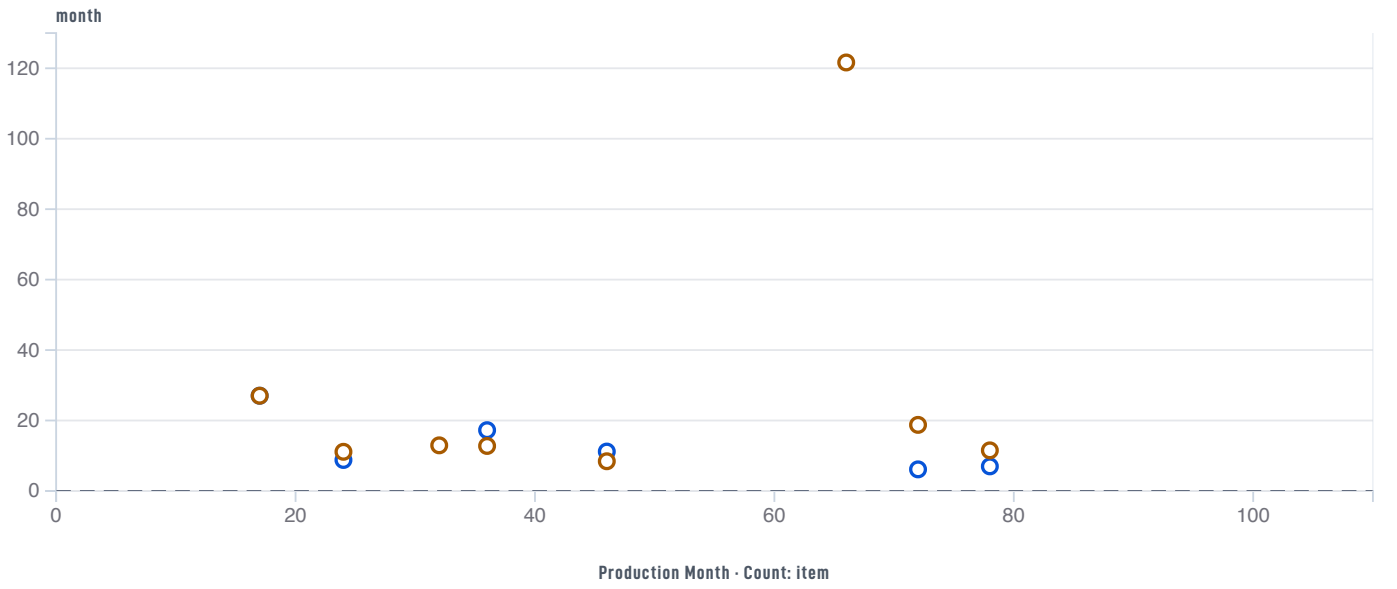
Numerical rounding protection is separate from engineering significance. It does not relax segment eligibility or fit quality. Calculations retain full precision; rounding is only for display.

Positive initial difference with a crossing is TEMPORARY_POSITIVE. Positive initial difference without a crossing is ONGOING_POSITIVE_WITHIN_HORIZON. Negative initial difference is NEGATIVE_WITHIN_HORIZON, or DELAYED_POSITIVE_RESPONSE when the first crossing leads upward. An unavailable common interval has its own status.

No crossing within the horizon leaves intersection and final duration blank. It does not establish infinite persistence. After a first crossing, later sign changes are outside the first-effect interval; the full-window signed comparison remains separately available.

The summary chart shows only a finite, retained time to the first sign-changing crossing, measured in Production Months from the target origin. A missing point is not zero duration: consult the LOCAL or BASELINE result table for the retained status and available horizon. No crossing within the horizon does not mean the effect lasts forever. X identifies each target segment by its endpoint Production Month.

Time to first crossing — production months



SERIES — LOCAL — months to crossing · month — BASELINE — months to crossing · month ---- 0 = 0

7.5 CALENDAR-WEIGHTED LIQUID VOLUMES

The producing-day denominator is already defined upstream. Historical uptime is days worked divided by calendar days, multiplied by 100%. Chapter 3.6 obtains calendar days from the last day of the relevant year and month; Chapter 5.7 uses actual active_days on the cleaned observations.

$$U_m = 100\,\frac{d_{\text{active},m}}{d_{\text{calendar},m}}$$

Accepted forecast assumption: continuous operation, uptime 100%. Future working days equal the actual calendar days of the corresponding future month: 28 or 29 for February, 30 or 31 otherwise. No constant 30-day or average 30.4375-day multiplier is used.

Historical Production Month retains its original period and actual active_days. Future indices after the last retained observation map to consecutive calendar months after its period. The same exposure is applied to both curves in a pair so this comparison isolates modelled rate differences.

$$\Delta Q(a,b) = \sum_m d_m \int_{\max(a,m)}^{\min(b,m+1)} \left[q_B(x) - q_A(x)\right] dx$$

Only non-empty intersections with bins [m, m+1) contribute. The day multiplier dm is the historical active_days or the forecast calendar-day count for that bin. A crossing inside a month uses the fractional interval rather than rounding the crossing to a whole month. Analytical Arps integration is applied within each bin.

Within each bin, evaluate the analytical primitive of the retained Arps curve at its own elapsed-time limits. Let t = x − x_0 and F be the primitive below; the bin contribution is dm × [F(t1) − F(t0)]. The implementation uses stable exponential and logarithmic differences near the limiting cases.

$$F(t) = \begin{cases} q_i t, & D = 0 \\ -\dfrac{q_i}{D} e^{-Dt}, & D > 0,\ b = 0 \\ \dfrac{q_i}{D} \ln(1 + Dt), & D > 0,\ b = 1 \\ \dfrac{q_i}{D(b-1)} (1 + bDt)^{(b-1)/b}, & D > 0,\ 0 < b < 1 \end{cases}$$

$$\Delta Q_{\text{final}} = \Delta Q(x_{0,B}, x_{\text{cross}}), \qquad \Delta Q_{\text{window}} = \Delta Q(x_{0,B}, x_F)$$

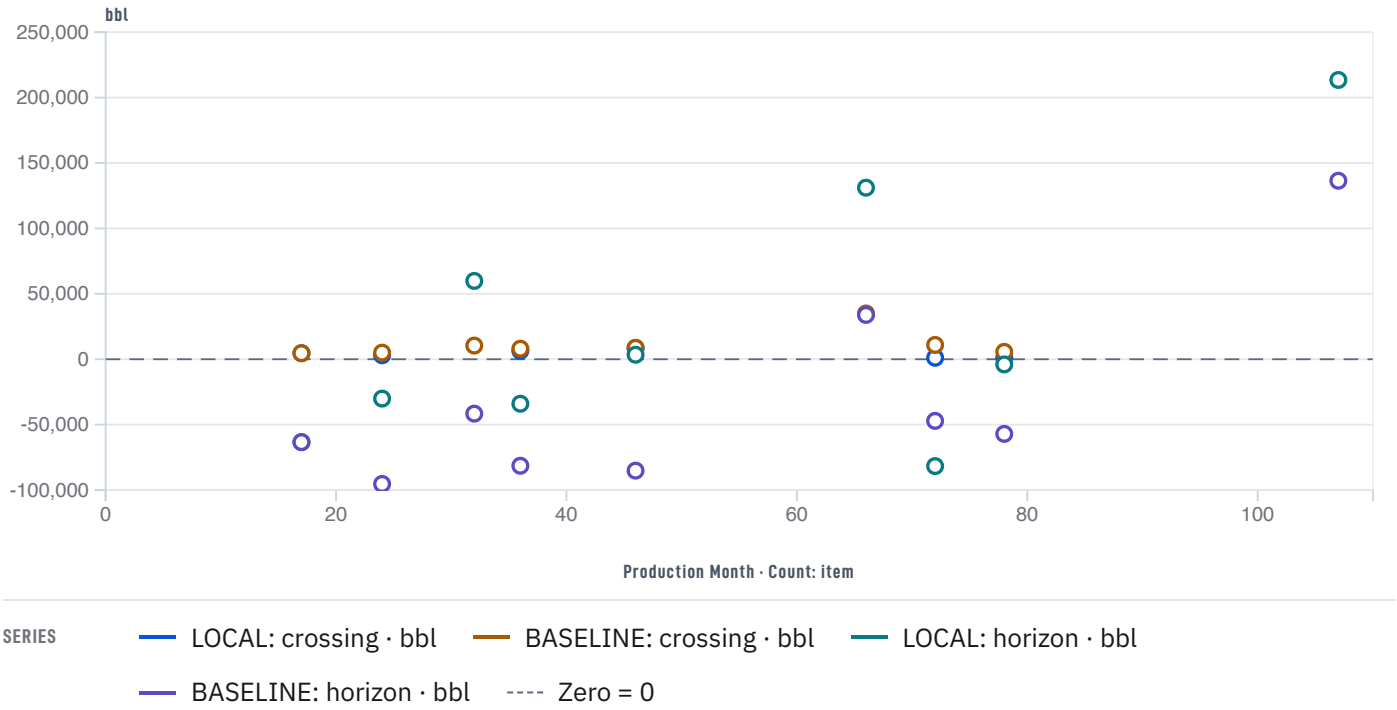
Final cumulative effect is retained only when a valid crossing is found. Otherwise it remains not finalized. The separately labelled window effect ends at the available horizon and must not be described as the final effect. Signed values distinguish gain from loss.

$$\Delta Q_{\%} = 100\,\frac{Q_B - Q_A}{Q_A}$$

The cumulative percentage uses the same final interval for both curves and is blank when the reference volume is zero or the final interval is undefined. These are liquid volumes in the upstream source unit. They are not automatically oil volumes, reserves or EUR.

The volume comparison chart uses source liquid volume units and the target segment endpoint Production Month on X. LOCAL and BASELINE are separate comparisons. Points labelled 'crossing' use the final interval; points labelled 'horizon' use the available comparison window. Missing final points mean the interval is not finalized or the pair is not applicable. These overlapping intervals must not be added together.

Signed liquid-volume differences — final interval and full horizon



SERIES

LOCAL: crossing · bbl
BASELINE: crossing · bbl
LOCAL: horizon · bbl
BASELINE: horizon · bbl
Zero = 0

7.6 RESULTS, INTERPRETATION AND REUSE

The calculation register below retains one result for each target segment and comparison family. It exposes the reference segment, point-rate change, common horizon, first crossing, duration, status, reference and target volumes, final signed effect, full-window signed effect, cumulative percentage and a short comparison summary.

Select a target segment in a comparison chart to isolate its reference/target pair. The vertical connector shows their rate separation at the transition; a point marks a valid crossing. Shading is shown only for one pair at a time to avoid visual double counting. The table is the authority for numeric volumes; chart geometry is not integrated in the browser.

Compare the LOCAL and BASELINE rows for the latest eligible segment to distinguish its change from the preceding regime from its change relative to the original fitted regime. When no shared forecast interval exists, the result is explicitly unavailable within the permitted horizon.

The curves describe differences between fitted production regimes. They do not prove an intervention caused the difference. Interpret them with uptime, water cut, WOR/GOR, pressure and documented operating events where those observations are available.

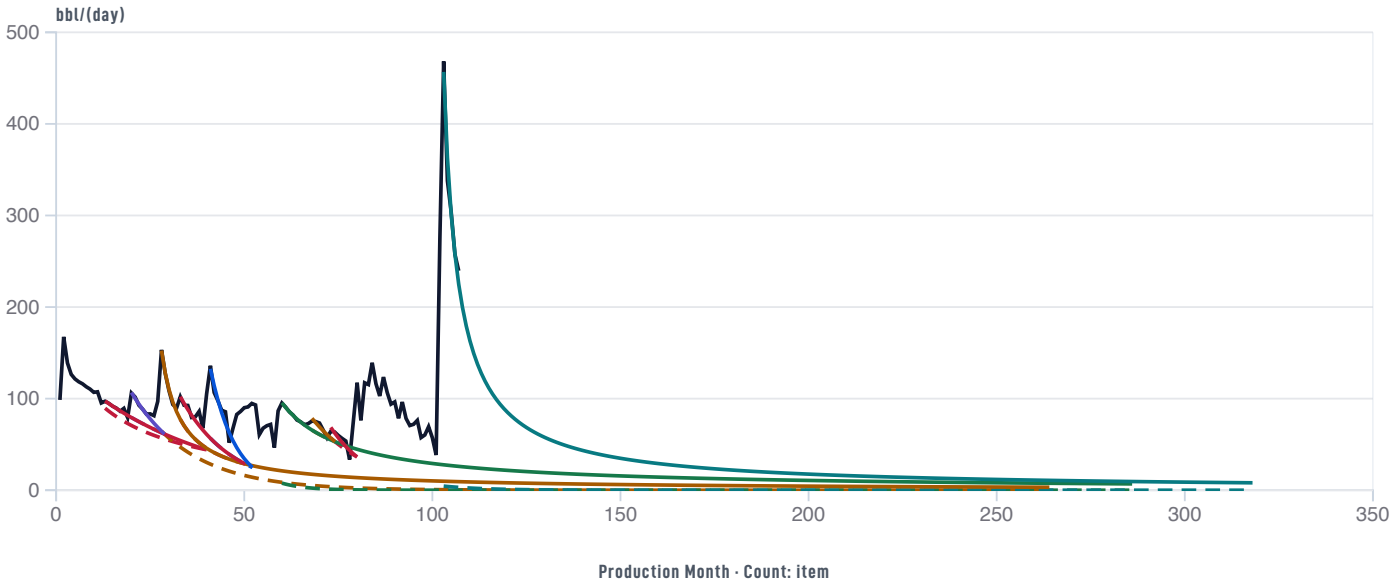
Downstream work must consume the retained exact Formula outputs and their run provenance. Do not reconstruct parameters from rounded table values or plotted coordinates. A saved chapter definition is distinct from the overnight calculation and its subsequently verified results.

7.7 LOCAL SEGMENT COMPARISON

Compare each retained segment with the nearest earlier retained segment of the selected well. Choose a target segment in the chart to inspect both independent curves, their initial rate difference and the first sign-changing intersection. Shading appears for the focused pair only; the table supplies the calendar-weighted liquid volume difference. Curves stop at the first crossing or the end of their common horizon. The first retained segment has no predecessor and therefore no local comparison.

Read these results after a successful full recalculation for the current definitions. Rate differences use the source liquid units per producing day; cumulative differences use source liquid volume units. Blank final values mean that a finite first crossing was not established within the common horizon, or that the pair is not applicable. A curve difference alone does not establish the cause of a production change.

Local Arps comparison — production history and retained curves



SERIES

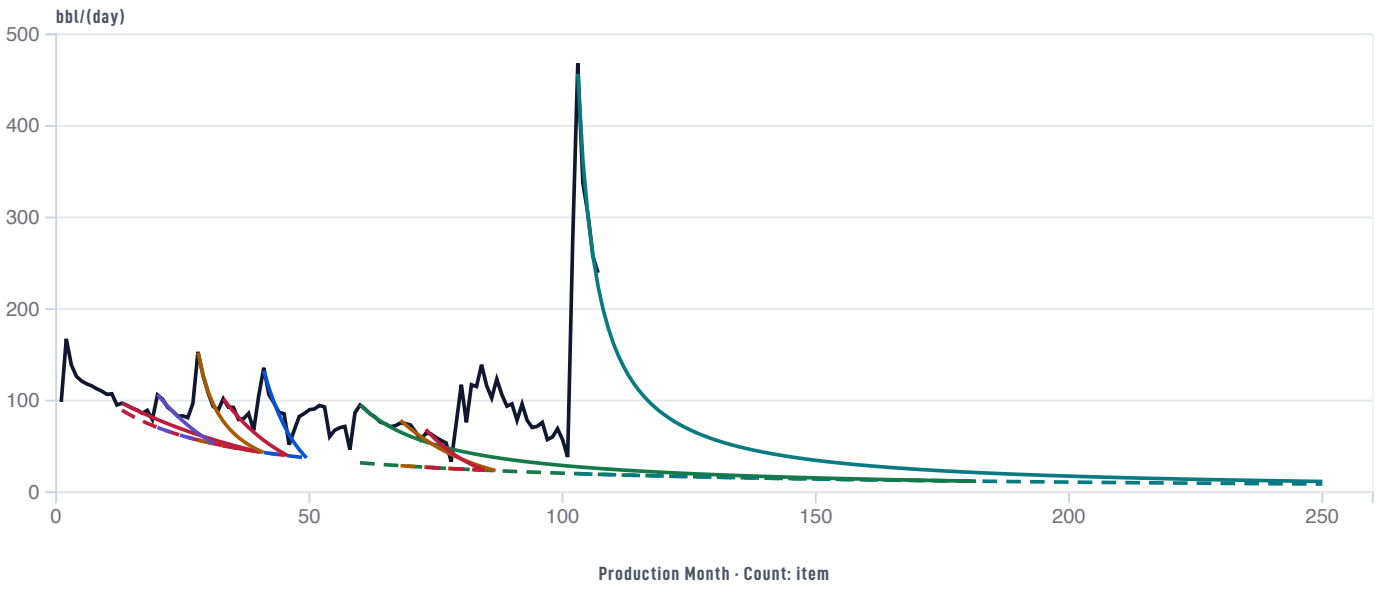
- Production · bbl/(day)
- Reference curve: segment-4 · bbl/(day)
- Reference curve: segment-6 · bbl/(day)
- Reference curve: segment-9 · bbl/(day)
- Reference curve: segment-10 · bbl/(day)
- Reference curve: segment-14 · bbl/(day)
- Reference curve: segment-25 · bbl/(day)
- Reference curve: segment-27 · bbl/(day)
- Reference curve: segment-28 · bbl/(day)
- Reference curve: segment-41 · bbl/(day)
- Target curve: segment-4 · bbl/(day)
- Target curve: segment-6 · bbl/(day)
- Target curve: segment-9 · bbl/(day)
- Target curve: segment-10 · bbl/(day)
- Target curve: segment-14 · bbl/(day)
- Target curve: segment-25 · bbl/(day)
- Target curve: segment-27 · bbl/(day)
- Target curve: segment-28 · bbl/(day)
- Target curve: segment-41 · bbl/(day)

7.8 BASELINE SEGMENT COMPARISON

Compare each later retained segment directly with the first retained segment of this well. These are independent comparisons, not a sum of adjacent effects. The reference and target keep their own fitted origins and parameters. Select a target to inspect the pair. If the two 240-month continuation domains do not overlap forward from the target origin, the result is NO_COMMON_FORECAST_WINDOW and no extrapolated effect is fabricated.

Read these results after a successful full recalculation for the current definitions. Rate differences use the source liquid units per producing day; cumulative differences use source liquid volume units. Blank final values mean that a finite first crossing was not established within the common horizon, or that the pair is not applicable. A curve difference alone does not establish the cause of a production change.

Baseline Arps comparison — production history and retained curves



SERIES

- Production · bbl/(day)
- Reference curve: segment-4 · bbl/(day)
- Reference curve: segment-6 · bbl/(day)
- Reference curve: segment-9 · bbl/(day)
- Reference curve: segment-10 · bbl/(day)
- Reference curve: segment-14 · bbl/(day)
- Reference curve: segment-25 · bbl/(day)
- Reference curve: segment-27 · bbl/(day)
- Reference curve: segment-28 · bbl/(day)
- Reference curve: segment-41 · bbl/(day)
- Target curve: segment-4 · bbl/(day)
- Target curve: segment-6 · bbl/(day)
- Target curve: segment-9 · bbl/(day)
- Target curve: segment-10 · bbl/(day)
- Target curve: segment-14 · bbl/(day)
- Target curve: segment-25 · bbl/(day)
- Target curve: segment-27 · bbl/(day)
- Target curve: segment-28 · bbl/(day)
- Target curve: segment-41 · bbl/(day)

8. PRODUCTION-DERIVED RESERVOIR DYNAMICS INTERPRETATION

8.1 PURPOSE AND INTERPRETATION BOUNDARIES

This chapter examines how oil, water and gas production change together and what those changes can support about reservoir and well behaviour. It combines observed phase performance with a specified production-derived proxy model. Its purpose is to identify reproducible observations, test the consistency of possible explanations and define the next investigation—not to infer a unique subsurface mechanism from a production curve alone. Observed rates and proxy-model outputs are interpreted under the limitations stated below.

Four evidence levels are kept separate.**Observed quantities** are reported volumes, producing days and their directly calculated rates or ratios.**Model-derived quantities** are outputs of the stated Proxy OFP equations and parameter set.**Hypotheses** are possible explanations for the observations. A**supported mechanism** requires relevant independent evidence and expert review. A model output does not move into the last category simply because its curve resembles an observed trend.

The discussion uses the existing Clean Well Data selection and does not repeat data qualification, segmentation or decline-curve fitting. Current Chapter 7 compares independent segment results; no continuous composite forecast is assumed here. Interpretations are conditional on the production-history basis, reporting units and operating context identified below.

8.2 DATA BASIS, TIME AND COMPARABLE OBSERVATIONS

For retained month i, let O_i, W_i and G_i be monthly oil, water and gas volumes, and let a_i be producing days. The producer-day average rates are

$$q_{o,i} = \frac{O_i}{a_i}, \qquad q_{w,i} = \frac{W_i}{a_i}, \qquad q_{liq,i} = \frac{O_i + W_i}{a_i}, \qquad q_{g,i} = \frac{G_i}{a_i}.$$

The liquid rates are in bbl/producing day and the gas rate is in Mcf/producing day. These are not calendar-day rates. Rate interpretation requires a known positive producing-day denominator; a zero returned for a non-positive denominator does not establish a measured zero rate. Monthly volumes, rather than sums of daily rates, underlie cumulative production.

$N_{p,i}$, $W_{p,i}$ and $G_{p,i}$ denote cumulative oil, water and gas in the approved accumulation history through month i. The available definitions accumulate retained Clean Well Data rows. This chapter uses**retained-history cumulative production from Clean Well Data**. Lifetime completeness has not been established. A display-window change must not silently reset these sums. An incomplete early history is a limitation of the input basis, not evidence of low depletion.

Production Month is the common coordinate for the time-series figures and numerical differences in this chapter. It is the ordinal position of a retained Clean Well Data observation, not elapsed calendar time.

$$m_i = i, \qquad \Delta m_i = m_i - m_{i-1} = 1.$$

Adjacent retained observations form a one-production-month interval even when excluded calendar months lie between them. The diagnostic therefore describes changes along the cleaned production sequence. It does not estimate a calendar-time rate of change. Producing days remain the denominator of phase rates; they do not replace Production Month in differences. Calendar-event alignment is outside the present analysis.

Use the same retained rows and Production Month origin across rates, ratios, cumulative production and interval diagnostics. Missing phase measurements, non-positive producing days and non-positive rates where a logarithm is required make the relevant calculation unavailable. Any independently established operating boundary must be disclosed when interpreting an interval. Calendar gaps alone do not remove a retained pair; no interpolation or smoothing is applied.

Analysis basis

The figures and calculation table use the Chapter 4 metrics on Clean Well Data for the selected well: producing-day phase rates, water cut, water–oil and gas–oil ratios, retained cumulative production and Production Month diagnostics.

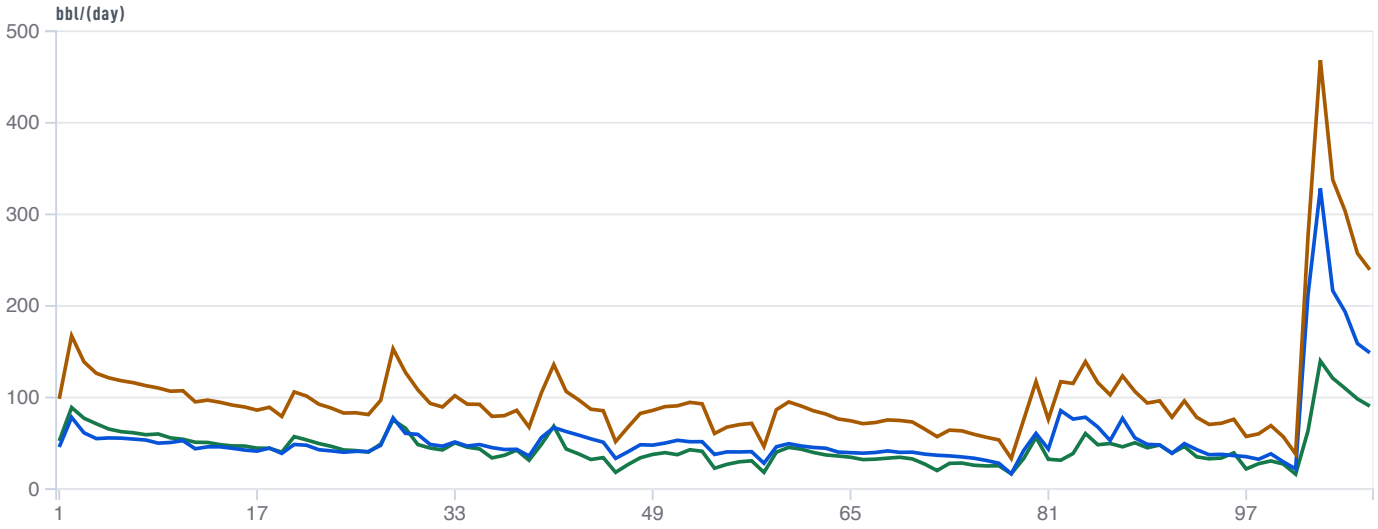
The calculation tables in Chapter 4 retain the underlying observations and calculated values. Figures 8.2-1 and 8.2-2 compare the available oil, water, liquid and gas rates; monthly phase volumes are the inputs to those rates.

Read Figures 8.2-1 and 8.2-2 together, while retaining their different units. A ratio change must be traced back to its numerator and denominator. The same ratio can arise from different volume or rate combinations. Comparisons spanning a restart, lift change or reporting change remain descriptive until the operating context

is reviewed.

Reading the figures. Figures 8.2-1 and 8.2-2 show producing-day liquid-phase rates in bbl/day and gas rate in Mcf/day. Time-series charts use the existing retained Production Month index, not uninterrupted calendar time. Their connecting lines guide the eye across adjacent retained observations and must not be interpreted as estimates for excluded calendar months. Charts against cumulative production or proxy coordinates connect retained observations in the displayed coordinate order. The lines do not add intermediate observations, smooth the data or establish a fitted relationship.

Figure 8.2-1 — Oil, water and liquid producer-day rates · Clean Well Data



SERIES

- Oil producer-day rate · bbl/(day)
- Water producer-day rate · bbl/(day)
- Liquid producer-day rate · bbl/(day)

Figure 8.2-2 — Gas producer-day rate · Clean Well Data



SERIES — Gas producer-day rate · Mcf/(day)

8.3 WATER PRODUCTION, WATER CUT AND OIL–LIQUID SEPARATION

The directly calculated water indicators are

$$WC_i = \frac{W_i}{O_i + W_i}, \qquad WOR_i = \frac{W_i}{O_i}.$$

WC is stored as a fraction; a displayed percentage is $100WC$. WOR is a water-to-oil volume ratio. The respective denominators must be positive. When they are valid,

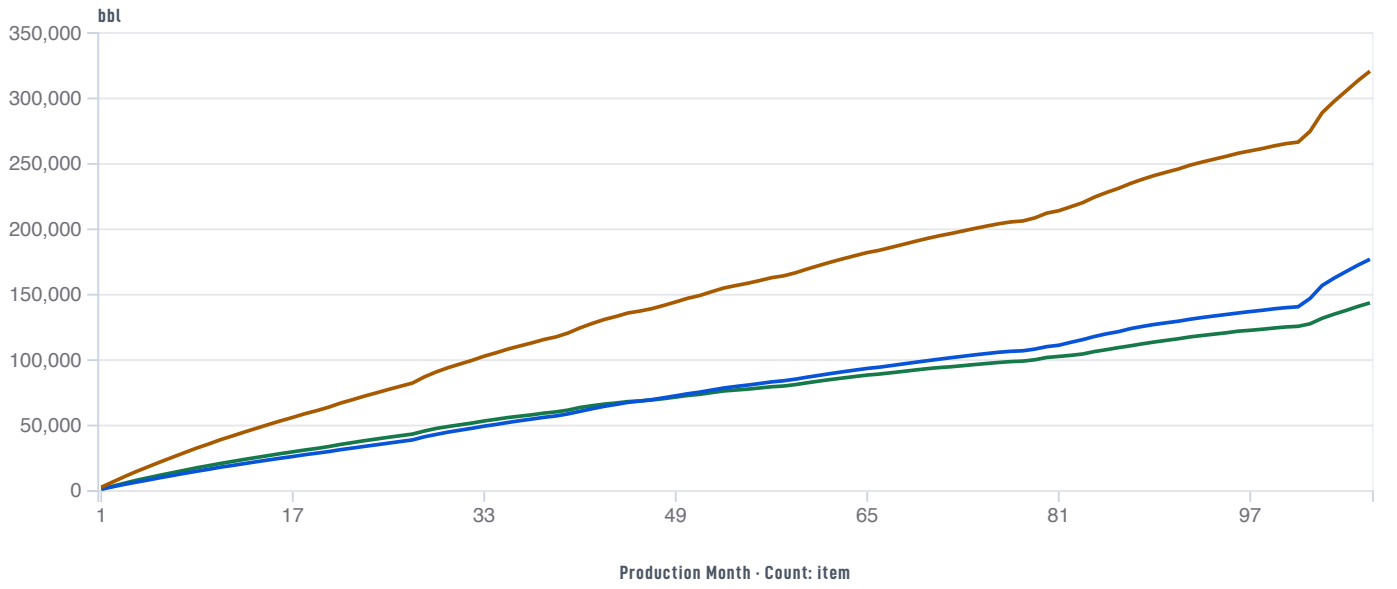
$$WOR = \frac{WC}{1 - WC}, \qquad q_o = q_{liq}(1 - WC).$$

These identities make WC and WOR complementary presentations of the same monthly liquid split, not independent confirmations of a mechanism. Rising WOR may reflect increasing water, declining oil, or both. A nearly unchanged liquid rate together with lower oil rate describes a change in phase composition; it does not, by itself, establish a loss of total inflow capacity. Figures 8.2-1, 8.3-1 and 8.3-2 show the constituent rates, water cut and WOR on the same retained Production Month axis.

The selected well has 107 retained Production Months. At Production Month 107, oil and water producer-day rates are 90.67 and 148.93 bbl/day, giving total liquid of 239.6 bbl/day, WC of 62.16% and WOR of 1.64265. The first retained observation has WC of 46.68% and WOR of 0.87541. These endpoint differences do not imply a continuous trend between the two observations.

Retained cumulative production through Production Month 107 is 143745 bbl oil, 177076 bbl water and 320821 bbl liquid. These totals cover Clean Well Data and do not establish complete lifetime production.

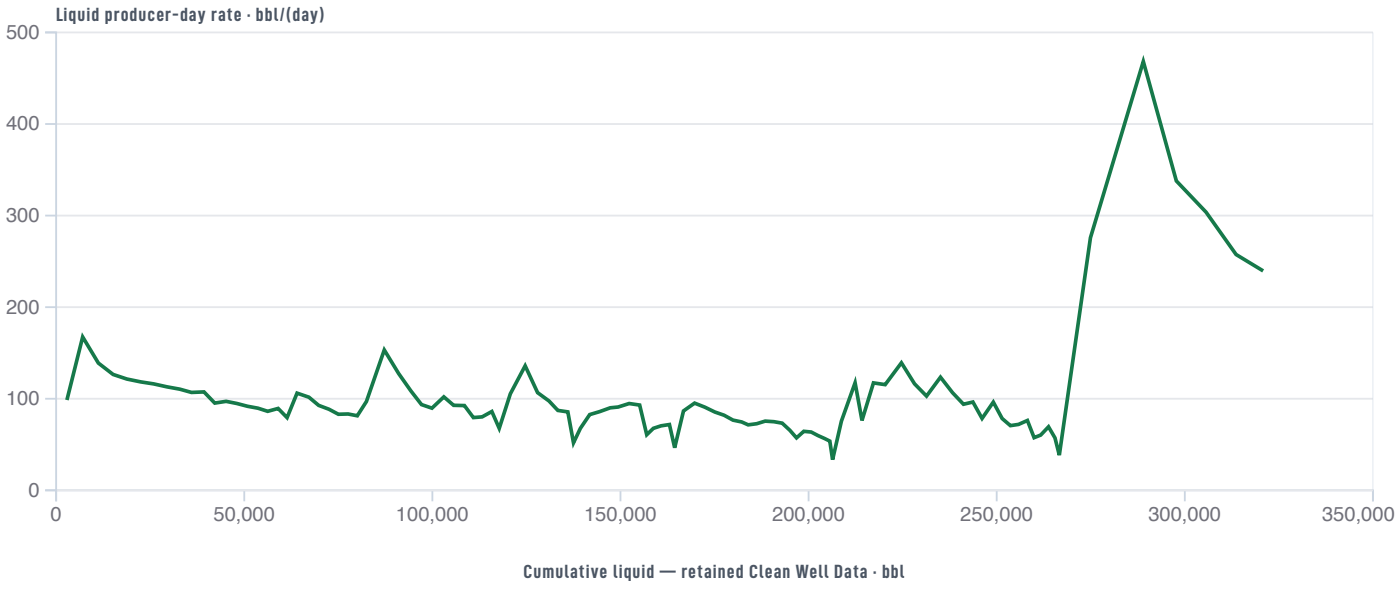
Figure 8.3-4 — Retained cumulative oil, water and liquid



SERIES

- Cumulative oil — Clean Well Data · bbl
- Cumulative water — Clean Well Data · bbl
- Cumulative liquid — retained Clean Well Data · bbl

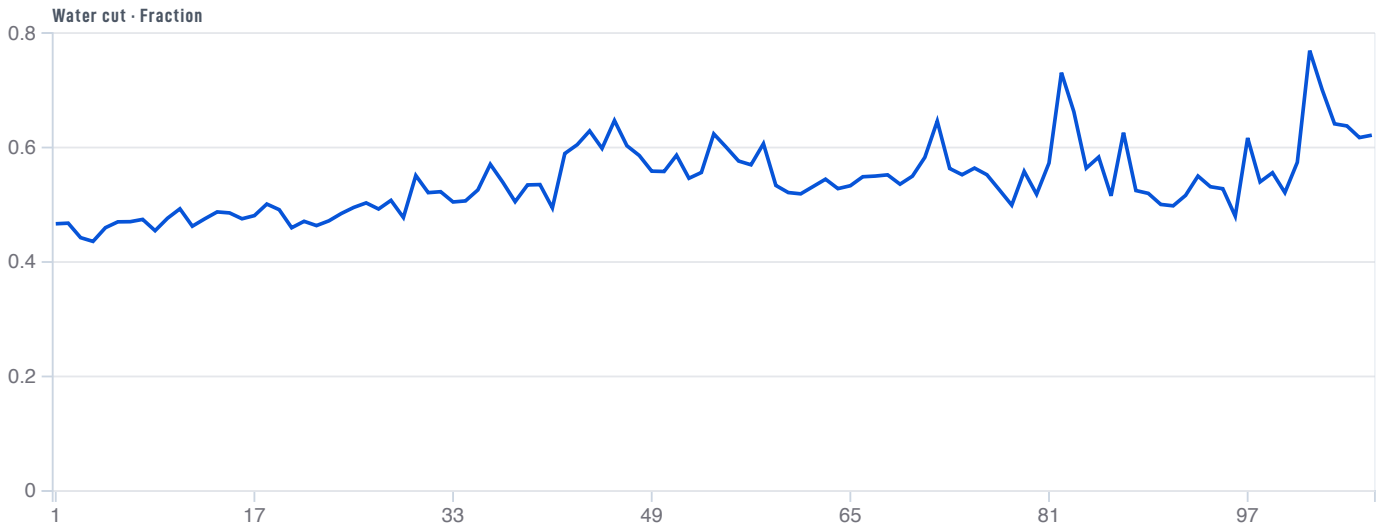
Figure 8.3-5 — Liquid rate versus retained cumulative liquid



SERIES

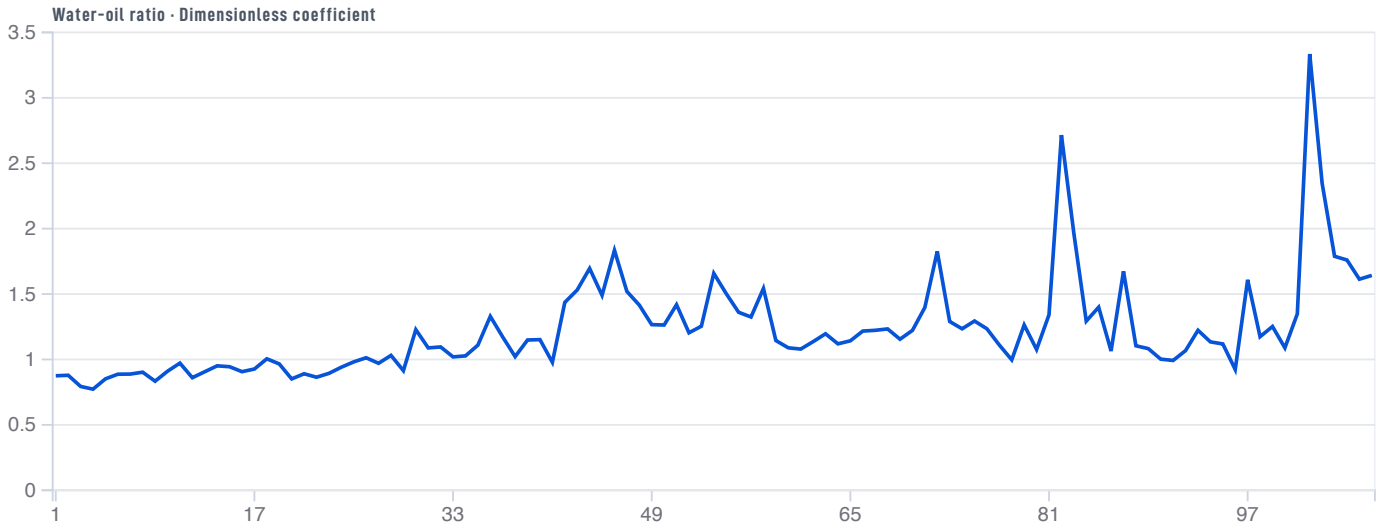
- Liquid producer-day rate · bbl/(day)

Figure 8.3-1 — Water cut on Clean Well Data



SERIES — Water cut · Fraction

Figure 8.3-2 — Water–oil ratio · Clean Well Data



SERIES — Water-oil ratio · Dimensionless coefficient

Production-progress views. Figure 8.3-3 plots WOR against cumulative oil from the same retained Clean Well Data history. Figure 8.4-2 provides the corresponding GOR view. The lines connect retained production observations in cumulative-oil order; they do not add intermediate observations. The cumulative oil, water and liquid curves use the same retained history.

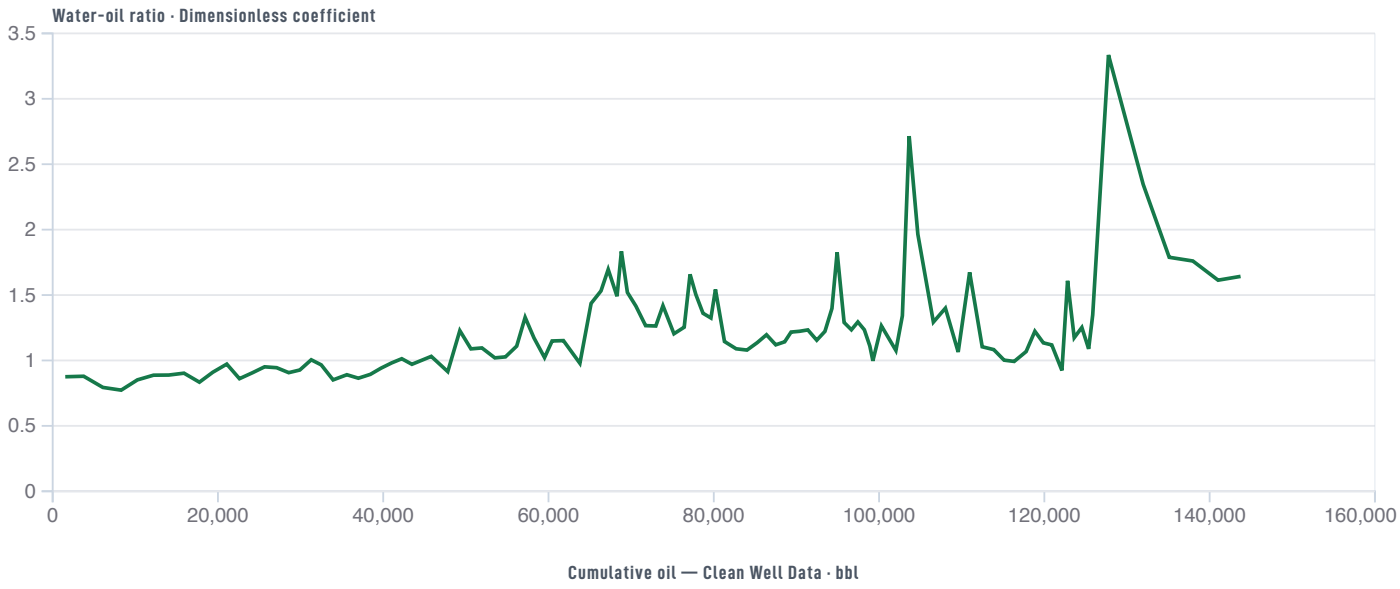
WOR versus retained cumulative oil gives a production-progress view alongside Production Month. Liquid rate versus cumulative liquid provides another view of oil–liquid separation. Neither horizontal axis is a measured recovery factor or a reservoir-volume balance; the origin and missing history remain material.

WOR and derivative plots have a history as water-control screening tools. However, simulation work reported by Seright and colleagues showed that channeling and coning can produce misleadingly similar diagnostic behaviour. Yortsos and colleagues also related WOR behaviour to both flow geometry and relative-permeability/mobility assumptions. Consequently, this chapter does not assign a mechanism from a universal slope rule. [S1], [S2], [S3]

Water-front movement, coning, preferential flow and changing phase competition remain possible explanations. Capillary-bound water mobilisation is also only a hypothesis here: it requires pressure, capillary and fluid-property evidence appropriate to the well. These possibilities must be checked against operations, completion history and independent reservoir information before a water-control action is selected.

WOR is undefined when oil volume is zero. WC and WOR describe the liquid split; their interpretation must retain the constituent oil and water rates. These ratios alone do not distinguish coning, channeling or breakthrough.

Figure 8.3-3 — WOR versus retained cumulative oil



SERIES — Water-oil ratio · Dimensionless coefficient

8.4 GAS BEHAVIOUR AND COMPETING EXPLANATIONS

The gas indicators use the reported gas-production volume for the same retained observation:

$$GOR_i = \frac{G_i}{O_i}, \qquad GLR_i = \frac{G_i}{O_i + W_i}.$$

Both ratios are in Mcf/bbl on the supplied reporting basis. GLR compares produced gas with total produced liquid on the same retained observation. With valid denominators,

$$GLR = GOR(1 - WC).$$

This identity helps distinguish a changing gas-to-oil ratio from a changing gas-to-total-liquid ratio. For example, a higher GOR accompanied by lower oil does not necessarily mean that the gas rate has increased. A completed comparison must retain gas rate, oil rate, liquid rate and the two gas ratios on matching monthly rows.

Possible explanations for changing gas production include pressure-related gas release, gas-cap influence, preferential gas flow and operational effects. Those explanations are not interchangeable, and the supplied production history does not identify one uniquely. A pressure/bubble-point interpretation requires relevant pressure and PVT evidence; a connectivity interpretation requires independent dynamic or geological support. In a black-oil formulation, components and phases are also distinct: produced gas is not automatically a direct measurement of free gas occupying reservoir pore space. [S4]

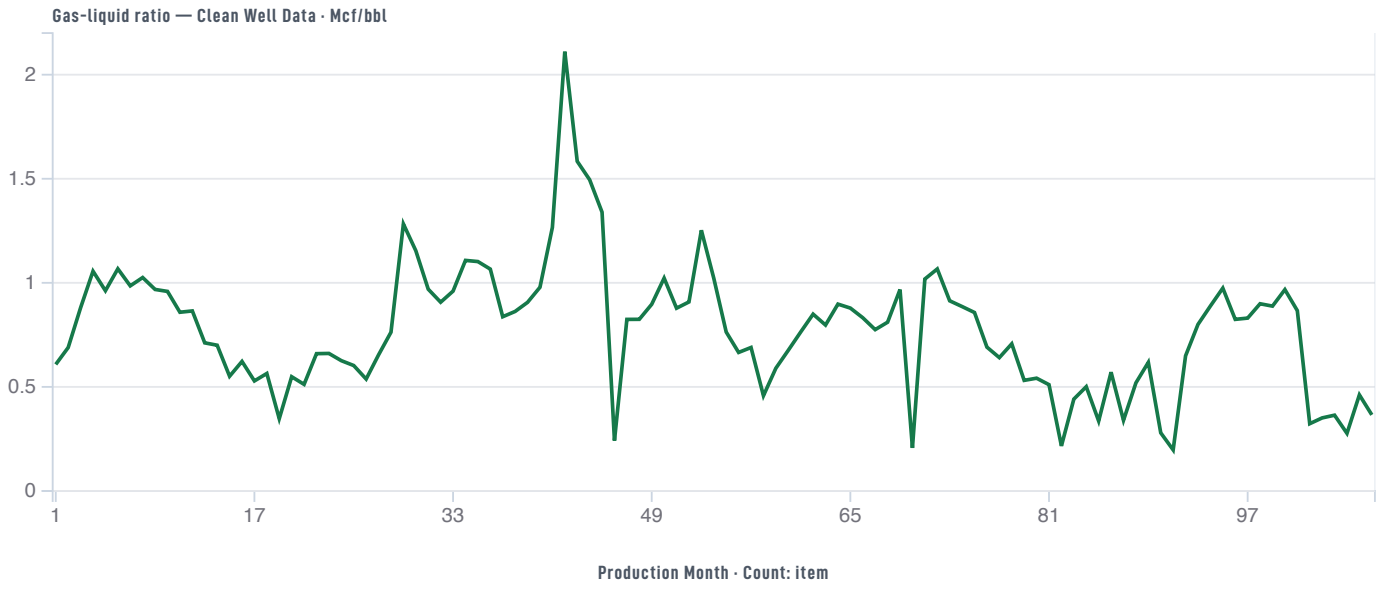
The useful outcome is therefore a precise description of the observed gas–oil–liquid relationship, followed by a targeted request for discriminating evidence. A gas breakthrough date is not reported from GOR alone.

Compare the gas producer-day rate, GOR and GLR on the same Production Month sequence. A GOR change can arise from a change in gas, oil or both; it alone does not identify gas entry or a breakthrough date.

Over Production Month 106→107, gas producer-day rate decreases from 118.84 to 87.6 Mcf/day. GOR decreases from 1.20629 to 0.96618 Mcf/bbl. GLR decreases from 0.46154 to 0.36561 Mcf/bbl. oil rate decreases from 98.52 to 90.67 bbl/day. liquid rate decreases from 257.48 to 239.6 bbl/day. These rate and ratio changes describe retained production observations; they do not identify gas breakthrough, pressure depletion or an operating cause.

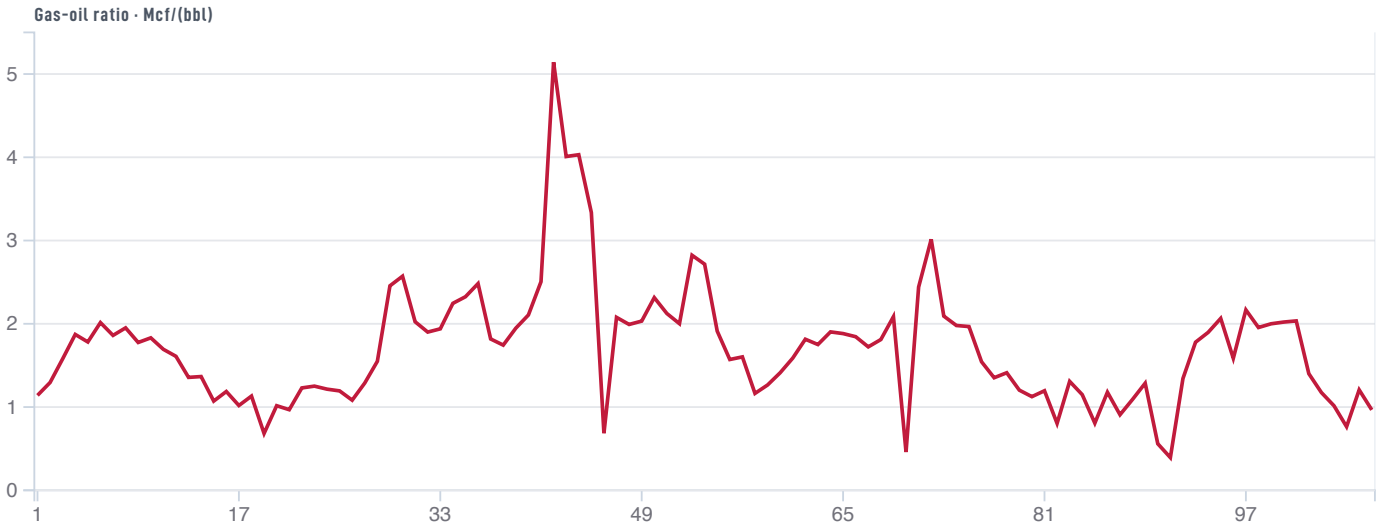
Retained cumulative gas through Production Month 107 is 235219 Mcf on the reported production basis.

Figure 8.4-3 — Gas–liquid ratio by Production Month



SERIES — Gas-liquid ratio — Clean Well Data · Mcf/bbl

Figure 8.4-1 — Gas–oil ratio · Clean Well Data



SERIES — Gas-oil ratio · Mcf/(bbl)

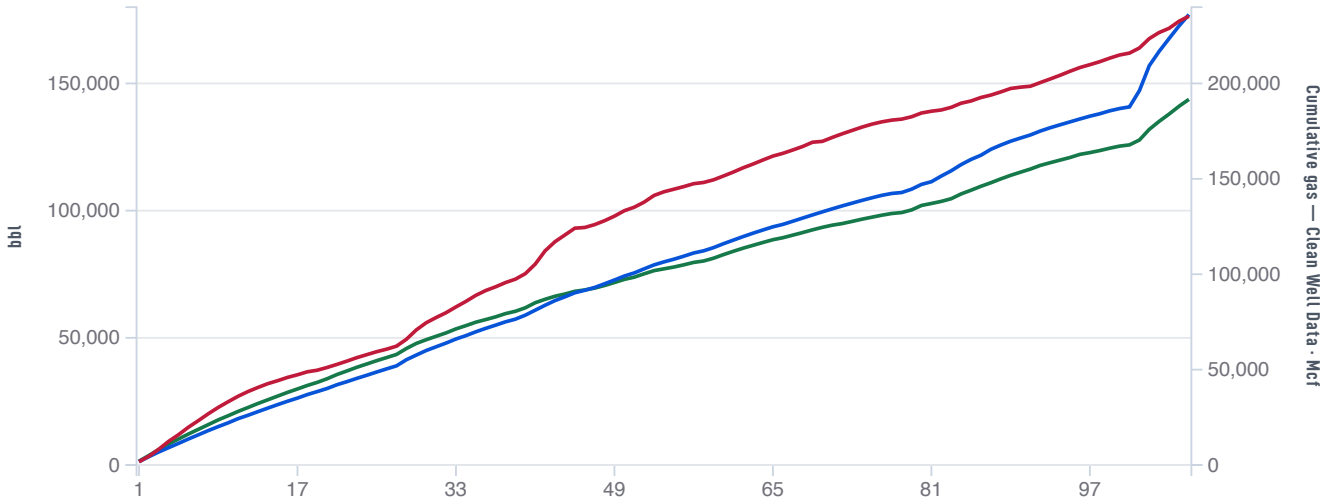
Figure 8.4-2 — GOR versus retained cumulative oil



SERIES — Gas-oil ratio · Mcf/(bbl)

8.5 THE SPECIFIED PROXY OFP MODEL

Figure 8.5-1 — Retained cumulative production used by the proxy model



SERIES

Cumulative oil — Clean Well Data · bbl

Cumulative water — Clean Well Data · bbl

Cumulative gas — Clean Well Data · Mcf

The Proxy OFP model transforms cumulative water and gas into proxy saturation coordinates and relative-permeability-like outputs. The exact expressions define a production-derived proxy transformation; they have not been established as a calibrated three-phase relative-permeability law. The ten configurable parameters must travel with every result. Their supplied values are a parameter set, not a universal calibration.

Supplied parameter set

The supplied values define the numerical Proxy OFP calculation in this chapter. PV and Bg are used as coefficients on the stated reporting basis. Their physical units and well-specific calibration are not established for this parameter set. The numerical curves describe the supplied transformation of production history, rather than measured reservoir saturations.

Using the exact source names, the first three outputs are

$$
\begin{aligned}
Sw_{proxy} &= Swc + \frac{CumulativeWater}{PV}, \\
Sg_{proxy} &= Sgc + \frac{CumulativeGas \times 1000 \times Bg}{PV}, \\
So_{proxy} &= \max(1 - Sw_{proxy} - Sg_{proxy}, 0).
\end{aligned}
$$

The normalised coordinates and complementary output are

$$
\begin{aligned}
Swn &= \frac{Sw_{proxy} - Swc}{1 - Swc - Soc}, \\
one_minus_swn &= 1 - Swn, \\
Son &= \max\left(\min\left(\frac{So_{proxy}}{1 - Swc - Soc}, 1\right), 0\right), \\
Sgn &= \max\left(\min\left(\frac{Sg_{proxy} - Sgc}{1 - Swc - Soc - Sgc}, 1\right), 0\right).
\end{aligned}
$$

The three proxy relative permeabilities are

$$
\begin{aligned}
krw &= krw_end\ Swn^{lambda_w}, \\
kro &= (1 - Swn)^{lambda_o}(1 - Sgn)^{lambda_g}, \\
krg &= krg_end\ Sgn^{lambda_g}.
\end{aligned}
$$

Son is retained because it is a specified output. It is**not** an input to any of these three permeability expressions. In particular, substitutingSon for an oil factor inkro would create a different model. The normalised coordinates are not three phase fractions constrained to sum to one.

The input coordinates are the numerical values of retained cumulative water reported in bbl and retained cumulative gas reported in Mcf. The calculation explicitly removes each reporting unit before applying the supplied coefficients:

$$
CumulativeWater = \frac{W_p}{1\,bbl}, \qquad CumulativeGas = \frac{G_p}{1\,Mcf}.
$$

The factor of 1000 in the supplied gas expression is applied once to the Mcf numerical value. No additional water or gas conversion is introduced. A different reporting unit would require an explicitly revised coefficient basis; the current curves cannot be interpreted as a physical reservoir volume balance without that calibration.

The source equations add cumulative production to baseline coordinates; they do not solve a spatial fluid inventory or a pressure/material-balance model. Their numerical outputs must retain the word**proxy**. Physical reservoir modelling separately accounts for component conservation, pressure/flow relations and saturation closure. [S4]

8.6 ADMISSIBLE DOMAIN, TRAJECTORY AND SENSITIVITY

The model must be readable at its limits, not only where it produces a smooth curve. Define

$$d_w = 1 - Swc - Soc, \qquad d_g = 1 - Swc - Soc - Sgc.$$

The operating domain requires positive PV, d_w and d_g, non-negative cumulative inputs, valid parameter values and a consistent volume/history basis. These checks determine whether the supplied expressions can be evaluated and interpreted; they do not change the expressions.

BecauseSwn is not clipped,

$$Swn = \frac{CumulativeWater}{PV\, d_w}.$$

If cumulative water exceeds $PV d_w$, then $1 - Swn < 0$. The supplied oil exponent is 3.2; the specified model does not authorise a negative-base extension of this fractional power. The calculation must report an out-of-domain result rather than apply an absolute value, clampSwn, or replace a failure with zero permeability. For the supplied parameter values, $d_w = 0.55$ and $PV d_w = 115{,}500$ on the cumulative-water numerical basis stated in Section 8.5. This is an algebraic boundary, not a water-breakthrough or reservoir-risk threshold.

The oil lower bound does not guarantee three-phase closure. An additional audit quantity is

$$c_{closure} = Sw_{proxy} + Sg_{proxy} + So_{proxy} - 1 = \max(Sw_{proxy} + Sg_{proxy} - 1, 0).$$

A positive value identifies loss of the phase-fraction interpretation. With the source set, the corresponding boundary is

$$CumulativeWater + 1000Bg\, CumulativeGas \le PV(1 - Swc - Sgc) = 157{,}500$$

on the reported cumulative-water and cumulative-gas numerical basis. No renormalisation is applied. A clippedSo_proxy of zero is not a measured absence of reservoir oil. Rows outside the approved interpretation domain remain auditable, but they are not silently connected into an admissible permeability trajectory.

Proxy output definitions

A central interpretation limitation follows directly from the equations. For fixed admissible parameters and non-decreasing non-negative cumulative inputs, the water and gas proxy coordinates cannot decrease;krw andkrg are non-decreasing, andkro is non-increasing within its admissible domain. These directions are partly imposed by construction. A fallingkro curve is therefore not independent evidence of worsening reservoir permeability. Likewise, agreement with WC/WOR/GOR is not an independent validation because those quantities share the underlying production inputs.

A permeability-versus-proxy-saturation plot is a view of this parameterised transformation. The water and gas branches can be inspected against their own normalised coordinates. The oil output depends on bothSwn andSgn; plotting it againstSo_proxy shows a history path, not a unique measured oil relative-permeability

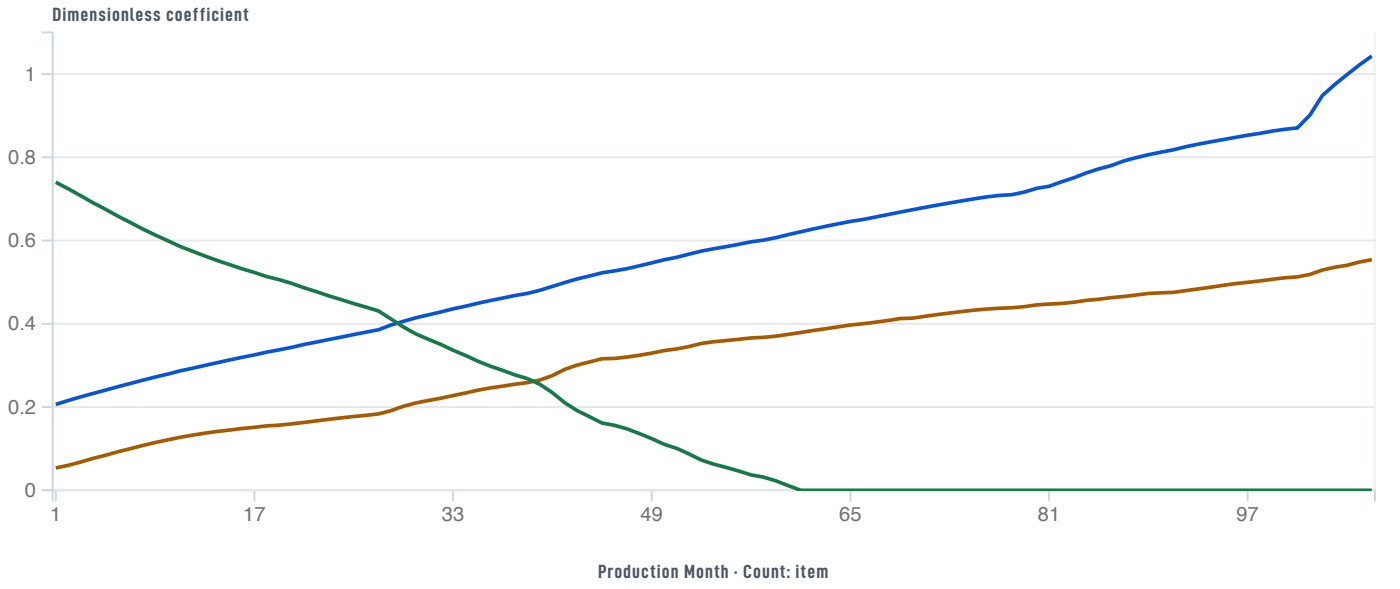
curve.

Parameter sensitivity must also be distinguished from measured uncertainty. Increasing PV reduces the incremental coordinates at fixed production; increasing Bg increases the gas contribution. Endpoints scale their associated branches, and exponents change curve shape. Saturation parameters alter both offsets and normalisation ranges. No confidence band or calibrated sensitivity range is provided by the source. Any later scenario comparison must state the complete parameter sets and hold the production-history basis constant.

Phase-coordinate closure is first lost at Production Month 61, where the closure excess is 3.595E-5. At Production Month 107, Sw_proxy = 1.04322, Sg_proxy = 0.55404, So_proxy = 0 and the closure excess is 0.59726. The latest coordinates cannot be interpreted as closing physical phase fractions. No clipping or renormalisation beyond the specified equations is used. Physical interpretation requires a confirmed PV/Bg volume convention and calibration to the retained history.

The oil-power base 1 − Swn first becomes negative at Production Month 83. kro is undefined for 25 retained observations; the first is Production Month 83 and the last is 107. At Production Month 107, krw = 1.48878 and krg = 0.65. Undefined kro values remain absent from the figures. These numerical outputs do not establish physical relative permeability, reservoir failure or absence of reservoir oil.

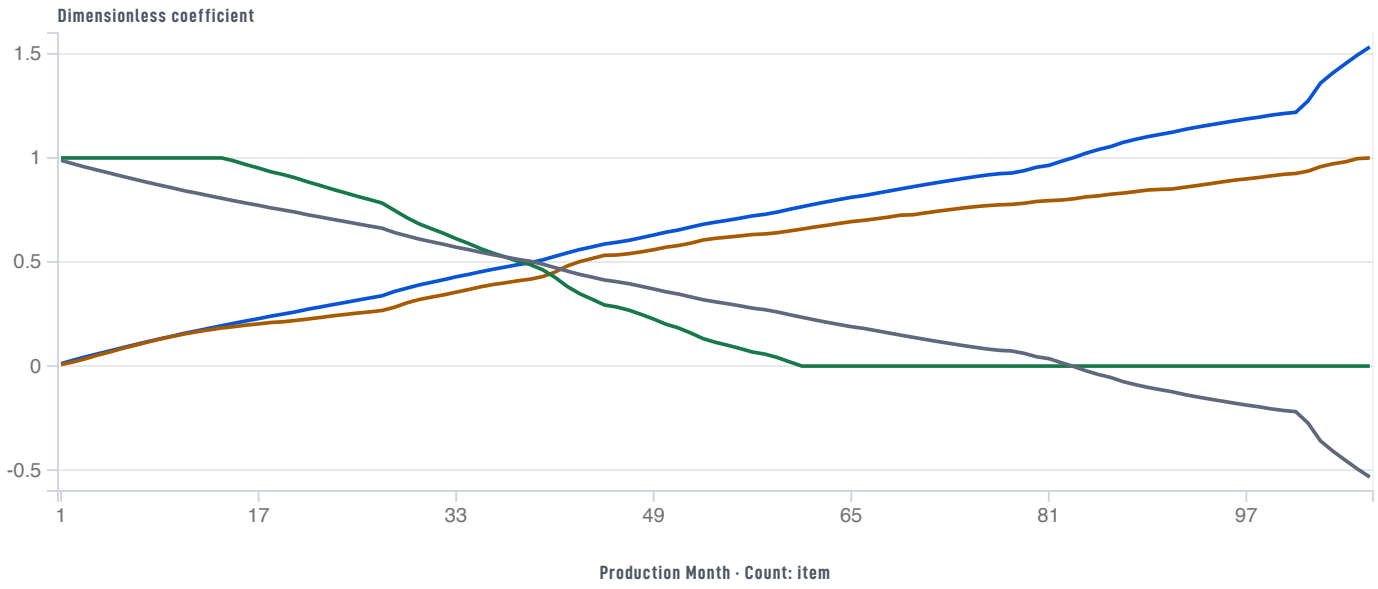
Figure 8.6-1 — Proxy OFP — Sw, Sg and So



SERIES

- Sw_proxy — numerical Proxy OFP · Dimensionless coefficient
- Sg_proxy — numerical Proxy OFP · Dimensionless coefficient
- So_proxy — numerical Proxy OFP · Dimensionless coefficient

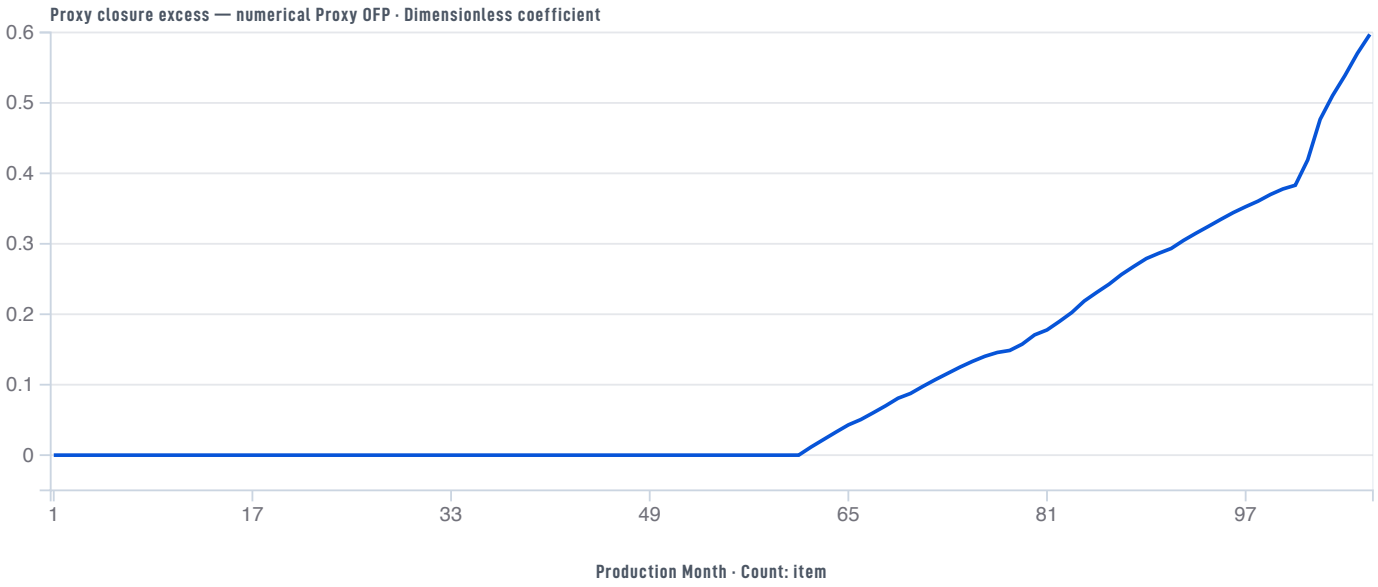
Figure 8.6-2 — Proxy OFP — normalised coordinates



SERIES

- Swn — numerical Proxy OFP · Dimensionless coefficient
- Sgn — numerical Proxy OFP · Dimensionless coefficient
- Son — numerical Proxy OFP · Dimensionless coefficient
- one_minus_swn — numerical Proxy OFP · Dimensionless coefficient

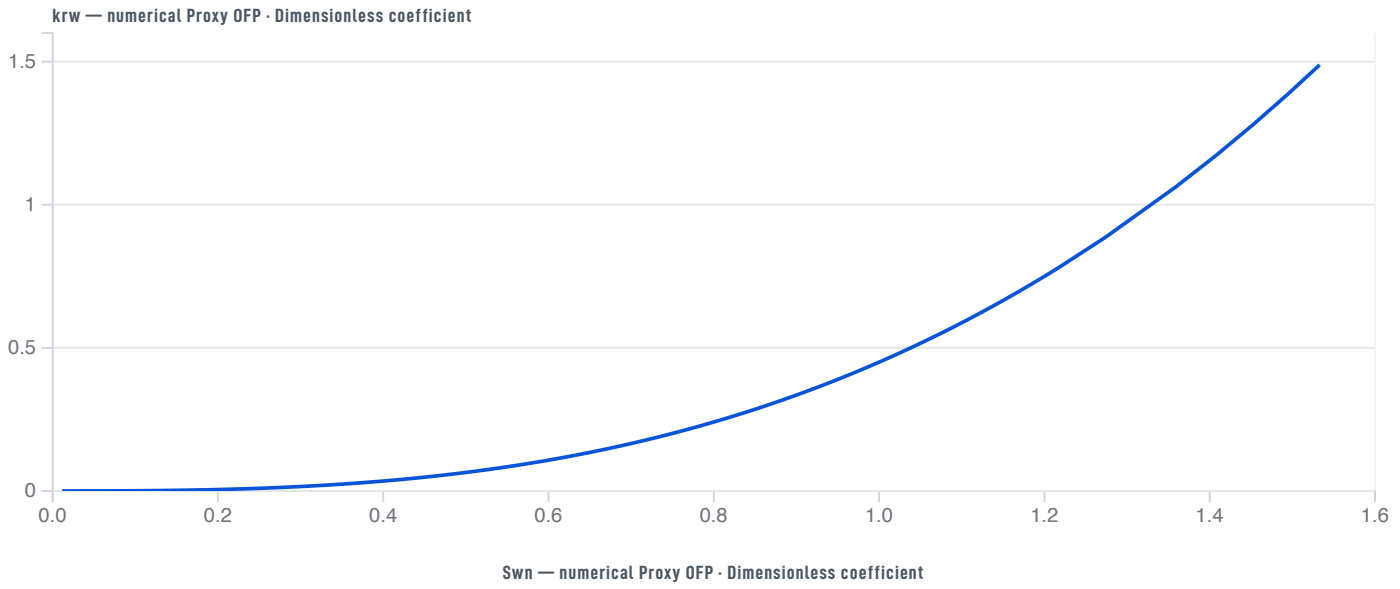
Figure 8.6-3 — Proxy OFP — coordinate sum minus one



SERIES

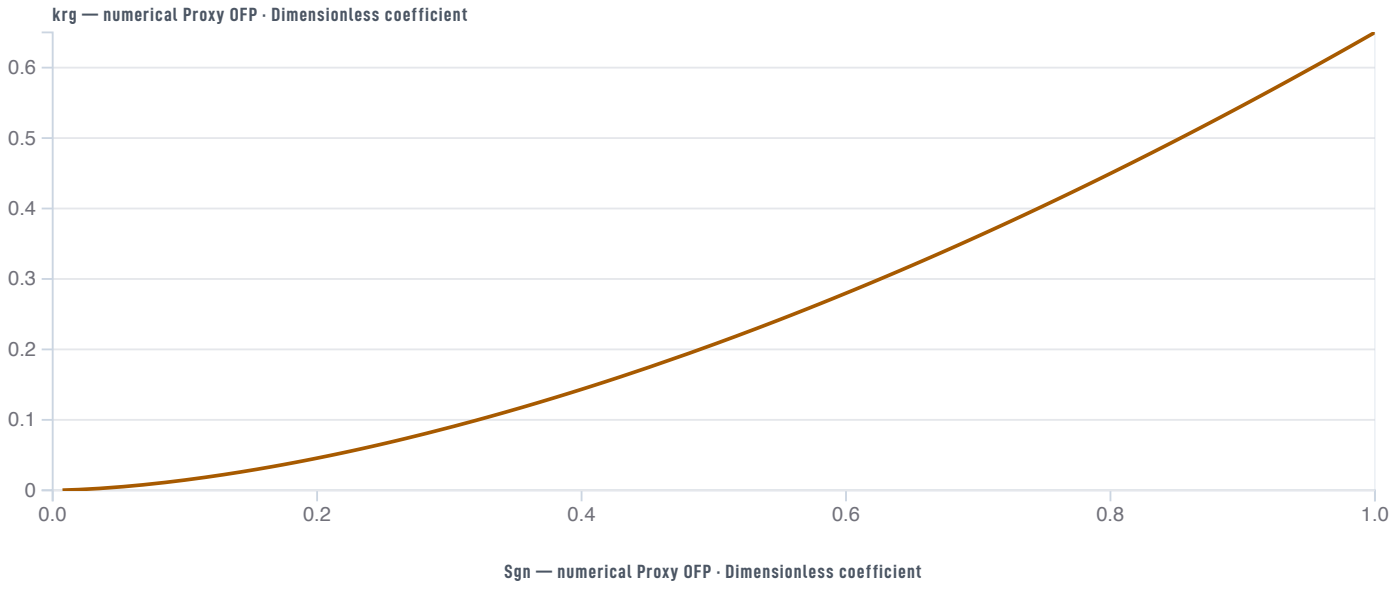
- Proxy closure excess — numerical Proxy OFP · Dimensionless coefficient

Figure 8.6-4 — Proxy OFP — krw versus Swn



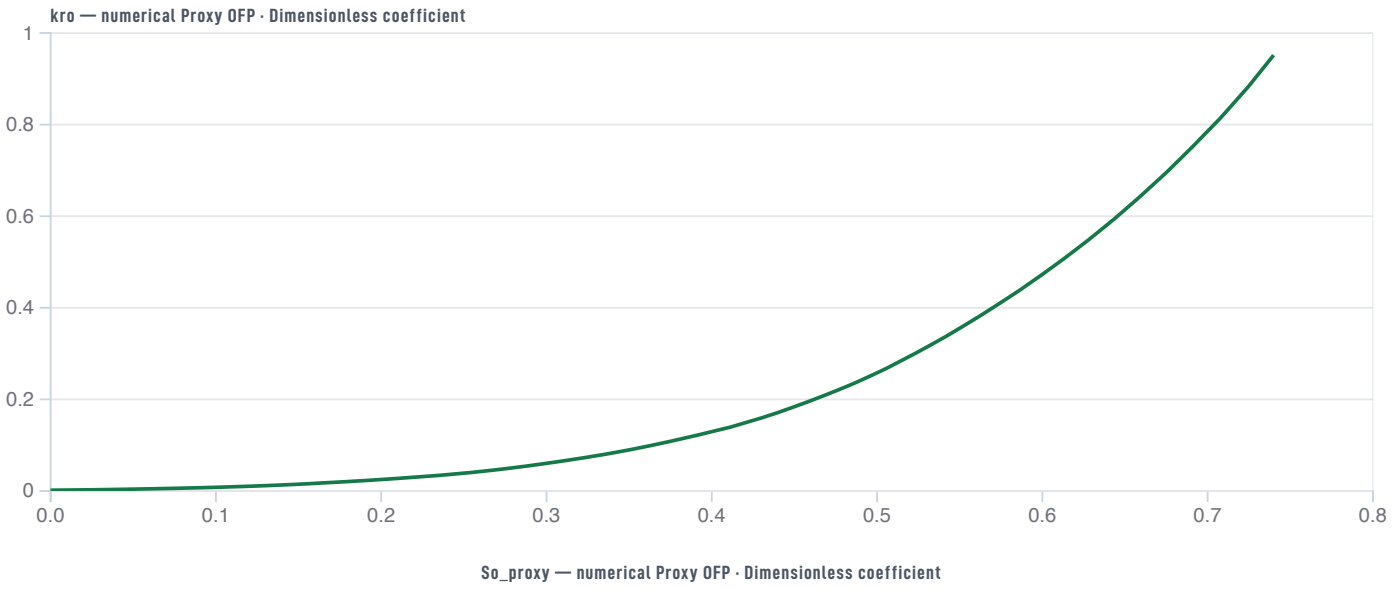
SERIES — krw — numerical Proxy OFP · Dimensionless coefficient

Figure 8.6-5 — Proxy OFP — krg versus Sgn



SERIES — krg — numerical Proxy OFP · Dimensionless coefficient

Figure 8.6-6 — Proxy OFP — kro versus So: retained history path



SERIES — kro — numerical Proxy OFP · Dimensionless coefficient

8.7 PHASE MOBILITY AND PRODUCTION DEGRADATION INDEX

Relative permeability is not mobility. Using $\mathcal{L}_\alpha$ to avoid confusion with the model's exponent names,

$$\mathcal{L}_\alpha = \frac{k_{r\alpha}}{\mu_\alpha},$$

where μ_α is phase viscosity. This is the conventional mobility definition; pressure/composition-dependent viscosities and the distinction between phase and reported surface volumes matter to its application. Proxy-based values would remain proxy mobilities, not measured rock properties. [S4]

A proportional water–oil indicator is

$$M_{ow}(t) \propto \frac{WOR(t)\,\mu_o/\mu_w}{1 - f_w(t)}.$$

The source does not specify viscosities, the proportionality constant or the relationship between f_w and observed WC. It therefore does not define a reproducible numerical M_ow result for the present chapter. Equating f_w with surface WC and setting the constant to one would be additional assumptions, not harmless substitutions. Under those assumptions and a constant viscosity ratio, the indicator would scale as $WOR(1 + WOR)$: an amplification of the same ratio, not an independent estimate of mobility.

Phase mobility requires viscosity for each phase at matched pressure, temperature and composition. The M_ow expression also requires a defined proportionality constant and fractional-flow convention.

The Production Degradation Index is defined as:

$$PDI(t) = \frac{q_{liq}(t)}{q_{liq,0}\,[1 - WC(t)]}.$$

For this history, q_liq,0 is the observed liquid producer-day rate in Production Month 1 of Clean Well Data. This reference is fixed across the retained sequence. It describes comparison with the first retained observation; no stabilised operating condition is assumed for that month. The reference rate must be positive and the current water cut must be below one for a finite PDI.

For a single-month reference at t_0, the equation is not generally normalised to one at the baseline:

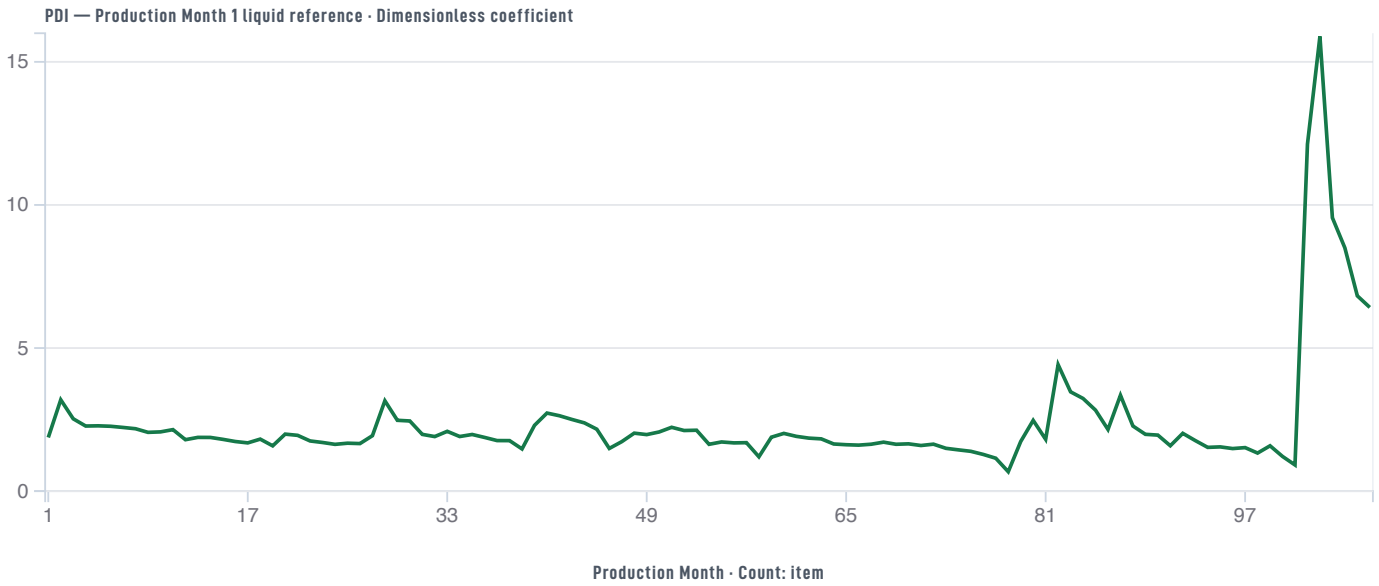
$$PDI(t_0) = \frac{1}{1 - WC(t_0)}.$$

Moreover, at fixed liquid rate and baseline, PDI rises as WC rises. It may also be written as $q_{liq}^2/(q_{liq,0}q_o)$ where the constituent rates are valid. A larger value therefore cannot be labelled automatically as better productivity or greater degradation. This chapter reports the defined indicator and its drivers without that directional judgement. A normalisation to one would require an explicitly revised equation. PDI is not a pressure-normalised productivity or skin measurement.

The PDI curve uses this same Production Month 1 reference for every retained observation. It combines changes in total liquid rate and water cut; increasing PDI alone does not establish worsening reservoir productivity.

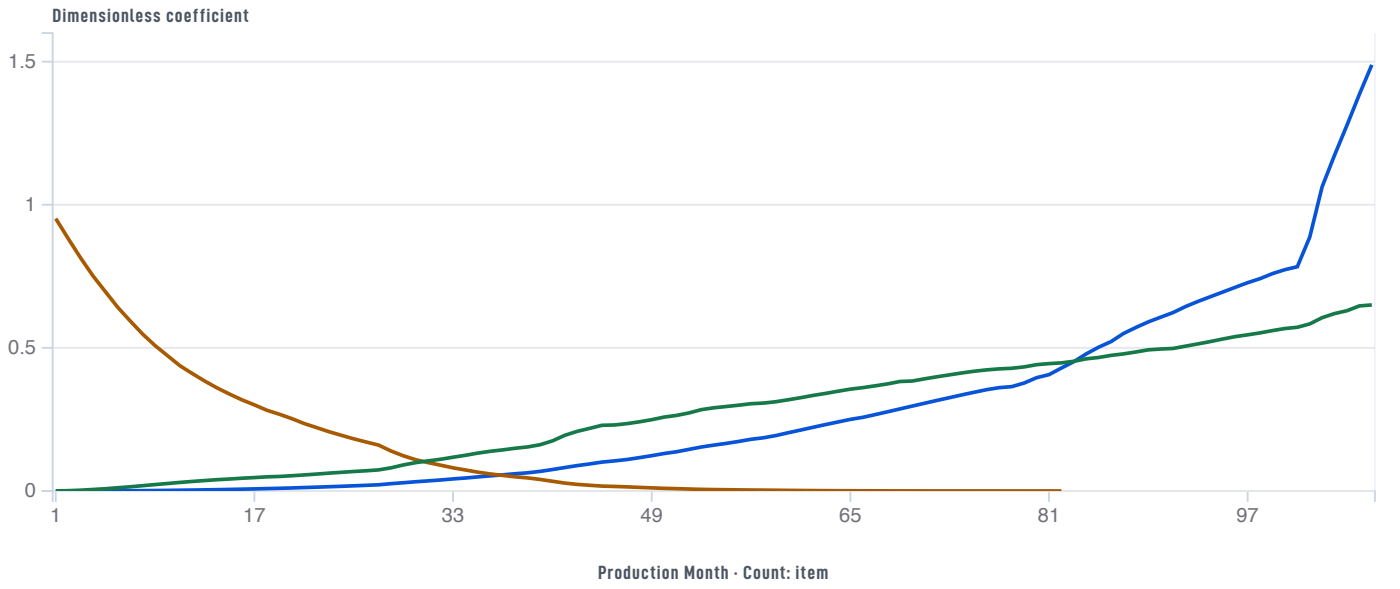
The fixed liquid-rate reference is 98.62069 bbl/day, observed in Production Month 1. PDI is 1.87541 in that month and 6.42034 at Production Month 107, where liquid rate is 239.6 bbl/day and WC is 62.16%. The indicator reflects liquid rate and water share. It does not establish pressure-normalised productivity loss, incremental recovery or an intervention benefit.

Figure 8.7-1 — PDI with the Production Month 1 liquid-rate reference



SERIES — PDI — Production Month 1 liquid reference · Dimensionless coefficient

Figure 8.7-2 — Proxy OFP — krw, kro and krg



SERIES

- krw — numerical Proxy OFP · Dimensionless coefficient
- kro — numerical Proxy OFP · Dimensionless coefficient
- krg — numerical Proxy OFP · Dimensionless coefficient

8.8 OIL–LIQUID DECLINE ASYMMETRY

The fractional decline definition expressed in the Production Month coordinate is

$$D_\alpha(m) = -\frac{1}{q_\alpha(m)}\frac{dq_\alpha(m)}{dm}.$$

For positive monthly producer-day rates, the operational estimate is the log-rate change over a retained Production Month interval:

$$\widehat{D}_{\alpha,i} = -\frac{\ln(q_{\alpha,i}/q_{\alpha,i-1})}{m_i - m_{i-1}}.$$

Its unit is production-month $^{-1}$. It is an interval-average logarithmic decline, stored and plotted at the interval-ending Production Month, not an instantaneous pressure-corrected reservoir decline. Positive values denote decreasing rate; negative values denote increasing rate. Production Month is the common coordinate. The existing Relative Rate Change is dimensionless and uses a different definition; it is not substituted for D.

For the same valid interval with positive oil and liquid declines, define the Decline Asymmetry Factor as

$$DAF_i = \frac{\widehat{D}_{o,i}}{\widehat{D}_{liq,i}}.$$

A ratio above one means that oil declined faster than total liquid over that interval under this definition. It does not identify why. A zero liquid decline makes the ratio undefined; a negative or non-declining component is reported through the separate signed declines rather than a misleading “degradation factor.” Very small positive liquid decline makes the ratio unstable, so both inputs must accompany it. No arbitrary significance threshold is imposed.

This diagnostic is not independent of water cut. From $q_o = q_{liq}(1 - WC)$,

$$D_o - D_{liq} = \frac{1}{1 - WC}\frac{dWC}{dm},$$

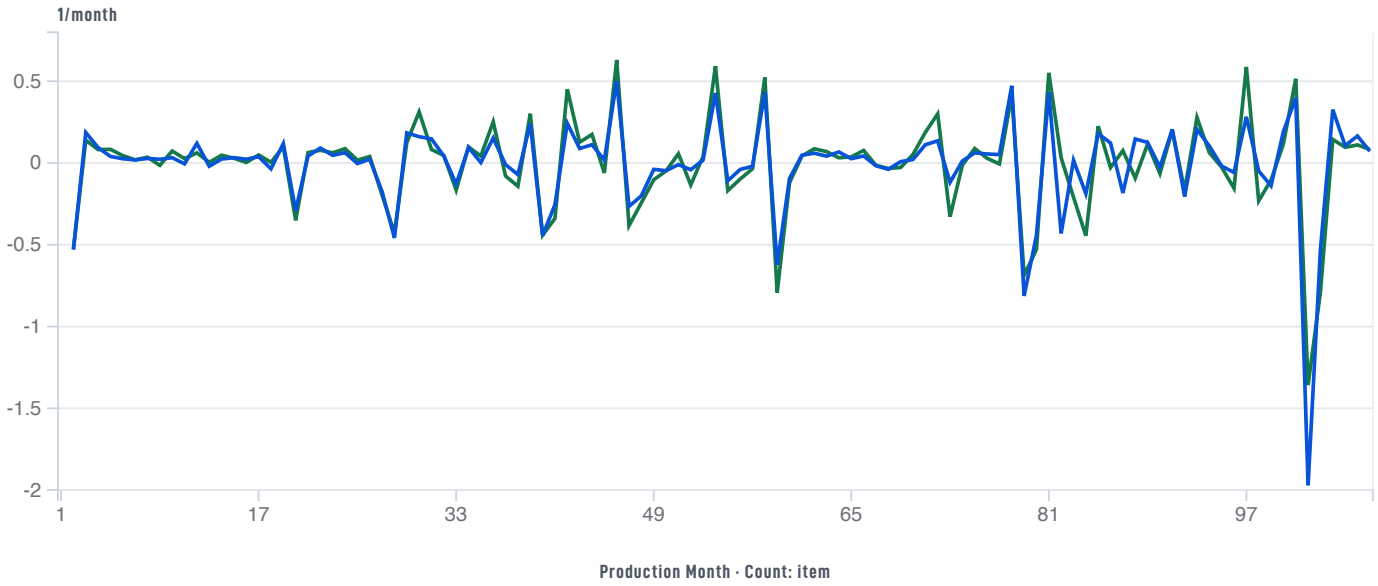
with the interval equivalent

$$\widehat{D}_o - \widehat{D}_{liq} = -\frac{\ln[(1 - WC_i)/(1 - WC_{i-1})]}{\Delta m_i}.$$

Thus, disagreement between oil and liquid decline can describe the same phase-composition shift already expressed by WC. It is not an additional independent vote for a reservoir mechanism.

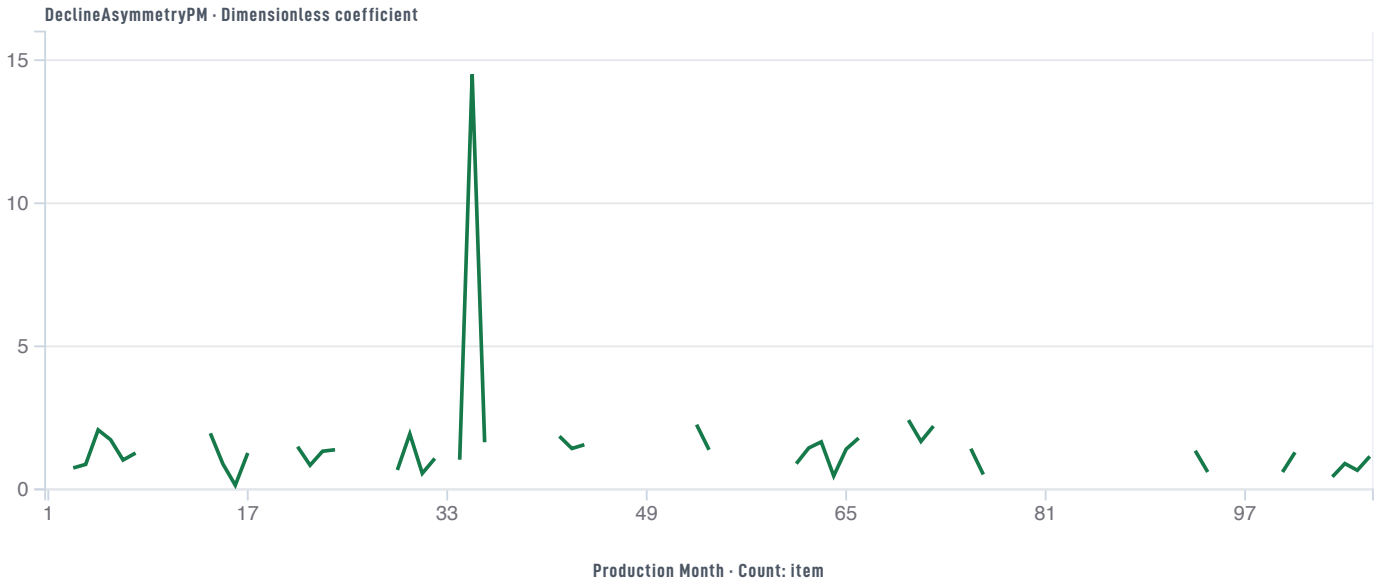
Over Production Month 106→107, oil rate decreases from 98.52 to 90.67 bbl/day. liquid rate decreases from 257.48 to 239.6 bbl/day. The signed interval log declines are D_o = 0.08303 and D_liq = 0.07199 per Production Month. DAF = 1.15342. Oil declines faster than liquid over this interval. WC increases from 61.74% to 62.16%. Across the retained history, 58 intervals have positive oil and liquid declines and a defined DAF under the stated condition.

Figure 8.8-1 — Signed log decline by Production Month



SERIES — OilLogDeclinePM · 1/month — LiquidLogDeclinePM · 1/month

Figure 8.8-2 — Decline Asymmetry Factor by Production Month



SERIES — DeclineAsymmetryPM · Dimensionless coefficient

8.9 DERIVATIVES, ACCELERATION AND CHANGE DETECTION

Derivatives make changes visible but must preserve the measurement and time basis. For a valid ratio X, a signed first difference is

$$\widehat{X}'_i = \frac{X_i - X_{i-1}}{m_i - m_{i-1}}.$$

WOR derivatives have units production-month $^{-1}$; GOR derivatives have units (Mcf/bbl)/production month. Negative values are informative and are not replaced with absolute values. Logarithmic views can display only strictly positive coordinates; omitted zero/negative observations must remain available in the linear view or table. A time-origin shift changes a log-time slope and must never be hidden.

For neighbouring valid decline estimates, the stored decline change is the backward difference at the ending Production Month of the three-observation window:

$$A_{\alpha,i} = \frac{\widehat{D}_{\alpha,i} - \widehat{D}_{\alpha,i-1}}{\Delta m}, \qquad \Delta m = 1.$$

Its unit is production-month squared in the denominator. Positive A means that the interval decline estimate increased; it does not directly identify a new flow regime. Rate curvature is a different quantity. For the same three adjacent retained observations, define

$$C_{\alpha,i} = \frac{q_{\alpha,i} - 2q_{\alpha,i-1} + q_{\alpha,i-2}}{(\Delta m)^2}, \qquad \Delta m = 1.$$

Rate curvature retains the producer-day rate divided by production months squared. C is stored and plotted at the window-ending Production Month m_i; the central-difference estimate describes the middle observation m_(i−1). Decline, ratio differences, DAF and decline change are also displayed at the interval or window ending m_i. For a smooth exponential decline, rate curvature can be positive while fractional-decline change is zero. These quantities must not share an ambiguous acceleration label.

Interval diagnostics — required observations

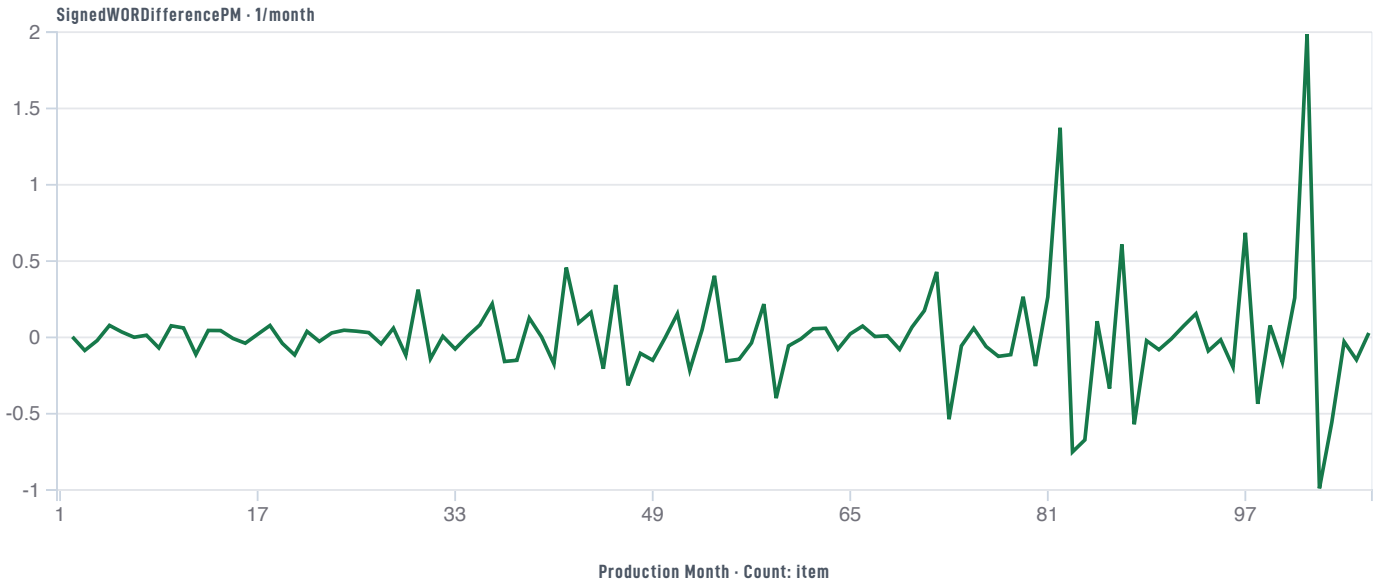
The signed differences and log declines describe adjacent retained observations. Changes in decline and rate curvature use three adjacent observations. All are plotted at the ending Production Month of their interval or window.

The baseline calculation uses adjacent retained Production Month observations without smoothing or interpolation. Calendar omissions do not create extra steps or automatically invalidate a pair. Missing required values, invalid denominators or an independently established operating boundary must be disclosed. A later smoothing method requires its own versioned window, boundary treatment and effect on timing. Short records or unstable operating conditions can limit interpretation even where a numerical difference exists; a numerical change alone does not establish a change point or mechanism.

At the interval ending in Production Month 107, the signed WOR difference is 0.02903 per Production Month and the signed GOR difference is -0.24011 (Mcf/bbl) per Production Month. The three-observation window ending there gives changes in oil and liquid log decline of -0.02758 and -0.0932 per Production

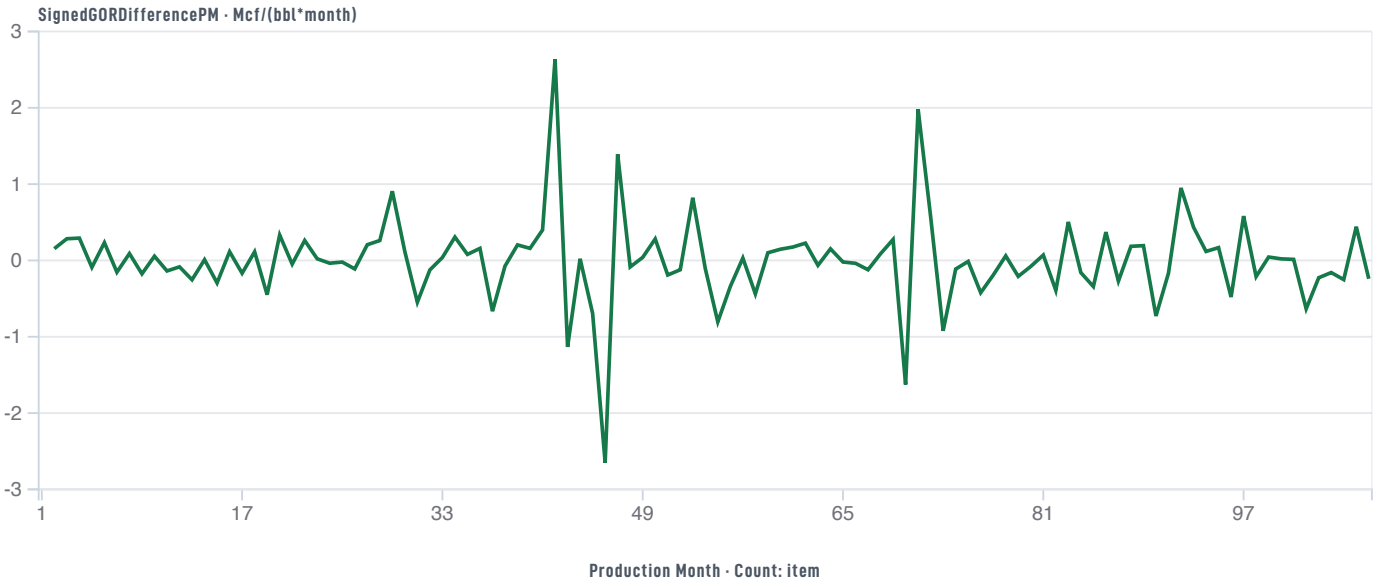
Month squared. The corresponding rate curvatures are 3.67287 and 28.36303 (bbl/producing day) per Production Month squared. Decline change and rate curvature describe different quantities. Their signs alone do not identify a reservoir mechanism.

Figure 8.9-1 — Signed WOR first difference by Production Month



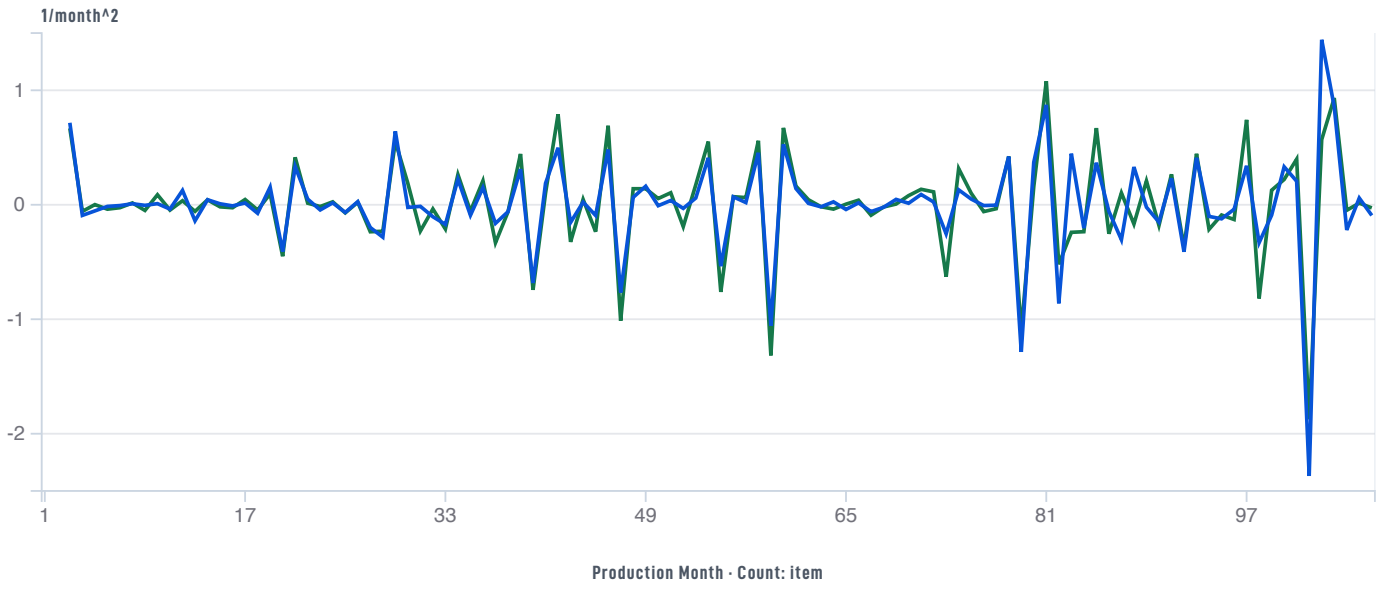
SERIES — SignedWORDifferencePM · 1/month

Figure 8.9-2 — Signed GOR first difference by Production Month



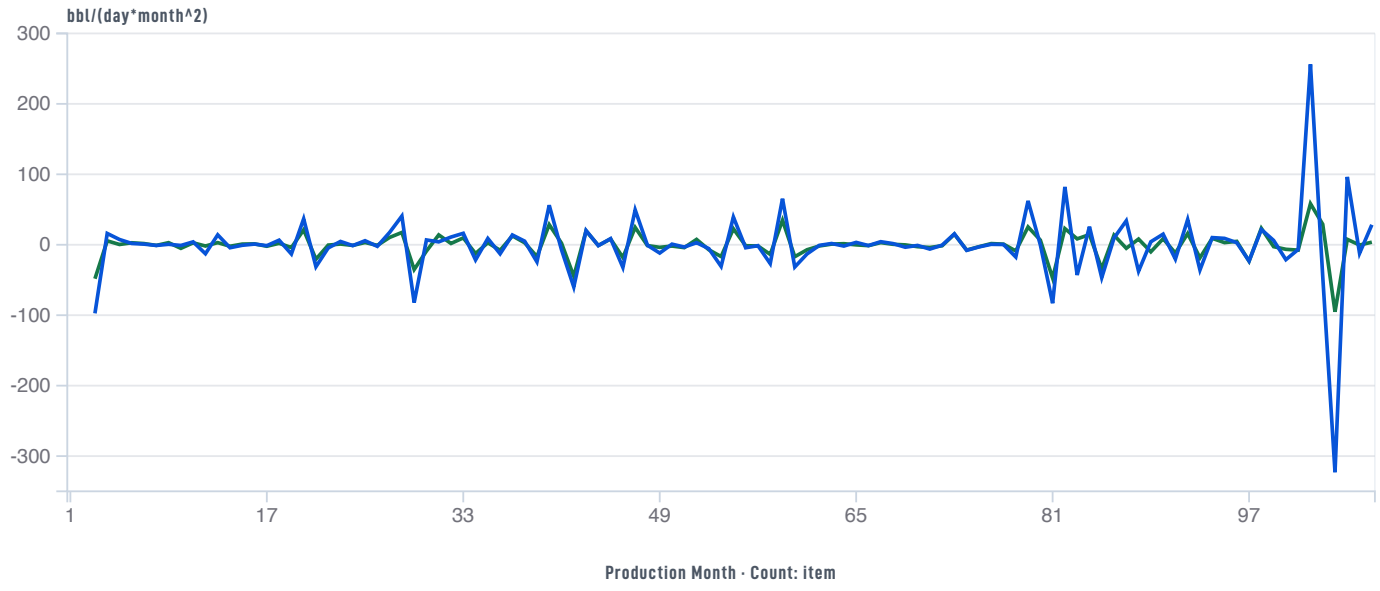
SERIES — SignedGORDifferencePM · Mcf/(bbl*month)

Figure 8.9-3 — Change in interval decline by Production Month



SERIES — OilDeclineChangePM · 1/month^2 — LiquidDeclineChangePM · 1/month^2

Figure 8.9-4 — Rate curvature; three-observation window ending at Production Month



SERIES — OilRateCurvaturePM · bbl/(day*month^2) — LiquidRateCurvaturePM · bbl/(day*month^2)

8.10 HETEROGENEITY AND ANISOTROPY: HYPOTHESES, NOT RECONSTRUCTED GEOMETRY

Repeated phase-response contrasts across comparable operating intervals may motivate hypotheses about uneven contribution, preferential paths, compartmentalisation or changing support. Differences among independently documented neighbouring wells can provide additional context, but such wells are not supplied merely by observing one well's time series. These interpretations are qualitative and non-unique.

A single production history cannot supply the orientation or magnitude of an anisotropy tensor, the geometry of a barrier, or a fracture azimuth. Nor does an apparent change in proxy permeability reconstruct a spatial permeability distribution. The evidence review should state which observation motivates the hypothesis and what independent test could distinguish it from operational and fluid-property explanations.

Potential corroboration includes appropriately matched pressure/interference information, production logging, completion and intervention records, geological interpretation or other independently sourced observations. Their absence is recorded explicitly. These are investigation requirements, not claims that the tests have been performed or that any particular test will prove a preferred explanation.

8.11 CONFIDENCE AND EVIDENCE QUALITY

A reproducible composite confidence score requires specified weights and calibration. No numerical confidence percentage or risk class is assigned here. Instead, each material interpretation is accompanied by a transparent evidence record.

Evidence needed to distinguish competing explanations

Absence of a record here does not establish absence of measurements in the organisation.

The record distinguishes the observation, its source and interval, the proxy contribution if any, the hypothesis, competing explanations, independent supporting or contradicting information, remaining gaps and the proposed next check. Repeated transformations of the same monthly volumes are recorded as related evidence, not independent confirmations.

Confidence is limited by what is missing as well as what agrees: unobserved early production, uncertain volume conditions, changing operations, weak denominators, unspecified physical units and calibration of the proxy coefficients and unavailable independent reservoir measurements each constrain a different part of the argument. An apparent contradiction is retained for investigation; it is not removed to make the narrative consistent. Any expert conclusion should identify its author, date and supporting records.

Evidence limitation. No numerical confidence score is assigned. Production-derived ratios, derivatives and proxy outputs share underlying inputs; they must not be counted as independent confirmations.

8.12 ENGINEERING SYNTHESIS AND NEXT ACTION

The selected well is described by 107 retained Clean Well Data observations. Production Month is the common coordinate; rates use producing days. The endpoint comparison summarises the reported phase rates and derived ratios. It does not imply a continuous trend or complete lifetime history.

The latest retained interval, Production Month 106→107, shows these phase-rate changes: oil decreases, water decreases, liquid decreases and gas decreases. D_o = 0.08303 and D_{liq} = 0.07199 per Production Month. DAF = 1.15342. Oil declines faster than liquid. WC increases from 61.74% to 62.16%; GOR decreases from 1.20629 to 0.96618 Mcf/bbl. These simultaneous phase-production observations do not establish which reservoir or operating mechanism caused them.

Phase-coordinate closure is first lost at Production Month 61, where the closure excess is 3.595E-5. At Production Month 107, Sw_{proxy} = 1.04322, Sg_{proxy} = 0.55404, So_{proxy} = 0 and the closure excess is 0.59726. The latest coordinates cannot be interpreted as closing physical phase fractions. No clipping or renormalisation beyond the specified equations is used. Physical interpretation requires a confirmed PV/Bg volume convention and calibration to the retained history. The oil-power base 1 − Swn first becomes negative at Production Month 83. kro is undefined for 25 retained observations; the first is Production Month 83 and the last is 107. At Production Month 107, krw = 1.48878 and krg = 0.65. Undefined kro values remain absent from the figures. These numerical outputs do not establish physical relative permeability, reservoir failure or absence of reservoir oil.

The fixed liquid-rate reference is 98.62069 bbl/day, observed in Production Month 1. PDI is 1.87541 in that month and 6.42034 at Production Month 107, where liquid rate is 239.6 bbl/day and WC is 62.16%. The indicator reflects liquid rate and water share. It does not establish pressure-normalised productivity loss, incremental recovery or an intervention benefit.

The immediate engineering priority is to explain the phase-rate observations over Production Month 106→107 using producing-day reporting, lift settings, intervention records, pressure history and PVT.

Physical interpretation of the Proxy OFP curves also requires a confirmed PV/Bg volume convention and a parameter set calibrated to the relevant history. Phase mobility additionally requires matched phase viscosities; M_{ow} requires its proportionality and fractional-flow definitions. Until those inputs are established, the production observations support description and comparison, while treatment selection remains unsupported.

Calculation basis

The calculations use the same retained Clean Well Data observations as the phase-rate and cumulative-production figures. Rates are monthly production volumes divided by positive producing days.

Production Month is the ordinal position within the retained production history. Log declines, signed differences, decline change and rate curvature use the definitions in Sections 8.8–8.9. These indicators share production inputs and do not provide independent evidence of a reservoir mechanism.

Cumulative production covers the retained history. The Proxy OFP equations and parameter values are stated in this chapter. Physical interpretation requires confirmed PV/Bg volume conventions, calibration to the relevant history and evaluation of the model-domain limitations.

Displayed values are rounded; the calculation table retains the numerical results.

Scientific references

These sources support the physical definitions and limits of diagnostic interpretation. They do not validate the project-specific Proxy OFP equations, their supplied parameters or a well-specific reservoir mechanism. Chan is cited for historical origin only; its complete publisher text was unavailable in the source review.

1. [S1] Chan, K. S. (1995). Water Control Diagnostic Plots. SPE-30775-MS. Historical origin; no slope classifier reproduced. Source
2. [S2] Yortsos, Y. C., Choi, Y., Yang, Z., and Shah, P. C. (1999). Analysis and Interpretation of Water/Oil Ratio in Waterfloods. SPE Journal, 4(4), 413–424. Author copy reviewed. Source
3. [S3] Seright, R. S., et al. (1998). Improved methods for water shutoff. DOE/PC/91008--14. Executive Summary, Water/Oil Ratio Diagnostic Plots. Source
4. [S4] Rasmussen, A. F., et al. (2019). The Open Porous Media Flow Reservoir Simulator. Sections 2.1 and 2.1.5. Source